NW Natural®

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August 29, 2025 NWN WUTC Advice No. 25-03

VIA ELECTRONIC FILING

Jeff Killip, Executive Director and Secretary
Washington Utilities and Transportation Commission
621 Woodland Square Loop SE
Lacey, Washington 98503

Re: UG-250610 – General Rate Increase; Tariff WN U-6, Natural Gas Service

Dear Mr. Killip:

Pursuant to RCW 80.28.050 and 80.28.060 and in accordance with WAC 480-07-510, Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company"), files herewith revisions to its Tariff WN U-6 to apply a general rate increase. In compliance with RCW 80.28.425(1), the Company is proposing a multi-year rate plan, which would begin with new rates effective August 1, 2026, and include rate increases occurring on August 1, 2027, and August 1, 2028.

The following proposed Tariff revisions associated with Year One of the multi-year rate plan listed in the table below have an issue date of August 29, 2025, and are stated to become effective with service on and after September 30, 2025. However, the Company requests that the tariffs be suspended with an effective date of August 1, 2026. NW Natural agrees to waive a suspension hearing and requests that the Commission immediately issue an order suspending the filed tariff revisions included in this filing and promptly set the matter for hearing, including the establishment of a prehearing conference, at the earliest possible date in accordance with WAC 480-07-440(1)(a).

Rate Year One Tariff Sheets:

TABLE OF TARIFF SHEET REVISIONS – Rate Year One		
PROPOSED	**CANCELS**	**TITLE**
Thirty-Sixth Revision of Sheet 101.1	Thirty-Fifth Revision of Sheet 101.1	Schedule 1 "General Sales Service"
Thirty-Seventh Revision of Sheet 102.1	Thirty-Sixth Revision of Sheet 102.1	Schedule 2 "Residential Sales Service"
Twenty-Fourth Revision of Sheet 103.3	Twenty-Third Revision of Sheet 103.3	Schedule 3 "Basic Firm Sales Service – Non-Residential (continued)"
Sixth Revision of Sheet 110.1	Fifth Revision of Sheet 110.1	Schedule 10 "Changes for Special Metering Equipment, Rental Meters and Metering Services"

TABLE OF TARIFF SHEET REVISIONS – Rate Year One		
PROPOSED	**CANCELS**	**TITLE**
Fourth Revision of Sheet 110.2	Third Revision of Sheet 110.2	Schedule 10 "Changes for Special Metering Equipment, Rental Meters and Metering Services (continued)"
Thirty-Sixth Revision of Sheet 127.1	Thirty-Fifth Revision of Sheet 127.1	Schedule 27 "Residential Heating Dry-Out Service"
Twenty-Second Revision of Sheet 141.9	Twenty-First Revision of Sheet 141.9	Schedule 41 "Non-Residential Sales and Transportation Service (continued)"
Seventeenth Revision of Sheet 141.10	Sixteenth Revision of Sheet 141.10	Schedule 41 "Non-Residential Sales and Transportation Service (continued)"
Twenty-Third Revision of Sheet 142.10	Twenty-Second Revision of Sheet 142.10	Schedule 42 "Large Volume Non-Residential Sales and Transportation Service (continued)"
Eighteenth Revision of Sheet 142.10.1	Seventeenth Revision of Sheet 142.10.1	Schedule 42 "Large Volume Non-Residential Sales and Transportation Service (continued)"
Twenty-Third Revision of Sheet 142.11	Twenty-Second Revision of Sheet 142.11	Schedule 42 "Large Volume Non-Residential Sales and Transportation Service (continued)"
Eighth Revision of Sheet 142.12	Seventh Revision of Sheet 142.12	Schedule 42 "Large Volume Non-Residential Sales and Transportation Service (continued)"
Twenty-Second Revision of Sheet 143.6	Twenty-First Revision of Sheet 143.6	Schedule 43 "High Volume Non-Residential Firm and Interruptible Transportation Service (continued)"
Thirteenth Revision of Sheet 200.1	Twelfth Revision of Sheet 200.1	Schedule 200 "Summary of Adjustments"
Ninth Revision of Sheet 200.2	Eighth Revision of Sheet 200.2	Schedule 200 "Summary of Adjustments (continued)"
Original Sheet 200.3	N/A	Schedule 200 "Summary of Adjustments (continued)"
Eighth Revision of Sheet 207.1	Seventh Revision of Sheet 207.1	Schedule 207 "General Rate Adjustment"
Eighth Revision of Sheet 207.2	Seventh Revision of Sheet 207.2	Schedule 207 "General Rate Adjustment (continued)"

TABLE OF TARIFF SHEET REVISIONS – Rate Year One		
PROPOSED	**CANCELS**	**TITLE**
Third Revision of Sheet 207.3	Second Revision of Sheet 207.3	Schedule 207 "General Rate Adjustment (continued)"
First Revision of Sheet 221.1	Original Sheet 221.1	Schedule 221 "Rate Adjustment for Updated Depreciation Rates"
Original Sheet 235.1	N/A	Schedule 235 "Temporary Adjustments to Rates for COVID-19 Public Health Emergency"
Original Sheet 236.1	N/A	Schedule 236 "Temporary Adjustments to Rates for Meter Modernization Program"
Original Sheet 237.1	N/A	Schedule 237 "Temporary Adjustments to Rates for TSA Operations and Maintenance Costs"
Original Sheet 238.1	N/A	Schedule 238 "Adjustments to Rates for Provisional Capital Adjustment"
Fifth Revision of Sheet J.1	Fourth Revision of Sheet J.1	Schedule J "Gas Residential Energy Assistance Tariff (GREAT)"

The following proposed Tariff revision associated with Year Two of the multi-year rate plan listed in the table below has an issue date of August 29, 2025, and is stated to become effective with service on and after August 1, 2027:

Rate Year Two Tariff Sheets:

TABLE OF TARIFF SHEET REVISIONS – Rate Year Two		
PROPOSED	**CANCELS**	**TITLE**
Thirty-Seventh Revision of Sheet 101.1	Thirty-Sixth Revision of Sheet 101.1	Schedule 1 "General Sales Service"
Thirty-Eighth Revision of Sheet 102.1	Thirty-Seventh Revision of Sheet 102.1	Schedule 2 "Residential Sales Service"
Twenty-Fifth Revision of Sheet 103.3	Twenty-Fourth Revision of Sheet 103.3	Schedule 3 "Basic Firm Sales Service – Non-Residential (continued)"
Fifth Revision of Sheet 110.2	Fourth Revision of Sheet 110.2	Schedule 10 "Changes for Special Metering Equipment, Rental Meters and Metering Services (continued)"
Thirty-Seventh Revision of Sheet 127.1	Thirty-Sixth Revision of Sheet 127.1	Schedule 27 "Residential Heating Dry-Out Service"

TABLE OF TARIFF SHEET REVISIONS – Rate Year Two		
PROPOSED	**CANCELS**	**TITLE**
Twenty-Third Revision of Sheet 141.9	Twenty-Second Revision of Sheet 141.9	Schedule 41 "Non-Residential Sales and Transportation Service (continued)"
Eighteenth Revision of Sheet 141.10	Seventeenth Revision of Sheet 141.10	Schedule 41 "Non-Residential Sales and Transportation Service (continued)"
Twenty-Fourth Revision of Sheet 142.10	Twenty-Third Revision of Sheet 142.10	Schedule 42 "Large Volume Non-Residential Sales and Transportation Service (continued)"
Nineteenth Revision of Sheet 142.10.1	Eighteenth Revision of Sheet 142.10.1	Schedule 42 "Large Volume Non-Residential Sales and Transportation Service (continued)"
Twenty-Fourth Revision of Sheet 142.11	Twenty-Third Revision of Sheet 142.11	Schedule 42 "Large Volume Non-Residential Sales and Transportation Service (continued)"
Ninth Revision of Sheet 142.12	Eighth Revision of Sheet 142.12	Schedule 42 "Large Volume Non-Residential Sales and Transportation Service (continued)"
Twenty-Third Revision of Sheet 143.6	Twenty-Second Revision of Sheet 143.6	Schedule 43 "High Volume Non-Residential Firm and Interruptible Transportation Service (continued)"
Fourteenth Revision of Sheet 200.1	Thirteenth Revision of Sheet 200.1	Schedule 200 "Summary of Adjustments"
Tenth Revision of Sheet 200.2	Ninth Revision of Sheet 200.2	Schedule 200 "Summary of Adjustments (continued)"
First Revision of Sheet 200.3	Original Sheet 200.3	Schedule 200 "Summary of Adjustments (continued)"
Ninth Revision of Sheet 207.1	Eighth Revision of Sheet 207.1	Schedule 207 "General Rate Adjustment"
Ninth Revision of Sheet 207.2	Eighth Revision of Sheet 207.2	Schedule 207 "General Rate Adjustment (continued)"
Fourth Revision of Sheet 207.3	Third Revision of Sheet 207.3	Schedule 207 "General Rate Adjustment (continued)"
First Revision of Sheet 235.1	Original Sheet 235.1	Schedule 235 "Temporary Adjustments to Rates for COVID-19 Public Health Emergency"

TABLE OF TARIFF SHEET REVISIONS – Rate Year Two		
PROPOSED	**CANCELS**	**TITLE**
First Revision of Sheet 236.1	Original Sheet 236.1	Schedule 236 "Temporary Adjustments to Rates for Meter Modernization Program"
First Revision of Sheet 237.1	Original Sheet 237.1	Schedule 237 "Temporary Adjustments to Rates for TSA Operations and Maintenance Costs"
First Revision of Sheet 238.1	Original Sheet 238.1	Schedule 238 "Adjustments to Rates for Provisional Capital Adjustment"

The following proposed Tariff revision associated with Year Three of the multi-year rate plan listed in the table below has an issue date of August 29, 2025, and is stated to become effective with service on and after August 1, 2028.

Rate Year Three Tariff Sheets:

TABLE OF TARIFF SHEET REVISIONS – Rate Year Three		
PROPOSED	**CANCELS**	**TITLE**
Thirty-Eighth Revision of Sheet 101.1	Thirty-Seventh Revision of Sheet 101.1	Schedule 1 "General Sales Service"
Thirty-Ninth Revision of Sheet 102.1	Thirty-Eighth Revision of Sheet 102.1	Schedule 2 "Residential Sales Service"
Twenty-Sixth Revision of Sheet 103.3	Twenty-Fifth Revision of Sheet 103.3	Schedule 3 "Basic Firm Sales Service – Non-Residential (continued)"
Sixth Revision of Sheet 110.2	Fifth Revision of Sheet 110.2	Schedule 10 "Changes for Special Metering Equipment, Rental Meters and Metering Services (continued)"
Thirty-Eighth Revision of Sheet 127.1	Thirty-Seventh Revision of Sheet 127.1	Schedule 27 "Residential Heating Dry-Out Service"
Twenty-Fourth Revision of Sheet 141.9	Twenty-Third Revision of Sheet 141.9	Schedule 41 "Non-Residential Sales and Transportation Service (continued)"
Nineteenth Revision of Sheet 141.10	Eighteenth Revision of Sheet 141.10	Schedule 41 "Non-Residential Sales and Transportation Service (continued)"
Twenty-Fifth Revision of Sheet 142.10	Twenty-Fourth Revision of Sheet 142.10	Schedule 42 "Large Volume Non-Residential Sales and Transportation Service (continued)"

TABLE OF TARIFF SHEET REVISIONS – Rate Year Three		
PROPOSED	**CANCELS**	**TITLE**
Twentieth Revision of Sheet 142.10.1	Nineteenth Revision of Sheet 142.10.1	Schedule 42 "Large Volume Non-Residential Sales and Transportation Service (continued)"
Twenty-Fifth Revision of Sheet 142.11	Twenty-Fourth Revision of Sheet 142.11	Schedule 42 "Large Volume Non-Residential Sales and Transportation Service (continued)"
Tenth Revision of Sheet 142.12	Ninth Revision of Sheet 142.12	Schedule 42 "Large Volume Non-Residential Sales and Transportation Service (continued)"
Twenty-Fourth Revision of Sheet 143.6	Twenty-Third Revision of Sheet 143.6	Schedule 43 "High Volume Non-Residential Firm and Interruptible Transportation Service (continued)"
Fifteenth Revision of Sheet 200.1	Fourteenth Revision of Sheet 200.1	Schedule 200 "Summary of Adjustments"
Eleventh Revision of Sheet 200.2	Tenth Revision of Sheet 200.2	Schedule 200 "Summary of Adjustments (continued)"
Second Revision of Sheet 200.3	First Revision Sheet 200.3	Schedule 200 "Summary of Adjustments (continued)"
Tenth Revision of Sheet 207.1	Ninth Revision of Sheet 207.1	Schedule 207 "General Rate Adjustment"
Tenth Revision of Sheet 207.2	Ninth Revision of Sheet 207.2	Schedule 207 "General Rate Adjustment (continued)"
Fifth Revision of Sheet 207.3	Fourth Revision of Sheet 207.3	Schedule 207 "General Rate Adjustment (continued)"
Second Revision of Sheet 235.1	First Revision of Sheet 235.1	Schedule 235 "Temporary Adjustments to Rates for COVID-19 Public Health Emergency"
Second Revision of Sheet 236.1	First Revision of Sheet 236.1	Schedule 236 "Temporary Adjustments to Rates for Meter Modernization Program"
Second Revision of Sheet 237.1	First Revision of Sheet 237.1	Schedule 237 "Temporary Adjustments to Rates for TSA Operations and Maintenance Costs"
Second Revision of Sheet 238.1	First Revision of Sheet 238.1	Schedule 238 "Adjustments to Rates for Provisional Capital Adjustment"

TABLE OF TARIFF SHEET REVISIONS – Rate Year Three		
PROPOSED	**CANCELS**	**TITLE**
Original Sheet 239.1	N/A	Schedule 239 "Temporary Adjustments to Rates for TSA Capital and Cost of Service Cost Recovery"

NW Natural is proposing to establish new rate adjustments of Schedule 235, Schedule 236, Schedule 237, Schedule 238, and Schedule 239, which are discussed in the Direct Testimony of Kyle T. Walker in Exh. KTW-1T.

NW Natural encloses all proposed tariff sheets formatted with the coding required by WAC 480-80-105 and in legislative format in accordance with WAC 480-07-510(2).

Purpose of Filing

NW Natural seeks Commission authorization to increase its rates and charges for its natural gas service in the state of Washington. For Year One of the multi-year rate plan in this filing, the Company proposes an increase in revenues from base rates by $25.6 million, which would result in an approximate 22.8 percent increase to overall base rates effective August 1, 2026. For Year Two of the proposed multi-year rate plan, NW Natural is proposing an increase of $8.6 million, or 6.2 percent, effective August 1, 2027. For Year Three of the proposed multi-year rate plan, NW Natural is proposing an increase of $8.3 million, or 5.7 percent, effective August 1, 2028.

The Company's Year One request is based on a proposed rate of return of 7.505 percent, reflecting a proposed return on equity of 10.1 percent and capital structure comprised of 51 percent common equity, 48 percent long-term debt, and 1 percent short-term debt. The full impact of the filing is described in greater detail in the Summary Document included with this filing in accordance with WAC 480-07-510(5) as Attachment A.

The tables below incorporate the impact of three deferrals that are proposed for recovery as part of this proceeding. The direct pre-filed testimony of Kyle T. Walker, Exh. KTW-1T, describe these deferrals and proposals for recovery. The net impact of the increase to base rates and the proposed offsetting measures is an overall increase to rates of $25.9 million, or 23.1 percent, in Year One, $8.6 million, or 6.2 percent, in Year Two, and $8.9 million, or 6.1 percent, in Year Three.

Effect on Customers

As proposed, this general rate case would increase the Company's sales service class customer rates for Year One of the multi-year rate plan, effective August 1, 2026, as follows:

Class	Rate Schedule*	Change in Monthly Customer Charge	Average Monthly Bill Change ($)	Average Monthly Bill Change (%) Existing Customers	Average Monthly Bill Change (%) New Customers
Residential	Schedule 1	$2.50	$7.37	26.3%	24.6%
Residential	Schedule 2	$0.00	$15.72	21.8%	19.7%
Commercial	Schedule 1	$3.00	$24.07	25.9%	24.5%
Commercial	Schedule 3	$0.00	$74.46	23.0%	20.7%
Residential/ Commercial	Schedule 27	$0.00	$21.47	37.1%	37.1%
Commercial Firm Sales	Schedule 41	$0.00	$679.15	21.1%	18.2%
Commercial Interruptible Sales	Schedule 41	n/a	n/a	n/a	n/a
Commercial Firm Sales	Schedule 42	$0.00	$2,584.20	21.2%	14.9%
Commercial Interruptible Sales	Schedule 42	$0.00	$3,310.06	14.2%	11.6%
Industrial Firm Sales	Schedule 41	$0.00	$490.10	14.5%	12.3%
Industrial Interruptible Sales	Schedule 41	n/a	n/a	n/a	n/a
Industrial Firm Sales	Schedule 42	$0.00	$1,109.08	18.3%	11.1%
Industrial Interruptible Sales	Schedule 42	$0.00	$1,213.36	14.7%	9.9%

As proposed, this general rate case would increase the Company's customer rates for Year Two of the multi-year rate plan, effective August 1, 2027, as follows:

Class	Rate Schedule*	Change in Monthly Customer Charge	Average Monthly Bill Change ($)	Average Monthly Bill Change (%) Existing Customers	Average Monthly Bill Change (%) New Customers
Residential	Schedule 1	$2.00	$2.39	6.8%	6.4%
Residential	Schedule 2	$2.00	$4.56	5.2%	4.8%
Commercial	Schedule 1	$0.00	$7.52	6.4%	6.1%
Commercial	Schedule 3	$0.00	$22.95	5.8%	5.3%
Residential/ Commercial	Schedule 27	$0.00	$4.31	5.4%	5.4%
Commercial Firm Sales	Schedule 41	$0.00	$225.49	5.8%	5.1%
Commercial Interruptible Sales	Schedule 41	n/a	n/a	n/a	n/a
Commercial Firm Sales	Schedule 42	$0.00	$860.90	5.8%	4.3%
Commercial Interruptible Sales	Schedule 42	$0.00	$904.53	3.4%	2.8%
Industrial Firm Sales	Schedule 41	$0.00	$198.26	5.1%	5.1%
Industrial Interruptible Sales	Schedule 41	n/a	n/a	n/a	n/a
Industrial Firm Sales	Schedule 42	$0.00	$449.42	6.3%	4.0%
Industrial Interruptible Sales	Schedule 42	$0.00	$638.81	6.7%	4.8%

As proposed, this general rate case would increase the Company's customer rates for Year Three of the multi-year rate plan, effective August 1, 2028, as follows:

Class	Rate Schedule*	Change in Monthly Customer Charge	Average Monthly Bill Change ($)	Average Monthly Bill Change (%) Existing Customers	Average Monthly Bill Change (%) New Customers
Residential	Schedule 1	$0.00	$2.40	6.3%	6.1%
Residential	Schedule 2	$0.00	$4.62	5.0%	4.6%
Commercial	Schedule 1	$0.00	$8.03	6.5%	6.2%
Commercial	Schedule 3	$0.00	$24.25	5.7%	5.3%
Residential/ Commercial	Schedule 27	$0.00	$4.55	5.4%	5.4%
Commercial Firm Sales	Schedule 41	$0.00	$239.65	5.8%	5.2%
Commercial Interruptible Sales	Schedule 41	n/a	n/a	n/a	n/a
Commercial Firm Sales	Schedule 42	$0.00	$901.74	5.8%	4.3%
Commercial Interruptible Sales	Schedule 42	$0.00	$1,000.64	3.6%	3.1%
Industrial Firm Sales	Schedule 41	$0.00	$202.82	5.0%	4.3%
Industrial Interruptible Sales	Schedule 41	n/a	n/a	n/a	n/a
Industrial Firm Sales	Schedule 42	$0.00	$451.76	5.9%	3.9%
Industrial Interruptible Sales	Schedule 42	$0.00	$519.00	5.1%	3.7%

*Schedule 41 and 42 sales customers may choose demand charges at a volumetric rate or based on MDDV. For convenience of presentation, demand charges are not included in the calculations for those schedules.
n/a represents schedules that currently do not have customers signed up for service.

Filing Support/Requirements

In support of this filing, and in compliance with WAC 480-07-510(1), the Company submits the prepared testimony and exhibits of:

Exhibit	Witness	Subject Matter
Exh. KAR-ZDK-1T	Kimberly A. Rush and Zachary D. Kravitz	Policy
Exh. CJT-1T	Cecelia J. Tanaka	Equity
Exh. KTW-1T	Kyle T. Walker	Multi-Year Rate Plan and Revenue Requirements
Exh. NCS-1T	Natasha C. Siores	Performance-Based Ratemaking Metrics
Exh. CAB-1T	Corey A. Beck	Language Access Approach
Exh. BJW-1CT	Brody J. Wilson	Cost of Capital
Exh. JEN-1T	Jennifer E. Nelson	Rate of Return on Equity
Exh. JOM-1T	Jorge O. Moncayo	Capital Expenditures: Budgeting/Forecasting, Management Approval, and Project Lifecycles
Exh. DBK-SSJ-1T	Daniel B. Kizer and Scott S. Johnson	Distribution System and Storage Facility Projects
Exh. WKP-1T	Wayne K. Pipes	Facilities
Exh. BEF-1CT	Brian E. Fellon	Information Technology & Services
Exh. BEF-23HCT	Brian E. Fellon	Transportation Security Administration Projects
Exh. JSK-1T	Joe S. Karney	Meter Modernization
Exh. MBR-1CT	Melinda B. Rogers	Compensation & Benefits
Exh. TFD-1CT	Tobin F. Davilla	Operations & Maintenance Expense
Exh. JJS-1T	John J. Spanos	Depreciation
Exh. HJB-1CT	Holly J. Braun	Thermal Energy Networks
Exh. RJW-1T	Robert J. Wyman	Embedded Cost of Service Model and Rate Design/Spread

Enclosed with this filing are:

- Attachment A – Summary Document required under WAC 480-07-510(5),
- Attachment B – Additional Documents required under WAC 480-07-510(7),
- Attachment C – Listing of Electronic Files in compliance with WAC 480-07-140(6)(b), and
- Attachment D – As a courtesy, the Company also includes a spreadsheet that provides Commission Staff's "Audit Guide – Initial Filing Assessment for Electric and Natural Gas Companies" requirements, and NW Natural's explanation of how or where the requirements were met.
- Attachment E – In compliance with Stipulating Condition 25e in Order 01 from Docket UG-170094, NW Natural includes its Master Services Agreement. Minor housekeeping changes have been made to Addendum 2 of the Master Services Agreement to update the List of

Services for completeness. There have been no changes to the agreement itself since it was last filed with the Commission, in Docket UG-200994 on May 19, 2021.

In accordance with WAC 480-07-510, all documents have been electronically filed consistent with the requirements in WAC 480-07-140, with the exception of highly confidential files withheld per WAC 480-07-160(6)(f). One complete copy of all documentation has also been served on Public Counsel. The summary document (Attachment A) required by WAC 480-07-510(5) has been served to the persons listed on the Certificate of Service attached to this letter.

Electronic copies of supporting workpapers will be provided to Commission Staff with a copy to Public Counsel within five business days of the date of this filing, in accordance with the provisions of WAC 480-07-510(4). The Company has included its cost of service study in accordance with WAC 480-85-040 with the testimony and exhibits of Robert J. Wyman; the cost of service study results are included in Exh. RJW-12. The Company will provide five paper copies of the Company's testimony and exhibits supporting this general rate case filing on or before September 2, 2025.

In compliance with WAC 480-07-510(3)(g), the Company states that there are no additional material affiliate transactions to report impacting the test year that were not otherwise reported in the Company's 2024 Affiliated Interest Report. The Company's 2024 Affiliated Interest Report, docketed as UG-250305, was filed on April 30, 2025, with minor revisions filed June 4, 2025.

Confidentiality Protections and Motion for Protective Order

NW Natural has marked certain pages "**SHADED INFORMATION IS DESIGNATED AS CONFIDENTIAL PER WAC 480-07-160.**" These documents are currently protected from any further disclosure by the Commission or the Office of the Attorney General, including their outside experts, **pursuant to RCW 80.04.095 and WAC 480-07-160**. Please note that the Company has also simultaneously-filed a motion for amended protective order with highly confidential provisions.

The Company therefore requests that the documents contained in the envelopes identified with the cover page marked "**SHADED INFORMATION IS DESIGNATED AS CONFIDENTIAL PER WAC 480-07-160**" as well as the files marked "Shaded Information is Designated as Confidential per WAC 480-07-160" be treated as confidential under the provisions of WAC 480-07-160, as they each contain sensitive commercial information. In accordance with WAC 480-07-160(5)(c), the Company has enclosed redacted versions of the documents containing confidential information along with the non-confidential documents in its filing, and has placed unredacted versions of the documents containing confidential information in separate envelopes with corresponding "**SHADED INFORMATION IS DESIGNATED AS CONFIDENTIAL PER WAC 480-07-160**" labels on the envelopes. Each page of the unredacted version containing confidential information has been printed on yellow paper.

Public Notice and Suspension

NW Natural agrees that following suspension of this filing, it will provide notice pursuant to WAC 480-90-197 once the public hearing dates have been selected by the Commission. Accordingly, the notice provisions of WAC 480-90-194 are not required at this time for this filing.

The Company stands ready to respond to any requests for data and information by telephone, or in writing, and to schedule any audit time that may be necessary. Please send any requests to the contact information shown below.

As requested by WAC 480-80-103(4)(a), I certify that I have authority to issue tariff revisions on behalf of NW Natural.

In accordance with WAC 480-90-193, a copy of the filing is available for public inspection at the Company's main office in Portland, Oregon and on its website at www.nwnatural.com.

Service and correspondence relating to this filing should be directed to:

Kyle Walker, CPA
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Portland, OR 97204
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ryan.sigurdson@nwnatural.com

Please contact me if you have any questions or require any further information.

Sincerely,

/s/ Zachary D. Kravitz

Zachary D. Kravitz
Vice President, Regulatory Affairs and Resource Planning
250 SW Taylor Street
Portland, Oregon 97204
Phone: (503) 610-7617
Email: zach.kravitz@nwnatural.com

Enclosures:
Please see Attachment C for the complete listing of all documents included with this submission.

NW Natural

CERTIFICATE OF SERVICE

UG-250610

I HEREBY CERTIFY that I have on this day served Northwest Natural Gas Company's, dba NW Natural ("NW Natural" or the "Company"), Direct Testimony and Exhibits in its Washington General Rate Case filing or summary document, if applicable, upon all parties of record in this proceeding and in the Company's previous General Rate Case proceeding (docket UG-200994) by electronic transmission to each party or party representative listed in the Washington Utilities and Transportation Commission's main service lists.

DATED at Portland, Oregon, this 29th day of August 2025.

/s/ Erica Lee-Pella
Erica Lee-Pella
Rates & Regulatory Specialist
NW Natural/Rates & Regulatory Affairs
250 SW Taylor Street
Portland, OR 97204
(503) 610-7330
erica.lee-pella@nwnatural.com

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August 29, 2025

VIA ELECTRONIC FILING

Jeff Killip, Executive Director and Secretary
Washington Utilities and Transportation Commission
621 Woodland Square Loop SE
Lacey, Washington 98503

Re: UG-250610 – General Rate Increase; Tariff WN U-6, Natural Gas Service

Dear Mr. Killip:

In compliance with WAC 480-07-510(5), Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company"), is serving you with the enclosed Summary Document (Attachment A) of the Company's general rate case filed in Docket UG-250610.

NW Natural's prefiled testimony and exhibits, along with accompanying workpapers, are available from the Company on request. Prefiled testimony and exhibits are also available at the Washington Utilities and Transportation website under docket UG-250610.

Sincerely,

/s/ Zachary D. Kravitz

Zachary D. Kravitz
Vice President, Regulatory Affairs and Resource Planning
250 SW Taylor Street
Portland, Oregon 97204
Phone: (503) 610-7617
Email: zach.kravitz@nwnatural.com

Enclosure:
250610-NWN-GRC-Attach-A-08-29-25 (PDF and Excel)

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Attachment A

Summary Document Required by WAC 480-07-510(5)

August 29, 2025

NW NATURAL
Summary of Requested Rate Increase
GAS Service
Based on Rates Currently in Effect
Washington Jurisdiction
Filed August 29th, 2025

As required in WAC 480-07-510(5)(a):

i) The date and amount of the latest prior general rate increase authorized by the Commission, and revenue realized from that authorized increase in the test period, based on the company's test period units of revenue.

Effective Date	UG-200994	11/01/2021
Amount (thousands)		$ 5,000
Revenue realized (thousands)		$ 5,488

Effective Date	UG-200994	11/01/2022
Amount (thousands)		$ 3,000
Revenue realized (thousands)		$ 3,296

ii) Total general business revenues at present rates and at requested rates.

Present Rates (thousands)	$ 112,036
Requested Rates (thousands) - Year 1	$ 137,887
Requested Rates (thousands) - Year 2	$ 146,185
Requested Rates (thousands) - Year 3	$ 155,125

iii) Requested revenue change in percentage, in total and by major customer class.

Year 1 Rate Period

	Base Tariff Revenue	Billed Revenue
Residential	39.1%	23.3%
Commercial	43.1%	23.4%
Industrial Firm Sales	28.2%	12.3%
Interruptible Sales	37.3%	12.2%
Transportation	27.2%	27.6%
Overall	39.5%	23.07%

Margin Increase %

Year 2 Rate Period

Requested revenue change in percentage, in total and by major customer class.	Base Tariff Revenue	Billed Revenue
Residential	9.5%	6.3%
Commercial	12.0%	7.6%
Industrial Firm Sales	9.5%	4.7%
Interruptible Sales	7.0%	2.8%
Transportation	9.5%	9.5%
Overall	9.5%	6.2%

Update to Revenue not margin

Year 3 Rate Period

Requested revenue change in percentage, in total and by major customer class.	Base Tariff Revenue	Billed Revenue
Residential	8.3%	6.1%
Commercial	10.8%	7.6%
Industrial Firm Sales	8.6%	4.7%
Interruptible Sales	6.3%	2.8%
Transportation	8.6%	9.2%
Overall	8.4%	6.1%

iv) Requested revenue change in thousands of dollars, in total and by major customer class.

	Year 1	Year 2	Year 3
Residential	$ 17,414	$ 5,834	$ 6,010
Commercial	$ 7,350	$ 2,294	$ 2,440
Industrial Firm Sales	$ 307	$ 130	$ 137
Interruptible Sales	$ 93	$ 32	$ 34
Transportation	$ 686	$ 301	$ 319
Total	$ 25,851	$ 8,591	$ 8,940

v) Requested rate change in dollars per month, per average customer, by customer class.

	Billing Rates Year 1	Billing Rates Year 2	Billing Rates Year 3
Residential	$15.66	$4.54	$4.59
Commercial	$295.34	$94.36	$98.60
Industrial Firm Sales	$791.85	$316.25	$318.68
Interruptible Sales	$2,935.85	$633.96	$672.60
Transportation	$2,569.56	$938.28	$951.87

vi) Most current customer count by major customer class. (1)

Residential	91,114
Commercial	7,377
Industrial Firm Sales	53
Interruptible Sales	3
Transportation	29
Total	98,576

(1) as of June 30, 2025

vii) Current authorized overall rate of return and authorized rate of return on common equity.

Overall rate of return	6.81%
Rate of return on common equity	9.40%

viii) Actual rate of return and actual rate of return on common equity for the test

Actual rate of return	5.55%
Actual Rate of return on common equity for test period	6.41%

ix) Requested overall rate of return and requested rate of return on common equity, and the method or methods used to calculate rate of return on common equity.

	Year 1	Year 2	Year 3
Overall rate of return	7.51%	7.62%	7.66%
Rate of return on common equity	10.10%	10.20%	10.20%

The methodologies utilized in the derivation of the rate of return on common equity were discounted cash flow analyses (single and multi-stage), risk premium model analysis, capital asset pricing model (CAPM) analysis, and Empirical CAPM analysis.

x) Requested capital structure.

Long Term Debt	48.00%
Short-Term Debt	1.00%
Common Equity	51.00%
Total	100.00%

xi) Requested total net operating income.

	Year 1	Year 2	Year 3
Net operating income (thousands)	$ 25,649	$ 29,076	$ 32,381

xii) Requested total rate base and method of calculation, or equivalent.

	Year 1	Year 2	Year 2
Rate base (thousands)	$ 341,761	$ 381,433	$ 422,679

Method of calculation is end of period basis.

xiii) Requested revenue effect of attrition allowance, if any requested.

No attrition allowance requested	$ -

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NORTHWEST NATURAL GAS COMPANY

Attachment B

Additional Documents Required by WAC 480-07-510(7)

August 29, 2025

Per WAC 480-07-510(7). Additional documents. The company's initial filing must include the following documents or an internet URL for each of these documents:

(a) The company's most recent annual report to shareholders, if any, and any subsequent quarterly reports to shareholders:

NW Natural's 2024 Annual Report:
https://ir.nwnaturalholdings.com/financials/annual-reports/default.aspx

(b) The company's most recent FERC Form 1 and FERC Form 2 for electric and natural gas companies;

NW Natural does not file a FERC Form 1.

NW Natural's 2024 FERC Form 2:
https://www.utc.wa.gov/sites/default/files/2025-05/02-NEW-NWN-2024-ARpt-04-29-25.pdf

Supplemental Filing:
https://www.utc.wa.gov/sites/default/files/2025-05/02-NEW-NWN-2024-ARpt-WA%20Supplemental%20-%2004-29-25.pdf

(c) The company's Form 10K's, Form 10Q's, any prospectuses for any issuances of securities, and quarterly reports to stockholders, if any, for the most recent two years prior to the rate change request:

NW Natural's 2024 Form 10-K:
https://www.sec.gov/Archives/edgar/data/73020/000173399825000020/nwn-20241231.htm

NW Natural's 2023 Form 10-K:
https://www.sec.gov/Archives/edgar/data/73020/000173399824000011/nwn-20231231.htm

NW Natural's Form 10Q's:

2025 Q2 Form 10-Q:
https://www.sec.gov/Archives/edgar/data/73020/000173399825000132/nwn-20250630.htm

2025 Q1 Form 10-Q:
https://www.sec.gov/Archives/edgar/data/73020/000173399825000094/nwn-20250331.htm

2024 Q3 Form 10-Q:
https://www.sec.gov/Archives/edgar/data/73020/000173399824000125/nwn-20240930.htm

2024 Q2 Form 10-Q:
https://www.sec.gov/Archives/edgar/data/73020/000173399824000093/nwn-20240630.htm

2024 Q1 Form 10-Q:
https://www.sec.gov/Archives/edgar/data/73020/000173399824000075/nwn-20240331.htm

2023 Q3 Form 10-Q:
https://www.sec.gov/Archives/edgar/data/73020/000173399823000067/nwn-20230930.htm

2023 Q2 Form 10-Q:
https://www.sec.gov/Archives/edgar/data/73020/000173399823000042/nwn-20230630.htm

2023 Q1 Form 10-Q:
https://www.sec.gov/Archives/edgar/data/73020/000173399823000016/nwn-20230331.htm

NW Natural's Prospectuses for any Issuances of Securities

August 2024 Prospectuses for Issuance of Medium-term notes:
https://www.sec.gov/Archives/edgar/data/73020/000119312524197933/d850419d424b2.htm

https://www.sec.gov/Archives/edgar/data/73020/000119312524197846/d876587ds3asr.htm

March 2023 Prospectuses for Issuance of Medium-term notes:
https://www.sec.gov/Archives/edgar/data/73020/000119312523059831/d440144d424b2.htm

Quarterly reports to stockholders, if any:

NW Natural does not provide quarterly reports to shareholders (other than the Form 10-Q provided above).

Q2 2025 Press Release
https://www.sec.gov/Archives/edgar/data/0000073020/000173399825000130/a2025q2ex991pressreleasedo.htm

Q1 2025 Press Release
https://www.sec.gov/Archives/edgar/data/0000073020/000173399825000091/a2025q1ex991pressreleasedo.htm

Q4 and FY 2024 Press Release
https://www.sec.gov/Archives/edgar/data/0000073020/000173399825000017/a991pressreleaseq42024.htm

Q3 2024 Press Release
https://www.sec.gov/Archives/edgar/data/0000073020/000173399824000122/a2024q3ex991pressreleasedo.htm

Q2 2024 Press Release
https://www.sec.gov/Archives/edgar/data/0000073020/000173399824000091/a2024q2ex991pressreleasedo.htm

Q1 2024 Press Release
https://www.sec.gov/Archives/edgar/data/0000073020/000173399824000073/a2024q1ex991pressreleasedo.htm

Q4 and FY 2023 Press Release
https://www.sec.gov/Archives/edgar/data/0000073020/000173399824000007/a991pressreleaseq42023.htm

Q3 2023 Press Release
https://www.sec.gov/Archives/edgar/data/0000073020/000173399823000063/a2023q3ex991pressreleasedo.htm

Q2 2023 Press Release
https://www.sec.gov/Archives/edgar/data/0000073020/000173399823000038/a2023q2ex991pressreleasedo.htm

Q1 2023 Press Release
https://www.sec.gov/Archives/edgar/data/0000073020/000173399823000013/a2023q1ex991pressreleasedo.htm

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NORTHWEST NATURAL GAS COMPANY

Attachment C

Listing of Electronic Files

August 29, 2025

250610-NWN-GRC-CLtr-08-29-25
250610-NWN-GRC-COS-08-29-25
250610-NWN-GRC-Attach-A-CLtr-08-29-25
250610-NWN-GRC-Attach-A-08-29-25
250610-NWN-GRC-Attach-A-08-29-25.xlsx
250610-NWN-GRC-Attach-B-08-29-25
250610-NWN-GRC-Attach-C-08-29-25
250610-NWN-GRC-Attach-D-Compliance-08-29-25
250610-NWN-GRC-Attach-E-08-29-25

Tariffs
- 250610-NWN-GRC-Trfs-Legislative-08-29-25
- 250610-NWN-GRC-Trfs-Proposed-08-29-25

Kimberly A. Rush and Zachary D. Kravitz
- 250610-NWN-Exh-KAR-ZDK-1T-08-29-25
- 250610-NWN-Exh-KAR-ZDK-2-08-29-25
- 250610-NWN-Exh-KAR-ZDK-3-08-29-25

Cecelia J. Tanaka
- 250610-NWN-Exh-CJT-1T-08-29-25
- 250610-NWN-Exh-CJT-2-08-29-25
- 250610-NWN-Exh-CJT-3-08-29-25
- 250610-NWN-Exh-CJT-4-08-29-25
- 250610-NWN-Exh-CJT-5-08-29-25
- 250610-NWN-Exh-CJT-6-08-29-25

Kyle T. Walker
- 250610-NWN-Exh-KTW-1T-08-29-25
- 250610-NWN-Exh-KTW-2-08-29-25
- 250610-NWN-Exh-KTW-2-to-KTW-9-08-29-25.xlsx
- 250610-NWN-Exh-KTW-3-08-29-25
- 250610-NWN-Exh-KTW-3-Page-4-9-10-08-29-25.xlsx
- 250610-NWN-Exh-KTW-3-Page-17-to-34-08-29-25.xlsx
- 250610-NWN-Exh-KTW-4-08-29-25
- 250610-NWN-Exh-KTW-5-08-29-25
- 250610-NWN-Exh-KTW-6-08-29-25
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- 250610-NWN-Exh-KTW-8-08-29-25
- 250610-NWN-Exh-KTW-9-08-29-25
- 250610-NWN-Exh-KTW-10-08-29-25
- 250610-NWN-Exh-KTW-10-08-29-25.xlsx
- 250610-NWN-Exh-KTW-11C-08-29-25.xlsx (C)
- 250610-NWN-Exh-KTW-11C-08-29-25 (R)
- 250610-NWN-Exh-KTW-12-08-29-25.xlsx

Natasha C. Siores

250610-NWN-Exh-NCS-1T-08-29-25
250610-NWN-Exh-NCS-2-08-29-25
250610-NWN-Exh-NCS-3-08-29-25

Corey A. Beck

250610-NWN-Exh-CAB-1T-08-29-25
250610-NWN-Exh-CAB-2-08-29-25
250610-NWN-Exh-CAB-3-08-29-25
250610-NWN-Exh-CAB-4-08-29-25
250610-NWN-Exh-CAB-5-08-29-25
250610-NWN-Exh-CAB-6-08-29-25

Brody J. Wilson

250610-NWN-Exh-BJW-1CT-08-29-25 (C)
250610-NWN-Exh-BJW-1CT-08-29-25 (R)
250610-NWN-Exh-BJW-2-08-29-25
250610-NWN-Exh-BJW-3-08-29-25
250610-NWN-Exh-BJW-4C-08-29-25.xlsx (C)
250610-NWN-Exh-BJW-4C-08-29-25 (R)
250610-NWN-Exh-BJW-5C-08-29-25 (C)
250610-NWN-Exh-BJW-5C-08-29-25 (R)
250610-NWN-Exh-BJW-6C-08-29-25 (C)
250610-NWN-Exh-BJW-6C-08-29-25 (R)
250610-NWN-Exh-BJW-7C-08-29-25 (C)
250610-NWN-Exh-BJW-7C-08-29-25 (R)

Jennifer E. Nelson

250610-NWN-Exh-JEN-1T-08-29-25
250610-NWN-Exh-JEN-2-08-29-25
250610-NWN-Exh-JEN-3-08-29-25
250610-NWN-Exh-JEN-3-to-Jen-12-08-29-25.xlsx
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250610-NWN-Exh-JEN-5-08-29-25
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250610-NWN-Exh-JEN-19C-08-29-25 (C)
250610-NWN-Exh-JEN-19C-08-29-25 (R)

Jorge O. Moncayo
250610-NWN-Exh-JOM-1T-08-29-25
250610-NWN-Exh-JOM-2-08-29-25
250610-NWN-Exh-JOM-3C-08-29-25 (C)
250610-NWN-Exh-JOM-3C-08-29-25 (R)

Daniel B. Kizer and Scott S. Johnson
250610-NWN-Exh-DBK-SSJ-1T-08-29-25
250610-NWN-Exh-DBK-SSJ-2-08-29-25
250610-NWN-Exh-DBK-SSJ-3-08-29-25
250610-NWN-Exh-DBK-SSJ-4-08-29-25
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250610-NWN-Exh-DBK-SSJ-20C-08-29-25 (R)
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250610-NWN-Exh-DBK-SSJ-22-08-29-25
250610-NWN-Exh-DBK-SSJ-23-08-29-25

Wayne K. Pipes
250610-NWN-Exh-WKP-1T-08-29-25
250610-NWN-Exh-WKP-2-08-29-25
250610-NWN-Exh-WKP-3-08-29-25
250610-NWN-Exh-WKP-4-08-29-25

250610-NWN-Exh-WKP-5-08-29-25
250610-NWN-Exh-WKP-6C-08-29-25 (C)
250610-NWN-Exh-WKP-6C-08-29-25 (R)
250610-NWN-Exh-WKP-7-08-29-25
250610-NWN-Exh-WKP-8-08-29-25

Brian E. Fellon

250610-NWN-Exh-BEF-1CT-08-29-25 (C)
250610-NWN-Exh-BEF-1CT-08-29-25 (R)
250610-NWN-Exh-BEF-2C-08-29-25 (C)
250610-NWN-Exh-BEF-2C-08-29-25 (R)
250610-NWN-Exh-BEF-3-08-29-25
250610-NWN-Exh-BEF-4-08-29-25
250610-NWN-Exh-BEF-5-08-29-25
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250610-NWN-Exh-BEF-8C-08-29-25 (R)
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250610-NWN-Exh-BEF-10-08-29-25
250610-NWN-Exh-BEF-11-08-29-25
250610-NWN-Exh-BEF-12-08-29-25
250610-NWN-Exh-BEF-13-08-29-25
250610-NWN-Exh-BEF-14-08-29-25
250610-NWN-Exh-BEF-15-08-29-25
250610-NWN-Exh-BEF-16-08-29-25
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250610-NWN-Exh-BEF-18C-08-29-25 (C)
250610-NWN-Exh-BEF-18C-08-29-25 (R)
250610-NWN-Exh-BEF-19-08-29-25
250610-NWN-Exh-BEF-20-08-29-25
250610-NWN-Exh-BEF-21-08-29-25
250610-NWN-Exh-BEF-22C-08-29-25 (C)
250610-NWN-Exh-BEF-22C-08-29-25 (R)

Brian E. Fellon

250610-NWN-Exh-BEF-23HCT-Placeholder-08-29-25
250610-NWN-Exh-BEF-24HC-Placeholder-08-29-25
250610-NWN-Exh-BEF-25HC-Placeholder-08-29-25
250610-NWN-Exh-BEF-26HC-Placeholder-08-29-25
250610-NWN-Exh-BEF-27HC-Placeholder-08-29-25
250610-NWN-Exh-BEF-28HC-Placeholder-08-29-25
250610-NWN-Exh-BEF-29HC-Placeholder-08-29-25
250610-NWN-Exh-BEF-30HC-Placeholder-08-29-25
250610-NWN-Exh-BEF-31HC-Placeholder-08-29-25

The below documents for Brian E. Fellon contain information designated as Sensitive Security Information by the U.S. Department of Homeland Security and is withheld pursuant to WAC 480-07-160 (6)(f). Complete unredacted and redacted versions will be submitted as soon as practicable after the Commission enters a Protective Order in this proceeding

Brian E. Fellon

- 250610-NWN-Exh-BEF-23HCT-08-29-25 (HC)
- 250610-NWN-Exh-BEF-23HCT-08-29-25 (R)
- 250610-NWN-Exh-BEF-24HC-08-29-25 (HC)
- 250610-NWN-Exh-BEF-24HC-08-29-25 (R)
- 250610-NWN-Exh-BEF-25HC-08-29-25 (HC)
- 250610-NWN-Exh-BEF-25HC-08-29-25 (R)
- 250610-NWN-Exh-BEF-26HC-08-29-25 (HC)
- 250610-NWN-Exh-BEF-26HC-08-29-25 (R)
- 250610-NWN-Exh-BEF-27HC-08-29-25 (HC)
- 250610-NWN-Exh-BEF-27HC-08-29-25 (R)
- 250610-NWN-Exh-BEF-28HC-08-29-25 (HC)
- 250610-NWN-Exh-BEF-28HC-08-29-25 (R)
- 250610-NWN-Exh-BEF-29HC-08-29-25 (HC)
- 250610-NWN-Exh-BEF-29HC-08-29-25 (R)
- 250610-NWN-Exh-BEF-30HC-08-29-25 (HC)
- 250610-NWN-Exh-BEF-30HC-08-29-25 (R)
- 250610-NWN-Exh-BEF-31HC-08-29-25 (HC)
- 250610-NWN-Exh-BEF-31HC-08-29-25 (R).

Joe S. Karney

- 250610-NWN-Exh-JSK-1T-08-29-25
- 250610-NWN-Exh-JSK-2C-08-29-25 (C)
- 250610-NWN-Exh-JSK-2C-08-29-25 (R)
- 250610-NWN-Exh-JSK-3C-08-29-25 (C)
- 250610-NWN-Exh-JSK-3C-08-29-25 (R)
- 250610-NWN-Exh-JSK-4C-08-29-25 (C)
- 250610-NWN-Exh-JSK-4C-08-29-25 (R)
- 250610-NWN-Exh-JSK-5C-08-29-25 (C)
- 250610-NWN-Exh-JSK-5C-08-29-25 (R)

Melinda B. Rogers

- 250610-NWN-Exh-MBR-1CT-08-29-25 (C)
- 250610-NWN-Exh-MBR-1CT-08-29-25 (R)
- 250610-NWN-Exh-MBR-2C-08-29-25 (C)
- 250610-NWN-Exh-MBR-2C-08-29-25 (R)
- 250610-NWN-Exh-MBR-3-08-29-25
- 250610-NWN-Exh-MBR-4-08-29-25
- 250610-NWN-Exh-MBR-5-08-29-25
- 250610-NWN-Exh-MBR-6C-08-29-25 (C)

250610-NWN-Exh-MBR-6C-08-29-25 (R)
250610-NWN-Exh-MBR-7C-08-29-25 (C)
250610-NWN-Exh-MBR-7C-08-29-25 (R)
250610-NWN-Exh-MBR-8C-08-29-25 (C)
250610-NWN-Exh-MBR-8C-08-29-25 (R)
250610-NWN-Exh-MBR-9C-08-29-25 (C)
250610-NWN-Exh-MBR-9C-08-29-25 (R)
250610-NWN-Exh-MBR-10-08-29-25
250610-NWN-Exh-MBR-11-08-29-25
250610-NWN-Exh-MBR-12-08-29-25
250610-NWN-Exh-MBR-13-08-29-25

Tobin F. Davilla

250610-NWN-Exh-TFD-1CT-08-29-25 (C)
250610-NWN-Exh-TFD-1CT-08-29-25 (R)
250610-NWN-Exh-TFD-2C-08-29-25.xlsx (C)
250610-NWN-Exh-TFD-2C-08-29-25 (R)
250610-NWN-Exh-TFD-3-08-29-25
250610-NWN-Exh-TFD-4C-08-29-25 (C)
250610-NWN-Exh-TFD-4C-08-29-25 (R)
250610-NWN-Exh-TFD-5C-08-29-25 (C)
250610-NWN-Exh-TFD-5C-08-29-25 (R)

John J. Spanos

250610-NWN-Exh-JJS-1T-08-29-25
250610-NWN-Exh-JJS-2-08-29-25
250610-NWN-Exh-JJS-3-08-29-25

Holly J. Braun

250610-NWN-Exh-HJB-1CT-08-29-25 (C)
250610-NWN-Exh-HJB-1CT-08-29-25 (R)
250610-NWN-Exh-HJB-2-08-29-25
250610-NWN-Exh-HJB-3C-08-29-25 (C)
250610-NWN-Exh-HJB-3C-08-29-25 (R)
250610-NWN-Exh-HJB-4-08-29-25
250610-NWN-Exh-HJB-5-08-29-25
250610-NWN-Exh-HJB-6-08-29-25
250610-NWN-Exh-HJB-7C-08-29-25 (C)
250610-NWN-Exh-HJB-7C-08-29-25 (R)
250610-NWN-Exh-HJB-8C-08-29-25 (C)
250610-NWN-Exh-HJB-8C-08-29-25 (R)

Robert J. Wyman

250610-NWN-Exh-RJW-1T-08-29-25
250610-NWN-Exh-RJW-2-08-29-25.xlsx
250610-NWN-Exh-RJW-3-08-29-25.xlsx

250610-NWN-Exh-RJW-4-08-29-25.xlsx
250610-NWN-Exh-RJW-5-08-29-25
250610-NWN-Exh-RJW-6-08-29-25.xlsx
250610-NWN-Exh-RJW-7-08-29-25.xlsx
250610-NWN-Exh-RJW-8-08-29-25.xlsx
250610-NWN-Exh-RJW-9-08-29-25.xlsx
250610-NWN-Exh-RJW-10-08-29-25.xlsx
250610-NWN-Exh-RJW-11-08-29-25.xlsx
250610-NWN-Exh-RJW-12-08-29-25.xlsx
250610-NWN-Exh-RJW-13-08-29-25.xlsx
250610-NWN-Exh-RJW-14-08-29-25
250610-NWN-Exh-RJW-14-08-29-25.xlsx
250610-NWN-Exh-RJW-15-08-29-25.xlsx
250610-NWN-Exh-RJW-16-08-29-25.xlsx
250610-NWN-Exh-RJW-17-08-29-25
250610-NWN-Exh-RJW-17-08-29-25.xlsx
250610-NWN-Exh-RJW-18-08-29-25.xlsx
250610-NWN-Exh-RJW-19C-08-29-25.xlsx (C)
250610-NWN-Exh-RJW-19C-08-29-25 (R)

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Attachment D

Staff Audit Guide – Initial Filing Assessment for Electric and Natural Gas Companies Matrix

August 29, 2025

Commission Staff's General Rate Case Audit Guide for Electric and Natural Gas Companies

1. Transmittal Letter (also referred to as a "Cover Letter")
Rule: WAC 480-80-104
A utility must submit a transmittal letter with all tariff and contract filings. The transmittal letter must:

		NW Natural's Compliance Demonstration
(✓)	a. Identify all new tariffs or contracts, or identify the tariff or contract changes;	Included in Cover Letter
(✓)	b. Explain in understandable terms why the tariff or contract filing is being submitted;	Included in Cover Letter
(✓)	c. Specify the changes requested in clear and concise terms and define any acronyms used;	Included in Cover Letter
(✓)	d. Refer to the commonly used name of the service, the advice number, if known, and the docket number, if applicable;	Service, Advice Number, and Docket Number included in table in Cover letter
(✓)	e. Include the advice number if the utility uses consecutively numbered advice letters;	Included Advice 25-03 on tariffs and Cover Letter information
(✓)	f. Describe the general effect of, and reasons for, tariff or contract filings involving only text changes;	Rate Change, not Text Change filing
(✓)	g. Describe which services are affected, and the dollar amount and percentage of increase or decrease if the filing is a rate change. If a combination of changes is filed (i.e., increases and decreases), each change should be described, as well as the net effect on company revenues; and	Included in Cover Letter and Attachment A
(✓)	h. If the utility does not include an authorizing signature on the tariff sheets, include a statement certifying that the submitting person has authority to issue tariff revisions on behalf of the utility.	Statement required by WAC 480-80-103(4)(a) included in Cover Letter

2. Acceptable Format
Rule: WAC 480-07-140(6)(a)

		NW Natural's Compliance Demonstration
(✓)	(i) All documents other than spreadsheets as described in (a)(ii) of this subsection and email correspondence or comments must be filed in searchable .pdf (adobe acrobat or comparable software) format and to the extent feasible should be saved or otherwise converted directly from the native format in which the document was created.	All files provided are searchable and include formulas
(✓)	(ii) Spreadsheets must include all formulas and may not include locked, password protected, or hidden cells or tabs, or any other restrictions that impair or hamper the commission's ability to review or modify the data in those cells.	All files provided are searchable and include formulas

Commission Staff's General Rate Case Audit Guide for Electric and Natural Gas Companies

3. File Naming Conventions
Rule: WAC 480-07-140(6)(b)

		NW Natural's Compliance Demonstration
(✓)	a. The docket number of the proceeding (except in the case of original submissions);	Docket Number is included in File Name (i.e., "250610-NWN-GRC-CLtr-08-29-25")
(✓)	b. Any confidentiality designation;	Included in File Name as appropriate - Confidential (C) and Highly Confidential (HC)
(✓)	c. The name of the document;	Included in File Name (i.e., "250610-NWN-GRC-CLtr-08-29-25")
(✓)	d. *[Missing from Staff's Form]*	N/A
(✓)	e. The name of the person or party on whose behalf the document is submitted;	Included in the File Names
(✓)	f. The last name of any witness sponsoring the document; and	Witness initals included in File Names per WAC 480-07-140(6)(b). List of witnesses, including full name with middle initial, provided in Cover Letter.
(✓)	g. The date the document is submitted.	Included in the File Names

4. Acceptable Organization
Rule: WAC 480-07-140(6)(c)
Except as provided in WAC 480-07-160(4)(c)(iv), - (5)(c)(iv), and (6)(c)(iv).

		NW Natural's Compliance Demonstration
(✓)	When submitting documents that include information designated as exempt, confidential, and/or highly confidential, all files required to meet a single deadline must be submitted at the same time and in the same message, if possible, or on the same disc or commonly used electronic storage medium.	All files provided through Box, upon coordiation with the WUTC Filing Center.

5. Confidential and Other Restricted Information
Rule: WAC 480-07-160

		NW Natural's Compliance Demonstration
(✓)	a. Designating information as exempt/confidential/highly confidential;	All Confidential information is provided in a confidential and redacted format, properly notated in file names, and on applicable pages or spreadsheets. Highly Confidential information is properly described and withheld pursuant to WAC 480-07-160(6)(f), and a complete unredacted and redacted version will be submitted as soon as practicable after the Commission enters a Protective Order in this proceeding
(✓)	b. Providing documents with information designated as exempt/confidential/highly confidential; and	
(✓)	c. Marking and submitting information designated as exempt/confidential/highly confidential.	

Commission Staff's General Rate Case Audit Guide for Electric and Natural Gas Companies

6. General Provision
Rule: WAC 480-07-510

		NW Natural's Compliance Demonstration
(✓)	The company and all parties to an adjudication in a general rate proceeding must file all required documents in electronic form consistent with the requirements in WAC 480-07-140 and by the next business day must file five paper copies of all testimony and exhibits unless the commission establishes a different number.	On Friday, August 29, 2025, the complete filing is being electronically filed with the WUTC. Five paper copies of the complete filing is scheduled for delivery to the WUTC on Tuesday, September 2, 2025. A complete unredacted and redacted version of Highly Confidential documents will be submitted as soon as practicable after the Commission enters a Protective Order in this proceeding

7. Testimony & Exhibits (T&E)
Rule: WAC 480-07-510(1)
The utility must provide an exhibit that includes:

		NW Natural's Compliance Demonstration
(✓)	a. Results-of-operations statement showing test year actual results;	See Walker Exhibits Exh.KTW-2 through Exh KTW-12
(✓)	b. Restating and pro forma adjustments in columnar format supporting its general rate request;	See Walker Exhibits Exh.KTW-2 through Exh KTW-12
(✓)	c. Each restating and pro forma adjustment and its effect on the results of operations and revenue requirement;	See Walker Exhibits Exh.KTW-2 through Exh KTW-12
(✓)	d. A written description (in the testimony) of each proposed restating and pro forma adjustment describing the reason, theory, and calculation of the adjustment.	See Walker Testimony Exh. KTW-1T

8. Tariff Sheets
Rule: WAC 480-07-510 (2)
The company must file a copy of:

		NW Natural's Compliance Demonstration
(✓)	a. The proposed new or revised tariff sheets in legislative format;	Provided with Cover Letter and Original Filing
(✓)	b. Any tariff sheets that are referenced by new or amended tariff sheets.	See the Cover Letter for complete list of tariff sheets included in this filing
(✓)	c. Changes to revised tariffs must be indicated by symbols or notations and consistent with the other requirements. (per WAC 480-80-105)	NW Natural has submitted coded tariff sheets consistent with WAC 480-80-105

Commission Staff's General Rate Case Audit Guide for Electric and Natural Gas Companies

9. Detailed Support for Proposals
Rule: WAC 480-07-510 (3)(a) – (3)(i)

		NW Natural's Compliance Demonstration
(✓)	a. The company must include in its initial T&E (testimony and exhibits), sufficient detail, calculations, information and descriptions necessary to meet its burden of proof.	NW Natural's direct case includes the testimony and supporting exhibits regarding 18 subjects supported by 19 witnesses. Workpapers will be provided within five business days.
(✓)	b. The company must include in T&E a detailed description of the development of any capital structure and rate of return (ROR) proposals.	See testimony and exhibits of Brody J. Wilson (Exh. BJW-1CT through BJW-7C) and Jennifer E. Nelson (Exh. JEN-1T through Exh. JEN-19)
(✓)	c. T&E must include a detailed portrayal of the restating and pro forma adjustments used to support its proposal or position (assumptions, etc.) T&E must include support for and calculations showing the derivation of each input number used in the detailed portrayal, as well as the derivation of all interstate and multiservice allocation factors. (See WAC 480-07-510(3)(c)(i) and WAC 480-07-510(3)(c)(ii) for definitions of restating and pro forma adjustments, respectively.)	See testimony and exhibits of Kyle T. Walker (Exh. KTW-1T through Exh. KTW-12). The allocation methodology is provided in Exh. KTW-3.
(✓)	d. The company must include in T&E a detailed portrayal of revenue from regulated sources, by source, during the test year and the changes that would result in those revenues if the commission approved the company's request, including an explanation of how the resulting changes were derived.	See testimony and exhibits of Kyle T. Walker (Exh. KTW-1T through Exh. KTW-12).
(✓)	e. The company must demonstrate in T&E why the company has not achieved its authorized ROR and what actions company has taken prior to and during the test year to improve its earnings in addition to its request for increased rates. If the company has not taken such action, the company must explain why it has not.	See testimony and exhibits of Kyle T. Walker (Exh. KTW-1T through Exh. KTW-12).
(✓)	f. T&E must include a representation of the company's actual rate base and results of operations during the test period, calculated in the same manner the commission used to calculate the revenue requirement in the final order in the company's most recent GRC.	See testimony and exhibits of Kyle T. Walker (Exh. KTW-1T through Exh. KTW-12) and Kimberly A. Rush and Zachary D. Kravitz (Exh.KAR-ZDK-1T)
(✓)	g. The company's T&E must supplement, as necessary, the annual affiliate and subsidiary transaction reports to include all such transactions during the test period. The company must identify all affiliate and subsidiary transactions that materially affect the proposed rates. The company must support the allocation method used to distribute common costs between regulated and nonregulated affiliated entities and the dollar amount of those costs.	Statement affirming no need to update annual affiliate and subsidiary transaction reports in this case in compliance with WAC 480-07-510(3)(g) included in Cover Letter.
(✓)	h. Electronic files must be fully functional and include all formulas and linked spreadsheet files. Electronic files that support exhibits must use logical file paths, as necessary, by witness and must use identifying file names consistent with the naming requirements in WAC 480-07-140.	NW Natural has complied with this requirement

Commission Staff's General Rate Case Audit Guide for Electric and Natural Gas Companies

(✓)	i. If T&E refer to a document including, but not limited to, a report, study, analysis, survey, article, or court or agency decision, the party's T & E must include that document except as provided below: (i) A party may include an official citation or internet Uniform Resource Locator (URL) to a commission order or to a court opinion or other state or federal agency decision; (ii) A party may include only the relevant excerpts of a voluminous document if the party also provides a publicly accessible internet URL; and (iii) A party is not required to file or distribute materials subject to third-party copyright protection.	NW Natural has complied with this requirement

10. Work Papers		**NW Natural's Compliance Demonstration**
(✓)	Rule: WAC 480-07-510 (4)(a) a. Within 5 business days, the company must provide copies of all supporting work papers of each witness and must comply with the requirements of this subsection.	NW Natural will provide workpapers within 5 business days.
(✓)	Rule : WAC 480-07-510 (4)(b) b. Work papers must be plainly identified and well organized, and must include an index. Work papers must be cross referenced and include a description of the cross-referencing methodology.	Workpapers will comply with these requirements and an index is included
(✓)	Rule : WAC 480-07-510 (4)(c) c. Any work papers provided to other parties must comply with requirements governing electronic documents and confidentiality and referenced documents.	Workpapers will comply with these requirements

Commission Staff's General Rate Case Audit Guide for Electric and Natural Gas Companies

11. Summary Document

Rule: WAC 480-07-510 (5)(a)		**NW Natural's Compliance Demonstration**
(✓)	a. The company must include in its initial filing a document that summarizes the information in this subsection on an annualized basis, if applicable, and must itemize revenues from any temporary, interim, periodic, or other non-continuing tariffs. (i) The date and amount of the last general rate change and the revenue the company realized from that change during the test period based on the company's test period units of sale; (ii) Total revenues the company is realizing at its present rates and the total revenues the company would realize at the requested rates; (iii) Requested revenue change in percentage, in total and by major customer class; (iv) Requested revenue change in dollars, in total and by major customer class; (v) The representative effect of the request in dollars for the average monthly use per customer, by customer class or other similar meaningful representation, i.e., dollars per month on residential customers by usage categories; (vi) Most current customer count, by major customer class; (vii) Current authorized overall ROR and authorized rate of return on common equity (ROE); (viii) Actual ROR and actual ROE for the test period; (ix) Requested overall ROR and requested ROE and the method or methods used to calculate the requested rates of return; (x) Requested capital structure; (xi) Requested net operating income; (xii) Requested rate base and method of calculation or equivalent; and (xiii) Revenue effect of any requested attrition allowance.	See Attachment A providing items required by WAC 480-07-510(5).

Cover Letter		**NW Natural's Compliance Demonstration**
(✓)	The company must enclose a cover letter with the summary document stating that the company's pre-filed testimony, exhibits, and work papers are available from the company on request, if the company is not serving them along with the summary document.	NW Natural provided a complete electronic copy of the entire filing, including Summary Document (Attachment A) to Public Counsel. The Company also served parties from its last general rate case with the Summary Document, including required cover letter.

12. Cost Studies (Cost of Service)

Rule: WAC 480-07-510 (6)		**NW Natural's Compliance Demonstration**
(✓)	a. The company must provide any cost studies it performed to prepare its filing.	Included in the Testimony and Exhibits of Robert J. Wyman Exh RJW-1T through RJW-19C. Exh. RJW-1T discussed previous cost studies and Exh. RJW-12 includes the WUTC's natural gas cost of service template. Cost studies are included in Exh. RJW-12 and Exh. RJW-13.
(✓)	b. The company must identify all cost studies conducted in the last five years for any of the company's services.	
(✓)	c. The company must describe the methodology used in all such cost studies. If the study is in the form of a model, the company must provide a copy of or reasonable access to the model	

Commission Staff's General Rate Case Audit Guide for Electric and Natural Gas Companies

13. Additional Documents
Rule: WAC 480-07-510 (7)
The company must file or provide URL for each of these:

		NW Natural's Compliance Demonstration
(✓)	a. Its most recent annual report to shareholders, if any, and any subsequent quarterly reports to shareholders;	See Attachment B for associated URLs
(✓)	b. The most recent FERC Form 1 and FERC Form 2;	See Attachment B for associated URLs
(✓)	c. The company's Form 10 Ks and Form 10 Qs, any prospectuses for any issuances of securities and quarterly reports to stockholders, if any, for the most recent two years prior to the rate change request.	See Attachment B for associated URLs

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Attachment E

Master Services Agreement, in Compliance with Stipulating Condition 25e in Order 01 from Docket UG-17009

August 29, 2025

MASTER SERVICES AGREEMENT

THIS MASTER SERVICES AGREEMENT (the "Agreement"), effective January 1, 2019, is between Northwest Natural Gas Company ("NW Natural"), its parent company, Northwest Natural Holding Company ("NW Natural Holdings"), and its affiliates and subsidiaries (together, the "Affiliates"). NW Natural and its Affiliates are "Affiliated Interests," as defined under ORS 757.015 and RCW 80.16.010.

RECITALS

A. NW Natural is an Oregon corporation that is a natural gas local distribution company that serves customers through separate facilities located in Oregon and southwestern Washington. NW Natural is a wholly owned subsidiary of NW Natural Holdings—a publicly held company traded on the New York Stock Exchange. A list of NW Natural's Affiliates is included in Addendum 1, which may be amended periodically. NW Natural and its Affiliates, as identified in Addendum 1, are referred to herein as "Party" or collectively as "Parties". NW Natural is subject to regulation by the Oregon Public Utility Commission ("OPUC") and Washington Utilities and Transportation Commission ("WUTC"), respectively, for its state-regulated gas distribution activities in such states, and by the OPUC and the Federal Energy Regulatory Commission ("FERC") for its regulated intrastate and interstate gas storage activities. NW Natural is headquartered in Portland, Oregon.

B. Attached as Addendum 1 is a list of NW Natural's Affiliates. Except as otherwise noted on the Addendum, all of these Affiliates are legal entities separate and apart from NW Natural. Nothing in the Agreement is to be interpreted to the contrary.

C. NW Natural employs certain trained personnel capable of performing needed management, analytical, professional, and administrative services (which, together with the more detailed services specified on Addendum 2, are referred to herein as the "Services") in furtherance of the Affiliated Interests' operations.

D. NW Natural desires to make available to NW Natural's Affiliates such personnel and Services as the board of directors, officers or managers of those Parties shall reasonably request in the future, without detriment to NW Natural's utility functions.

E. NW Natural's Affiliates desire to make available to NW Natural such personnel and Services as the board of directors, officers or managers of NW Natural shall reasonably request in the future, without detriment to NW Natural's Affiliates' respective business functions.

THEREFORE, the Parties agree as follows:

1. **Services Provided by NW Natural**

Upon the request of the board of directors, officers, or managers of NW Natural, NW Natural shall furnish to its Affiliates the Services listed in Addendum 2 as requested, subject to applicable requirements of the cognizant utility commission(s), and given the terms and conditions as follows:

2. **Requests for Service**

All Services provided shall be mutually agreeable and based upon a written request for Services in a form substantially similar to that attached as Addendum 3 hereto ("Request for Services"), specifying the scope of Services. Changes in the Request for Services shall be agreed to in writing by the Parties.

3. **Basis of Charges**

3.1 Costs Included in State Utility Revenue Requirements. If the service cost or benefit is intended for inclusion in NW Natural's state operations revenue requirements, then:

a. All billing by NW Natural to an Affiliate shall be at the higher of cost or market, unless otherwise specified by the Parties and approved by the OPUC and/or, as appropriate, the WUTC.

b. All billings by an Affiliate to NW Natural shall be at the lower of cost or market, unless otherwise specified by the Parties and approved by the OPUC and/or the WUTC, or unless provided at an approved rate on file with the OPUC and/or the WUTC or the FERC.

c. All billings for Services rendered to NW Natural by an Affiliate shall meet the following three criteria: (1) they must be just and reasonable regulated utility expenses; (2) they must be for functions that NW Natural would perform as a stand-alone utility; and (3) they must not duplicate, but may augment/supplement, functions already performed by NW Natural.

3.2 Costs Defined. For the purpose of this Agreement, "costs" shall include both of the following:

a. All out-of-pocket expenses of the Party providing the Services incurred in connection with the provision of Services rendered, including salaries, labor costs and benefits and other payroll overhead costs; amounts paid for independent technical and professional Services; amounts paid to third-party contractors; and all administrative overhead expenses, including, but not limited to, space utilization, utilities, IT costs and other administrative costs. Labor costs shall be based on the number of hours worked by the employees multiplied by the average cost rate per hour applicable to those employees. The hourly rate shall be adjusted to

include all appropriate payroll overhead loadings (for vacation, benefits, taxes, etc.). In addition, the applicable Administrative overhead loading rate shall be applied to derive the fully loaded cost of employee time associated with Services provided. Materials, supplies, and non-labor vouchered items shall similarly be charged to the other Party on the basis of the full cost of the items supplied. Supporting documentation on the cost of non-labor items shall be available to the other Party to substantiate the charges billed. Non-labor costs shall not have an A&G loading rate applied.

b. A reasonable return on any investment in assets, equipment, or plant ("Assets") supporting the provision of Services in the following amounts:

(i) For Services provided by NW Natural, the return on Assets employed, if any, shall be no less than the rate case authorized rate of return on its investment serving its ratepayers; and

(ii) For Services provided by an Affiliate to NW Natural, the return on Assets employed, if any, shall be no more than the rate case authorized rate of return on its investment serving its ratepayers, if applicable.

4. **Method of Charging for Services**

4.1 Direct Assignment and Allocation Methods. Direct assignment of costs shall be the primary method for charging for Services according to the accounting procedures in NW Natural's Cost Allocation Manual, attached as Exhibit A. Exhibit A contains rules for determining and allocating any remaining costs associated with those Services that cannot be directly assigned to a user of a Service. The allocation methods set forth in Exhibit A shall be applied to allocate those costs that cannot be directly assigned.

4.2 Review of Affiliate Charges to NW Natural. At least annually, NW Natural shall review the Services supplied by the Affiliates under each of the Addenda executed. The

review shall include a determination that billing is consistent with the accounting and cost assignment procedures in Section 3 and Exhibit A.

5. **Invoicing**

a. As soon as practicable after the last day of each month, the provider of Services shall invoice the recipient of Services for expenses for the month concluded, computed pursuant to Sections 3 and 4 above.

b. All invoice charges shall be supported by documentation satisfactory to the recipient. Charges for Services shall be entered into the accounting records in the month following the period in which Services were rendered. However, if the invoice charges are less than $50,000 per Party, then invoice may be delayed until either (1) total charges are more than $50,000 per Party, or (2) quarterly, whichever comes first.

6. **Monitoring and Control**

The Inter-Company Services Coordinator ("Coordinator") is responsible for reviewing, monitoring and maintaining Services Requests that are active. The Coordinator ensures authorization of new Services Requests and that allocation factors are proper and accurate. Additionally, the Coordinator is responsible for coordinating the monthly billing process as described in Section 5 above.

7. **Billing Disputes**

Disputes on billings for Services shall be resolved through negotiations between the authorized representative(s) of the Affiliate, the Controller of NW Natural, and the Vice President(s) of the department at NW Natural responsible for providing or receiving Services, or their respective designee(s).

8. **Books and Records**

a. All transactions made under this Agreement shall be recorded by NW Natural in accordance with the Uniform System of Accounts prescribed by the regulatory authorities having jurisdiction over NW Natural.

b. Each Party shall have the right at all reasonable times to examine the books and records of the other for the purpose of verifying the cost, or the market value determination if applicable, of the Services performed by the other Party.

9. **Limitations on Service**

a. NW Natural shall diligently and competently render all Services reasonably requested by the Affiliates to the extent NW Natural can make available its resources without detriment to its utility functions.

b. The Affiliates shall diligently and competently render all Services reasonably requested by NW Natural to the extent those entities can make available their resources without detriment to their business functions, and to the extent that such Services to NW Natural are specified in the attached Addendum 2 to this Agreement.

c. NW Natural and its Affiliates shall coordinate and administer all Services being rendered under this Agreement in order that such Services shall be furnished as efficiently and economically as possible.

d. Except as provided in subsections 9.a. and b. above, neither NW Natural nor its Affiliates shall have priority over the other in obtaining Services under this Agreement.

10. **Limitation of Authority**

The Parties agree that no Party shall assume nor create any obligation on behalf of any other Party other than as specifically provided for in this Agreement. Each Party reserves to itself

the right to make commitments for loans, financing, mortgages, and other commitments necessary and proper for its corporate purposes.

11. **Inspection and Reporting**

a. All books, records, and other data in possession of the Parties relating to the provision of Services pursuant to this Agreement shall at all times, during normal business hours, be made available to or copies provided to any regulatory agency having jurisdiction when engaged in the performance of its lawful functions, except to the extent that such information is reasonably determined by any Party to be confidential in nature in which case any such information shall be submitted to any such regulatory agency under confidential treatment in accordance with the applicable laws and regulations governing such confidential treatment request.

b. Each Party shall timely furnish to each other Party such information with regard to its operations as shall be reasonably required.

12. **Regulatory Jurisdiction**

The Parties acknowledge that NW Natural is a public utility company subject to regulation and control by various state and federal governmental regulatory agencies. The provisions of this Agreement shall be construed in aid of and not in derogation of the lawful control and regulatory power of any such agency.

13. **Damages**

In no event shall a Party be liable to another Party for any lost or prospective profits or any other special, punitive, exemplary, consequential, incidental or indirect losses or damages (in tort, contract or otherwise) under or in respect of this Agreement or for any failure of performance however caused, whether or not arising from the Party's sole, joint, or concurrent negligence. To the extent any payment required to be made under this Agreement is agreed by the Parties to

constitute liquidated damages, the Parties acknowledge that actual damages in such circumstances are difficult or impossible to determine and that such payment of liquidated damages constitutes a reasonable approximation of such damages, and not a penalty.

14. **Governing Law**

This Agreement shall be governed by and construed and enforced in accordance with the laws of the State of Oregon.

15. **Waiver**

Any of the terms and conditions of this Agreement may be waived at any time and from time to time by the Party entitled to the benefit of such term or condition, but a waiver in one instance shall not be construed as a waiver in any other instance. A failure to enforce any provision of this Agreement shall not operate as a waiver of such provision or of any other provision. A waiver by any Party in favor of another Party shall not bind any regulatory agency with jurisdiction over such matter if the agency determines that such waiver would violate its regulations, orders, or applicable statutes.

16. **Assignment**

This Agreement shall be binding upon the Parties and their representatives and may not be assigned.

17. **Termination**

NW Natural reserves the right at any time upon thirty (30) days notice to its Affiliates to terminate this Agreement in whole or part. NW Natural shall promptly notify the OPUC and/or WUTC, if applicable, of such termination. NW Natural, or any Affiliate, reserves the right at any time upon notice to the other to terminate any or all of NW Natural or any Affiliate's Services Request(s) under this Agreement.

18. **Integrated Agreement**

This Agreement embodies the entire agreement and understanding between the Parties and does not supersede any prior agreement between such Parties, but governs all agreements entered into after the Effective Date. This Agreement may be executed by the Parties in separate counterparts, each of which when executed and delivered shall be an original, but which together shall constitute but one and the same agreement.

19. **Adoption of Agreement by Affiliates**

At such time that a NW Natural Affiliate requests or provides Services from/to any Party to this Agreement, the Affiliate shall sign Addendum 3 which adopts this Agreement.

Date as of December 21, 2018

NORTHWEST NATURAL GAS COMPANY

By: _____

Name: Brody J. Wilson

Title: Vice President, Controller, Treasurer & Chief Accounting Officer

Addendum 1:
Affiliates of NW Natural

The Appliance Center**
Northwest Energy Corporation
NWN Gas Reserves, LLC
Northwest Biogas, LLC
NNG Financial Corporation
KB Pipeline Company
Gill Ranch Storage, LLC
NW Natural Energy, LLC
NW Natural Gas Storage, LLC
Trail West Holdings, LLC
Trail West Pipeline, LLC
BL Credit Holdings, LLC
NW Natural Water Company, LLC
NW Natural Water of Oregon, LLC
NW Natural Water of Washington, LLC
NW Natural Water of Idaho, LLC
Salmon Valley Water Company
Falls Water Company
Cascadia Water, LLC
Gem State Water Company

Please note this is the affiliate list included in the MSA filed on December 28, 2018 in docket UG-170094 in compliance with Order 01.

For the most recent list of affiliates, please refer to the Company's most recent annual Affiliated Interest Report filed with the Washington Utilities & Transportation Commission.

*Each of these businesses with the exception of the Appliance Center is a legal entity separate and apart from NW Natural. Nothing in this Agreement is intended to be interpreted to the contrary.

**The Appliance Center is a nonregulated business segment of NW Natural.

Addendum 2:
Updated April 2023

List of Services

This Addendum provides a description of the Services that **may be** performed by the Parties, which may be modified from time to time. This list is exemplary only, and nothing in this addendum suggests that such services have or shall actually be performed by or for any Party. The specific Services to be provided to a particular Party are set forth in Addendum 3.

All Services provided by the Parties shall be based on a mutually agreeable work scope, specifying the scope of Services, personnel, and budget for Services. Changes in the scope of work shall be agreed to by the Parties involved.

Executives – Management Oversight	Provided executive and management oversight.
Internal Auditing / Business Controls and SOX	Reviews internal controls and procedures to ensure assets are safeguarded and transactions are properly authorized and recorded. Reviews current or proposed processes for improvements, compliance or SOX and audit requirements. Periodically audits accounting and other records and coordinates their examination, where applicable, with that of independent public accountants.
Legal	Provide legal advice and assistance with respect to labor and employment law, litigation, contracts, rates and regulation, environmental matters, and real estate legal issues, as well as, authorizations and compliance with matters under federal and state laws.
Corporate and Strategic Planning and Business Analysis and Development	Facilitates preparation of strategic plans, monitors trends and evaluates business opportunities, including acquisitions and dispositions. Facilitates process improvements by investigating and conducting research into issues relating to production, utilization, testing, manufacture, transmission, storage and distribution of energy. Keeps current on all research developments and programs of significance affecting company and the energy industry. Conducts research and development in promising areas and advises and assists in the solution of technical problems.

Accounting/ Accounts Payable/Finance/Budgeting/Treasury	Provide advice and assistance to Company in finance, treasury and accounting matters, including the development of accounting practices, procedures and controls, the maintenance of the general ledger and related subsidiary financial systems, the preparation and analysis of financial reports, treasury management and credit. Provide services related to managing all administrative activities associated with financing, including management of capital structure; cash, credit and risk management activities; investment and commercial banking relationships; oversight of retirement trust funds and general financing activities. Advise and assist company and Affiliates in studying and planning in connection with infrastructure, budgets, economic forecasts, benchmarking, capital expenditures and special projects. Provide centralized accounts payable processing. Provide shared services management and respective intercompany accounting and settlement processes.
Tax	Advise and assist in the preparation of federal, state and other tax returns, and respective tax accounting entries and generally advise company as to any issues involving taxes.
Risk Management	Advise and assist company in its risk and control framework. Manage the purchase and administration of all property and casualty insurance including the settlement of insured claims and in providing risk prevention advice.
Land and Environmental	Provide right of way services, including encroachments. Establishes policies and procedures for compliance with environmental laws and regulations. Researches emerging environmental issues and monitors compliance with environmental requirements. Provides oversight for environmental remediation services.
Corporate Communications	Prepares and disseminates information to employees, customers, government agencies, communities and the media.
Public Policy and Governmental Affairs	Provide services in support of corporate strategies for managing relationships with federal, state and local governments, agencies

	and legislative bodies. Monitor, review, research, and advocate legislative issues. Formulate and assist with public relations and communications programs and administration of corporate contribution and community affairs programs.
Human Resources/Employee Benefits/Payroll/Safety	Advise and assist company in the formulation and administration of human resources and employee relations' policies and programs relating to personnel administration, training, wage and salary administration and safety programs. Provide central accounting for employee benefits and payroll. Direct and administer all medical and health activities for company. Advise and assist company in the administration of such plans and prepare and maintain records of employee and company accounts under the said plans, together with such statistical data and reports as are pertinent to the plans. Provide centralized payroll system.
Information Technology and Services	Provide the resources for the operation of an information technology function, including the development, implementation, and operation of a centralized data processing facility and the management of a telecommunications network. This function includes the central processing of computerized applications, support of individual applications and the development, implementation and processing of those computerized applications that can be best accomplished on a centralized basis. This function provides centralized help desk.
Facilities Management / Security	Manage headquarters facilities, service centers, and district offices. Administers contracts for real estate leases, security, housekeeping, and maintenance of facilities. Maintain database of real estate contracts, managing lease/rental properties, handling purchases and sales of real property.
Office Services/Clerical Administrative Services	Provide centralized mail, imaging, record management services, and other general administrative support services.
Purchasing and Stores	Procure materials, supplies and services necessary for all operations, with the exception of wholesale gas purchases. Manage materials and supplies inventories. Work closely with

	business unit teams, seeking the best value for company through refined sourcing strategies, contracts and supplier agreements.
Marketing	Provide initial contact service related to new customer additions. Plan, formulate and implement marketing programs, as well as provide associated marketing services to improving customer satisfaction, load retention and shaping, growth of energy sales and deliveries, etc. Assist in carrying out policies and programs for the development of plant location and of industrial, commercial and wholesale markets. Provide customer support for industrial and commercial customers. Assist large customers in meeting business requirements related to gas quality, conservation, etc. Seek to maintain positive working relationships with major customers.
Engineering and Operations	Provide advice and assistance to Company in engineering and operations matters.
Rates and Regulatory	Provide advice and assistance to Company in rates and regulatory matters. Provide centralized rates and regulatory services and regulatory compliance.
Front Office – Gas Supply	Provide advice and assistance to Company in Gas Supply purchasing and compliance matters.
Other Services/Functions as Requested	Provide advice and assistance to Company in other matters including, but not limited to, Project Management, Safety, etc.

Addendum 3:

Sample Services Request Form

Services Requested

The undersigned requests that **[Party Providing Services]** provide Services listed in Addendum 2 to the Master Services Agreement.

The undersigned agrees to the terms and conditions contained in the Master Services Agreement, and further agrees that all requests for Services from **[name of Party]** to NW Natural will be governed by the Master Services Agreement.

Services are requested beginning **[Dates Services Requested].**

[Party Requesting Services]

By: _____

Print Name: _____

Title: _____

Date: _____

Exhibit A – COST ALLOCATION MANUAL

For the most current Cost Allocation Manual, please refer to the Company's most recent annual Affiliated Interest Report filed with the Washington Utilities & Transportation Commission.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

RATE YEAR 1 TARIFF SHEETS

LEGISLATIVE

August 29, 2025

RATE SCHEDULE 1
GENERAL SALES SERVICE

AVAILABLE:
To all Residential and Commercial Customer classes in all territory served by the Company under the Tariff of which this Rate Schedule is a part, except that service under this Rate Schedule is not available for Standby Service to Commercial Customers. Seasonal or temporary Discontinuance of Service is allowed subject to Special Provision 1 of this Rate Schedule. The installation of Distribution Facilities, when required before service can be provided to equipment served under this Rate Schedule, is subject to the provisions of **Schedule E**.

SERVICE DESCRIPTION:
Service under this Rate Schedule is Firm Sales Service to gas-fired equipment, including but not limited to one or any multiple or combination of the following:

(a) Non-ducted space heating equipment that does not qualify as primary heating systems under Rate Schedule 2, including but not limited to fireplace inserts, free standing gas stoves, and room heaters;
(b) Supplemental or Standby space heating equipment including but not limited to natural gas back-up to electric heat pumps, used in residential applications;
(c) Water heating equipment used to serve single-family residential swimming pools, spas, and hot tubs;
(d) Other equipment including, but not limited to, log lighter, gas log, gas barbecue, tiki torch, Bunsen burner, Domestic cooking equipment, hobby kilns, refrigeration or Domestic clothes drying;
(e) Equipment installed for use in detached garages, shops, or outbuildings.

MONTHLY RATE: Effective: ~~January 1, 2025~~ September 30, 2025
The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 200** for a list of applicable adjustments. Rates are subject to charges for purchased gas costs and technical rate adjustments. (C)

	Base Rate	Pipeline Capacity Rate	Commodity Rate	Temporary Adjustment	Billing Rate	
Residential:	-	-	-	-	-	
Customer Charge	~~$5.50~~$8.00	—	—	—	**~~$5.50~~$8.00**	(I)
Schedule 308 Credits (per bill)	-	-	-	($1.82)	**($1.82)**	~~(R)~~
Volumetric Charge (per therm)	~~$0.83469~~ $1.16131	~~$0.10337~~$0.10337	~~$0.43274~~$0.43274	$0.30387 ~~$0.29750~~	**~~$1.66830~~ $2.00129**	(I)
	-	-	-	-	-	
Commercial:	-	-	-	-	-	
Customer Charge	~~$7.00~~ $10.00	—	—	—	**~~$7.00~~ $10.00**	(I)
Schedule 308 Credits (per bill)	-	-	-	$(5.34)	**($5.34)**	~~(I)~~
Volumetric Charge (per therm)	~~$0.86308~~ $1.24467	$0.10337	$0.43274	$0.27830 ~~$0.27345~~	**~~$1.67264~~ $2.05908**	~~(R)~~(I)

Minimum Monthly Bill: Customer Charge, plus charges under **Schedule C** and **Schedule 10** (if applicable)

(continue to Sheet 101.2)

RATE SCHEDULE 2
RESIDENTIAL SALES SERVICE

AVAILABLE:
To Residential Customers, in all territory served by the Company under the Tariff of which this Rate Schedule is a part. Seasonal or temporary Discontinuance of Service is allowed subject to Special Provision 1 of this Rate Schedule. The installation of Distribution Facilities, when required before service can be provided to equipment served under this Rate Schedule, are subject to the provisions of **SCHEDULE E**.

SERVICE DESCRIPTION:
Service under this Rate Schedule is Firm Sales Service to gas-fired equipment used in Residential dwellings that provide complete family living facilities in which the occupant normally cooks, eats, sleeps, and carries on the household operations incident to Domestic life, for at least one of the following purposes:

(a) Operation of ducted forced air Natural Gas space heating equipment that is the primary source for space heating requirements;
(b) Operation of a gas-fired hearth product or wall heater as the primary source for space heating requirements where the hearth or wall heater has a verified nameplate rating of 20,000 BTUs or greater, and is installed in a primary residence defined as a dwelling that is occupied year-round, and where that dwelling is 1,500 square feet or less; and, or;
(c) Operation of fully automatic water heating equipment for primary water heating requirements.

Service under this Rate Schedule includes the use of gas for equipment installed in addition to (a) and (b).

MONTHLY RATE: Effective: ~~January 1, 2025~~September 30, 2025 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

	Base Rate	Pipeline Capacity Rate	Commodity Rate	Temporary Adjustment	Billing Rate	
Customer Charge:	$8.00	—	—	—	**$8.00**	
Schedule 308 Credits - Winter (per bill)	-	-	-	($10.97)	**($10.97)**	(I)
Schedule 308 Credits - Non-Winter (per bill)	-	-	-	($4.84)	**($4.84)**	(I)
Volumetric Charge (per therm)	~~$0.55820~~ $0.84344	$0.10337	$0.43274	~~$0.22096~~ $0.22427	**~~$1.31527~~$1.60382**	(I~~R~~)

Minimum Monthly Bill: Customer Charge, plus charges under **Schedule C** and **Schedule 10** (if applicable)

Issued ~~December 18, 2024~~August 29, 2025
NWN WUTC Advice No. 25-03~~24-17~~
September 30, 2025

Effective with service on and after ~~January 1, 2025~~

RATE SCHEDULE 3
BASIC FIRM SALES SERVICE - NON-RESIDENTIAL
(continued)

(C)

MONTHLY RATE: Effective: ~~January 1, 2025~~ September 30, 2025

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM SALES SERVICE CHARGES (03 SF):					**Billing Rates [1]**	
Customer Charge (per month):					**$22.00**	
	Base Rate	Pipeline Capacity	Commodity Component [2]	Temporary Adjustment		
Schedule 308 Credits (per bill):						
Commercial - Winter				($46.59)	**($46.59)**	(I)
Commercial - Non-Winter				($25.89)	**($25.89)**	
Industrial				($129.16)	**($129.16)**	(I)
Volumetric Charges (per therm):						
Commercial	~~$0.53350~~ $0.81318	$0.10337	$0.43274	~~$0.20893~~ $0.21184	**~~$1.27854~~ $1.56113**	(I~~R~~)
Industrial	~~$0.54385~~ $0.77961	$0.10337	$0.43274	~~$0.15035~~ $0.15305	**~~$1.23031~~$1.46877**	(I~~R~~)
Standby Charge (per therm of MHDV) [3]:					**$5.00**	

[1] **Schedule C** and **Schedule 10** Charges shall apply, if applicable.
[2] The Commodity Component will be either Annual Sales WACOG or Monthly Incremental Cost of Gas.
[3] Applies to Standby Sales Service only.

Minimum Monthly Bill. The Minimum Monthly Bill shall be any **Schedule C** and **Schedule 10** Charges, plus:

(a) ***Firm Sales Service.*** Customer Charge
(b) ***Firm Sales Standby Service.*** Customer Charge, plus Standby Service Charge

RATE SCHEDULE 10
CHARGES FOR SPECIAL METERING EQUIPMENT, RENTAL METERS AND METERING SERVICES

AVAILABLE:
In all territory served by the Company under the Tariff of which this Rate Schedule is a part.

TERM OF SERVICE:
The Term of Service for monthly meter rentals and metering services provided under this Schedule is one (1) Year. At the end of a full Term of Service, service under this Rate Schedule will continue on a billing month basis until terminated by either the Customer or the Company upon one (1) billing month advance notice.

MONTHLY METER RENTAL RATES AND SPECIAL METERING EQUPMENT (OPTIONAL):

Any Customer may pay to rent supplementary displacement type meters from the Company on a monthly basis calculated at theas follow sing rates: (C) (C) (D) (N) (R)

$$= \frac{Net\ Present\ Value\ (\text{Total Cost to Serve Meter at Discount Rate } r \text{ over Period } t)}{12}$$

- The Rental Meter is the meter inclusive of an Encoder Receiver Transmitter (ERT), if necessary, as well as required fittings and components (e.g., swivel, gasket, flange, etc.) which can vary by meter type and size.
- Cost to Serve incudes incremental capital-related costs (the cost of the Rental Meter) as well as any other costs customarily relating to recovery of the utility investment, including but not limited to capital depreciation, regulatory fees, and income and property taxes.
- Discount Rate *r* is the weighted cost of capital and cost of long-term debt authorized by the Commission in the Company's most recent general rate case. Period *t* is equal to the total depreciable life (in years) of the assembled meter set.

The Net Present Value calculation produces a levelized cost of the Company to serve the rental meter at Discount Rate *r* over Period *t*. Dividing this value by 12 produces the Monthly Meter Rental Charge.

The Company will consult with the Customer regarding available meters of sizes and pressures that meet their service requirements prior to entering into a rental agreement. The meter rental charge, which is calculated as a monthly rate as described above, is presented to the Customer prior to the rental period and installation at the Customer premise. (N)

. (R)

~~Diaphragm Meters~~

~~Meter Size (Cubic Feet/hour)~~	~~Monthly Charge~~
~~250~~	~~$1.98~~
~~630~~	~~$5.64~~
~~1000~~	~~$9.69~~

~~No new service after April 27, 2018. These charges are for service agreements initiated prior to April 27, 2018.~~

~~425~~	~~$0.86~~
~~750~~	~~$1.40~~
~~800~~	~~$1.48~~

Issued ~~October 25, 2021~~August 29, 2025
NWN WUTC Advice No. 25-031-09 ~~2021~~September 30,2025

Effective with service on and after ~~November 1,~~

1400	$2.93
2500	$5.58

Rotary Meters

Meter Size	Meter Capacity (Cubic Feet/hour)	Monthly Charge
1.5M175/15C175	1500	$26.01
3M175	3000	$28.07
5M175	5000	$31.59
7M175	7000	$32.45
11M175	11000	$50.28
16M175	16000	$65.15
23M175	23000	$181.03
38M175	38000	$239.76

No new service after April 27, 2018. These charges are for service agreements initiated prior to April 27, 2018.

8C175	800	$ 13.00

(continue to Sheet 110.2)

RATE SCHEDULE 10
CHARGES FOR SPECIAL METERING EQUIPMENT, RENTAL METERS AND METERING SERVICES
(continued)

Metering Services and Charges	One Time Charge	Installation Charge	Monthly Charge	
Rental Read	---	---	$0.36	
Advanced Automated Meter Reading (AAMR) Device[1]	---	$1,270.53	$~~48.05~~52.49	(~~I~~R)
Remote Index	---	$50.00	$4.00	
Pulse Output	---	$100.00	$8.00	
Administrative Set-Up/Consultation Fee (all meters)	$145~~00~~.00	---	---	(I)
Technical Assistance (Rotary meters only)	$145~~00~~.00	---	---	(I)

[1] Site specific engineering design costs for AAMR will be added to the installation charge if needed.

SPECIAL PROVISIONS FOR RENTAL METERS AND SPECIAL METERING EQUIPMENT:

1. Prior to receiving service under this section of the Schedule, the Customer must sign a service agreement that requires a minimum 12-month term. Customers who terminate service after less than 12 months will be required to pay all charges otherwise due to fulfill the 12-month obligation under the service agreement.
2. Service under this section of this Schedule is voluntary and separate from billing for or delivery of natural gas to a Customer's premise.
3. Since the Company does not maintain an inventory of all meter types offered under this Schedule, a delay may occur from the time a Customer requests service under this Schedule until the Company can provide it.
4. The Customer will be responsible for the meter pick-up and return of diaphragm meters.
5. The Customer will incur the Administrative Set-Up/Consultation Fee for each rental meter.
6. Upon delivery of a rotary meter, the Customer will incur the Technical Assistance charge listed above for each rental rotary meter. A Customer may not waive this provision or the associated fee. Technical assistance helps the Company ensure proper handling of rotary meters.
7. The Company will install AAMR devices for the charge listed above. AAMR devices will only be installed on Company owned meters and the Company will require that the Customer provide active and continuous electric power per company specifications to enable meter communications.
8. Upon request, the Company will provide one differential test per calendar year on rotary meters. The testing will be scheduled at the Company's convenience.
9. The Customer is responsible to protect all rental equipment from damage including but not limited to installing parking bollards to protect the rental equipment from vehicular or other damage.

(continue to Sheet 110.3)

RATE SCHEDULE 27
RESIDENTIAL HEATING DRY-OUT SERVICE

AVAILABLE:
To Residential home builders, developers, and contractors during the period that a Residential dwelling is under construction, in all territory served by the Company under the Tariff of which this schedule is a part.

SERVICE DESCRIPTION:
Service under this Rate Schedule is restricted to the use of gas in approved permanently-installed gas heating equipment in place during the period the dwelling is under construction. Upon occupancy of the dwelling, service under this Rate Schedule shall terminate automatically. In no event will service under this Rate Schedule continue for more a period of time greater than twelve (12) months from the date the gas meter is set at the dwelling. Upon termination of service under this Rate Schedule, gas service shall transfer to **Schedule 1** or **Schedule 2**, whichever is applicable.

MONTHLY RATE: Effective: ~~January 1, 2025~~September 30, 2025 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 200** for a list of applicable adjustments. Rates are subject to charges for purchased gas costs and technical rate adjustments.

	Base Rate	Pipeline Capacity Rate	Commodity Rate	Temporary Adjustment	Billing Rate
Customer Charge:	$9.00	---	---	---	**$9.00**
Volumetric Charge (per therm)					
All therms	~~$0.31253~~ $0.79988	$0.10337	$0.43274	~~$0.26727~~ $0.26973	~~**$1.11591**~~**$1.60572** (I~~R~~)

Minimum Monthly Bill: Customer Charge, plus charges under **Schedule C** and **Schedule 10** (if applicable)

GENERAL TERMS:
Service under this Rate Schedule is governed by the terms of this Rate Schedule, the General Rules and Regulations contained in this Tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

Issued ~~December 18, 2024~~August 29, 2025
NWN WUTC Advice No. 25-03~~24-17~~
~~2025~~September 30, 2025

Effective with service on and after ~~January 1,~~

RATE SCHEDULE 41
NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES FOR COMMERCIAL CUSTOMER CLASS: Effective: January 1, 2025September 30, 2025 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. **SEE SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM SALES SERVICE CHARGES (C41SF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$250.00**	
	Base Rate		Commodity Component [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($515.09)	**($515.09)**	(I)
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	$0.41608 $0.62232		$0.43274	$0.19067 $0.19304	**$1.03949 $1.24810**	(IR)
Block 2: All additional therms	$0.36663 $0.54836		$0.43274	$0.18179 $0.18387	**$0.98116 1.16497**	(IR)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.10337**	
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.54**	
INTERRUPTIBLE SALES SERVICE CHARGES (C41SI) [1]:						
Customer Charge (per month):					**$250.00**	
	Base Rate		Commodity Component: [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($515.09)	**($515.09)**	(I)
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	$0.38453 $0.53329		$0.43274	$0.14700 $0.14899	**$0.96427 $1.11502**	(IR)
Block 2: All additional therms	$0.33880 $0.46987		$0.43274	$0.13893 $0.14068	**$0.91047 $1.04329**	(IR)
Plus: Interruptible Pipeline Capacity Charge - Volumetric (per therm):					**$0.03612**	
FIRM TRANSPORTATION SERVICE CHARGES (C41TF):						
Customer Charge (per month):					**$250.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Total Temporary Adjustments [4]		
Schedule 308 Credits (per bill):				($515.09)	**($515.09)**	(I)
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	$0.37785 $0.51532			$0.26259 $0.26489	**$0.64044 $0.78021**	(IR)

Issued August 29, 2025December 18, 2024
NWN WUTC Advice No. 25-0324-17
2025September 30, 2025

Effective with service on and after January 1,

Block 2: All additional therms	~~$0.33291~~ $0.45404			~~$0.26011~~ $0.26213	~~**$0.59302**~~ **$0.71617**	(I~~R~~)

[1] The Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from Schedule C and Schedule 10.
[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG, or Monthly Incremental Cost of Gas.
[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 may not apply.

(continue to Sheet 141.10)

RATE SCHEDULE 41
NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES FOR INDUSTRIAL CUSTOMER CLASS: Effective: ~~January 1, 2025~~September 30, 2025 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. **SEE SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM SALES SERVICE CHARGES (I41SF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$250.00**	
	Base Rate		Commodity Component [2]	Total Temporary Adjustments [3]		(I)
Schedule 308 Credits (per bill):				($622.72)	**($622.72)**	
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	~~$0.37147~~ $0.49786		$0.43274	~~$0.14201~~ $0.14412	~~**$0.94622**~~ **$1.07472**	(I~~R~~)
Block 2: All additional therms	~~$0.32731~~ $0.43867		$0.43274	~~$0.13904~~ $0.14089	~~**$0.89909**~~ **$1.01230**	(R~~I~~)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.10337**	
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.54**	
INTERRUPTIBLE SALES SERVICE CHARGES (I41SI) [1]:						
Customer Charge (per month):					**$250.00**	
	Base Rate		Commodity Component: [2]	Total Temporary Adjustments [3]		(I)
Schedule 308 Credits (per bill):				($622.72)	**($622.72)**	
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	~~$0.36378~~ $0.50451		$0.43274	~~$0.10593~~ $0.10779	~~**$0.90245**~~ **$1.04504**	(I~~R~~)
Block 2: All additional therms	~~$0.32050~~ $0.44449		$0.43274	~~$0.10285~~ $0.10450	~~**$0.85609**~~ **$0.98173**	(I~~R~~)
Plus: Interruptible Pipeline Capacity Charge - Volumetric (per therm):					**$0.03612**	
FIRM TRANSPORTATION SERVICE CHARGES (I41TF):						
Customer Charge (per month):					**$250.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Total Temporary Adjustments [4]		(I)
Schedule 308 Credits (per bill):				($622.72)	**($622.72)**	
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	~~$0.36781~~ $0.51010			~~$0.26075~~ $0.26265	~~**$0.62856**~~ **$0.77275**	(I~~R~~)
Block 2: All additional therms	~~$0.32406~~ $0.44943			~~$0.25850~~ $0.26016	~~**$0.58256**~~ **$0.70959**	(I~~R~~)

[1] The Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity

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Charge selected by the Customer, plus any other charges that may apply from Schedule C and Schedule 10.

[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG, or Monthly Incremental Cost of Gas.

[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 may not apply.

RATE SCHEDULE 42
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY SALES RATES - FIRM SERVICE: Effective: September 30, 2025~~January 1, 2025~~ (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM SALES SERVICE CHARGES [1]:					**Billing Rates**	
Customer Charge (per month, all service types):					**$1,300.00**	
	Base Rate		Commodity Component [2]	Total Temporary Adjustments [3]		
C42SF						
Schedule 308 Credits (per bill):				($5,142.27)	($5,142.27)	(I)
Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	~~$0.20610~~ $0.33774		$0.43274	~~$0.15742~~ $0.15892	~~$0.79626~~ $0.92940	(I/R)
Block 2: Next 20,000 therms	~~$0.18448~~ $0.30232		$0.43274	~~$0.15305~~ $0.15440	~~$0.77027~~ $0.88946	
Block 3: Next 20,000 therms	~~$0.14150~~ $0.23188		$0.43274	~~$0.14439~~ $0.14543	~~$0.71863~~ $0.81005	
Block 4: Next 100,000 therms	~~$0.11318~~ $0.18547		$0.43274	~~$0.13869~~ $0.13952	~~$0.68461~~ $0.75773	
Block 5: Next 600,000 therms	~~$0.07545~~ $0.12364		$0.43274	~~$0.13108~~ $0.13164	~~$0.63927~~ $0.68802	
Block 6: All additional therms	~~$0.02828~~ $0.04635		$0.43274	~~$0.12157~~ $0.12178	~~$0.58259~~ $0.60087	(I/R)
I42SF						
Schedule 308 Credits (per bill):				($3,945.77)	($3,945.77)	(I)
Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	~~$0.16641~~ $0.25913		$0.43274	~~$0.13254~~ $0.13408	~~$0.73169~~ $0.82595	(I/R)
Block 2: Next 20,000 therms	~~$0.14895~~ $0.23195		$0.43274	~~$0.13089~~ $0.13227	~~$0.71258~~ $0.79696	
Block 3: Next 20,000 therms	~~$0.11422~~ $0.17786		$0.43274	~~$0.12761~~ $0.12867	~~$0.67457~~ $0.73927	
Block 4: Next 100,000 therms	~~$0.09138~~ $0.14229		$0.43274	~~$0.12545~~ $0.12630	~~$0.64957~~ $0.70133	
Block 5: Next 600,000 therms	~~$0.06094~~ $0.09490		$0.43274	~~$0.12258~~ $0.12315	~~$0.61626~~ $0.65079	
Block 6: All additional therms	~~$0.02283~~ $0.03555		$0.43274	~~$0.11898~~ $0.11919	~~$0.57455~~ $0.58748	(I/R)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	
Firm Sales Service Storage Charge (per therm of MDDV per month):					**$0.20415**	
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.10337**	
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV per month):					**$1.54**	

[1] For Firm Sales Service, the Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges,

plus the Distribution Capacity Charge, plus the Storage Capacity Charge, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from Schedule C or Schedule 10.

[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG or Monthly Incremental Cost of Gas.

[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 may not apply.

(continue to Sheet 142.10.1)

RATE SCHEDULE 42
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY SALES RATES – INTERRUPTIBLE SERVICE: Effective: January 1, 2025September 30, 2025 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

INTERRUPTIBLE SALES SERVICE CHARGES [1]: (C42SI)					**Billing Rates**	
Customer Charge (per month):					**$1,300.00**	
	Base Rate		Commodity Component [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($5,142.27)	**($5,142.27)**	(I)
Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	~~$0.16872~~ $0.26337		$0.43274	~~$0.10987~~ $0.11096	~~**$0.71133**~~ **$0.80707**	(IR)
Block 2: Next 20,000 therms	~~$0.15103~~ $0.23575		$0.43274	~~$0.10666~~ $0.10763	~~**$0.69043**~~ **$0.77612**	
Block 3: Next 20,000 therms	~~$0.11580~~ 0.18076		$0.43274	~~$0.10024~~ $0.10098	~~**$0.64878**~~ **$0.71448**	
Block 4: Next 100,000 therms	~~$0.09264~~ $0.14461		$0.43274	~~$0.09603~~ $0.09663	~~**$0.62141**~~ **$0.67398**	
Block 5: Next 600,000 therms	~~$0.06178~~ $0.09644		$0.43274	~~$0.09041~~ $0.09080	~~**$0.58493**~~ **$0.61998**	
Block 6: All additional therms	~~$0.02317~~ $0.03617		$0.43274	~~$0.08334~~ $0.08348	~~**$0.53925**~~ **$0.55239**	(IR)
Interruptible Pipeline Capacity Charge (per therm):					**$0.03612**	
Interruptible Sales Service Storage Charge (per therm of MDDV per month)					**$0.10208**	
INTERRUPTIBLE SALES SERVICE CHARGES [1]: (I42SI)						
Customer Charge (per month):					**$1,300.00**	
Schedule 308 Credits (per bill):				($3,945.77)	**($3,945.77)**	(I)
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	~~$0.16353~~ $0.24136		$0.43274	~~$0.09437~~ $0.09567	~~**$0.69064**~~ **$0.76977**	(IR)
Block 2: Next 20,000 therms	~~$0.14638~~ $0.21605		$0.43274	~~$0.09287~~ $0.09404	~~**$0.67199**~~ **$0.74283**	
Block 3: Next 20,000 therms	~~$0.11225~~ $0.16567		$0.43274	~~$0.08990~~ $0.09079	~~**$0.63489**~~ **$0.68920**	
Block 4: Next 100,000 therms	~~$0.08981~~ $0.13255		$0.43274	~~$0.08793~~ $0.08865	~~**$0.61048**~~ **$0.65394**	
Block 5: Next 600,000 therms	~~$0.05986~~ $0.08835		$0.43274	~~$0.08531~~ $0.08579	~~**$0.57791**~~ **$0.60688**	
Block 6: All additional therms	~~$0.02244~~ $0.03312		$0.43274	~~$0.08206~~ $0.08224	~~**$0.53724**~~ **$0.54810**	(IR)
Interruptible Pipeline Capacity Charge (per therm):					**$0.03612**	

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Effective with service on and after ~~January 1,~~

Interruptible Sales Service Storage Charge (per therm of MDDV per month)	**$0.10208**

[1] For Interruptible Sales Service, the Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge, plus any other charges that apply from Schedule C or Schedule 10.
[2] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 201 may also apply.
[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 may not apply.

(continue to Sheet 142.11)

RATE SCHEDULE 42
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY TRANSPORTATION RATES: Effective: January 1, 2025September 30, 2025 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (C42TI) [1]:					**Billing Rates**	
Customer Charge (per month):					**$1,300.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Temporary Adjustments [2]		
Schedule 308 Credits (per bill):				($5,142.27)	**($5,142.27)**	(I)
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	~~$0.14169~~ $0.19650			~~$0.24907~~ $0.24980	**~~$0.39076~~ $0.44630**	(IR)
Block 2: Next 20,000 therms	~~$0.12685~~ $0.17592			~~$0.24831~~ $0.24896	**~~$0.37516~~ $0.42488**	
Block 3: Next 20,000 therms	~~$0.09727~~ $0.13490			~~$0.24678~~ $0.24728	**~~$0.34405~~$0.38218**	
Block 4: Next 100,000 therms	~~$0.07782~~ $0.10792			~~$0.24578~~ $0.24618	**~~$0.32360~~ $0.35410**	
Block 5: Next 600,000 therms	~~$0.05189~~ $0.07197			~~$0.24444~~ $0.24470	**~~$0.29633~~ $0.31667**	
Block 6: All additional therms	~~$0.01944~~ $0.02696			~~$0.24277~~ $0.24287	**~~$0.26221~~$0.26983**	(IR)
INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (I42TI) [1]:					**Billing Rates**	
Customer Charge (per month):					**$1,300.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Temporary Adjustments [2]		
Schedule 308 Credits (per bill):				($3,945.77)	**($3,945.77)**	(I)
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	~~$0.14430~~ $0.19129	-	-	~~$0.24917~~ $0.24995	**~~$0.39347~~ $0.44124**	(IR)
Block 2: Next 20,000 therms	~~$0.12917~~ $0.17123	-	-	~~$0.24841~~ $0.24911	**~~$0.37758~~ $0.42034**	
Block 3: Next 20,000 therms	~~$0.09905~~ $0.13131	-	-	~~$0.24687~~ $0.24741	**~~$0.34592~~ $0.37872**	
Block 4: Next 100,000 therms	~~$0.07925~~ $0.10506	-	-	~~$0.24586~~ $0.24629	**~~$0.32511~~ $0.35135**	
Block 5: Next 600,000 therms	~~$0.05284~~ $0.07005	-	-	~~$0.24452~~ $0.24481	**~~$0.29736~~ $0.31486**	
Block 6: All additional therms	~~$0.01981~~ $0.02627	-	-	~~$0.24285~~ $0.24296	**~~$0.26266~~$0.26923**	(IR)

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Effective with service on and after ~~January 1,~~

[1] For Interruptible Transportation Service, the Monthly Bill shall equal the sum of the Customer Charge, plus Transportation Charge, plus the Volumetric Charges, plus any other charges that may apply from Schedule C or Schedule 10.
[2] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 201 may also apply.

(continue to Sheet 142.12)

RATE SCHEDULE 42
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

FIRM TRANSPORTATION SERVICE CHARGES (C42TF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$1,300.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Total Temporary Adjustments [2]		
Schedule 308 Credits (per bill):				($5,142.27)	**($5,142.27)**	(I)
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	~~$0.15442~~ $0.22706			~~$0.24890~~ $0.25011	~~**$0.40332**~~ **$0.47717**	(I/R)
Block 2: Next 20,000 therms	~~$0.13824~~ $0.20327			~~$0.24816~~ $0.24925	~~**$0.38640**~~ **$0.45252**	
Block 3: Next 20,000 therms	~~$0.10600~~ $0.15587			~~$0.24669~~ $0.24752	~~**$0.35269**~~ **$0.40339**	
Block 4: Next 100,000 therms	~~$0.08481~~ $0.12471			~~$0.24573~~ $0.24640	~~**$0.33054**~~ **$0.37111**	
Block 5: Next 600,000 therms	~~$0.05654~~ $0.08314			~~$0.24443~~ $0.24487	~~**$0.30097**~~ **$0.32801**	
Block 6: All additional therms	~~$0.02120~~ $0.03117			~~$0.24283~~ $0.24300	~~**$0.26403**~~ **$0.27417**	(I/R)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	
FIRM TRANSPORTATION SERVICE CHARGES (I42TF) [1]:						
Customer Charge (per month):					**$1,300.00**	
Transportation Charge (per month):					**$250.00**	
Schedule 308 Credits (per bill):				($3,945.77)	**($3,945.77)**	(I)
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	~~$0.15161~~ $0.20621			~~$0.24935~~ $0.25026	~~**$0.40096**~~ **$0.45647**	(I/R)
Block 2: Next 20,000 therms	~~$0.13571~~ $0.18459			~~$0.24856~~ $0.24938	~~**$0.38427**~~ **$0.43397**	
Block 3: Next 20,000 therms	~~$0.10406~~ $0.14154			~~$0.24699~~ $0.24762	~~**$0.35105**~~ **$0.38916**	
Block 4: Next 100,000 therms	~~$0.08326~~ $0.11325			~~$0.24596~~ $0.24646	~~**$0.32922**~~ **$0.35971**	
Block 5: Next 600,000 therms	~~$0.05550~~ $0.07549			~~$0.24459~~ $0.24493	~~**$0.30009**~~ **$0.32042**	
Block 6: All additional therms	~~$0.02082~~ $0.02831			~~$0.24287~~ 0.24300	~~**$0.26369**~~ **$0.27131**	(I/R)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	

[1] For Firm Transportation Service, the Monthly Bill shall equal the sum of the Customer Charge, plus Transportation Charge, plus the Volumetric Charges, plus the Distribution Capacity Charge, plus any other charges that may apply from Schedule C or Schedule 10.
[2] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 201 may also apply.

RATE SCHEDULE 43
HIGH VOLUME NON-RESIDENTIAL
FIRM AND INTERRUPTIBLE TRANSPORTATION SERVICE
(continued)

MONTHLY RATE: Effective: January 1, 2025September 30, 2025 (C)

The rates shown below may not always reflect actual billing rates. See **Schedule 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM TRANSPORTATION SERVICE CHARGES (C43TF and I43TF)					
					Billing Rates
Customer Charge:					**$38,000.00**
Transportation Charge:					**$250.00**
Volumetric Charge	Base Rate			Total Temporary Adjustment [1]	
Per therm, all therms	$0.00491 $0.00685			$ 0.24194	**$0.24685 $0.24879** (IR)
Firm Service Distribution Capacity Charge: Per therm of MDDV per month					**$0.15748**
Minimum Monthly Bill: Customer Charge, plus Transportation Charge, plus Firm Service Distribution Capacity Charge, plus any other charges that may apply from **Schedule C** and **Schedule 10**.					

INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (C43TI and I43TI)					
					Billing Rates
Customer Charge:					**$38,000.00**
Transportation Charge:					**$250.00**
Volumetric Charge:	Base Rate			Total Temporary Adjustment [1]	
Per therm, all therms	$0.00491 $0.00685			$ 0.24194	**$0.24685 $0.24879** (IR)
Minimum Monthly Bill: Customer Charge, plus Transportation Charge, plus any other charges that may apply from **Schedule C** and **Schedule 10**.					

[1] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 shall apply.

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SCHEDULE 200
SUMMARY OF ADJUSTMENTS

PURPOSE:
The purpose of this Schedule is to list and summarize the adjustment Schedules applicable to each of the Company's Rate Schedules.

SCHEDULE	A	201	203	207	210	212	215	220	221	230	232	233	234	235	236	237	238	303	305	306	308
R1	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
C1	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
2	ADD	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
03CSF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
03ISF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
10	ADD			INC																	
27	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
C41SF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
C41SI	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
C41TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I41SF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I41SI	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I41TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C42SF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
C42SI	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
C42TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C42TI	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I42SF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I42SI	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I42TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I42TI	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C43TI/ I43TI	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C43TF/ I43TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC

(N)
(N)

Table Code Key:

ADD This adjustment is added to the billing rates at the time the bill is issued.
INC This adjustment is included in the billing rates shown on the Rate Schedule

(continue to Sheet 200.2)

SCHEDULE 200
SUMMARY OF ADJUSTMENTS
(continued)

The following is a brief description of the applicable Schedules:

Schedule A "Billing for City and County Exactions."
This adjustment will be reflected directly on Customer bills.

Schedule 201 "Temporary (Technical) Adjustments to Rates."
These are temporary Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 203 "Purchased Gas Cost Adjustments to Rates."
These are pipeline capacity and commodity charges.

Schedule 207 "General Adjustments to Rates."
These are Base Rate Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 210 "Adjustment to Rates for Property Sales."
These are Temporary Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 212 "Adjustment to Rates Residential Rate Mitigation."
These are Temporary Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 215 "Adjustment to Rates for Energy Conservation Programs."
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 220 "Special Rate Adjustment."
These are Base Rate Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 221 "Rate Adjustment for Updated Depreciation Rates"
These are Base Rate Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 230 "Temporary Adjustments to Rates for Low-Income Programs."
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 231 "Temporary Adjustments to Rates for Residential Discount Program."
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 232 "Temporary Adjustments to Rates for Regulatory Fee Increase"
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 233 "Temporary Adjustments to Rates for Industrial Customer Energy Efficiency Audit Costs"
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 234 "Temporary Adjustments to Rates for Residential Arrearage Management Program" (N)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 235 "Temporary Adjustments to Rates for COVID-19 Public Health Emergency" (N)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills. (N)

(K)

(K) Schedules 303, 305, 306 and 308 transferred to Sheet 200.3.

(continue to Sheet 200.3)

Schedule 303 "Washington Environmental Cost Recovery Mechanism."
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 305 "Adjustment for Certain Income Taxes (2017 Federal Tax Cuts and Jobs Act)."
These are base and temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 306 "Multi-Year Rate Plan Adjustment."
These are base rate adjustments that will be added to the Billing Rate on the effective date of the Schedule.

Schedule 308 "Washington Climate Commitment Act Recovery Mechanism."
These are temporary rate adjustments that will be added to the Billing Rate on the effective date of the Schedule.

SCHEDULE 200
SUMMARY OF ADJUSTMENTS
(continued)

Schedule 236 "Temporary Adjustments to Rates for Meter Modernization Program." (N)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 237 "Temporary Adjustments to Rates for TSA Operations and Maintenance Costs." (N)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 238 "Adjustments to Rates for Provisional Capital Adjustment." (N)
These are base rate adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 303 "Washington Environmental Cost Recovery Mechanism." (M)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 305 "Adjustment for Certain Income Taxes (2017 Federal Tax Cuts and Jobs Act)."
These are base and temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 306 "Multi-Year Rate Plan Adjustment."
These are base rate adjustments that will be added to the Billing Rate on the effective date of the Schedule.

Schedule 308 "Washington Climate Commitment Act Recovery Mechanism."
These are temporary rate adjustments that will be added to the Billing Rate on the effective date of the Schedule. (M)

(M) Schedules 303, 305, 306 and 308 transferred from Sheet 200.2.

NORTHWEST NATURAL GAS COMPANY

WN U-6 Eighth~~Seventh~~ Revision of Sheet 207.1
Cancels Seventh~~Sixth~~ Revision of Sheet 207.1

SCHEDULE 207
GENERAL RATE ADJUSTMENT

PURPOSE:
To identify the effects of general rate changes approved in the company's most recent general rate case proceeding (Docket UG-200994)

APPLICATION TO RATE SCHEDULES: Effective: ~~November 1, 2022~~ September 30, 2025 (C) (T) (T)

Rate Schedule 1	Rate Schedule 3	Rate Schedule 41	Rate Schedule 43
Rate Schedule 2	Rate Schedule 27	Rate Schedule 42	

The Base Rates in the listed Rate Schedules include the adjustment shown below.
NO FURTHER ADJUSTMENT TO RATES IS REQUIRED.

SCHEDULES	BLOCKS	AMOUNT		
Schedule 1 - Residential	Customer Charge	$20.5000	(I)	
	Per Therm (all therms)	$0.~~06165~~.32662	(I~~R~~)	
Schedule 1 - Commercial	Customer Charge	$30.00	(I)	
	Per Therm (all therms)	$0.~~05126~~38159	(I~~R~~)	
Schedule 2	Customer Charge	$0.00		
	Per Therm (all therms)	$0.~~03902~~28524	(I~~R~~)	
Schedule 3 - Commercial	Customer Charge	$0.00		
	Per Therm (all therms)	$0.~~03503~~27968	(I~~R~~)	
Schedule 3 - Industrial	Customer Charge	$0.00		
	Per Therm (all therms)	$0.~~.03173~~23576	(I~~R~~)	
Schedule 27	Customer Charge	$0.00		
	Per Therm (all therms)	$0.~~02777~~48735	(I~~R~~)	(D)
Schedule 41 - Commercial Firm Sales Service	Customer Charge	$0.00		
	First 2,000 therms	$ 0.20624 ~~$0.02782~~	(I~~R~~)	
	All additional therms	~~$0.02451~~ $ 0.18173	(I~~R~~)	
Schedule 41 - Commercial Interruptible Sales Service	Customer Charge	$0.00		
	First 2,000 therms	~~$0.02162~~ $ 0.14876 ~~$~~	(I~~R~~)	
	All additional therms	~~$0.01905~~ $ 0.13107	(I~~R~~)	
Schedule 41 - Industrial Firm Sales Service	Customer Charge	$0.00		
	First 2,000 therms	$ 0.12639 ~~$0.00873~~	(I~~R~~)	
	All additional therms	~~$0.00769~~ $ 0.11136	(I~~R~~)	
Schedule 41 - Industrial Interruptible Sales Service	Customer Charge	$0.00		
	First 2,000 therms	$ 0.14073 ~~$0.00713~~	(I~~R~~)	

Issued ~~October 14, 2022~~August 29, 2025
NWN WUTC Advice No. 25-03~~22-09~~
September 30, 2025

Effective with service on and after ~~November 1, 2022~~

		$0.00628 $ $ 0.12399	(IR))
Schedule 41 - Commercial Firm Transportation Service	Customer Charge	$0.00	
	First 2,000 therms	$ 0.13747 $0.00971	(IR)
	All additional therms	$0.00855 $ 0.12113	(IR)
Schedule 41 - Industrial Firm Transportation Service	Customer Charge	$0.00	
	First 2,000 therms	$ 0.14229 $0.00721	(IR)
	All additional therms	$0.00635 $ 0.12537	(IR)

(continue to Sheet 207.2)

SCHEDULE 207
GENERAL RATE ADJUSTMENT
(continued)

SCHEDULES	BLOCKS	AMOUNT	
Schedule 42 Commercial - Firm Sales Service	Customer Charge	$0.00	
	First 10,000	~~0.02095~~	(I~~R~~)
	therms	0.13164	
	Next 20,000	0.11784	
	therms	~~0.01875~~	
	Next 20,000	~~0.01438~~	
	therms	0.09038	
	Next 100,000	0.07229	
	therms	~~0.01151~~	
	Next 600,000	~~0.00767~~	
	therms	0.04819	
	All additional	~~0.00288~~	
	therms	0.01807	(I~~R~~)
Schedule 42 Commercial - Interruptible Sales Service	Customer Charge	$0.00	
	First 10,000	~~0.01245~~	(I~~R~~)
	therms	0.09465	
	Next 20,000	~~0.01114~~	
	therms	0.08472	
	Next 20,000	~~0.00854~~	
	therms	0.06496	
	Next 100,000	~~0.00683~~	
	therms	0.05197	
	Next 600,000	~~0.00456~~	
	therms	0.03466	
	All additional	~~0.00171~~	
	therms	0.01300	(I~~R~~)
Schedule 42 Industrial - Firm Sales Service	Customer Charge	$0.00	(I~~R~~)
	First 10,000	~~0.00614~~	
	therms	0.09272	
	Next 20,000	~~0.00550~~	
	therms	0.08300	
	Next 20,000	~~0.00422~~	
	therms	0.06364	
	Next 100,000	~~0.00337~~	
	therms	0.05091	

Issued ~~October 14, 2022~~ August 29, 2025
NWN WUTC Advice No. 25-03~~22-09~~
September 30, 2025

Effective with service on
and after ~~November 1, 2022~~

	Next 600,000	0.00225	
	therms	0.03396	
	All additional	0.0084	
	therms	0.01272	(IR)
Schedule 42 Industrial - Interruptible Sales Service	Customer Charge	$0.00	
	First 10,000	0.00566	(IR)
	therms	0.07783	
	Next 20,000	0.00507	
	therms	0.06967	
	Next 20,000	0.00389	
	therms	0.05342	
	Next 100,000	0.00311	
	therms	0.04274	
	Next 600,000	0.00207	
	therms	0.02849	
	All additional	0.00078	(IR)
	therms	0.01068	

(continue to Sheet 207.3)

SCHEDULE 207
GENERAL RATE ADJUSTMENT
(continued)

SCHEDULES	BLOCKS	AMOUNT	
Schedule 42 Commercial - Firm Transportation Service	Customer Charge	$0.00	
		~~0.00594~~	(I~~R~~)
	First 10,000 therms	0.07264	
		~~0.00531~~	
	Next 20,000 therms	0.06503	
		~~0.00407~~	
	Next 20,000 therms	0.04987	
		~~0.00326~~	
	Next 100,000 therms	0.03990	
		~~0.00217~~	
	Next 600,000 therms	0.02660	
		~~0.00081~~	
	All additional therms	0.00997	(I~~R~~)
Schedule 42 Industrial - Firm Transportation Service	Customer Charge	$0.00	
		~~0.00396~~	(I~~R~~)
	First 10,000 therms	0.05460	
		~~0.00354~~	
	Next 20,000 therms	0.04888	
		~~0.00272~~	
	Next 20,000 therms	0.03748	
		~~0.00217~~	
	Next 100,000 therms	0.02999	
		~~0.00145~~	
	Next 600,000 therms	0.01999	
		~~0.0005~~	
	All additional therms	0.00749	(I~~R~~)
Schedule 42 - Commercial Interruptible Transportation Service	Customer Charge	$0.00	
		0.05481	(I~~R~~)
	First 10,000 therms	~~0.00278~~	
		0.04907	
	Next 20,000 therms	~~0.00249~~	
		0.03763	
	Next 20,000 therms	~~0.00191~~	
		0.03010	
	Next 100,000 therms	~~0.00153~~	

Issued ~~October 14, 2022~~August 29, 2025
NWN WUTC Advice No. 25-03~~2-09 2022~~September 30, 2025

Effective with service on and after ~~November 1,~~

		0.02008	
	Next 600,000 therms	~~0.00102~~	
		~~0.00038~~	
	All additional therms	0.00752	(I~~R~~)
Schedule 42 - Industrial Interruptible Transportation Service	Customer Charge	$0.00	
		0.04699	(I~~R~~)
	First 10,000 therms	~~0.00333~~	
		0.04206	
	Next 20,000 therms	~~0.00298~~	
		0.03226	
	Next 20,000 therms	~~0.00228~~	
		0.02581	
	Next 100,000 therms	~~0.00183~~	
		0.01721	
	Next 600,000 therms	~~0.00122~~	
		~~0.00046~~	
	All additional therms	0.00646	(I~~R~~) ~~(D)~~

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

NORTHWEST NATURAL GAS COMPANY

WN U-6 ~~Original~~ First Revision of Sheet 221.1
Cancels Original Sheet 221.1

SCHEDULE 221
RATE ADJUSTMENT FOR UPDATED DEPRECIATION RATES

~~(N)~~

PURPOSE:
The purpose of this Schedule is to reflect the adjustments from the Company's updated depreciation rates filed in docket UG-210974.

APPLICABLE:
To all Sales and Transportation Service Customers served under the following Rate Schedules:

Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective:** ~~November 1, 2023~~September 30, 2025

The Adjustment amount shown below is included in the Base Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)	
1R		~~($0.00660)~~ $0.00000		42 CTF	Block 1	~~($0.00064)~~ $0.00000	(I) (I)
1C		~~($0.00548)~~ $0.00000			Block 2	~~($0.00056)~~ $0.00000	
2R		~~($0.00418)~~ $0.00000			Block 3	~~($0.00043)~~ $0.00000	
3C		~~($0.00375)~~ $0.00000			Block 4	~~($0.00035)~~ $0.00000	
3I		~~($0.00339)~~ $0.00000			Block 5	~~($0.00023)~~ $0.00000	
27		~~($0.00297)~~ $0.00000			Block 6	~~($0.00008)~~ $0.00000	
41 CSF	Block 1	~~($0.00297)~~ $0.00000		42 ITF	Block 1	~~($0.00043)~~ $0.00000	
	Block 2	~~($0.00262)~~ $0.00000			Block 2	~~($0.00038)~~ $0.00000	
41 ISF	Block 1	~~($0.00093)~~ $0.00000			Block 3	~~($0.00030)~~ $0.00000	
	Block 2	~~($0.00082)~~ $0.00000			Block 4	~~($0.00023)~~ $0.00000	
41 CSI	Block 1	~~($0.01409)~~ $0.00000			Block 5	~~($0.00016)~~ $0.00000	
	Block 2	~~($0.01241)~~ $0.00000			Block 6	~~($0.00005)~~ $0.00000	(I)
41 ISI	Block 1	$0.00000		42 CSI	Block 1	~~($0.00133)~~ $0.00000	
	Block 2	$0.00000			Block 2	~~($0.00119)~~ $0.00000	
41 CTF	Block 1	~~($0.00104)~~ $0.00000			Block 3	~~($0.00091)~~ $0.00000	(I)
	Block 2	~~($0.00091)~~ $0.00000			Block 4	~~($0.00073)~~ $0.00000	
41ITF	Block 1	$0.00000			Block 5	~~($0.00049)~~ $0.00000	
	Block 2	$0.00000			Block 6	~~($0.00018)~~ $0.00000	
42 CSF	Block 1	~~($0.00224)~~ $0.00000		42 ISI	Block 1	~~($0.00060)~~ $0.00000	
	Block 2	~~($0.00200)~~ $0.00000			Block 2	~~($0.00054)~~ $0.00000	

Issued ~~September 15, 2023~~August 29, 2025
NWN WUTC Advice No. ~~23-12~~25-03
~~2023~~September 3~~2~~0, 2025

Effective with service on and after ~~November 1,~~

	Block 3	~~($0.00153)~~ $0.00000			Block 3	~~($0.00042)~~ $0.00000
	Block 4	~~($0.00123)~~ $0.00000			Block 4	~~($0.00033)~~ $0.00000
	Block 5	~~($0.00082)~~ $0.00000			Block 5	~~($0.00022)~~ $0.00000
	Block 6	~~($0.00031)~~ $0.00000			Block 6	~~($0.00009)~~ $0.00000
42 ISF	Block 1	~~($0.00065)~~ $0.00000		42 CTI	Block 1	$0.00000
	Block 2	~~($0.00059)~~ $0.00000			Block 2	$0.00000
	Block 3	~~($0.00045)~~ $0.00000			Block 3	$0.00000
	Block 4	~~($0.00036)~~ $0.00000			Block 4	$0.00000
	Block 5	~~($0.00024)~~ $0.00000			Block 5	$0.00000
	Block 6	~~($0.00009)~~ $0.00000			Block 6	$0.00000
				42 ITI	Block 1	~~($0.00036)~~ $0.00000
					Block 2	~~($0.00032)~~ $0.00000
					Block 3	~~($0.00024)~~ $0.00000
					Block 4	~~($0.00020)~~ $0.00000
					Block 5	~~($0.00013)~~ $0.00000
					Block 6	~~($0.00005)~~ $0.00000
				43 TF		$0.00000
				43 TF		$0.00000

(I)
(I)
(I)
(I)
~~(N)~~

(continue to Sheet 221.2)

SCHEDULE 235
TEMPORARY ADJUSTMENTS TO RATES FOR COVID-19 PUBLIC HEALTH EMERGENCY

(N)

PURPOSE: To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of deferred amounts for the costs and savings incurred due to the COVID-19 pandemic, as authorized for deferred accounting by the WUTC in Docket UG-200264.

APPLICABLE:
Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: September 30, 2025**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		$0.00344		42 CTF	Block 1	$0.00065
1C		$0.00262			Block 2	$0.00059
2R		$0.00179			Block 3	$0.00045
3C		$0.00157			Block 4	$0.00036
3I		$0.00146			Block 5	$0.00024
27		$0.00133			Block 6	$0.00009
41 CSF	Block 1	$0.00128		42 ITF	Block 1	$0.00049
	Block 2	$0.00112			Block 2	$0.00044
41 ISF	Block 1	$0.00114			Block 3	$0.00034
	Block 2	$0.00100			Block 4	$0.00027
41 CSI	Block 1	$0.00118			Block 5	$0.00018
	Block 2	$0.00104			Block 6	$0.00007
41 ISI	Block 1	$0.00111		42 CSI	Block 1	$0.00059
	Block 2	$0.00098			Block 2	$0.00052
41 CTF	Block 1	$0.00124			Block 3	$0.00040
	Block 2	$0.00109			Block 4	$0.00032
41ITF	Block 1	$0.00113			Block 5	$0.00021
	Block 2	$0.00099			Block 6	$0.00008
42 CSF	Block 1	$0.00081		42 ISI	Block 1	$0.00070
	Block 2	$0.00073			Block 2	$0.00063
	Block 3	$0.00056			Block 3	$0.00048
	Block 4	$0.00045			Block 4	$0.00039
	Block 5	$0.00030			Block 5	$0.00026
	Block 6	$0.00011			Block 6	$0.00010
42 ISF	Block 1	$0.00083		42 CTI	Block 1	$0.00043
	Block 2	$0.00075			Block 2	$0.00039
	Block 3	$0.00057			Block 3	$0.00030
	Block 4	$0.00046			Block 4	$0.00024
	Block 5	$0.00031			Block 5	$0.00016
	Block 6	$0.00011			Block 6	$0.00006
				42 ITI	Block 1	$0.00042
					Block 2	$0.00038
					Block 3	$0.00029
					Block 4	$0.00023
					Block 5	$0.00015
					Block 6	$0.00006
				43 TF		$0.00000
				43 TF		$0.00000

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

(N)

Issued August 29, 2025
NWN WUTC Advice No. 25-03

Effective with service on
and after September 30, 2025

SCHEDULE 236
TEMPORARY ADJUSTMENTS TO RATES FOR METER MODERNIZATION PROGRAM

(N)

PURPOSE: To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of deferred amounts for the costs related to the Company's Meter Modernization Program, as authorized for deferred accounting by the WUTC in Docket UG-240012.

APPLICABLE:
Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: September 30, 2025**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		$0.00148		42 CTF	Block 1	$0.00028
1C		$0.00114			Block 2	$0.00025
2R		$0.00077			Block 3	$0.00019
3C		$0.00068			Block 4	$0.00016
3I		$0.00063			Block 5	$0.00010
27		$0.00057			Block 6	$0.00004
41 CSF	Block 1	$0.00055		42 ITF	Block 1	$0.00021
	Block 2	$0.00049			Block 2	$0.00019
41 ISF	Block 1	$0.00049			Block 3	$0.00015
	Block 2	$0.00043			Block 4	$0.00012
41 CSI	Block 1	$0.00041			Block 5	$0.00008
	Block 2	$0.00036			Block 6	$0.00003
41 ISI	Block 1	$0.00038		42 CSI	Block 1	$0.00025
	Block 2	$0.00034			Block 2	$0.00023
41 CTF	Block 1	$0.00054			Block 3	$0.00017
	Block 2	$0.00047			Block 4	$0.00014
41ITF	Block 1	$0.00039			Block 5	$0.00009
	Block 2	$0.00034			Block 6	$0.00003
42 CSF	Block 1	$0.00035		42 ISI	Block 1	$0.00030
	Block 2	$0.00031			Block 2	$0.00027
	Block 3	$0.00024			Block 3	$0.00021
	Block 4	$0.00019			Block 4	$0.00017
	Block 5	$0.00013			Block 5	$0.00011
	Block 6	$0.00005			Block 6	$0.00004
42 ISF	Block 1	$0.00036		42 CTI	Block 1	$0.00015
	Block 2	$0.00032			Block 2	$0.00013
	Block 3	$0.00025			Block 3	$0.00010
	Block 4	$0.00020			Block 4	$0.00008
	Block 5	$0.00013			Block 5	$0.00005
	Block 6	$0.00005			Block 6	$0.00002
				42 ITI	Block 1	$0.00018
					Block 2	$0.00016
					Block 3	$0.00013
					Block 4	$0.00010
					Block 5	$0.00007
					Block 6	$0.00003
				43 TF		$0.00000
				43 TF		$0.00000

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

(N)

Issued August 29, 2025
NWN WUTC Advice No. 25-03

Effective with service on
and after September 30, 2025

SCHEDULE 237
TEMPORARY ADJUSTMENTS TO RATES FOR TSA OPERATIONS AND MAINTENANCE COSTS

(N)

PURPOSE: To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of deferred amounts for the start-up Operations and Maintenance costs incurred for compliance with TSA Security Directives, as authorized for deferred accounting by the WUTC in Docket UG-210900.

APPLICABLE:
Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: September 30, 2025**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		$0.00145		42 CTF	Block 1	$0.00028
1C		$0.00109			Block 2	$0.00025
2R		$0.00075			Block 3	$0.00019
3C		$0.00066			Block 4	$0.00015
3I		$0.00061			Block 5	$0.00010
27		$0.00056			Block 6	$0.00004
41 CSF	Block 1	$0.00054		42 ITF	Block 1	$0.00021
	Block 2	$0.00047			Block 2	$0.00019
41 ISF	Block 1	$0.00048			Block 3	$0.00014
	Block 2	$0.00042			Block 4	$0.00011
41 CSI	Block 1	$0.00040			Block 5	$0.00008
	Block 2	$0.00035			Block 6	$0.00003
41 ISI	Block 1	$0.00037		42 CSI	Block 1	$0.00025
	Block 2	$0.00033			Block 2	$0.00022
41 CTF	Block 1	$0.00052			Block 3	$0.00017
	Block 2	$0.00046			Block 4	$0.00014
41ITF	Block 1	$0.00038			Block 5	$0.00009
	Block 2	$0.00033			Block 6	$0.00003
42 CSF	Block 1	$0.00034		42 ISI	Block 1	$0.00030
	Block 2	$0.00031			Block 2	$0.00027
	Block 3	$0.00024			Block 3	$0.00020
	Block 4	$0.00019			Block 4	$0.00016
	Block 5	$0.00013			Block 5	$0.00011
	Block 6	$0.00005			Block 6	$0.00004
42 ISF	Block 1	$0.00035		42 CTI	Block 1	$0.00015
	Block 2	$0.00031			Block 2	$0.00013
	Block 3	$0.00024			Block 3	$0.00010
	Block 4	$0.00019			Block 4	$0.00008
	Block 5	$0.00013			Block 5	$0.00005
	Block 6	$0.00005			Block 6	$0.00002
				42 ITI	Block 1	$0.00018
					Block 2	$0.00016
					Block 3	$0.00012
					Block 4	$0.00010
					Block 5	$0.00007
					Block 6	$0.00002
				43 TF		$0.00000
				43 TF		$0.00000

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

(N)

Issued August 29, 2025
NWN WUTC Advice No. 25-03

Effective with service on
and after September 30, 2025

SCHEDULE 238
ADJUSTMENTS TO RATES FOR PROVISIONAL CAPITAL ADJUSTMENT

(N)

PURPOSE: To identify adjustments to rates in the Rate Schedules listed below that relate to the capital with Rate Year 1 as authorized by the WUTC in Docket UG-250610.

APPLICABLE:
Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: September 30, 2025**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		$0.00000		42 CTF	Block 1	$0.00000
1C		$0.00000			Block 2	$0.00000
2R		$0.00000			Block 3	$0.00000
3C		$0.00000			Block 4	$0.00000
3I		$0.00000			Block 5	$0.00000
27		$0.00000			Block 6	$0.00000
41 CSF	Block 1	$0.00000		42 ITF	Block 1	$0.00000
	Block 2	$0.00000			Block 2	$0.00000
41 ISF	Block 1	$0.00000			Block 3	$0.00000
	Block 2	$0.00000			Block 4	$0.00000
41 CSI	Block 1	$0.00000			Block 5	$0.00000
	Block 2	$0.00000			Block 6	$0.00000
41 ISI	Block 1	$0.00000		42 CSI	Block 1	$0.00000
	Block 2	$0.00000			Block 2	$0.00000
41 CTF	Block 1	$0.00000			Block 3	$0.00000
	Block 2	$0.00000			Block 4	$0.00000
41ITF	Block 1	$0.00000			Block 5	$0.00000
	Block 2	$0.00000			Block 6	$0.00000
42 CSF	Block 1	$0.00000		42 ISI	Block 1	$0.00000
	Block 2	$0.00000			Block 2	$0.00000
	Block 3	$0.00000			Block 3	$0.00000
	Block 4	$0.00000			Block 4	$0.00000
	Block 5	$0.00000			Block 5	$0.00000
	Block 6	$0.00000			Block 6	$0.00000
42 ISF	Block 1	$0.00000		42 CTI	Block 1	$0.00000
	Block 2	$0.00000			Block 2	$0.00000
	Block 3	$0.00000			Block 3	$0.00000
	Block 4	$0.00000			Block 4	$0.00000
	Block 5	$0.00000			Block 5	$0.00000
	Block 6	$0.00000			Block 6	$0.00000
				42 ITI	Block 1	$0.00000
					Block 2	$0.00000
					Block 3	$0.00000
					Block 4	$0.00000
					Block 5	$0.00000
					Block 6	$0.00000
				43 TF		$0.00000
				43 TF		$0.00000

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

(N)

Issued August 29, 2025
NWN WUTC Advice No. 25-03

Effective with service on
and after September 30, 2025

SCHEDULE J
GAS RESIDENTIAL ENERGY ASSISTANCE TARIFF (GREAT)

APPLICABLE:
To Residential Customers ("Households") that take service under Rate Schedule 1 or Rate Schedule 2 of this Tariff and that have qualified for bill payment assistance through a NW Natural authorized Delivery Agent.

PROGRAM YEAR:
Funds will be made available under this program on a continuous twelve-month basis. For accounting and ratemaking purposes, the program year will extend from October 1 through September 30 ("Program Year").

PROGRAM FUNDING:
Total Program Funds (where Total Program Funds are equal to customer grants plus administrative and delivery costs) are subject to a combined program year cap of $~~500~~750,000. This cap may be exceeded as need upon discussion and consensus of the GREAT Advisory Group. (C) ~~(N)~~ ~~(N)~~ ~~(N)~~

A surcharge will apply to the regular monthly bills of all Sales Service Class Customers that take service under Rate Schedules 1, 2, 3, 41 and 42. The surcharge will be designed to amortize the actual amount of Total Program Funds accumulated for the Program Year on an equal percent of margin basis, adjusted for revenue sensitive effects. The surcharge calculation will be included with the Company's Annual Purchased Gas Cost Adjustment filing, and will be effective November 1 of each year. The surcharge amount for the respective Rate Schedules will be set forth in Schedule 230 of this Tariff.

PROGRAM ADMINISTRATION AND DELIVERY:
This program will be administered through designated agencies ("Delivery Agents") that: (a) meet the criteria for a "Qualifying Organization" as defined in RCW 82.16.0497; (b) the Company determines is capable of meeting performance obligations under this program; and (c) executes a contract with the Company that is consistent with the terms of this Schedule.

Each Delivery Agent will have sole responsibility to screen and approve bill payment assistance applicants for eligibility. Each Agent shall follow the established protocols for the qualification of and disbursement to eligible participants in accordance with the guidelines established by the Washington Department of Commerce for disbursement of federal Low-Income Home Energy Assistance Program (LIHEAP) funds. Except that, for purposes of this program, income-eligibility will be based on gross household income (adjusted for household size) at or below 200% Federal Poverty Level (FPL) or 80% Area Median Income (AMI), whichever is greater. The GREAT Program will be available to eligible participants regardless of citizenship status.

(continue to Sheet J.2)

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

RATE YEAR 2 TARIFF SHEETS

LEGISLATIVE

August 29, 2025

RATE SCHEDULE 1
GENERAL SALES SERVICE

AVAILABLE:
To all Residential and Commercial Customer classes in all territory served by the Company under the Tariff of which this Rate Schedule is a part, except that service under this Rate Schedule is not available for Standby Service to Commercial Customers. Seasonal or temporary Discontinuance of Service is allowed subject to Special Provision 1 of this Rate Schedule. The installation of Distribution Facilities, when required before service can be provided to equipment served under this Rate Schedule, is subject to the provisions of **Schedule E**.

SERVICE DESCRIPTION:
Service under this Rate Schedule is Firm Sales Service to gas-fired equipment, including but not limited to one or any multiple or combination of the following:

(a) Non-ducted space heating equipment that does not qualify as primary heating systems under Rate Schedule 2, including but not limited to fireplace inserts, free standing gas stoves, and room heaters;
(b) Supplemental or Standby space heating equipment including but not limited to natural gas back-up to electric heat pumps, used in residential applications;
(c) Water heating equipment used to serve single-family residential swimming pools, spas, and hot tubs;
(d) Other equipment including, but not limited to, log lighter, gas log, gas barbecue, tiki torch, Bunsen burner, Domestic cooking equipment, hobby kilns, refrigeration or Domestic clothes drying;
(e) Equipment installed for use in detached garages, shops, or outbuildings.

MONTHLY RATE: Effective: ~~January 1, 2025~~ August 1, 2027 (C)
The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 200** for a list of applicable adjustments. Rates are subject to charges for purchased gas costs and technical rate adjustments.

	Base Rate	Pipeline Capacity Rate	Commodity Rate	Temporary Adjustment	Billing Rate	
Residential:						
Customer Charge	~~$5.50~~ $10.00	~~---~~	~~---~~	~~---~~	~~**$5.50**~~$10.00	(I)
Schedule 308 Credits (per bill)				($1.82)	**($1.82)**	~~(I)~~
Volumetric Charge (per therm)	~~$0.83469~~ $1.18963	$0.10337	$0.43274	~~$0.29750~~ $0.30287	~~**$1.66830**~~**$2.02861**	(~~I~~R)
Commercial:						
Customer Charge	~~$7.00~~ $10.00	~~—~~	~~—~~	~~—~~	~~**$7.00**~~ **$10.00**	(I)
Schedule 308 Credits (per bill)				$(5.34)	**($5.34)**	~~(I)~~
Volumetric Charge (per therm)	~~$0.86308~~ $1.38304	$0.10337	$0.43274	~~$0.27345~~$0.27790	~~**$1.67264**~~**$2.19705**	(~~I~~R)

Minimum Monthly Bill: Customer Charge, plus charges under **Schedule C** and **Schedule 10** (if applicable)

(continue to Sheet 101.2)

Issued ~~December 18, 2024~~August 29, 2025
NWN WUTC Advice No. 25-03~~24-17~~
1, 2027

Effective with service on
and after ~~January 1, 2025~~August

RATE SCHEDULE 2
RESIDENTIAL SALES SERVICE

AVAILABLE:
To Residential Customers, in all territory served by the Company under the Tariff of which this Rate Schedule is a part. Seasonal or temporary Discontinuance of Service is allowed subject to Special Provision 1 of this Rate Schedule. The installation of Distribution Facilities, when required before service can be provided to equipment served under this Rate Schedule, are subject to the provisions of **SCHEDULE E**.

SERVICE DESCRIPTION:
Service under this Rate Schedule is Firm Sales Service to gas-fired equipment used in Residential dwellings that provide complete family living facilities in which the occupant normally cooks, eats, sleeps, and carries on the household operations incident to Domestic life, for at least one of the following purposes:

(a) Operation of ducted forced air Natural Gas space heating equipment that is the primary source for space heating requirements;
(b) Operation of a gas-fired hearth product or wall heater as the primary source for space heating requirements where the hearth or wall heater has a verified nameplate rating of 20,000 BTUs or greater, and is installed in a primary residence defined as a dwelling that is occupied year-round, and where that dwelling is 1,500 square feet or less; and, or;
(c) Operation of fully automatic water heating equipment for primary water heating requirements.

Service under this Rate Schedule includes the use of gas for equipment installed in addition to (a) and (b).

MONTHLY RATE: Effective: ~~January 1, 2025~~August 1, 2027 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

	Base Rate	Pipeline Capacity Rate	Commodity Rate	Temporary Adjustment	Billing Rate	
Customer Charge:	~~$8.00~~ $10.00	—	—	—	**~~$8.00~~ $10.00**	(I)
Schedule 308 Credits - Winter (per bill)	-	-	-	($10.97)	**($10.97)**	~~(I)~~
Schedule 308 Credits - Non-Winter (per bill)	-	-	-	($4.84)	**($4.84)**	~~(I)~~
Volumetric Charge (per therm)	~~$0.55820~~ $0.90239	$0.10337	$0.43274	~~$0.22096~~ $0.22426	**~~$1.31527~~ $1.66276**	(I~~R~~)

Minimum Monthly Bill: Customer Charge, plus charges under **Schedule C** and **Schedule 10** (if applicable)

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1, 2027~~8~~

Effective with service on
and after ~~January 1, 2025~~August

RATE SCHEDULE 3
BASIC FIRM SALES SERVICE - NON-RESIDENTIAL
(continued)

MONTHLY RATE: Effective: ~~January 1, 2025~~ August 1, 2027 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM SALES SERVICE CHARGES (03 SF):					**Billing Rates [1]**	
Customer Charge (per month):					**$22.00**	
	Base Rate	Pipeline Capacity	Commodity Component [2]	Temporary Adjustment		
Schedule 308 Credits (per bill):						
Commercial - Winter				($46.59)	**($46.59)**	~~(I)~~
Commercial - Non-Winter				($25.89)	**($25.89)**	
Industrial				($129.16)	**($129.16)**	~~(I)~~
Volumetric Charges (per therm):						
Commercial	~~$0.53350~~ $0.90033	$0.10337	$0.43274	~~$0.20893~~ $0.21182	~~**$1.27854**~~ **$1.64826**	(~~I~~R)
Industrial	~~$0.54385~~ $0.85917	$0.10337	$0.43274	~~$0.15035~~ $$0.15298	~~**$1.23031**~~ **$1.54826**	(~~I~~R)
Standby Charge (per therm of MHDV) [3]:					**$5.00**	

[1] **Schedule C** and **Schedule 10** Charges shall apply, if applicable.
[2] The Commodity Component will be either Annual Sales WACOG or Monthly Incremental Cost of Gas.
[3] Applies to Standby Sales Service only.

Minimum Monthly Bill. The Minimum Monthly Bill shall be any **Schedule C** and **Schedule 10** Charges, plus:

(a) ***Firm Sales Service.*** Customer Charge
(b) ***Firm Sales Standby Service.*** Customer Charge, plus Standby Service Charge

RATE SCHEDULE 10
CHARGES FOR SPECIAL METERING EQUIPMENT, RENTAL METERS AND METERING SERVICES
(continued)

Metering Services and Charges	One Time Charge	Installation Charge	Monthly Charge	
Rental Read	---	---	$0.36	
Advanced Automated Meter Reading (AAMR) Device[1]	---	$1,270.53	$~~48.05~~52.75	(~~I~~R)
Remote Index	---	$50.00	$4.00	
Pulse Output	---	$100.00	$8.00	
Administrative Set-Up/Consultation Fee (all meters)	$145~~00~~.00	---	---	(I)
Technical Assistance (Rotary meters only)	$145~~00~~.00	---	---	(I)

[1] Site specific engineering design costs for AAMR will be added to the installation charge if needed.

SPECIAL PROVISIONS FOR RENTAL METERS AND SPECIAL METERING EQUIPMENT:

1. Prior to receiving service under this section of the Schedule, the Customer must sign a service agreement that requires a minimum 12-month term. Customers who terminate service after less than 12 months will be required to pay all charges otherwise due to fulfill the 12-month obligation under the service agreement.
2. Service under this section of this Schedule is voluntary and separate from billing for or delivery of natural gas to a Customer's premise.
3. Since the Company does not maintain an inventory of all meter types offered under this Schedule, a delay may occur from the time a Customer requests service under this Schedule until the Company can provide it.
4. The Customer will be responsible for the meter pick-up and return of diaphragm meters.
5. The Customer will incur the Administrative Set-Up/Consultation Fee for each rental meter.
6. Upon delivery of a rotary meter, the Customer will incur the Technical Assistance charge listed above for each rental rotary meter. A Customer may not waive this provision or the associated fee. Technical assistance helps the Company ensure proper handling of rotary meters.
7. The Company will install AAMR devices for the charge listed above. AAMR devices will only be installed on Company owned meters and the Company will require that the Customer provide active and continuous electric power per company specifications to enable meter communications.
8. Upon request, the Company will provide one differential test per calendar year on rotary meters. The testing will be scheduled at the Company's convenience.
9. The Customer is responsible to protect all rental equipment from damage including but not limited to installing parking bollards to protect the rental equipment from vehicular or other damage.

(continue to Sheet 110.3)

RATE SCHEDULE 27
RESIDENTIAL HEATING DRY-OUT SERVICE

AVAILABLE:
To Residential home builders, developers, and contractors during the period that a Residential dwelling is under construction, in all territory served by the Company under the Tariff of which this schedule is a part.

SERVICE DESCRIPTION:
Service under this Rate Schedule is restricted to the use of gas in approved permanently-installed gas heating equipment in place during the period the dwelling is under construction. Upon occupancy of the dwelling, service under this Rate Schedule shall terminate automatically. In no event will service under this Rate Schedule continue for more a period of time greater than twelve (12) months from the date the gas meter is set at the dwelling. Upon termination of service under this Rate Schedule, gas service shall transfer to **Schedule 1** or **Schedule 2**, whichever is applicable.

MONTHLY RATE: Effective: January 1, 2025August 1, 2027 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 200** for a list of applicable adjustments. Rates are subject to charges for purchased gas costs and technical rate adjustments.

	Base Rate	Pipeline Capacity Rate	Commodity Rate	Temporary Adjustment	Billing Rate
Customer Charge:	$9.00	---	---	---	**$9.00**
Volumetric Charge (per therm)					
All therms	$0.31253 $0.89745	$0.10337	$0.43274	$0.26727 $0.27052	**$1.11591$1.70408** (IR)

Minimum Monthly Bill: Customer Charge, plus charges under **Schedule C** and **Schedule 10** (if applicable)

GENERAL TERMS:
Service under this Rate Schedule is governed by the terms of this Rate Schedule, the General Rules and Regulations contained in this Tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

Issued December 18, 2024August 29, 2025
NWN WUTC Advice No. 25-0324-17
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RATE SCHEDULE 41
NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES FOR COMMERCIAL CUSTOMER CLASS: Effective: January 1, 2025 August 1, 2027 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. **SEE SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM SALES SERVICE CHARGES (C41SF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$250.00**	
	Base Rate		Commodity Component [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($515.09)	**($515.09)**	(I)
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	~~$0.41608~~ $0.69165		$0.43274	~~$0.19067~~ $0.19297	~~**$1.03949**~~ **$1.31736**	(IR) (IR)
Block 2: All additional therms	~~$0.36663~~ $0.60945		$0.43274	~~$0.18179~~ $0.18381	~~**$0.98116**~~ **$1.22600**	
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.10337**	
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.54**	
INTERRUPTIBLE SALES SERVICE CHARGES (C41SI) [1]:						
Customer Charge (per month):					**$250.00**	
	Base Rate		Commodity Component: [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				~~($515.09) Z$~~ ($622.72)	~~($515.09)~~ **($622.72)**	(RI)
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	~~$0.38453~~ $0.57062		$0.43274	~~$0.14700~~ $0.14883	~~**$0.96427**~~ **$1.15219**	(IR) (IR)
Block 2: All additional therms	~~$0.33880~~ $0.50276		$0.43274	~~$0.13893~~ $0.14056	~~**$0.91047**~~ **$1.07606**	
Plus: Interruptible Pipeline Capacity Charge - Volumetric (per therm):					**$0.03612**	
FIRM TRANSPORTATION SERVICE CHARGES (C41TF):						
Customer Charge (per month):					**$250.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Total Temporary Adjustments [4]		
Schedule 308 Credits (per bill):				($515.09)	**($515.09)**	(I)
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	~~$0.37785~~ $0.57719			~~$0.26259~~ $0.26465	~~**$0.64044**~~ **$0.84184**	(IR)

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Block 2: All additional therms	~~$0.33291~~ $0.50855			~~$0.26011~~ $0.26192	**~~$0.59302~~** **$0.77047**	(I~~R~~)

[1] The Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from Schedule C and Schedule 10.
[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG, or Monthly Incremental Cost of Gas.
[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 may not apply.

(continue to Sheet 141.10)

RATE SCHEDULE 41
NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES FOR INDUSTRIAL CUSTOMER CLASS: Effective: ~~January 1, 2025~~August 1, 2027 (C)
The rates shown in this Rate Schedule may not always reflect actual billing rates. **SEE SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM SALES SERVICE CHARGES (I41SF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$250.00**	
	Base Rate		Commodity Component [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($622.72)	**($622.72)**	~~(I)~~
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	~~$0.37147~~ $0.55452		$0.43274	~~$0.14201~~ $0.14389	**~~$0.94622~~ $1.13115**	(~~I~~R)
Block 2: All additional therms	~~$0.32731~~ $0.48859		$0.43274	~~$0.13904~~ $0.14070	**~~$0.85609~~ $1.06203**	(~~I~~R)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.10337**	
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.54**	
INTERRUPTIBLE SALES SERVICE CHARGES (I41SI) [1]:						
Customer Charge (per month):					**$250.00**	
	Base Rate		Commodity Component: [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($622.72)	**($622.72)**	~~(I)~~
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	~~$0.36378~~ $0.53983		$0.43274	~~$0.10593~~ $0.10769	**~~$0.90245~~ $1.08026**	(~~I~~R)
Block 2: All additional therms	~~$0.36378~~ $0.47561		$0.43274	~~$0.10285~~ $0.10441	**~~0.85609~~ $1.01276**	(~~I~~R)
Plus: Interruptible Pipeline Capacity Charge - Volumetric (per therm):					**$0.03612**	
FIRM TRANSPORTATION SERVICE CHARGES (I41TF):						
Customer Charge (per month):					**$250.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Total Temporary Adjustments [4]		
Schedule 308 Credits (per bill):				($622.72)	**($622.72)**	~~(I)~~

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~~1~~, 2027

Effective with service on
and after ~~January 1, 2025~~August

Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	~~$0.36781~~ $0.54581			~~$0.26075~~ $0.26254	~~**$0.62856**~~ **$0.80835**	(I~~R~~)
Block 2: All additional therms	~~$0.32406~~ $0.48089			~~$0.25850~~ $0.26007	~~**$0.58256**~~ **$0.74096**	(I~~R~~)

[1] The Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from Schedule C and Schedule 10.
[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG, or Monthly Incremental Cost of Gas.
[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 may not apply.

RATE SCHEDULE 42
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY SALES RATES - FIRM SERVICE: Effective: ~~January 1, 2025~~ August 1, 2027 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM SALES SERVICE CHARGES [1]:					**Billing Rates**	
Customer Charge (per month, all service types):					**$1,300.00**	
	Base Rate		Commodity Component [2]	Total Temporary Adjustments [3]		
C42SF						
Schedule 308 Credits (per bill):				($5,142.27)	($5,142.27)	(I)
Volumetric Charges (per therm):						(I~~R~~)
Block 1: 1st 10,000 therms	~~$0.20610~~ $0.38199		$0.43274	~~$0.15742~~ $0.15902	~~$0.79626~~ $0.97375	
Block 2: Next 20,000 therms	~~$0.18448~~ $0.34193		$0.43274	~~$0.15305~~ $0.15450	~~$0.77027~~ $0.92917	
Block 3: Next 20,000 therms	~~$0.14150~~ $0.26226		$0.43274	~~$0.14439~~ $0.14550	~~$0.71863~~ $0.84050	
Block 4: Next 100,000 therms	~~$0.11318~~ $0.20977		$0.43274	~~$0.13869~~ $0.13958	~~$0.68461~~ $0.78209	
Block 5: Next 600,000 therms	~~$0.07545~~ $0.13984		$0.43274	~~$0.13108~~ $0.13167	~~$0.63927~~ $0.70425	
Block 6: All additional therms	~~$0.02828~~ $0.05242		$0.43274	~~$0.12157~~ $0.12179	~~$0.58259~~ $0.60695	(I~~R~~)
I42SF						
Schedule 308 Credits (per bill):				($3,945.77)	($3,945.77)	(I)
Volumetric Charges (per therm):						(I~~R~~)
Block 1: 1st 10,000 therms	~~$0.16641~~ $0.30071		$0.43274	~~$0.13254~~ $0.13417	~~$0.73169~~ $0.86762	
Block 2: Next 20,000 therms	~~$0.14895~~ $0.26917		$0.43274	~~$0.13089~~ $0.13235	~~$0.71258~~ $0.83426	
Block 3: Next 20,000 therms	~~$0.11422~~ $0.20640		$0.43274	~~$0.12761~~ $0.12874	~~$0.67457~~ $0.76788	
Block 4: Next 100,000 therms	~~$0.09138~~ $0.16512		$0.43274	~~$0.12545~~ $0.12635	~~$0.64957~~ $0.72421	
Block 5: Next 600,000 therms	~~$0.06094~~ $0.11013		$0.43274	~~$0.12258~~ $0.12318	~~$0.61626~~ $0.66605	
Block 6: All additional therms	~~$0.02283~~ $0.04125		$0.43274	~~$0.11898~~ $0.11920	~~$0.57455~~ $0.59319	(I~~R~~)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	
Firm Sales Service Storage Charge (per therm of MDDV per month):					**$0.20415**	
Pipeline Capacity Charge Options (select one):						

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Firm Pipeline Capacity Charge - Volumetric option (per therm):	**$0.10337**
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV per month):	**$1.54**

[1] For Firm Sales Service, the Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Distribution Capacity Charge, plus the Storage Capacity Charge, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from Schedule C or Schedule 10.
[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG or Monthly Incremental Cost of Gas.
[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 may not apply.

(continue to Sheet 142.10.1)

RATE SCHEDULE 42
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY SALES RATES – INTERRUPTIBLE SERVICE: Effective: August 1 2027~~January 1, 2025~~ (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

INTERRUPTIBLE SALES SERVICE CHARGES [1]: (C42SI)					**Billing Rates**	
Customer Charge (per month):					**$1,300.00**	
	Base Rate		Commodity Component [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($5,142.27)	**($5,142.27)**	~~(I)~~
Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	~~$0.16872~~ $0.29512		$0.43274	~~$0.10987~~ $0.11093	~~**$0.71133**~~ **$0.83879**	(~~IR~~)
Block 2: Next 20,000 therms	~~$0.15103~~ $0.26417		$0.43274	~~$0.10666~~ $0.10760	~~**$0.69043**~~ **$0.80451**	
Block 3: Next 20,000 therms	~~$0.11580~~ $0.20255		$0.43274	~~$0.10024~~ $0.10096	~~**$0.64878**~~ **$0.73625**	
Block 4: Next 100,000 therms	~~$0.09264~~ $0.16205		$0.43274	~~$0.09603~~ $0.09660	~~**$0.62141**~~ **$0.69139**	
Block 5: Next 600,000 therms	~~$0.06178~~ $0.10807		$0.43274	~~$0.09041~~ $0.09080	~~**$0.58493**~~ **$0.63161**	
Block 6: All additional therms	~~$0.02317~~ $0.04053		$0.43274	~~$0.08334~~ $0.08348	~~**$0.53925**~~ **$0.55675**	(~~IR~~)
Interruptible Pipeline Capacity Charge (per therm):					**$0.03612**	
Interruptible Sales Service Storage Charge (per therm of MDDV per month)					**$0.10208**	
INTERRUPTIBLE SALES SERVICE CHARGES [1]: (I42SI)						
Customer Charge (per month):					**$1,300.00**	
Schedule 308 Credits (per bill):				($3,945.77)	**($3,945.77)**	~~(I)~~
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	~~$0.16353~~ $0.27732		$0.43274	~~$0.09437~~ $0.09556	~~**$0.69064**~~ **$0.80562**	(~~IR~~)
Block 2: Next 20,000 therms	~~$0.14638~~ $0.24824		$0.43274	~~$0.09287~~ $0.09394	~~**$0.67199**~~ **$0.77492**	
Block 3: Next 20,000 therms	~~$0.11225~~ $0.19035		$0.43274	~~$0.08990~~ $0.09072	~~**$0.63489**~~ **$0.71381**	
Block 4: Next 100,000 therms	~~$0.08981~~ $0.15230		$0.43274	~~$0.08793~~ $0.08858	~~**$0.61048**~~ **$0.67362**	
Block 5: Next 600,000 therms	~~$0.05986~~ $0.10151		$0.43274	~~$0.08531~~ $0.08575	~~**$0.57791**~~ **$0.62000**	
Block 6: All additional therms	~~$0.02244~~ $0.03805		$0.43274	~~$0.08206~~ $0.08223	~~**$0.53724**~~ **$0.55302**	(~~IR~~)
Interruptible Pipeline Capacity Charge (per therm):					**$0.03612**	
Interruptible Sales Service Storage Charge (per therm of MDDV per month)					**$0.10208**	

Issued ~~December 18, 2024~~August 29, 2025
NWN WUTC Advice No. 25-03~~24-17~~
1, 2027

Effective with service on
and after ~~January 1, 2025~~August

[1] For Interruptible Sales Service, the Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge, plus any other charges that apply from Schedule C or Schedule 10.
[2] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 201 may also apply.
[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 may not apply.

(continue to Sheet 142.11)

RATE SCHEDULE 42
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY TRANSPORTATION RATES: Effective: January 1, 2025August 1, 2027 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (C42TI) [1]:					**Billing Rates**	
Customer Charge (per month):					**$1,300.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Temporary Adjustments [2]		
Schedule 308 Credits (per bill):				($5,142.27)	**($5,142.27)**	(I)
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	~~$0.14169~~ $0.2102633			~~$0.24907~~ $0.24975	~~**$0.39076**~~ **$0.460018**	(IR)
Block 2: Next 20,000 therms	~~$0.12685~~ $0.1882330			~~$0.24831~~ $0.24893	~~**$0.37516**~~ **$0.4371623**	
Block 3: Next 20,000 therms	~~$0.09727~~ $0.144349			~~$0.24678~~ $0.247256	~~**$0.34405**~~ **$0.3915965**	
Block 4: Next 100,000 therms	~~$0.07782~~ $0.1154751			~~$0.24578~~ $0.24616	~~**$0.32360**~~ **$0.361637**	
Block 5: Next 600,000 therms	~~$0.05189~~ $0.077013			~~$0.24444~~ $0.24469	~~**$0.29633**~~ **$0.321702**	
Block 6: All additional therms	~~$0.01944~~ $0.028856			~~$0.24277~~ $0.24286	~~**$0.26221**~~ **$0.271712**	(IR)
INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (I42TI) [1]:					**Billing Rates**	
Customer Charge (per month):					**$1,300.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Temporary Adjustments [2]		
Schedule 308 Credits (per bill):				($3,945.77)	**($3,945.77)**	(I)
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	~~$0.14430~~ $0.21245	-	-	~~$0.24917~~ $0.24987	~~**$0.39347**~~ **$0.46232**	(IR)
Block 2: Next 20,000 therms	~~$0.12917~~ $0.19017	-	-	~~$0.24841~~ $0.24904	~~**$0.37758**~~ **$0.43921**	
Block 3: Next 20,000 therms	~~$0.09905~~ $0.14583	-	-	~~$0.24687~~ $0.24735	~~**$0.34592**~~ **$0.39318**	
Block 4: Next 100,000 therms	~~$0.07925~~ $0.11668	-	-	~~$0.24586~~ $0.24625	~~**$0.32511**~~ **$0.36293**	
Block 5: Next 600,000 therms	~~$0.05284~~ $0.07780	-	-	~~$0.24452~~ $0.24478	~~**$0.29736**~~ **$0.32258**	
Block 6: All additional therms	~~$0.01981~~ $0.02918	-	-	~~$0.24285~~ $0.24294	~~**$0.26266**~~**$0.27212**	(IR)

[1] For Interruptible Transportation Service, the Monthly Bill shall equal the sum of the Customer Charge, plus Transportation Charge, plus the Volumetric Charges, plus any other charges that may apply from Schedule C or Schedule 10.
[2] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 201 may also apply.

(continue to Sheet 142.12)

RATE SCHEDULE 42
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

FIRM TRANSPORTATION SERVICE CHARGES (C42TF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$1,300.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Total Temporary Adjustments [2]		
Schedule 308 Credits (per bill):				($5,142.27)	**($5,142.27)**	(I)
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	~~$0.15442~~ $0.25976			~~$0.24890~~ $0.25028	~~**$0.40332**~~ **$0.51004**	(I/R)
Block 2: Next 20,000 therms	~~$0.13824~~ $0.23254			~~$0.24816~~ $0.24940	~~**$0.38640**~~ **$0.48194**	
Block 3: Next 20,000 therms	~~$0.10600~~ $0.17831			~~$0.24669~~ $0.24763	~~**$0.35269**~~ **$0.42594**	
Block 4: Next 100,000 therms	~~$0.08481~~ $0.14267			~~$0.24573~~ $0.24649	~~**$0.33054**~~ **$0.38916**	
Block 5: Next 600,000 therms	~~$0.05654~~ $0.09511			~~$0.24443~~ $0.24493	~~**$0.30097**~~ **$0.34004**	
Block 6: All additional therms	~~$0.02120~~ $0.03566			~~$0.24283~~ $0.24301	~~**$0.26403**~~ **$0.27867**	(I/R)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	
FIRM TRANSPORTATION SERVICE CHARGES (I42TF) [1]:						
Customer Charge (per month):					**$1,300.00**	
Transportation Charge (per month):					**$250.00**	
Schedule 308 Credits (per bill):				($3,945.77)	**($3,945.77)**	(I)
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	~~$0.15161~~ $0.23078			~~$0.24935~~ $0.25022	~~**$0.40096**~~ **$0.48100**	(I/R)
Block 2: Next 20,000 therms	~~$0.13571~~ $0.20659			~~$0.24856~~ $0.24934	~~**$0.38427**~~ **$0.45593**	
Block 3: Next 20,000 therms	~~$0.10406~~ $0.15841			~~$0.24699~~ $0.24760	~~**$0.35105**~~ **$0.40601**	
Block 4: Next 100,000 therms	~~$0.08326~~ $0.12675			~~$0.24596~~ $0.24644	~~**$0.32922**~~ **$0.37319**	
Block 5: Next 600,000 therms	~~$0.05550~~ $0.08449			~~$0.24459~~ $0.24490~~4~~	~~**$0.30009**~~ **$0.3293940**	
Block 6: All additional therms	~~$0.02082~~ $0.03168			~~$0.24287~~ $0.24300	~~**$0.26369**~~ **$0.27468**	(I/R)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	

[1] For Firm Transportation Service, the Monthly Bill shall equal the sum of the Customer Charge, plus Transportation Charge, plus the Volumetric Charges, plus the Distribution Capacity Charge, plus any other charges that may apply from Schedule C or Schedule 10.
[2] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 201 may also apply.

Issued ~~December 18, 2024~~August 29, 2025
NWN WUTC Advice No. 25-03~~24-17~~ 2027

Effective with service on
and after ~~January 1, 2025~~August 1,

RATE SCHEDULE 43
HIGH VOLUME NON-RESIDENTIAL
FIRM AND INTERRUPTIBLE TRANSPORTATION SERVICE
(continued)

MONTHLY RATE: Effective: January 1, 2025 August 1, 2027 (C)

The rates shown below may not always reflect actual billing rates. See **Schedule 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM TRANSPORTATION SERVICE CHARGES (C43TF and I43TF)					
					Billing Rates
Customer Charge:					**$38,000.00**
Transportation Charge:					**$250.00**
Volumetric Charge	Base Rate			Total Temporary Adjustment [1]	
Per therm, all therms	$0.00491 $0.00733			$ 0.24194	**$0.24685** **$0.24927** (IR)
Firm Service Distribution Capacity Charge: Per therm of MDDV per month					**$0.15748**

Minimum Monthly Bill: Customer Charge, plus Transportation Charge, plus Firm Service Distribution Capacity Charge, plus any other charges that may apply from **Schedule C** and **Schedule 10**.

INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (C43TI and I43TI)					
					Billing Rates
Customer Charge:					**$38,000.00**
Transportation Charge:					**$250.00**
Volumetric Charge:	Base Rate			Total Temporary Adjustment [1]	
Per therm, all therms	$0.00491 $0.00733			$ 0.24194	**$0.24685** **$0.24927** (IR)
Minimum Monthly Bill: Customer Charge, plus Transportation Charge, plus any other charges that may apply from **Schedule C** and **Schedule 10**.					

[1] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 shall apply.

Issued December 18, 2024August 29, 2025
NWN WUTC Advice No. 25-0324-17
1, 2027

Effective with service on
and after January 1, 2025August

SCHEDULE 200
SUMMARY OF ADJUSTMENTS

PURPOSE:
The purpose of this Schedule is to list and summarize the adjustment Schedules applicable to each of the Company's Rate Schedules.

SCHEDULE	A	201	203	207	210	212	215	220	221	230	232	233	234	235	236	237	238	303	305	306	308
R1	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
C1	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
2	ADD	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
03CSF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
03ISF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
10	ADD			INC																	
27	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
C41SF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
C41SI	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
C41TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I41SF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I41SI	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I41TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C42SF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
C42SI	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
C42TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C42TI	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I42SF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I42SI	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I42TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I42TI	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C43TI/ I43TI	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C43TF/ I43TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC

(N) (N)

Table Code Key:

ADD This adjustment is added to the billing rates at the time the bill is issued.
INC This adjustment is included in the billing rates shown on the Rate Schedule

(continue to Sheet 200.2)

SCHEDULE 200
SUMMARY OF ADJUSTMENTS
(continued)

The following is a brief description of the applicable Schedules:

Schedule A "Billing for City and County Exactions."
This adjustment will be reflected directly on Customer bills.

Schedule 201 "Temporary (Technical) Adjustments to Rates."
These are temporary Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 203 "Purchased Gas Cost Adjustments to Rates."
These are pipeline capacity and commodity charges.

Schedule 207 "General Adjustments to Rates."
These are Base Rate Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 210 "Adjustment to Rates for Property Sales."
These are Temporary Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 212 "Adjustment to Rates Residential Rate Mitigation."
These are Temporary Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 215 "Adjustment to Rates for Energy Conservation Programs."
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 220 "Special Rate Adjustment."
These are Base Rate Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 221 "Rate Adjustment for Updated Depreciation Rates"
These are Base Rate Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 230 "Temporary Adjustments to Rates for Low-Income Programs."
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 231 "Temporary Adjustments to Rates for Residential Discount Program."
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 232 "Temporary Adjustments to Rates for Regulatory Fee Increase"
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 233 "Temporary Adjustments to Rates for Industrial Customer Energy Efficiency Audit Costs"
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 234 "Temporary Adjustments to Rates for Residential Arrearage Management Program" (N)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 235 "Temporary Adjustments to Rates for COVID-19 Public Health Emergency" (N)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills. (N)

(K)

(K) Schedules 303, 305, 306 and 308 transferred to Sheet 200.3.

(continue to Sheet 200.3)

Schedule 303 "Washington Environmental Cost Recovery Mechanism."
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 305 "Adjustment for Certain Income Taxes (2017 Federal Tax Cuts and Jobs Act)."
These are base and temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 306 "Multi-Year Rate Plan Adjustment."
These are base rate adjustments that will be added to the Billing Rate on the effective date of the Schedule.

Schedule 308 "Washington Climate Commitment Act Recovery Mechanism."
These are temporary rate adjustments that will be added to the Billing Rate on the effective date of the Schedule.

SCHEDULE 200
SUMMARY OF ADJUSTMENTS
(continued)

Schedule 236 "Temporary Adjustments to Rates for Meter Modernization Program." (N)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 237 "Temporary Adjustments to Rates for TSA Operations and Maintenance Costs." (N)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 238 "Adjustments to Rates for Provisional Capital Adjustment." (N)
These are base rate adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 303 "Washington Environmental Cost Recovery Mechanism." (M)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 305 "Adjustment for Certain Income Taxes (2017 Federal Tax Cuts and Jobs Act)."
These are base and temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 306 "Multi-Year Rate Plan Adjustment."
These are base rate adjustments that will be added to the Billing Rate on the effective date of the Schedule.

Schedule 308 "Washington Climate Commitment Act Recovery Mechanism."
These are temporary rate adjustments that will be added to the Billing Rate on the effective date of the Schedule. (M)

(M) Schedules 303, 305, 306 and 308 transferred from Sheet 200.2.

SCHEDULE 207
GENERAL RATE ADJUSTMENT

PURPOSE:
To identify the effects of general rate changes approved in the company's most recent general rate case proceeding (Docket UG-200994)

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2022 August 1, 2027 (C) (T) (T)

Rate Schedule 1	Rate Schedule 3	Rate Schedule 41	Rate Schedule 43
Rate Schedule 2	Rate Schedule 27	Rate Schedule 42	

The Base Rates in the listed Rate Schedules include the adjustment shown below.
NO FURTHER ADJUSTMENT TO RATES IS REQUIRED.

SCHEDULES	BLOCKS	AMOUNT		
Schedule 1 - Residential	Customer Charge	$20.00	(I)	
	Per Therm (all therms)	$0.0616502832	(R)	
Schedule 1 - Commercial	Customer Charge	$0.00		
	Per Therm (all therms)	$0.0512613837	(IR)	
Schedule 2	Customer Charge	$20.00	(I)	
	Per Therm (all therms)	$0.0390205895	(IR)	
Schedule 3 - Commercial	Customer Charge	$0.00		
	Per Therm (all therms)	$0.0350308715	(IR)	
Schedule 3 - Industrial	Customer Charge	$0.00		
	Per Therm (all therms)	$0.0317307956	(IR)	
Schedule 27	Customer Charge	$0.00		
	Per Therm (all therms)	$0.0277709757	(IR)	(D)
Schedule 41 - Commercial Firm Sales Service	Customer Charge	$0.00		
		0.02782	(IR)	
	First 2,000 therms	0.06933		
	All additional therms	$ 0.06109	(IR)	
Schedule 41 - Commercial Interruptible Sales Service	Customer Charge	$0.00		
		$0.02162 $	(IR)	
	First 2,000 therms	0.03733		
	All additional therms	$ 0.03289	(IR)	
Schedule 41 - Industrial Firm Sales Service	Customer Charge	$0.00		
		0.00873	(IR)	
	First 2,000 therms	0.05666		
	All additional therms	$ 0.04992	(IR)	
Schedule 41 - Industrial Interruptible Sales Service	Customer Charge	$0.00		
		0.00713	(IR)	
	First 2,000 therms	0.03532		
	All additional therms	$ 0.03112	(IR)	
Schedule 41 - Commercial Firm Transportation Service	Customer Charge	$0.00		
		0.00971	(IR)	
	First 2,000 therms	0.06187		

Issued October 14, 2022August 29, 2025
NWN WUTC Advice No. 22-0925-03
August 1, 2027

Effective with service on and after November 1, 2022

	All additional therms	$ 0.05451	(IR)
Schedule 41 - Industrial Firm Transportation Service	Customer Charge	$0.00	
		0.00721	(IR)
	First 2,000 therms	0.03571	
	All additional therms	$ 0.03146	(IR)

(continue to Sheet 207.2)

SCHEDULE 207
GENERAL RATE ADJUSTMENT
(continued)

SCHEDULES	BLOCKS	AMOUNT	
Schedule 42 Commercial - Firm Sales Service	Customer Charge	$0.00	
	First 10,000 therms	~~0.02095~~ 0.04425	(I~~R~~)
	Next 20,000 therms	~~0.01875~~ 0.03961	
	Next 20,000 therms	~~0.01438~~ 0.03038	
	Next 100,000 therms	~~0.01151~~ 0.02430	
	Next 600,000 therms	~~0.00767~~ 0.01620	
	All additional therms	~~0.00288~~ 0.00607	(I~~R~~)
Schedule 42 Commercial - Interruptible Sales Service	Customer Charge	$0.00	
	First 10,000 therms	~~0.01245~~ 0.03175	(I~~R~~)
	Next 20,000 therms	~~0.01114~~ 0.02842	
	Next 20,000 therms	~~0.00854~~ 0.02179	
	Next 100,000 therms	~~0.00683~~ 0.01744	
	Next 600,000 therms	~~0.00456~~ 0.01163	
	All additional therms	~~0.00171~~ 0.00436	(I~~R~~)
Schedule 42 Industrial - Firm Sales Service	Customer Charge	$0.00	
	First 10,000 therms	~~0.00614~~ 0.04158	(I~~R~~)
	Next 20,000 therms	~~0.00550~~ 0.03722	
	Next 20,000 therms	~~0.00422~~ 0.02854	
	Next 100,000 therms	~~0.00337~~ 0.02283	

Issued ~~October 14, 2022~~ August 29, 2025
NWN WUTC Advice No. ~~22-09~~25-03

Effective with service on and after ~~November 1, 2022~~ August 1, 2027

		0.00225	
	Next 600,000 therms	0.01523	
	All additional therms	0.000840.00570	(IR)
Schedule 42 Industrial - Interruptible Sales Service	Customer Charge	$0.00	
	First 10,000 therms	0.005660.03596	(IR)
		0.00507	
	Next 20,000 therms	0.03219	
		0.00389	
	Next 20,000 therms	0.02468	
		0.00311	
	Next 100,000 therms	0.01975	
		0.00207	
	Next 600,000 therms	0.01316	
		0.00078	
	All additional therms	0.00493	(IR)

(continue to Sheet 207.3)

(N)

SCHEDULE 235
TEMPORARY ADJUSTMENTS TO RATES FOR COVID-19 PUBLIC HEALTH EMERGENCY

PURPOSE: To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of deferred amounts for the costs and savings incurred due to the COVID-19 pandemic, as authorized for deferred accounting by the WUTC in Docket UG-200264.

APPLICABLE:
Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: ~~September 30, 2025~~August 1, 2027**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)	Schedule	Block	Adjustment (per therm)
1R		$0.00290	42 CTF	Block 1	$0.00075
1C		$0.00240		Block 2	$0.00067
2R		$0.00178		Block 3	$0.00051
3C		$0.00156		Block 4	$0.00041
3I		$0.00142		Block 5	$0.00027
27		$0.00175		Block 6	$0.00010
41 CSF	Block 1	$0.00124	42 ITF	Block 1	$0.00047
	Block 2	$0.00109		Block 2	$0.00042
41 ISF	Block 1	$0.00101		Block 3	$0.00033
	Block 2	$0.00089		Block 4	$0.00026
41 CSI	Block 1	$0.00106		Block 5	$0.00017
	Block 2	$0.00094		Block 6	$0.00007
41 ISI	Block 1	$0.00103	42 CSI	Block 1	$0.00057
	Block 2	$0.00091		Block 2	$0.00051
41 CTF	Block 1	$0.00111		Block 3	$0.00039
	Block 2	$0.00098		Block 4	$0.00031
41ITF	Block 1	$0.00104		Block 5	$0.00021
	Block 2	$0.00092		Block 6	$0.00008
42 CSF	Block 1	$0.00087	42 ISI	Block 1	$0.00064
	Block 2	$0.00078		Block 2	$0.00058
	Block 3	$0.00060		Block 3	$0.00044
	Block 4	$0.00048		Block 4	$0.00035
	Block 5	$0.00032		Block 5	$0.00024
	Block 6	$0.00012		Block 6	$0.00009
42 ISF	Block 1	$0.00088	42 CTI	Block 1	$0.00040
	Block 2	$0.00079		Block 2	$0.00036
	Block 3	$0.00061		Block 3	$0.00027
	Block 4	$0.00049		Block 4	$0.00022
	Block 5	$0.00032		Block 5	$0.00015
	Block 6	$0.00012		Block 6	$0.00005
			42 ITI	Block 1	$0.00038
				Block 2	$0.00034
				Block 3	$0.00026
				Block 4	$0.00021
				Block 5	$0.00014
				Block 6	$0.00005
			43 TF		$0.00000
			43 TF		$0.00000

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this

(N)

Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

SCHEDULE 236
TEMPORARY ADJUSTMENTS TO RATES FOR METER MODERNIZATION PROGRAM

(N)

PURPOSE: To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of deferred amounts for the costs related to the Company's Meter Modernization Program, as authorized for deferred accounting by the WUTC in Docket UG-240012.

APPLICABLE:
Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: ~~September 30, 2025~~August 1, 2027**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		$0.00125		42 CTF	Block 1	$0.00032
1C		$0.00105			Block 2	$0.00029
2R		$0.00077			Block 3	$0.00022
3C		$0.00067			Block 4	$0.00018
3I		$0.00061			Block 5	$0.00012
27		$0.00076			Block 6	$0.00004
41 CSF	Block 1	$0.00054		42 ITF	Block 1	$0.00020
	Block 2	$0.00047			Block 2	$0.00018
41 ISF	Block 1	$0.00044			Block 3	$0.00014
	Block 2	$0.00039			Block 4	$0.00011
41 CSI	Block 1	$0.00039			Block 5	$0.00007
	Block 2	$0.00035			Block 6	$0.00003
41 ISI	Block 1	$0.00037		42 CSI	Block 1	$0.00025
	Block 2	$0.00033			Block 2	$0.00022
41 CTF	Block 1	$0.00048			Block 3	$0.00017
	Block 2	$0.00042			Block 4	$0.00013
41ITF	Block 1	$0.00038			Block 5	$0.00009
	Block 2	$0.00033			Block 6	$0.00003
42 CSF	Block 1	$0.00037		42 ISI	Block 1	$0.00028
	Block 2	$0.00034			Block 2	$0.00025
	Block 3	$0.00026			Block 3	$0.00019
	Block 4	$0.00021			Block 4	$0.00015
	Block 5	$0.00014			Block 5	$0.00010
	Block 6	$0.00005			Block 6	$0.00004
42 ISF	Block 1	$0.00038		42 CTI	Block 1	$0.00014
	Block 2	$0.00034			Block 2	$0.00013
	Block 3	$0.00026			Block 3	$0.00010
	Block 4	$0.00021			Block 4	$0.00008
	Block 5	$0.00014			Block 5	$0.00005
	Block 6	$0.00005			Block 6	$0.00002
				42 ITI	Block 1	$0.00016
					Block 2	$0.00015
					Block 3	$0.00011
					Block 4	$0.00009
					Block 5	$0.00006
					Block 6	$0.00002
				43 TF		$0.00000
				43 TF		$0.00000

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this

(N)

Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

SCHEDULE 237
TEMPORARY ADJUSTMENTS TO RATES FOR TSA OPERATIONS AND MAINTENANCE COSTS

(N)

PURPOSE: To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of deferred amounts for the start-up Operations and Maintenance costs incurred for compliance with TSA Security Directives, as authorized for deferred accounting by the WUTC in Docket UG-210900.

APPLICABLE:
Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: ~~September 30, 2025~~August 1, 2027**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		$0.00122		42 CTF	Block 1	$0.00031
1C		$0.00100			Block 2	$0.00028
2R		$0.00075			Block 3	$0.00021
3C		$0.00066			Block 4	$0.00017
3I		$0.00060			Block 5	$0.00011
27		$0.00074			Block 6	$0.00004
41 CSF	Block 1	$0.00052		42 ITF	Block 1	$0.00020
	Block 2	$0.00046			Block 2	$0.00018
41 ISF	Block 1	$0.00043			Block 3	$0.00014
	Block 2	$0.00038			Block 4	$0.00011
41 CSI	Block 1	$0.00038			Block 5	$0.00007
	Block 2	$0.00034			Block 6	$0.00003
41 ISI	Block 1	$0.00036		42 CSI	Block 1	$0.00024
	Block 2	$0.00032			Block 2	$0.00021
41 CTF	Block 1	$0.00047			Block 3	$0.00016
	Block 2	$0.00041			Block 4	$0.00013
41ITF	Block 1	$0.00037			Block 5	$0.00009
	Block 2	$0.00032			Block 6	$0.00003
42 CSF	Block 1	$0.00036		42 ISI	Block 1	$0.00027
	Block 2	$0.00033			Block 2	$0.00024
	Block 3	$0.00025			Block 3	$0.00019
	Block 4	$0.00020			Block 4	$0.00015
	Block 5	$0.00013			Block 5	$0.00010
	Block 6	$0.00005			Block 6	$0.00004
42 ISF	Block 1	$0.00037		42 CTI	Block 1	$0.00014
	Block 2	$0.00033			Block 2	$0.00013
	Block 3	$0.00026			Block 3	$0.00010
	Block 4	$0.00020			Block 4	$0.00008
	Block 5	$0.00014			Block 5	$0.00005
	Block 6	$0.00005			Block 6	$0.00002
				42 ITI	Block 1	$0.00016
					Block 2	$0.00014
					Block 3	$0.00011
					Block 4	$0.00009
					Block 5	$0.00006
					Block 6	$0.00002
				43 TF		$0.00000
				43 TF		$0.00000

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this

(N)

Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

NORTHWEST NATURAL GAS COMPANY

WN U-6 First Revision of ~~Original~~ Sheet 238.1

Cancels Original Sheet 238.1

SCHEDULE 238
ADJUSTMENTS TO RATES FOR PROVISIONAL CAPITAL ADJUSTMENT

(N)

PURPOSE: To identify adjustments to rates in the Rate Schedules listed below that relate to the capital with Rate Year 1 as authorized by the WUTC in Docket UG-250610.

APPLICABLE:

Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective:** ~~September 30, 2025~~August 1, 2027

The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		0.04621		42 CTF	Block 1	0.00684
1C		0.04041			Block 2	0.00613
2R		0.02622			Block 3	0.00470
3C		0.02569			Block 4	0.00376
3I		0.02192			Block 5	0.00251
27		0.04463			Block 6	0.00094
41 CSF	Block 1	0.01910		42 ITF	Block 1	0.00514
	Block 2	0.01683			Block 2	0.00460
41 ISF	Block 1	0.01186			Block 3	0.00353
	Block 2	0.01045			Block 4	0.00282
41 CSI	Block 1	0.01341			Block 5	0.00188
	Block 2	0.01182			Block 6	0.00071
41 ISI	Block 1	0.01269		42 CSI	Block 1	0.00875
	Block 2	0.01118			Block 2	0.00783
41 CTF	Block 1	0.01295			Block 3	0.00601
	Block 2	0.01141			Block 4	0.00480
41ITF	Block 1	0.01283			Block 5	0.00320
	Block 2	0.01130			Block 6	0.00120
42 CSF	Block 1	0.01219		42 ISI	Block 1	0.00753
	Block 2	0.01091			Block 2	0.00674
	Block 3	0.00837			Block 3	0.00517
	Block 4	0.00670			Block 4	0.00413
	Block 5	0.00446			Block 5	0.00276
	Block 6	0.00167			Block 6	0.00103
42 ISF	Block 1	0.00870		42 CTI	Block 1	0.00494
	Block 2	0.00779			Block 2	0.00442
	Block 3	0.00597			Block 3	0.00339
	Block 4	0.00478			Block 4	0.00271
	Block 5	0.00319			Block 5	0.00181
	Block 6	0.00119			Block 6	0.00068
				42 ITI	Block 1	0.00443
					Block 2	0.00396
					Block 3	0.00304
					Block 4	0.00243
					Block 5	0.00162
					Block 6	0.00061
				43 TF		0.00017
				43 TF		0.00017

GENERAL TERMS:

This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

(N)

Issued August 29, 2025
NWN WUTC Advice No. 25-03
~~2025~~August 1, 2027

Effective with service on and after ~~September 30,~~

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

RATE YEAR 3 TARIFF SHEETS

LEGISLATIVE

August 29, 2025

RATE SCHEDULE 1
GENERAL SALES SERVICE

AVAILABLE:
To all Residential and Commercial Customer classes in all territory served by the Company under the Tariff of which this Rate Schedule is a part, except that service under this Rate Schedule is not available for Standby Service to Commercial Customers. Seasonal or temporary Discontinuance of Service is allowed subject to Special Provision 1 of this Rate Schedule. The installation of Distribution Facilities, when required before service can be provided to equipment served under this Rate Schedule, is subject to the provisions of **Schedule E**.

SERVICE DESCRIPTION:
Service under this Rate Schedule is Firm Sales Service to gas-fired equipment, including but not limited to one or any multiple or combination of the following:

(a) Non-ducted space heating equipment that does not qualify as primary heating systems under Rate Schedule 2, including but not limited to fireplace inserts, free standing gas stoves, and room heaters;
(b) Supplemental or Standby space heating equipment including but not limited to natural gas back-up to electric heat pumps, used in residential applications;
(c) Water heating equipment used to serve single-family residential swimming pools, spas, and hot tubs;
(d) Other equipment including, but not limited to, log lighter, gas log, gas barbecue, tiki torch, Bunsen burner, Domestic cooking equipment, hobby kilns, refrigeration or Domestic clothes drying;
(e) Equipment installed for use in detached garages, shops, or outbuildings.

MONTHLY RATE: Effective: August 1, 2028~~January 1, 2025~~ (C)
The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 200** for a list of applicable adjustments. Rates are subject to charges for purchased gas costs and technical rate adjustments.

	Base Rate	Pipeline Capacity Rate	Commodity Rate	Temporary Adjustment	Billing Rate	
Residential:	-	-	-	-	-	
Customer Charge	~~$5.50~~ $10.00	—	—	—	**~~$5.50~~ $10.00**	(I)
Schedule 308 Credits (per bill)	-	-	-	($1.82)	**($1.82)**	~~(I)~~
Volumetric Charge (per therm)	~~$0.83469~~ $1.34069	$0.10337	$0.43274	~~$0.29750~~ $0.31603	**~~$1.66830~~ $2.19283**	(I~~R~~)
	-	-	-	-	-	
Commercial:	-	-	-	-	-	
Customer Charge	~~$7.00~~ $10.00	—	—	—	**~~$7.00~~ $10.00**	(I)
Schedule 308 Credits (per bill)	-	-	-	$(5.34)	**($5.34)**	~~(I)~~
Volumetric Charge (per therm)	~~$0.86308~~ $1.51935	$0.10337	$0.43274	~~$0.27345~~ $0.28890	**~~$1.67264~~ $2.34436**	(I~~R~~)

Minimum Monthly Bill: Customer Charge, plus charges under **Schedule C** and **Schedule 10** (if applicable)

(continue to Sheet 101.2)

RATE SCHEDULE 2
RESIDENTIAL SALES SERVICE

AVAILABLE:
To Residential Customers, in all territory served by the Company under the Tariff of which this Rate Schedule is a part. Seasonal or temporary Discontinuance of Service is allowed subject to Special Provision 1 of this Rate Schedule. The installation of Distribution Facilities, when required before service can be provided to equipment served under this Rate Schedule, are subject to the provisions of **SCHEDULE E**.

SERVICE DESCRIPTION:
Service under this Rate Schedule is Firm Sales Service to gas-fired equipment used in Residential dwellings that provide complete family living facilities in which the occupant normally cooks, eats, sleeps, and carries on the household operations incident to Domestic life, for at least one of the following purposes:

(a) Operation of ducted forced air Natural Gas space heating equipment that is the primary source for space heating requirements;
(b) Operation of a gas-fired hearth product or wall heater as the primary source for space heating requirements where the hearth or wall heater has a verified nameplate rating of 20,000 BTUs or greater, and is installed in a primary residence defined as a dwelling that is occupied year-round, and where that dwelling is 1,500 square feet or less; and, or;
(c) Operation of fully automatic water heating equipment for primary water heating requirements.

Service under this Rate Schedule includes the use of gas for equipment installed in addition to (a) and (b).

MONTHLY RATE: Effective: ~~January 1, 2025~~August 1, 2028 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

	Base Rate	Pipeline Capacity Rate	Commodity Rate	Temporary Adjustment	Billing Rate	
Customer Charge:	~~$8.00~~ $10.00	—	—	—	**~~$8.00~~** $10.00	(I)
Schedule 308 Credits - Winter (per bill)	-	-	-	($10.97)	**($10.97)**	~~(I)~~
Schedule 308 Credits - Non-Winter (per bill)	-	-	-	($4.84)	**($4.84)**	~~(I)~~
Volumetric Charge (per therm)	~~$0.55820~~ $0.99302	$0.10337	$0.43274	$0.23171	**~~$1.31627~~ $1.76084**	(~~I~~R)

Minimum Monthly Bill: Customer Charge, plus charges under **Schedule C** and **Schedule 10** (if applicable)

Issued ~~December 18, 2024~~August 29, 2025
NWN WUTC Advice No. ~~24-17~~25-03
~~1, 2025~~

Effective with service on
and after August 1, 2028~~January~~

RATE SCHEDULE 3
BASIC FIRM SALES SERVICE - NON-RESIDENTIAL
(continued)

MONTHLY RATE: Effective: ~~January 1, 2025~~August 1, 2028 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM SALES SERVICE CHARGES (03 SF):					**Billing Rates [1]**	
Customer Charge (per month):					**$22.00**	
	Base Rate	Pipeline Capacity	Commodity Component [2]	Temporary Adjustment		
Schedule 308 Credits (per bill):						
Commercial - Winter				($46.59)	**($46.59)**	~~(I)~~
Commercial - Non-Winter				($25.89)	**($25.89)**	
Industrial				($129.16)	**($129.16)**	~~(I)~~
Volumetric Charges (per therm):						
Commercial	~~$0.53350~~ $0.98552	$0.10337	$0.43274	~~$0.20893~~ $0.21865	~~**$1.27854**~~ **$1.74028**	(~~I~~R)
Industrial	~~$0.54385~~ $0.93801	$0.10337	$0.43274	~~$0.15035~~ $0.15912	~~**$1.23031**~~ **$1.63324**	(~~I~~R)
Standby Charge (per therm of MHDV) [3]:					**$5.00**	

[1] **Schedule C** and **Schedule 10** Charges shall apply, if applicable.
[2] The Commodity Component will be either Annual Sales WACOG or Monthly Incremental Cost of Gas.
[3] Applies to Standby Sales Service only.

Minimum Monthly Bill. The Minimum Monthly Bill shall be any **Schedule C** and **Schedule 10** Charges, plus:

(a) ***Firm Sales Service.*** Customer Charge
(b) ***Firm Sales Standby Service.*** Customer Charge, plus Standby Service Charge

RATE SCHEDULE 10
CHARGES FOR SPECIAL METERING EQUIPMENT, RENTAL METERS AND METERING SERVICES
(continued)

Metering Services and Charges	One Time Charge	Installation Charge	Monthly Charge	
Rental Read	---	---	$0.36	
Advanced Automated Meter Reading (AAMR) Device[1]	---	$1,270.53	$~~48.05~~52.82	(~~I~~R)
Remote Index	---	$50.00	$4.00	
Pulse Output	---	$100.00	$8.00	
Administrative Set-Up/Consultation Fee (all meters)	$145~~00~~.00	---	---	(I)
Technical Assistance (Rotary meters only)	$145~~00~~.00	---	---	(I)

[1] Site specific engineering design costs for AAMR will be added to the installation charge if needed.

SPECIAL PROVISIONS FOR RENTAL METERS AND SPECIAL METERING EQUIPMENT:

1. Prior to receiving service under this section of the Schedule, the Customer must sign a service agreement that requires a minimum 12-month term. Customers who terminate service after less than 12 months will be required to pay all charges otherwise due to fulfill the 12-month obligation under the service agreement.
2. Service under this section of this Schedule is voluntary and separate from billing for or delivery of natural gas to a Customer's premise.
3. Since the Company does not maintain an inventory of all meter types offered under this Schedule, a delay may occur from the time a Customer requests service under this Schedule until the Company can provide it.
4. The Customer will be responsible for the meter pick-up and return of diaphragm meters.
5. The Customer will incur the Administrative Set-Up/Consultation Fee for each rental meter.
6. Upon delivery of a rotary meter, the Customer will incur the Technical Assistance charge listed above for each rental rotary meter. A Customer may not waive this provision or the associated fee. Technical assistance helps the Company ensure proper handling of rotary meters.
7. The Company will install AAMR devices for the charge listed above. AAMR devices will only be installed on Company owned meters and the Company will require that the Customer provide active and continuous electric power per company specifications to enable meter communications.
8. Upon request, the Company will provide one differential test per calendar year on rotary meters. The testing will be scheduled at the Company's convenience.
9. The Customer is responsible to protect all rental equipment from damage including but not limited to installing parking bollards to protect the rental equipment from vehicular or other damage.

(continue to Sheet 110.3)

RATE SCHEDULE 27
RESIDENTIAL HEATING DRY-OUT SERVICE

AVAILABLE:
To Residential home builders, developers, and contractors during the period that a Residential dwelling is under construction, in all territory served by the Company under the Tariff of which this schedule is a part.

SERVICE DESCRIPTION:
Service under this Rate Schedule is restricted to the use of gas in approved permanently-installed gas heating equipment in place during the period the dwelling is under construction. Upon occupancy of the dwelling, service under this Rate Schedule shall terminate automatically. In no event will service under this Rate Schedule continue for more a period of time greater than twelve (12) months from the date the gas meter is set at the dwelling. Upon termination of service under this Rate Schedule, gas service shall transfer to **Schedule 1** or **Schedule 2**, whichever is applicable.

MONTHLY RATE: Effective: ~~January 1, 2025~~August 1, 2028 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 200** for a list of applicable adjustments. Rates are subject to charges for purchased gas costs and technical rate adjustments.

	Base Rate	Pipeline Capacity Rate	Commodity Rate	Temporary Adjustment	Billing Rate
Customer Charge:	$9.00	---	---	---	**$9.00**
Volumetric Charge (per therm)					
All therms	~~$0.31253~~ $0.99357	$0.10337	$0.43274	~~$0.26727~~ $0.27817	~~**$1.11591**~~ **$1.80785** (I~~R~~)

Minimum Monthly Bill: Customer Charge, plus charges under **Schedule C** and **Schedule 10** (if applicable)

GENERAL TERMS:
Service under this Rate Schedule is governed by the terms of this Rate Schedule, the General Rules and Regulations contained in this Tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

Issued ~~December 18, 2024~~August 29, 2025
NWN WUTC Advice No. 25-03~~24-17~~
1, 2028

Effective with service on
and after ~~January 1, 2025~~August

RATE SCHEDULE 41
NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES FOR COMMERCIAL CUSTOMER CLASS: Effective: ~~January 1, 2025~~August 1, 2028 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. **SEE SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM SALES SERVICE CHARGES (C41SF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$250.00**	
	Base Rate		Commodity Component [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($515.09)	**($515.09)**	(I)
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	~~$0.41608~~ $0.75994		$0.43274	~~$0.19067~~ $0.19829	~~**$1.03949**~~ $1.39097	(I/R)
Block 2: All additional therms	~~$0.36663~~ $0.66963		$0.43274	~~$0.18179~~ $0.18849	~~**$0.98116**~~ **$1.29086**	(I/R)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.10337**	
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.54**	
INTERRUPTIBLE SALES SERVICE CHARGES (C41SI) [1]:						
Customer Charge (per month):					**$250.00**	
	Base Rate		Commodity Component: [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($515.09)	**($515.09)**	(I)
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	~~$0.38453~~ $0.61948		$0.43274	~~$0.14700~~ $0.15275	~~**$0.96427**~~ **$1.20497**	(I/R)
Block 2: All additional therms	~~$0.33880~~ $0.54581		$0.43274	~~$0.13893~~ $0.14399	~~**$0.91047**~~ **$1.12254**	(I/R)
Plus: Interruptible Pipeline Capacity Charge - Volumetric (per therm):					**$0.03612**	
FIRM TRANSPORTATION SERVICE CHARGES (C41TF):						
Customer Charge (per month):					**$250.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Total Temporary Adjustments [4]		
Schedule 308 Credits (per bill):				$(515.09)	**($515.09)**	(I)
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	~~$0.37785~~ $0.63879			~~$0.26259~~ $0.26958	~~**$0.64044**~~ $0.90837	(I/R)

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Block 2: All additional therms	~~$0.3329~~ $0.56283			~~$0.26011~~ $0.26627	~~**$0.59302**~~ $0.82910	(~~I~~R)

[1] The Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from Schedule C and Schedule 10.
[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG, or Monthly Incremental Cost of Gas.
[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 may not apply.

(continue to Sheet 141.10)

RATE SCHEDULE 41
NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES FOR INDUSTRIAL CUSTOMER CLASS: Effective: ~~January 1, 2025~~August 1, 2028 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. **SEE SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM SALES SERVICE CHARGES (I41SF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$250.00**	
	Base Rate		Commodity Component [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($622.72)	**($622.72)**	(I)
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	~~$0.37147~~ $0.61067		$0.43274	~~$0.14201~~ $0.14816	**~~$0.94622~~ $1.19157**	(I~~R~~)
Block 2: All additional therms	~~$0.32731~~ $0.53807		$0.43274	~~$0.13904~~ $0.14445	**~~$0.89909~~ $1.11526**	(I~~R~~)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.10337**	
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.54**	
INTERRUPTIBLE SALES SERVICE CHARGES (I41SI) [1]:						
Customer Charge (per month):					**$250.00**	
	Base Rate		Commodity Component: [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($622.72)	**($622.72)**	(I)
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	~~$0.36378~~ $0.58605		$0.43274	~~$0.10593~~ $0.11138	**~~$0.90245~~** $1.13017	(I~~R~~)
Block 2: All additional therms	~~$0.32050~~ $0.51633		$0.43274	~~$0.10285~~ $0.10763	**~~$0.85609~~** $1.05670	(I~~R~~)
Plus: Interruptible Pipeline Capacity Charge - Volumetric (per therm):					**$0.03612**	
FIRM TRANSPORTATION SERVICE CHARGES (I41TF):						
Customer Charge (per month):					**$250.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Total Temporary Adjustments [4]		
Schedule 308 Credits (per bill):				($622.72)	**($622.72)**	(I)
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	~~$0.36781~~ $0.59254			~~$0.26075~~ $0.26625	**~~$0.62856~~ $0.85879**	(I~~R~~)
Block 2: All additional therms	~~$0.32406~~ $0.52206			~~$0.25850~~ $0.26335	**~~$0.58256~~** $0.78541	(I~~R~~)

[1] The Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity

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Charge selected by the Customer, plus any other charges that may apply from Schedule C and Schedule 10.

[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG, or Monthly Incremental Cost of Gas.

[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 may not apply.

RATE SCHEDULE 42
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY SALES RATES - FIRM SERVICE: Effective: August 1, 2028 ~~January 1, 2025~~ (C)
The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM SALES SERVICE CHARGES [1]:					**Billing Rates**	
Customer Charge (per month, all service types):					**$1,300.00**	
	Base Rate		Commodity Component [2]	Total Temporary Adjustments [3]		
C42SF						
Schedule 308 Credits (per bill):				($5,142.27)	($5,142.27)	(I)
Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	~~$0.20610~~ $0.42558		$0.43274	~~$0.15742~~ $0.16190	~~$0.79626~~ $1.02022	(I/R)
Block 2: Next 20,000 therms	~~$0.18448~~ $0.38095		$0.43274	~~$0.15305~~ $0.15706	~~$0.77027~~ $0.97075	
Block 3: Next 20,000 therms	~~$0.14150~~ $0.29219		$0.43274	~~$0.14439~~ $0.14746	~~$0.71863~~ $0.87239	
Block 4: Next 100,000 therms	~~$0.11318~~ $0.23371		$0.43274	~~$0.13869~~ $0.14114	~~$0.68461~~ $0.80759	
Block 5: Next 600,000 therms	~~$0.07545~~ $0.15580		$0.43274	~~$0.13108~~ $0.13272	~~$0.63927~~ $0.72126	
Block 6: All additional therms	~~$0.02828~~ $0.05840		$0.43274	~~$0.12157~~ $0.12218	~~$0.58259~~ $0.61332	(I/R)
I42SF						
Schedule 308 Credits (per bill):				($3,945.77)	($3,945.77)	(I)
Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	~~$0.16641~~ $0.34190		$0.43274	~~$0.13254~~ $0.13666	~~$0.73169~~ $0.91130	(I/R)
Block 2: Next 20,000 therms	~~$0.14895~~ $0.30604		$0.43274	~~$0.13089~~ $0.13458	~~$0.71258~~ $0.87336	
Block 3: Next 20,000 therms	~~$0.11422~~ $0.23467		$0.43274	~~$0.12761~~ $0.13044	~~$0.67457~~ $0.79785	
Block 4: Next 100,000 therms	~~$0.09138~~ $0.18774		$0.43274	~~$0.12545~~ $0.12772	~~$0.64957~~ $0.74820	
Block 5: Next 600,000 therms	~~$0.06094~~ $0.12522		$0.43274	~~$0.12258~~ $0.12409	~~$0.61626~~ $0.68205	
Block 6: All additional therms	~~$0.02283~~ $0.04690		$0.43274	~~$0.11898~~ $0.11954	~~$0.57455~~ $0.59918	(I/R)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	
Firm Sales Service Storage Charge (per therm of MDDV per month):					**$0.20415**	
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.10337**	
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV per month):					**$1.54**	

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[1] For Firm Sales Service, the Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Distribution Capacity Charge, plus the Storage Capacity Charge, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from Schedule C or Schedule 10.
[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG or Monthly Incremental Cost of Gas.
[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 may not apply.

(continue to Sheet 142.10.1)

RATE SCHEDULE 42
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY SALES RATES – INTERRUPTIBLE SERVICE: Effective: ~~January 1, 2025~~August 1, 2028 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

INTERRUPTIBLE SALES SERVICE CHARGES [1]: (C42SI)					**Billing Rates**	
Customer Charge (per month):					**$1,300.00**	
	Base Rate		Commodity Component [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($5,142.27)	**($5,142.27)**	(I)
Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	~~$0.16872~~ $0.32657		$0.43274	~~$0.10987~~ $0.11316	**~~$0.71133~~** **$0.87247**	(IR)
Block 2: Next 20,000 therms	~~$0.15103~~ $0.29232		$0.43274	~~$0.10666~~ $0.10960	**~~$0.69043~~** **$0.83466**	
Block 3: Next 20,000 therms	~~$0.11580~~ $0.22413		$0.43274	~~$0.10024~~ $0.10250	**~~$0.64878~~** **$0.75937**	
Block 4: Next 100,000 therms	~~$0.09264~~ $0.17932		$0.43274	~~$0.09603~~ $0.09784	**~~$0.62141~~** **$0.70990**	
Block 5: Next 600,000 therms	~~$0.06178~~ $0.11959		$0.43274	~~$0.09041~~ $0.09162	**~~$0.58493~~** **$0.64395**	
Block 6: All additional therms	~~$0.02317~~ $0.04485		$0.43274	~~$0.08334~~ $0.08378	**~~$0.53925~~** **$0.56137**	(IR)
Interruptible Pipeline Capacity Charge (per therm):					**$0.03612**	
Interruptible Sales Service Storage Charge (per therm of MDDV per month)					**$0.10208**	
INTERRUPTIBLE SALES SERVICE CHARGES [1]: (I42SI)						
Customer Charge (per month):					**$1,300.00**	
Schedule 308 Credits (per bill):				($3,945.77)	**($3,945.77)**	(I)
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	~~$0.16353~~ $0.31293		$0.43274	~~$0.09437~~ $0.09803	**~~$0.69064~~** **$0.84370**	(IR)
Block 2: Next 20,000 therms	~~$0.14638~~ $0.28012		$0.43274	~~$0.09287~~ $0.09614	**~~$0.67199~~** **$0.80900**	
Block 3: Next 20,000 therms	~~$0.11225~~ $0.21479		$0.43274	~~$0.08990~~ $0.09241	**~~$0.63489~~** **$0.73994**	
Block 4: Next 100,000 therms	~~$0.08981~~ $0.17186		$0.43274	~~$0.08793~~ $0.08994	**~~$0.61048~~** **$0.69454**	
Block 5: Next 600,000 therms	~~$0.05986~~ $0.11455		$0.43274	~~$0.08531~~ $0.08665	**~~$0.57791~~** **$0.63394**	
Block 6: All additional therms	~~$0.02244~~ $0.04294		$0.43274	~~$0.08206~~ $0.08256	**~~$0.53724~~** **$0.55824**	(IR)
Interruptible Pipeline Capacity Charge (per therm):					**$0.03612**	
Interruptible Sales Service Storage Charge (per therm of MDDV per month)					**$0.10208**	

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[1] For Interruptible Sales Service, the Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge, plus any other charges that apply from Schedule C or Schedule 10.
[2] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 201 may also apply.
[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 may not apply.

(continue to Sheet 142.11)

RATE SCHEDULE 42
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY TRANSPORTATION RATES: Effective: January 1, 2025August 1, 2028 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (C42TI) [1]:					**Billing Rates**	
Customer Charge (per month):					**$1,300.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Temporary Adjustments [2]		
Schedule 308 Credits (per bill):				($5,142.27)	**($5,142.27)**	(I)
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	~~$0.14169~~ $0.22826			~~$0.24907~~ $0.25119	~~**$0.39076**~~ **$0.47945**	(IR)
Block 2: Next 20,000 therms	~~$0.12685~~ $0.20435			~~$0.24831~~ $0.25021	~~**$0.37516**~~ **$0.45456**	
Block 3: Next 20,000 therms	~~$0.09727~~ $0.15670			~~$0.24678~~ $0.24823	~~**$0.34405**~~ **$0.40493**	
Block 4: Next 100,000 therms	~~$0.07782~~ $0.12536			~~$0.24578~~ $0.24695	~~**$0.32360**~~ **$0.37231**	
Block 5: Next 600,000 therms	~~$0.05189~~ $0.08360			~~$0.24444~~ $0.24521	~~**$0.29633**~~ **$0.32881**	
Block 6: All additional therms	~~$0.01944~~ $0.03132			~~$0.24277~~ $0.24306	~~**$0.26221**~~ **$0.27438**	(IR)

INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (I42TI) [1]:					**Billing Rates**	
Customer Charge (per month):					**$1,300.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Temporary Adjustments [2]		
Schedule 308 Credits (per bill):				($3,945.77)	**($3,945.77)**	(I)
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	~~$0.14430~~ $0.23350	-	-	~~$0.24917~~ $0.25155	~~**$0.39347**~~ **$0.48505**	(IR)
Block 2: Next 20,000 therms	~~$0.12917~~ $0.20902	-	-	~~$0.24841~~ $0.25055	~~**$0.37758**~~ **$0.45957**	
Block 3: Next 20,000 therms	~~$0.09905~~ $0.16028	-	-	~~$0.24687~~ $0.24851	~~**$0.34592**~~ **$0.40879**	
Block 4: Next 100,000 therms	~~$0.07925~~ $0.12824	-	-	~~$0.24586~~ $0.24717	~~**$0.32511**~~ **$0.37541**	
Block 5: Next 600,000 therms	~~$0.05284~~ $0.08551	-	-	~~$0.24452~~ $0.24539	~~**$0.29736**~~ **$0.33090**	
Block 6: All additional therms	~~$0.01981~~ $0.03207	-	-	~~$0.24285~~ $0.24317	~~**$0.26266**~~ **$0.27524**	(IR)

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Effective with service on and after ~~January~~ August 1, 2028
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[1] For Interruptible Transportation Service, the Monthly Bill shall equal the sum of the Customer Charge, plus Transportation Charge, plus the Volumetric Charges, plus any other charges that may apply from Schedule C or Schedule 10.
[2] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 201 may also apply.

(continue to Sheet 142.12)

RATE SCHEDULE 42
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

FIRM TRANSPORTATION SERVICE CHARGES (C42TF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$1,300.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Total Temporary Adjustments [2]		
Schedule 308 Credits (per bill):				($5,142.27)	**($5,142.27)**	~~(I)~~
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	~~$0.15442~~ $0.29231			~~$0.24890~~ $0.25250	~~**$0.40332**~~ **$0.54481**	(~~I~~R)
Block 2: Next 20,000 therms	~~$0.13824~~ $0.26168			~~$0.24816~~ $0.25139	~~**$0.38640**~~ **$0.51307**	
Block 3: Next 20,000 therms	~~$0.10600~~ $0.20065			~~$0.24669~~ $0.24916	~~**$0.35269**~~ **$0.44981**	
Block 4: Next 100,000 therms	~~$0.08481~~ $0.16055			~~$0.24573~~ $0.24771	~~**$0.33054**~~ **$0.40826**	
Block 5: Next 600,000 therms	~~$0.05654~~ $0.10703			~~$0.24443~~ $0.24575	~~**$0.30097**~~ **$0.35278**	
Block 6: All additional therms	~~$0.02120~~ $0.04013			~~$0.24283~~ $0.24331	~~**$0.26403**~~ **$0.28344**	(~~I~~R)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	
FIRM TRANSPORTATION SERVICE CHARGES (I42TF) [1]:						
Customer Charge (per month):					**$1,300.00**	
Transportation Charge (per month):					**$250.00**	
Schedule 308 Credits (per bill):				($3,945.77)	**($3,945.77)**	~~(I)~~
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	~~$0.15161~~ $0.25524			~~$0.24935~~ $0.25198	~~**$0.40096**~~ **$0.50722**	(~~I~~R)
Block 2: Next 20,000 therms	~~$0.13571~~ $0.22849			~~$0.24856~~ $0.25092	~~**$0.38427**~~ **$0.47941**	
Block 3: Next 20,000 therms	~~$0.10406~~ $0.17520			~~$0.24699~~ $0.24880	~~**$0.35105**~~ **$0.42400**	
Block 4: Next 100,000 therms	~~$0.08326~~ $0.14019			~~$0.24596~~ $0.24741	~~**$0.32922**~~ **$0.38760**	
Block 5: Next 600,000 therms	~~$0.05550~~ $0.09345			~~$0.24459~~ $0.24556	~~**$0.30009**~~ **$0.33901**	
Block 6: All additional therms	~~$0.02082~~ $0.03504			~~$0.24287~~ $0.24323	~~**$0.26369**~~ **$0.27827**	(~~I~~R)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	

[1] For Firm Transportation Service, the Monthly Bill shall equal the sum of the Customer Charge, plus Transportation Charge, plus the Volumetric Charges, plus the Distribution Capacity Charge, plus any other charges that may apply from Schedule C or Schedule 10.
[2] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 201 may also apply.

Issued ~~December 18, 2024~~August 29, 2025
NWN WUTC Advice No. ~~24-17~~25-03

Effective with service on
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RATE SCHEDULE 43
HIGH VOLUME NON-RESIDENTIAL
FIRM AND INTERRUPTIBLE TRANSPORTATION SERVICE
(continued)

MONTHLY RATE: Effective: ~~January 1, 2025~~August 1, 2028 (C)

The rates shown below may not always reflect actual billing rates. See **Schedule 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM TRANSPORTATION SERVICE CHARGES (C43TF and I43TF)					
					Billing Rates
Customer Charge:					**$38,000.00**
Transportation Charge:					**$250.00**
Volumetric Charge	Base Rate			Total Temporary Adjustment [1]	
Per therm, all therms	~~$0.00491~~ $0.00796			$0.24194	~~**$0.24685**~~ **$0.24990** (~~I~~R)
Firm Service Distribution Capacity Charge: Per therm of MDDV per month					**$0.15748**
Minimum Monthly Bill: Customer Charge, plus Transportation Charge, plus Firm Service Distribution Capacity Charge, plus any other charges that may apply from **Schedule C** and **Schedule 10**.					

INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (C43TI and I43TI)					
					Billing Rates
Customer Charge:					**$38,000.00**
Transportation Charge:					**$250.00**
Volumetric Charge:	Base Rate			Total Temporary Adjustment [1]	
Per therm, all therms	~~$0.00491~~ $0.00796			$0.24194	~~**$0.24685**~~ **$0.24990** (~~I~~R)
Minimum Monthly Bill: Customer Charge, plus Transportation Charge, plus any other charges that may apply from **Schedule C** and **Schedule 10**.					

[1] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 shall apply.

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SCHEDULE 200
SUMMARY OF ADJUSTMENTS

PURPOSE:
The purpose of this Schedule is to list and summarize the adjustment Schedules applicable to each of the Company's Rate Schedules.

SCHEDULE	A	201	203	207	210	212	215	220	221	230	232	233	234	235	236	237	238	239	303	305	306	308
R1	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C1	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
2	ADD	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
03CSF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
03ISF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
10	ADD			INC																		
27	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C41SF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C41SI	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C41TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I41SF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I41SI	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I41TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C42SF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C42SI	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C42TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C42TI	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I42SF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I42SI	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I42TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I42TI	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C43TI/ I43TI	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC		INC	INC	INC	INC
C43TF/ I43TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC		INC	INC	INC	INC

(N) (N)

Table Code Key:

ADD This adjustment is added to the billing rates at the time the bill is issued.
INC This adjustment is included in the billing rates shown on the Rate Schedule

(continue to Sheet 200.2)

SCHEDULE 200
SUMMARY OF ADJUSTMENTS
(continued)

The following is a brief description of the applicable Schedules:

Schedule A "Billing for City and County Exactions."
This adjustment will be reflected directly on Customer bills.

Schedule 201 "Temporary (Technical) Adjustments to Rates."
These are temporary Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 203 "Purchased Gas Cost Adjustments to Rates."
These are pipeline capacity and commodity charges.

Schedule 207 "General Adjustments to Rates."
These are Base Rate Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 210 "Adjustment to Rates for Property Sales."
These are Temporary Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 212 "Adjustment to Rates Residential Rate Mitigation."
These are Temporary Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 215 "Adjustment to Rates for Energy Conservation Programs."
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 220 "Special Rate Adjustment."
These are Base Rate Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 221 "Rate Adjustment for Updated Depreciation Rates"
These are Base Rate Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 230 "Temporary Adjustments to Rates for Low-Income Programs."
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 231 "Temporary Adjustments to Rates for Residential Discount Program."
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 232 "Temporary Adjustments to Rates for Regulatory Fee Increase"
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 233 "Temporary Adjustments to Rates for Industrial Customer Energy Efficiency Audit Costs"
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 234 "Temporary Adjustments to Rates for Residential Arrearage Management Program" (N)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 235 "Temporary Adjustments to Rates for COVID-19 Public Health Emergency" (N)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills. (N)

(K)

(K) Schedules 303, 305, 306 and 308 transferred to Sheet 200.3.

(continue to Sheet 200.3)

Schedule 303 "Washington Environmental Cost Recovery Mechanism."
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 305 "Adjustment for Certain Income Taxes (2017 Federal Tax Cuts and Jobs Act)."
These are base and temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 306 "Multi-Year Rate Plan Adjustment."
These are base rate adjustments that will be added to the Billing Rate on the effective date of the Schedule.

Schedule 308 "Washington Climate Commitment Act Recovery Mechanism."
These are temporary rate adjustments that will be added to the Billing Rate on the effective date of the Schedule.

SCHEDULE 200
SUMMARY OF ADJUSTMENTS
(continued)

Schedule 236 "Temporary Adjustments to Rates for Meter Modernization Program." (N)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 237 "Temporary Adjustments to Rates for TSA Operations and Maintenance Costs." (N)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 238 "Adjustments to Rates for Provisional Capital Adjustment." (N)
These are base rate adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 239 "Temporary Adjustments to Rates for TSA Capital and Cost of Service Cost Recovery." (N)
These are base rate adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 303 "Washington Environmental Cost Recovery Mechanism." (M)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 305 "Adjustment for Certain Income Taxes (2017 Federal Tax Cuts and Jobs Act)."
These are base and temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 306 "Multi-Year Rate Plan Adjustment."
These are base rate adjustments that will be added to the Billing Rate on the effective date of the Schedule.

Schedule 308 "Washington Climate Commitment Act Recovery Mechanism."
These are temporary rate adjustments that will be added to the Billing Rate on the effective date of the Schedule. (M)

(M) Schedules 303, 305, 306 and 308 transferred from Sheet 200.2.

Issued ~~February 12, 2024~~August 29, 2025
NWN WUTC Advice No. 25-03~~24-02~~
~~2024~~~~September 30, 2025~~August 1, 2028

Effective with service on
and after ~~March 15,~~

NORTHWEST NATURAL GAS COMPANY

WN U-6 ~~Seventh~~Tenth Revision of Sheet 207.1
Cancels ~~Sixth~~Ninth Revision of Sheet 207.1

SCHEDULE 207
GENERAL RATE ADJUSTMENT

PURPOSE:
To identify the effects of general rate changes approved in the company's most recent general rate case proceeding (Docket UG-200994)

APPLICATION TO RATE SCHEDULES: Effective: ~~November 1, 2022~~ August 1, 2028 (C) (T) (T)

Rate Schedule 1	Rate Schedule 3	Rate Schedule 41	Rate Schedule 43
Rate Schedule 2	Rate Schedule 27	Rate Schedule 42	

The Base Rates in the listed Rate Schedules include the adjustment shown below.
NO FURTHER ADJUSTMENT TO RATES IS REQUIRED.

SCHEDULES	BLOCKS	AMOUNT	
Schedule 1 - Residential	Customer Charge	$0.00	
	Per Therm (all therms)	$0.~~06165~~.15106	(I~~R~~)
Schedule 1 - Commercial	Customer Charge	$0.00	
	Per Therm (all therms)	$0.~~05126~~.13631	(I~~R~~)
Schedule 2	Customer Charge	$0.00	
	Per Therm (all therms)	$0.~~03902~~09063	(I~~R~~)
Schedule 3 - Commercial	Customer Charge	$0.00	
	Per Therm (all therms)	$0.~~03503~~08519	(I~~R~~)
Schedule 3 - Industrial	Customer Charge	$0.00	
	Per Therm (all therms)	$0.~~03173~~07884	(I~~R~~)
Schedule 27	Customer Charge	$0.00	
	Per Therm (all therms)	$0.~~02777~~09612	(I~~R~~) (~~D~~)
Schedule 41 - Commercial Firm Sales Service	Customer Charge	$0.00	
	First 2,000 therms	~~$0.02782~~$ 0.06829	(I~~R~~)
	All additional therms	~~$0.02451~~ $ 0.06018	(I~~R~~)
Schedule 41 - Commercial Interruptible Sales Service	Customer Charge	$0.00	
	First 2,000 therms	~~$0.02162~~ $ 0.04886	(I~~R~~)
	All additional therms	~~$0.01905~~ $ 0.04305	(I~~R~~)
Schedule 41 - Industrial Firm Sales Service	Customer Charge	$0.00	
	First 2,000 therms	~~$0.00873~~$ 0.05615	(I~~R~~)
	All additional therms	~~$0.00769~~ $ 0.04948	(I~~R~~)
Schedule 41 - Industrial Interruptible Sales Service	Customer Charge	$0.00	

Issued ~~October 14, 2022~~August 29, 2025
NWN WUTC Advice No. ~~22-09~~25-03
~~2022~~August 1, 2028

Effective with service on and after ~~November 1,~~

	First 2,000 therms	~~$0.00713~~$ 0.04622	(~~R~~)
	All additional therms	~~$0.00628~~ $ 0.04072	(~~R~~)
Schedule 41 - Commercial Firm Transportation Service	Customer Charge	$0.00	
	First 2,000 therms	~~$0.00971~~$ 0.06160	(~~R~~)
	All additional therms	~~$0.00855~~ $ 0.05428	(~~R~~)
Schedule 41 - Industrial Firm Transportation Service	Customer Charge	$0.00	
	First 2,000 therms	~~$0.00721~~$ 0.04673	(~~R~~)
	All additional therms	~~$0.00635~~ $ 0.04117	(~~R~~)

(continue to Sheet 207.2)

SCHEDULE 207
GENERAL RATE ADJUSTMENT
(continued)

SCHEDULES	BLOCKS	AMOUNT	
Schedule 42 Commercial - Firm Sales Service	Customer Charge	$0.00	
		~~0.02095~~	(IR)
	First 10,000 therms	0.04359	
		~~0.01875~~	
	Next 20,000 therms	0.03902	
		~~0.01438~~	
	Next 20,000 therms	0.02993	
		~~0.01151~~	
	Next 100,000 therms	0.02394	
		~~0.00767~~	
	Next 600,000 therms	0.01596	
		~~0.00288~~	
	All additional therms	0.00598	(IR)
Schedule 42 Commercial - Interruptible Sales Service	Customer Charge	$0.00	
		~~0.01245~~	(IR)
	First 10,000 therms	0.03145	
		~~0.01114~~	
	Next 20,000 therms	0.02815	
		~~0.00854~~	
	Next 20,000 therms	0.02158	
		~~0.00683~~	
	Next 100,000 therms	0.01727	
		~~0.00456~~	
	Next 600,000 therms	0.01152	
		~~0.00171~~	
	All additional therms	0.00432	(IR)
Schedule 42 Industrial - Firm Sales Service	Customer Charge	$0.00	
		~~0.00614~~	
	First 10,000 therms	0.04119	(IR)
		~~0.00550~~	
	Next 20,000 therms	0.03687	
		~~0.00422~~	
	Next 20,000 therms	0.02827	
		~~0.00337~~	
	Next 100,000 therms	0.02262	
		~~0.00225~~	
	Next 600,000 therms	0.01509	

Issued ~~October 14, 2022~~ August 29, 2025
NWN WUTC Advice No. 25-03~~22-09~~ 2028

Effective with service on and after ~~November 1, 2022~~August 1,

		~~0.00084~~	
	All additional therms	0.00565	(I~~R~~)
Schedule 42 Industrial - Interruptible Sales Service	Customer Charge	$0.00	
		~~0.00566~~	
	First 10,000 therms	0.03561	(I~~R~~)
		~~0.00507~~	
	Next 20,000 therms	0.03188	
		~~0.00389~~	
	Next 20,000 therms	0.02444	
		~~0.00311~~	
	Next 100,000 therms	0.01956	
		~~0.00207~~	
	Next 600,000 therms	0.01304	
		~~0.00078~~	
	All additional therms	0.00489	(I~~R~~)

(continue to Sheet 207.3)

SCHEDULE 207
GENERAL RATE ADJUSTMENT
(continued)

SCHEDULES	BLOCKS	AMOUNT	
Schedule 42 Commercial - Firm Transportation Service	Customer Charge	$0.00	
		~~0.00594~~	(I~~R~~)
	First 10,000 therms	0.03255	
		~~0.00531~~	
	Next 20,000 therms	0.02914	
		~~0.00407~~	
	Next 20,000 therms	0.02234	
		~~0.00326~~	
	Next 100,000 therms	0.01788	
		~~0.00217~~	
	Next 600,000 therms	0.01192	
		~~0.00081~~	
	All additional therms	0.00447	(I~~R~~)
Schedule 42 Industrial - Firm Transportation Service	Customer Charge	$0.00	
		~~0.00396~~	(I~~R~~)
	First 10,000 therms	0.02446	
		~~0.00354~~	
	Next 20,000 therms	0.02190	
		~~0.00272~~	
	Next 20,000 therms	0.01679	
		~~0.00217~~	
	Next 100,000 therms	0.01344	
		~~0.00145~~	
	Next 600,000 therms	0.00896	
		~~0.00054~~	
	All additional therms	0.00336	(I~~R~~)
Schedule 42 - Commercial Interruptible Transportation Service	Customer Charge	$0.00	
		~~0.00278~~	(I~~R~~)
	First 10,000 therms	0.01800	
		~~0.00249~~	
	Next 20,000 therms	0.01612	
		~~0.00191~~	
	Next 20,000 therms	0.01236	
		~~0.00153~~	
	Next 100,000 therms	0.00989	

Issued ~~October 14, 2022~~August 29, 2025
NWN WUTC Advice No. ~~22-09~~25-03

Effective with service on
and after ~~November 1, 2022~~August 1, 2028

		~~0.00102~~	
	Next 600,000 therms	0.00659	
		~~0.00038~~	
	All additional therms	0.00247	(I~~R~~)
Schedule 42 - Industrial Interruptible Transportation Service	Customer Charge	$0.00	
		~~0.00333~~	(I~~R~~)
	First 10,000 therms	0.02105	
		~~0.00298~~	
	Next 20,000 therms	0.01885	
		~~0.00228~~	
	Next 20,000 therms	0.01445	
		~~0.00183~~	
	Next 100,000 therms	0.01156	
		~~0.00122~~	
	Next 600,000 therms	0.00771	
		~~0.00046~~	
	All additional therms	0.00289	(I~~R~~) ~~(D)~~

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

(N)

SCHEDULE 235
TEMPORARY ADJUSTMENTS TO RATES FOR COVID-19 PUBLIC HEALTH EMERGENCY

PURPOSE: To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of deferred amounts for the costs and savings incurred due to the COVID-19 pandemic, as authorized for deferred accounting by the WUTC in Docket UG-200264.

APPLICABLE:
Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: ~~September 30, 2025~~August 1, 2028**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)	Schedule	Block	Adjustment (per therm)
1R		$0.00304	42 CTF	Block 1	$0.00059
1C		$0.00253		Block 2	$0.00053
2R		$0.00176		Block 3	$0.00041
3C		$0.00159		Block 4	$0.00032
3I		$0.00144		Block 5	$0.00022
27		$0.00179		Block 6	$0.00008
41 CSF	Block 1	$0.00125	42 ITF	Block 1	$0.00043
	Block 2	$0.00110		Block 2	$0.00039
41 ISF	Block 1	$0.00101		Block 3	$0.00030
	Block 2	$0.00089		Block 4	$0.00024
41 CSI	Block 1	$0.00103		Block 5	$0.00016
	Block 2	$0.00091		Block 6	$0.00006
41 ISI	Block 1	$0.00098	42 CSI	Block 1	$0.00054
	Block 2	$0.00086		Block 2	$0.00048
41 CTF	Block 1	$0.00115		Block 3	$0.00037
	Block 2	$0.00101		Block 4	$0.00030
41ITF	Block 1	$0.00099		Block 5	$0.00020
	Block 2	$0.00087		Block 6	$0.00007
42 CSF	Block 1	$0.00073	42 ISI	Block 1	$0.00060
	Block 2	$0.00066		Block 2	$0.00054
	Block 3	$0.00050		Block 3	$0.00041
	Block 4	$0.00040		Block 4	$0.00033
	Block 5	$0.00027		Block 5	$0.00022
	Block 6	$0.00010		Block 6	$0.00008
42 ISF	Block 1	$0.00068	42 CTI	Block 1	$0.00038
	Block 2	$0.00061		Block 2	$0.00034
	Block 3	$0.00046		Block 3	$0.00026
	Block 4	$0.00037		Block 4	$0.00021
	Block 5	$0.00025		Block 5	$0.00014
	Block 6	$0.00009		Block 6	$0.00005
			42 ITI	Block 1	$0.00039
				Block 2	$0.00035
				Block 3	$0.00027
				Block 4	$0.00022
				Block 5	$0.00014
				Block 6	$0.00005
			43 TF		$0.00000
			43 TF		$0.00000

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this

(N)

Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

SCHEDULE 236
TEMPORARY ADJUSTMENTS TO RATES FOR METER MODERNIZATION PROGRAM

(N)

PURPOSE: To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of deferred amounts for the costs related to the Company's Meter Modernization Program, as authorized for deferred accounting by the WUTC in Docket UG-240012.

APPLICABLE:
Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: ~~September 30, 2025~~August 1, 2028**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		$0.00131		42 CTF	Block 1	$0.00025
1C		$0.00109			Block 2	$0.00023
2R		$0.00076			Block 3	$0.00017
3C		$0.00069			Block 4	$0.00014
3I		$0.00062			Block 5	$0.00009
27		$0.00077			Block 6	$0.00003
41 CSF	Block 1	$0.00054		42 ITF	Block 1	$0.00019
	Block 2	$0.00047			Block 2	$0.00017
41 ISF	Block 1	$0.00044			Block 3	$0.00013
	Block 2	$0.00038			Block 4	$0.00010
41 CSI	Block 1	$0.00040			Block 5	$0.00007
	Block 2	$0.00035			Block 6	$0.00003
41 ISI	Block 1	$0.00038		42 CSI	Block 1	$0.00023
	Block 2	$0.00033			Block 2	$0.00021
41 CTF	Block 1	$0.00049			Block 3	$0.00016
	Block 2	$0.00043			Block 4	$0.00013
41ITF	Block 1	$0.00038			Block 5	$0.00009
	Block 2	$0.00034			Block 6	$0.00003
42 CSF	Block 1	$0.00032		42 ISI	Block 1	$0.00026
	Block 2	$0.00028			Block 2	$0.00023
	Block 3	$0.00022			Block 3	$0.00018
	Block 4	$0.00017			Block 4	$0.00014
	Block 5	$0.00012			Block 5	$0.00010
	Block 6	$0.00004			Block 6	$0.00004
42 ISF	Block 1	$0.00029		42 CTI	Block 1	$0.00015
	Block 2	$0.00026			Block 2	$0.00013
	Block 3	$0.00020			Block 3	$0.00010
	Block 4	$0.00016			Block 4	$0.00008
	Block 5	$0.00011			Block 5	$0.00005
	Block 6	$0.00004			Block 6	$0.00002
				42 ITI	Block 1	$0.00017
					Block 2	$0.00015
					Block 3	$0.00012
					Block 4	$0.00009
					Block 5	$0.00006
					Block 6	$0.00002
				43 TF		$0.00000
				43 TF		$0.00000

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this

(N)

Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

SCHEDULE 237
TEMPORARY ADJUSTMENTS TO RATES FOR TSA OPERATIONS AND MAINTENANCE COSTS

(N)

PURPOSE: To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of deferred amounts for the start-up Operations and Maintenance costs incurred for compliance with TSA Security Directives, as authorized for deferred accounting by the WUTC in Docket UG-210900.

APPLICABLE:
Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: ~~September 30, 2025~~August 1, 2028**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		$0.00128		42 CTF	Block 1	$0.00025
1C		$0.00105			Block 2	$0.00022
2R		$0.00074			Block 3	$0.00017
3C		$0.00067			Block 4	$0.00014
3I		$0.00061			Block 5	$0.00009
27		$0.00075			Block 6	$0.00003
41 CSF	Block 1	$0.00053		42 ITF	Block 1	$0.00018
	Block 2	$0.00046			Block 2	$0.00016
41 ISF	Block 1	$0.00042			Block 3	$0.00012
	Block 2	$0.00037			Block 4	$0.00010
41 CSI	Block 1	$0.00039			Block 5	$0.00007
	Block 2	$0.00034			Block 6	$0.00002
41 ISI	Block 1	$0.00037		42 CSI	Block 1	$0.00023
	Block 2	$0.00032			Block 2	$0.00020
41 CTF	Block 1	$0.00048			Block 3	$0.00016
	Block 2	$0.00043			Block 4	$0.00012
41ITF	Block 1	$0.00037			Block 5	$0.00008
	Block 2	$0.00033			Block 6	$0.00003
42 CSF	Block 1	$0.00031		42 ISI	Block 1	$0.00025
	Block 2	$0.00028			Block 2	$0.00022
	Block 3	$0.00021			Block 3	$0.00017
	Block 4	$0.00017			Block 4	$0.00014
	Block 5	$0.00011			Block 5	$0.00009
	Block 6	$0.00004			Block 6	$0.00003
42 ISF	Block 1	$0.00028		42 CTI	Block 1	$0.00014
	Block 2	$0.00025			Block 2	$0.00013
	Block 3	$0.00020			Block 3	$0.00010
	Block 4	$0.00016			Block 4	$0.00008
	Block 5	$0.00010			Block 5	$0.00005
	Block 6	$0.00004			Block 6	$0.00002
				42 ITI	Block 1	$0.00016
					Block 2	$0.00015
					Block 3	$0.00011
					Block 4	$0.00009
					Block 5	$0.00006
					Block 6	$0.00002
				43 TF		$0.00000
				43 TF		$0.00000

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this

(N)

Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

SCHEDULE 238
ADJUSTMENTS TO RATES FOR PROVISIONAL CAPITAL ADJUSTMENT

(N)

PURPOSE: To identify adjustments to rates in the Rate Schedules listed below that relate to the capital with Rate Year 1 as authorized by the WUTC in Docket UG-250610.

APPLICABLE:
Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: ~~September 30, 2025~~August 1, 2028**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		0.06242		42 CTF	Block 1	0.00917
1C		0.05458			Block 2	0.00821
2R		0.03569			Block 3	0.00630
3C		0.03492			Block 4	0.00504
3I		0.02949			Block 5	0.00336
27		0.06027			Block 6	0.00126
41 CSF	Block 1	0.02580		42 ITF	Block 1	0.00689
	Block 2	0.02273			Block 2	0.00617
41 ISF	Block 1	0.01596			Block 3	0.00473
	Block 2	0.01406			Block 4	0.00379
41 CSI	Block 1	0.01902			Block 5	0.00252
	Block 2	0.01676			Block 6	0.00095
41 ISI	Block 1	0.01799		42 CSI	Block 1	0.01184
	Block 2	0.01585			Block 2	0.01060
41 CTF	Block 1	0.01736			Block 3	0.00813
	Block 2	0.01529			Block 4	0.00650
41ITF	Block 1	0.01819			Block 5	0.00434
	Block 2	0.01603			Block 6	0.00163
42 CSF	Block 1	0.01647		42 ISI	Block 1	0.00983
	Block 2	0.01474			Block 2	0.00880
	Block 3	0.01131			Block 3	0.00674
	Block 4	0.00904			Block 4	0.00540
	Block 5	0.00603			Block 5	0.00360
	Block 6	0.00226			Block 6	0.00135
42 ISF	Block 1	0.01171		42 CTI	Block 1	0.00701
	Block 2	0.01048			Block 2	0.00627
	Block 3	0.00803			Block 3	0.00481
	Block 4	0.00643			Block 4	0.00385
	Block 5	0.00429			Block 5	0.00257
	Block 6	0.00161			Block 6	0.00096
				42 ITI	Block 1	0.00593
					Block 2	0.00531
					Block 3	0.00407
					Block 4	0.00326
					Block 5	0.00217
					Block 6	0.00081
				43 TF		0.00024
				43 TF		0.00024

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this

(N)

Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

SCHEDULE 239
TEMPORARY ADJUSTMENTS TO RATES FOR TSA CAPITAL AND COST OF SERVICE COST RECOVERY

(N)

APPLICABLE:

APPLICABLE:

Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: August 1, 2028**

The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		$0.01290		42 CTF	Block 1	$0.00251
1C		$0.01078			Block 2	$0.00225
2R		$0.00749			Block 3	$0.00172
3C		$0.00677			Block 4	$0.00138
3I		$0.00610			Block 5	$0.00092
27		$0.00759			Block 6	$0.00034
41 CSF	Block 1	$0.00530		42 ITF	Block 1	$0.00183
	Block 2	$0.00467			Block 2	$0.00164
41 ISF	Block 1	$0.00428			Block 3	$0.00126
	Block 2	$0.00377			Block 4	$0.00101
41 CSI	Block 1	$0.00393			Block 5	$0.00067
	Block 2	$0.00346			Block 6	$0.00025
41 ISI	Block 1	$0.00372		42 CSI	Block 1	$0.00229
	Block 2	$0.00327			Block 2	$0.00205
41 CTF	Block 1	$0.00487			Block 3	$0.00157
	Block 2	$0.00429			Block 4	$0.00126
41ITF	Block 1	$0.00376			Block 5	$0.00084
	Block 2	$0.00331			Block 6	$0.00031
42 CSF	Block 1	$0.00312		42 ISI	Block 1	$0.00255
	Block 2	$0.00279			Block 2	$0.00228
	Block 3	$0.00214			Block 3	$0.00175
	Block 4	$0.00171			Block 4	$0.00140
	Block 5	$0.00114			Block 5	$0.00093
	Block 6	$0.00043			Block 6	$0.00035
42 ISF	Block 1	$0.00287		42 CTI	Block 1	$0.00145
	Block 2	$0.00257			Block 2	$0.00130
	Block 3	$0.00197			Block 3	$0.00099
	Block 4	$0.00158			Block 4	$0.00080
	Block 5	$0.00105			Block 5	$0.00053
	Block 6	$0.00039			Block 6	$0.00020
				42 ITI	Block 1	$0.00166
					Block 2	$0.00149
					Block 3	$0.00114
					Block 4	$0.00091
					Block 5	$0.00061
					Block 6	$0.00023
				43 TF		$0.00000
				43 TF		$0.00000

GENERAL TERMS:

This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

(N)

Issued August 29, 2025
NWN WUTC Advice No. 25-03

Effective with service on
and after August 1, 2028

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

RATE YEAR 1 TARIFF SHEETS

PROPOSED

August 29, 2025

RATE SCHEDULE 1
GENERAL SALES SERVICE

AVAILABLE:
To all Residential and Commercial Customer classes in all territory served by the Company under the Tariff of which this Rate Schedule is a part, except that service under this Rate Schedule is not available for Standby Service to Commercial Customers. Seasonal or temporary Discontinuance of Service is allowed subject to Special Provision 1 of this Rate Schedule. The installation of Distribution Facilities, when required before service can be provided to equipment served under this Rate Schedule, is subject to the provisions of **Schedule E**.

SERVICE DESCRIPTION:
Service under this Rate Schedule is Firm Sales Service to gas-fired equipment, including but not limited to one or any multiple or combination of the following:

(a) Non-ducted space heating equipment that does not qualify as primary heating systems under Rate Schedule 2, including but not limited to fireplace inserts, free standing gas stoves, and room heaters;
(b) Supplemental or Standby space heating equipment including but not limited to natural gas back-up to electric heat pumps, used in residential applications;
(c) Water heating equipment used to serve single-family residential swimming pools, spas, and hot tubs;
(d) Other equipment including, but not limited to, log lighter, gas log, gas barbecue, tiki torch, Bunsen burner, Domestic cooking equipment, hobby kilns, refrigeration or Domestic clothes drying;
(e) Equipment installed for use in detached garages, shops, or outbuildings.

MONTHLY RATE: Effective: September 30, 2025 (C)
The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 200** for a list of applicable adjustments. Rates are subject to charges for purchased gas costs and technical rate adjustments.

	Base Rate	Pipeline Capacity Rate	Commodity Rate	Temporary Adjustment	Billing Rate	
Residential:						
Customer Charge	$8.00				**$8.00**	(I)
Schedule 308 Credits (per bill)				($1.82)	**($1.82)**	
Volumetric Charge (per therm)	$1.16131	$0.10337	$0.43274	$0.30387	**$2.00129**	(I)
Commercial:						
Customer Charge	$10.00				**$10.00**	(I)
Schedule 308 Credits (per bill)				$(5.34)	**($5.34)**	
Volumetric Charge (per therm)	$1.24467	$0.10337	$0.43274	$0.27830	**$2.05908**	(I)

Minimum Monthly Bill: Customer Charge, plus charges under **Schedule C** and **Schedule 10** (if applicable)

(continue to Sheet 101.2)

RATE SCHEDULE 2
RESIDENTIAL SALES SERVICE

AVAILABLE:
To Residential Customers, in all territory served by the Company under the Tariff of which this Rate Schedule is a part. Seasonal or temporary Discontinuance of Service is allowed subject to Special Provision 1 of this Rate Schedule. The installation of Distribution Facilities, when required before service can be provided to equipment served under this Rate Schedule, are subject to the provisions of **SCHEDULE E**.

SERVICE DESCRIPTION:
Service under this Rate Schedule is Firm Sales Service to gas-fired equipment used in Residential dwellings that provide complete family living facilities in which the occupant normally cooks, eats, sleeps, and carries on the household operations incident to Domestic life, for at least one of the following purposes:

(a) Operation of ducted forced air Natural Gas space heating equipment that is the primary source for space heating requirements;
(b) Operation of a gas-fired hearth product or wall heater as the primary source for space heating requirements where the hearth or wall heater has a verified nameplate rating of 20,000 BTUs or greater, and is installed in a primary residence defined as a dwelling that is occupied year-round, and where that dwelling is 1,500 square feet or less; and, or;
(c) Operation of fully automatic water heating equipment for primary water heating requirements.

Service under this Rate Schedule includes the use of gas for equipment installed in addition to (a) and (b).

MONTHLY RATE: Effective: September 30, 2025 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

	Base Rate	Pipeline Capacity Rate	Commodity Rate	Temporary Adjustment	Billing Rate
Customer Charge:	$8.00				**$8.00**
Schedule 308 Credits - Winter (per bill)				($10.97)	**($10.97)**
Schedule 308 Credits - Non-Winter (per bill)				($4.84)	**($4.84)**
Volumetric Charge (per therm)	$0.84344	$0.10337	$0.43274	$0.22427	**$1.60382** (I)

Minimum Monthly Bill: Customer Charge, plus charges under **Schedule C** and **Schedule 10** (if applicable)

RATE SCHEDULE 3
BASIC FIRM SALES SERVICE - NON-RESIDENTIAL
(continued)

MONTHLY RATE: Effective: September 30, 2025 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM SALES SERVICE CHARGES (03 SF):					**Billing Rates [1]**	
Customer Charge (per month):					**$22.00**	
	Base Rate	Pipeline Capacity	Commodity Component [2]	Temporary Adjustment		
Schedule 308 Credits (per bill):						
Commercial - Winter				($46.59)	**($46.59)**	
Commercial - Non-Winter				($25.89)	**($25.89)**	
Industrial				($129.16)	**($129.16)**	
Volumetric Charges (per therm):						
Commercial	$0.81318	$0.10337	$0.43274	$0.21184	**$1.56113**	(I)
Industrial	$0.77961	$0.10337	$0.43274	$0.15305	**$1.46877**	(I)
Standby Charge (per therm of MHDV) [3]:					**$5.00**	

[1] **Schedule C** and **Schedule 10** Charges shall apply, if applicable.
[2] The Commodity Component will be either Annual Sales WACOG or Monthly Incremental Cost of Gas.
[3] Applies to Standby Sales Service only.

Minimum Monthly Bill. The Minimum Monthly Bill shall be any **Schedule C** and **Schedule 10** Charges, plus:

(a) ***Firm Sales Service.*** Customer Charge
(b) ***Firm Sales Standby Service.*** Customer Charge, plus Standby Service Charge

RATE SCHEDULE 10
CHARGES FOR SPECIAL METERING EQUIPMENT, RENTAL METERS AND METERING SERVICES

AVAILABLE:
In all territory served by the Company under the Tariff of which this Rate Schedule is a part.

TERM OF SERVICE:
The Term of Service for monthly meter rentals and metering services provided under this Schedule is one (1) Year. At the end of a full Term of Service, service under this Rate Schedule will continue on a billing month basis until terminated by either the Customer or the Company upon one (1) billing month advance notice.

MONTHLY METER RENTAL RATES AND SPECIAL METERING EQUPMENT (OPTIONAL):

Any Customer may pay to rent supplementary displacement type meters from the Company on a monthly basis calculated as follows: (C) (C) (D) (N)

$$= \frac{Net\ Present\ Value\ (\text{Total Cost to Serve Meter at Discount Rate } r \text{ over Period } t)}{12}$$

- The Rental Meter is the meter inclusive of an Encoder Receiver Transmitter (ERT), if necessary, as well as required fittings and components (e.g., swivel, gasket, flange, etc.) which can vary by meter type and size.
- Cost to Serve incudes incremental capital-related costs (the cost of the Rental Meter) as well as any other costs customarily relating to recovery of the utility investment, including but not limited to capital depreciation, regulatory fees, and income and property taxes.
- Discount Rate *r* is the weighted cost of capital and cost of long-term debt authorized by the Commission in the Company's most recent general rate case. Period *t* is equal to the total depreciable life (in years) of the assembled meter set.

The Net Present Value calculation produces a levelized cost of the Company to serve the rental meter at Discount Rate *r* over Period *t*. Dividing this value by 12 produces the Monthly Meter Rental Charge.

The Company will consult with the Customer regarding available meters of sizes and pressures that meet their service requirements prior to entering into a rental agreement. The meter rental charge, which is calculated as a monthly rate as described above, is presented to the Customer prior to the rental period and installation at the Customer premise. (N)

(continue to Sheet 110.2)

RATE SCHEDULE 10
CHARGES FOR SPECIAL METERING EQUIPMENT, RENTAL METERS AND METERING SERVICES
(continued)

Metering Services and Charges	One Time Charge	Installation Charge	Monthly Charge	
Rental Read	---	---	$0.36	
Advanced Automated Meter Reading (AAMR) Device[1]	---	$1,270.53	$52.49	(I)
Remote Index	---	$50.00	$4.00	
Pulse Output	---	$100.00	$8.00	
Administrative Set-Up/Consultation Fee (all meters)	$145.00	---	---	(I)
Technical Assistance (Rotary meters only)	$145.00	---	---	(I)

[1] Site specific engineering design costs for AAMR will be added to the installation charge if needed.

SPECIAL PROVISIONS FOR RENTAL METERS AND SPECIAL METERING EQUIPMENT:

1. Prior to receiving service under this section of the Schedule, the Customer must sign a service agreement that requires a minimum 12-month term. Customers who terminate service after less than 12 months will be required to pay all charges otherwise due to fulfill the 12-month obligation under the service agreement.
2. Service under this section of this Schedule is voluntary and separate from billing for or delivery of natural gas to a Customer's premise.
3. Since the Company does not maintain an inventory of all meter types offered under this Schedule, a delay may occur from the time a Customer requests service under this Schedule until the Company can provide it.
4. The Customer will be responsible for the meter pick-up and return of diaphragm meters.
5. The Customer will incur the Administrative Set-Up/Consultation Fee for each rental meter.
6. Upon delivery of a rotary meter, the Customer will incur the Technical Assistance charge listed above for each rental rotary meter. A Customer may not waive this provision or the associated fee. Technical assistance helps the Company ensure proper handling of rotary meters.
7. The Company will install AAMR devices for the charge listed above. AAMR devices will only be installed on Company owned meters and the Company will require that the Customer provide active and continuous electric power per company specifications to enable meter communications.
8. Upon request, the Company will provide one differential test per calendar year on rotary meters. The testing will be scheduled at the Company's convenience.
9. The Customer is responsible to protect all rental equipment from damage including but not limited to installing parking bollards to protect the rental equipment from vehicular or other damage.

(continue to Sheet 110.3)

RATE SCHEDULE 27
RESIDENTIAL HEATING DRY-OUT SERVICE

AVAILABLE:
To Residential home builders, developers, and contractors during the period that a Residential dwelling is under construction, in all territory served by the Company under the Tariff of which this schedule is a part.

SERVICE DESCRIPTION:
Service under this Rate Schedule is restricted to the use of gas in approved permanently-installed gas heating equipment in place during the period the dwelling is under construction. Upon occupancy of the dwelling, service under this Rate Schedule shall terminate automatically. In no event will service under this Rate Schedule continue for more a period of time greater than twelve (12) months from the date the gas meter is set at the dwelling. Upon termination of service under this Rate Schedule, gas service shall transfer to **Schedule 1** or **Schedule 2**, whichever is applicable.

MONTHLY RATE: Effective: September 30, 2025 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 200** for a list of applicable adjustments. Rates are subject to charges for purchased gas costs and technical rate adjustments.

	Base Rate	Pipeline Capacity Rate	Commodity Rate	Temporary Adjustment	Billing Rate
Customer Charge:	$9.00	---	---	---	**$9.00**
Volumetric Charge (per therm)					
All therms	$0.79988	$0.10337	$0.43274	$0.26973	**$1.60572** (I)

Minimum Monthly Bill: Customer Charge, plus charges under **Schedule C** and **Schedule 10** (if applicable)

GENERAL TERMS:
Service under this Rate Schedule is governed by the terms of this Rate Schedule, the General Rules and Regulations contained in this Tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

RATE SCHEDULE 41
NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES FOR COMMERCIAL CUSTOMER CLASS: Effective: September 30, 2025 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. **SEE SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM SALES SERVICE CHARGES (C41SF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$250.00**	
	Base Rate		Commodity Component [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($515.09)	**($515.09)**	
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	$0.62232		$0.43274	$0.19304	**$1.24810**	(I)
Block 2: All additional therms	$0.54836		$0.43274	$0.18387	**1.16497**	(I)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.10337**	
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.54**	
INTERRUPTIBLE SALES SERVICE CHARGES (C41SI) [1]:						
Customer Charge (per month):					**$250.00**	
	Base Rate		Commodity Component: [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($515.09)	**($515.09)**	
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	$0.53329		$0.43274	$0.14899	**$1.11502**	(I)
Block 2: All additional therms	$0.46987		$0.43274	$0.14068	**$1.04329**	(I)
Plus: Interruptible Pipeline Capacity Charge - Volumetric (per therm):					**$0.03612**	
FIRM TRANSPORTATION SERVICE CHARGES (C41TF):						
Customer Charge (per month):					**$250.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Total Temporary Adjustments [4]		
Schedule 308 Credits (per bill):				($515.09)	**($515.09)**	
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	$0.51532			$0.26489	**$0.78021**	(I)
Block 2: All additional therms	$0.45404			$0.26213	**$0.71617**	(I)

[1] The Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from Schedule C and Schedule 10.

[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG, or Monthly Incremental Cost of Gas.

[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 may not apply.

(continue to Sheet 141.10)

RATE SCHEDULE 41
NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES FOR INDUSTRIAL CUSTOMER CLASS: Effective: September 30, 2025 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. **SEE SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM SALES SERVICE CHARGES (I41SF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$250.00**	
	Base Rate		Commodity Component [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($622.72)	**($622.72)**	
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	$0.49786		$0.43274	$0.14412	**$1.07472**	(I)
Block 2: All additional therms	$0.43867		$0.43274	$0.14089	**$1.01230**	(I)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.10337**	
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.54**	
INTERRUPTIBLE SALES SERVICE CHARGES (I41SI) [1]:						
Customer Charge (per month):					**$250.00**	
	Base Rate		Commodity Component: [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($622.72)	**($622.72)**	
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	$0.50451		$0.43274	$0.10779	**$1.04504**	
Block 2: All additional therms	$0.44449		$0.43274	$0.10450	**$0.98173**	(I)
Plus: Interruptible Pipeline Capacity Charge - Volumetric (per therm):					**$0.03612**	(I)
FIRM TRANSPORTATION SERVICE CHARGES (I41TF):						
Customer Charge (per month):					**$250.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Total Temporary Adjustments [4]		
Schedule 308 Credits (per bill):				($622.72)	**($622.72)**	
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	$0.51010			$0.26265	**$0.77275**	(I)
Block 2: All additional therms	$0.44943			$0.26016	**$0.70959**	(I)

[1] The Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from Schedule C and Schedule 10.

[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG, or Monthly Incremental Cost of Gas.

[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 may not apply.

RATE SCHEDULE 42
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY SALES RATES - FIRM SERVICE: Effective: September 30, 2025 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM SALES SERVICE CHARGES [1]:					**Billing Rates**	
Customer Charge (per month, all service types):					**$1,300.00**	
	Base Rate		Commodity Component [2]	Total Temporary Adjustments [3]		
C42SF						
Schedule 308 Credits (per bill):				($5,142.27)	($5,142.27)	
Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	$0.33774		$0.43274	$0.15892	$0.92940	(I)
Block 2: Next 20,000 therms	$0.30232		$0.43274	$0.15440	$0.88946	
Block 3: Next 20,000 therms	$0.23188		$0.43274	$0.14543	$0.81005	
Block 4: Next 100,000 therms	$0.18547		$0.43274	$0.13952	$0.75773	
Block 5: Next 600,000 therms	$0.12364		$0.43274	$0.13164	$0.68802	
Block 6: All additional therms	$0.04635		$0.43274	$0.12178	$0.60087	(I)
I42SF						
Schedule 308 Credits (per bill):				($3,945.77)	($3,945.77)	
Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	$0.25913		$0.43274	$0.13408	$0.82595	(I)
Block 2: Next 20,000 therms	$0.23195		$0.43274	$0.13227	$0.79696	
Block 3: Next 20,000 therms	$0.17786		$0.43274	$0.12867	$0.73927	
Block 4: Next 100,000 therms	$0.14229		$0.43274	$0.12630	$0.70133	
Block 5: Next 600,000 therms	$0.09490		$0.43274	$0.12315	$0.65079	
Block 6: All additional therms	$0.03555		$0.43274	$0.11919	$0.58748	(I)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	
Firm Sales Service Storage Charge (per therm of MDDV per month):					**$0.20415**	
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.10337**	
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV per month):					**$1.54**	

[1] For Firm Sales Service, the Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Distribution Capacity Charge, plus the Storage Capacity Charge, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from Schedule C or Schedule 10.

[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG or Monthly Incremental Cost of Gas.

[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 may not apply.

(continue to Sheet 142.10.1)

RATE SCHEDULE 42
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY SALES RATES – INTERRUPTIBLE SERVICE: Effective: September 30, 2025 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

INTERRUPTIBLE SALES SERVICE CHARGES [1]: (C42SI)					**Billing Rates**	
Customer Charge (per month):					**$1,300.00**	
	Base Rate		Commodity Component [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($5,142.27)	**($5,142.27)**	
Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	$0.26337		$0.43274	$0.11096	**$0.80707**	(I)
Block 2: Next 20,000 therms	$0.23575		$0.43274	$0.10763	**$0.77612**	
Block 3: Next 20,000 therms	0.18076		$0.43274	$0.10098	**$0.71448**	
Block 4: Next 100,000 therms	$0.14461		$0.43274	$0.09663	**$0.67398**	
Block 5: Next 600,000 therms	$0.09644		$0.43274	$0.09080	**$0.61998**	
Block 6: All additional therms	$0.03617		$0.43274	$0.08348	**$0.55239**	(I)
Interruptible Pipeline Capacity Charge (per therm):					**$0.03612**	
Interruptible Sales Service Storage Charge (per therm of MDDV per month)					**$0.10208**	
INTERRUPTIBLE SALES SERVICE CHARGES [1]: (I42SI)						
Customer Charge (per month):					**$1,300.00**	
Schedule 308 Credits (per bill):				($3,945.77)	**($3,945.77)**	
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	$0.24136		$0.43274	$0.09567	**$0.76977**	(I)
Block 2: Next 20,000 therms	$0.21605		$0.43274	$0.09404	**$0.74283**	
Block 3: Next 20,000 therms	$0.16567		$0.43274	$0.09079	**$0.68920**	
Block 4: Next 100,000 therms	$0.13255		$0.43274	$0.08865	**$0.65394**	
Block 5: Next 600,000 therms	$0.08835		$0.43274	$0.08579	**$0.60688**	
Block 6: All additional therms	$0.03312		$0.43274	$0.08224	**$0.54810**	(I)
Interruptible Pipeline Capacity Charge (per therm):					**$0.03612**	
Interruptible Sales Service Storage Charge (per therm of MDDV per month)					**$0.10208**	

[1] For Interruptible Sales Service, the Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge, plus any other charges that apply from Schedule C or Schedule 10.
[2] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 201 may also apply.
[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 may not apply.

(continue to Sheet 142.11)

RATE SCHEDULE 42
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY TRANSPORTATION RATES: Effective: September 30, 2025 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (C42TI) [1]:					**Billing Rates**	
Customer Charge (per month):					**$1,300.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Temporary Adjustments [2]		
Schedule 308 Credits (per bill):				($5,142.27)	**($5,142.27)**	
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	$0.19650			$0.24980	**$0.44630**	(I)
Block 2: Next 20,000 therms	$0.17592			$0.24896	**$0.42488**	
Block 3: Next 20,000 therms	$0.13490			$0.24728	**$0.38218**	
Block 4: Next 100,000 therms	$0.10792			$0.24618	**$0.35410**	
Block 5: Next 600,000 therms	$0.07197			$0.24470	**$0.31667**	
Block 6: All additional therms	$0.02696			$0.24287	**$0.26983**	(I)
INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (I42TI) [1]:					**Billing Rates**	
Customer Charge (per month):					**$1,300.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Temporary Adjustments [2]		
Schedule 308 Credits (per bill):				($3,945.77)	**($3,945.77)**	
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	$0.19129			$0.24995	**$0.44124**	(I)
Block 2: Next 20,000 therms	$0.17123			$0.24911	**$0.42034**	
Block 3: Next 20,000 therms	$0.13131			$0.24741	**$0.37872**	
Block 4: Next 100,000 therms	$0.10506			$0.24629	**$0.35135**	
Block 5: Next 600,000 therms	$0.07005			$0.24481	**$0.31486**	
Block 6: All additional therms	$0.02627			$0.24296	**$0.26923**	(I)

[1] For Interruptible Transportation Service, the Monthly Bill shall equal the sum of the Customer Charge, plus Transportation Charge, plus the Volumetric Charges, plus any other charges that may apply from Schedule C or Schedule 10.
[2] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 201 may also apply.

(continue to Sheet 142.12)

RATE SCHEDULE 42
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

FIRM TRANSPORTATION SERVICE CHARGES (C42TF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$1,300.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Total Temporary Adjustments [2]		
Schedule 308 Credits (per bill):				($5,142.27)	**($5,142.27)**	
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	$0.22706			$0.25011	**$0.47717**	(I)
Block 2: Next 20,000 therms	$0.20327			$0.24925	**$0.45252**	
Block 3: Next 20,000 therms	$0.15587			$0.24752	**$0.40339**	
Block 4: Next 100,000 therms	$0.12471			$0.24640	**$0.37111**	
Block 5: Next 600,000 therms	$0.08314			$0.24487	**$0.32801**	
Block 6: All additional therms	$0.03117			$0.24300	**$0.27417**	(I)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	
FIRM TRANSPORTATION SERVICE CHARGES (I42TF) [1]:						
Customer Charge (per month):					**$1,300.00**	
Transportation Charge (per month):					**$250.00**	
Schedule 308 Credits (per bill):				($3,945.77)	**($3,945.77)**	
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	$0.20621			$0.25026	**$0.45647**	(I)
Block 2: Next 20,000 therms	$0.18459			$0.24938	**$0.43397**	
Block 3: Next 20,000 therms	$0.14154			$0.24762	**$0.38916**	
Block 4: Next 100,000 therms	$0.11325			$0.24646	**$0.35971**	
Block 5: Next 600,000 therms	$0.07549			$0.24493	**$0.32042**	
Block 6: All additional therms	$0.02831			0.24300	**$0.27131**	(I)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	

[1] For Firm Transportation Service, the Monthly Bill shall equal the sum of the Customer Charge, plus Transportation Charge, plus the Volumetric Charges, plus the Distribution Capacity Charge, plus any other charges that may apply from Schedule C or Schedule 10.

[2] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 201 may also apply.

RATE SCHEDULE 43
HIGH VOLUME NON-RESIDENTIAL
FIRM AND INTERRUPTIBLE TRANSPORTATION SERVICE
(continued)

MONTHLY RATE: Effective: September 30, 2025 (C)

The rates shown below may not always reflect actual billing rates. See **Schedule 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM TRANSPORTATION SERVICE CHARGES (C43TF and I43TF)					
					Billing Rates
Customer Charge:					**$38,000.00**
Transportation Charge:					**$250.00**
Volumetric Charge	Base Rate			Total Temporary Adjustment [1]	
Per therm, all therms	$0.00685			$ 0.24194	**$0.24879** (I)
Firm Service Distribution Capacity Charge: Per therm of MDDV per month					**$0.15748**
Minimum Monthly Bill: Customer Charge, plus Transportation Charge, plus Firm Service Distribution Capacity Charge, plus any other charges that may apply from **Schedule C** and **Schedule 10**.					

INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (C43TI and I43TI)					
					Billing Rates
Customer Charge:					**$38,000.00**
Transportation Charge:					**$250.00**
Volumetric Charge:	Base Rate			Total Temporary Adjustment [1]	
Per therm, all therms	$0.00685			$ 0.24194	**$0.24879** (I)
Minimum Monthly Bill: Customer Charge, plus Transportation Charge, plus any other charges that may apply from **Schedule C** and **Schedule 10**.					

[1] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 shall apply.

SCHEDULE 200
SUMMARY OF ADJUSTMENTS

PURPOSE:
The purpose of this Schedule is to list and summarize the adjustment Schedules applicable to each of the Company's Rate Schedules.

SCHEDULE	A	201	203	207	210	212	215	220	221	230	232	233	234	235	236	237	238	303	305	306	308
R1	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
C1	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
2	ADD	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
03CSF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
03ISF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
10	ADD			INC																	
27	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
C41SF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
C41SI	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
C41TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I41SF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I41SI	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I41TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C42SF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
C42SI	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
C42TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C42TI	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I42SF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I42SI	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I42TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I42TI	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C43TI/ I43TI	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C43TF/ I43TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC

(N)

(N)

Table Code Key:

ADD This adjustment is added to the billing rates at the time the bill is issued.
INC This adjustment is included in the billing rates shown on the Rate Schedule

(continue to Sheet 200.2)

SCHEDULE 200
SUMMARY OF ADJUSTMENTS
(continued)

The following is a brief description of the applicable Schedules:

Schedule A "Billing for City and County Exactions."
This adjustment will be reflected directly on Customer bills.

Schedule 201 "Temporary (Technical) Adjustments to Rates."
These are temporary Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 203 "Purchased Gas Cost Adjustments to Rates."
These are pipeline capacity and commodity charges.

Schedule 207 "General Adjustments to Rates."
These are Base Rate Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 210 "Adjustment to Rates for Property Sales."
These are Temporary Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 212 "Adjustment to Rates Residential Rate Mitigation."
These are Temporary Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 215 "Adjustment to Rates for Energy Conservation Programs."
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 220 "Special Rate Adjustment."
These are Base Rate Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 221 "Rate Adjustment for Updated Depreciation Rates"
These are Base Rate Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 230 "Temporary Adjustments to Rates for Low-Income Programs."
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 231 "Temporary Adjustments to Rates for Residential Discount Program."
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 232 "Temporary Adjustments to Rates for Regulatory Fee Increase"
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 233 "Temporary Adjustments to Rates for Industrial Customer Energy Efficiency Audit Costs"
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 234 "Temporary Adjustments to Rates for Residential Arrearage Management Program." (N)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 235 "Temporary Adjustments to Rates for COVID-19 Public Health Emergency." (N)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills. (N)

(K)

(K) Schedules 303, 305, 306 and 308 transferred to Sheet 200.3.

(continue to Sheet 200.3)

SCHEDULE 200
SUMMARY OF ADJUSTMENTS
(continued)

Schedule 236 "Temporary Adjustments to Rates for Meter Modernization Program." (N)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 237 "Temporary Adjustments to Rates for TSA Operations and Maintenance Costs." (N)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 238 "Adjustments to Rates for Provisional Capital Adjustment." (N)
These are base rate adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 303 "Washington Environmental Cost Recovery Mechanism." (M)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 305 "Adjustment for Certain Income Taxes (2017 Federal Tax Cuts and Jobs Act)."
These are base and temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 306 "Multi-Year Rate Plan Adjustment."
These are base rate adjustments that will be added to the Billing Rate on the effective date of the Schedule.

Schedule 308 "Washington Climate Commitment Act Recovery Mechanism."
These are temporary rate adjustments that will be added to the Billing Rate on the effective date of the Schedule. (M)

(M) Schedules 303, 305, 306 and 308 transferred from Sheet 200.2.

SCHEDULE 207
GENERAL RATE ADJUSTMENT

PURPOSE:
To identify the effects of general rate changes approved in the company's most recent general rate case proceeding (Docket UG-200994)

APPLICATION TO RATE SCHEDULES: Effective: September 30, 2025 (C)

Rate Schedule 1	Rate Schedule 3	Rate Schedule 41	Rate Schedule 43
Rate Schedule 2	Rate Schedule 27	Rate Schedule 42	

The Base Rates in the listed Rate Schedules include the adjustment shown below.
NO FURTHER ADJUSTMENT TO RATES IS REQUIRED.

SCHEDULES	BLOCKS	AMOUNT	
Schedule 1 - Residential	Customer Charge	$2.50	(I)
	Per Therm (all therms)	$0.32662	(I)
Schedule 1 - Commercial	Customer Charge	$3.00	(I)
	Per Therm (all therms)	$0.38159	(I)
Schedule 2	Customer Charge	$0.00	
	Per Therm (all therms)	$0.28524	(I)
Schedule 3 - Commercial	Customer Charge	$0.00	
	Per Therm (all therms)	$0.27968	(I)
Schedule 3 - Industrial	Customer Charge	$0.00	
	Per Therm (all therms)	$0.23576	(I)
Schedule 27	Customer Charge	$0.00	
	Per Therm (all therms)	$0.48735	(I)
Schedule 41 - Commercial Firm Sales Service	Customer Charge	$0.00	
	First 2,000 therms	$ 0.20624	(I)
	All additional therms	$ 0.18173	(I)
Schedule 41 - Commercial Interruptible Sales Service	Customer Charge	$0.00	
	First 2,000 therms	$ 0.14876	(I)
	All additional therms	$ 0.13107	(I)
Schedule 41 - Industrial Firm Sales Service	Customer Charge	$0.00	
	First 2,000 therms	$ 0.12639	(I)
	All additional therms	$ 0.11136	(I)
Schedule 41 - Industrial Interruptible Sales Service	Customer Charge	$0.00	
	First 2,000 therms	$ 0.14073	(I)
	All additional therms	$ 0.12399	(I)
Schedule 41 - Commercial Firm Transportation Service	Customer Charge	$0.00	
	First 2,000 therms	$ 0.13747	(I)
	All additional therms	$ 0.12113	(I)
Schedule 41 - Industrial Firm Transportation Service	Customer Charge	$0.00	
	First 2,000 therms	$ 0.14229	(I)
	All additional therms	$ 0.12537	(I)

(continue to Sheet 207.2)

SCHEDULE 207
GENERAL RATE ADJUSTMENT
(continued)

SCHEDULES	BLOCKS	AMOUNT	
Schedule 42 Commercial - Firm Sales Service	Customer Charge	$0.00	
	First 10,000 therms	0.13164	(I)
	Next 20,000 therms	0.11784	
	Next 20,000 therms	0.09038	
	Next 100,000 therms	0.07229	
	Next 600,000 therms	0.04819	
	All additional therms	0.01807	(I)
Schedule 42 Commercial - Interruptible Sales Service	Customer Charge	$0.00	
	First 10,000 therms	0.09465	(I)
	Next 20,000 therms	0.08472	
	Next 20,000 therms	0.06496	
	Next 100,000 therms	0.05197	
	Next 600,000 therms	0.03466	
	All additional therms	0.01300	(I)
Schedule 42 Industrial - Firm Sales Service	Customer Charge	$0.00	
	First 10,000 therms	0.09272	(I)
	Next 20,000 therms	0.08300	
	Next 20,000 therms	0.06364	
	Next 100,000 therms	0.05091	
	Next 600,000 therms	0.03396	
	All additional therms	0.01272	(I)
Schedule 42 Industrial - Interruptible Sales Service	Customer Charge	$0.00	
	First 10,000 therms	0.07783	(I)
	Next 20,000 therms	0.06967	
	Next 20,000 therms	0.05342	
	Next 100,000 therms	0.04274	
	Next 600,000 therms	0.02849	
	All additional therms	0.01068	(I)

(continue to Sheet 207.3)

SCHEDULE 207
GENERAL RATE ADJUSTMENT
(continued)

SCHEDULES	BLOCKS	AMOUNT	
Schedule 42 Commercial - Firm Transportation Service	Customer Charge	$0.00	
	First 10,000 therms	0.07264	(I)
	Next 20,000 therms	0.06503	
	Next 20,000 therms	0.04987	
	Next 100,000 therms	0.03990	
	Next 600,000 therms	0.02660	
	All additional therms	0.00997	(I)
Schedule 42 Industrial - Firm Transportation Service	Customer Charge	$0.00	
	First 10,000 therms	0.05460	(I)
	Next 20,000 therms	0.04888	
	Next 20,000 therms	0.03748	
	Next 100,000 therms	0.02999	
	Next 600,000 therms	0.01999	
	All additional therms	0.00749	(I)
Schedule 42 - Commercial Interruptible Transportation Service	Customer Charge	$0.00	
	First 10,000 therms	0.05481	(I)
	Next 20,000 therms	0.04907	
	Next 20,000 therms	0.03763	
	Next 100,000 therms	0.03010	
	Next 600,000 therms	0.02008	
	All additional therms	0.00752	(I)
Schedule 42 - Industrial Interruptible Transportation Service	Customer Charge	$0.00	
	First 10,000 therms	0.04699	(I)
	Next 20,000 therms	0.04206	
	Next 20,000 therms	0.03226	
	Next 100,000 therms	0.02581	
	Next 600,000 therms	0.01721	
	All additional therms	0.00646	(I)

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

NORTHWEST NATURAL GAS COMPANY

WN U-6 First Revision of Sheet 221.1
Cancels Original Sheet 221.1

SCHEDULE 221
RATE ADJUSTMENT FOR UPDATED DEPRECIATION RATES

PURPOSE:
The purpose of this Schedule is to reflect the adjustments from the Company's updated depreciation rates filed in docket UG-210974.

APPLICABLE:
To all Sales and Transportation Service Customers served under the following Rate Schedules:

Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42
Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: September 30, 2025**
The Adjustment amount shown below is included in the Base Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		$0.00000		42 CTF	Block 1	$0.00000
1C		$0.00000			Block 2	$0.00000
2R		$0.00000			Block 3	$0.00000
3C		$0.00000			Block 4	$0.00000
3I		$0.00000			Block 5	$0.00000
27		$0.00000			Block 6	$0.00000
41 CSF	Block 1	$0.00000		42 ITF	Block 1	$0.00000
	Block 2	$0.00000			Block 2	$0.00000
41 ISF	Block 1	$0.00000			Block 3	$0.00000
	Block 2	$0.00000			Block 4	$0.00000
41 CSI	Block 1	$0.00000			Block 5	$0.00000
	Block 2	$0.00000			Block 6	$0.00000
41 ISI	Block 1	$0.00000		42 CSI	Block 1	$0.00000
	Block 2	$0.00000			Block 2	$0.00000
41 CTF	Block 1	$0.00000			Block 3	$0.00000
	Block 2	$0.00000			Block 4	$0.00000
41ITF	Block 1	$0.00000			Block 5	$0.00000
	Block 2	$0.00000			Block 6	$0.00000
42 CSF	Block 1	$0.00000		42 ISI	Block 1	$0.00000
	Block 2	$0.00000			Block 2	$0.00000
	Block 3	$0.00000			Block 3	$0.00000
	Block 4	$0.00000			Block 4	$0.00000
	Block 5	$0.00000			Block 5	$0.00000
	Block 6	$0.00000			Block 6	$0.00000
42 ISF	Block 1	$0.00000		42 CTI	Block 1	$0.00000
	Block 2	$0.00000			Block 2	$0.00000
	Block 3	$0.00000			Block 3	$0.00000
	Block 4	$0.00000			Block 4	$0.00000
	Block 5	$0.00000			Block 5	$0.00000
	Block 6	$0.00000			Block 6	$0.00000
				42 ITI	Block 1	$0.00000
					Block 2	$0.00000
					Block 3	$0.00000
					Block 4	$0.00000
					Block 5	$0.00000
					Block 6	$0.00000
				43 TF		$0.00000
				43 TF		$0.00000

(I) (I) (I) (I) (I) (I) (I) (I) (I) (I) (I)

(continue to Sheet 221.2)

Issued August 29, 2025
NWN WUTC Advice No. 25-03

Effective with service on
and after September 30, 2025

SCHEDULE 235
TEMPORARY ADJUSTMENTS TO RATES FOR COVID-19 PUBLIC HEALTH EMERGENCY

(N)

PURPOSE: To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of deferred amounts for the costs and savings incurred due to the COVID-19 pandemic, as authorized for deferred accounting by the WUTC in Docket UG-200264.

APPLICABLE:
Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: September 30, 2025**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		$0.00344		42 CTF	Block 1	$0.00065
1C		$0.00262			Block 2	$0.00059
2R		$0.00179			Block 3	$0.00045
3C		$0.00157			Block 4	$0.00036
3I		$0.00146			Block 5	$0.00024
27		$0.00133			Block 6	$0.00009
41 CSF	Block 1	$0.00128		42 ITF	Block 1	$0.00049
	Block 2	$0.00112			Block 2	$0.00044
41 ISF	Block 1	$0.00114			Block 3	$0.00034
	Block 2	$0.00100			Block 4	$0.00027
41 CSI	Block 1	$0.00118			Block 5	$0.00018
	Block 2	$0.00104			Block 6	$0.00007
41 ISI	Block 1	$0.00111		42 CSI	Block 1	$0.00059
	Block 2	$0.00098			Block 2	$0.00052
41 CTF	Block 1	$0.00124			Block 3	$0.00040
	Block 2	$0.00109			Block 4	$0.00032
41ITF	Block 1	$0.00113			Block 5	$0.00021
	Block 2	$0.00099			Block 6	$0.00008
42 CSF	Block 1	$0.00081		42 ISI	Block 1	$0.00070
	Block 2	$0.00073			Block 2	$0.00063
	Block 3	$0.00056			Block 3	$0.00048
	Block 4	$0.00045			Block 4	$0.00039
	Block 5	$0.00030			Block 5	$0.00026
	Block 6	$0.00011			Block 6	$0.00010
42 ISF	Block 1	$0.00083		42 CTI	Block 1	$0.00043
	Block 2	$0.00075			Block 2	$0.00039
	Block 3	$0.00057			Block 3	$0.00030
	Block 4	$0.00046			Block 4	$0.00024
	Block 5	$0.00031			Block 5	$0.00016
	Block 6	$0.00011			Block 6	$0.00006
				42 ITI	Block 1	$0.00042
					Block 2	$0.00038
					Block 3	$0.00029
					Block 4	$0.00023
					Block 5	$0.00015
					Block 6	$0.00006
				43 TF		$0.00000
				43 TF		$0.00000

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

(N)

Issued August 29, 2025
NWN WUTC Advice No. 25-03

Effective with service on
and after September 30, 2025

SCHEDULE 236
TEMPORARY ADJUSTMENTS TO RATES FOR METER MODERNIZATION PROGRAM

(N)

PURPOSE: To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of deferred amounts for the costs related to the Company's Meter Modernization Program, as authorized for deferred accounting by the WUTC in Docket UG-240012.

APPLICABLE:
Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: September 30, 2025**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		$0.00148		42 CTF	Block 1	$0.00028
1C		$0.00114			Block 2	$0.00025
2R		$0.00077			Block 3	$0.00019
3C		$0.00068			Block 4	$0.00016
3I		$0.00063			Block 5	$0.00010
27		$0.00057			Block 6	$0.00004
41 CSF	Block 1	$0.00055		42 ITF	Block 1	$0.00021
	Block 2	$0.00049			Block 2	$0.00019
41 ISF	Block 1	$0.00049			Block 3	$0.00015
	Block 2	$0.00043			Block 4	$0.00012
41 CSI	Block 1	$0.00041			Block 5	$0.00008
	Block 2	$0.00036			Block 6	$0.00003
41 ISI	Block 1	$0.00038		42 CSI	Block 1	$0.00025
	Block 2	$0.00034			Block 2	$0.00023
41 CTF	Block 1	$0.00054			Block 3	$0.00017
	Block 2	$0.00047			Block 4	$0.00014
41ITF	Block 1	$0.00039			Block 5	$0.00009
	Block 2	$0.00034			Block 6	$0.00003
42 CSF	Block 1	$0.00035		42 ISI	Block 1	$0.00030
	Block 2	$0.00031			Block 2	$0.00027
	Block 3	$0.00024			Block 3	$0.00021
	Block 4	$0.00019			Block 4	$0.00017
	Block 5	$0.00013			Block 5	$0.00011
	Block 6	$0.00005			Block 6	$0.00004
42 ISF	Block 1	$0.00036		42 CTI	Block 1	$0.00015
	Block 2	$0.00032			Block 2	$0.00013
	Block 3	$0.00025			Block 3	$0.00010
	Block 4	$0.00020			Block 4	$0.00008
	Block 5	$0.00013			Block 5	$0.00005
	Block 6	$0.00005			Block 6	$0.00002
				42 ITI	Block 1	$0.00018
					Block 2	$0.00016
					Block 3	$0.00013
					Block 4	$0.00010
					Block 5	$0.00007
					Block 6	$0.00003
				43 TF		$0.00000
				43 TF		$0.00000

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

(N)

Issued August 29, 2025
NWN WUTC Advice No. 25-03

Effective with service on
and after September 30, 2025

SCHEDULE 237
TEMPORARY ADJUSTMENTS TO RATES FOR TSA OPERATIONS AND MAINTENANCE COSTS

(N)

PURPOSE: To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of deferred amounts for the start-up Operations and Maintenance costs incurred for compliance with TSA Security Directives, as authorized for deferred accounting by the WUTC in Docket UG-210900.

APPLICABLE:
Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: September 30, 2025**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		$0.00145		42 CTF	Block 1	$0.00028
1C		$0.00109			Block 2	$0.00025
2R		$0.00075			Block 3	$0.00019
3C		$0.00066			Block 4	$0.00015
3I		$0.00061			Block 5	$0.00010
27		$0.00056			Block 6	$0.00004
41 CSF	Block 1	$0.00054		42 ITF	Block 1	$0.00021
	Block 2	$0.00047			Block 2	$0.00019
41 ISF	Block 1	$0.00048			Block 3	$0.00014
	Block 2	$0.00042			Block 4	$0.00011
41 CSI	Block 1	$0.00040			Block 5	$0.00008
	Block 2	$0.00035			Block 6	$0.00003
41 ISI	Block 1	$0.00037		42 CSI	Block 1	$0.00025
	Block 2	$0.00033			Block 2	$0.00022
41 CTF	Block 1	$0.00052			Block 3	$0.00017
	Block 2	$0.00046			Block 4	$0.00014
41ITF	Block 1	$0.00038			Block 5	$0.00009
	Block 2	$0.00033			Block 6	$0.00003
42 CSF	Block 1	$0.00034		42 ISI	Block 1	$0.00030
	Block 2	$0.00031			Block 2	$0.00027
	Block 3	$0.00024			Block 3	$0.00020
	Block 4	$0.00019			Block 4	$0.00016
	Block 5	$0.00013			Block 5	$0.00011
	Block 6	$0.00005			Block 6	$0.00004
42 ISF	Block 1	$0.00035		42 CTI	Block 1	$0.00015
	Block 2	$0.00031			Block 2	$0.00013
	Block 3	$0.00024			Block 3	$0.00010
	Block 4	$0.00019			Block 4	$0.00008
	Block 5	$0.00013			Block 5	$0.00005
	Block 6	$0.00005			Block 6	$0.00002
				42 ITI	Block 1	$0.00018
					Block 2	$0.00016
					Block 3	$0.00012
					Block 4	$0.00010
					Block 5	$0.00007
					Block 6	$0.00002
				43 TF		$0.00000
				43 TF		$0.00000

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

(N)

Issued August 29, 2025
NWN WUTC Advice No. 25-03

Effective with service on
and after September 30, 2025

SCHEDULE 238
ADJUSTMENTS TO RATES FOR PROVISIONAL CAPITAL ADJUSTMENT

(N)

PURPOSE: To identify adjustments to rates in the Rate Schedules listed below that relate to the capital with Rate Year 1 as authorized by the WUTC in Docket UG-250610.

APPLICABLE:
Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: September 30, 2025**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		$0.00000		42 CTF	Block 1	$0.00000
1C		$0.00000			Block 2	$0.00000
2R		$0.00000			Block 3	$0.00000
3C		$0.00000			Block 4	$0.00000
3I		$0.00000			Block 5	$0.00000
27		$0.00000			Block 6	$0.00000
41 CSF	Block 1	$0.00000		42 ITF	Block 1	$0.00000
	Block 2	$0.00000			Block 2	$0.00000
41 ISF	Block 1	$0.00000			Block 3	$0.00000
	Block 2	$0.00000			Block 4	$0.00000
41 CSI	Block 1	$0.00000			Block 5	$0.00000
	Block 2	$0.00000			Block 6	$0.00000
41 ISI	Block 1	$0.00000		42 CSI	Block 1	$0.00000
	Block 2	$0.00000			Block 2	$0.00000
41 CTF	Block 1	$0.00000			Block 3	$0.00000
	Block 2	$0.00000			Block 4	$0.00000
41ITF	Block 1	$0.00000			Block 5	$0.00000
	Block 2	$0.00000			Block 6	$0.00000
42 CSF	Block 1	$0.00000		42 ISI	Block 1	$0.00000
	Block 2	$0.00000			Block 2	$0.00000
	Block 3	$0.00000			Block 3	$0.00000
	Block 4	$0.00000			Block 4	$0.00000
	Block 5	$0.00000			Block 5	$0.00000
	Block 6	$0.00000			Block 6	$0.00000
42 ISF	Block 1	$0.00000		42 CTI	Block 1	$0.00000
	Block 2	$0.00000			Block 2	$0.00000
	Block 3	$0.00000			Block 3	$0.00000
	Block 4	$0.00000			Block 4	$0.00000
	Block 5	$0.00000			Block 5	$0.00000
	Block 6	$0.00000			Block 6	$0.00000
				42 ITI	Block 1	$0.00000
					Block 2	$0.00000
					Block 3	$0.00000
					Block 4	$0.00000
					Block 5	$0.00000
					Block 6	$0.00000
				43 TF		$0.00000
				43 TF		$0.00000

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

(N)

Issued August 29, 2025
NWN WUTC Advice No. 25-03

Effective with service on
and after September 30, 2025

SCHEDULE J
GAS RESIDENTIAL ENERGY ASSISTANCE TARIFF (GREAT)

APPLICABLE:
To Residential Customers ("Households") that take service under Rate Schedule 1 or Rate Schedule 2 of this Tariff and that have qualified for bill payment assistance through a NW Natural authorized Delivery Agent.

PROGRAM YEAR:
Funds will be made available under this program on a continuous twelve-month basis. For accounting and ratemaking purposes, the program year will extend from October 1 through September 30 ("Program Year").

PROGRAM FUNDING:
Total Program Funds (where Total Program Funds are equal to customer grants plus administrative and delivery costs) are subject to a combined program year cap of $750,000. This cap may be exceeded as need upon discussion and consensus of the GREAT Advisory Group. (C)

A surcharge will apply to the regular monthly bills of all Sales Service Class Customers that take service under Rate Schedules 1, 2, 3, 41 and 42. The surcharge will be designed to amortize the actual amount of Total Program Funds accumulated for the Program Year on an equal percent of margin basis, adjusted for revenue sensitive effects. The surcharge calculation will be included with the Company's Annual Purchased Gas Cost Adjustment filing, and will be effective November 1 of each year. The surcharge amount for the respective Rate Schedules will be set forth in Schedule 230 of this Tariff.

PROGRAM ADMINISTRATION AND DELIVERY:
This program will be administered through designated agencies ("Delivery Agents") that: (a) meet the criteria for a "Qualifying Organization" as defined in RCW 82.16.0497; (b) the Company determines is capable of meeting performance obligations under this program; and (c) executes a contract with the Company that is consistent with the terms of this Schedule.

Each Delivery Agent will have sole responsibility to screen and approve bill payment assistance applicants for eligibility. Each Agent shall follow the established protocols for the qualification of and disbursement to eligible participants in accordance with the guidelines established by the Washington Department of Commerce for disbursement of federal Low-Income Home Energy Assistance Program (LIHEAP) funds. Except that, for purposes of this program, income-eligibility will be based on gross household income (adjusted for household size) at or below 200% Federal Poverty Level (FPL) or 80% Area Median Income (AMI), whichever is greater. The GREAT Program will be available to eligible participants regardless of citizenship status.

(continue to Sheet J.2)

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

RATE YEAR 2 TARIFF SHEETS

PROPOSED

August 29, 2025

RATE SCHEDULE 1
GENERAL SALES SERVICE

AVAILABLE:
To all Residential and Commercial Customer classes in all territory served by the Company under the Tariff of which this Rate Schedule is a part, except that service under this Rate Schedule is not available for Standby Service to Commercial Customers. Seasonal or temporary Discontinuance of Service is allowed subject to Special Provision 1 of this Rate Schedule. The installation of Distribution Facilities, when required before service can be provided to equipment served under this Rate Schedule, is subject to the provisions of **Schedule E**.

SERVICE DESCRIPTION:
Service under this Rate Schedule is Firm Sales Service to gas-fired equipment, including but not limited to one or any multiple or combination of the following:

(a) Non-ducted space heating equipment that does not qualify as primary heating systems under Rate Schedule 2, including but not limited to fireplace inserts, free standing gas stoves, and room heaters;
(b) Supplemental or Standby space heating equipment including but not limited to natural gas back-up to electric heat pumps, used in residential applications;
(c) Water heating equipment used to serve single-family residential swimming pools, spas, and hot tubs;
(d) Other equipment including, but not limited to, log lighter, gas log, gas barbecue, tiki torch, Bunsen burner, Domestic cooking equipment, hobby kilns, refrigeration or Domestic clothes drying;
(e) Equipment installed for use in detached garages, shops, or outbuildings.

MONTHLY RATE: Effective: August 1, 2027 (C)
The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 200** for a list of applicable adjustments. Rates are subject to charges for purchased gas costs and technical rate adjustments.

	Base Rate	Pipeline Capacity Rate	Commodity Rate	Temporary Adjustment	Billing Rate	
Residential:						
Customer Charge	$10.00				$10.00	(I)
Schedule 308 Credits (per bill)				($1.82)	**($1.82)**	
Volumetric Charge (per therm)	$1.18963	$0.10337	$0.43274	$0.30287	**$2.02861**	(I)
Commercial:						
Customer Charge	$10.00				**$10.00**	(I)
Schedule 308 Credits (per bill)				$(5.34)	**($5.34)**	
Volumetric Charge (per therm)	$1.38304	$0.10337	$0.43274	$0.27790	**$2.19705**	(I)

Minimum Monthly Bill: Customer Charge, plus charges under **Schedule C** and **Schedule 10** (if applicable)

(continue to Sheet 101.2)

RATE SCHEDULE 2
RESIDENTIAL SALES SERVICE

AVAILABLE:
To Residential Customers, in all territory served by the Company under the Tariff of which this Rate Schedule is a part. Seasonal or temporary Discontinuance of Service is allowed subject to Special Provision 1 of this Rate Schedule. The installation of Distribution Facilities, when required before service can be provided to equipment served under this Rate Schedule, are subject to the provisions of **SCHEDULE E**.

SERVICE DESCRIPTION:
Service under this Rate Schedule is Firm Sales Service to gas-fired equipment used in Residential dwellings that provide complete family living facilities in which the occupant normally cooks, eats, sleeps, and carries on the household operations incident to Domestic life, for at least one of the following purposes:

(a) Operation of ducted forced air Natural Gas space heating equipment that is the primary source for space heating requirements;
(b) Operation of a gas-fired hearth product or wall heater as the primary source for space heating requirements where the hearth or wall heater has a verified nameplate rating of 20,000 BTUs or greater, and is installed in a primary residence defined as a dwelling that is occupied year-round, and where that dwelling is 1,500 square feet or less; and, or;
(c) Operation of fully automatic water heating equipment for primary water heating requirements.

Service under this Rate Schedule includes the use of gas for equipment installed in addition to (a) and (b).

MONTHLY RATE: Effective: August 1, 2027 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

	Base Rate	Pipeline Capacity Rate	Commodity Rate	Temporary Adjustment	Billing Rate	
Customer Charge:	$10.00				**$10.00**	(I)
Schedule 308 Credits - Winter (per bill)				($10.97)	**($10.97)**	
Schedule 308 Credits - Non-Winter (per bill)				($4.84)	**($4.84)**	
Volumetric Charge (per therm)	$0.90239	$0.10337	$0.43274	$0.22426	**$1.66276**	(I)

Minimum Monthly Bill: Customer Charge, plus charges under **Schedule C** and **Schedule 10** (if applicable)

RATE SCHEDULE 3
BASIC FIRM SALES SERVICE - NON-RESIDENTIAL
(continued)

MONTHLY RATE: Effective: August 1, 2027 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM SALES SERVICE CHARGES (03 SF):					**Billing Rates [1]**	
Customer Charge (per month):					**$22.00**	
	Base Rate	Pipeline Capacity	Commodity Component [2]	Temporary Adjustment		
Schedule 308 Credits (per bill):						
Commercial - Winter				($46.59)	**($46.59)**	
Commercial - Non-Winter				($25.89)	**($25.89)**	
Industrial				($129.16)	**($129.16)**	
Volumetric Charges (per therm):						
Commercial	$0.90033	$0.10337	$0.43274	$0.21182	**$1.64826**	(I)
Industrial	$0.85917	$0.10337	$0.43274	$0.15298	**$1.54826**	(I)
Standby Charge (per therm of MHDV) [3]:					**$5.00**	

[1] **Schedule C** and **Schedule 10** Charges shall apply, if applicable.
[2] The Commodity Component will be either Annual Sales WACOG or Monthly Incremental Cost of Gas.
[3] Applies to Standby Sales Service only.

Minimum Monthly Bill. The Minimum Monthly Bill shall be any **Schedule C** and **Schedule 10** Charges, plus:

(a) ***Firm Sales Service.*** Customer Charge
(b) ***Firm Sales Standby Service.*** Customer Charge, plus Standby Service Charge

RATE SCHEDULE 10
CHARGES FOR SPECIAL METERING EQUIPMENT, RENTAL METERS AND METERING SERVICES
(continued)

Metering Services and Charges	One Time Charge	Installation Charge	Monthly Charge	
Rental Read	---	---	$0.36	
Advanced Automated Meter Reading (AAMR) Device[1]	---	$1,270.53	$52.75	(I)
Remote Index	---	$50.00	$4.00	
Pulse Output	---	$100.00	$8.00	
Administrative Set-Up/Consultation Fee (all meters)	$145.00	---	---	(I)
Technical Assistance (Rotary meters only)	$145.00	---	---	(I)

[1] Site specific engineering design costs for AAMR will be added to the installation charge if needed.

SPECIAL PROVISIONS FOR RENTAL METERS AND SPECIAL METERING EQUIPMENT:

1. Prior to receiving service under this section of the Schedule, the Customer must sign a service agreement that requires a minimum 12-month term. Customers who terminate service after less than 12 months will be required to pay all charges otherwise due to fulfill the 12-month obligation under the service agreement.
2. Service under this section of this Schedule is voluntary and separate from billing for or delivery of natural gas to a Customer's premise.
3. Since the Company does not maintain an inventory of all meter types offered under this Schedule, a delay may occur from the time a Customer requests service under this Schedule until the Company can provide it.
4. The Customer will be responsible for the meter pick-up and return of diaphragm meters.
5. The Customer will incur the Administrative Set-Up/Consultation Fee for each rental meter.
6. Upon delivery of a rotary meter, the Customer will incur the Technical Assistance charge listed above for each rental rotary meter. A Customer may not waive this provision or the associated fee. Technical assistance helps the Company ensure proper handling of rotary meters.
7. The Company will install AAMR devices for the charge listed above. AAMR devices will only be installed on Company owned meters and the Company will require that the Customer provide active and continuous electric power per company specifications to enable meter communications.
8. Upon request, the Company will provide one differential test per calendar year on rotary meters. The testing will be scheduled at the Company's convenience.
9. The Customer is responsible to protect all rental equipment from damage including but not limited to installing parking bollards to protect the rental equipment from vehicular or other damage.

(continue to Sheet 110.3)

RATE SCHEDULE 27
RESIDENTIAL HEATING DRY-OUT SERVICE

AVAILABLE:
To Residential home builders, developers, and contractors during the period that a Residential dwelling is under construction, in all territory served by the Company under the Tariff of which this schedule is a part.

SERVICE DESCRIPTION:
Service under this Rate Schedule is restricted to the use of gas in approved permanently-installed gas heating equipment in place during the period the dwelling is under construction. Upon occupancy of the dwelling, service under this Rate Schedule shall terminate automatically. In no event will service under this Rate Schedule continue for more a period of time greater than twelve (12) months from the date the gas meter is set at the dwelling. Upon termination of service under this Rate Schedule, gas service shall transfer to **Schedule 1** or **Schedule 2**, whichever is applicable.

MONTHLY RATE: Effective: August 1, 2027 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 200** for a list of applicable adjustments. Rates are subject to charges for purchased gas costs and technical rate adjustments.

	Base Rate	Pipeline Capacity Rate	Commodity Rate	Temporary Adjustment	Billing Rate
Customer Charge:	$9.00	---	---	---	**$9.00**
Volumetric Charge (per therm)					
All therms	$0.89745	$0.10337	$0.43274	$0.27052	**$1.70408** (I)

Minimum Monthly Bill: Customer Charge, plus charges under **Schedule C** and **Schedule 10** (if applicable)

GENERAL TERMS:
Service under this Rate Schedule is governed by the terms of this Rate Schedule, the General Rules and Regulations contained in this Tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

RATE SCHEDULE 41
NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES FOR COMMERCIAL CUSTOMER CLASS: Effective: August 1, 2027 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. **SEE SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM SALES SERVICE CHARGES (C41SF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$250.00**	
	Base Rate		Commodity Component [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($515.09)	**($515.09)**	
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	$0.69165		$0.43274	$0.19297	**$1.31736**	(I)
Block 2: All additional therms	$0.60945		$0.43274	$0.18381	**$1.22600**	(I)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.10337**	
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.54**	
INTERRUPTIBLE SALES SERVICE CHARGES (C41SI) [1]:						
Customer Charge (per month):					**$250.00**	
	Base Rate		Commodity Component: [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($515.09)	($515.09)	
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	$0.57062		$0.43274	$0.14883	**$1.15219**	(I)
Block 2: All additional therms	$0.50276		$0.43274	$0.14056	**$1.07606**	(I)
Plus: Interruptible Pipeline Capacity Charge - Volumetric (per therm):					**$0.03612**	
FIRM TRANSPORTATION SERVICE CHARGES (C41TF):						
Customer Charge (per month):					**$250.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Total Temporary Adjustments [4]		
Schedule 308 Credits (per bill):				($515.09)	**($515.09)**	
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	$0.57719			$0.26465	**$0.84184**	(I)
Block 2: All additional therms	$0.50855			$0.26192	**$0.77047**	(I)

[1] The Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from Schedule C and Schedule 10.

[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG, or Monthly Incremental Cost of Gas.

[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 may not apply.

(continue to Sheet 141.10)

RATE SCHEDULE 41
NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES FOR INDUSTRIAL CUSTOMER CLASS: Effective: August 1, 2027 (C)
The rates shown in this Rate Schedule may not always reflect actual billing rates. **SEE SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM SALES SERVICE CHARGES (I41SF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$250.00**	
	Base Rate		Commodity Component [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($622.72)	**($622.72)**	
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	$0.55452		$0.43274	$0.14389	**$1.13115**	(I)
Block 2: All additional therms	$0.48859		$0.43274	$0.14070	**$1.06203**	(I)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.10337**	
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.54**	
INTERRUPTIBLE SALES SERVICE CHARGES (I41SI) [1]:						
Customer Charge (per month):					**$250.00**	
	Base Rate		Commodity Component: [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($622.72)	**($622.72)**	
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	$0.53983		$0.43274	$0.10769	**$1.08026**	(I)
Block 2: All additional therms	$0.47561		$0.43274	$0.10441	**$1.01276**	(I)
Plus: Interruptible Pipeline Capacity Charge - Volumetric (per therm):					**$0.03612**	
FIRM TRANSPORTATION SERVICE CHARGES (I41TF):						
Customer Charge (per month):					**$250.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Total Temporary Adjustments [4]		
Schedule 308 Credits (per bill):				($622.72)	**($622.72)**	
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	$0.54581			$0.26254	**$0.80835**	(I)
Block 2: All additional therms	$0.48089			$0.26007	**$0.74096**	(I)

[1] The Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from Schedule C and Schedule 10.
[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG, or Monthly Incremental Cost of Gas.
[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 may not apply.

RATE SCHEDULE 42
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY SALES RATES - FIRM SERVICE: Effective: August 1, 2027 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM SALES SERVICE CHARGES [1]:					**Billing Rates**	
Customer Charge (per month, all service types):					**$1,300.00**	
	Base Rate		Commodity Component [2]	Total Temporary Adjustments [3]		
C42SF						
Schedule 308 Credits (per bill):				($5,142.27)	($5,142.27)	
Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	$0.38199		$0.43274	$0.15902	$0.97375	(I)
Block 2: Next 20,000 therms	$0.34193		$0.43274	$0.15450	$0.92917	
Block 3: Next 20,000 therms	$0.26226		$0.43274	$0.14550	$0.84050	
Block 4: Next 100,000 therms	$0.20977		$0.43274	$0.13958	$0.78209	
Block 5: Next 600,000 therms	$0.13984		$0.43274	$0.13167	$0.70425	
Block 6: All additional therms	$0.05242		$0.43274	$0.12179	$0.60695	(I)
I42SF						
Schedule 308 Credits (per bill):				($3,945.77)	($3,945.77)	
Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	$0.30071		$0.43274	$0.13417	$0.86762	(I)
Block 2: Next 20,000 therms	$0.26917		$0.43274	$0.13235	$0.83426	
Block 3: Next 20,000 therms	$0.20640		$0.43274	$0.12874	$0.76788	
Block 4: Next 100,000 therms	$0.16512		$0.43274	$0.12635	$0.72421	
Block 5: Next 600,000 therms	$0.11013		$0.43274	$0.12318	$0.66605	
Block 6: All additional therms	$0.04125		$0.43274	$0.11920	$0.59319	(I)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	
Firm Sales Service Storage Charge (per therm of MDDV per month):					**$0.20415**	
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.10337**	
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV per month):					**$1.54**	

[1] For Firm Sales Service, the Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Distribution Capacity Charge, plus the Storage Capacity Charge, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from Schedule C or Schedule 10.

[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG or Monthly Incremental Cost of Gas.

[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 may not apply.

(continue to Sheet 142.10.1)

RATE SCHEDULE 42
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY SALES RATES – INTERRUPTIBLE SERVICE: Effective: August 1, 2027 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

INTERRUPTIBLE SALES SERVICE CHARGES [1]: (C42SI)					**Billing Rates**	
Customer Charge (per month):					**$1,300.00**	
	Base Rate		Commodity Component [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($5,142.27)	**($5,142.27)**	
Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	$0.29512		$0.43274	$0.11093	**$0.83879**	(I)
Block 2: Next 20,000 therms	$0.26417		$0.43274	$0.10760	**$0.80451**	
Block 3: Next 20,000 therms	$0.20255		$0.43274	$0.10096	**$0.73625**	
Block 4: Next 100,000 therms	$0.16205		$0.43274	$0.09660	**$0.69139**	
Block 5: Next 600,000 therms	$0.10807		$0.43274	$0.09080	**$0.63161**	
Block 6: All additional therms	$0.04053		$0.43274	$0.08348	**$0.55675**	(I)
Interruptible Pipeline Capacity Charge (per therm):					**$0.03612**	
Interruptible Sales Service Storage Charge (per therm of MDDV per month)					**$0.10208**	
INTERRUPTIBLE SALES SERVICE CHARGES [1]: (I42SI)						
Customer Charge (per month):					**$1,300.00**	
Schedule 308 Credits (per bill):				($3,945.77)	**($3,945.77)**	
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	$0.27732		$0.43274	$0.09556	**$0.80562**	(I)
Block 2: Next 20,000 therms	$0.24824		$0.43274	$0.09394	**$0.77492**	
Block 3: Next 20,000 therms	$0.19035		$0.43274	$0.09072	**$0.71381**	
Block 4: Next 100,000 therms	$0.15230		$0.43274	$0.08858	**$0.67362**	
Block 5: Next 600,000 therms	$0.10151		$0.43274	$0.08575	**$0.62000**	
Block 6: All additional therms	$0.03805		$0.43274	$0.08223	**$0.55302**	(I)
Interruptible Pipeline Capacity Charge (per therm):					**$0.03612**	
Interruptible Sales Service Storage Charge (per therm of MDDV per month)					**$0.10208**	

[1] For Interruptible Sales Service, the Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge, plus any other charges that apply from Schedule C or Schedule 10.
[2] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 201 may also apply.
[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 may not apply.

(continue to Sheet 142.11)

RATE SCHEDULE 42
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY TRANSPORTATION RATES: Effective: August 1, 2027 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (C42TI) [1]:					**Billing Rates**	
Customer Charge (per month):					**$1,300.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Temporary Adjustments [2]		
Schedule 308 Credits (per bill):				($5,142.27)	**($5,142.27)**	
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	$0.21026			$0.24975	**$0.46001**	(I)
Block 2: Next 20,000 therms	$0.18823			$0.24893	**$0.43716**	
Block 3: Next 20,000 therms	$0.14434			$0.24725	**$0.39159**	
Block 4: Next 100,000 therms	$0.11547			$0.24616	**$0.36163**	
Block 5: Next 600,000 therms	$0.07701			$0.24469	**$0.32170**	
Block 6: All additional therms	$0.02885			$0.24286	**$0.27171**	(I)
INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (I42TI) [1]:					**Billing Rates**	
Customer Charge (per month):					**$1,300.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Temporary Adjustments [2]		
Schedule 308 Credits (per bill):				($3,945.77)	**($3,945.77)**	
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	$0.21245			$0.24987	**$0.46232**	(I)
Block 2: Next 20,000 therms	$0.19017			$0.24904	**$0.43921**	
Block 3: Next 20,000 therms	$0.14583			$0.24735	**$0.39318**	
Block 4: Next 100,000 therms	$0.11668			$0.24625	**$0.36293**	
Block 5: Next 600,000 therms	$0.07780			$0.24478	**$0.32258**	
Block 6: All additional therms	$0.02918			$0.24294	**$0.27212**	(I)

[1] For Interruptible Transportation Service, the Monthly Bill shall equal the sum of the Customer Charge, plus Transportation Charge, plus the Volumetric Charges, plus any other charges that may apply from Schedule C or Schedule 10.

[2] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 201 may also apply.

(continue to Sheet 142.12)

RATE SCHEDULE 42
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

FIRM TRANSPORTATION SERVICE CHARGES (C42TF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$1,300.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Total Temporary Adjustments [2]		
Schedule 308 Credits (per bill):				($5,142.27)	**($5,142.27)**	
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	$0.25976			$0.25028	**$0.51004**	(I)
Block 2: Next 20,000 therms	$0.23254			$0.24940	**$0.48194**	
Block 3: Next 20,000 therms	$0.17831			$0.24763	**$0.42594**	
Block 4: Next 100,000 therms	$0.14267			$0.24649	**$0.38916**	
Block 5: Next 600,000 therms	$0.09511			$0.24493	**$0.34004**	
Block 6: All additional therms	$0.03566			$0.24301	**$0.27867**	(I)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	
FIRM TRANSPORTATION SERVICE CHARGES (I42TF) [1]:						
Customer Charge (per month):					**$1,300.00**	
Transportation Charge (per month):					**$250.00**	
Schedule 308 Credits (per bill):				($3,945.77)	**($3,945.77)**	
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	$0.23078			$0.25022	**$0.48100**	(I)
Block 2: Next 20,000 therms	$0.20659			$0.24934	**$0.45593**	
Block 3: Next 20,000 therms	$0.15841			$0.24760	**$0.40601**	
Block 4: Next 100,000 therms	$0.12675			$0.24644	**$0.37319**	
Block 5: Next 600,000 therms	$0.08449			$0.24490	**$0.32939**	
Block 6: All additional therms	$0.03168			$0.24300	**$0.27468**	(I)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	

[1] For Firm Transportation Service, the Monthly Bill shall equal the sum of the Customer Charge, plus Transportation Charge, plus the Volumetric Charges, plus the Distribution Capacity Charge, plus any other charges that may apply from Schedule C or Schedule 10.

[2] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 201 may also apply.

RATE SCHEDULE 43
HIGH VOLUME NON-RESIDENTIAL
FIRM AND INTERRUPTIBLE TRANSPORTATION SERVICE
(continued)

MONTHLY RATE: Effective: August 1, 2027 (C)

The rates shown below may not always reflect actual billing rates. See **Schedule 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM TRANSPORTATION SERVICE CHARGES (C43TF and I43TF)					
					Billing Rates
Customer Charge:					**$38,000.00**
Transportation Charge:					**$250.00**
Volumetric Charge	Base Rate			Total Temporary Adjustment [1]	
Per therm, all therms	$0.00733			$ 0.24194	**$0.24927** (I)
Firm Service Distribution Capacity Charge: Per therm of MDDV per month					**$0.15748**

Minimum Monthly Bill: Customer Charge, plus Transportation Charge, plus Firm Service Distribution Capacity Charge, plus any other charges that may apply from **Schedule C** and **Schedule 10**.

INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (C43TI and I43TI)					
					Billing Rates
Customer Charge:					**$38,000.00**
Transportation Charge:					**$250.00**
Volumetric Charge:	Base Rate			Total Temporary Adjustment [1]	
Per therm, all therms	$0.00733			$ 0.24194	**$0.24927** (I)
Minimum Monthly Bill: Customer Charge, plus Transportation Charge, plus any other charges that may apply from **Schedule C** and **Schedule 10**.					

[1] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 shall apply.

SCHEDULE 200
SUMMARY OF ADJUSTMENTS

PURPOSE:
The purpose of this Schedule is to list and summarize the adjustment Schedules applicable to each of the Company's Rate Schedules.

SCHEDULE	A	201	203	207	210	212	215	220	221	230	232	233	234	235	236	237	238	303	305	306	308
R1	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
C1	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
2	ADD	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
03CSF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
03ISF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
10	ADD			INC																	
27	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
C41SF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
C41SI	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
C41TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I41SF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I41SI	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I41TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C42SF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
C42SI	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC
C42TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C42TI	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I42SF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I42SI	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I42TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I42TI	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C43TI/ I43TI	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C43TF/ I43TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC

(N)

(N)

Table Code Key:

ADD This adjustment is added to the billing rates at the time the bill is issued.
INC This adjustment is included in the billing rates shown on the Rate Schedule

(continue to Sheet 200.2)

SCHEDULE 200
SUMMARY OF ADJUSTMENTS
(continued)

The following is a brief description of the applicable Schedules:

Schedule A "Billing for City and County Exactions."
This adjustment will be reflected directly on Customer bills.

Schedule 201 "Temporary (Technical) Adjustments to Rates."
These are temporary Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 203 "Purchased Gas Cost Adjustments to Rates."
These are pipeline capacity and commodity charges.

Schedule 207 "General Adjustments to Rates."
These are Base Rate Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 210 "Adjustment to Rates for Property Sales."
These are Temporary Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 212 "Adjustment to Rates Residential Rate Mitigation."
These are Temporary Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 215 "Adjustment to Rates for Energy Conservation Programs."
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 220 "Special Rate Adjustment."
These are Base Rate Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 221 "Rate Adjustment for Updated Depreciation Rates"
These are Base Rate Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 230 "Temporary Adjustments to Rates for Low-Income Programs."
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 231 "Temporary Adjustments to Rates for Residential Discount Program."
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 232 "Temporary Adjustments to Rates for Regulatory Fee Increase"
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 233 "Temporary Adjustments to Rates for Industrial Customer Energy Efficiency Audit Costs"
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 234 "Temporary Adjustments to Rates for Residential Arrearage Management Program" (N)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 235 "Temporary Adjustments to Rates for COVID-19 Public Health Emergency" (N)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills. (N)

(K)

(K) Schedules 303, 305, 306 and 308 transferred to Sheet 200.3.

(continue to Sheet 200.3)

SCHEDULE 200
SUMMARY OF ADJUSTMENTS
(continued)

Schedule 236 "Temporary Adjustments to Rates for Meter Modernization Program." (N)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 237 "Temporary Adjustments to Rates for TSA Operations and Maintenance Costs." (N)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 238 "Adjustments to Rates for Provisional Capital Adjustment." (N)
These are base rate adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 303 "Washington Environmental Cost Recovery Mechanism." (M)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 305 "Adjustment for Certain Income Taxes (2017 Federal Tax Cuts and Jobs Act)."
These are base and temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 306 "Multi-Year Rate Plan Adjustment."
These are base rate adjustments that will be added to the Billing Rate on the effective date of the Schedule.

Schedule 308 "Washington Climate Commitment Act Recovery Mechanism."
These are temporary rate adjustments that will be added to the Billing Rate on the effective date of the Schedule. (M)

(M) Schedules 303, 305, 306 and 308 transferred from Sheet 200.2.

SCHEDULE 207
GENERAL RATE ADJUSTMENT

PURPOSE:
To identify the effects of general rate changes approved in the company's most recent general rate case proceeding (Docket UG-200994)

APPLICATION TO RATE SCHEDULES: Effective: August 1, 2027 (C)

Rate Schedule 1	Rate Schedule 3	Rate Schedule 41	Rate Schedule 43
Rate Schedule 2	Rate Schedule 27	Rate Schedule 42	

The Base Rates in the listed Rate Schedules include the adjustment shown below.
NO FURTHER ADJUSTMENT TO RATES IS REQUIRED.

SCHEDULES	BLOCKS	AMOUNT	
Schedule 1 - Residential	Customer Charge	$2.00	(I)
	Per Therm (all therms)	$0.02832	(R)
Schedule 1 - Commercial	Customer Charge	$0.00	
	Per Therm (all therms)	$0.13837	(I)
Schedule 2	Customer Charge	$2.00	(I)
	Per Therm (all therms)	$0.05895	(I)
Schedule 3 - Commercial	Customer Charge	$0.00	
	Per Therm (all therms)	$0.08715	(I)
Schedule 3 - Industrial	Customer Charge	$0.00	
	Per Therm (all therms)	$0.07956	(I)
Schedule 27	Customer Charge	$0.00	
	Per Therm (all therms)	$0.09757	(I)
Schedule 41 - Commercial Firm Sales Service	Customer Charge	$0.00	
	First 2,000 therms	$ 0.06933	(I)
	All additional therms	$ 0.06109	(I)
Schedule 41 - Commercial Interruptible Sales Service	Customer Charge	$0.00	
	First 2,000 therms	$ 0.03733	(I)
	All additional therms	$ 0.03289	(I)
Schedule 41 - Industrial Firm Sales Service	Customer Charge	$0.00	
	First 2,000 therms	$ 0.05666	(I)
	All additional therms	$ 0.04992	(I)
Schedule 41 - Industrial Interruptible Sales Service	Customer Charge	$0.00	
	First 2,000 therms	$ 0.03532	(I)
	All additional therms	$ 0.03112	(I)
Schedule 41 - Commercial Firm Transportation Service	Customer Charge	$0.00	
	First 2,000 therms	$ 0.06187	(I)
	All additional therms	$ 0.05451	(I)
Schedule 41 - Industrial Firm Transportation Service	Customer Charge	$0.00	
	First 2,000 therms	$ 0.03571	(I)
	All additional therms	$ 0.03146	(I)

(continue to Sheet 207.2)

SCHEDULE 207
GENERAL RATE ADJUSTMENT
(continued)

SCHEDULES	BLOCKS	AMOUNT	
Schedule 42 Commercial - Firm Sales Service	Customer Charge	$0.00	
	First 10,000 therms	0.04425	(I)
	Next 20,000 therms	0.03961	
	Next 20,000 therms	0.03038	
	Next 100,000 therms	0.02430	
	Next 600,000 therms	0.01620	
	All additional therms	0.00607	(I)
Schedule 42 Commercial - Interruptible Sales Service	Customer Charge	$0.00	
	First 10,000 therms	0.03175	(I)
	Next 20,000 therms	0.02842	
	Next 20,000 therms	0.02179	
	Next 100,000 therms	0.01744	
	Next 600,000 therms	0.01163	
	All additional therms	0.00436	(I)
Schedule 42 Industrial - Firm Sales Service	Customer Charge	$0.00	
	First 10,000 therms	0.04158	(I)
	Next 20,000 therms	0.03722	
	Next 20,000 therms	0.02854	
	Next 100,000 therms	0.02283	
	Next 600,000 therms	0.01523	
	All additional therms	0.00570	(I)
Schedule 42 Industrial - Interruptible Sales Service	Customer Charge	$0.00	
	First 10,000 therms	0.03596	(I)
	Next 20,000 therms	0.03219	
	Next 20,000 therms	0.02468	
	Next 100,000 therms	0.01975	
	Next 600,000 therms	0.01316	
	All additional therms	0.00493	(I)

(continue to Sheet 207.3)

SCHEDULE 207
GENERAL RATE ADJUSTMENT
(continued)

SCHEDULES	BLOCKS	AMOUNT	
Schedule 42 Commercial - Firm Transportation Service	Customer Charge	$0.00	
	First 10,000 therms	0.03270	(I)
	Next 20,000 therms	0.02927	
	Next 20,000 therms	0.02244	
	Next 100,000 therms	0.01796	
	Next 600,000 therms	0.01197	
	All additional therms	0.00449	(I)
Schedule 42 Industrial - Firm Transportation Service	Customer Charge	$0.00	
	First 10,000 therms	0.02457	(I)
	Next 20,000 therms	0.02200	
	Next 20,000 therms	0.01687	
	Next 100,000 therms	0.01350	
	Next 600,000 therms	0.00900	
	All additional therms	0.00337	(I)
Schedule 42 - Commercial Interruptible Transportation Service	Customer Charge	$0.00	
	First 10,000 therms	0.01376	(I)
	Next 20,000 therms	0.01231	
	Next 20,000 therms	0.00944	
	Next 100,000 therms	0.00755	
	Next 600,000 therms	0.00504	
	All additional therms	0.00189	(I)
Schedule 42 - Industrial Interruptible Transportation Service	Customer Charge	$0.00	
	First 10,000 therms	0.02116	(I)
	Next 20,000 therms	0.01894	
	Next 20,000 therms	0.01452	
	Next 100,000 therms	0.01162	
	Next 600,000 therms	0.00775	
	All additional therms	0.00291	(I)

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time

Issued August 29, 2025
NWN WUTC Advice No. 25-03

Effective with service on and after August 1,2027

(N)

SCHEDULE 235
TEMPORARY ADJUSTMENTS TO RATES FOR COVID-19 PUBLIC HEALTH EMERGENCY

PURPOSE: To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of deferred amounts for the costs and savings incurred due to the COVID-19 pandemic, as authorized for deferred accounting by the WUTC in Docket UG-200264.

APPLICABLE:
Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: August 1, 2027**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		$0.00290		42 CTF	Block 1	$0.00075
1C		$0.00240			Block 2	$0.00067
2R		$0.00178			Block 3	$0.00051
3C		$0.00156			Block 4	$0.00041
3I		$0.00142			Block 5	$0.00027
27		$0.00175			Block 6	$0.00010
41 CSF	Block 1	$0.00124		42 ITF	Block 1	$0.00047
	Block 2	$0.00109			Block 2	$0.00042
41 ISF	Block 1	$0.00101			Block 3	$0.00033
	Block 2	$0.00089			Block 4	$0.00026
41 CSI	Block 1	$0.00106			Block 5	$0.00017
	Block 2	$0.00094			Block 6	$0.00007
41 ISI	Block 1	$0.00103		42 CSI	Block 1	$0.00057
	Block 2	$0.00091			Block 2	$0.00051
41 CTF	Block 1	$0.00111			Block 3	$0.00039
	Block 2	$0.00098			Block 4	$0.00031
41ITF	Block 1	$0.00104			Block 5	$0.00021
	Block 2	$0.00092			Block 6	$0.00008
42 CSF	Block 1	$0.00087		42 ISI	Block 1	$0.00064
	Block 2	$0.00078			Block 2	$0.00058
	Block 3	$0.00060			Block 3	$0.00044
	Block 4	$0.00048			Block 4	$0.00035
	Block 5	$0.00032			Block 5	$0.00024
	Block 6	$0.00012			Block 6	$0.00009
42 ISF	Block 1	$0.00088		42 CTI	Block 1	$0.00040
	Block 2	$0.00079			Block 2	$0.00036
	Block 3	$0.00061			Block 3	$0.00027
	Block 4	$0.00049			Block 4	$0.00022
	Block 5	$0.00032			Block 5	$0.00015
	Block 6	$0.00012			Block 6	$0.00005
				42 ITI	Block 1	$0.00038
					Block 2	$0.00034
					Block 3	$0.00026
					Block 4	$0.00021
					Block 5	$0.00014
					Block 6	$0.00005
				43 TF		$0.00000
				43 TF		$0.00000

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

(N)

Issued August 29, 2025
NWN WUTC Advice No. 25-03

Effective with service on
and after August 1, 2027

SCHEDULE 236
TEMPORARY ADJUSTMENTS TO RATES FOR METER MODERNIZATION PROGRAM

(N)

PURPOSE: To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of deferred amounts for the costs related to the Company's Meter Modernization Program, as authorized for deferred accounting by the WUTC in Docket UG-240012.

APPLICABLE:
Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: August 1, 2027**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		$0.00125		42 CTF	Block 1	$0.00032
1C		$0.00105			Block 2	$0.00029
2R		$0.00077			Block 3	$0.00022
3C		$0.00067			Block 4	$0.00018
3I		$0.00061			Block 5	$0.00012
27		$0.00076			Block 6	$0.00004
41 CSF	Block 1	$0.00054		42 ITF	Block 1	$0.00020
	Block 2	$0.00047			Block 2	$0.00018
41 ISF	Block 1	$0.00044			Block 3	$0.00014
	Block 2	$0.00039			Block 4	$0.00011
41 CSI	Block 1	$0.00039			Block 5	$0.00007
	Block 2	$0.00035			Block 6	$0.00003
41 ISI	Block 1	$0.00037		42 CSI	Block 1	$0.00025
	Block 2	$0.00033			Block 2	$0.00022
41 CTF	Block 1	$0.00048			Block 3	$0.00017
	Block 2	$0.00042			Block 4	$0.00013
41ITF	Block 1	$0.00038			Block 5	$0.00009
	Block 2	$0.00033			Block 6	$0.00003
42 CSF	Block 1	$0.00037		42 ISI	Block 1	$0.00028
	Block 2	$0.00034			Block 2	$0.00025
	Block 3	$0.00026			Block 3	$0.00019
	Block 4	$0.00021			Block 4	$0.00015
	Block 5	$0.00014			Block 5	$0.00010
	Block 6	$0.00005			Block 6	$0.00004
42 ISF	Block 1	$0.00038		42 CTI	Block 1	$0.00014
	Block 2	$0.00034			Block 2	$0.00013
	Block 3	$0.00026			Block 3	$0.00010
	Block 4	$0.00021			Block 4	$0.00008
	Block 5	$0.00014			Block 5	$0.00005
	Block 6	$0.00005			Block 6	$0.00002
				42 ITI	Block 1	$0.00016
					Block 2	$0.00015
					Block 3	$0.00011
					Block 4	$0.00009
					Block 5	$0.00006
					Block 6	$0.00002
				43 TF		$0.00000
				43 TF		$0.00000

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

(N)

Issued August 29, 2025 Effective with service on
NWN WUTC Advice No. 25-03 and after August 1, 2027

SCHEDULE 237
TEMPORARY ADJUSTMENTS TO RATES FOR TSA OPERATIONS AND MAINTENANCE COSTS

(N)

PURPOSE: To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of deferred amounts for the start-up Operations and Maintenance costs incurred for compliance with TSA Security Directives, as authorized for deferred accounting by the WUTC in Docket UG-210900.

APPLICABLE:
Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: August 1, 2027**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		$0.00122		42 CTF	Block 1	$0.00031
1C		$0.00100			Block 2	$0.00028
2R		$0.00075			Block 3	$0.00021
3C		$0.00066			Block 4	$0.00017
3I		$0.00060			Block 5	$0.00011
27		$0.00074			Block 6	$0.00004
41 CSF	Block 1	$0.00052		42 ITF	Block 1	$0.00020
	Block 2	$0.00046			Block 2	$0.00018
41 ISF	Block 1	$0.00043			Block 3	$0.00014
	Block 2	$0.00038			Block 4	$0.00011
41 CSI	Block 1	$0.00038			Block 5	$0.00007
	Block 2	$0.00034			Block 6	$0.00003
41 ISI	Block 1	$0.00036		42 CSI	Block 1	$0.00024
	Block 2	$0.00032			Block 2	$0.00021
41 CTF	Block 1	$0.00047			Block 3	$0.00016
	Block 2	$0.00041			Block 4	$0.00013
41ITF	Block 1	$0.00037			Block 5	$0.00009
	Block 2	$0.00032			Block 6	$0.00003
42 CSF	Block 1	$0.00036		42 ISI	Block 1	$0.00027
	Block 2	$0.00033			Block 2	$0.00024
	Block 3	$0.00025			Block 3	$0.00019
	Block 4	$0.00020			Block 4	$0.00015
	Block 5	$0.00013			Block 5	$0.00010
	Block 6	$0.00005			Block 6	$0.00004
42 ISF	Block 1	$0.00037		42 CTI	Block 1	$0.00014
	Block 2	$0.00033			Block 2	$0.00013
	Block 3	$0.00026			Block 3	$0.00010
	Block 4	$0.00020			Block 4	$0.00008
	Block 5	$0.00014			Block 5	$0.00005
	Block 6	$0.00005			Block 6	$0.00002
				42 ITI	Block 1	$0.00016
					Block 2	$0.00014
					Block 3	$0.00011
					Block 4	$0.00009
					Block 5	$0.00006
					Block 6	$0.00002
				43 TF		$0.00000
				43 TF		$0.00000

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

(N)

Issued August 29, 2025
NWN WUTC Advice No. 25-03

Effective with service on
and after August 1, 2027

SCHEDULE 238
ADJUSTMENTS TO RATES FOR PROVISIONAL CAPITAL ADJUSTMENT

(N)

PURPOSE: To identify adjustments to rates in the Rate Schedules listed below that relate to the capital with Rate Year 1 as authorized by the WUTC in Docket UG-250610.

APPLICABLE:
Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: August 1, 2027**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		0.04621		42 CTF	Block 1	0.00684
1C		0.04041			Block 2	0.00613
2R		0.02622			Block 3	0.00470
3C		0.02569			Block 4	0.00376
3I		0.02192			Block 5	0.00251
27		0.04463			Block 6	0.00094
41 CSF	Block 1	0.01910		42 ITF	Block 1	0.00514
	Block 2	0.01683			Block 2	0.00460
41 ISF	Block 1	0.01186			Block 3	0.00353
	Block 2	0.01045			Block 4	0.00282
41 CSI	Block 1	0.01341			Block 5	0.00188
	Block 2	0.01182			Block 6	0.00071
41 ISI	Block 1	0.01269		42 CSI	Block 1	0.00875
	Block 2	0.01118			Block 2	0.00783
41 CTF	Block 1	0.01295			Block 3	0.00601
	Block 2	0.01141			Block 4	0.00480
41ITF	Block 1	0.01283			Block 5	0.00320
	Block 2	0.01130			Block 6	0.00120
42 CSF	Block 1	0.01219		42 ISI	Block 1	0.00753
	Block 2	0.01091			Block 2	0.00674
	Block 3	0.00837			Block 3	0.00517
	Block 4	0.00670			Block 4	0.00413
	Block 5	0.00446			Block 5	0.00276
	Block 6	0.00167			Block 6	0.00103
42 ISF	Block 1	0.00870		42 CTI	Block 1	0.00494
	Block 2	0.00779			Block 2	0.00442
	Block 3	0.00597			Block 3	0.00339
	Block 4	0.00478			Block 4	0.00271
	Block 5	0.00319			Block 5	0.00181
	Block 6	0.00119			Block 6	0.00068
				42 ITI	Block 1	0.00443
					Block 2	0.00396
					Block 3	0.00304
					Block 4	0.00243
					Block 5	0.00162
					Block 6	0.00061
				43 TF		0.00017
				43 TF		0.00017

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

(N)

Issued August 29, 2025
NWN WUTC Advice No. 25-03

Effective with service on
and after August 1, 2027

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

RATE YEAR 3 TARIFF SHEETS

PROPOSED

August 29, 2025

RATE SCHEDULE 1
GENERAL SALES SERVICE

AVAILABLE:
To all Residential and Commercial Customer classes in all territory served by the Company under the Tariff of which this Rate Schedule is a part, except that service under this Rate Schedule is not available for Standby Service to Commercial Customers. Seasonal or temporary Discontinuance of Service is allowed subject to Special Provision 1 of this Rate Schedule. The installation of Distribution Facilities, when required before service can be provided to equipment served under this Rate Schedule, is subject to the provisions of **Schedule E**.

SERVICE DESCRIPTION:
Service under this Rate Schedule is Firm Sales Service to gas-fired equipment, including but not limited to one or any multiple or combination of the following:

(a) Non-ducted space heating equipment that does not qualify as primary heating systems under Rate Schedule 2, including but not limited to fireplace inserts, free standing gas stoves, and room heaters;
(b) Supplemental or Standby space heating equipment including but not limited to natural gas back-up to electric heat pumps, used in residential applications;
(c) Water heating equipment used to serve single-family residential swimming pools, spas, and hot tubs;
(d) Other equipment including, but not limited to, log lighter, gas log, gas barbecue, tiki torch, Bunsen burner, Domestic cooking equipment, hobby kilns, refrigeration or Domestic clothes drying;
(e) Equipment installed for use in detached garages, shops, or outbuildings.

MONTHLY RATE: Effective: August 1, 2028 (C)
The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 200** for a list of applicable adjustments. Rates are subject to charges for purchased gas costs and technical rate adjustments.

	Base Rate	Pipeline Capacity Rate	Commodity Rate	Temporary Adjustment	Billing Rate	
Residential:						
Customer Charge	$10.00				**$10.00**	(I)
Schedule 308 Credits (per bill)				($1.82)	**($1.82)**	
Volumetric Charge (per therm)	$1.34069	$0.10337	$0.43274	$0.31603	**$2.19283**	(I)
Commercial:						
Customer Charge	$10.00				**$10.00**	(I)
Schedule 308 Credits (per bill)				$(5.34)	**($5.34)**	
Volumetric Charge (per therm)	$1.51935	$0.10337	$0.43274	$0.28890	**$2.34436**	(I)

Minimum Monthly Bill: Customer Charge, plus charges under **Schedule C** and **Schedule 10** (if applicable)

(continue to Sheet 101.2)

RATE SCHEDULE 2
RESIDENTIAL SALES SERVICE

AVAILABLE:
To Residential Customers, in all territory served by the Company under the Tariff of which this Rate Schedule is a part. Seasonal or temporary Discontinuance of Service is allowed subject to Special Provision 1 of this Rate Schedule. The installation of Distribution Facilities, when required before service can be provided to equipment served under this Rate Schedule, are subject to the provisions of **SCHEDULE E**.

SERVICE DESCRIPTION:
Service under this Rate Schedule is Firm Sales Service to gas-fired equipment used in Residential dwellings that provide complete family living facilities in which the occupant normally cooks, eats, sleeps, and carries on the household operations incident to Domestic life, for at least one of the following purposes:

(a) Operation of ducted forced air Natural Gas space heating equipment that is the primary source for space heating requirements;
(b) Operation of a gas-fired hearth product or wall heater as the primary source for space heating requirements where the hearth or wall heater has a verified nameplate rating of 20,000 BTUs or greater, and is installed in a primary residence defined as a dwelling that is occupied year-round, and where that dwelling is 1,500 square feet or less; and, or;
(c) Operation of fully automatic water heating equipment for primary water heating requirements.

Service under this Rate Schedule includes the use of gas for equipment installed in addition to (a) and (b).

MONTHLY RATE: Effective: August 1, 2028 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

	Base Rate	Pipeline Capacity Rate	Commodity Rate	Temporary Adjustment	Billing Rate	
Customer Charge:	$10.00				$10.00	(I)
Schedule 308 Credits - Winter (per bill)				($10.97)	**($10.97)**	
Schedule 308 Credits - Non-Winter (per bill)				($4.84)	**($4.84)**	
Volumetric Charge (per therm)	$0.99302	$0.10337	$0.43274	$0.23171	**$1.76084**	(I)

Minimum Monthly Bill: Customer Charge, plus charges under **Schedule C** and **Schedule 10** (if applicable)

RATE SCHEDULE 3
BASIC FIRM SALES SERVICE - NON-RESIDENTIAL
(continued)

MONTHLY RATE: Effective: August 1, 2028 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM SALES SERVICE CHARGES (03 SF):					**Billing Rates [1]**	
Customer Charge (per month):					**$22.00**	
	Base Rate	Pipeline Capacity	Commodity Component [2]	Temporary Adjustment		
Schedule 308 Credits (per bill):						
Commercial - Winter				($46.59)	**($46.59)**	
Commercial - Non-Winter				($25.89)	**($25.89)**	
Industrial				($129.16)	**($129.16)**	
Volumetric Charges (per therm):						
Commercial	$0.98552	$0.10337	$0.43274	$0.21865	**$1.74028**	(I)
Industrial	$0.93801	$0.10337	$0.43274	$0.15912	**$1.63324**	(I)
Standby Charge (per therm of MHDV) [3]:					**$5.00**	

[1] **Schedule C** and **Schedule 10** Charges shall apply, if applicable.
[2] The Commodity Component will be either Annual Sales WACOG or Monthly Incremental Cost of Gas.
[3] Applies to Standby Sales Service only.

Minimum Monthly Bill. The Minimum Monthly Bill shall be any **Schedule C** and **Schedule 10** Charges, plus:

(a) ***Firm Sales Service.*** Customer Charge
(b) ***Firm Sales Standby Service.*** Customer Charge, plus Standby Service Charge

RATE SCHEDULE 10
CHARGES FOR SPECIAL METERING EQUIPMENT, RENTAL METERS AND METERING SERVICES
(continued)

Metering Services and Charges	One Time Charge	Installation Charge	Monthly Charge	
Rental Read	---	---	$0.36	
Advanced Automated Meter Reading (AAMR) Device[1]	---	$1,270.53	$52.82	(I)
Remote Index	---	$50.00	$4.00	
Pulse Output	---	$100.00	$8.00	
Administrative Set-Up/Consultation Fee (all meters)	$145.00	---	---	(I)
Technical Assistance (Rotary meters only)	$145.00	---	---	(I)

[1] Site specific engineering design costs for AAMR will be added to the installation charge if needed.

SPECIAL PROVISIONS FOR RENTAL METERS AND SPECIAL METERING EQUIPMENT:

1. Prior to receiving service under this section of the Schedule, the Customer must sign a service agreement that requires a minimum 12-month term. Customers who terminate service after less than 12 months will be required to pay all charges otherwise due to fulfill the 12-month obligation under the service agreement.
2. Service under this section of this Schedule is voluntary and separate from billing for or delivery of natural gas to a Customer's premise.
3. Since the Company does not maintain an inventory of all meter types offered under this Schedule, a delay may occur from the time a Customer requests service under this Schedule until the Company can provide it.
4. The Customer will be responsible for the meter pick-up and return of diaphragm meters.
5. The Customer will incur the Administrative Set-Up/Consultation Fee for each rental meter.
6. Upon delivery of a rotary meter, the Customer will incur the Technical Assistance charge listed above for each rental rotary meter. A Customer may not waive this provision or the associated fee. Technical assistance helps the Company ensure proper handling of rotary meters.
7. The Company will install AAMR devices for the charge listed above. AAMR devices will only be installed on Company owned meters and the Company will require that the Customer provide active and continuous electric power per company specifications to enable meter communications.
8. Upon request, the Company will provide one differential test per calendar year on rotary meters. The testing will be scheduled at the Company's convenience.
9. The Customer is responsible to protect all rental equipment from damage including but not limited to installing parking bollards to protect the rental equipment from vehicular or other damage.

(continue to Sheet 110.3)

RATE SCHEDULE 27
RESIDENTIAL HEATING DRY-OUT SERVICE

AVAILABLE:
To Residential home builders, developers, and contractors during the period that a Residential dwelling is under construction, in all territory served by the Company under the Tariff of which this schedule is a part.

SERVICE DESCRIPTION:
Service under this Rate Schedule is restricted to the use of gas in approved permanently-installed gas heating equipment in place during the period the dwelling is under construction. Upon occupancy of the dwelling, service under this Rate Schedule shall terminate automatically. In no event will service under this Rate Schedule continue for more a period of time greater than twelve (12) months from the date the gas meter is set at the dwelling. Upon termination of service under this Rate Schedule, gas service shall transfer to **Schedule 1** or **Schedule 2**, whichever is applicable.

MONTHLY RATE: Effective: August 1, 2028 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 200** for a list of applicable adjustments. Rates are subject to charges for purchased gas costs and technical rate adjustments.

	Base Rate	Pipeline Capacity Rate	Commodity Rate	Temporary Adjustment	Billing Rate
Customer Charge:	$9.00	---	---	---	**$9.00**
Volumetric Charge (per therm)					
All therms	$0.99357	$0.10337	$0.43274	$0.27817	**$1.80785** (I)

Minimum Monthly Bill: Customer Charge, plus charges under **Schedule C** and **Schedule 10** (if applicable)

GENERAL TERMS:
Service under this Rate Schedule is governed by the terms of this Rate Schedule, the General Rules and Regulations contained in this Tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

RATE SCHEDULE 41
NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES FOR COMMERCIAL CUSTOMER CLASS: Effective: August 1, 2028 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. **SEE SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM SALES SERVICE CHARGES (C41SF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$250.00**	
	Base Rate		Commodity Component [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($515.09)	**($515.09)**	
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	$0.75994		$0.43274	$0.19829	**$1.39097**	(I)
Block 2: All additional therms	$0.66963		$0.43274	$0.18849	**$1.29086**	(I)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.10337**	
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.54**	
INTERRUPTIBLE SALES SERVICE CHARGES (C41SI) [1]:						
Customer Charge (per month):					**$250.00**	
	Base Rate		Commodity Component: [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($515.09)	**($515.09)**	
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	$0.61948		$0.43274	$0.15275	**$1.20497**	(I)
Block 2: All additional therms	$0.54581		$0.43274	$0.14399	**$1.12254**	(I)
Plus: Interruptible Pipeline Capacity Charge - Volumetric (per therm):					**$0.03612**	
FIRM TRANSPORTATION SERVICE CHARGES (C41TF):						
Customer Charge (per month):					**$250.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Total Temporary Adjustments [4]		
Schedule 308 Credits (per bill):				$(515.09)	**($515.09)**	
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	$0.63879			$0.26958	**$0.90837**	(I)
Block 2: All additional therms	$0.56283			$0.26627	**$0.82910**	(I)

[1] The Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from Schedule C and Schedule 10.

[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG, or Monthly Incremental Cost of Gas.

[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 may not apply.

(continue to Sheet 141.10)

RATE SCHEDULE 41
NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES FOR INDUSTRIAL CUSTOMER CLASS: Effective: August 1, 2028 (C)
The rates shown in this Rate Schedule may not always reflect actual billing rates. **SEE SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM SALES SERVICE CHARGES (I41SF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$250.00**	
	Base Rate		Commodity Component [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($622.72)	**($622.72)**	
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	$0.61067		$0.43274	$0.14816	**$1.19157**	(I)
Block 2: All additional therms	$0.53807		$0.43274	$0.14445	**$1.11526**	(I)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.10337**	
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.54**	
INTERRUPTIBLE SALES SERVICE CHARGES (I41SI) [1]:						
Customer Charge (per month):					**$250.00**	
	Base Rate		Commodity Component: [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($622.72)	**($622.72)**	
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	$0.58605		$0.43274	$0.11138	**$1.13017**	(I)
Block 2: All additional therms	$0.51633		$0.43274	$0.10763	**$1.05670**	(I)
Plus: Interruptible Pipeline Capacity Charge - Volumetric (per therm):					**$0.03612**	
FIRM TRANSPORTATION SERVICE CHARGES (I41TF):						
Customer Charge (per month):					**$250.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Total Temporary Adjustments [4]		
Schedule 308 Credits (per bill):				($622.72)	**($622.72)**	
Volumetric Charges (per therm):						
Block 1: 1st 2,000 therms	$0.59254			$0.26625	**$0.85879**	(I)
Block 2: All additional therms	$0.52206			$0.26335	**$0.78541**	(I)

[1] The Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from Schedule C and Schedule 10.
[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG, or Monthly Incremental Cost of Gas.
[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 may not apply.

RATE SCHEDULE 42
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY SALES RATES - FIRM SERVICE: Effective: August 1, 2028 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM SALES SERVICE CHARGES [1]:					**Billing Rates**	
Customer Charge (per month, all service types):					**$1,300.00**	
	Base Rate		Commodity Component [2]	Total Temporary Adjustments [3]		
C42SF						
Schedule 308 Credits (per bill):				($5,142.27)	($5,142.27)	
Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	$0.42558		$0.43274	$0.16190	$1.02022	(I)
Block 2: Next 20,000 therms	$0.38095		$0.43274	$0.15706	$0.97075	
Block 3: Next 20,000 therms	$0.29219		$0.43274	$0.14746	$0.87239	
Block 4: Next 100,000 therms	$0.23371		$0.43274	$0.14114	$0.80759	
Block 5: Next 600,000 therms	$0.15580		$0.43274	$0.13272	$0.72126	
Block 6: All additional therms	$0.05840		$0.43274	$0.12218	$0.61332	(I)
I42SF						
Schedule 308 Credits (per bill):				($3,945.77)	($3,945.77)	
Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	$0.34190		$0.43274	$0.13666	$0.91130	(I)
Block 2: Next 20,000 therms	$0.30604		$0.43274	$0.13458	$0.87336	
Block 3: Next 20,000 therms	$0.23467		$0.43274	$0.13044	$0.79785	
Block 4: Next 100,000 therms	$0.18774		$0.43274	$0.12772	$0.74820	
Block 5: Next 600,000 therms	$0.12522		$0.43274	$0.12409	$0.68205	
Block 6: All additional therms	$0.04690		$0.43274	$0.11954	$0.59918	(I)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	
Firm Sales Service Storage Charge (per therm of MDDV per month):					**$0.20415**	
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.10337**	
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV per month):					**$1.54**	

[1] For Firm Sales Service, the Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Distribution Capacity Charge, plus the Storage Capacity Charge, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from Schedule C or Schedule 10.

[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG or Monthly Incremental Cost of Gas.

[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 may not apply.

(continue to Sheet 142.10.1)

RATE SCHEDULE 42
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY SALES RATES – INTERRUPTIBLE SERVICE: Effective: August 1, 2028 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

INTERRUPTIBLE SALES SERVICE CHARGES [1]: (C42SI)					**Billing Rates**	
Customer Charge (per month):					**$1,300.00**	
	Base Rate		Commodity Component [2]	Total Temporary Adjustments [3]		
Schedule 308 Credits (per bill):				($5,142.27)	**($5,142.27)**	
Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	$0.32657		$0.43274	$0.11316	**$0.87247**	(I)
Block 2: Next 20,000 therms	$0.29232		$0.43274	$0.10960	**$0.83466**	
Block 3: Next 20,000 therms	$0.22413		$0.43274	$0.10250	**$0.75937**	
Block 4: Next 100,000 therms	$0.17932		$0.43274	$0.09784	**$0.70990**	
Block 5: Next 600,000 therms	$0.11959		$0.43274	$0.09162	**$0.64395**	
Block 6: All additional therms	$0.04485		$0.43274	$0.08378	**$0.56137**	(I)
Interruptible Pipeline Capacity Charge (per therm):					**$0.03612**	
Interruptible Sales Service Storage Charge (per therm of MDDV per month)					**$0.10208**	
INTERRUPTIBLE SALES SERVICE CHARGES [1]: (I42SI)						
Customer Charge (per month):					**$1,300.00**	
Schedule 308 Credits (per bill):				($3,945.77)	**($3,945.77)**	
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	$0.31293		$0.43274	$0.09803	**$0.84370**	(I)
Block 2: Next 20,000 therms	$0.28012		$0.43274	$0.09614	**$0.80900**	
Block 3: Next 20,000 therms	$0.21479		$0.43274	$0.09241	**$0.73994**	
Block 4: Next 100,000 therms	$0.17186		$0.43274	$0.08994	**$0.69454**	
Block 5: Next 600,000 therms	$0.11455		$0.43274	$0.08665	**$0.63394**	
Block 6: All additional therms	$0.04294		$0.43274	$0.08256	**$0.55824**	(I)
Interruptible Pipeline Capacity Charge (per therm):					**$0.03612**	
Interruptible Sales Service Storage Charge (per therm of MDDV per month)					**$0.10208**	

[1] For Interruptible Sales Service, the Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge, plus any other charges that apply from Schedule C or Schedule 10.
[2] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 201 may also apply.
[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 may not apply.

(continue to Sheet 142.11)

RATE SCHEDULE 42
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY TRANSPORTATION RATES: Effective: August 1, 2028 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (C42TI) [1]:					**Billing Rates**	
Customer Charge (per month):					**$1,300.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Temporary Adjustments [2]		
Schedule 308 Credits (per bill):				($5,142.27)	**($5,142.27)**	
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	$0.22826			$0.25119	**$0.47945**	(I)
Block 2: Next 20,000 therms	$0.20435			$0.25021	**$0.45456**	
Block 3: Next 20,000 therms	$0.15670			$0.24823	**$0.40493**	
Block 4: Next 100,000 therms	$0.12536			$0.24695	**$0.37231**	
Block 5: Next 600,000 therms	$0.08360			$0.24521	**$0.32881**	
Block 6: All additional therms	$0.03132			$0.24306	**$0.27438**	(I)
INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (I42TI) [1]:					**Billing Rates**	
Customer Charge (per month):					**$1,300.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Temporary Adjustments [2]		
Schedule 308 Credits (per bill):				($3,945.77)	**($3,945.77)**	
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	$0.23350			$0.25155	**$0.48505**	(I)
Block 2: Next 20,000 therms	$0.20902			$0.25055	**$0.45957**	
Block 3: Next 20,000 therms	$0.16028			$0.24851	**$0.40879**	
Block 4: Next 100,000 therms	$0.12824			$0.24717	**$0.37541**	
Block 5: Next 600,000 therms	$0.08551			$0.24539	**$0.33090**	
Block 6: All additional therms	$0.03207			$0.24317	**$0.27524**	(I)

[1] For Interruptible Transportation Service, the Monthly Bill shall equal the sum of the Customer Charge, plus Transportation Charge, plus the Volumetric Charges, plus any other charges that may apply from Schedule C or Schedule 10.

[2] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 201 may also apply.

(continue to Sheet 142.12)

RATE SCHEDULE 42
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

FIRM TRANSPORTATION SERVICE CHARGES (C42TF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$1,300.00**	
Transportation Charge (per month):					**$250.00**	
	Base Rate			Total Temporary Adjustments [2]		
Schedule 308 Credits (per bill):				($5,142.27)	**($5,142.27)**	
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	$0.29231			$0.25250	**$0.54481**	(I)
Block 2: Next 20,000 therms	$0.26168			$0.25139	**$0.51307**	
Block 3: Next 20,000 therms	$0.20065			$0.24916	**$0.44981**	
Block 4: Next 100,000 therms	$0.16055			$0.24771	**$0.40826**	
Block 5: Next 600,000 therms	$0.10703			$0.24575	**$0.35278**	
Block 6: All additional therms	$0.04013			$0.24331	**$0.28344**	(I)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	
FIRM TRANSPORTATION SERVICE CHARGES (I42TF) [1]:						
Customer Charge (per month):					**$1,300.00**	
Transportation Charge (per month):					**$250.00**	
Schedule 308 Credits (per bill):				($3,945.77)	**($3,945.77)**	
Volumetric Charges (per therm)						
Block 1: 1st 10,000 therms	$0.25524			$0.25198	**$0.50722**	(I)
Block 2: Next 20,000 therms	$0.22849			$0.25092	**$0.47941**	
Block 3: Next 20,000 therms	$0.17520			$0.24880	**$0.42400**	
Block 4: Next 100,000 therms	$0.14019			$0.24741	**$0.38760**	
Block 5: Next 600,000 therms	$0.09345			$0.24556	**$0.33901**	
Block 6: All additional therms	$0.03504			$0.24323	**$0.27827**	(I)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	

[1] For Firm Transportation Service, the Monthly Bill shall equal the sum of the Customer Charge, plus Transportation Charge, plus the Volumetric Charges, plus the Distribution Capacity Charge, plus any other charges that may apply from Schedule C or Schedule 10.

[2] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 201 may also apply.

RATE SCHEDULE 43
HIGH VOLUME NON-RESIDENTIAL
FIRM AND INTERRUPTIBLE TRANSPORTATION SERVICE
(continued)

MONTHLY RATE: Effective: August 1, 2028 (C)

The rates shown below may not always reflect actual billing rates. See **Schedule 200** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM TRANSPORTATION SERVICE CHARGES (C43TF and I43TF)					
					Billing Rates
Customer Charge:					**$38,000.00**
Transportation Charge:					**$250.00**
Volumetric Charge	Base Rate			Total Temporary Adjustment [1]	
Per therm, all therms	$0.00796			$0.24194	**$0.24990** (I)
Firm Service Distribution Capacity Charge: Per therm of MDDV per month					**$0.15748**
Minimum Monthly Bill: Customer Charge, plus Transportation Charge, plus Firm Service Distribution Capacity Charge, plus any other charges that may apply from **Schedule C** and **Schedule 10**.					

INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (C43TI and I43TI)					
					Billing Rates
Customer Charge:					**$38,000.00**
Transportation Charge:					**$250.00**
Volumetric Charge:	Base Rate			Total Temporary Adjustment [1]	
Per therm, all therms	$0.00796			$0.24194	**$0.24990** (I)
Minimum Monthly Bill: Customer Charge, plus Transportation Charge, plus any other charges that may apply from **Schedule C** and **Schedule 10**.					

[1] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 201 shall apply.

SCHEDULE 200
SUMMARY OF ADJUSTMENTS

PURPOSE:
The purpose of this Schedule is to list and summarize the adjustment Schedules applicable to each of the Company's Rate Schedules.

SCHEDULE	A	201	203	207	210	212	215	220	221	230	232	233	234	235	236	237	238	239	303	305	306	308
R1	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C1	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
2	ADD	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
03CSF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
03ISF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
10	ADD			INC																		
27	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C41SF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C41SI	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C41TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I41SF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I41SI	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I41TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C42SF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C42SI	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C42TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C42TI	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I42SF	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I42SI	ADD	INC	INC	INC	INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I42TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
I42TI	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC	INC
C43TI/ I43TI	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC		INC	INC	INC	INC
C43TF/ I43TF	ADD	INC		INC	INC		INC		INC		INC	INC	INC	INC	INC	INC	INC		INC	INC	INC	INC

(N)

Table Code Key:

ADD This adjustment is added to the billing rates at the time the bill is issued.
INC This adjustment is included in the billing rates shown on the Rate Schedule

(continue to Sheet 200.2)

SCHEDULE 200
SUMMARY OF ADJUSTMENTS
(continued)

The following is a brief description of the applicable Schedules:

Schedule A "Billing for City and County Exactions."
This adjustment will be reflected directly on Customer bills.

Schedule 201 "Temporary (Technical) Adjustments to Rates."
These are temporary Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 203 "Purchased Gas Cost Adjustments to Rates."
These are pipeline capacity and commodity charges.

Schedule 207 "General Adjustments to Rates."
These are Base Rate Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 210 "Adjustment to Rates for Property Sales."
These are Temporary Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 212 "Adjustment to Rates Residential Rate Mitigation."
These are Temporary Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 215 "Adjustment to Rates for Energy Conservation Programs."
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 220 "Special Rate Adjustment."
These are Base Rate Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 221 "Rate Adjustment for Updated Depreciation Rates"
These are Base Rate Adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 230 "Temporary Adjustments to Rates for Low-Income Programs."
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 231 "Temporary Adjustments to Rates for Residential Discount Program."
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 232 "Temporary Adjustments to Rates for Regulatory Fee Increase"
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 233 "Temporary Adjustments to Rates for Industrial Customer Energy Efficiency Audit Costs"
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 234 "Temporary Adjustments to Rates for Residential Arrearage Management Program" (N)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 235 "Temporary Adjustments to Rates for COVID-19 Public Health Emergency" (N)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills. (N)

(K)

(K) Schedules 303, 305, 306 and 308 transferred to Sheet 200.3.

(continue to Sheet 200.3)

SCHEDULE 200
SUMMARY OF ADJUSTMENTS
(continued)

Schedule 236 "Temporary Adjustments to Rates for Meter Modernization Program." (N)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 237 "Temporary Adjustments to Rates for TSA Operations and Maintenance Costs." (N)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 238 "Adjustments to Rates for Provisional Capital Adjustment." (N)
These are base rate adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 239 "Temporary Adjustments to Rates for TSA Capital and Cost of Service Cost Recovery." (N)
These are base rate adjustments that are included in the Billing Rate reflected on Customer bills. (N)

Schedule 303 "Washington Environmental Cost Recovery Mechanism." (M)
These are temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 305 "Adjustment for Certain Income Taxes (2017 Federal Tax Cuts and Jobs Act)."
These are base and temporary adjustments that are included in the Billing Rate reflected on Customer bills.

Schedule 306 "Multi-Year Rate Plan Adjustment."
These are base rate adjustments that will be added to the Billing Rate on the effective date of the Schedule.

Schedule 308 "Washington Climate Commitment Act Recovery Mechanism."
These are temporary rate adjustments that will be added to the Billing Rate on the effective date of the Schedule. (M)

(M) Schedules 303, 305, 306 and 308 transferred from Sheet 200.2.

SCHEDULE 207
GENERAL RATE ADJUSTMENT

PURPOSE:
To identify the effects of general rate changes approved in the company's most recent general rate case proceeding (Docket UG-200994)

APPLICATION TO RATE SCHEDULES: Effective: August 1, 2028 (C)

Rate Schedule 1	Rate Schedule 3	Rate Schedule 41	Rate Schedule 43
Rate Schedule 2	Rate Schedule 27	Rate Schedule 42	

The Base Rates in the listed Rate Schedules include the adjustment shown below.
NO FURTHER ADJUSTMENT TO RATES IS REQUIRED.

SCHEDULES	BLOCKS	AMOUNT	
Schedule 1 - Residential	Customer Charge	$0.00	
	Per Therm (all therms)	$0.15106	(I)
Schedule 1 - Commercial	Customer Charge	$0.00	
	Per Therm (all therms)	$0.13631	(I)
Schedule 2	Customer Charge	$0.00	
	Per Therm (all therms)	$0.09063	(I)
Schedule 3 - Commercial	Customer Charge	$0.00	
	Per Therm (all therms)	$0.08519	(I)
Schedule 3 - Industrial	Customer Charge	$0.00	
	Per Therm (all therms)	$0.07884	(I)
Schedule 27	Customer Charge	$0.00	
	Per Therm (all therms)	$0.09612	(I)
Schedule 41 - Commercial Firm Sales Service	Customer Charge	$0.00	
	First 2,000 therms	$0.06829	(I)
	All additional therms	$0.06018	(I)
Schedule 41 - Commercial Interruptible Sales Service	Customer Charge	$0.00	
	First 2,000 therms	$0.04886	(I)
	All additional therms	$0.04305	(I)
Schedule 41 - Industrial Firm Sales Service	Customer Charge	$0.00	
	First 2,000 therms	$0.05615	(I)
	All additional therms	$0.04948	(I)
Schedule 41 - Industrial Interruptible Sales Service	Customer Charge	$0.00	
	First 2,000 therms	$0.04622	(I)
	All additional therms	$0.04072	(I)
Schedule 41 - Commercial Firm Transportation Service	Customer Charge	$0.00	
	First 2,000 therms	$0.06160	(I)
	All additional therms	$0.05428	(I)
Schedule 41 - Industrial Firm Transportation Service	Customer Charge	$0.00	
	First 2,000 therms	$0.04673	(I)
	All additional therms	$0.04117	(I)

(continue to Sheet 207.2)

SCHEDULE 207
GENERAL RATE ADJUSTMENT
(continued)

SCHEDULES	BLOCKS	AMOUNT	
Schedule 42 Commercial - Firm Sales Service	Customer Charge	$0.00	
	First 10,000 therms	0.04359	(I)
	Next 20,000 therms	0.03902	
	Next 20,000 therms	0.02993	
	Next 100,000 therms	0.02394	
	Next 600,000 therms	0.01596	
	All additional therms	0.00598	(I)
Schedule 42 Commercial - Interruptible Sales Service	Customer Charge	$0.00	
	First 10,000 therms	0.03145	(I)
	Next 20,000 therms	0.02815	
	Next 20,000 therms	0.02158	
	Next 100,000 therms	0.01727	
	Next 600,000 therms	0.01152	
	All additional therms	0.00432	(I)
Schedule 42 Industrial - Firm Sales Service	Customer Charge	$0.00	
	First 10,000 therms	0.04119	(I)
	Next 20,000 therms	0.03687	
	Next 20,000 therms	0.02827	
	Next 100,000 therms	0.02262	
	Next 600,000 therms	0.01509	
	All additional therms	0.00565	(I)
Schedule 42 Industrial - Interruptible Sales Service	Customer Charge	$0.00	
	First 10,000 therms	0.03561	(I)
	Next 20,000 therms	0.03188	
	Next 20,000 therms	0.02444	
	Next 100,000 therms	0.01956	
	Next 600,000 therms	0.01304	
	All additional therms	0.00489	(I)

(continue to Sheet 207.3)

SCHEDULE 207
GENERAL RATE ADJUSTMENT
(continued)

SCHEDULES	BLOCKS	AMOUNT	
Schedule 42 Commercial - Firm Transportation Service	Customer Charge	$0.00	
	First 10,000 therms	0.03255	(I)
	Next 20,000 therms	0.02914	
	Next 20,000 therms	0.02234	
	Next 100,000 therms	0.01788	
	Next 600,000 therms	0.01192	
	All additional therms	0.00447	(I)
Schedule 42 Industrial - Firm Transportation Service	Customer Charge	$0.00	
	First 10,000 therms	0.02446	(I)
	Next 20,000 therms	0.02190	
	Next 20,000 therms	0.01679	
	Next 100,000 therms	0.01344	
	Next 600,000 therms	0.00896	
	All additional therms	0.00336	(I)
Schedule 42 - Commercial Interruptible Transportation Service	Customer Charge	$0.00	
	First 10,000 therms	0.01800	(I)
	Next 20,000 therms	0.01612	
	Next 20,000 therms	0.01236	
	Next 100,000 therms	0.00989	
	Next 600,000 therms	0.00659	
	All additional therms	0.00247	(I)
Schedule 42 - Industrial Interruptible Transportation Service	Customer Charge	$0.00	
	First 10,000 therms	0.02105	(I)
	Next 20,000 therms	0.01885	
	Next 20,000 therms	0.01445	
	Next 100,000 therms	0.01156	
	Next 600,000 therms	0.00771	
	All additional therms	0.00289	(I)

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

Issued August 29, 2025
NWN WUTC Advice No. 25-03

Effective with service on
and after August 1, 2028

(N)

SCHEDULE 235
TEMPORARY ADJUSTMENTS TO RATES FOR COVID-19 PUBLIC HEALTH EMERGENCY

PURPOSE: To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of deferred amounts for the costs and savings incurred due to the COVID-19 pandemic, as authorized for deferred accounting by the WUTC in Docket UG-200264.

APPLICABLE:
Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: August 1, 2028**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		$0.00304		42 CTF	Block 1	$0.00059
1C		$0.00253			Block 2	$0.00053
2R		$0.00176			Block 3	$0.00041
3C		$0.00159			Block 4	$0.00032
3I		$0.00144			Block 5	$0.00022
27		$0.00179			Block 6	$0.00008
41 CSF	Block 1	$0.00125		42 ITF	Block 1	$0.00043
	Block 2	$0.00110			Block 2	$0.00039
41 ISF	Block 1	$0.00101			Block 3	$0.00030
	Block 2	$0.00089			Block 4	$0.00024
41 CSI	Block 1	$0.00103			Block 5	$0.00016
	Block 2	$0.00091			Block 6	$0.00006
41 ISI	Block 1	$0.00098		42 CSI	Block 1	$0.00054
	Block 2	$0.00086			Block 2	$0.00048
41 CTF	Block 1	$0.00115			Block 3	$0.00037
	Block 2	$0.00101			Block 4	$0.00030
41ITF	Block 1	$0.00099			Block 5	$0.00020
	Block 2	$0.00087			Block 6	$0.00007
42 CSF	Block 1	$0.00073		42 ISI	Block 1	$0.00060
	Block 2	$0.00066			Block 2	$0.00054
	Block 3	$0.00050			Block 3	$0.00041
	Block 4	$0.00040			Block 4	$0.00033
	Block 5	$0.00027			Block 5	$0.00022
	Block 6	$0.00010			Block 6	$0.00008
42 ISF	Block 1	$0.00068		42 CTI	Block 1	$0.00038
	Block 2	$0.00061			Block 2	$0.00034
	Block 3	$0.00046			Block 3	$0.00026
	Block 4	$0.00037			Block 4	$0.00021
	Block 5	$0.00025			Block 5	$0.00014
	Block 6	$0.00009			Block 6	$0.00005
				42 ITI	Block 1	$0.00039
					Block 2	$0.00035
					Block 3	$0.00027
					Block 4	$0.00022
					Block 5	$0.00014
					Block 6	$0.00005
				43 TF		$0.00000
				43 TF		$0.00000

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

(N)

SCHEDULE 236
TEMPORARY ADJUSTMENTS TO RATES FOR METER MODERNIZATION PROGRAM

(N)

PURPOSE: To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of deferred amounts for the costs related to the Company's Meter Modernization Program, as authorized for deferred accounting by the WUTC in Docket UG-240012.

APPLICABLE:
Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: August 1, 2028**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		$0.00131		42 CTF	Block 1	$0.00025
1C		$0.00109			Block 2	$0.00023
2R		$0.00076			Block 3	$0.00017
3C		$0.00069			Block 4	$0.00014
3I		$0.00062			Block 5	$0.00009
27		$0.00077			Block 6	$0.00003
41 CSF	Block 1	$0.00054		42 ITF	Block 1	$0.00019
	Block 2	$0.00047			Block 2	$0.00017
41 ISF	Block 1	$0.00044			Block 3	$0.00013
	Block 2	$0.00038			Block 4	$0.00010
41 CSI	Block 1	$0.00040			Block 5	$0.00007
	Block 2	$0.00035			Block 6	$0.00003
41 ISI	Block 1	$0.00038		42 CSI	Block 1	$0.00023
	Block 2	$0.00033			Block 2	$0.00021
41 CTF	Block 1	$0.00049			Block 3	$0.00016
	Block 2	$0.00043			Block 4	$0.00013
41ITF	Block 1	$0.00038			Block 5	$0.00009
	Block 2	$0.00034			Block 6	$0.00003
42 CSF	Block 1	$0.00032		42 ISI	Block 1	$0.00026
	Block 2	$0.00028			Block 2	$0.00023
	Block 3	$0.00022			Block 3	$0.00018
	Block 4	$0.00017			Block 4	$0.00014
	Block 5	$0.00012			Block 5	$0.00010
	Block 6	$0.00004			Block 6	$0.00004
42 ISF	Block 1	$0.00029		42 CTI	Block 1	$0.00015
	Block 2	$0.00026			Block 2	$0.00013
	Block 3	$0.00020			Block 3	$0.00010
	Block 4	$0.00016			Block 4	$0.00008
	Block 5	$0.00011			Block 5	$0.00005
	Block 6	$0.00004			Block 6	$0.00002
				42 ITI	Block 1	$0.00017
					Block 2	$0.00015
					Block 3	$0.00012
					Block 4	$0.00009
					Block 5	$0.00006
					Block 6	$0.00002
				43 TF		$0.00000
				43 TF		$0.00000

GENERAL TERMS:
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

(N)

SCHEDULE 237
TEMPORARY ADJUSTMENTS TO RATES FOR TSA OPERATIONS AND MAINTENANCE COSTS

(N)

PURPOSE: To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of deferred amounts for the start-up Operations and Maintenance costs incurred for compliance with TSA Security Directives, as authorized for deferred accounting by the WUTC in Docket UG-210900.

APPLICABLE:
Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: August 1, 2028**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		$0.00128		42 CTF	Block 1	$0.00025
1C		$0.00105			Block 2	$0.00022
2R		$0.00074			Block 3	$0.00017
3C		$0.00067			Block 4	$0.00014
3I		$0.00061			Block 5	$0.00009
27		$0.00075			Block 6	$0.00003
41 CSF	Block 1	$0.00053		42 ITF	Block 1	$0.00018
	Block 2	$0.00046			Block 2	$0.00016
41 ISF	Block 1	$0.00042			Block 3	$0.00012
	Block 2	$0.00037			Block 4	$0.00010
41 CSI	Block 1	$0.00039			Block 5	$0.00007
	Block 2	$0.00034			Block 6	$0.00002
41 ISI	Block 1	$0.00037		42 CSI	Block 1	$0.00023
	Block 2	$0.00032			Block 2	$0.00020
41 CTF	Block 1	$0.00048			Block 3	$0.00016
	Block 2	$0.00043			Block 4	$0.00012
41ITF	Block 1	$0.00037			Block 5	$0.00008
	Block 2	$0.00033			Block 6	$0.00003
42 CSF	Block 1	$0.00031		42 ISI	Block 1	$0.00025
	Block 2	$0.00028			Block 2	$0.00022
	Block 3	$0.00021			Block 3	$0.00017
	Block 4	$0.00017			Block 4	$0.00014
	Block 5	$0.00011			Block 5	$0.00009
	Block 6	$0.00004			Block 6	$0.00003
42 ISF	Block 1	$0.00028		42 CTI	Block 1	$0.00014
	Block 2	$0.00025			Block 2	$0.00013
	Block 3	$0.00020			Block 3	$0.00010
	Block 4	$0.00016			Block 4	$0.00008
	Block 5	$0.00010			Block 5	$0.00005
	Block 6	$0.00004			Block 6	$0.00002
				42 ITI	Block 1	$0.00016
					Block 2	$0.00015
					Block 3	$0.00011
					Block 4	$0.00009
					Block 5	$0.00006
					Block 6	$0.00002
				43 TF		$0.00000
				43 TF		$0.00000

GENERAL TERMS:
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(N)

Issued August 29, 2025
NWN WUTC Advice No. 25-03

Effective with service on
and after August 1, 2028

SCHEDULE 238
ADJUSTMENTS TO RATES FOR PROVISIONAL CAPITAL ADJUSTMENT

(N)

PURPOSE: To identify adjustments to rates in the Rate Schedules listed below that relate to the capital with Rate Year 1 as authorized by the WUTC in Docket UG-250610.

APPLICABLE:
Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: August 1, 2028**
The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		0.06242		42 CTF	Block 1	0.00917
1C		0.05458			Block 2	0.00821
2R		0.03569			Block 3	0.00630
3C		0.03492			Block 4	0.00504
3I		0.02949			Block 5	0.00336
27		0.06027			Block 6	0.00126
41 CSF	Block 1	0.02580		42 ITF	Block 1	0.00689
	Block 2	0.02273			Block 2	0.00617
41 ISF	Block 1	0.01596			Block 3	0.00473
	Block 2	0.01406			Block 4	0.00379
41 CSI	Block 1	0.01902			Block 5	0.00252
	Block 2	0.01676			Block 6	0.00095
41 ISI	Block 1	0.01799		42 CSI	Block 1	0.01184
	Block 2	0.01585			Block 2	0.01060
41 CTF	Block 1	0.01736			Block 3	0.00813
	Block 2	0.01529			Block 4	0.00650
41ITF	Block 1	0.01819			Block 5	0.00434
	Block 2	0.01603			Block 6	0.00163
42 CSF	Block 1	0.01647		42 ISI	Block 1	0.00983
	Block 2	0.01474			Block 2	0.00880
	Block 3	0.01131			Block 3	0.00674
	Block 4	0.00904			Block 4	0.00540
	Block 5	0.00603			Block 5	0.00360
	Block 6	0.00226			Block 6	0.00135
42 ISF	Block 1	0.01171		42 CTI	Block 1	0.00701
	Block 2	0.01048			Block 2	0.00627
	Block 3	0.00803			Block 3	0.00481
	Block 4	0.00643			Block 4	0.00385
	Block 5	0.00429			Block 5	0.00257
	Block 6	0.00161			Block 6	0.00096
				42 ITI	Block 1	0.00593
					Block 2	0.00531
					Block 3	0.00407
					Block 4	0.00326
					Block 5	0.00217
					Block 6	0.00081
				43 TF		0.00024
				43 TF		0.00024

GENERAL TERMS:
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(N)

Issued August 29, 2025
NWN WUTC Advice No. 25-03

Effective with service on
and after August 1, 2028

SCHEDULE 239
TEMPORARY ADJUSTMENTS TO RATES FOR TSA CAPITAL AND COST OF SERVICE COST RECOVERY

(N)

APPLICABLE:

APPLICABLE:

Schedule 1 Schedule 2 Schedule 3 Schedule 27 Schedule 41 Schedule 42 Schedule 43

APPLICATION TO RATE SCHEDULES: **Effective: August 1, 2028**

The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Adjustment (per therm)		Schedule	Block	Adjustment (per therm)
1R		$0.01290		42 CTF	Block 1	$0.00251
1C		$0.01078			Block 2	$0.00225
2R		$0.00749			Block 3	$0.00172
3C		$0.00677			Block 4	$0.00138
3I		$0.00610			Block 5	$0.00092
27		$0.00759			Block 6	$0.00034
41 CSF	Block 1	$0.00530		42 ITF	Block 1	$0.00183
	Block 2	$0.00467			Block 2	$0.00164
41 ISF	Block 1	$0.00428			Block 3	$0.00126
	Block 2	$0.00377			Block 4	$0.00101
41 CSI	Block 1	$0.00393			Block 5	$0.00067
	Block 2	$0.00346			Block 6	$0.00025
41 ISI	Block 1	$0.00372		42 CSI	Block 1	$0.00229
	Block 2	$0.00327			Block 2	$0.00205
41 CTF	Block 1	$0.00487			Block 3	$0.00157
	Block 2	$0.00429			Block 4	$0.00126
41ITF	Block 1	$0.00376			Block 5	$0.00084
	Block 2	$0.00331			Block 6	$0.00031
42 CSF	Block 1	$0.00312		42 ISI	Block 1	$0.00255
	Block 2	$0.00279			Block 2	$0.00228
	Block 3	$0.00214			Block 3	$0.00175
	Block 4	$0.00171			Block 4	$0.00140
	Block 5	$0.00114			Block 5	$0.00093
	Block 6	$0.00043			Block 6	$0.00035
42 ISF	Block 1	$0.00287		42 CTI	Block 1	$0.00145
	Block 2	$0.00257			Block 2	$0.00130
	Block 3	$0.00197			Block 3	$0.00099
	Block 4	$0.00158			Block 4	$0.00080
	Block 5	$0.00105			Block 5	$0.00053
	Block 6	$0.00039			Block 6	$0.00020
				42 ITI	Block 1	$0.00166
					Block 2	$0.00149
					Block 3	$0.00114
					Block 4	$0.00091
					Block 5	$0.00061
					Block 6	$0.00023
				43 TF		$0.00000
				43 TF		$0.00000

GENERAL TERMS:

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(N)

Issued August 29, 2025
NWN WUTC Advice No. 25-03

Effective with service on
and after August 1, 2028

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Direct Testimony of Kimberly A. Rush and Zachary D. Kravitz

POLICY

Exh. KAR-ZDK-1T

August 29, 2025

DIRECT TESTIMONY OF KIMBERLY A. RUSH AND ZACHARY D. KRAVITZ

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position with Northwest Natural Gas Company ("NW Natural" or "the Company") and summarize your educational background and business experience.

A. My name is Kimberly A. Rush, and I am President of NW Natural. I have worked at NW Natural since 1998 and have had leadership roles related to communications, marketing, and operations with increasing responsibility. I have held my current position since April 1, 2025. Prior to joining NW Natural, I held management and senior communications positions at Alltel Corporation and Bank of America Corporation in Chicago. I received a Bachelor of Arts in Communications from the University of Iowa and a Master of Science in Communications from Northwestern University.

My name is Zachary D. Kravitz. I am the Vice President of Regulatory Affairs and Resource Planning for NW Natural. I joined NW Natural's Legal Department in 2014 as Associate Regulatory Counsel. In 2018, I joined the Rates and Regulatory Affairs Department in the position of Director of Rates & Regulatory Affairs, and later Senior Director. Prior to joining NW Natural, I worked in the energy and utility practice at the law firms of Chester, Wilcox & Saxbe, LLC and Taft, Stettinius & Hollister, LLP in Columbus, Ohio. Before that, I worked at the Ohio Attorney General's Office in the Labor Relations Division. I received a Bachelor of Arts degree in English and Government from the University of Texas at Austin and a Juris Doctor degree from the University of Florida.

Q. What is the purpose of your testimony?

A. Our testimony describes NW Natural's current operating environment, an overview of NW Natural's petition for a general rate revision, and the Company's continued focus on equity and expanding its affordability programs. Finally, we introduce the Company's witnesses and provide a high-level description of their testimony.

II. NW NATURAL'S CURRENT OPERATING ENVIRONMENT

Q. Please describe the business of NW Natural.

A. As the largest standalone gas utility in the Pacific Northwest, NW Natural's employee base of approximately 1,300 dedicated employees provides natural gas service to approximately two million people in more than 140 communities in Oregon and southwest Washington with one of the most modern pipeline systems in the nation. In Washington specifically, NW Natural provides service in 15 cities and neighboring communities in three counties. The Company has approximately 98,000 customer accounts in Washington, which accounts for about 12.2 percent of its total customer base.

Q. Please describe the value that NW Natural provides to its customers.

A. NW Natural provides value to its customers through the delivery of safe, reliable and affordable utility services. NW Natural delivers natural gas to its customers through more than 14,000 miles of transmission and distribution pipelines. In addition, the Company has over 20 billion cubic feet of natural gas storage at its three storage operations, which allows us to reliably and affordably provide energy to its customers on the coldest of winter days.

Q. Please describe the value that NW Natural provides to the Pacific Northwest as a whole.

A. NW Natural plays a vital role in the overall energy system of the Pacific Northwest. In NW Natural's service territory, the gas and electric systems have a concurrent peak in winter. During the January 2024 winter storm event, the Bonneville Power Administration—the Pacific Northwest's largest power supplier—had a modern record peak load of 11,396 MW.[1] NW Natural's combined Washington and Oregon peak gas send out of 407,055 average therms per hour occurred between 10 and 11 am on the same day as Bonneville's peak. NW Natural's peak exceeded that of Bonneville's system, with a peak equivalent to 11,930 MW.

Q. Please provide more detail on the January 2024 winter storm event.

A. As stated above, NW Natural's service territory experienced severe winter weather in mid-January 2024, which demonstrated the capacity, resiliency, and reliability values of the natural gas system. On January 13, 2024, as temperatures dropped to 15 degrees in the Portland-Vancouver area, NW Natural delivered 9 million therms of natural gas to homes and businesses, virtually matching its previous record for a single gas day, and approximately doubling its average daily winter send out. NW Natural delivered approximately 8 million therms of natural gas for each of the following three days. In addition to matching a single gas day delivery record and sustaining high volumes of natural gas delivery to its customers, NW Natural also broke previous Mist Storage

[1] Exh. KAR-ZDK-2.

Facility send out records for five days during this period and delivered over 4.5 million therms of stored natural gas on January 13, 2024.

Q. Did NW Natural's system provide a critical resiliency benefit to communities during this January storm?

A. Yes. During this week-long winter event, icy conditions caused widespread power outages in the communities that also serves in Washington and Oregon, with more than 700,000 electric customers without power for multiple days during freezing temperatures. Clark Public Utilities specifically reported 25,000 customers without power in Washington. However, NW Natural's underground pipeline and storage system was able to perform very well, with only 266 gas customers losing service throughout the entire event systemwide (both Washington and Oregon). Because many natural gas fireplaces, cooktops, and water heaters work in a power outage, as well as gas generators, NW Natural was able to provide energy to our customers and a vital public health alternative for facilities like hospitals, nursing homes and community warming centers.

Q. Is that the only recent winter storm that has demonstrated the reliability and capacity value of NW Natural's system?

A. No. Approximately one year prior, on December 22, 2022, NW Natural's system experienced another extremely cold day where temperatures dropped to 17 degrees resulting in record throughput on its system that would only be matched by the January 2024 weather event discussed above. Both of these recent winter weather events demonstrate the capacity value of NW Natural's system during the coldest winter weather.

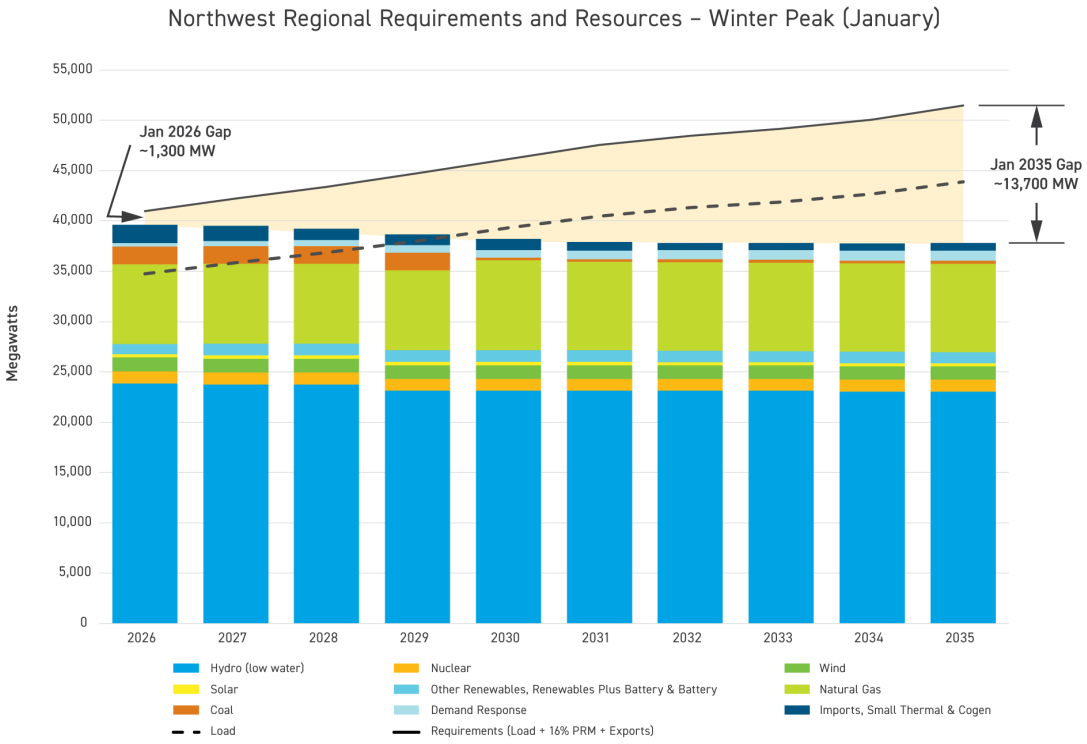
Q. Given record throughput during these severe weather events, is it fair to say that the Pacific Northwest's reliance on NW Natural's capacity is increasing?

A. Yes. These severe winter storm events illustrate how important NW Natural's system is to both its customers and the Pacific Northwest as a whole. During the severe weather events in both winters, NW Natural reliably met its customers' needs to heat their homes and their businesses despite record setting demand. In addition, the capacity provided by NW Natural is critical to ensuring that the Pacific Northwest's overall energy system remains reliable, resilient, and affordable. On the coldest winter days, NW Natural's system meets 90 percent of the energy needs for its residential space and water heat customers.

This amount of capacity would be extremely difficult and expensive to replace with electric solutions given the limitations already facing the Pacific Northwest's power system. According to the Pacific Northwest Utilities Conference Committee ("PNUCC") annual power loads and resource study, the Pacific Northwest is facing winter peak power deficits throughout the next decade that increase to approximately 13,700 MW in 2035, as shown in Figure 1 below:[2]

[2] PNUCC, Northwest Regional Forecast of Power Loads and Resources – August 2025 through July 2035 at 23, Table 3 (Apr. 2025) (available at: https://www.pnucc.org/wp-content/uploads/2025-PNUCC-Northwest-Regional-Forecast-final.pdf).

Figure 1



Source: PNUCC 2025 Northwest Regional Forecast

Aside from the resource adequacy issues that would further be exacerbated by seeking to replace the capacity that the Company provides with electricity, NW Natural also serves commercial and industrial customers whose use of natural gas simply cannot be electrified at any price given current technology.

Q. Has PNUCC recently commissioned an analysis of regional energy studies that further analyzed increasing energy demand and the frequency of extreme weather events?

A. Yes. PNUCC and the Northwest Gas Association ("NWGA") hired a consultant—Guidehouse—to conduct a literature review that analyzed 19 studies published by gas and electric organizations to identify common themes and risks associated with rising

energy demand and the increasing frequency of extreme weather events in the Pacific Northwest and the broader western United States.[3] The PNUCC and NWGA working group included representatives from a number of utilities and pipeline operators in the United States and Canada, including Clark Public Utilities, Avista, Puget Sound Energy, Cascade Natural Gas, Portland General Electric, PNGC Power, Eugene Water and Electric Board, NW Natural, FortisBC, Enbridge, and Williams NW Pipeline.[4]

Guidehouse's analysis found that the Pacific Northwest electricity demand is forecasted to increase by over 30 percent in the next ten years.[5] It also shows the magnitude and frequency of demand at-risk hours significantly increase from 2026 onward, indicating a shortfall in resource plans.[6] At the same time, hydroelectricity may become increasingly unreliable due to droughts. These conditions will continue to stress not only the electric grid in the region, but also the interstate pipeline system. Driven by an increase in gas-fired electric generation, the average utilization of interstate pipelines in Washington, and the entire Pacific Northwest, has exceeded 95 percent in recent years and its use is expected to grow, even during normal winters.[7]

[3] Exh. KAR-ZDK-3.

[4] Exh. KAR-ZDK-3.

[5] Exh. KAR-ZDK-3.

[6] Exh. KAR-ZDK-3.

[7] Exh. KAR-ZDK-3.

Q. Did Guidehouse make any recommendations to combat these resource adequacy issues?

A. Yes. Instead of looking at energy policy as a zero-sum game where natural gas utilities play less and less of a role in favor of massive load growth on the electric system, Guidehouse recommends "enhanced planning coordination between gas and electric systems" in order to "prepare for these changes to the system," such as increased demand and increasing stress on existing resources that we described above.[8] Specifically, Guidehouse's analysis states that electric and gas utilities should collaboratively develop planning tools and models that co-optimize both the natural gas and electric systems.[9] We believe that these types of joint planning solutions can address resource adequacy while still helping the Pacific Northwest achieve its emissions reductions goals as affordably as possible.

Q. How does this type of joint system planning advance equity?

A. Joint system planning is an example of equity in action. Broadly speaking, joint system planning, if done correctly, can help facilitate a fair and just allocation of benefits and burdens to a less emissions-intensive energy system. By working together, natural gas and electric utilities can take advantage of the strengths of their respective systems to lower overall costs, promote resource adequacy, and reduce emissions. By increasing the benefits and reducing the burdens related to emissions reductions, it is possible to craft more equitable results. While achieving resource adequacy and emissions

[8] Exh. KAR-ZDK-3.

[9] Exh. KAR-ZDK-3.

reductions at an affordable cost is an incredibly difficult problem, joint system planning places the overall energy system in the best position to maximize benefits and minimize burdens to all Washingtonians regardless of the fuel that they choose to use to heat their homes.

Q. How can the electric and natural gas systems work together to take advantage of the strengths of their respective systems to lower overall costs, promote resource adequacy, and reduce emissions?

A. Dual-fuel solutions are a way for electric and natural gas systems to work together to lower overall costs, promote resource adequacy, and reduce emissions. In particular, we believe that hybrid heating, where an air source heat pump is paired with a gas furnace, could reduce natural gas throughput, as well as address continuing resource adequacy and reliability concerns on the electric grid. Today, air source heat pumps typically utilize electric resistance heating as a back-up and they are less energy efficient during periods of cold weather than during periods of milder weather. Utilizing a natural gas furnace instead eliminates the need to rely on higher emitting and more costly electric resistance back up heat, especially during prolonged cold weather where renewable electric power is limited due to a lack of sun and wind. These types of solutions offer the promise to lower the cost of meeting climate targets for the electric and gas system, while also preserving reliability and optionality.

Q. Is NW Natural currently pursuing a dual fuel (or "hybrid") pilot?

A. Yes. The Clark County Dual Fuel Pilot is being managed and delivered in partnership with the Northwest Energy Efficiency Alliance and the local electric utility—Clark Public Utilities. This pilot is examining a hybrid application where an air-source heat

pump is combined with an air handling unit and tankless gas water heater. The system is controlled with an iFlow Smart Controller that allows the heat pump and gas water heater to operate in parallel. Fifteen homes have been selected for this pilot. The research objectives for this pilot are to evaluate the overall heating and water heating efficiency of this specific system along with the functionality of the iFlow Smart Controller. In addition to the efficiency research, demand response scenarios will also be performed on the systems. Final installations are currently underway.

NW Natural believes this pilot has the potential to lead to solutions that can help promote equitable outcomes in energy system planning, ensure resource adequacy while reducing emissions as affordably as possible. However, it may also eventually lead to an evolution of the regulatory model and incentives to properly support dual-fuel (hybrid) solutions, although—to be clear—NW Natural is not seeking any such changes in this proceeding.

Q. Is NW Natural working with a local electric utility on any other innovative pilot projects that will reduce emissions?

A. Yes. In coordination with Clark Public Utilities, NW Natural is developing a thermal energy network ("TEN") pilot[10] in downtown Vancouver, as fully described in the confidential Direct Testimony of Holly J. Braun (Exh. HJB-1CT). The TEN system is designed to achieve a maximum coefficient of performance ("COP") of approximately 6.0, which significantly outperforms conventional air source heat pumps. This higher

[10] A TEN connects multiple buildings through a loop of underground pipes carrying water. This water exchanges heat with the earth through geothermal boreholes or wells. Each building connects to the TEN using a ground source heat pump, which provides heating, cooling, and hot water. Recent changes in state law (HB 2131) have facilitated the development of TEN pilot projects by natural gas companies.

performance translates into greater system-level energy efficiency. Also, unlike air source heat pumps, TENs' efficiency and effectiveness does not depend on air temperatures that rise and fall dramatically with the seasons. In its letter of support for the project, Clark Public Utilities states that it has "concluded [that] TEN projects have potential to provide capacity value to the electric utility; when measured against the baseline technologies that would be providing space and water conditioning, a TEN achieves much lower peak demand during both the summer and winter seasons."[11]

As both the dual fuel and the TENs pilots show, NW Natural is eager to collaborate with local electric utilities, such as Clark Public Utilities, to continue to develop these innovative solutions to the pressing issues that all regional energy utilities face regardless of whether they are natural gas or electric, consumer or investor owned.

III. NW NATURAL'S APPLICATION FOR GENERAL RATE REVISION

A. Overview of Multi-Year Rate Plan ("MYRP")

Q. Please summarize the Company's proposed multi-year rate plan.

A. NW Natural is filing its first general rate case under Washington's MYRP statute, RCW 80.28.425(1), which became effective on January 1, 2022. NW Natural is proposing a three-year rate plan with the first year rate effective date of August 1, 2026. Specifically, rate year one ("RY1") covers August 1, 2026 through July 31, 2027, rate year two ("RY2") covers August 1, 2027 through July 31, 2028, and rate year three ("RY3") covers August 1, 2028 through July 31, 2029.

[11] Exh. HJB-4.

NW Natural is proposing to increase revenues from base rates by $25.6 million in RY1, which is a 22.8 percent increase in revenues. For RY2 and RY3, the Company proposes an additional increase in base rates of $8.6 million and $8.3 million, respectively. This would be an additional increase of 6.2 percent in RY2 and 5.7 percent in RY3. NW Natural is also seeking to amortize: 1) its Transportation Security Administration ("TSA") Security Directive 2 deferral, 2) its COVID-19 deferral, and 3) its meter modernization deferral. To limit the size of the RY1 and RY2 rate increase, NW Natural is proposing to amortize the TSA Security Directive 2 deferral over a three-period beginning in RY3. NW Natural is also proposing to amortize the COVID-19 and meter modernization deferral over the three-year MYRP to limit the size of the rate increases in the MYRP.

The requested increase in base rates includes a capital structure of 51 percent common equity, 48 percent long-term debt, and 1 percent short-term debt with a requested 10.1 percent return on equity ("ROE") in RY1, increasing to 10.2 percent in RY2 and RY3, resulting in an overall rate of return ("ROR") on rate base of 7.505 percent in RY1, 7.623 percent in RY2, and 7.661 percent RY3.[12]

Q. Without this rate relief, what is the financial impact to NW Natural?

A. Without the requested increase in base rates, NW Natural's gas distribution utility would expect the overall ROR to be 1.86 percent, with a corresponding ROE of -0.95 percent in RY1, well below the proposed ROR and ROE in this case of 7.51 percent and 10.1 percent, respectively.[13] The Company, therefore, needs to increase its rates

[12] *See* Exh. BJW-1CT, Table 1. The slightly higher ROR in RY3 is due to a higher cost of debt in that year.

[13] *See* Exh. KTW-2.

in order to maintain an ability to recover its costs and earn a reasonable return that will allow it to attract the capital that is required to safely and reliably run its utility system for the benefit of its customers.

B. Considerations in Developing the MYRP

Q. Please comment on the considerations NW Natural undertook before filing its MYRP.

A. As described above, NW Natural is committed to customer satisfaction and providing natural gas service at reasonable rates for customers. NW Natural understands that natural gas plays a vital role in its customers' lives, and the Company does not take lightly the prospect of this magnitude of rate increase in RY1. These rate increases cause customers concern, and any significant increase in overall rates can present a financial hardship for some of NW Natural's customers. We recognize that not all households and businesses have natural gas service, and they have other options for serving their energy needs. This means that, even as a regulated utility, NW Natural competes for business with other energy providers, and therefore is always motivated to keep natural gas rates as low as possible while still being able to provide excellent customer service, exceed safety standards, and maintain financial integrity as a Company. NW Natural determined, however, that after five years of managing the Company without a general rate request, NW Natural would file this MYRP with the Commission seeking to revise its rates to recognize an increased revenue requirement related to its provision of utility service.

Q. Has NW Natural taken any specific steps to mitigate the size of the rate increase?

A. Yes. NW Natural has taken several steps to mitigate the size of the rate increase. First, NW Natural is not seeking recovery of provisional capital in RY1. Specifically, to calculate RY1 rates, the Company used plant balances as of July 31, 2026, as opposed to also including investments that will enter service during RY1. By not including these investments, NW Natural is limiting the size of the RY1 increase. In addition, NW Natural is not proposing to include the reasonable cost of construction work in progress in valuing its plant, although the Commission has the discretion to include such costs under RCW 80.04.250(2).

Second, NW Natural is not seeking to recover the long-term portion of the Company's executive compensation program that applies to officers, high-performing managers, and key employees. The Company is also proposing to hold all incentive pay flat over the course of the MYRP, even though inflation will cause these costs to increase over the term of the three-year MYRP.[14]

Third, while the Company's actual capital structure has a 52 percent equity layer as of June 30, 2025, it is requesting a 51 percent equity layer in its MYRP to also help mitigate the size of the rate increase. By doing so, NW Natural is seeking to balance near-term rate impacts with its commitment to a strong and stable balance sheet that helps maintain its current credit ratings.

[14] *See* Exh. JEN-1T ("[I]nflation is expected to remain markedly above levels experienced prior to the COVID-19 pandemic").

Fourth, NW Natural is not seeking to increase the amount of renewable natural gas ("RNG") it purchases to serve Washington customers in its upcoming Purchased Gas Adjustment ("PGA") proceeding this year. Although these RNG costs are recovered through the PGA (not general rate cases), they nonetheless are a part of customers' bills. By holding the amount of RNG steady, the Company is balancing near-term rate increases with the purchase of decarbonized fuels that are more expensive than conventional natural gas.

Fifth, as part of this proceeding, NW Natural is seeking to revise its depreciation rates to better reflect the depreciable lives of the Company's plant. As explained in the Direct Testimony of John J. Spanos (Exh. JJS-1T), these revised depreciation rates increase depreciation expense. To mitigate the size of the RY1 and RY2 increase, NW Natural proposes to incorporate these revised depreciation rates into RY3 rates, which reduces rate pressure in RY1 and RY2.

Sixth, as stated above, NW Natural is seeking to amortize several deferrals in a way that limits their immediate rate impact. For example, NW Natural is proposing to not begin amortizing the TSA Security Directive 2 deferral until RY3, and it is seeking to amortize several other deferrals over the course of the MYRP, limiting the size of annual rate increases in the MYRP.

Q. Despite the steps it has taken to mitigate the size of the rate increases over the course of the MYRP, NW Natural is still proposing a three-year rate plan. How do the rate increases in the rate plan compare to the average residential bill that customers have paid since the rate effective date of its last general rate case (November 1, 2022)?[15]

A. Although NW Natural acknowledges it is seeking rate increases over the course of the MYRP, it nonetheless results in existing residential customers' average RY1 bills being nearly the same as they were throughout most of 2024.[16] Since the rate effective date of NW Natural's last general rate case (November 1, 2022), customers' bills have fluctuated due to the PGA and the implementation of the Climate Commitment Act ("CCA").[17]

The effect of changing commodity costs for the price of natural gas is well established. It can lead to bill increases or decreases through the annual PGA. However, the effect of the CCA, especially its initial implementation, is new. The CCA caps and reduces the State's greenhouse gas emissions over time. Beginning in 2023, the CCA requires the State's industries, including NW Natural, to obtain allowances equal to the greenhouse gas emissions attributed to them and then submit those

[15] NW Natural filed its last general case before the current version of RCW 80.28.425(1) took effect and, therefore, it was not a MYRP under that statute. However, the Company's last rate case did result in the Commission approving rate changes that took effect on November 1, 2021 and November 1, 2022 respectively. See *Wash. Util Comm'n v. N.W. Natural Gas Co*., Dockets UG-200994, UG-200995, UG-210085 (consolidated), Order 05 (Oct. 21, 2021).

[16] As explained below, "existing customers" are defined under the Climate Commitment Act ("CCA") as those customers whose premises that were receiving natural gas service as of July 25, 2021. The overwhelming majority of NW Natural's residential customers are existing customers.

[17] RCW 70A.65 et seq.

allowances to the Department of Ecology. Under the CCA, those premises that were receiving natural gas service as of July 25, 2021 ("existing customers") receive a credit to mitigate some CCA costs, whereas premises that began receiving natural gas service after that date do not ("new customers").[18] Importantly, however, low-income customers, regardless of when their premises began receiving natural gas service, are held harmless from CCA charges.[19]

Existing customers saw a temporary increase in their average monthly bill due to the initial implementation of the CCA beginning on January 1, 2024, when NW Natural began recovering the CCA allowance costs it had already incurred in 2023 and that it was forecasted to incur in 2024.[20] Beginning on January 1, 2025, however, the average customer existing bill has declined due to NW Natural only recovering the cost of CCA allowances it has forecast for the upcoming year, as well as a decline in commodity costs.

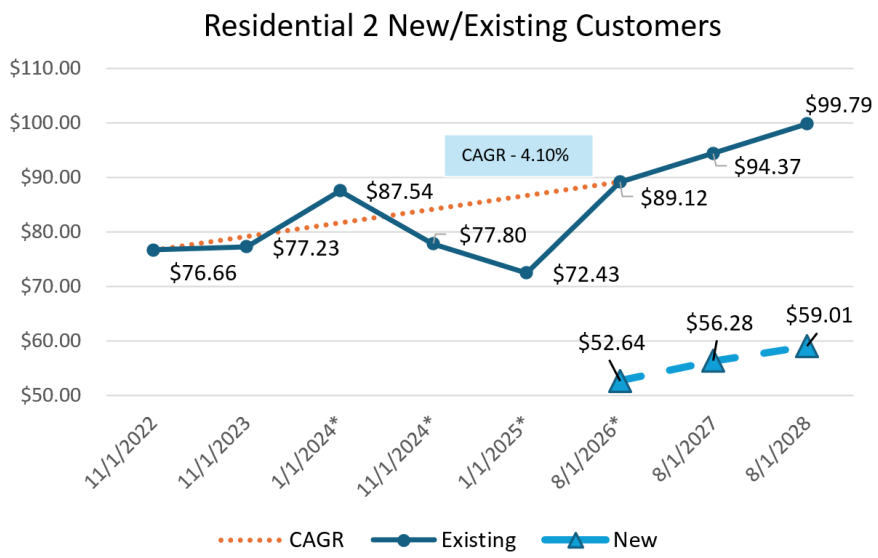
Figure 2 below shows the average existing residential customer monthly bill since November 1, 2022 under Rate Schedule 2, Residential Sales Service, which illustrates these changes.

[18] RCW 70A.65.130(2)(c).

[19] RCW 70A.65.130(2)(b-c). See also the Company's Schedule 308, Washington CCA Cost Recovery Mechanism, ("Low Income customers are held harmless and will see a [CCA] charge and offsetting credit on their bill.").

[20] Again, low-income customers do not pay CCA costs, so their bills would not have increased due to CCA.

Figure 2



As shown in Figure 2 above, beginning on January 1, 2024, the average existing residential customer's bill increased from $76.66 per month to $87.54 per month as NW Natural recovered the CCA allowance costs. With the proposed RY1 rate increase, the average customer bill would increase to $89.12 per month, only slightly higher than what the average residential bill was throughout most of 2024. After incorporating the proposed RY1 increase, the Compound Annual Growth Rate ("CAGR") would be 4.10 percent since the rate effective date of NW Natural's last general rate case.

Despite new customers not receiving credits to mitigate CCA costs, the average new customer bill is projected to be substantially lower than the average existing customer bill because these new customers use substantially less gas than existing customers. Over the course of the MYRP, NW Natural projects that the average new

customer will use 27.8 therms per year, whereas an existing customer will use 55.2 therms per year.[21]

Q. Is NW Natural taking steps to limit the volatility in customer bills that occurred between 2023 and 2025?

A. Yes. NW Natural is filing a three-year rate plan to help smooth the rate impacts after RY1. Also, as explained above, NW Natural is currently recovering the cost of CCA allowances on regular annual cadence, whose initial implementation led to a relatively substantial rate increase in 2024 as explained above.

Q. How does the average RY1 monthly residential bill compare to the average monthly residential bill historically?

A. For existing customers, which makes up the overwhelming majority of NW Natural's customer base,[22] the RY1 monthly residential bill is $89.12. This bill is only slightly more than the 2008-09 average monthly residential customer bill of $82.49 without taking inflation into account.[23] After taking inflation into account, the average monthly residential bill for existing customers is approximately 27.80 percent less than it was in 2008-09. To be clear, these figures are not a rationale for the proposed rate increases in this MYRP, but we point this out because it provides relevant context when evaluating the impact on customers of this request. Moreover, these figures do not

[21] NW Natural has not calculated the use-per-customer for new customers prior to the MYRP and, therefore, did not compare new customers' residential bills over this time period.

[22] In other words, most of the premises served by NW Natural were receiving natural gas service as of July 25, 2021, which is the date that separates existing customers from new customers. See RCW 70A.65.130(2)(c).

[23] Specifically from November 1, 2008 to October 31, 2009.

account for NW Natural's Bill Discount Program ("BDP"), which has reduced monthly bills for participating low-income residential customers well below 2008-09 levels.

Q. Please explain how the BDP has reduced participating low-income residential customers' bills well below 2008-09 levels.

A. In RY1, the average monthly low-income residential customer bill is $83.23 before applying the BDP.[24] The average low-income residential bill is lower than the average monthly bill for existing customers ($89.12) because low-income residential customers are held harmless from CCA costs. After applying the BDP, low-income customers' bills are dramatically lower than they were in 2008-09, as shown in Figure 3 below.

Figure 3

Comparison of Average RY1 BDP Bill to Average 2008-09 Residential Bill ($82.49)

BDP Tier Level	BDP Discount of Total Bill	Average RY1 Monthly Bill Under BDP	RY1 BDP Monthly Bill Compared to Average 2008-09 Bill
Tier 0 0-60% FPL	80%	$16.65	-80%
Tier 1 61-120% FPL	40%	$49.94	-39%
Tier 2 121-150% FPL	20%	$66.58	-19%
Tier 3 Greater of 151-200% FPL or 80% AMI	15%	$70.74	-14%

[24] To calculate the average bill, NW Natural utilized the same use-per-customer as existing customers (55.2 therms per year).

These figures are not adjusted for inflation. If they were, the average RY1 low-income residential customer monthly bill would be even lower compared to 2008-09.

Again, these comparisons to both recent and historical residential bills do not provide a rationale for the proposed rate increases in this MYRP. However, they do provide relevant context when evaluating the impact of the Company's rate request in this proceeding.

C. Drivers of the MYRP

Q. What are the significant drivers for the MYRP?

A. There are five significant factors that are driving the need to file this MYRP:

- Investments in storage facility and distribution system projects to ensure continued safe and reliable operations.
- The TEN pilot project.
- The Meter Modernization Program.
- Replacement of end-of-life information technology and services ("IT&S") systems.
- Escalating costs due to inflation.

Q. Before describing NW Natural's investments in storage facility and distribution system projects, please summarize the changes that NW Natural has recently made to its distribution system planning.

A. As a result of implementing the Customer Management Module ("CMM") modeling in 2022, NW Natural can now model future distribution system needs with a longer lead time. CMM more accurately models local system pressures by using individual historical customer usage, rather than local average customer usages. Utilizing CMM

gives the Company additional time to study demand side management alternatives that can cost-effectively avoid or delay a system reinforcement project. CMM has already identified areas of the system where NW Natural can pursue these opportunities. However, it has also identified areas of the Company's system in near-term need of reinforcement. With the implementation of CMM, NW Natural is also expanding its suite of non-pipeline solutions such as Geographically Targeted Energy Efficiency (GeoTEE) and Geographically Targeted Demand Response (GeoDR). In addition, NW Natural is studying whether CNG or LNG trucking may be a viable alternative to a pipeline solution for a peak weather event in certain circumstances.

Despite the potential of non-pipeline solutions, NW Natural must nonetheless continue to make improvements to its distribution system in order to keep its system safe, reliable, and economical, especially in areas of its system that are already constrained. Non-pipeline solutions typically require longer lead-times than pipeline solutions. However, as NW Natural moves away from distribution system planning on a just-in-time basis where traditional pipeline solutions were not developed until areas of the system became constrained, the Company expects non-pipeline alternatives to play a greater role in the planning process. That said, non-pipeline solutions will not be able to satisfy every system need NW Natural has.

Q. Is NW Natural moving forward with a reinforcement project in this case?

A. Yes, the Vancouver Reinforcement Project is necessary to maintain adequate pressure on NW Natural's high pressure distribution system in Clark County during a peak cold weather event. NW Natural first identified this constraint utilizing its CMM modeling. CMM revealed that NW Natural's distribution pressures for the design cold weather

planning event would not be adequate. Subsequent measurements and monitoring of real-world experience during cold weather events demonstrate that pressure on the distribution system has fallen below our standards, and the Company needs to take action to address this constraint.

NW Natural is currently evaluating both pipeline and non-pipeline solutions. The pipeline solution would involve constructing approximately 2.5 miles of 12-inch gas main to reinforce a segment of 4-inch main near Lacamas Lake in the east Vancouver area. NW Natural is also considering uprating the operating pressure of the 250 MAOP high pressure distribution system to 300 MAOP or injecting gas from CNG or LNG trailers cited on a parcel of land in the east Vancouver area during peak cold weather events. NW Natural is completing its final alternatives analysis. The Company conservatively expects to complete the project by December 2028, although it is also evaluating whether the project can be completed in 2027 given the low pressures in the system that are currently being recorded during cold weather events.

The Direct Testimony of Daniel B. Kizer, Senior Director of Engineering, and Scott S. Johnson, Senior Director of Gas Supply, (Exh. DBK-SSJ-1T) further explains NW Natural's distribution system planning changes.

Q. Please summarize the storage facility and distribution system projects that are included in this case.

A. As fully explained in the Direct Testimony of Daniel B. Kizer and Scott S. Johnson (Exh. DBK-SSJ-1T), NW Natural has included a number of storage facility and distribution system projects in this case. Each of them is necessary to ensure that NW Natural continues to provide safe reliable service. Of these projects, the two most

significant are the replacement of end-of-life compressors at NW Natural's Mist Storage Facility and the Vancouver Reinforcement Project.

Q. Please describe the compressor replacement project at the Mist Storage Facility.

A. At the Mist Storage Facility, natural gas can be stored indefinitely and dispatched over the entire winter season including sustained multi-day cold stretches. NW Natural's access to the Mist Storage Facility, its liquified natural gas ("LNG") storage facilities in Portland and Newport, Oregon, and its contract for storage service at Jackson Prairie near Centralia, gives the Company the ability to store natural gas for use during the coldest days of the year irrespective of increased demand during that time of year.

NW Natural has also already developed additional capacity at the Mist Storage Facility in advance of utility customer need. This capacity currently serves the interstate/intrastate storage market but can be recalled for service to NW Natural's utility customers at its depreciated value, providing real-time access to incremental capacity at a low cost. The Mist Storage Facility is ideally located in NW Natural's service territory, eliminating the need for upstream interstate pipeline transportation service to deliver the gas during the heating season. NW Natural has recalled an incremental 20,000 Dth/day of Mist deliverability to meet this demand beginning November 1, 2024, and expects additional recalls to meet demand in the future.

Therefore, the Mist Storage Facility is a significant portion of NW Natural's firm resource stack. However, the facility depends on the GC500 and GC600 compressors to provide operating compression so that NW Natural can utilize it to meet winter demand, and both compressors have exceeded their useful lives and require ongoing "break-fix" repairs that routinely disrupt the operations at Mist. To ensure the

continued reliability of the Mist Storage Facility, the Company will replace the GC500 unit first, by October 2025, because it is the oldest unit (installed in 1998). NW Natural will use the GC600 unit to support injection operations during the replacement period. NW Natural plans to replace the GC600 compressor (installed in 2001-02) by October 2026. Replacing both compressors is vital to ensure the future reliability of the Mist Storage Facility.

Q. Please briefly summarize the TENs pilot project.

A. As mentioned above, NW Natural is pursuing a TENs pilot project in downtown Vancouver. As designed, the pilot will deliver thermal service to an estimated 430 new market-rate multifamily units, 36,800 square feet of retail commercial space, and Vancouver's City Hall. These buildings, located within a couple of city blocks, represent a cross-section of residential, commercial, and public-sector customers, enabling the pilot to test and refine a scalable service model across multiple customer classes. NW Natural currently estimates that the Vancouver TEN pilot project will cost approximately $12.8 million in total, but the Company anticipates that investment tax credits and incentives will reduce that cost to $9.2 million. NW Natural is also seeking a grant from the Washington State Department of Commerce that will further reduce the costs that customers would pay for this project. The confidential Direct Testimony of Holly J. Braun (Exh. HJB-1CT) discusses the TENs pilot project in detail.

Q. Please briefly explain the Company's Meter Modernization Program.

A. The Meter Modernization Program is a four-year program that began in 2024 and will continue through 2027. It is an ongoing Company initiative that focuses on the replacement of a large portion of NW Natural's metering assets due to aging batteries

inside the communication devices (encoder receiver transmitters, or "ERTs") attached to its meters. Without functioning ERTs, NW Natural cannot bill its customers. Additionally, the Meter Modernization Program will maximize cost-efficiency by combining ERT replacement with the replacement of meters that are out of compliance with applicable standards. The Direct Testimony of Joe S. Karney (Exh. JSK-1T) further explains the Meter Modernization Program.

Q. Please discuss the Company's plans to update its IT&S infrastructure.

A. NW Natural is seeking cost recovery of essential projects that are necessary to ensure the continued functionality of its IT&S infrastructure. Specifically, NW Natural is continuing its multi-year program to phase out end-of-life field and web mapping software and transition to a consolidated set of modern software solutions, as well as improving its Field Workforce Management tools that are necessary to schedule, dispatch, and route NW Natural personnel in the field. Ongoing work is also necessary to improve its Identity Governance and Administration (IGA), which is the process of granting, updating, reviewing and revoking access to technology systems for NW Natural employees and contractors, based on job changes or other Company needs. In addition, NW Natural is pursuing customer self-service enhancements to help customers manage their accounts more easily through the web-based and phone systems.

Further, NW Natural is maintaining and upgrading its IT&S infrastructure. These efforts include: 1) refreshing the physical infrastructure necessary to enable the Company's IT&S, including microwave towers, voice radio, and telemetry equipment, 2) replacing the Company's aging, custom-built supervisory control and data

acquisition ("SCADA") platform with a modern, modular, and secure SCADA platform to control and monitor the Company's distributed pipeline infrastructure, 3) updating and maintaining critical IT&S applications and platforms through its Application Lifecycle Management (ALM) initiative, and 4) ensuring continued back office functionality, including financial reporting software, billing systems, risk analytic tools, and report generation functions.

The confidential Direct Testimony of Brian E. Fellon (Exh. BEF-1CT), the Company's Vice President and Chief Information Officer, provides a comprehensive explanation of the Company's IT&S projects, including those mentioned above.

Q. Please describe how operations and maintenance costs have escalated since NW Natural's last rate case.

A. Since the rate effective date of NW Natural's last general rate case that adjusted operations and maintenance costs (November 1, 2021),[25] inflation has increased NW Natural's operations and maintenance costs substantially. The Direct Testimony of Jennifer E. Nelson (Exh. JEN-1T) explains that when the U.S. economy opened from the COVID-19 lockdowns, economic activity quickly rebounded, causing inflation to reach the highest levels seen in the last 40 years. Seasonally adjusted inflation has increased 16.3 percent between October 2021 when the Commission's decision in the Company's last rate case was issued and June 2025.[26] NW Natural is unable to

[25] The rate change that took effect on November 1, 2022, did not adjust the Company's operations and maintenance costs.

[26] Exh. JEN-1T.

continue to absorb these increasing costs, which is a major driver of NW Natural's MYRP.

Q. Given all of the considerations and cost drivers explained above, please briefly explain why NW Natural is proposing its MYRP.

A. NW Natural recognizes that its proposed RY1 increase is significant. However, at its core, this rate case is about recovering the costs of NW Natural's investments to continue to support its utility service to customers, as well as recovering escalating costs since the Company's last general rate case. NW Natural understands that natural gas has an essential role in our customers' lives, and we do not take lightly the prospect of increasing our customers' rates.

After five years without a general rate case, the Company nonetheless determined that NW Natural would need to file this MYRP with the Commission seeking to revise its rates to recognize an increased revenue requirement related to its provision of utility service. As we have stated above, without the requested increase in base rates, NW Natural's gas distribution utility would expect the overall ROR to be 1.86 percent, with a corresponding ROE of -0.95 percent in RY1, well below the proposed ROR and ROE in this case of 7.51 percent and 10.1 percent, respectively. Therefore, the MYRP is necessary for the Company to recover its costs and have the opportunity to earn a reasonable return that attracts capital that is necessary to maintain safe and reliable service for its customers.

IV. ENERGY EQUITY AND AFFORDABILITY

Q. Please briefly summarize NW Natural's primary energy equity and affordability initiatives.

A. NW Natural continues to strengthen considerations of energy equity and affordability into its day-to-day operations and program offerings to customers. First, participation in its BDP is continuing to grow. Second, working with a third-party consultant, the Company has also completed its second Energy Burden Assessment ("EBA") that analyzed energy burden in its service territory. Third, NW Natural has recently expanded its Washington Low-Income Energy Efficiency ("WALIEE") program. Finally, the Company has have made enhancements to several other energy affordability and equity programs as well. The Direct Testimony of Cecelia J. Tanaka (Exh. CJT-1T) fully discusses the Company's energy equity programs and initiatives, but we will briefly touch on each here.

Q. Please briefly explain NW Natural's BDP, including how the Company is conducting outreach to expand participation.

A. On January 1, 2024, NW Natural began offering its BDP to income-eligible customers. The BDP offers three tiers of discounts ranging from 15 percent to 80 percent depending on household income. In the first 17 months of its Washington program, roughly 9,000 customers enrolled, representing half of the Company's estimated income-eligible population in its service territory. Customers who have received energy assistance or weatherization services within the last two years are automatically enrolled in the BDP. NW Natural also works with community partners throughout its service territory, such as community action agencies, school systems, housing

networks, places of worship, food banks, culturally specific organizations, and healthcare networks, to increase enrollment in its BDP.

In addition, NW Natural's community partners utilize a wide variety of communication channels including check-in calls with homebound seniors, inserts in food boxes at schools and food pantries, direct mail, community newsletters, and social media posts. Leveraging these relationships and networks is particularly valuable, enabling the Company to reach customers who might otherwise be inaccessible to deliver BDP information through other important and trusted sources.

NW Natural continues to take direct action to increase BDP participation as well, such as a direct mail campaign to over 3,600 Washington customers who have been identified through its EBA as likely eligible and energy burdened but not participating in the BDP.

The Company also hosted a Winter Preparedness Fair in November 2024 that offered weatherization kits, a vaccine clinic, winter coats for kids, food boxes, and a BDP sign-up station covering several utilities and services for income-eligible households—all at no cost to the customer. NW Natural continues to participate in other community forums to increase BDP participation, such as hosting a table at Clark Public Utilities' Race for Warmth and sponsoring the Clark County Fire Department #6 Open House on June 7, 2025, where the Company hosted three tables on safety and preparedness, resource planning, and ways to reduce bills through energy efficiency, weatherization, and bill discount offerings.

Q. Did NW Natural re-examine its BDP discount tiers due to its proposed RY1 rate increase?

A. Yes. NW Natural re-examined its BDP discount tiers due to its proposed RY1 rate increase. Applying an illustrative 25 percent increase (which is greater than the proposed RY1 rate increase) to the existing BDP discount tiers results in a natural gas energy burden between 1.2 and 2.1 percent, depending on the BDP tier. Specifically, customers receiving a 15 percent discount (Tier 3) would have an energy burden associated with their natural gas bill of approximately 1.2 percent. Customers receiving a 20 discount (Tier 2) would have a natural gas energy burden of approximately 1.9 percent. Those customers receiving a 40 percent discount (Tier 1) and an 80 percent discount (Tier 0) would each have a natural gas energy burden of 2.1 percent. Since a household is considered energy burdened if it spends more than 6 percent of their income on energy costs (or 2 percent on just gas per the EBA), NW Natural is not proposing any changes to the BDP discount tiers.[27]

The BDP, including NW Natural's outreach to increase participation in its BDP and its evaluation of the program to date, is fully explained in the Direct Testimony of Cecelia J. Tanaka (Exh. CJT-1T).

Q. Please summarize the key findings of the Company's EBA.

A. Specific to Washington, the EBA found that about 23 percent of its residential customers meet low-income guidelines, nearly double that of its Oregon customer base. This greater number is because the Washington BDP has a higher income threshold

[27] See Exh. CJT-1T for additional details regarding energy burden and how it is calculated.

than Oregon's BDP. In Washington, the income threshold is the greater of 80 percent of the area median income or 200 percent of the federal poverty line, meaning that it is about $25,000 higher than Oregon's threshold (60 percent of state median income). For a family of four, households that earn up to $94,400 are eligible for some level of discount. The same household would be required to earn just under $71,000 to be eligible for the bill discount program in Oregon.

The EBA also found that the BDP is targeting customers most in need, evidenced by the highest participation rates in the lowest income tier where customers obtain an 80 percent discount from their bills.

Q. How has NW Natural used the EBA information?

A. Although the EBA revealed healthy participation in the BDP, it also identified pockets of need and opportunities for further outreach. Based on these findings, NW Natural launched the direct mail campaign that we referenced above to increase participation in the BDP. This campaign was specifically targeted at customers who were identified through the EBA as likely eligible for the BDP. The Company's outreach to over 3,600 Washington customers was part of the Company's larger direct mail campaign to over 15,000 customers.

Q. Please briefly explain the expanded WALIEE program.

A. The WALIEE program provides energy efficiency benefits through whole home weatherization to income-qualifying residential dwellings. Prior to 2024, WALIEE funded up to $5,000 for energy efficiency measures and an average of $1,000 per household per community action agency for health, safety, and repairs reimbursement. Last year, NW Natural, working with its Energy Efficiency Advisory Group, tripled

the maximum amount available for a residence's energy efficiency measures to $15,000, as well as increasing the health, safety, and repairs reimbursement to $4,000. This increase in funding can help address the approximately 10,000 high-burden, low-income customers within NW Natural's Washington service territory who its EBA identified as significant opportunities for high impact energy efficiency upgrades.

Q. Please highlight some of the enhancements that NW Natural has made to other energy affordability and equity programs.

A. In addition to the BDP and WALIEE, NW Natural offers additional resources for customers to better afford their natural gas bills. Like the BDP, income eligibility is set at the greater of 80 percent of Area Median Income or 200 percent of the Federal Poverty Level. These programs include an arrearage management program that has delivered $80,000 in instant grants since it launched on April 1, 2025, as well as a ratepayer-funded energy assistance program—the Gas Residential Energy Assistance Tariff (GREAT)—which distributed approximately $620,000 to 913 customers in the most recent program year (2023-2024)—surpassing previous year records in dollars allocated and customers served. In addition, the Gas Assistance Program (GAP) is a supplemental energy assistance program funded by NW Natural shareholders, employees, retirees, and customers that is matched by the Company up to $60,000 annually. Funds are allocated directly to customers via a network of Community Action Agencies. The program has raised and delivered over $6.7 million to 60,000 customers in Washington and Oregon since it was established in 1982.

The Company also offers several payment plan options to help customers manage their monthly expenses. Equal Pay is an option that smooths out customers'

bills over 12 months to make them more predictable; and the Company's Level Pay and Current Bill Plus plans offer more time and manageable payments for customers who need help with paying past due balances.

The Direct Testimony of Cecelia J. Tanaka (Exh. CJT-1T) fully describes all of these efforts, in addition to a comprehensive explanation of NW Natural's ongoing affordability and equity initiatives.

V. SUMMARY OF WITNESSES

Q. Can you briefly describe the testimony provided by other witnesses in this case?

A. Seventeen other witnesses describe the various components of cost that demonstrate the need for the requested rate increase.

Cecelia J. Tanaka, Energy Equity and Affordability Lead, describes the Company's initiatives and priorities regarding energy equity and inclusion, including NW Natural's BDP, details on the Company's EBA and low-income assistance offerings. Exh. CJT-1T.

Kyle T. Walker, Senior Manager of Rates and Regulatory Affairs, explains NW Natural's MYRP proposal, which covers three years beginning on August 1, 2026. Mr. Walker also explains how NW Natural determined the revenue requirement for each of the three years in the MYRP, including restating, proforma, and provisional adjustments. Exh. KTW-1T.

Natasha C. Siores, Senior Manager, Regulatory Affairs, explains NW Natural's proposed performance measures consistent with Commission rules and guidance. These performance metrics reflect three strategic goals that align with NW Natural's business principles: ensuring a resilient, reliable, and customer-focused

distribution grid; promoting customer affordability; and advancing equity in utility operations. Exh. NCS-1T.

Cory A. Beck, Director of Customer Experience Services, describe NW Natural's commitment to making sure that all customers—regardless of English proficiency or income level—have equitable access to essential utility programs and information. Exh. CAB-1T.

Brody J. Wilson, Vice President, Treasurer, Chief Accounting Officer and Controller, explains the Company proposed capital structure of 51 percent common equity, 1 percent short-term debt, and 48 percent long-term debt in order to support its strong investment grade credit profile. Exh. BJW-1CT.

Jennifer E. Nelson, Assistant Vice President of Concentric Energy Advisors, Inc., a firm with expertise on utility finance and required rates of return for regulated companies, provides testimony about the Company's cost of equity, or in other words, the return that NW Natural should be given the opportunity to earn in order to attract capital. Her analysis shows that a reasonable range of the cost of equity is between 10.0 percent and 11.0 percent. Ms. Nelson recommends that NW Natural be allowed an opportunity to earn a 10.1 percent return on equity in RY1 and 10.2 percent return on equity in RY2 and RY3. Exh. JEN-1T.

Jorge O. Moncayo, Business Planning Senior Director, describes the Company's capital project budgeting and forecasting processes, including management approval and lifecycle phases, as well as the Company's ongoing capital expenditure levels. Exh. JOM-1T.

Daniel B. Kizer, Engineering Senior Director, and **Scott S. Johnson**, Senior Director of Gas Supply, provide testimony about aspects of the Company's long-term system planning and the Company's recent improvements to its system modeling, as well as the improvements to NW Natural's distribution system and storage facilities that the Company is undertaking in order to keep NW Natural's system safe, reliable, and economical. Exh. DBK-SSJ-1T.

Wayne K. Pipes, Director of Facilities, Security and Emergency Management, discusses The Dalles Resource Center and physical security upgrades the Company is undertaking at various sites. Exh. WKP-1T.

Brian E. Fellon, Vice President and Chief Information Officer, describes the IT&S projects and programs for which the Company is seeking recovery in this case. He also provides an overview of NW Natural's strategic vision and explains major program IT&S planning areas. Exh. BEF-1CT. In a separate piece of testimony, Mr. Fellon also discusses NW Natural's ongoing efforts to comply with the Transportation Security Administration's Security Directive Pipeline-2021-02 series, including future projects that will be necessary due to those series of directives. Exh. BEF-23HCT.

Joe S. Karney, Vice President of Engineering and Utility Operations, explains the NW Natural's Meter Modernization Program, including the background and drivers for the program, NW Natural's evaluation of technology options, MMP deployment plans, and new employees associated with the MMP. Mr. Karney also describe the Company's cost recovery proposal for the Meter Modernization Program. Exh. JSK-1T.

Melinda B. Rogers, Vice President, Chief Human Resources and Diversity Officer, provides testimony on NW Natural's labor costs, and describes the Company's practices related to compensation, which ensure that all employees receive compensation at market-median rates. Additionally, Ms. Rogers describes the Company's overall employee count over the course of the MYRP. Exh. MBR-1CT.

Tobin F. Davilla, Senior Manager of Financial Planning and Budget, explains how NW Natural calculated operations and maintenance expense, including how NW Natural adjusted Test Year operations and maintenance expense (April 2024 – March 2025), as well as the adjustments made for each year of the MYRP. Exh. TFD-1CT.

John J. Spanos, President of Gannett Fleming Valuation and Rate Consultants, LLC, presents the depreciation study that is used to calculate the Company's depreciation rates. Exh. JJS-1T.

Holly J. Braun, Business Development Consultant, explains NW Natural's TEN pilot project in Vancouver, including how the Company proposes to recover the costs of the project. Exh. HJB-1CT.

Robert J. Wyman, Rates and Regulatory Economist, describes the methodology for NW Natural's weather normalized use-per-customer forecast for the Residential and Commercial rate classes, presents the Embedded Cost of Service Study ("EmCOSS"), and describes the Company's rate spread and rate design proposal. Exh. RJW-1T.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

VI. LIST OF EXHIBITS

Exh. KAR-ZDK-2 ..... BPA System Peak

Exh. KAR-ZDK-3 ..... Guidehouse Study

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Kimberly A. Rush and Zachary D. Kravitz

POLICY

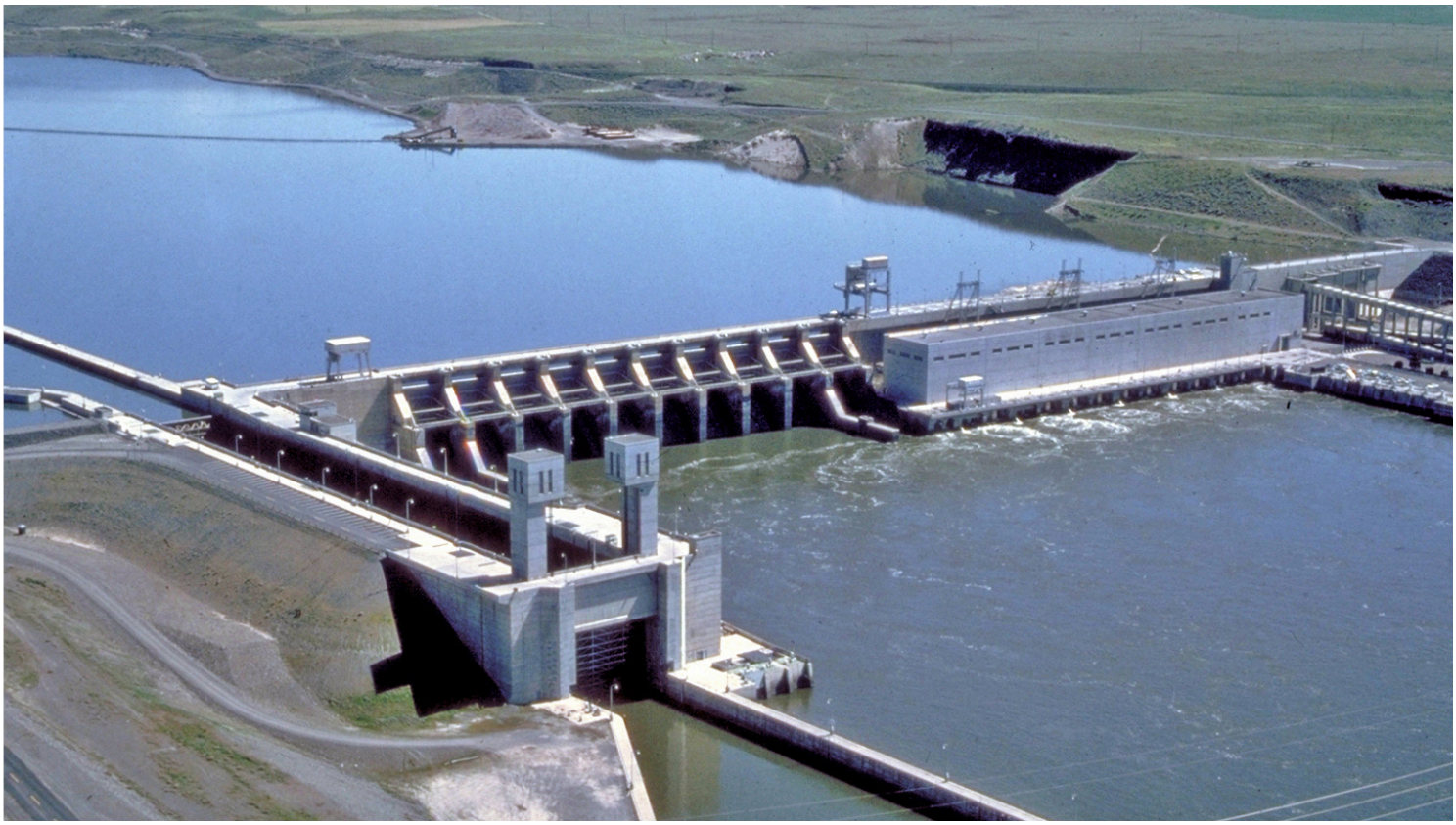
Exh. KAR-ZDK-2

August 29, 2025

Back to Newsroom

Federal hydro system powers region through arctic blast

January 31, 2024



Federal dams like Ice Harbor pictured here were instrumental in keeping the lights on during the recent cold snap.

Federal dams were operating at levels not seen since the age of aluminum smelters in the Northwest and were key to keeping the lights on during the recent arctic blast.

Serving consistently high energy demand took significant coordination with multiple partners for both proactive planning ahead of the weather and real-time adjustments as conditions evolved.

Vice President of Generation and Asset Management Michelle Cathcart

Plunging temperatures across the Pacific Northwest that stayed below freezing for four days from Jan. 12-16 were no match for the Federal Columbia River Power System. Despite record-breaking energy demand and other challenges, the federal power system supported its utility customers and the region through the most intense cold snap the Northwest had seen in 20 years.

“The federal dams and Columbia Generating Station, the region's one nuclear plant, were vital to keeping the lights on during this dangerous freezing weather event," said Power Services Senior Vice President Suzanne Cooper. “While other generation experienced outages, federal generation operated reliably. This performance combined with activity in the wholesale power market allowed us to meet our customers' load and help supply others during this event."

“There were challenging pockets throughout the system caused by physical damage to equipment, but our real-time staff made adjustments to preserve reliability, and our field teams did an excellent job of safely responding to interruptions in really challenging weather conditions," said Ricky Bustamante, acting vice president Transmission System Operations.

BPA's area load peaked at 11,396 megawatts during the morning of Saturday, Jan. 13, which is a modern era energy demand record since the time aluminum smelters were served with federal power. The previous post-aluminum record was set on Dec. 22, 2022, with 11,068 MW. The all-time peak load, which includes service to aluminum smelters, was set in 1990 with 11,930 MW. For context, area loads above 10,000 MW are uncommon and tend to only be observed during significant cold snaps.

Also on Jan. 13, BPA's aggregate customer load climbed even higher, peaking at 13,267 MW.

“Serving consistently high energy demand took significant coordination with multiple partners for both proactive planning ahead of the weather and real-time adjustments as conditions evolved," said Vice President of Generation and Asset Management Michelle Cathcart. “The dependability of the federal power system in extreme and dangerous weather events demonstrates its value and importance to BPA's power customers and the broader region."

Hydro power performance and operational considerations

BPA ramped up the output of the FCRPS during the day as electricity demand climbed and used power imports, or purchases, during light load hours at night to hold water back to maximize power generation

and meet peak demand. This helped BPA keep the lights on for the duration of the cold snap. During the cold snap, BPA did successfully work to optimize system conditions and operations to limit the potential financial exposure but ended the period as net buyer.

Leading up to the event, BPA coordinated with the U.S. Army Corps of Engineers and the Bureau of Reclamation to delay planned maintenance, ensuring the FCRPS had as many units available as possible. In addition, BPA requested restricted maintenance for CGS through Jan. 18.

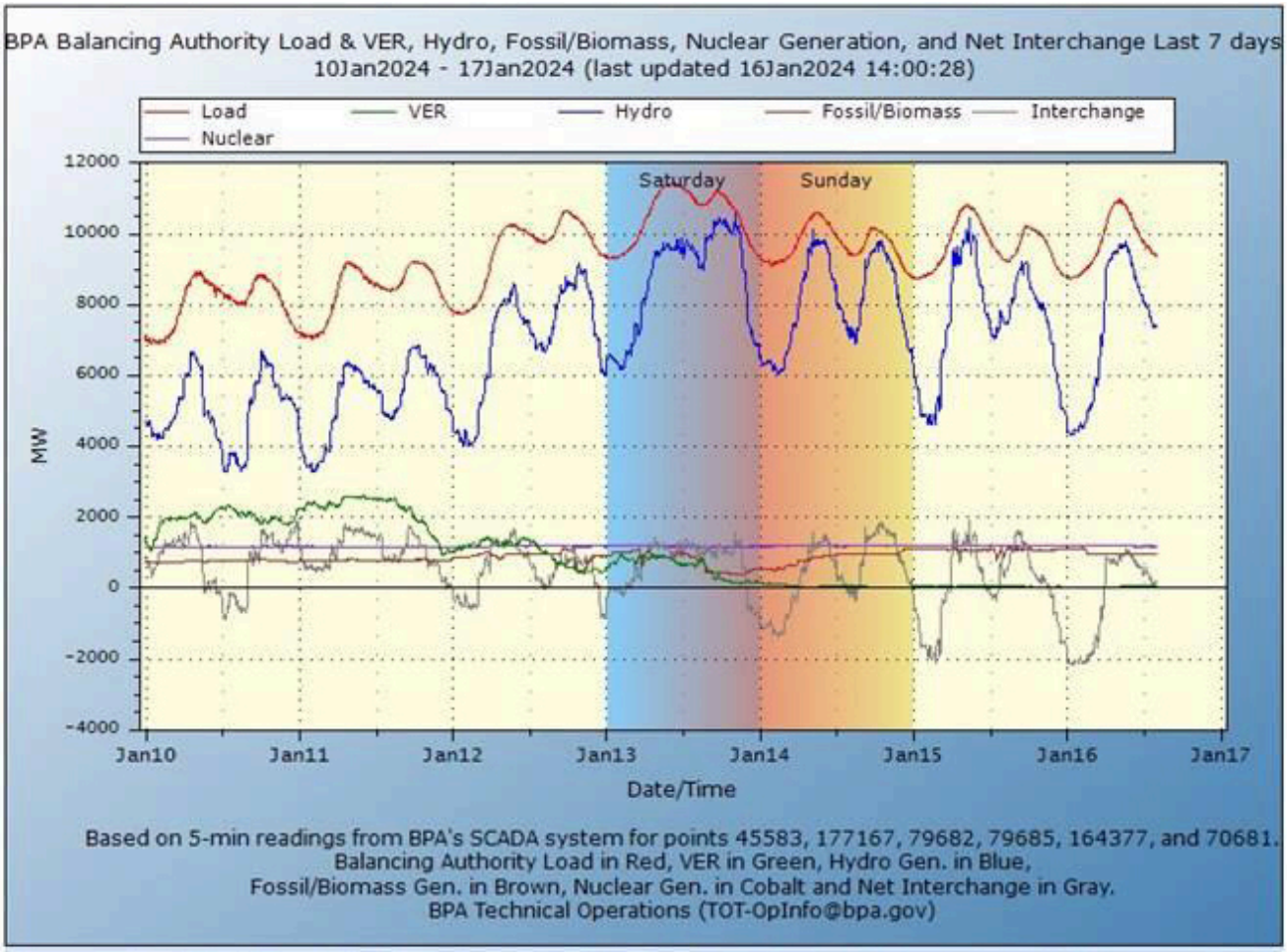
Due to a low water year this year, BPA's planned winter operations are managing the river to minimum flows. The requirement to save water above Grand Coulee for spring fish operations limited the amount of additional generation during the artic event; however, creative management of the lower Columbia projects allowed BPA to increase generation without reducing the amount of water in Grand Coulee's reservoir needed for springtime. Leading up to the impending cold snap, operations focused on creating storage space in the lower Columbia projects so upstream projects could increase generation without increasing flows below Bonneville Dam above the minimum needed to protect Endangered Species Act-listed chum salmon redds. This led to 525 average megawatts of extra generation from Jan. 12-16.

BPA also worked with Canada to release extra water from Canadian storage reservoirs. This provided an additional 600 aMW from Jan. 13-16.

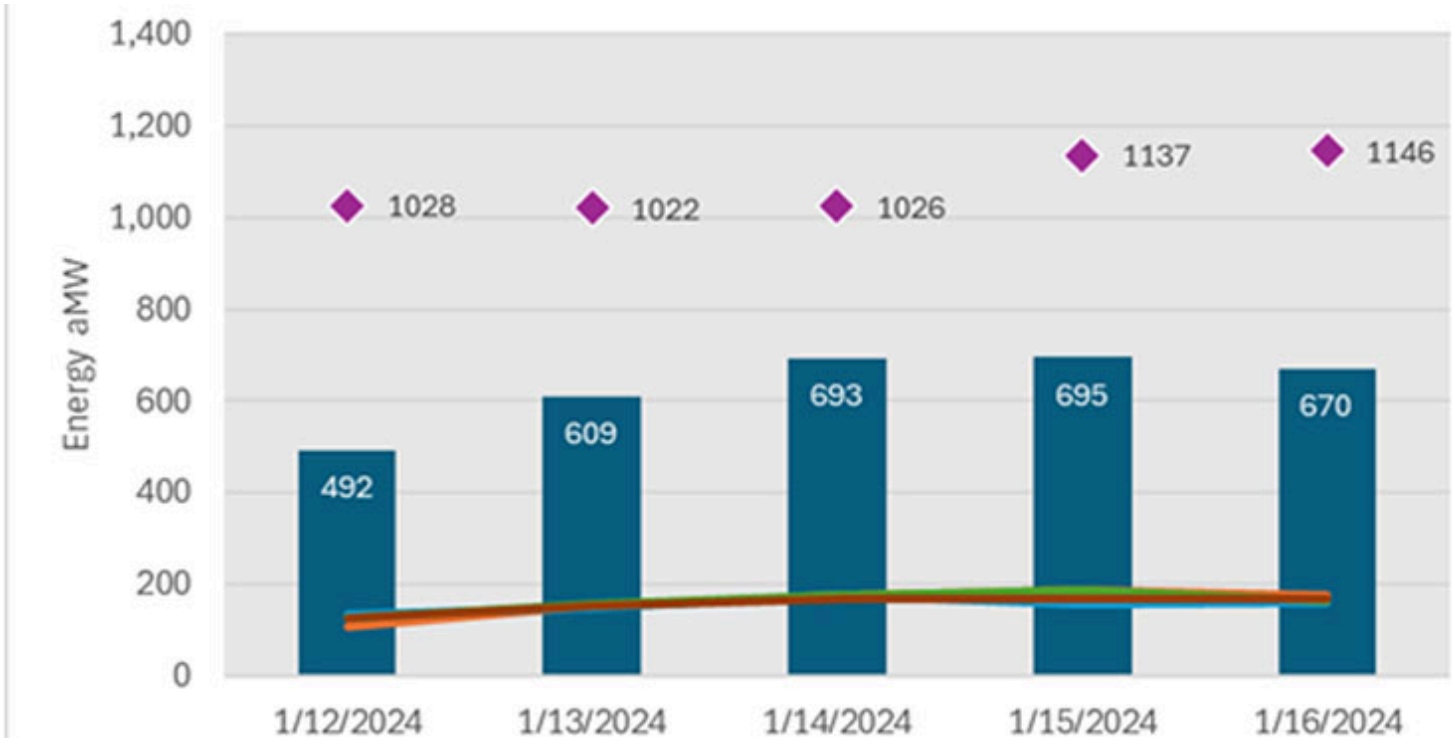
Lower Snake River dams performance

The lower Snake River dams made major contributions to BPA's efforts to keep the lights on during the cold snap. Combined, Lower Granite, Little Goose, Lower Monumental and Ice Harbor dams peaked to more than 1,000 aMW each day from Jan. 13-16 with the highest one-hour peak of 1,146 MW achieved on Tuesday, Jan. 16. This was accomplished by reducing generation late at night into the early morning hours to less than 200 MWs and ramping to over 1100 MWs during the peak daytime hours.

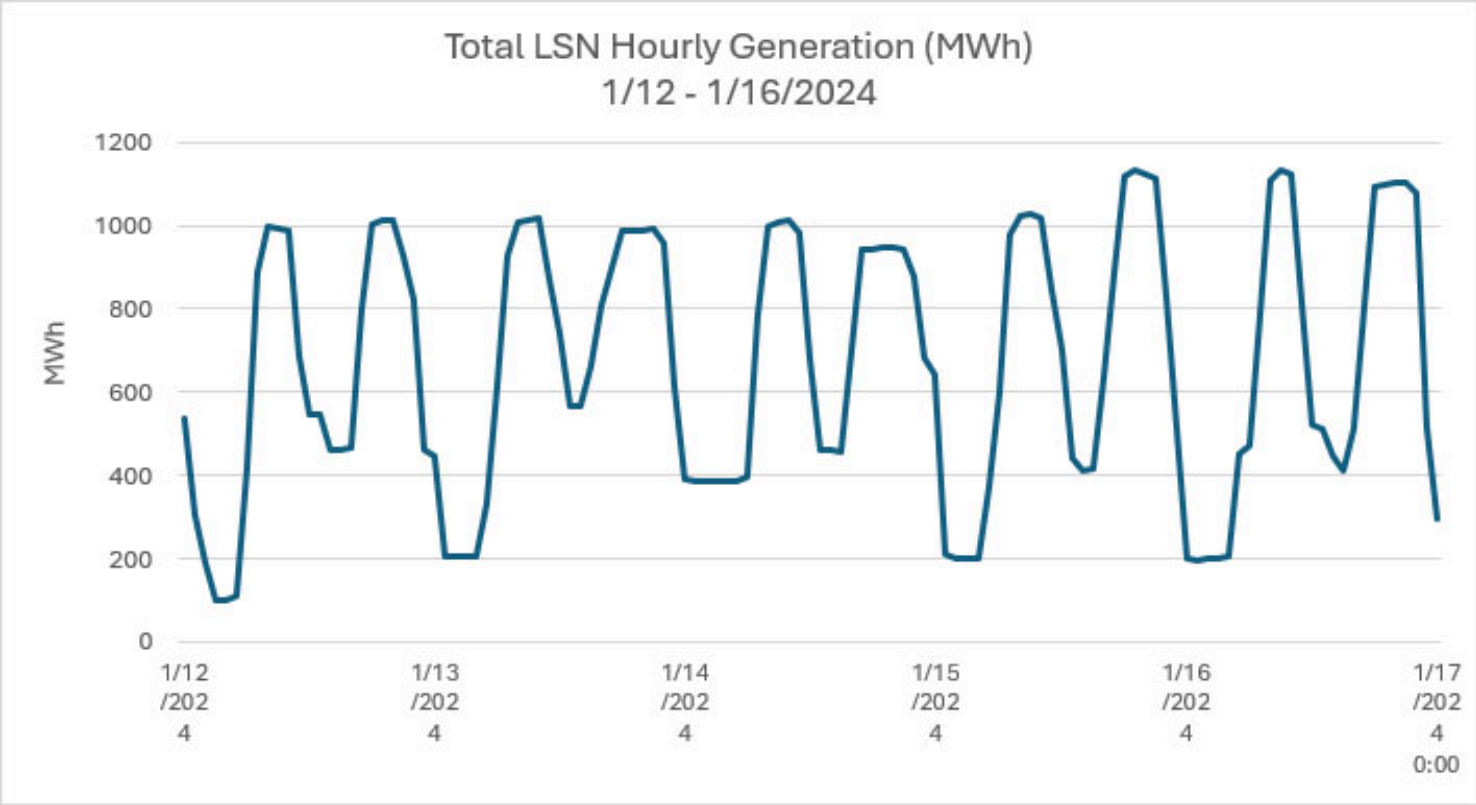
In addition to peaking performance, Ice Harbor Dam provided much needed local energy in the Tri-Cities area by increasing minimum generation throughout the extreme weather event.



On the chart above, VER = Wind and Solar.



The lower Snake River dams also registered an impressive, 18-hour sustained peak during the cold snap. Sustained peak measures the highest six hours per day of generation over a three-day period. The chart below demonstrates that sustained peak was 1,071 MW.



An hourly view of lower Snake River dam generation from Jan. 12-16. Generation at these dams can follow load demand, increasing to meet morning and evening peaks while lowering generation during nighttime hours.

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July 30, 2025

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Exhibit of Kimberly A. Rush and Zachary D. Kravitz

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Exh. KAR-ZDK-3

August 29, 2025

GAS-ELECTRIC COORDINATION

THIRD-PARTY ANALYSIS OF REGIONAL ENERGY STUDIES

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Contractor:

Guidehouse
Outwit Complexity

April 2025

The Pacific Northwest energy landscape is evolving rapidly, with more frequent extreme weather events and increasing energy demand placing new pressures on reliability and resource adequacy. The January 2024 cold weather event revealed the Pacific Northwest's energy system is dangerously close to having insufficient supply and highlighted enhanced coordination between electric and natural gas systems is critical to ensuring a resilient and reliable energy supply.

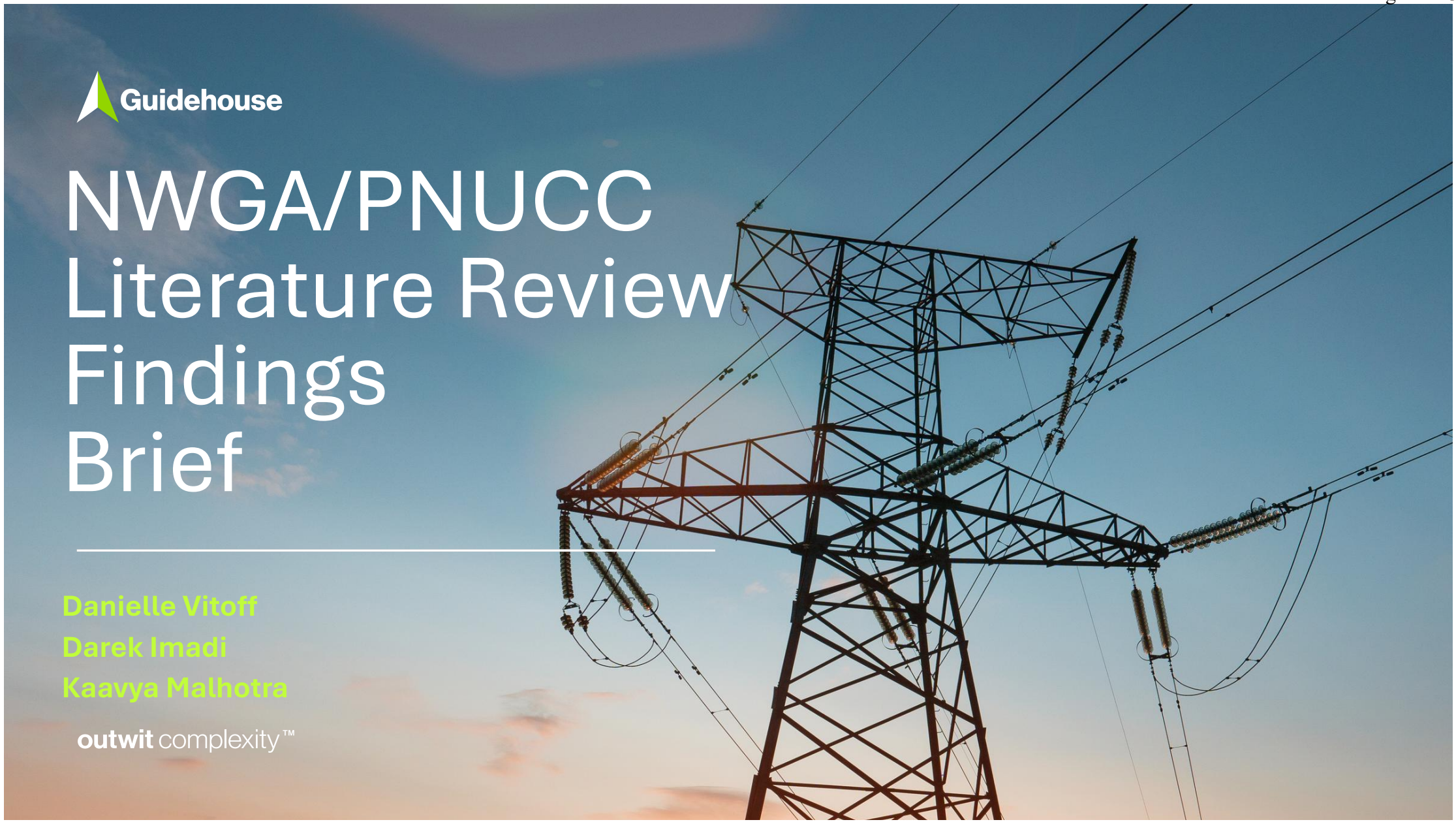
Industry leaders came together in May 2024 to address the need for enhanced coordination of the gas and electric systems. Although several individual studies examining the changing regional landscape have been conducted in recent years, we identified a need to synthesize these studies to identify a common understanding of how the region is planning to meet demand and assess risks. This bird's-eye view across the analytical landscape could provide insights and recommendations to enhance gas-electric planning and coordination.

To execute on this vital task, we asked Guidehouse to conduct a thorough literature review. Guidehouse synthesized the key findings from relevant studies, including regional forecasts, adequacy assessments, and extreme weather retrospectives. Guidehouse developed gaps and recommendations based on the findings that serve as an essential foundation for improving coordinated strategies for regional planning.

The stakes are enormous – the reliability of energy supply to our customers, the achievement of our clean energy goals, and the continued economic vitality of our region require us to work together on the transition to a clean energy future. By proactively coming together to support this literature review, we are taking a crucial step in building a clearer understanding of what we need to do to secure a more sustainable and resilient energy future for the Pacific Northwest.

With thanks to and on behalf of the work group,

Steve Andersen, Clark Public Utilities and Shawn Hill, FortisBC
Work Group Co-leaders



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NWGA/PNUCC Literature Review Findings Brief

Danielle Vitoff
Darek Imadi
Kaavya Malhotra

outwit complexity™

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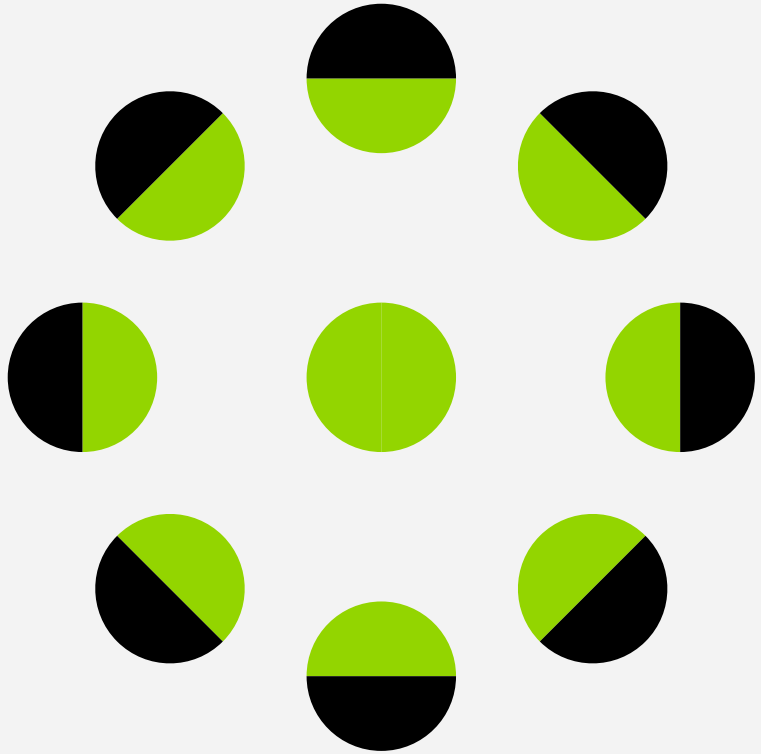

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Scope and Purpose

Helping inform improvements in gas and electricity sector coordination with the goal of enhancing reliability and resilience at a time of rapid change.

The literature review analyzed 19 studies published by gas and electric organizations to identify common themes and risks associated with rising energy demand and the increasing frequency of extreme weather events in the Pacific Northwest and the broader Western U.S.

Based on this analysis, and input from utility planners involved in the NWGA/PNUCC joint working group, we have developed recommendations aimed at enhancing coordination between gas and electric systems.

The key findings and gaps and recommendations are summarized in the following findings brief for regulators, policymakers, and utilities to better understand the issue.

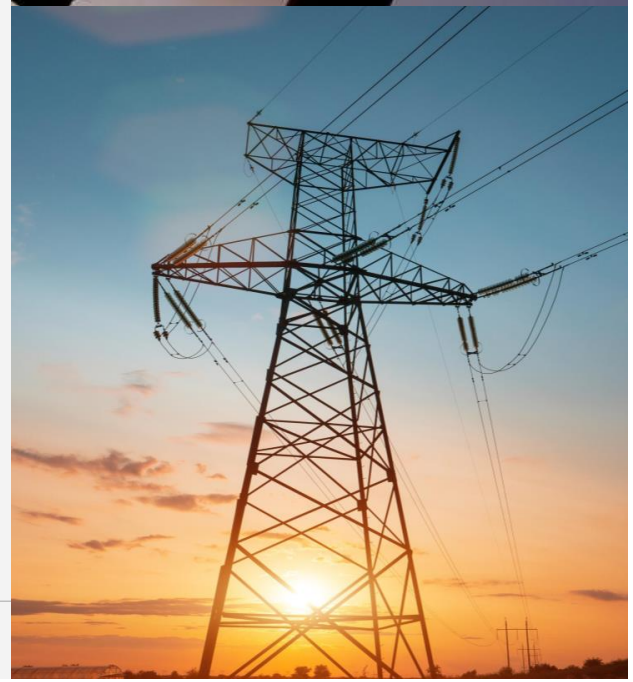

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Table of Studies Reviewed

#	Title	Author	Year
1	2024 Pacific Northwest Loads and Resources Study	BPA	2024
2	Winter Conditions Report for January 2024	CAISO	2024
3	Net-Zero NW: Energy Pathways Technical Report	Clean Energy Transition Institute	2023
4	Northwest Regional Forecast of Power Loads and Resources	PNUCC	2024
5	Pacific Northwest Gas Market Outlook	NWGA	2023
6	Pacific Northwest Pathways to 2050	E3	2018
7	Pacific Northwest Power Supply Adequacy Assessment for 2029	NPCC	2024
8	Analysis of the January 2024 Winter Weather Event	Powerex	2024
9	Assessment of January 2024 Cold Weather Event	WPP	2024
10	2024 Summer Reliability Assessment	NERC	2024

#	Title	Author	Year
11	2023 Long-Term Reliability Assessment	NERC	2023
12	2023 Western Assessment of Resource Adequacy *(Note: Weblink Archived)*	WECC	2023
13	Resource Adequacy in the Pacific Northwest	E3	2019
14	National Gas Reliability: Issues for Congress	Congressional Research Service	2024
15	2023-2024 Winter Reliability Assessment	NERC	2024
16	Year 10 Extreme Cold Weather Event Report	WECC	2023
17	EPRI AI Powering Intelligence	EPRI	2024
18	Kelowna Electrification Case Study	Fortis BC	2023
19	PNW Electric Utilities IRP Comparison Table	Fortis BC	2020

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Literature Review - Key Findings

The studies reveal insights into energy demand projections, resource adequacy, system resilience, and the impact of extreme weather events in the Western region. They reveal the need for gas/electric coordination and regional planning to adapt to a changing landscape.

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Theme 1

Key Findings: Demand and Load Growth

1

A significant driver of load growth in the Western Interconnection and the Northwest is the expansion of data centers

Data centers consume large amounts of electricity due to their cooling needs, leading to substantial increases in electricity demand. This expansion is projected to continue in the Northwest, with load increases ranging from 50% to 200% depending on the specific Balancing Authority.

Data center expansion is also being considered and forecast to grow in other areas, such as the Desert Southwest, which could result in a doubling of the share of data center demand by 2030.

2

The projected load growth in the Western Interconnection over the next ten years is almost double the rate reported in the previous year's assessment

The 2023 assessment predicts a 16.8% increase in demand in WECC over the next decade, compared to a 9.6% increase reported in 2022. The PNW is forecasting an increase of over 30% in the next 10 years.

This surge in demand is a primary factor contributing to the growing resource adequacy risks in the region. Data centers, as mentioned in #1, are the major contributor to this increased growth and steep revisions of past projections. High-tech manufacturing and the trend towards electrification are also cited.

3

Electrification policies and trends are contributing to the increase in demand – limited analysis considering implications of direct use of natural gas

The transition to electric vehicles and the electrification of heating in buildings are contributing to the increasing need for electricity. While energy efficiency measures help to offset some of this increased demand, utilities are still forecasting significant load growth in the coming years.

The switch from gas to electric in residential homes will also have a significant impact on peak demand. The value of the direct use of natural gas during extreme weather events and the impact of attachment policies for new customers is an important topic that was not discussed in the studies reviewed.

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Theme 2

Key Findings: Resource Adequacy/Reliability

1

Resource adequacy remains a critical risk - planned resources may be insufficient to meet future demand

This risk has increased compared to the previous year. The Western Interconnection faces challenges in meeting future energy demands under various system conditions. The most significant risk factors include substantial load growth, extreme weather, uncertainty in forecasting, and the integration of non-dispatchable resources like solar and wind power.

While short-term projections (2024-2025) for WECC show a minimal number of demand-at-risk hours, the magnitude and frequency of these hours significantly increase from 2026 onward, indicating a shortfall in resource plans.

2

System flexibility is significantly impacted by the increasing integration of variable renewable energy (VRE).

Renewables pose challenges for maintaining a reliable electricity supply. The Variability Margin Index (VMI), a metric used to assess the variability in the resource and load mix, showcases this trend in system flexibility. The VMI has increased substantially between 2022 and 2023 in the WECC due to higher renewable resources, highlighting the growing need for dispatchable flexible resources in the Western Interconnection.

Increasing drought conditions are also responsible for 23% lower hydro generation in the NW, demonstrating heightened risks of climate change on this critical regional resource.

3

Increasing variability coupled with baseload retirements and an increasingly constrained natural gas system pose a challenge to resource adequacy.

Traditional resources can be readily dispatched to meet demand, while variable resources like solar and wind power cannot. The increasing reliance on variable resources, coupled with the retirement of traditional baseload resources, makes it challenging to ensure a consistent energy supply under diverse conditions.

As coal plants are retired natural gas is increasingly being relied upon as a flexible generation resource. However, existing natural gas infrastructure, such as interstate pipelines that are at times reaching 95% utilization, are becoming increasingly constrained. New natural gas infrastructure will need to be developed in coming years to accommodate new generation.

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Theme 3

Key Findings: System Resilience and Flexibility

1

Natural gas generation flexibility is critical in maintaining grid resilience

The Western Electricity Coordinating Council (WECC) modeled a simulated extreme cold weather event in 2033 to understand the impacts on the system, determining that the Western Interconnection experienced load shedding when natural gas derates were modeled signifying the reliance on natural gas during extreme events.

2

Natural gas generation will be a needed resource for system resilience and flexibility even under a decarbonized grid

Natural gas is required to provide firm capacity not met by variable renewables, even under up to a 98% decarbonization scenario in the NW. As variable renewable energy use increases, gas generation will become crucial in avoiding loss-of-load events.

Natural gas generation capacity factors are forecasted to decline over time in these decarbonization scenarios but remain cheaper than relying on other forms of firm generation or energy storage.

3

Enhancing system resilience requires addressing vulnerabilities related to natural gas fuel supply

The critical role of natural gas generation hinges on a functioning natural gas system. The 2024 cold snap and Winter Storms in Texas underscored the need for more resilient natural gas infrastructure. Fuel assurance is vital for grid stability and reliability during extreme weather events. To mitigate fuel-related risks, proactive emergency planning, infrastructure hardening, improved gas-electric communication, and increased natural gas supply resources are essential.

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Theme 4

Key Findings: Gas/Electric System Interdependence

1

The increasing interdependence of systems necessitates enhanced coordination to mitigate the risk of cascading failures.

The growing reliance on natural gas-fired generation to meet peak demand and compensate for the intermittency of renewable energy sources necessitates increased coordination between gas and electric utilities to ensure the reliability of both systems. Emerging technologies, such as hybrid-heating systems, should be jointly explored especially in infrastructure-constrained areas as they can yield significant cost savings through peak shaving.

2

Gas-Electricity Coordination is hindered by regulation misalignment

Misalignment between natural gas and electricity markets poses significant challenges to efficient coordination and reliability.

Incompatibilities in contracting practices, scheduling discrepancies, and insufficient infrastructure investment incentives hinder the ability of power generators to secure reliable gas supplies, and natural gas companies from making necessary midstream infrastructure investments, underscoring the urgent need for market reforms in certain energy markets.

3

Siloed planning in gas and electric systems, has a detrimental effect on overall energy reliability

Planning often occurs in isolation from considerations related to natural gas supply and transportation.

Similarly, efforts to electrify building heating and other end uses that traditionally rely on natural gas must consider the capacity limitations of existing gas infrastructure for delivery to power.

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Theme 5

Key Findings: Extreme Weather Events

1

Natural gas played a vital role in maintaining electricity supply during extreme cold snaps

During the January 2024 cold snap, the natural gas system satisfied 70% of end-use energy demand during the peak hour of this event in the PNW. The Western Electricity Coordinating Council (WECC) modeled a similar extreme cold weather event ten years in the future (2032) and found that natural gas generation was needed to meet load. When natural gas derates were modeled, load shedding occurred, demonstrating the reliance on natural gas during these events.

2

Improve the quality of forecasting load during extreme weather is critical for ensuring resource adequacy

Extreme weather events, especially those involving extreme cold, can cause electricity demand to deviate significantly from historical forecasts. This is partly due to the growing electrification of the heating sector, which makes demand more sensitive to temperature changes. Underestimating demand ahead of extreme weather events can lead to insufficient resource scheduling and potential reliability issues.

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Theme 6

Key Findings: Regional Planning

1

Prioritize collaborative regional planning efforts

Numerous studies highlight the critical need for improved regional coordination and collaboration to tackle the complex challenges related to resource adequacy and grid reliability, especially considering the increased interdependence of gas and electric systems following the significant rise in natural gas generation capacity over the past two decades.

Current planning processes are inadequate given the evolution of the energy system.

2

Incorporate extreme weather and fuel security in planning

With increasing frequency of extreme weather events, cold and hot, the supply and demand for electricity and natural gas is disrupted, leading to reliability challenges.

Planners must incorporate better scenario planning and robust strategies to enhance resilience to these events including weatherization and hardening, fuel assurance plans especially for natural gas, and emergency response capabilities between gas and electric systems at an operational level.

3

Address uncertainties forecasting load growth – in particular, data centers

Data centers and electrification of buildings and transport represent a significant and rapidly growing source of electricity demand in the region. This growth and the uncertainties forecasting it adds to the pressure on the grid and presents challenges for resource adequacy planning.

Regional planning must proactively address the implications of data center expansion and electrification by implementing better data sharing, coordinating planning, and encouraging energy efficiency, demand management, adequate transmission infrastructure, and strategic siting.

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Planning Implications for Gas-Electric Utilities

Gaps, and Recommendations

From these studies, we have identified gaps in electric and gas sector planning and highlighted corresponding recommendations to improve coordination and preparedness.

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Planning Implications: Gaps

Varying gas and electric sector approaches to forecasting loads from electrification, data centers, demand side resources, and evolving consumer behavior drive uncertainty in planning

- Current load forecasting methods used by PNW utilities often fail to adequately account for the impacts of electrification. Only 40% of PNW Balancing Authorities directly incorporate electrification assumptions in their forecasts.
- Differing planning assumptions, data inputs, and granularity between gas and electric utilities in the region hinder effective coordination and comparisons of forecasts.
- Utilities differ in how they forecast demand response programs and customer participation, not just passive load. Some consider demand response as a supply-side resource while others treat it as load modifying. This lack of transparency limits broader alignment amongst entities.
- The direct use of natural gas in buildings is a key factor in meeting baseline demand and peak loads but is often overlooked in studies. Current approaches do not fully account for its impact, creating gaps in demand projections. Electrification efforts must better consider how transitioning direct-use gas customers affects total load growth, peak forecasting, and grid reliability.

Insufficient understanding of peak demand and how gas/electric entities can jointly manage peak events

- Electric and gas utilities lack a clear understanding of how both sectors interact during peak events, in addition to how electrification and extreme weather will impact peak energy demand in each respective system.
- Peak events manifest differently and have distinct resource needs for gas and electric systems. For example, the gas system may experience a sharp single day peak driven by space heating demand while the electric system may face a multi-day capacity challenge during a prolonged cold weather event. Analyzing the varied nature of peak demands and how they are mitigated across the sectors is important for understanding the most efficient mitigation solutions. Gaps also exist in quantifying and incorporating such solutions into planning processes.
- Electric and gas system planners don't have a way of looking at coincident peak impacts on their systems under both extreme weather and end-use changes, and thus how to invest in different kinds of technology.

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Planning Implications: Gaps

Planners have obscured visibility of gas-electric interdependencies

- Gas and electric system planners often lack detailed visibility and data into the constraints, performance, and interdependencies of the other sector, making it difficult to accurately assess resource adequacy and identify potential risks.

Traditional planning metrics are insufficient in capturing new risks

- Metrics like planning reserve margins (PRMs), which measure the amount of capacity above forecasted peak demand, fail to account for the energy limitations of VERs, fuel supply risks, and the impact of extreme weather events on resource availability.
- Traditional resource adequacy models, often based on a loss-of-load event (LOLE) of 1 day in 10 years, may not adequately capture the risks associated with more frequent and severe extreme weather events. These events can simultaneously impact both demand and resource availability, leading to extended periods of high risk.

Lack of a framework to measure and optimize the full value and affordability of energy services that customers receive

- There is a lack of an integrated perspective on how to best serve customers' total energy needs across all sources. When gas and electric planning are siloed, the focus on optimizing overall delivered energy value to customers is often lost. Separate gas and electric planning processes, often governed by distinct regulatory models, typically aim to maximize value for either gas or electric ratepayers rather than the total cost and quality of energy services delivered. This leads to suboptimal resource choices and missed opportunities for synergy.
- Current planning approaches and regulatory constructs are not well suited to comprehensively evaluate tradeoffs and complementarities across the gas and electric systems.

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Planning Implications: Recommendations

Facilitate better coordination and collaboration between gas and electric entities by establishing cross-sector platforms and forums that actively develop and recommend planning assumptions or methodologies

- Regular forums that convene gas and electric utilities, pipelines, ISOs/RTOs, and other stakeholders to share information, align planning assumptions, and develop solutions can meaningfully advance coordination. Existing forums like the PNUCC/NWGA working group should be leveraged and expanded to serve this function. Leverage regional bodies, conferences, and other forums as venues to recommend and implement enhanced gas-electric coordination initiatives.

Promote enhanced operational data sharing between gas and electric utilities to improve system resilience

- Promote routine operational data sharing through joint platforms, regular coordination meetings, and standardized data formats/protocols. One notable example is in the Northeast where the NE-ISO decided to provide day-ahead hourly dispatch data from power plants to gas system operators to help them better plan for loads and ensure natural gas system integrity.

Engage stakeholders on benefits of assessing overall energy value instead of siloed gas vs. electric perspectives

- Partner on developing accessible tools and guides that empower stakeholders to evaluate holistic energy value. Dialogue should be facilitated with consumer groups, environmental advocates, and policymakers on integrated value frameworks.
- Articulate customer, reliability and cost benefits of more holistic gas-electric planning to regulators and policymakers. Fact-based, data-driven case studies and whitepapers that quantify benefits can build support. Examples could include peak demand reduction, consumer savings, improved grid resilience from backup fuel capability, and gas and electric rate stability from coordinated infrastructure build.

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Planning Implications: Recommendations

Jointly plan and collaborate on understanding load growth and peak mitigation options

- Planners and policymakers need to better consider a range of peak mitigation options like hybrid heating across gas and electric sectors. For example, hybrid gas-electric heating systems, if aggregated and dispatched effectively, could provide significant peak reduction value for the electric system while creating more manageable gas demand. Developing a shared understanding of these options and their associated infrastructure needs, operational coordination requirements, and market structures can unlock significant value.
- Inputs used for load forecasting should be improved and better aligned across entities to more accurately account for the impact of load growth.
- Develop new techniques and utilize information beyond historical data to model decarbonization and increasing frequency of extreme weather.
- Improve point load forecasting techniques to anticipate future data center, manufacturing, and other large load growth.

Better integrate gas and electric planning processes by reducing barriers and designing new models

- Utilize or develop coupled gas-electric models to better understand system interdependencies. Modeling tools that can stress test gas and electric systems under a range of future demand and weather cases can identify key vulnerabilities and quantify the value of solutions like demand response, storage, and inter-regional transmission. Partnerships between gas and electric utilities, universities, national labs, and vendors should be formed to advance this research.
- Identify changes needed to regulatory models and planning processes to enable more holistic, integrated approach optimizing customer value. Potential evolutions could include aligning gas and electric utility revenue models, mandating joint gas-electric planning studies, creating new customer energy service metrics, and enabling co-optimized gas-electric operations. Regulators should engage stakeholders to assess barriers and design new models.

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Planning Implications: Recommendations

Establish tools and frameworks for quantifying the full value of gas-electric interdependencies

- Develop metrics to quantify reliability and resilience value of gas-electric coordination. Candidate metrics could include probability of coincident gas-electric system failure and customer outage costs. Standard calculation methodologies should be developed and benchmarking efforts undertaken.

Adopt more robust reliability indicators that go beyond traditional metrics

- Loss of load metrics and planning reserve margins need to evolve to better reflect energy limitations of renewables, fuel supply risks, and weather impacts. New techniques such as effective load carrying capability for wind and solar and convolution of fuel disruption probabilities are needed. Scenario-based planning that captures correlated outages across resources should complement traditional Monte Carlo simulations.

Align planning and regulatory approaches to mitigate policy whiplash

- Policymakers should strive for durable, long-term policy frameworks that reduce investment risk. Varying policy approaches at different government levels (i.e. city, county, state) and lack of long-term clarity is a key planning challenge. Abrupt shifts in federal, state or local policies around issues like building electrification, renewable tax credits, and gas hookup moratoriums create significant uncertainty for utility planners.
- Explore approaches to de-risk and depoliticize energy system planning to improve investment certainty. Potential strategies include formalizing long-term resource and reliability targets in legislation, using independent expert panels to set planning assumptions and study methodologies, and creating accountability mechanisms. Best practices should be researched and socialized.

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Demand and Load Growth

Electricity demand growth has outpaced estimates and magnitude of future increases are uncertain. Demand uncertainty is a challenge for energy planners.

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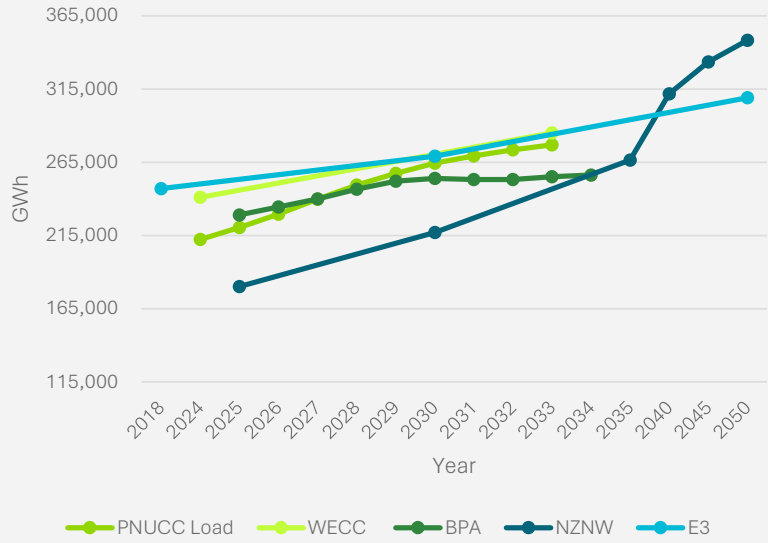
Electricity demand is set to more than double previous projections

- **Studies anticipate significant increases in both annual energy demand and peak demand, though total demand will increase at a faster rate.[1, 3, 4, 6, 12]**
  - WECC projects a 16.8% increase in total energy demand over the next 10 years, nearly double the growth projected in 2022.[12]
  - In the NW, specifically, aggregated utility forecasts show demand could rise by over 30% in the next 10 years, from 23,700 aMW in 2024 to 31,100 aMW in 2033.[4]

- **Data center expansion is identified as a primary driver of the increasing future load growth projections between 2022 and 2023, with the Northwest region experiencing the most substantial increases.[4, 7, 12, 17, 13]**
  - Northwest Balancing Authorities (BAs) project potential load increases of 50% to 200% depending on the specific BA. [12]
  - The NPCC adequacy assessment highlights a scenario where higher data center loads result in exceeding 41,000 MW at peak system needs.[7]

- **The push toward electrification is another significant driver. Electrification of transport expected to add more load than buildings in the short-medium term.**
  - New projections reflect electrification policies such as Washington's updated energy codes.
  - Increased demand from charging EVs is projected to approach 4% of total load in the NW by 2034. [4]
  - Forecasting impact of electrification is a challenge across the board. Utilities in WECC have different planning process to estimate impact of electrification on load growth.[12]
  - Only 40% of BAs in the West incorporate electrification assumptions directly into their load forecasts. Another 40% consider electrification as a separate forecast.

NW Electricity Demand Forecast by Study



- *Differences in total demand can be attributed to varying definitions of "Northwest" geography and forecasting approaches*
- *Evolved Energy and E3's forecasts assume scenarios in which long-term decarbonization goals have been achieved with heavy electrification, whereas PNUCC/WECC/BPA examine 10-year projections*

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Case Study:

Data Centers

% of total state electricity consumption attributed to data centers

Region	State	2023	2030			
		Present	Low	Moderate	High	Very High
Pacific Northwest	Idaho	0.57%	0.68%	0.74%	1.03%	1.40%
	Oregon	11.39%	13.39%	14.43%	18.93%	24.14%
	Washington	5.69%	6.77%	7.34%	9.88%	13.00%
Desert Southwest	Arizona	7.43%	8.81%	9.53%	12.73%	16.58%
	California	3.70%	4.43%	4.81%	6.54%	8.70%
	Nevada	8.69%	10.28%	11.10%	14.75%	19.07%
	New Mexico	1.48%	1.78%	1.94%	2.66%	3.60%
Rocky Mountain West	Colorado	2.66%	3.18%	3.46%	4.73%	6.34%
	Montana	3.71%	4.43%	4.81%	6.54%	8.71%
	Utah	7.68%	9.10%	9.84%	13.13%	17.08%
	Wyoming	11.26%	13.24%	14.27%	18.73%	23.90%

Sources: EPRI

- **Data center electricity consumption has reached approximately 5-11% of total electricity consumption in PNW state in 2023 and under a high growth scenario share of demand could grow to more than 13-24% of demand by 2030.** [17]
- This emphasizes the already significant contribution of data centers to regional electricity demand, and uncertainty of future scale of growth.
- **High data center load growth is a major risk in the projected energy shortfalls in the Northwest.** [7]
- **Data centers are a major driver of increasing load growth in all demand forecasts, especially in the Northwest**
  - The expansion of data centers will cause greater electricity usage in the next several years (17% load growth according to NERC), with recent assessments being much higher past predictions.[11]
  - NPCC predicts 2,400 aMW-4,000 aMW of new load in the NW due to data centers and chip fabrication, much higher than the 261 aMW predicted by the 2021 Plan. [7]
  - NPCC data center reference forecast falls between EPRI's moderate and high load growth scenario.[7]
  - Data centers are identified as the primary cause for the increase in demand projections between 2022 and 2023 WECC Resource Adequacy assessment
- **The relatively flat demand profiles of data centers mean they have a greater effect on annual energy than on peak demand**. While data centers consume a lot of energy throughout the year, their demand remains relatively stable and insensitive to changes in temperature. This contrasts with loads like building electrification, which have a more pronounced effect on peak demand.

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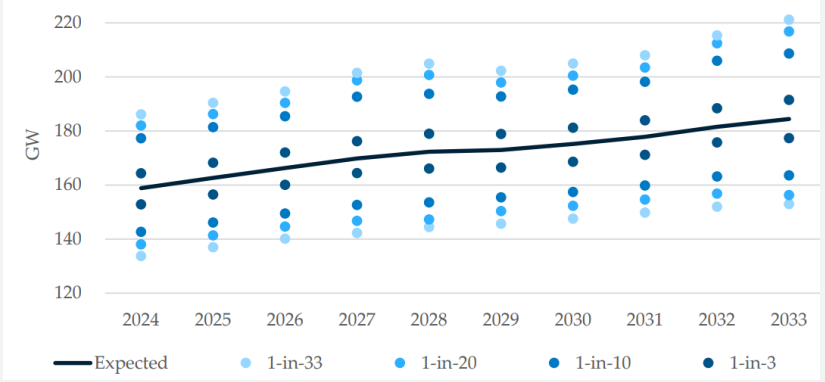
Uncertainties in expected peak demand and the pace at which demand will grow makes it difficult for entities to plan system adequately

- In the summer, the Western Interconnection's peak demand is projected to be 159 GW, but under a heat event, it could be as high as 186 GW. By 2033, this variability only increases, with peak demand expected to be 184 GW, but a 3% chance it is above 221 GW.[12] This increasing uncertainty means that entities need to be prepared for far higher peak demands.

- **Extreme weather conditions, which are likely to increase the coming years, are changing the peak demand profile of the region, which increases the risk of resource shortfalls.**
  - They will increase uncertainty in peak demand forecasts, which will make it more difficult for entities to prepare for future loads. From 2024 – 2033, the uncertainty range in summer peak demand will increase from 27 to 37 GW.[12]
  - Summer and winter extreme weather events will shift the shape of electricity consumption profiles away from peak periods.[7,11]
  - Extreme summer conditions are also increasing in frequency and are expected to change the NW from a traditionally winter-peaking area into a dual-peaking area. [12]

- **There are large uncertainties regarding the pace at which demand will increase, making it difficult for entities to plan accordingly to prevent resource shortfalls. Adequacy threatened under specific scenarios.**
  - If data center load growth accelerates faster than current projections, demand will surpass available resources and all reliability metrics measured by the NWPCC will be violated. The region will be at risk during both the winter and the summer. [7]
  - If energy efficiency improvements do not occur as expected, there will be higher risk of resource inadequacy during the winter region. [7]

Western Interconnection Summer Peak w/ Uncertainty Ranges



Source: WECC

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Resource Adequacy and Reliability

Planned resource additions may be insufficient to keep up with the expected increases in load. The anticipated increase in variable resources will also create more unreliability on the system.

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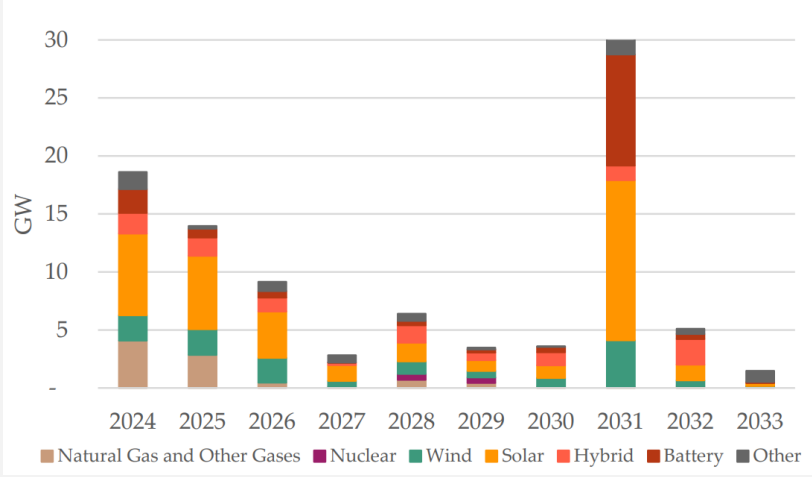
Renewable additions and coal retirements lead changes to the resource portfolio in the coming years, although these plans may be impacted by resource adequacy concerns

- **Northwest utilities plan to add 29 GW of new resources over the next decade to keep up with increasing demand, most of which are wind, solar, and battery resources.[4]**
  - This pattern matches additions from 2020-2025. Wind has accounted for 36% of new additions, solar 25%, and storage 16%.[4]
  - Battery energy storage system (BESS) capacity in the WECC (excluding CAISO) is projected to reach 18.8 GW by the end of 2025, a 38 % increase from the 13.6 GW at the end of 2024 according to S&P.
  - These plans may be disrupted by the long interconnection queue, supply chain delays, and project approvals.[4, 12]

- **Planned coal retirements are also projected to continue, although they are slowing down due to resource adequacy concerns**
  - In the NW, 730 MW of coal is expected to be retired in the near-term (2024-2025) and 660 MW in the long-term (2029-2033). 100 MW of natural gas is expected to be retired by 2033.[7]
  - To reduce resource adequacy risks, some retirements are being delayed. A comparison between 2023 and 2022 resource plans for WECC entities shows that there was an increased delay in coal and natural gas retirements.
    - In 2022 IRPs, for example, nearly 8,000 MW was planned to be retired in 2025, whereas in 2023 IRPs, only 4,000 MW is planned to be retired in 2025.[12]
  - In some cases, coal plants are being converted to natural gas plants which are helping to provide an adequate system such as Jim Bridger 1 & 2 and Valmy 1 & 2 in the NW.[12]

Resource portfolio of the WECC



Source: WECC

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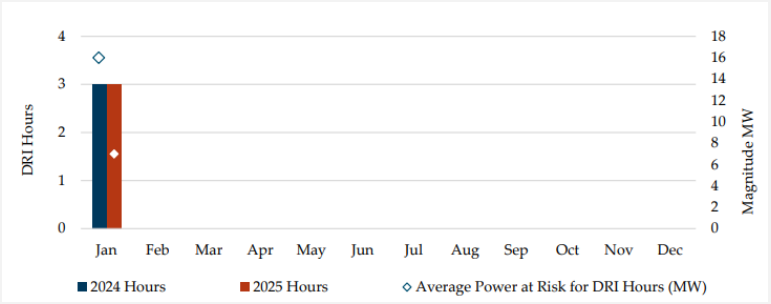
With high renewable penetration projected, low generation events are more likely to occur, increasing the likelihood of loss-of-load conditions

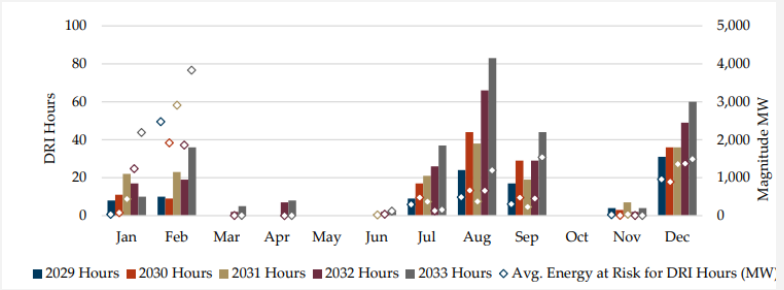
- Renewable resources are limited by weather patterns and have much higher capacity than actual energy produced. With bad conditions, over 100 GW of installed capacity can produce less than 10 GW.[12]
- **As variable resources like solar and wind become primary sources of electricity, low generation events are more likely to occur**. If these events are not considered during resource planning, variability in weather patterns will cause multiday loss-of-load. **With high renewable penetration, low generation will usurp drought hydro conditions as the biggest threat to loss-of-load events.**
  - The number of demand-at-risk (DRI) hours in the WECC is expected to greatly increase In the coming decade. This indicates that planned resources will be insufficient to meet the expected levels of demand and demonstrates the higher likelihood of loss-of-load events. In the NW, specifically, resources will need to keep up with high levels of demand growth expected in the next two years.[12]
  - The variability margin indicator (VMI) was found to increase over the next 10 years. The WECC Resource Adequacy Assessment found a much greater risk in variability in the WECC in 2023 compared to 2022 due to increases in planned variable resources from roughly 20% to 27% until 2030. Although capacity is expected to increase by 95 GW by 2033, the energy from these (mostly) variable resources is expected to increase by 15 GW. [12]
- Some studies modeled that it would be expensive to rely on renewable overbuild to increase capacity and decrease the chances of loss-of-load events occurring. Instead, coordination with natural gas can allow for more reliable energy production.[7, 13]

Demand at Risk Hours (DRI) for WECC

2024-2025



2029-2033



Source: WECC

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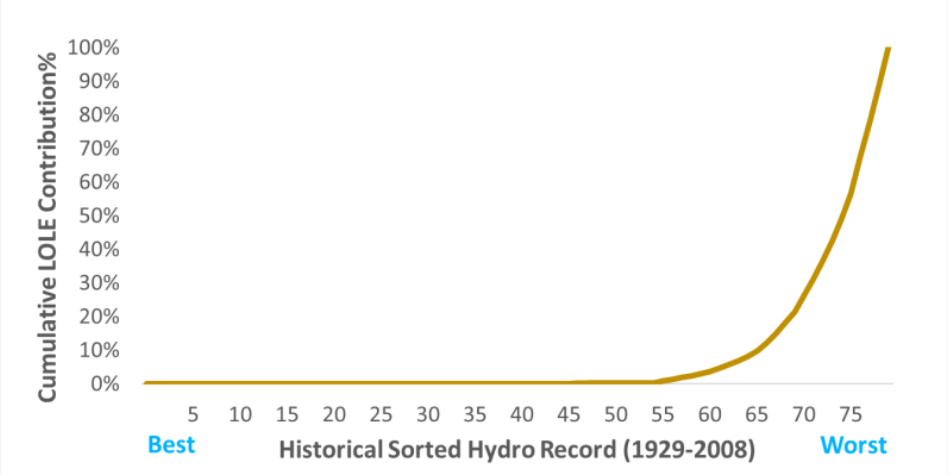
Increasingly unreliable hydropower due to droughts

- **The impact of recent droughts in the NW on electricity generation is a warning of lower generation that could occur as drought conditions increase due to climate change**
  - According to the EIA, the NW relies on hydropower generation for 43% of its electricity needs. With the region experiencing a drought, water supply at dams has reached less than 75% of normal levels in several counties this year.
  - Recent drought conditions have caused reservoirs to have limited capacity and have lowered hydropower generation in 2024 to 23% lower than the 10-year average.
  - Water at The Dalles Dam, an indicator of water supply conditions in the Columbia River, was 74% of the 30-year normal at the end of September 2024.
  - Reservoir storage at the end of September was at 48% of capacity in OR, 67% in WA, 76% in MT, and 60% in ID.

- It is projected that the worst 25% of hydro conditions would be responsible for nearly all loss of load events in the region. If drought conditions continue to lower hydro generation, the risk of reserve shortfall and number of loss-of-load events (LOLEs) will increase.[11, 13]

- As electrification occurs, low hydro conditions should cause fewer LOLEs (low solar and wind generation, on the other hand, will cause more), but they will still lead to some unreliability. There is a heightened risk for resource shortfall in the winter, as cold weather could cause extended periods of low hydro, solar, and wind generation coupled with high demand.[12,13]

Loss-of-load under various hydro conditions



Source: E3

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System Flexibility and Resilience

Natural gas can be used as a firm resource to improve reliability and resilience, although further planning is required to ensure the system is able to support peak demand.

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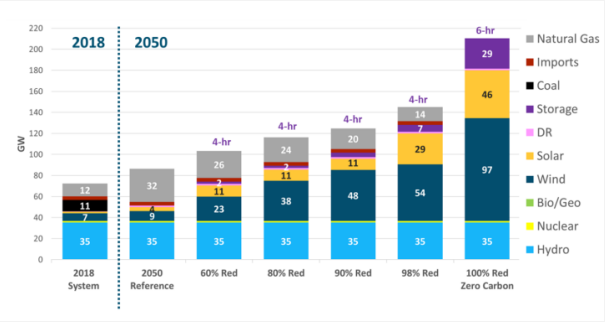
Natural gas will continue to be needed to provide grid flexibility even under deep decarbonization scenarios

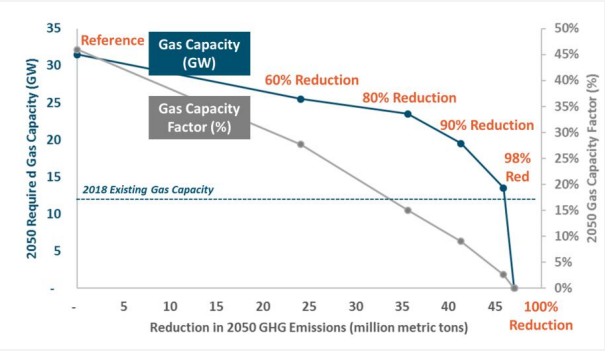
- Across all modeled scenarios, renewables need to be accompanied by firm resources to serve the remaining incremental peak load. To ensure reliability, electricity cannot rely on a single system. **Even under scenarios with 98% decarbonization, natural gas is required to provide reliability, providing the bulk of firm capacity not met by variable renewables.** It is necessary to continue serving load and prevent load shedding.[13]

- **Natural gas is the most cost-effective solution to address capacity challenges, even under deep decarbonization**. It is a more cost-effective and reliable source than alternative options such as battery storage or pumped-hydro, especially during low variable generation and high demand events such as extreme cold events. It also was found to **be a more effective option than renewable overbuild**, which would be costly and could still be unreliable during extreme weather events.[13]

- **As electrification increases, it is modeled that natural gas will transition towards being primarily used to avoid loss-of-load events during low renewable generation events.** Gas will be used sparingly but will need high capacity to ensure reliability, leading to capacity factors as low as 3% under 98% decarbonization scenarios for natural gas plants. To create this high capacity, the addition of new gas generation capacity is necessary even under deep decarbonization. [13]

Generation portfolios and natural gas capacity for various stages of decarbonization





Source: E3

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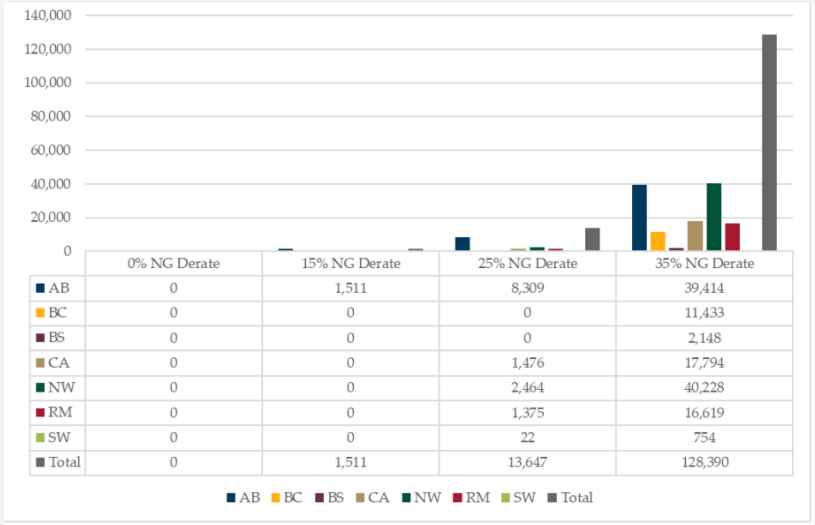
Natural gas generation will be a needed resource for ensuring system resilience and flexibility

- The reliability of the electric grid will continue to be dependent on the natural gas system during peak load events well into the future. The NW is the most vulnerable to loss of load. Southern WECC less suspectable.
  - WECC projecting out the 2022 Cold snap out to 2032 found that any loss of natural gas load would result in unserved load across the region.[16]
  - With all natural gas generators operating, there was no load shedding. However, when natural gas availability was reduced by 15%, 25%, and 35%, load shedding occurred in Alberta and other regions.[16]
  - Highest loss of load occurs in the NW at 40,228 MWh under a 35% natural gas derating scenario.[16]
  - While batteries helped to reduce unserved load hours, they were insufficient alone to mitigate natural gas derating.[16]
  - The study highlights the Western Interconnection's dependence on natural gas generation during extreme weather, even with the transition to renewable generation and energy storage.[16]

Total unserved load by region during simulated 2032 cold snap and NG Capacity Derating Scenarios (MWh)



	0% NG Derate	15% NG Derate	25% NG Derate	35% NG Derate
AB	0	1,511	8,309	39,414
BC	0	0	0	11,433
BS	0	0	0	2,148
CA	0	0	1,476	17,794
NW	0	0	2,464	40,228
RM	0	0	1,375	16,619
SW	0	0	22	754
Total	0	1,511	13,647	128,390

Sources: WECC

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Increasing reliance on natural gas to meet peak electricity demand raises concerns about the adequacy of natural gas infrastructure - new vulnerabilities planners must consider

- The increasing use of natural gas for electricity generation, in response to the increasing deployment of renewables, raises concerns about whether the region has enough natural gas infrastructure to support the level of real-time flexibility needed to respond quickly to fluctuations in renewable energy supply. [7,12,13,14,16]
- In 2020, three Western states reported that growth in the use of renewable energy could add stress to the natural gas pipeline system if there is not enough pipeline capacity to transport the increased volumes of natural gas needed for power generation. [14]
  - **Average utilization of interstate pipelines in the Pacific Northwest has exceeded 95% in recent years** and is expected to grow during normal winters. [5, 14]
- **Disruptions in one system can cascade to the other**, as seen during Winter Storm Uri in Texas, where the **loss of electricity impacted natural gas production and distribution**, further exacerbating power outages.
- From 2010 to 2019, there were 1,800 reported disruptions on interstate natural gas transmission pipelines. These disruptions were varied in nature but highlight potential vulnerabilities in the natural gas system that need to be assessed. [14]
- The multi-day cold snap in January 2024 was aggravated by constraints in the natural gas system. A fiber optic cable failure at the Jackson Prairie Natural Gas Storage Facility led to reduced system inventory for gas companies in the NW and BC, prompting a curtailment watch. [2]

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Gas and Electric System Interdependence

To prepare for these changes to the system and avoid system shocks, there must be enhanced planning coordination between gas and electric systems.

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Studies repeatedly highlight growing interdependence necessitates changes to current planning processes and commercial structures

- **Increasing interdependence can lead to failure cascades**: The electric grid relies on natural gas for reliable generation, especially during peak demand periods and when renewable energy output is low. This dependence is expected to grow as older thermal generators retire and are replaced with a mix of renewables and natural gas plants. However, the natural gas system itself relies on electricity for operation, particularly for powering compressors and other critical infrastructure. This creates a complex interdependence, where disruptions in one system can cascade into the other. [14]

- **Traditional metrics, such as Planning Reserve Margins, are insufficient for systems increasingly dependent on variable energy resources and just-in-time natural gas delivery.** To address this, gas and electric entities must collaboratively develop advanced planning tools and models. Key considerations include accounting for both peak and non-peak load hours, incorporating probabilistic assessments of energy risks like fuel supply limitations and extreme weather events, evaluating interregional transfer capabilities, and considering the operational flexibility of diverse resources, including natural gas generation, renewables, and energy storage. Moving to modeling platforms that co-optimize both the natural gas and electric systems is also recommended. [4,7,11,13]

- **Market misalignment:** The structure of gas and electricity markets can create barriers to efficient coordination. Differences in scheduling practices, trading requirements, and pricing structures can complicate gas procurement for power plants and hinder investment in new gas infrastructure. [14]
  - **Contracting structures** hinder power generators' ability to secure necessary pipeline capacity for reliable fuel supply. Power plants often need to quickly adjust their natural gas consumption based on fluctuating electricity demand. However, the lack of efficient **pricing mechanisms for intraday volumetric variability** makes it difficult for them to procure gas transportation services that meet this need. [14]
  - **Pipeline capacity expansion**: Conversely, the structure of competitive wholesale electricity markets does not adequately incentivize generators to invest in the capital-intensive expansion of gas transportation infrastructure which poses reliability risks. [14]

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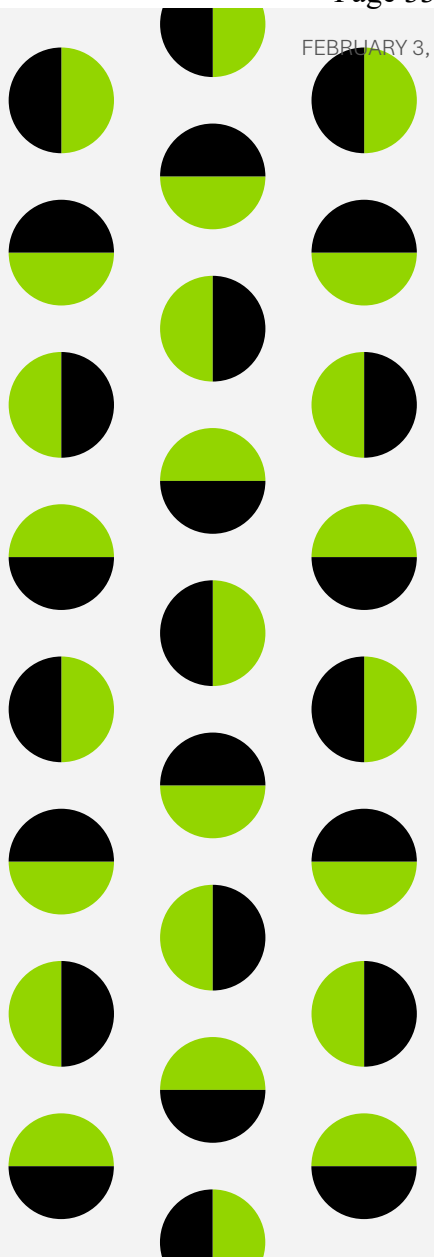
Impact of Weather Events

Recent extreme weather events highlight the gaps in system planning that will limit gas and electric entities' ability to support higher demand with a changing resource portfolio.



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Case study

January 2024 Cold-Snap

This extreme cold weather event provides an example of future system shocks that may occur if there is insufficient planning for extreme weather events.

- Near-record low temperatures across the PNW contributed to high demand requiring around 4900 MW of imports from the Southwest and Rockies during peak demand hours. Peak demand during this period was not exclusive to peak hours.[8, 9] These levels of high demand are an indicator of future unpredictable demand profiles that may be seen with increased extreme weather events.
- During the cold snap, low temperatures caused low hydro generation, which limited fuel supply and meant that utilities were not able to provide sufficient capacity to meet peak demand. [8, 9] This demonstrated the risk of heavy reliance on variable energy resources to provide capacity during moments of peak demand and highlighted the need for available dispatchable resources to avoid resource shortfall during these events.
- There was significant reliance on inter-regional imports to support the cold snap. Despite this, transmission was limited by a preplanned forced outage on the NV-OR border.[2] Congestion also caused outages and limited import capability. [2, 8, 9]

Observed load for 12 BAs during January 12 – 16 relative to peak loads during the last 10 years

Figure 3 - The observed load for 12 BAs during January 12 – 16, 2024 (trend lines) relative to their peak loads (horizontal line at 1.0) during the winter for the last 10 years (Source: U.S. Energy Information Administration (EIA) - Real-time Operating Grid [select download data -> Balancing Authority/Region Files])

Source: WPP

During the event, peak demand was not exclusive to peak hours and came close to, or crossed, in some instances, the average winter peak loads for the last 10 years.

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BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Direct Testimony of Cecelia J. Tanaka

EQUITY

Exh. CJT-1T

August 29, 2025

DIRECT TESTIMONY OF CECELIA J. TANAKA

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position at Northwest Natural Gas Company dba NW Natural ("NW Natural" or "the Company").

A. My name is Cecelia J. Tanaka. I am the Energy Equity and Affordability Lead at NW Natural.

Q. Please describe your education and employment background.

A. I hold a Master's in Public Administration, International Policy and Management from the New York University Robert F. Wagner Graduate School of Public Service; and an undergraduate degree in Humanities from the University of Colorado - Boulder. I have over 15 years of experience developing and leading major social impact and corporate responsibility initiatives that advance equity and social justice. I joined NW Natural in January 2021 to lead the Company's community investments focused on improving energy equity and easing energy burden for our most vulnerable communities—including energy efficiency resources for multi-family residents, discounted rate programs for income-eligible customers and philanthropic giving across our Washington and Oregon territories. In April 2024, I joined NW Natural's Regulatory Affairs team to lead the Company's energy equity and affordability efforts and have played a central role in advancing the Company's energy equity strategy through rate case proceedings, stakeholder engagement, and program innovation. Prior to NW Natural, I worked as a Vice President at JPMorgan Chase & Co., the Robin Hood Foundation and New York University; and consulted for the United Nations, Meyer Memorial Trust, and The Collins Foundation.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to detail the Company's commitment to equity and inclusion that encompasses social, environmental and economic dimensions; and to provide an update on the Company's low-income needs assessment and low-income assistance offerings.

Q. Please summarize your testimony.

A. In my testimony, I present an overview of the Company's new and long-standing efforts in energy equity and affordability. I discuss the findings from the Company's Energy Burden Assessment ("EBA"), highlighting key insights, lessons learned, and early plans for next steps. My testimony details the significant progress the Company has made in delivering deeper discounts to more income eligible customers through its bill discount program, launched January 1, 2024, in Washington; as well as updates on the Company's larger portfolio of energy assistance and efficiency offerings.

To ensure the continued success and responsiveness of these initiatives, my testimony underscores our commitment to sustained and expanded resources—both financial and operational—to support the Company's energy equity and affordability commitments. These resources are essential to maintain program effectiveness, scale outreach, and adapt to evolving community needs and regulatory expectations. I also provide an update on the Company's Community and Equity Advisory Group ("CEAG"), and detail how engagement with and feedback from the CEAG is informing the Company's work. My testimony also details the Company's Washington Low Income Energy Efficiency ("WALIEE") Program, highlighting major projects to date.

Finally, I outline the Company's diversity, equity, and inclusion core values; and recent initiatives demonstrative of this commitment.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes.

II. UPDATES FOR 2025 AND ONGOING PRIORITIES

Q. Please describe the evolving regulatory landscape.

NW Natural navigates a complex and broad landscape of regulatory dockets that emphasize equity and public participation in energy planning and utility operations. Since NW Natural's last general rate case in Washington (docket UG-200994, effective November 2021), the Washington Utilities and Transportation Commission ("WUTC" or "Commission") has advanced several key policies and Orders that reflect a sharpened focus on energy equity, affordability, and procedural justice. These developments shape the regulatory environment in which NW Natural operates, as well as the expectations placed on utilities to embed equity considerations into core planning, customer programs, operational frameworks, and engagement strategies. Legislative actions and dockets have focused on climate action and advancing energy equity in Washington. Notable recent developments include:

- WUTC Equity docket (docket A-230217)[1] represents a landmark effort to embed equity and justice within regulatory processes in Washington State. The Commission's recommendations emphasize equitable access to data, inclusive public participation, and language access planning. This multi-year proceeding was

[1] https://apiproxy.utc.wa.gov/cases/GetDocument?docID=54&year=2023&docketNumber=230217.

launched in response to legislative mandates such as the Clean Energy Transformation Act ("CETA"), the Climate Commitment Act ("CCA"), and the Healthy Environment for All ("HEAL") Act, all of which emphasize equitable outcomes for vulnerable communities. The docket is structured around four tenets of energy justice: distributional, procedural, recognition, and restorative justice. The first phase focused on procedural justice—analyzing decision-making processes and increasing collaboration with impacted communities to ensure proceedings are fair and inclusive for participants. Phase two will explore distributional equity. The Commission issued its Interim Policy Statement Regarding Procedural Justice ("Policy Statement") in the Procedural Justice phase on May 12, 2025.

- RCW 80.28.425(1)[2] broadened the Commission's authority to consider a wider range of public interest factors when evaluating multiyear rate plans. These factors explicitly include equity, environmental health, health and safety, economic development, and greenhouse gas emissions reductions, insofar as they affect the rates, services, and practices of regulated gas and electric utilities.
- In parallel, the Commission's Order 01 in docket UG-230739[3] approved NW Natural's proposal for a Residential Arrearage Management Program ("AMP"), offering income-qualified customers up to $1,500 in arrearage forgiveness every 24 months.

[2] RCW 80.28.425: Multiyear rate plan.

[3] UTC Case Docket Detail Page | UTC.

- Integrated Resource Plan (docket UG-230801): The 2025 Integrated Resource Plan ("IRP") emphasizes procedural justice, including enhanced public participation strategies and targeted engagement with underrepresented communities.
- NW Natural's Energy Assistance Program and Bill Discount Program (docket UG-240625)[4]: The Company revised its tariff Schedule L for it Gas Residential Energy Assistance Tariff ("GREAT") program to: 1) Expand bill assistance program income eligibility to 80 percent average median income ("AMI"), and 2) Clarify how benefits are applied when customers receive both federal energy assistance and the Bill Discount Program. Additionally, the Company revised tariff Schedule J for its residential bill discount program to extend eligibility for fixed-income customers to a four-year term (from two years).
- In 2024, Schedule I of UG-240074, the tariff that sets the terms and conditions of NW Natural's WALIEE Program, the per project allowance for health, safety, and repair ("HSR") measures increased by $4,000. HSR measures are measures that if not completed would adversely impact the safety and effectiveness of the energy efficiency measures or the health of the occupants.

Together, these developments underscore a dynamic and increasingly equity-focused regulatory environment. This shift requires utilities to demonstrate compliance with emerging mandates and to lead with clear intent, transparency, and meaningful engagement with the communities they serve.

[4] UTC Case Docket Detail Page | UTC.

Q. How does NW Natural address energy equity considerations in this case?

A. The Company acknowledges the pressing issue of energy burden and energy justice and remains steadfast in its commitment to ensuring that low-income and energy burdened customers, who often face the greatest challenges in affording their energy bills, receive the resources and attention they need. NW Natural also recognizes that broader policy and historical issues can impact equitable and affordable energy access. To this end, the Company is committed to focusing its resources and efforts on areas where it can make a direct and meaningful impact. And by concentrating on what the Company can influence—such as improving access to energy efficiency programs, designing and refining offerings to ease household natural gas burden, and enhancing community engagement practices, to name a few—it can make progress in advancing energy equity considerations and fulfilling its core responsibility to deliver safe, reliable, and affordable natural gas service to all customers.

Table 1 below offers a snapshot of NW Natural's energy equity and affordability centered portfolio that includes robust energy assistance offerings, energy efficiency resources, energy education information, and community philanthropy and engagement. The portfolio has grown significantly in the past few years—highlighted in the table below.

Table 1 – Energy Equity and Affordability Portfolio
(income-qualified program)***

New since last rate case	Offering/Initiative	Description
Y	Community Equity Advisory Group (CEAG)	Strengthen procedural equity practices; broaden engagement and participation in energy planning.
	Community Grants and partnerships	Support over 250 nonprofit organizations through NW Natural territory; community event support and programmatic outreach.
Y	Conservation Programs	Improve energy efficiency / reduce energy bills[5]; the Company's Behavioral Energy Efficiency program (BEE) provides home energy usage reports, tips for saving, and links to Company programs.
	Energy Education	Tools, programs and resources available to help customers lower bills; improve engagement, and understanding of role of utilities and programs, customer bills and charges, and safety.
Y	Energy Burden Assessment	Review of EBA findings; prioritization of recommendations; implications for program design.
	Gas Assistance Program* (GAP)	Company and employee funded energy assistance for customers in Oregon and Washington.
	Gas Residential Energy Assistance Tariff * (GREAT)	Bill assistance for income eligible Washington customers.
Y	Integrated Resource Planning (IRP) – Equity Considerations	2025 IRP is being developed with focus on equity and enhanced public participation/stakeholder engagement requirements.
Y	Residential Weatherization Kits	Improve energy efficiency and reduce energy bills through efficiency gains.
Y	Washington Arrearage Management Program* (AMP)	Supplemental grant program to cover past-due bills for lowest income customers.
Y	Washington Bill Discount Program* (2024)	Four-tiered program with highest discounts reserved for lowest income households to address energy burden and improve affordability.
	Washington Low Income Energy Efficiency* (WALIEE)	WALIEE finances whole-home retrofits, weatherization projects, high-efficient gas equipment, and energy literacy services for income-eligible customers.

† items marked with an asterisk indicate an income qualified program.

[5] https://www.nwnatural.com/-/media/nwnatural/pdfs/washington-tariff-book-summary/new-nwn-2024-25-beep-11-15-2023.pdf.

Q. Please describe the Company's goals, guiding principles, and strategies that define its approach to energy equity and affordability.

A. Collectively, the Company's equity work spans the following goals, guiding principles, and strategies in which it:

- Prioritizes measures that target the Company's lowest-income, highest-burdened customers;
- Develops and implement measures informed by robust data analysis and feedback from advisory groups;
- Pursues, vets, and prioritizes cost-effective solutions;
- Balances immediate support with longer-term strategies; and
- Regularly evaluates efforts and adjusts strategies as needed to maintain and enhance their effectiveness.

Q. How is NW Natural considering the cost implications of incorporating equity and affordability into the Company's strategy and program development?

A. The regulatory landscape is evolving, with a growing emphasis on equity and affordability. Energy equity considerations have emerged as dedicated topics in rate cases, and they now comprise a full chapter in NW Natural's IRP. The path to achieving regulatory compliance and advancing energy equity is complex and resource-intensive—necessitating substantial and deliberate investments in time, expertise, and personnel to manage and expand programs that address affordability and equity in utility services.

The Company is forced to make hard decisions and constantly balance the need to reduce energy burden for lowest earning households with the necessary costs that

this assistance has for all customers. Whether or not to offer a specific program or other type of resource or service is not determined nor weighed in isolation—but in the context of trade-offs that may impact other forms of support, such as deeper discounts or expanded eligibility thresholds. Ultimately, NW Natural's goal is to ensure that equity-focused investments are prudent, targeted, and reflect regulatory requirements and customer needs.

Since its last rate case, NW Natural has added numerous programs and services to help customers afford household natural gas costs, as demonstrated previously in Table 1. By securing the necessary resources and fostering a collaborative approach, the Company, along with its equity partners, can ensure efforts are authentic and impactful, and align with regulatory and policy goals.

Q. How is the Company evolving its resources to meet its commitment to energy equity and affordability?

A. The Company's commitment to energy equity and affordability has deepened significantly in the five years since its last Washington rate case. This evolution is not only a reflection of Company values, but it is a direct response to regulatory developments such as Commission orders and its policy statement regarding procedural equity, the EBA, and the implementation of the AMP under docket UG-230739.

The WUTC's evolving regulatory framework—anchored in docket A-230217 and RCW 80.28.425—requires natural gas utilities to operationalize equity across all aspects of planning, ratemaking, and customer engagement. Each tenet of equity requires new data systems, stakeholder engagement models, and internal capacity to interpret and act on community input.

There are several areas where the Company has developed resources and areas where it will continue to evolve.

- The Company added a new Energy Equity & Affordability Manager role to the Rates & Regulatory Team in 2024. This strategic investment reflects the evolving regulatory landscape and the increasing complexity of equity-centered work across our operations. The role is designed to ensure that our programs are not only responsive to community needs but also compliant with emerging regulatory expectations. In addition to program oversight, the role supports regulatory strategy, resource planning and testimony development, ensuring that equity considerations are embedded in rate case proceedings and policy design.

  NW Natural is currently filling a Data Scientist position that will support analyzing disconnection trends, arrearage data, and energy burden metrics to inform program adjustments. This will allow the Company to conduct data-informed outreach to households likely experiencing high energy burdens who are eligible for but not enrolled in the bill discount program.

- The Company is evaluating a more holistic departmental organization to (i) lead the administration of income-based programs such as WALIEE, the bill discount program, and the AMP, ensuring offerings remain responsive to community needs and compliant with regulatory requirements; and (ii) lead coordination of advisory groups, including the CEAG and the GREAT Advisory Group; and manage relevant public comment, processes, and facilitate inclusive engagement strategies.

The Company views these responsibilities as foundational to the Company's ability to deliver on the Commission's directives and its own commitments.

The WUTC's equity framework is reshaping the regulatory landscape for natural gas utilities. Meeting these expectations is not a matter of marginal adjustments—it requires transformational investment in people, systems, and community partnerships.

III. BILL DISCOUNT PROGRAM

Q. What is NW Natural's residential bill discount program?

A. NW Natural launched its Washington residential bill discount program for qualifying residential customers on January 1, 2024. Customers can qualify for up to an 80 percent discount on their monthly bill based on household size and income. The program features low barriers to participation that include auto-enrollment for customers who have received energy assistance, self-certification of income eligibility, and a tiered discount structure that provides larger discounts to households with lower incomes. Customers with income less than 80 percent of the Washington State median income qualify for assistance within the program's four tiers. Income thresholds and discounted tiers are provided in Table 2, below.

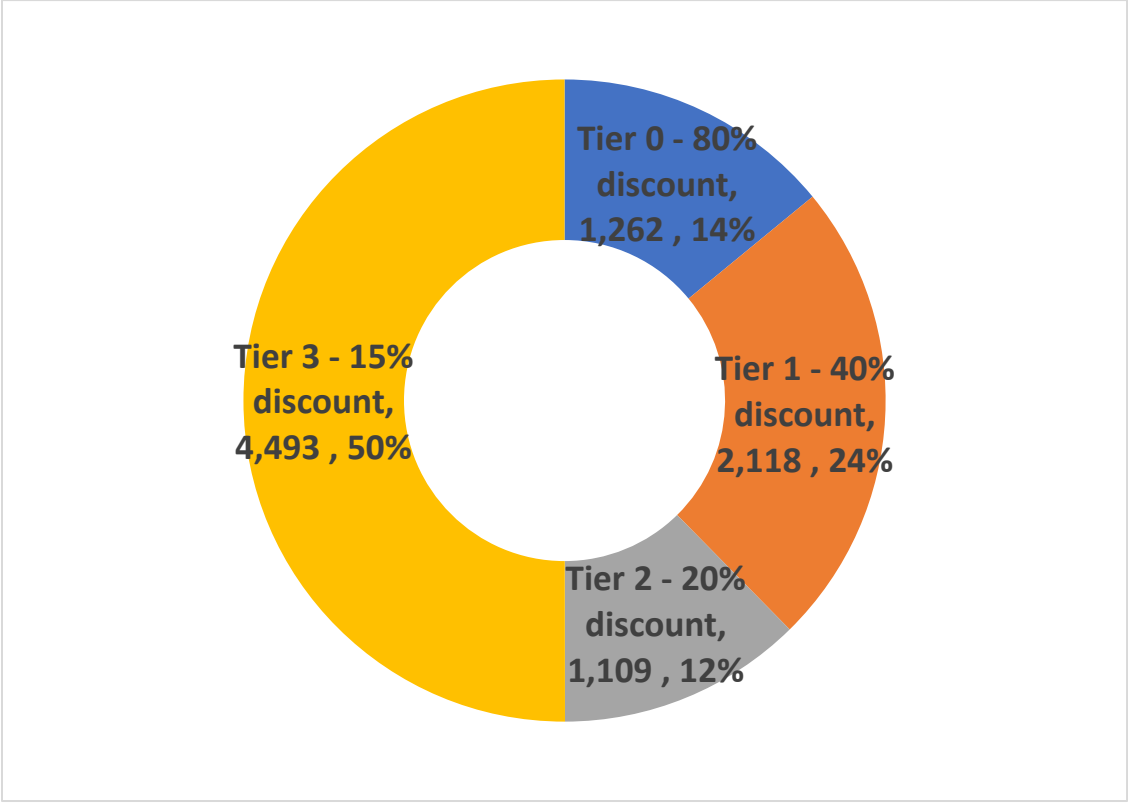
Table 2 – NW Natural Bill Discount Program Tiers

	Household Income Qualifying	Bill Discount Percentage
Tier 0	0-60% FPL	80%
Tier 1	61-120% FPL	40%
Tier 2	121%-150% FPL	20%
Tier 3	The greater of 151%-200% FPL or 80% AMI	15%

Q. What are recent enrollment figures for the bill discount program?

A. Enrollments in the Company's Washington bill discount program have grown steadily since it launched and continue to grow. In the first 17 months of the program, roughly 9,000[6] customers enrolled— representing half of the Company's pool of likely income-eligible customers in the State, as identified through the energy burden assessment. Table 3, below, shows enrollment in the bill discount program by discount tier as of May 2025.

Table 3 – NW Natural Bill Discount Program Enrollments by Discount Tier



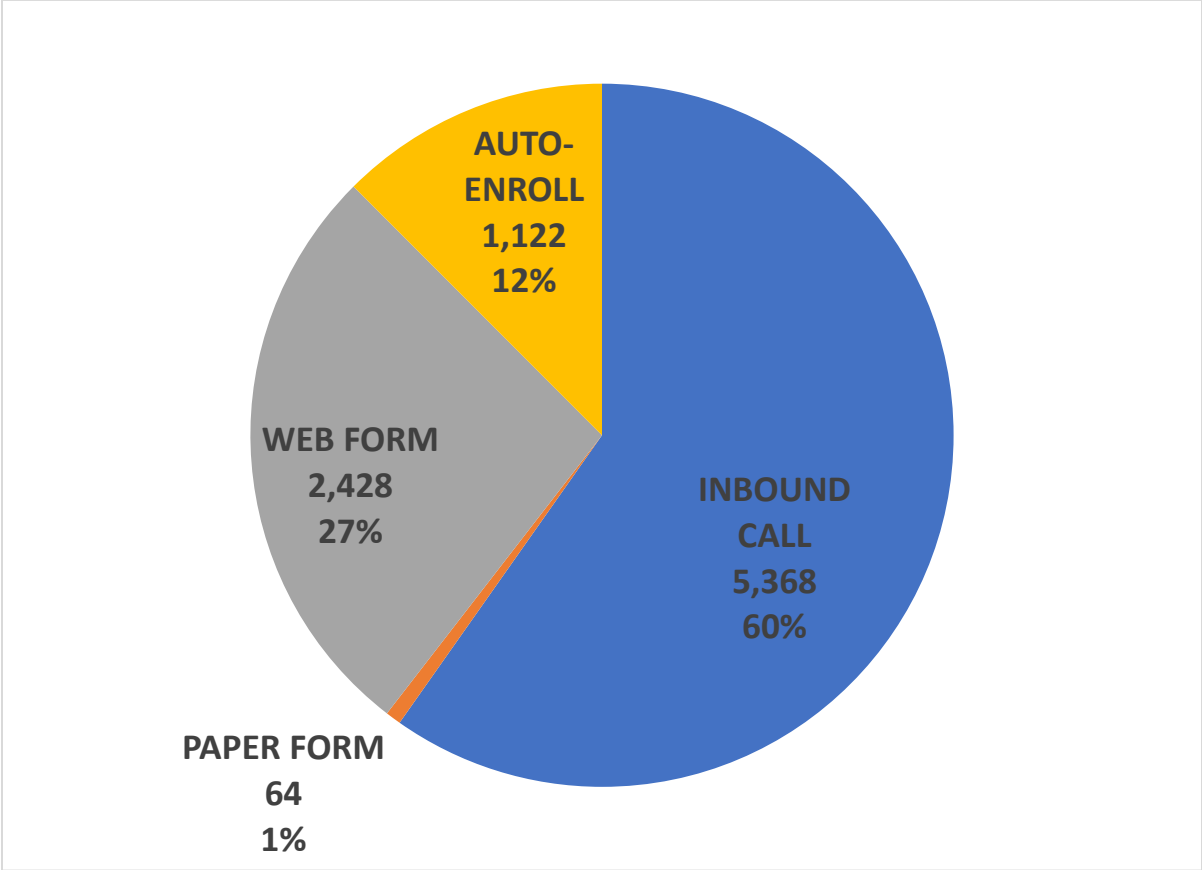
[6] Actual enrollments in the first 17 months: 8,982.

Q. How do customers enroll in the program?

A. The bill discount program has seen a successful uptake in participation thanks to the Program's auto-enrollment features, robust outreach strategies, and ease of entry. This has been echoed by customers, Community Action Agencies, and interested parties alike.

The bill discount program incorporates several inclusive and accessible enrollment practices designed to reduce barriers for eligible customers, as shown below in Table 4. One key feature is the automatic enrollment of customers who have received energy assistance or weatherization services. Any customer who accessed either of these services within the two years prior to the program's launch was automatically enrolled. And this practice continues—new recipients of these services are enrolled without needing to take further action. For those who need to apply manually, the process is intentionally simple and flexible. Customers can complete the application online, via email, by mailing a printed form, or by speaking directly with a NW Natural customer service representative over the phone. Importantly, the program does not require applicants to submit financial documents; instead, eligibility is verified through self-reported information on household size and annual income. There are no deadlines or enrollment windows, allowing customers to apply at any time through the method most convenient for them.

Table 4 –Bill Discount Program Enrollment Methods



Q. How is NW Natural leveraging relationships with community partners to promote outreach and engagement regarding energy assistance and bill discount offerings?

A. NW Natural works with community partners throughout its service territory, such as community action agencies, community-based organizations, affordable housing networks, places of worship, food banks, culturally specific organizations, and healthcare networks. Community partners share bill discount information through check-in calls with homebound seniors, neighborhood newsletters, food boxes, home weatherization kits, in-person events like farmer's markets, open houses, and community meetings---just to name a few. Leveraging these relationships is especially

meaningful and allows the Company to reach customers it may not otherwise have been able to reach and deliver bill discount program information from other important and trusted resources.

The Company tapped a wide network of nonprofit organizations, educational institutions, local governments, and service providers across its three Washington counties to disseminate information. This spanned: 200 K-12 schools in 30 districts, where approximately 80,000 students attend; 15 Head Start and Early Learning Centers, supporting outreach to families with young children; 15 public library branches, serving as high-traffic community hubs; 25 neighborhood newsletters, ensuring geographic coverage in urban and rural areas; and over 60 distinct community-based organizations, including food banks, housing authorities, health clinics, and faith-based institutions. These partners were selected for their deep community ties and their ability to reach priority populations, including low-income families, students, and seniors.

The Company developed an Outreach and Communications Toolkit,[7] which includes printable resources, digital materials, and other customizable content to streamline outreach efforts and allow for easy integration into existing channels of communication—allowing for external partners to choose what works best for who they serve and how. The Toolkit covers key program information like unique URLs to allow easy access to information, program and enrollment details to be disseminated, talking points to keep community partners informed and able to assist enrollment,

[7] Available at https://www.nwnatural.com/account/bill-discount-program/bill-discount-toolkit. The Toolkit is attached as Exh. CJT-4.

language and graphics to be used on social media, text messages, and newsletters to allow digital outreach, and brochures and posters that can be posted prominently to inform customers.

Feedback on our bill discount program materials has been overwhelmingly positive with partners noting appreciation for the accessible language, tailored to a 6th-8th grade reading level; the multi-language presentation covering the five most commonly used languages in our territory; and the inclusion of contact information for other utility bill discount programs.

Another important indicator of the success of NW Natural's innovative and creative outreach qualities is that peer utilities have modeled their own outreach efforts after NW Natural's and have called upon the expertise of Company staff to present on outreach recommendations. And outreach efforts are paying off: 60 percent of enrollments[8] are initiated by customers reaching out directly to NW Natural.

Additional outreach highlights include:

- A direct mail campaign to over 3,600 Washington customers, identified through the EBA as likely eligible and energy burdened, though not participating, was completed in Spring 2025. This is part of the Company's larger direct mail campaign to over 15,000 customers identified through the EBA.
- Proactive, cross-promotional activities: When customers access information about any income-based program, details on all income-based offerings are provided.

[8] 60 percent of bill discount program enrollments occur over the phone.

- In-person events:
  - The Company spearheaded a Winter Preparedness Fair in November 2024; the resource-rich event offered weatherization kits, a vaccine clinic, winter coats for kids, food boxes, and a bill discount sign-up station covering several utilities and services for income-eligible households (all at no cost).
  - The Company hosted a table at Clark PUD's 2025 Race for Warmth event and included information about income-based programs, including the bill discount program.
  - The Company was the headlining sponsor at the Clark County Fire Department #6 Open House on June 7, 2025, and hosted three tables on safety and preparedness, resource planning, and ways to reduce bills through energy efficiency, weatherization, and bill discount offerings.
- Currently underway is a brand new outreach strategy to leverage NW Natural's pay station kiosks in high traffic areas. Bill discount posters and postcards are being delivered to these pay stations in Washington (when and where feasible).

Q. Is the Company also advertising its income-based offerings?

A. Yes. These efforts are further supported by paid ads on local radio stations, including Spanish-language ads, and digital ads across various websites and social media platforms. NW Natural also prepares integrated communications plans annually, with the bill discount program prominently featured.

Q. Did NW Natural consider customers' household natural gas energy burden in the design of its bill discount program?

A. Yes. Table 5, below, from the Company's 2023 tariff filing introducing the bill discount program (docket UG-230739) illustrates the estimated impact on energy burden by bill discount tier. Discounts bring estimated energy burden below the threshold of 3 percent (or less).[9] The intent of targeting 3 percent is to minimize the energy burden related to natural gas service to less than half of the 6 percent that is commonly understood as the indicator of energy-burdened customers.

Table 5 – NW Natural Bill Discount Program Original Design Targeting 3 Percent Energy Burden (from UG-230739 filing)

Bill Discount Program Impacts, Assuming Household of 4:				
	Greater of 200% FPL or AMI 80% Tier 3 - 15%	FPL 150% Tier 2 - 20%	FPL 120% Tier 1 - 40%	FPL 60% Tier 0 - 80%
Income mid-point of tier	$67,601	$40,501	$27,001	$9,000
Average annual bill	$960.11	$960.11	$960.11	$960.11
Bill as % income before discount	1.4%	2.4%	3.6%	10.7%
Bill discount	$144.02	$192.02	$384.04	$768.09
Bill after discount	$816.09	$768.09	$576.07	$192.02
Bill as % income after discount	1.2%	1.9%	2.1%	2.1%

[9] See *In the Matter of the Petition of Northwest Natural Gas Company dba NW Natural, For a Revision to Northwest Natural Gas Company's Tariff WN U-6, Introducing Schedule L and Schedule 231*, Docket UG-230739 (Sept. 12, 2023).

IV. ENERGY BURDEN ASSESSMENT

Q. Has the Company completed an Energy Burden Assessment?

A. Yes. NW Natural engaged Empower Dataworks to conduct an Energy Burden Assessment[10] (EBA) in 2024. Empower Dataworks is a regional consulting firm that specializes in energy equity analytics and has performed similar assessments for numerous utilities throughout the Pacific Northwest. Three types of metrics were calculated in the Company's EBA:

(1) those related to energy burden based on demographic and geographic characteristics,

(2) participation in and funding levels for energy assistance programs (including GAP), and

(3) customer energy use characteristics.

NW Natural provided several customer-level datasets to Empower Dataworks (governed by a confidentiality agreement) to enable this analysis. Customer Information System ("CIS") data included monthly gas bills; on-time payment, late payment and disconnection notices; and customer accounts participating in the Company's bill discount program, other income-eligible energy assistance programs (OLGA, GREAT, GAP, OLIEE) and Low Income Home Energy Assistance Program ("LIHEAP"), along with discount levels and participation timeframes. The data

[10] The Company conducted a Low Income Needs Assessment ("LINA") in 2023. The LINA consisted of a compilation and analysis of relevant data to inform NW Natural's low-income programs in both Oregon and Washington. The Company revised and replaced its LINA with an updated assessment that aligned with workstreams outlined in Oregon docket UM 2211 which focused on the implementation of HB 2475. A complete EBA report and findings were submitted in OPUC docket UM 2211 on September 16, 2024. The EBA is available in Exh. CJT-3.

covered a 27-month period from January 2022 through March 2024 and reflected the most up to date and reliable data on customer billing, payment behavior, and participation in assistance programs available at that time. As time passes, the risk of data obsolescence increases; therefore, the Company is proposing to update the underlying datasets every four years to maintain the integrity of the analysis and ensure that programs align with customer needs.

Q. What is natural gas energy burden?[11]

A. Energy burden is defined as the percentage of gross household income spent on energy costs. Gas energy burden for a household is calculated by dividing annual gas expenses by gross household income. If a household spends more than 6 percent of their income on energy costs, they are considered energy burdened (or 3 percent on just gas), and if a household spends more than 10 percent of their income on energy costs, they are considered extremely energy burdened.

$$Gas\ Burden\ [\%] = \frac{Annual\ Gas\ Expenses\ [\$]}{Annual\ Household\ Income\ [\$]}$$

Q. What are some highlights from the Energy Burden Assessment?

A. Key findings from the Company's EBA[12] for its Washington customers[13] include:

[11] Low-Income Energy Affordability Data (LEAD) Tool Factsheet.

[12] Data pulled as of Q1 2024. This data included monthly gas bills for 27 months between January 2022 and March 2024, account numbers and service addresses. A separate data extract included the dates and customer accounts that received late payment and disconnection notices, allowing the Company to calculate the on-time payment rate for different customer segments.

[13] All estimates are specific to Washington customers unless explicitly noted otherwise.

- 23 percent of Washington's 78,000 customers (approximately 18,000) meet income guidelines.[14] This is a rate nearly double that of NW Natural's customer base in Oregon, and it is attributed to the higher income threshold in Washington's program. In Washington, the income threshold is the greater of 80 percent of the area median income or 200 percent of the federal poverty line. In Oregon, it is 60 percent of state median income.[15] In dollars alone, this translates to a $25,000 higher income threshold in Washington. Specifically, for a family of four, households that earn up to $94,400 are eligible for some level of discount. The same household would be required to earn just under $71,000 to be eligible for the bill discount program in Oregon.
- The Company's bill discount program is targeting customers most in need, evidenced by the highest participation rates in the lowest income tier[16] (Tier 0).
- Low- and non-low-income customers share similar average annual gas bills.
- Average and median household natural gas energy burden rates are 1.5 and 1.0 percent, respectively.

Additional summary metrics are provided in Table 6, below:

[14] NW Natural Washington Bill Discount Program - NW Natural.

[15] Payment assistance options for your natural gas bill - NW Natural.

[16] The EBA states that the goal of an effective energy assistance portfolio should be to prioritize the customers who most need the assistance, i.e. the customers exceeding the high burden thresholds. Page 17 NW Natural Energy Burden Assessment.

Table 6 – EBA Summary Metrics

Metric	Washington
Total # customers	78,000
% eligible	23%
Enrollment rate (among those eligible)	48%
Average gas burden (all customers)	1.5%
Median gas burden[17] (low-income customers)	1%
# of customers energy burden >3%	13,000 (estimate)
# of low-income customers energy burden >3%	10,000
Home vintage[18]	1980-Present: 85% 1940-1979: 11% Pre-1939: 4%

Q. How does the Company plan to use this information?

A. The EBA revealed early and healthy participation in the bill discount program—driven by strong partnerships, outreach and a streamlined enrollment design. It also uncovered pockets of need and opportunity to strengthen engagement and participation—including coastal/non-urban areas, households with high energy burdens, geographically and/or linguistically isolated customers, mobile home park residents, and households that have demonstrated difficulty paying their bills in the past (as evidenced by a past due notice and/or risk of disconnection).

In spring 2025, the Company launched a direct mail campaign to over 3,600 Washington customers who were identified through the EBA as likely eligible[19] for the bill discount program and experiencing household gas energy burden rates above 3

[17] NW Natural's median total energy burden, including an estimate of electricity burden, is between other rural and metropolitan regions in the Pacific Northwest.

[18] Older homes have more opportunities for weatherization, while newer homes could benefit more from lighting, controls and efficient appliances.

[19] Income eligibility is set at 80 percent of Area Median Income or 200 percent of the Federal Poverty Level (whichever is greater).

percent but not enrolled in the program. This effort is part of the Company's larger direct mail campaign to over 15,000 customers. A copy of the postcard is available in Exh. CJT-2.

V. OTHER ENERGY AFFORDABILITY PROGRAMS

Q. Please describe NW Natural's other income-based assistance programs.

A. NW Natural offers a broad set of resources, programs and services to help customers ease energy burden and better afford their natural gas bills. Income eligibility[20] is set at 80 percent of Area Median Income or 200 percent of the Federal Poverty Level (whichever is greater). These include:

- An Arrearage Management Program (AMP) which has delivered over $85,000 in instant grants since it launched on April 1, 2025.
- The Gas Residential Energy Assistance Tariff (GREAT) is a ratepayer-funded energy assistance program that launched in 2009. Roughly $620,000 in GREAT funds were distributed to 913 customers in the most recent program year (2023-2024)—surpassing previous year records in dollars allocated and customers served. GREAT assistance dollars provided in the 2024-2025 program year are expected to again exceed $500,000.
- The Washington Low-Income Energy Efficiency (WALIEE) is a no-cost, whole home weatherization program.
- The Gas Assistance Program (GAP) is a supplemental energy assistance program funded by NW Natural shareholders, employees, retirees, and customers; and

[20] NW Natural Bill Discount Program - NW Natural.

matched by the Company up to $60,000 annually. Funds are allocated directly to customers via a network of Community Action Agencies. The program has raised and delivered over $6.7 million to 60,000 customers in Washington and Oregon since it was established in 1982.

Q. Does NW Natural offer additional tools to assist with affordability?

A. Yes. The Company offers several payment plan options to help customers manage their monthly expenses. Equal Pay is an option that smooths out customers' bills over 12 months to make them more predictable; and the Company's Level Pay and Current Bill Plus plans offer more time and manageable payments for customers who need help with paying past due balances. In addition, through customer communications, including its website, NW Natural provides energy-saving solutions including tips on free fixes and low-cost home improvements.

Q. Is there also federal energy assistance available to customers?

A. Yes. The Low Income Home Energy Assistance Program[21] (LIHEAP) is a federally funded program that provides grants to eligible customers to assist with their energy bills.

LIHEAP is a discretionary program funded through the annual appropriations process. The budget reconciliation[22] signed into law on July 4th did not affect LIHEAP FY 2026 appropriations. Ultimately, LIHEAP funding will be determined through the regular appropriations process, which involves the passage of 12 annual funding bills.

[21] Low Income Home Energy Assistance Program (LIHEAP) | The Administration for Children and Families.

[22] Local Impacts from Congress' One, Big, Beautiful Bill - National League of Cities.

And while current administration has proposed eliminating the program, LIHEAP continues to enjoy strong bipartisan support, particularly among members of the House and Senate Appropriations Committees. As of July 2025, Congress has not finalized FY 2026 appropriations, and a continuing resolution is expected to maintain LIHEAP funding at the current level of $4.1 billion until full appropriations are passed.[23]

Q. How many customers do these programs reach?

A. Please see Tables 7 and 8, below, summarizing the past five program years for each of these programs:

Table 7 – Energy Affordability Program Expenditure History

	October 1 - September 30 Program Years			Calendar year 2024	
	GREAT	**WALIEE**	**LIHEAP**	**Bill Discount**	**Totals**
2019-20	$332,965	$190,457	$88,628	n/a	$612,050
2020-21	$399,849	$13,308	$95,060	n/a	$508,217
2021-22	$383,232	$54,960	$103,182	n/a	$541,374
2022-23	$416,667	$58,251	$178,532	n/a	$653,450
2023-24	$619,435	$82,396	$175,939	$1,229,259	$2,107,029
	$2,152,148	$399,372	$641,341	$1,229,259	$4,422,120

Table 8 - Energy Affordability Program Participation History

	October 1 - September 30 Program Years			December 2024 count	
	GREAT	**WALIEE**	**LIHEAP**	**Bill Discount**	**Totals**
2019-20	706	22	499	n/a	1,227
2020-21	811	3	581	n/a	1,395
2021-22	794	11	600	n/a	1,405
2022-23	785	11	839	n/a	1,635
2023-24	916	10	653	7,513	9,092
	4,012	57	3,172	7,513	14,754

[23] FY2026 LIHEAP Appropriations Testimony - NCLC.

Q. Please share how the Company's broader energy affordability offerings—such as arrearage management support, energy efficiency resources, and assistance grants—complement the bill discount program. Does the current design of the bill discount program remain effective in reducing energy burden for income-eligible customers?

A. Yes. The current design of the bill discount program continues to remain effective in reducing energy burdens for income eligible customers. The Company's EBA, completed in the summer of 2024, found that household natural gas energy burden at 2 percent (or below) would be an affordable, feasible, and meaningful threshold for NW Natural customers. Table 9, below, shows household natural gas energy burden rates below 2 percent for each tier after discounts have been applied—evidence that the program is bringing energy burden rates to an affordable level for eligible customers. Even modeling a hypothetical 25 percent increase in rates, the analysis indicates that current discount levels remain effective in achieving the target 2 percent threshold.

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Table 9 – NW Natural Bill Discount Effectiveness Targeting 2 Percent Energy Burden

	Tier 3 Example	Tier 2 Example	Tier 1 Example	Tier 0 Example
NW Natural bill discount tier	15%	20%	40%	80%
average annual usage	662	662	662	662
annual bill	$807.35	$807.35	$807.35	$807.35
Mid point of income for the tier	$73,763	$43,403	$28,935	$9,645
Existing				
NW Natural bill discount	$121.10	$161.47	$322.94	$645.88
annual bill after bill discount	$686.24	$645.88	$484.41	$161.47
Annual Bill as a % of income before discount	1.1%	1.9%	2.8%	8.4%
Annual Bill as a % of income after discount	**0.9%**	**1.5%**	**1.7%**	**1.7%**
Rate case increase - illustrative	25.0%			
annual bill	$1,009.18	$1,009.18	$1,009.18	$1,009.18
NW Natural bill discount	$151.38	$201.84	$403.67	$807.35
annual bill after bill discount	$857.80	$807.35	$605.51	$201.84
Annual Bill as a % of income before discount	1.4%	2.3%	3.5%	10.5%
Annual Bill as a % of income after discount	**1.2%**	**1.9%**	**2.1%**	**2.1%**

In addition, eligible customers can participate in GREAT and/or LIHEAP, which provided an average benefit of $676 and $269, respectively, in the 2023-2024 program year. Thus, the bill discount program in concert with the GREAT, LIHEAP, WALIEE and AMP energy affordability programs continues to provide customers with effective solutions to reduce energy burden.

Q. What is the GREAT Advisory Group?

A. The Gas Residential Energy Assistance Tariff (GREAT) Advisory Group was established in August 2019 as part of a WUTC-adopted joint settlement agreement in NW Natural's general rate case, with goals to keep customers connected to natural gas service, provide energy assistance to more customers, lower the energy burden of participants, collect data to assess program effectiveness, and inform ongoing policy

discussions. NW Natural has been meeting with the GREAT Advisory group at least monthly; convening 20 times in 2024 and more than 10 times to date in 2025.

Q. Please share recent updates to the GREAT Program.

A. NW Natural worked collaboratively with the GREAT Advisory Group to enact the following recent changes:

- Increased income threshold for GREAT program eligibility to the greater of 80% AMI or 200% federal poverty level (FPL). This change allows for more customers to access energy assistance; it also aligns the GREAT program with income guidelines for Washington electric utilities (defined by RCW 19.405), as well as the Company's bill discount program income eligibility threshold.
- Extended the bill discount program enrollment period to four years (from two years) for eligible customers on fixed incomes.
- Created a process to collaborate with the GREAT Advisory Group to allow for increased spending above the $500,000 soft cap; this process was used successfully in 2024 and twice in 2025.
- Enacted the prioritization of tapping LIHEAP funds before a bill discount is applied when calculating a customer's bill in response to feedback[24] from the GREAT Advisory Group.

[24] LIHEAP funds are typically used first because of federal rules requiring that at least 90 percent be obligated within the same fiscal year. This creates a "use-it-or-lose-it" dynamic. Additionally, future LIHEAP allocations are often based on prior year spending, so fully utilizing funds helps secure future support. Strategically, LIHEAP is prioritized during peak heating seasons, while state and utility programs fill in during off-peak months to ensure year-round coverage.

- Designed, refined and launched a post-enrollment income verification ("PEV") process for bill discount program participants who enrolled through self-attestation. The Company engaged the GREAT Advisory Group and other community partners across its service territory—including those involved in NW Natural's parallel program development in Oregon, to identify and understand best practices for equitable, effective, and economical post-enrollment income verification. These practices were shaped to anticipate and mitigate potential barriers customers may face in providing documentation. The Company initiated the PEV process on April 1, 2025.

VI. WASHINGTON LOW-INCOME ENERGY EFFICIENCY

Q. Please describe NW Natural's Washington Low-Income Energy Efficiency program.

A. NW Natural's low-income energy efficiency program (WALIEE) is administered by community action agencies. The agencies provide weatherization services, health and safety repairs, and energy education services to qualifying customers at no charge. Program details are available in the Company's tariff Schedule I,[25] "Washington Low Income Energy Efficiency Program."

The goal of the low-income program is primarily to address underserved markets and customers that do not have access to energy efficiency incentive programs. For whole home efforts, WALIEE administrators leverage funds provided by other state, federal and local agencies. Those leveraged funds utilize Savings to Investment

[25] View Schedule I – WALIEE Program (PDF).

Ratio (SIR) tests or approved measure lists to meet cost-effectiveness requirements. Within NW Natural's southwest Washington service territory, Clark County serves as the primary community action agency and provider of income-based energy assistance and weatherization services. In Skamania and Klickitat counties, access to weatherization support is limited and service gaps persist. To address this, NW Natural has been working to identify and engage qualified partners capable of delivering services in these underserved areas. Recently, the Washington State Department of Commerce designated Northwest Community Action Center ("NCAC") as the new provider for low-income weatherization services in Skamania and Klickitat counties. NW Natural is currently in the process of establishing an agreement with NCAC to offer free energy efficiency retrofits to eligible NW Natural customers in the region.

Q. Are there updates to the WALIEE Program to share?

A. Yes. Recently, NW Natural has collaborated with local organizations in Skamania and Klickitat counties to distribute do-it-yourself (DIY) weatherization kits. The kits include door draft stoppers, window insulation kits, socket sealers, and other materials intended to provide temporary relief from home drafts. In addition to providing immediate benefits, these kits promote awareness of weatherization opportunities and connect customers to NW Natural's bill discount program.

In recent years, NW Natural funding has been predominantly allocated to furnace tune-ups and replacements. This is not a signal that broader weatherization efforts are being neglected. Rather, it reflects a deliberate sequencing strategy: federal funds are prioritized and spent first because current-year expenditures directly influence next year's budget allocations. By deploying federal dollars early, program

administrators reduce the risk of underutilization, which could otherwise result in reduced funding in subsequent cycles. This approach ensures that broader weatherization measures continue under complementary funding streams, like WALIEE, while preserving long-term program capacity.

In 2024, with input from our stakeholders, including Clark County Community Action Agency and the Energy Efficiency Advisory Group ("EEAG"), NW Natural championed for and secured additional program funding for whole home weatherization projects. Recognizing the critical need for additional health and safety funds to help homes meet the necessary standards for weatherization, NW Natural implemented a $4,000 flexible spending increase per year, per project. This funding can be used to support essential health and safety measures and/or additional energy efficiency improvements.

In 2024, NW Natural completed an impact and process evaluation of its low-income energy efficiency programs. The evaluation found that participating customers are realizing average energy bill savings of 16%-18% along with an annual reduction in arrearages of approximately $213.

The Company's EBA identified approximately 10,000 high-burden, low-income customers within the southwest Washington service territory, including a pool of 1,200 households eligible for free energy efficiency services. The findings highlight opportunities to deliver impactful energy efficiency upgrades in the region. And with the recent addition of a new partner in Skamania and Klickitat counties (as well as efforts to identify and engage new partners), the Company plans to implement a

targeted outreach strategy to engage eligible households in these areas as identified by the EBA.

Q. What is NW Natural's Energy Efficiency Advisory Group?

A. NW Natural's Energy Efficiency Advisory Group was established in 2009 to provide guidance and oversight of the Company's energy efficiency programs and pilot offerings in Washington. The EEAG is comprised of representatives from the WUTC, Washington Public Counsel, Northwest Energy Coalition, Alliance of Western Energy Consumes, The Energy Project, and program staff. Quarterly calls are held to review current program activity and seek guidance on proposed program changes or strategies.

VII. COMMUNITY EQUITY ADVISORY GROUP

Q. Please describe NW Natural's Community Equity Advisory Group.

A. The CEAG is an extension of existing community engagement priorities at NW Natural and a natural outgrowth of NW Natural's commitment to enhancing energy equity and easing energy burden for our most vulnerable customers. From a place of listening and learning, the CEAG seeks out and elevates historically underrepresented voices, perspectives, and lived experiences to advance inclusive practices and institutional actions and bring a racial equity and environmental justice lens to NW Natural's energy and operational planning. NW Natural holds quarterly CEAG discussions with its members on specific topics related to equity, energy justice, or other topics of interest related to NW Natural's operations and energy services. More information about the CEAG can be found on the Company website.[26]

[26] Available at https://www.nwnatural.com/about-us/community/caring, the CEAG Charter and Operating Guidelines document is attached as Exh. CJT-5.

The purpose of the CEAG is to provide NW Natural direct feedback, recommendations, advice, and review on areas related to (a) system planning and renewable resource development, (b) low-income programs, (c) arrearage programs, (d) Company-sponsored philanthropic investments, and (e) other areas as determined by the CEAG and NW Natural.

Q. How is NW Natural demonstrating its commitment to advancing equity through the CEAG?

A. NW Natural is committed to an authentic and effective process: a core tenet of the group is to solicit ideas and encourage engagement from new perspectives, voices, and lived experiences in an authentic, non-extractive way. The Company recognizes that the true value of the CEAG lies in its ability to bring forth diverse perspectives, voices, and lived experiences in a manner that is genuine and non-extractive. This approach helps the Company avoid the pitfalls of diversity, equity, and inclusion work that can often become transactional and performative.

Quarterly meetings are meticulously planned to focus on concrete, actionable items that directly impact households. This strategy ensures that our discussions are not only relevant but also meaningful to the communities the Company serves. By centering our meetings on issues with a direct household impact, the Company creates a space where members can see the tangible effects of their contributions. Questions like "What is the direct impact this topic or issue will have on the household?" and "How will this impact me and my family?" guide our topic selection process. This approach is based on direct feedback from the CEAG. People are busy and overwhelmed, so when the Company asks for their time and feedback, it must be on

something that has a tangible impact and influence in their lives. This ensures that their participation is both valuable and relevant.

Q. What are other examples of the equity-lens approach the Company took in building the CEAG?

A. Other examples of NW Natural's approach include:

- Centering quarterly meetings on concrete, actionable asks of the advisory group—an approach that demands clear expectations, thoughtful planning, and ongoing dialogue.
- Compensating organizations for their time, expertise, and engagement; organizations receive $5,000 per year and the estimated time requirement for the year is 30 hours (rate of $160/hour which is on par with similar types of consulting services).
- Hiring a third-party consultant to lead meetings, advise, and ensure responsiveness and accountability; NW Natural utilizes best practices and guidance from the third-party consultant to develop processes of documentation and response to advisory items brought forward by the CEAG.
- Formalizing feedback and accountability measures with respect to CEAG input: at each CEAG meeting, NW Natural provides a detailed report to the CEAG on topics such as the concrete actions, deliverables, and milestones achieved that were undertaken or achieved since the last meeting and under the recommendations from CEAG members.
- Sourcing meeting topics based on feedback from CEAG members.

- Recruiting culturally specific organizations not currently involved in the energy justice sphere.

Q. Please provide a recent example of how CEAG feedback is being used.

A. A notable highlight of the year was CEAG engagement in the development of the Company's 2025 IRP. Enhancements to public participation in the IRP process play an important role in advancing equity principles and updates to the 2025 IRP center on strengthening inclusive and meaningful engagement in the development of the IRP—core elements of procedural justice and equity, and aligned with the first phase of WUTC's Equity Docket, to analyze decision-making processes and ensure proceedings are fair and inclusive for participants.[27] The 2025 IRP is the first of NW Natural's IRPs to incorporate CEAG feedback into its processes.

In August 2023, CEAG member organizations were introduced to Integrated Resource Planning through short vignettes about NW Natural operations. The intended type of engagement during this session was informational and served as a foundation for future meetings. This introduction to resource planning built upon prior CEAG meeting topics in which the Company's presentations covered its regulatory requirements; stakeholders traditionally involved in its public proceedings; and the meaning and implications of energy planning, affordability and equity.

During the February 2024 CEAG session, the IRP team reviewed the current IRP process (including both NW Natural-led and Commission-led portions) and past stakeholder engagement. CEAG members were provided an IRP public engagement

[27] UTC Equity Docket.

proposal document one week in advance of the meeting for review. This document provided an overview of the IRP purpose and content, historical practices for public engagement opportunities during the IRP process, a proposal for changes in the process, and a request that members come prepared to discuss and provide feedback. As has become standard practice for CEAG materials, this document was written in plain language and translated into Spanish.[28]

The IRP team guided CEAG members through proposed adjustments to the IRP public engagement process to enhance procedural equity considerations, with each proposal discussed in detail. Finally, the group discussed if, and how, the new proposal moved the Company in the direction of improving procedural equity and justice. CEAG members highlighted the need for a community-based, family-friendly event that provides tangible, meaningful resources. They emphasized partnering with trusted organizations, expanding the event's focus beyond energy planning, and scheduling it to accommodate working families and public transportation users.

With these recommendations in mind, the Company dedicated the August 2024 CEAG meeting to several key aspects of energy planning and the importance of the IRP in ensuring NW Natural's capacity to meet energy demands during extreme weather events. The Company emphasized that while the IRP is a dense and technical document, its influence shows up in our daily lives—pointing to uninterrupted gas service during the January 2024 cold snap to illustrate the everyday relevance of the IRP. When temperatures dropped significantly and demands on both the electric

[28] The Company offers translation into any language by request and has received consistent requests for Spanish language materials.

system and gas infrastructure were pushed to their limits, NW Natural was still able to deliver gas to its customers without interruption. This event underscored the IRP's role as a strategic roadmap that guides NW Natural in planning for and managing such extreme weather events; ensuring that NW Natural can maintain service reliability and safety, even during periods of high demand. The Company provided a progress report on its public participation enhancements, highlighting progress made on the IRP Fair concept that stemmed from the CEAG earlier that year.

Q. Please describe the Winter Preparedness Fair.

A. The IRP Fair was borne out of CEAG engagement that centered on ways to enhance procedural equity practices and public engagement opportunities in the development of the IRP. The Fair, held on November 16, 2024, was a comprehensive, resource-rich event that offered weatherization kits, a vaccine clinic, winter coats for kids, food boxes, a bill discount sign-up station covering several utilities and services for income-eligible households (all at no cost)—as well as took early steps to enhance awareness of energy planning and ultimately increase informed participation in energy planning in the future.

NW Natural partnered with Community Services Network and the City of Portland Bureau of Planning and Sustainability to bring this event to the community on November 16th at Parkrose High School. Approximately 45 community-based groups hosted tables at the Fair; and an estimated 850 people attended (representing nearly 2,000 total household members). The flyer for the Fair is included as Exh. CJT-6.

More recently, NW Natural hosted a set of interactive tables at the Clark County Fire District Open House/ Get Ready Community Event on June 7, 2025. These tables

featured information on energy planning, safety, weatherization, and the bill discount program. NW Natural representatives actively engaged with attendees to raise awareness about Energy Planning—including what it entails and how community members can get involved—as well as the public comment period for the draft IRP. Materials were presented in plain language in multiple languages including English, Spanish, Vietnamese, Russian, and Simplified Chinese to ensure accessibility. As part of its outreach efforts, NW Natural also distributed 65 weatherization kits to attendees, providing tangible support for home energy efficiency.

VIII. NW NATURAL'S EFFORTS TO ADDRESS DIVERSITY, EQUITY, AND INCLUSION

Q. What is NW Natural's philosophy regarding diversity, equity, and inclusion?

A. At NW Natural, diversity, equity and inclusion are core to our success and embedded in all aspects of our work, from the way the Company hires and operates every day, to the biggest decisions the Company makes as a business. The Company recognizes the interconnectedness of its actions with the well-being of its customers, communities and planet and is committed to a forward-thinking and strategic approach to equity.

As an employer, the Company strives to advance diversity, equity and inclusion to support its colleagues, customers, contractors, suppliers and community members, regardless of race, gender, color, sexual orientation, age, religion, national origin, or physical or mental disability, so everyone has an equal opportunity to thrive, engage, and belong. NW Natural's commitment to equity, diversity, and inclusion advances its culture and business success.

NW Natural's CEO and Officer team, in partnership with its DE&I Council, defined the following commitments:

- Reinforce our zero-tolerance policy for racism and discrimination at NW Natural;
- Hold listening sessions to understand the experience and needs of Black, Indigenous and People of Color ("BIPOC") employees;
- Foster an inclusive and diverse culture/workforce in our existing employee population;
- Recruit more diversity into NW Natural, focusing on BIPOC, female, trans, and non-binary talent, as well as people with disabilities;
- Assess and expand our ability to work with diverse suppliers, and increase the positive impact on our diverse supplier network;
- Foster diversity, equity and inclusion in our communities through partnerships, volunteering, and financial support; and
- Ensure all customers have equitable access to natural gas programs and resources.
- Through NW Natural's Diversity, Equity and Inclusion Council, which has championed equity and inclusion in the Company and community for 20 years, the Company continues to grow our Employee Resource Groups ("ERGs"). A quarter of NW Natural employees are connected to an ERG. ERGs offer our employees the opportunity to influence our workplace culture: African American ERG, Allyship ERG, Asian American Network, Somos Unidos (LatinX ERG), Rainbow Alliance (LGBTQ+ ERG), Women's Network, and Veterans ERG. NW Natural is

also proud to offer a Neurodiversity ERG, which is one of the first of its kind for U.S. utilities.

Deepening and expanding relationships with a diverse supplier base are integral to the Company's corporate culture and strategy and procurement spending for women owned, minority owned, veteran owned, and small business continues to grow. In 2022, the Company laid the foundation to build out this capacity; and doubled its purchasing spend with diverse suppliers in 2023. The Company is also proud to report that it continued to increase investments with diverse suppliers to $51,888,094 in 2024, which was about 11 percent of the Company's total spend.

Additionally, charitable investments and partnerships help create safe, healthy, and thriving communities where the Company's employees live and work. Through NW Natural's matching gifts program, the Company matched the time and dollars employees gave to the organizations they care about most. The Company provided $1,273,077 of support for organizations that serve its southwest Washington and Oregon service territories. Nineteen percent of our total philanthropic giving went to organizations whose primary mission is furthering needs of communities of color or other marginalized groups.

Q. Does this conclude your Direct Testimony?

A. Yes.

IX. LIST OF EXHIBITS

Exh. CJT-2	2025 Direct Mailing Postcard
Exh. CJT-3	2024 NW Natural EBA
Exh. CJT-4	Washington Bill Discount Program Outreach and Communication Toolkit
Exh. CJT-5	CEAG Charter and Operating Guidelines
Exh. CJT-6	Winter Preparedness Fair Flyer

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Cecelia J. Tanaka

EQUITY

Exh. CJT-2

August 29, 2025

WASHINGTON

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Được giảm giá 15% đến 80% hóa đơn khí đốt hàng tháng của bạn với Chương trình Giảm giá Hóa đơn Tự nhiên Tây Bắc.

Получите скидку от 15% до 80% на ежемесячный счет за газ с помощью программы скидок NW Natural Bill.

We are here to help lower your energy bills with discounts. Scan the QR code to see qualifying incomes and apply. The application only takes minutes to complete online, by email, by traditional mail, or over the phone. You may be able to save more with free home energy improvements and flexible payment plans.

Estamos aquí para ayudarle a reducir sus facturas de energía con descuentos en la factura. Escanee el Código QR para ver los ingresos que califican y hacer la solicitud. Toma solo unos cuantos minutos completar la solicitud en línea, por correo electrónico o por correspondencia postal tradicional, o por teléfono. También podría ahorrar más con mejoras energéticas gratuitas en su hogar y con planes de pagos flexibles.

我们致力于帮助您降低能源费用，提供账单折扣。扫描二维码查看符合条件的收入并提出申请。申请只需几分钟即可在线、通过电子邮件、传统邮寄或电话完成。通过免费家庭节能改善和灵活的付款计划，您可能可以节省更多。

Chúng tôi ở đây để giúp quý vị giảm hóa đơn tiền điện bằng các khoản chiết khấu hóa đơn. Quét mã QR này để xem khả năng đủ điều kiện về thu nhập và nộp đơn. Chỉ mất vài phút để hoàn tất đơn trực tuyến, qua email hoặc thư truyền thống hoặc qua điện thoại. Quý vị có thể tiết kiệm nhiều hơn với các cải tiến năng lượng miễn phí tại nhà và các gói thanh toán linh hoạt.

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BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

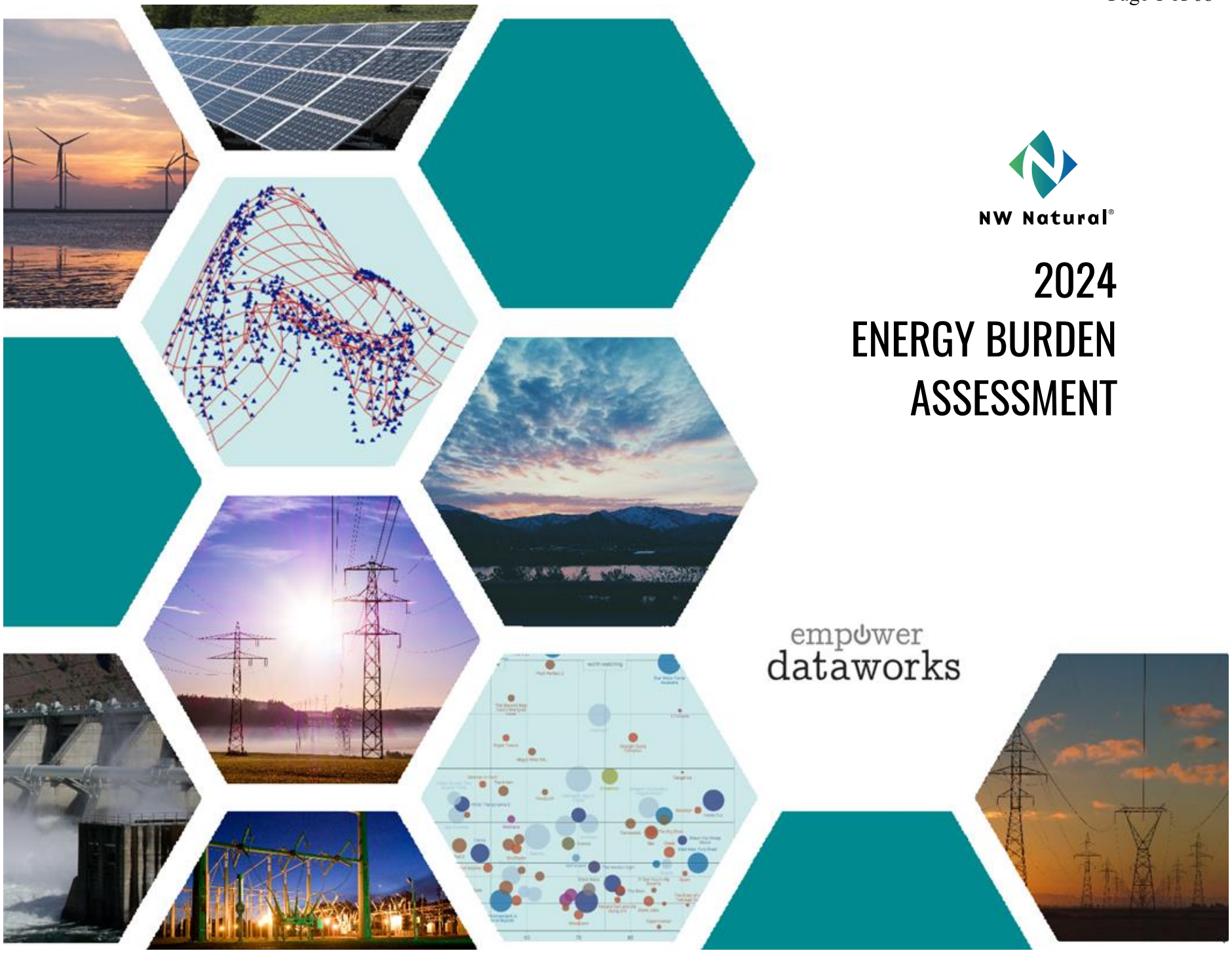
NORTHWEST NATURAL GAS COMPANY

Exhibit of Cecelia J. Tanaka

EQUITY

Exh. CJT-3

August 29, 2025



NW Natural®

2024 ENERGY BURDEN ASSESSMENT

empower dataworks

2024 ENERGY BURDEN ASSESSMENT

AUGUST 2024

PREPARED FOR

Amy Schulties

Northwest Natural

PREPARED BY

Hassan Shaban, Ph.D.

Empower Dataworks

INTRODUCTION

This brief report presents the methodology and findings from NW Natural (NWN)'s 2024 energy burden assessment for Oregon and Washington.

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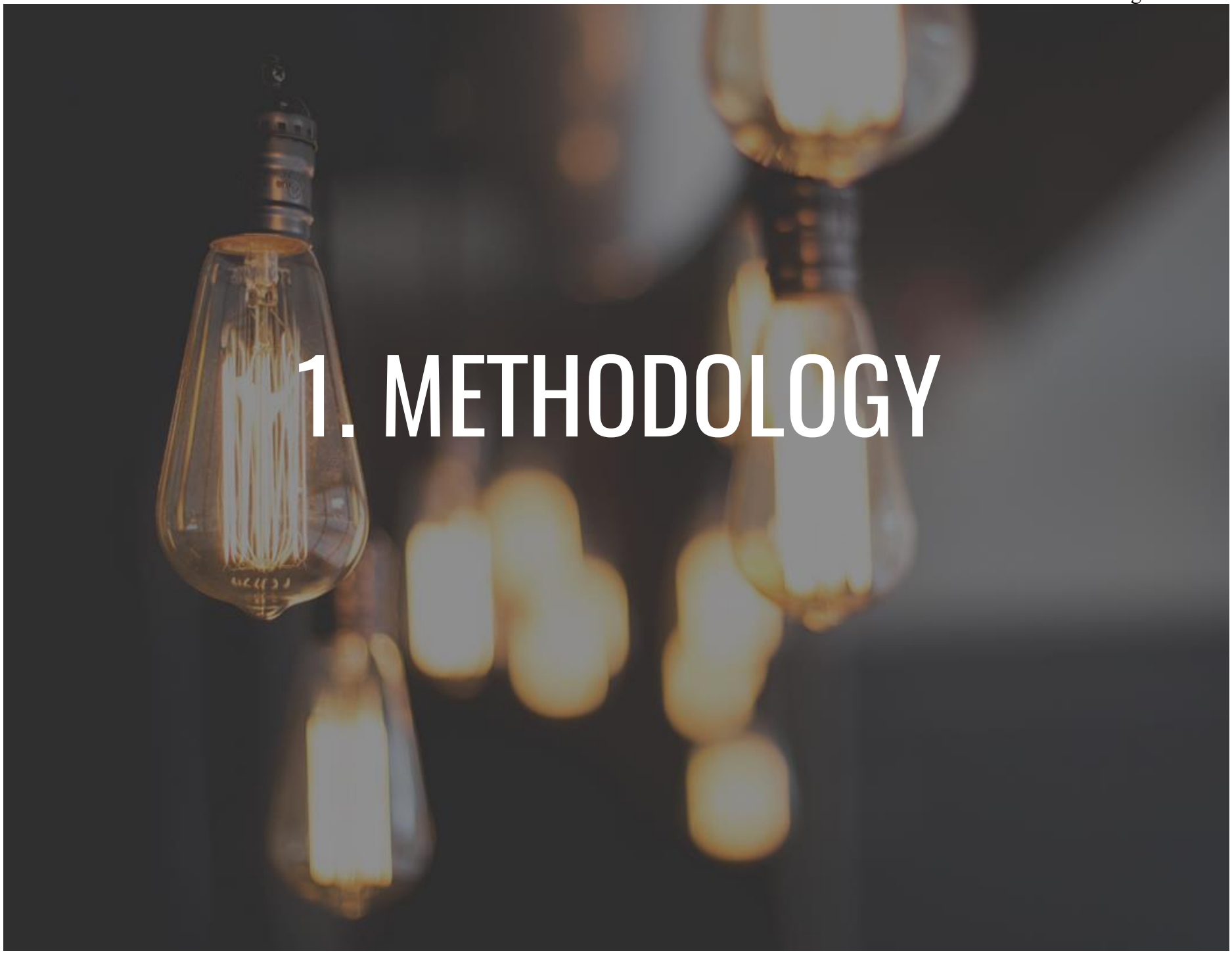


1. METHODOLOGY

1.1 GENERAL APPROACH

This energy burden assessment relies on collecting customer-level data, modeling missing attributes, then aggregating key metrics by geographic, demographic or building variables for analysis. Prior to this project, Empower Dataworks performed energy burden assessments in over 15 utility service areas (both gas and electric) using this approach. The methodology is also updated occasionally to align with energy assistance best practices. The energy burden assessment results are typically used to guide program design, evaluate the performance of energy assistance programs and develop targeted marketing and outreach strategies.

The customer data (including estimated household income) comes from various sources as described in the rest of Section 1. Some demographic attributes were modeled or inferred using statistical techniques due to lack of primary data in the Customer Information System (CIS) or other sources. American Community Survey data was mainly used to sanity check aggregate statistics of customer-level data at the census tract level.

Three types of metrics were calculated:

- Metrics related to energy burden based on demographic and geographic characteristics
- Participation and funding in Energy Assistance Programs
- Customer energy use characteristics

The final dataset and results were provided to NWN staff.

1.2 DATA SOURCES

The data sources leveraged for the analysis are described in this section.

DATA PROVIDED BY NWN

NWN provided various customer-level datasets to Empower Dataworks to enable this analysis. Data sharing was governed by a confidentiality agreement between Empower Dataworks and NWN. Empower Dataworks was also subject to various cybersecurity requirements to safeguard customer data.

Customer Information System (CIS): This data included monthly gas bills for 27 months between January 2022 and March 2024, account numbers and service addresses. A separate data extract included the dates and customer accounts that received late payment and disconnection notices, allowing us to calculate the on-time payment rate for different customer segments.

Direct Assistance Program Data: We received a list of participating accounts in the Bill Discount Program (BDP), other NWN low-income programs (OLGA, GREAT, GAP, LIEE), and LIHEAP between January 2022 and March 2024, along with discount amounts and dates. This allowed us to calculate the total assistance funding at the household level.

Demographic Data: Demographic data was procured from a third-party data compiler that aggregates data from a variety of sources. This data was mapped to the CIS dataset using customer addresses and included estimated household income, and homeownership status for most residential households. Demographic attributes for some customers were modeled due to lack of primary data in CIS or other sources. The modeling approaches are described in the next section.

DATA OBTAINED FROM OTHER SOURCES

Geocoding: We mapped the latitude/longitude of customer premises to census tracts, block groups and blocks in order to pull additional aggregate statistics.

County Assessor Data: We obtained publicly available assessor data from all counties in NWN's service area. The data from most assessors included appraised values for homes, square footage, building year built, land use codes (residential, mobile homes, commercial and industrial), and other minor data points that were useful for performing general QA.

The addresses in this dataset were standardized to US Postal Service format, then matched with addresses in the CIS data. Some addresses existed in the CIS data but not in the assessor data (typically happens when multiple buildings occupy the same land parcel).

American Community Survey (ACS): ACS data (2018-22 5 year averages) was primarily used for QA to ensure that aggregate counts for various demographic attributes match the expected distributions from ACS.

1.3 FINAL ATTRIBUTES AND METRICS

The calculation methods for the metrics and attributes used in this report are described in this section. For all attributes, we also captured metadata related to the source of data and the confidence in the value (for example, data from primary sources has a high confidence, while modeled data has lower confidence). All of the data is robust for aggregate analysis, while high confidence data is better suited to customer-level marketing and program targeting.

Household Income: Estimated household incomes were obtained using three methods: (i) self-attested incomes for program participants, (ii) third-party purchased and calibrated demographic data, and (iii) modeled income for households with missing data. Self-attested household income was available for about 45,000 households that had participated in the BDP and declared their household income. Third-party estimated income data is sourced from public or commercially available data sources. Since household income from data vendors can become outdated quickly, we adjusted the unverified household incomes by a constant percent, so that the median household income in each county matched the median household income from the DOE LEAD tool and the Federal Reserve's FRED tool. For households with missing income data, an estimated income was calculated as the average of the incomes of the five geographically closest households.

Poverty Status: The number of people living in a household cannot be easily obtained from any public data sources. This makes it difficult to identify a household's poverty status compared to the State Median Income, which is defined by household size. According to the Census Bureau, the median household size in the NWN counties varies from 2.2 to 2.8. In general, we used the income limits for two person households in this analysis as they produced the best estimates of state median income tiers compared to the DOE LEAD tool.

Validation: According to the DOE LEAD tool, between 10-18% of gas-heat households in the four largest Oregon counties served by NWN would fall under 60% of the State Median Income. In this assessment, the county poverty rates range from 9-17% (with an approximately

10% margin of error), which is within the census range. The LEAD tool estimates that 24% of gas-heat customers in Clark County, WA fall under 80% of the Area Median Income, compared to 23% estimated through this assessment.

Building type: Meters were classified into one of five building types: single family, mobile homes, multifamily apartments, commercial or master metered and unoccupied. Commercial meters were those tagged with a specific commercial use by the county assessor or that were on a commercial rate class. Additionally, we filtered out meters using in excess of 3,600 Therms per year as those are likely associated with commercial uses or are master metered. Meters that showed energy consumption less than 60 Therms/year were flagged as potentially unoccupied or vacation homes.

Overall, the number of residential meters was 706,000. When excluding high-use and low-use outliers (suspected seasonal, unoccupied or master-metered), the final number of occupied households for the analysis was approximately 645,000 (567k in OR, 78k in WA). NWN provided internal data to identify single family and multifamily building types – this was used in conjunction with county assessor land use codes to categorize building types.

Validation: The aggregate housing type counts (85-89% single family) are very similar to data from the DOE LEAD tool for the five largest counties in NWN's service area.

Homeownership Status: Some homeownership data (rent vs. own) was available from NWN and the third party demographic dataset. For the remainder, households in multifamily apartments were tagged as "Likely Renters", and households without any account changes during the two year analysis period were tagged as "Likely Homeowners".

Validation: The owner-occupied housing rate from the DOE LEAD tool for the five largest counties in NWN's service area (80-85%) is slightly lower than the homeownership rate from this analysis (85-90%).

Energy Burden and Energy Efficiency Potential thresholds: These thresholds were set as follows:

- High-burden threshold: Greater than 2% in marine climate counties and greater than 3% in cold climate counties – using climate zones defined by DOE. Cold climate counties (1% of households): Hood River, Wasco (OR), Klickitat, Skamania (WA).
- High efficiency potential threshold: Greater than 0.6 therms/sq.ft.

Gas Burden: Gas energy burden for a household is calculated simply by dividing annual gas expenses by gross household income.

$$Gas\ Burden\ [\%] = \frac{Annual\ Gas\ Expenses\ [\$]}{Annual\ Household\ Income\ [\$]}$$

Excess Burden: Excess burden is the portion of a household's gas burden in excess of the high burden threshold.

$$\begin{aligned} Excess\ Burden\ [\$] \\ &= \max(0, Energy\ Burden\ [\%] \\ &\quad - High\ Burden\ Threshold[\%]) \\ &\quad \times Annual\ Household\ Income[\$] \end{aligned}$$

On-Time Payment Rate: This is the proportion of all energy bills that did not require a late payment or disconnect notice to be sent out.

Energy Assistance Funding: The dollar amount of funding flowing through energy assistance programs (including discount, donation and weatherization programs) through discounts or rebates.

Customer Bill Reductions (**Avoided Burden**)**:** The total bill impact (in dollars) from energy assistance programs.

Avoided Need: The total bill impact (in dollars) from energy assistance programs, specifically for program participants flagged as "high-burden". Bill impact is equal to the amount of assistance grants or discounts for direct assistance programs and is equal to measure savings (therms/year) multiplied by the residential therms rate ($/therms) for energy efficiency programs.

Census Tract Statistics: Since each customer has been mapped to a census tract and block group, we are also able to match customers to census tract average statistics (e.g. highly impacted communities, presence of children, non-English speakers, education level, environmental pollution etc.).

Energy Assistance Need: This is the sum of excess burden across all customers.

2024 Projections: Since NWN customers experienced a rate change in November 2023, some figures in this assessment related to need and energy burden are projections for 2024 including the impact of the rate change. The 2024 energy bills were projected by using the 2023 energy usage for customers and applying the 2024 rate structure. 2024 household incomes were estimated by adding a 7% multiplier to the estimated 2023 household incomes (LIHEAP applied a 7% income adjustment to their 2024 income guidelines compared to 2023). This will be noted where relevant.

1.4 SOURCES OF UNCERTAINTY

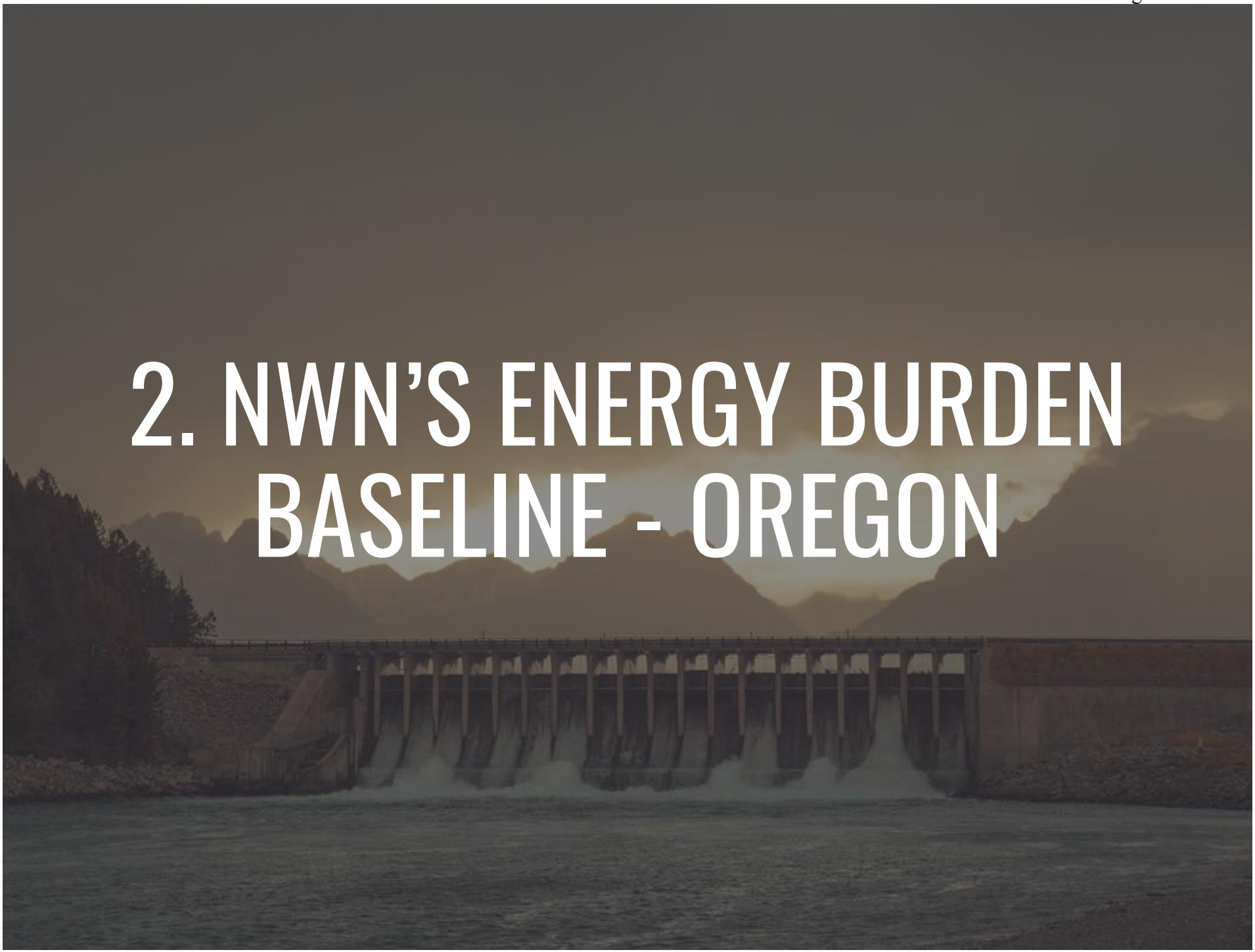
- **Household income** is a dynamic piece of data as residents move in and out of homes and income data can become outdated within a year or two.

- **Poverty status.** Since household size cannot be reliably captured through any available data source, household poverty status is subject to uncertainty. The State Median Income uses household size as a scaling factor. In this analysis, we have used income thresholds for 2-person households for consistency and clarity, but they may under-estimate or over-estimate the actual income eligibility depending on the actual sizes of low-income households in this service area.

- **Individual vs. aggregate data usage.** The underlying dataset has customer-level flags for data quality – data from primary sources is considered high quality while modeled data is considered medium or low quality, depending on the availability of supporting sources of information (example, home values and location). Higher quality data can be used for individual program targeting, lower quality data can be used for program design and aggregate reporting.

- **Building types.** There is some uncertainty in the classification of building types as described in Section 1.3. This could results in misclassifying non-residential meters as occupied households or single family/mobile homes as multifamily.

- **Achievable reductions in energy assistance need.** This analysis presents a *technical* energy assistance need based on energy burden. However, in our experience with energy assistance programs in general, many customers may not participate in programs, regardless of program design or available benefits due to a variety of barriers like access to information, application process difficulties, stigma and lack of trust. Understanding the *economically achievable* reduction in energy assistance need through utility programs would require a qualitative research of non-participants in a utility's service area.



2. NWN'S ENERGY BURDEN BASELINE - OREGON

2.1 NWN RESIDENTIAL SECTOR PROFILE - OR

NWN's service territory in Oregon was composed of approximately **567,000 occupied households** in 2023 (exceeding a minimal level of 60 therms/year of energy use and not exceeding 3,600 therms/year).

Ethnicity: According to the U.S. Census Bureau, approximately 62-78% of residents in NWN's largest counties are non-Hispanic white.

Household Income: The median household income for residents in NWN's service area was approximately $114,000 in 2024, significantly higher than the state median. Approximately **12.5%** of residents would fall under 60% of the State Median Income (see table on following page for SMI values). An additional 13% of households earn between 60-100% of the state median income. These "borderline" customers would be ineligible for almost all energy assistance programs, but may still bear a relatively high level of energy burden. Designs for programs that are ratepayer-funded should take into account the degree of additional burden that would be imposed on these customers.

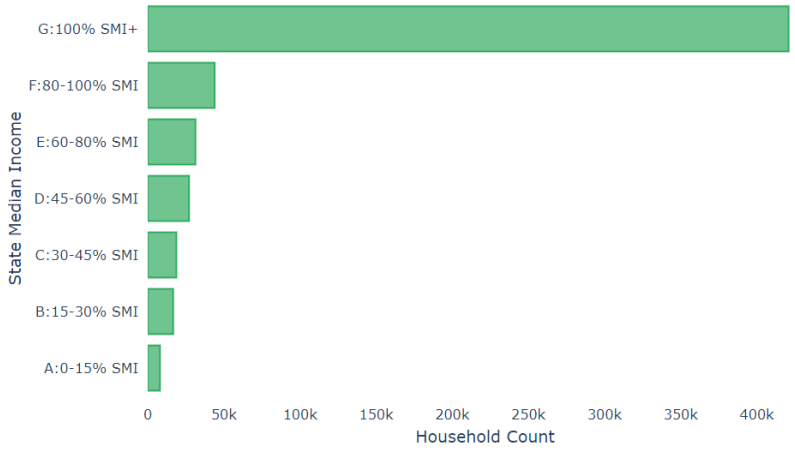


Figure 1. Distribution of households by household income as a percent of state median income for NWN residential customers

	60% of Annual State Median Income (SMI)	
Household Size	**2023**	**2024**
1	$31,266	$33,427
2	$40,886	$43,712
3	$50,506	$53,997
4	$60,126	$64,282
5	$69,747	$74,567
6	$79,367	$84,852
Each additional member	$1,803	$1,929

Energy Bills: NWN's residential volumetric gas rates in 2024 were about average for the region, and the basic charge is relatively low. Annual gas bills average **approximately $1,100/year (2024 projection) with an average annual consumption of 720 therms**. Figure 2 shows the distribution of annual gas bills.

Home Vintage: Of the homes with a known age, approximately 48% were built after 1980, 36% were built between 1940 and 1980, with the remainder built prior to 1940. Older homes have more opportunities for weatherization, while newer homes could benefit more from lighting, controls and efficient appliances.

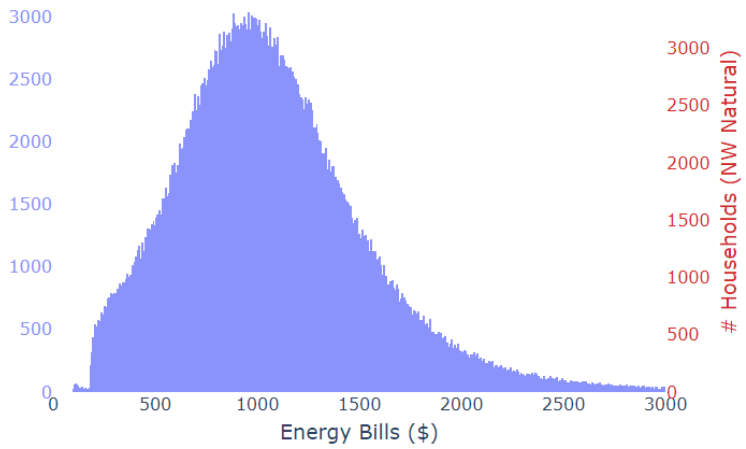


Figure 2. 2024 Household gas bill distribution for NWN residential customers in Oregon

2.2 ENERGY BURDEN

NWN customers in Oregon have an **average and median gas energy burden of 1.4% and 0.9%**, respectively. Figure 3 compares NWN's median total energy burden (including an estimate of electricity burden) to values published in other jurisdictions. The median burden is between other rural and metropolitan regions in the Pacific Northwest.

The average household will pay $1,100/year in gas bills in 2024. Of 567,000 identified households, **75,000 were deemed to have a high energy burden**, of which an estimated 50,000 would fall under 60% State Median income - meaning that annual gas bills exceeded 2/3% of their income, depending on their climate zone. Low-income high-burden customers paid an average of $1,100 in annual gas bills as well; indicating that the high burden is driven by low incomes rather than high gas usage. The **total energy assistance need for NWN customers in Oregon is approximately $38M across all incomes and $29M in households that earn under 60% SMI**—this is the total reduction that would bring all customer gas bills below the high burden threshold.

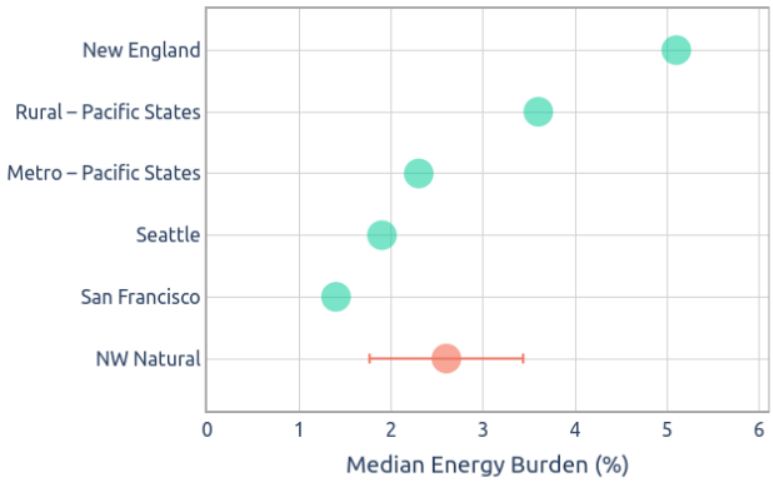


Figure 3. Energy burden benchmarking vs. other regions. Data for other regions is the median across each region, not specific to any utility.

NWN's energy charge in its 2024 residential retail rate is approximately $1.3/therm, which is similar to other gas utilities in the region and slightly lower than the national average of $1.45/therm. Low incomes appear to be the most significant drivers of high energy burden in the area for a minority of customers.

Although averages and medians give a general indication of energy burden across a service territory, the reality is that **energy burden is a customer-level metric** and its distribution is a better indicator of the burden that

customers experience. The distribution of energy burden among NWN customers is shown in Figure 4.

The goal of an effective energy assistance portfolio should be to prioritize the customers who most need the assistance, i.e. the customers exceeding the high burden thresholds.

Approximately 84% of the energy assistance need is borne by single family households. Only 15-20% of the energy assistance need for NWN customers in Oregon is among renters – high-burden single-family homeowners represent a promising opportunity for eliminating gas burden through energy efficiency or weatherization. Other customer segments can be investigated in more detail in the data dashboard.

Number of Occupied Households

~567,000

Low Income Households Under 60% SMI:

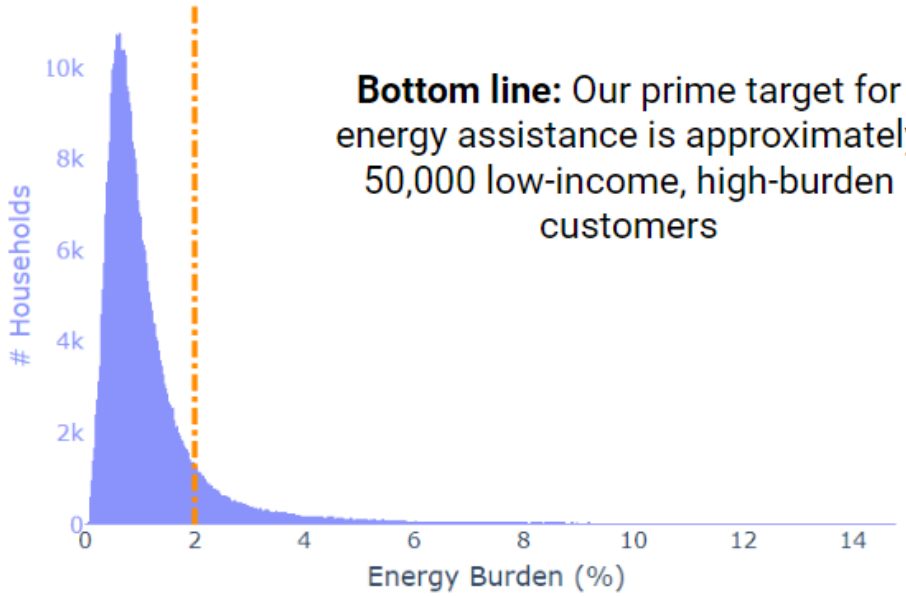
~71k ± 10%

High Burden Households*

~75,000 (all)

~50,000 (LI)

Median Gas Burden
~0.9% (all)
~3% (LI)



Bottom line: Our prime target for energy assistance is approximately 50,000 low-income, high-burden customers

*Energy bills and burden are calculated without factoring in any forms of energy assistance

Figure 4. Distribution of energy burden among NWN customers in Oregon.
Figure shows all homes but dashed line indicating 2% high energy burden threshold applies to marine climate counties (99% of all households).

2.3 ENERGY EFFICIENCY VS DIRECT ASSISTANCE

Figure 5 shows the distribution of energy burden and energy efficiency potential (defined through Energy Use Intensity thresholds) across all low-income residential customers. In a perfect world, the energy assistance portfolio would match these customer segments. For example:

- Energy efficiency and weatherization programs should primarily serve **high burden, high potential** households
- Direct assistance programs should primarily serve **high burden, low potential** households
- Crisis/emergency programs should primarily serve **low burden, low potential** households
- Traditional energy efficiency programs with financing should serve **low burden, high potential** households

Aligning targeted customers with program strengths results are the most cost-effective pathway to energy burden reduction.

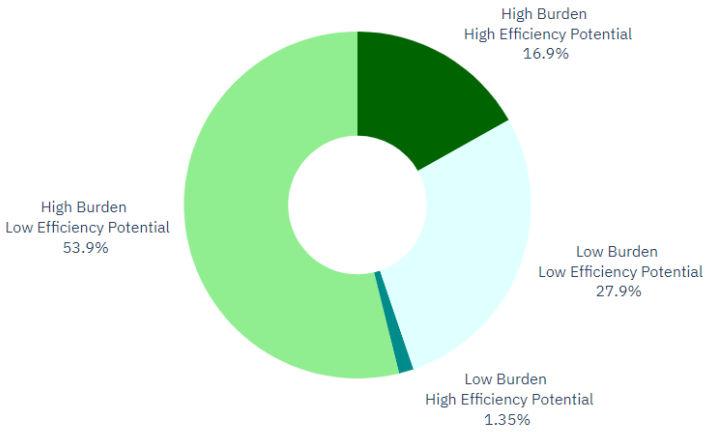
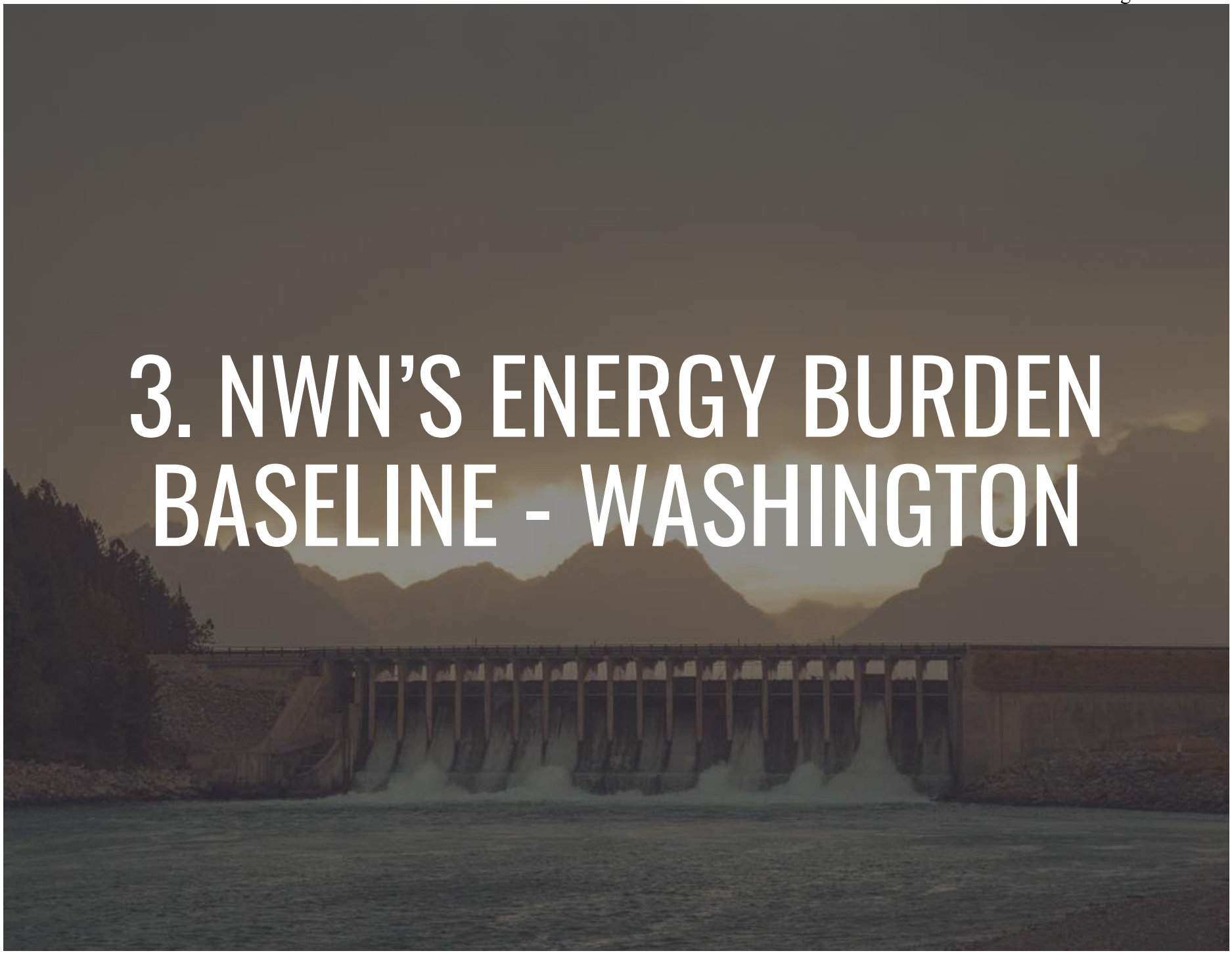


Figure 5. NWN low-income customer segments by energy burden and energy efficiency potential.

Approximately 28% of NWN's low-income customers are low-burden and low-efficiency potential. These customers' energy bills may not be a huge expense relative to housing, medical and education expenses, and they should not be prioritized in the more intensive programs, such as weatherization.

Almost 24% of high burden customers also have a high efficiency potential indicating that the energy assistance program mix should prioritize immediate relief through bill discounts. While energy efficiency is a more sustained form of energy burden reduction, we should recognize that scaling up low-income weatherization faces a host of barriers. Energy efficiency and direct assistance are not mutually exclusive and there is still a large group of households who would benefit most from energy efficiency to alleviate their high gas burden.



3. NWN'S ENERGY BURDEN BASELINE - WASHINGTON

3.1 NWN RESIDENTIAL SECTOR PROFILE - WA

NWN's service territory in Washington was composed of approximately **78,000 occupied households** in 2023 (exceeding a minimal level of 60 therms/year of energy use and not exceeding 3,600 therms/year).

Ethnicity: According to the U.S. Census Bureau, approximately 73% of residents in Clark County are non-Hispanic white.

Household Income: The median household income for residents in NWN's service area was approximately $123,000 in 2024, significantly higher than the state median. Approximately **23%** of residents would fall under 80% of the Area Median Income (see table on following page for AMI values). An additional 11% of households earn between 80-100% of the area median income. These "borderline" customers would be ineligible for almost all energy assistance programs, but may still bear a relatively high level of energy burden. Designs for programs that are ratepayer-funded should take into account the degree of additional burden that would be imposed on these customers.

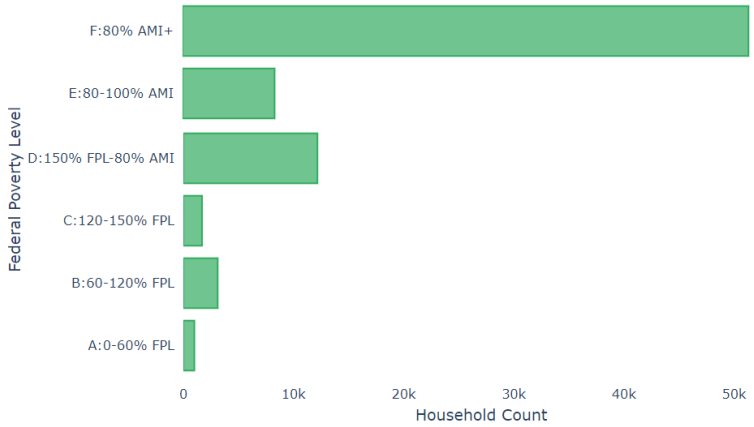


Figure 6. Distribution of households by household income as a percent of federal poverty level and area median income for NWN residential customers

	80% of Annual Area Median Income (AMI) – Clark County, WA	
Household Size	**2023**	**2024**
1	$63,150	$66,100
2	$72,200	$75,550
3	$81,200	$85,000
4	$90,200	$94,400
5	$97,450	$102,000
6	$104,650	$109,550
Each additional member	$7,200	$7,550

Energy Bills: NWN's residential volumetric gas rates in 2024 were about average for the region, and the basic charge is relatively low. But the inclusion of the $0.5/therm CCA charge drives up the cost of gas significantly for customers who haven't been certified as low-income. Annual gas bills average **approximately $1,340/year (2024 projection – not including potential CCA credits which are hard to predict) with an average annual consumption of 740 therms**. Figure 7 shows the distribution of annual gas bills.

Home Vintage: Of the homes with a known age, approximately 86% were built after 1980, 11% were built between 1940 and 1980, with the remainder built prior to 1940. Older homes have more opportunities for weatherization, while newer homes could benefit more from lighting, controls and efficient appliances.

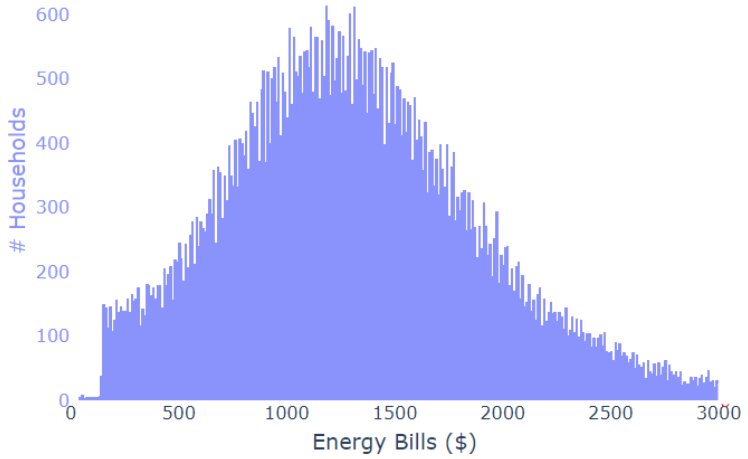


Figure 7. 2024 Household gas bill distribution for NWN residential customers in Oregon

3.2 ENERGY BURDEN

NWN customers in Washington have an **average and median gas energy burden of 1.5% and 1.0%**, respectively. Figure 8 compares NWN's median total energy burden (including an estimate of electricity burden) to values published in other jurisdictions. The median burden is between other rural and metropolitan regions in the Pacific Northwest.

The average household will pay $1,340/year in gas bills in 2024. Of 78,000 identified households, **13,000 were deemed to have a high energy burden**, of which an estimated 10,000 would fall under 80% Area Median income - meaning that annual gas bills exceeded 2/3% of their income, depending on their climate zone. Low-income high-burden customers paid an average of $1,380 in annual gas bills, despite most being exempt from the CCA charges; indicating a higher likelihood of living in less efficient homes. The **total energy assistance need for NWN customers in Washington is approximately $7.3M across all incomes and $5.9M in households that earn under 80% AMI**—this is the total reduction that would bring all customer gas bills below the high burden threshold.

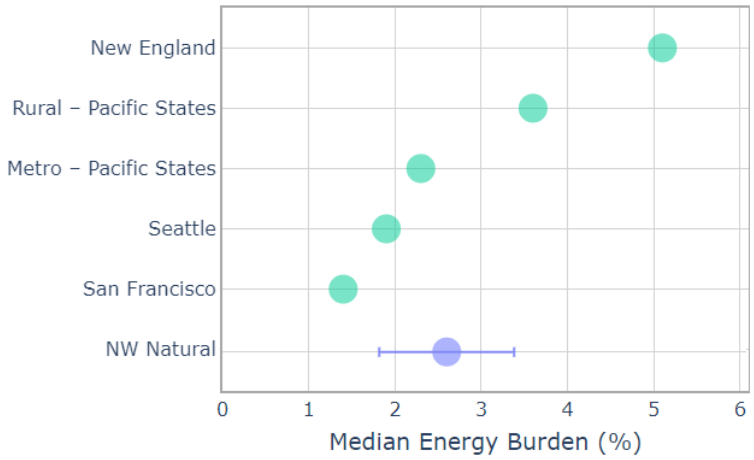


Figure 8. Energy burden benchmarking vs. other regions. Data for other regions is the median across each region, not specific to any utility.

NWN's energy charge in its 2024 residential retail rate is approximately $1.7/therm (inclusing Washington CCA charges), which is higher than other gas utilities in the region and the national average of $1.45/therm. Higher gas use coupled with the CCA charges appear to be a big driver of high energy burden in the region.

Although averages and medians give a general indication of energy burden across a service territory, the reality is

that **energy burden is a customer-level metric** and its distribution is a better indicator of the burden that customers experience. The distribution of energy burden among NWN customers is shown in Figure 9.

The goal of an effective energy assistance portfolio should be to prioritize the customers who most need the assistance, i.e. the customers exceeding the high burden thresholds.

Approximately 88% of the energy assistance need is borne by single family households. Only 9-10% of the energy assistance need for NWN customers in Washington is among renters – high-burden single-family homeowners represent a promising opportunity for eliminating gas burden through energy efficiency or weatherization. Other customer segments can be investigated in more detail in the data dashboard.

Number of Occupied Households

~78,000

Low Income Households Under 80% AMI:

~18k ± 10%

High Burden Households*

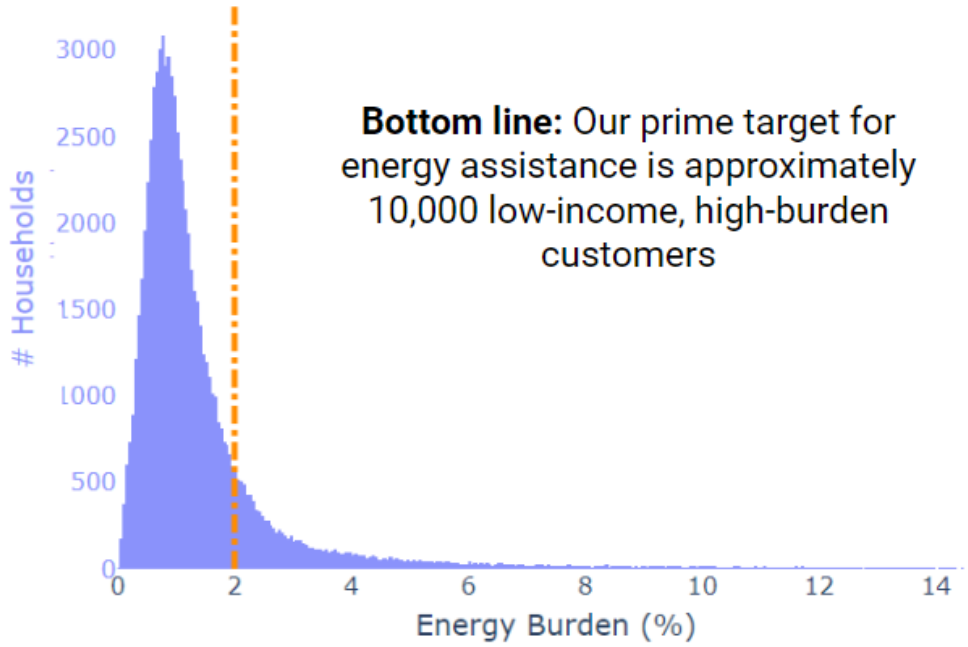
~13,000 (all)

~10,000 (LI)

Median Gas Burden

~1% (all)

~2.2% (LI)



Bottom line: Our prime target for energy assistance is approximately 10,000 low-income, high-burden customers

*Energy bills and burden are calculated without factoring in any forms of energy assistance

Figure 9. Distribution of energy burden among NWN customers in Washington.
Figure shows all homes but dashed line indicating 2% high energy burden threshold applies to marine climate counties (99% of all households).

3.3 ENERGY EFFICIENCY VS DIRECT ASSISTANCE

Figure 10 shows the distribution of energy burden and energy efficiency potential (defined through Energy Use Intensity thresholds) across all low-income residential customers. In a perfect world, the energy assistance portfolio would match these customer segments. For example:

- Energy efficiency and weatherization programs should primarily serve **high burden, high potential** households
- Direct assistance programs should primarily serve **high burden, low potential** households
- Crisis/emergency programs should primarily serve **low burden, low potential** households
- Traditional energy efficiency programs with financing should serve **low burden, high potential** households

Aligning targeted customers with program strengths results are the most cost-effective pathway to energy burden reduction.

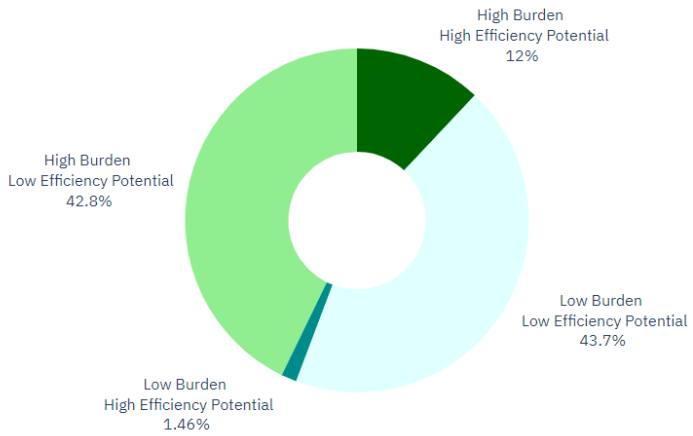


Figure 10. NWN WA low-income customer segments by energy burden and energy efficiency potential.

Approximately 44% of NWN's low-income customers in Washington are low-burden and low-efficiency potential. These customers' energy bills may not be a huge expense relative to housing, medical and education expenses, and they should not be prioritized in the more intensive programs, such as weatherization.

Almost 22% of high burden customers also have a high efficiency potential indicating that the energy assistance program mix should prioritize immediate relief through bill discounts. While energy efficiency is a more sustained form of energy burden reduction, we should

recognize that scaling up low-income weatherization faces a host of barriers. Energy efficiency and direct assistance are not mutually exclusive and there is still a large group of households who would benefit most from energy efficiency to alleviate their high gas burden.

4. KEY CUSTOMER SEGMENTS

4.1 OVERVIEW

This section presents statistics and profiles related to some key customer segments in NWN's service area. These customer segments were selected for a combination of reasons:

1. Flagged in this assessment as having high overall burden or high prevalence of energy burden

2. Identified as having low access to existing programs

3. Identified as vulnerable through the Department of Energy's environmental justice screen

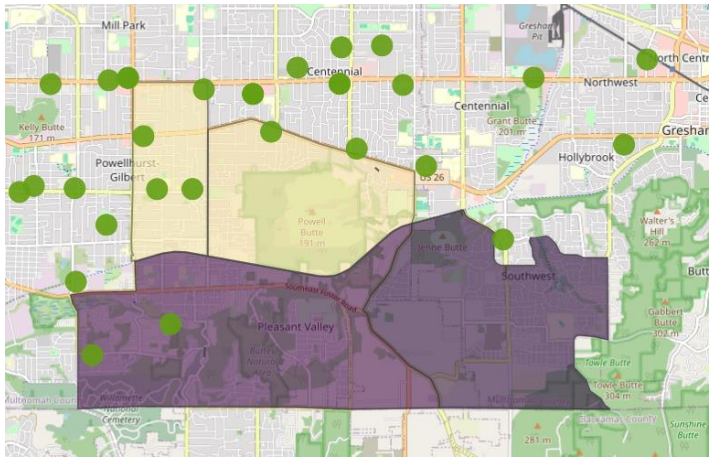
This analysis is primarily geographic, focusing on specific neighborhoods. The maps in the following sections display the level of energy assistance need in these areas as well as locations of social services for potential outreach (green dots).

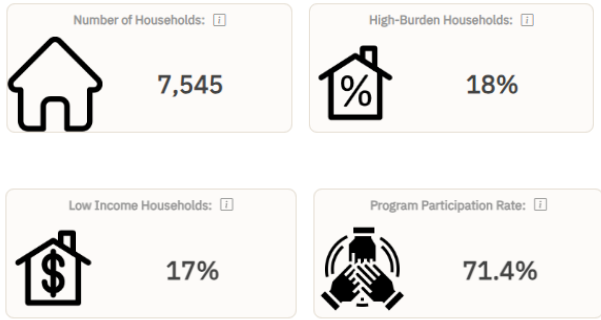
These customer segments represent only a portion of the high energy burden among NWN's customers, but they are intended to serve as an example of the targeting analysis that NWN can perform for their programs or outreach initiatives in the future.

4.2 PLEASANT VALLEY

Census tracts: **41051008901, 41051009000, 41051009102, 41051009903**

Total Assistance Need: **$745k (1.6% of total need)**
Total Assistance Funding: **$414k (2.5% of total funding)**
People of Color: 38%
Linguistic Isolation: 8%





PROFILE: The Pleasant Valley neighborhood in Eastern Multnomah county is a very diverse community with over 38% people of color and over 8% of the population living in linguistic isolation (mix of Spanish, Asian and East European). Members of this community tend to be single family homeowners. On the other hand, it appears to be well served by existing assistance programs.

RECOMMENDATIONS: Households in this area already have very high participation rates, yet the energy assistance funding only covers 56% of the need. It is evident that higher benefits or connecting participants to additional programs may be needed to fully alleviate gas burden.

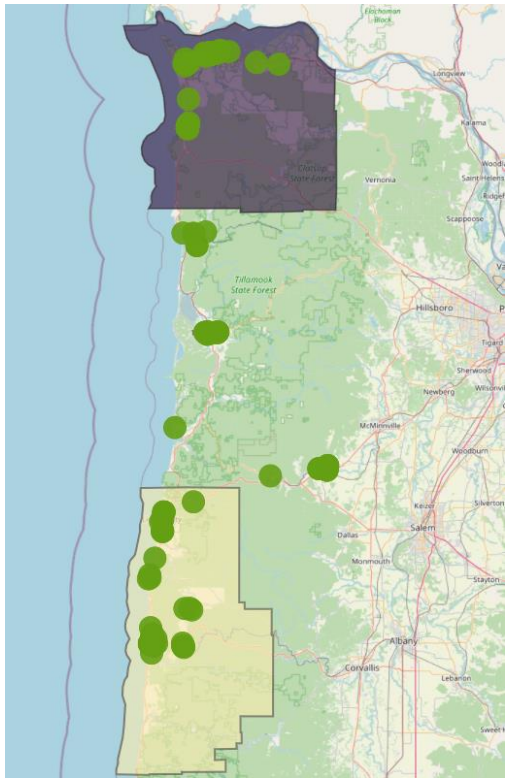
4.3 COASTAL AREAS

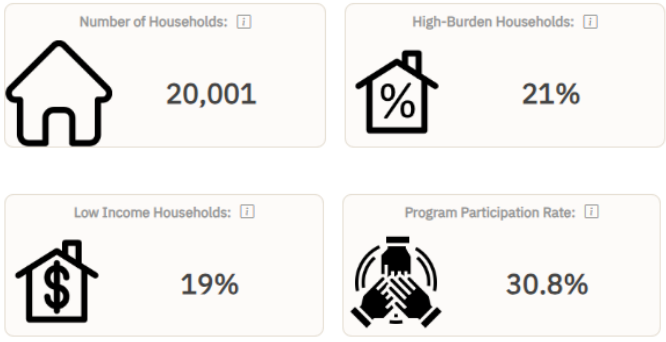
Total Assistance Need: **$2.1M (4.6% of total need)**

Total Assistance Funding: **$0.4M (2.4% of total funding)**

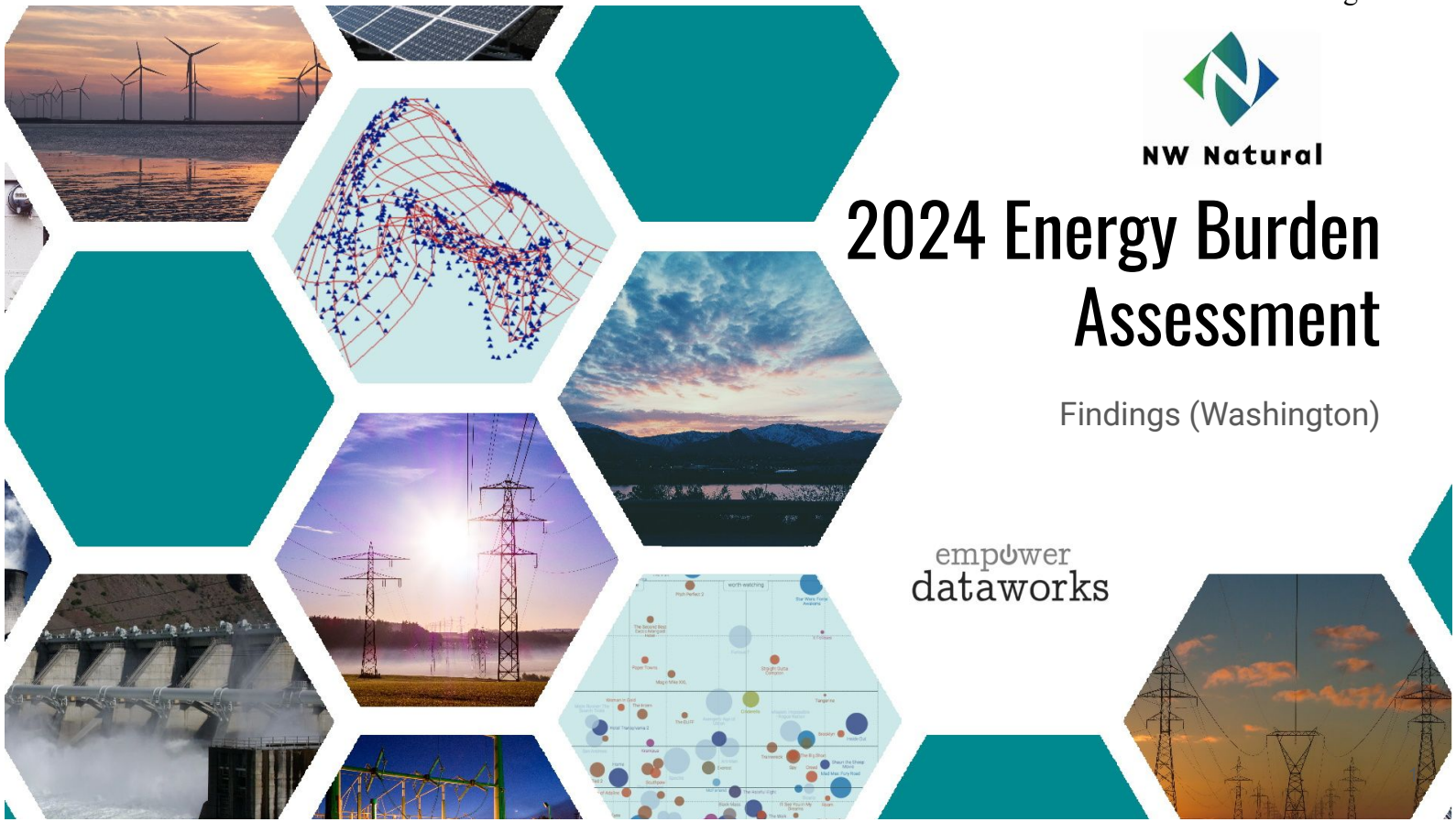
PROFILE: Clatsop and Lincoln counties are characterized by smaller towns and rural areas. Households in these areas experience moderate energy burden – 21% of households are considered high burden. The region was flagged for having relatively low participation rates. Most of these residents are single family homeowners.

RECOMMENDATIONS: Consult with local community-based organizations on the best approach to reaching potentially eligible households. Locally targeted marketing campaigns might be effective at reaching customers as well as collaborating with schools and local.





empower dataworks
www.empowerdataworks.com



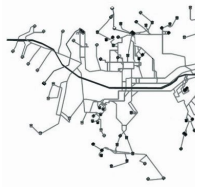
NW Natural

2024 Energy Burden Assessment

Findings (Washington)

empower dataworks

What is an Energy Burden Assessment?



Data analysis (not a survey) that uses utility and third-party customer data.

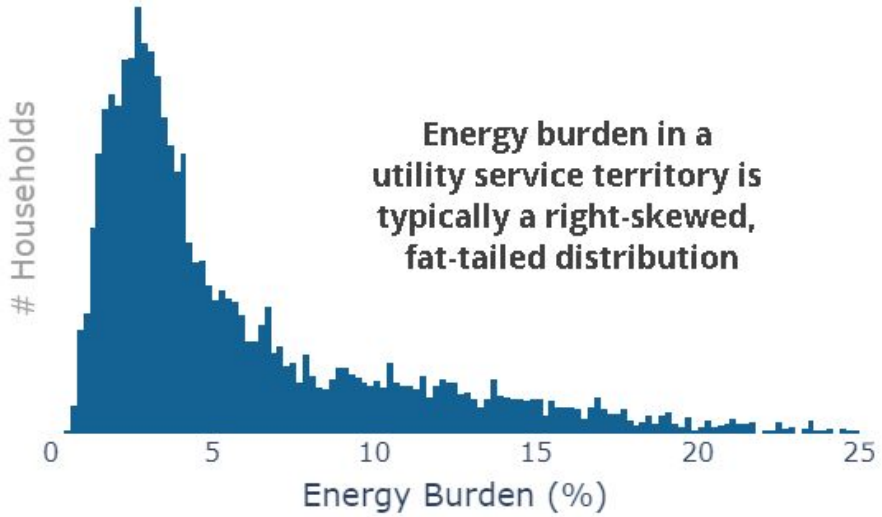
Primary purpose is to estimate the energy assistance need based on customer-level geographic, demographic and building data.

Comparing the need to actual program performance gives us an **actionable** path to improving our energy assistance programs

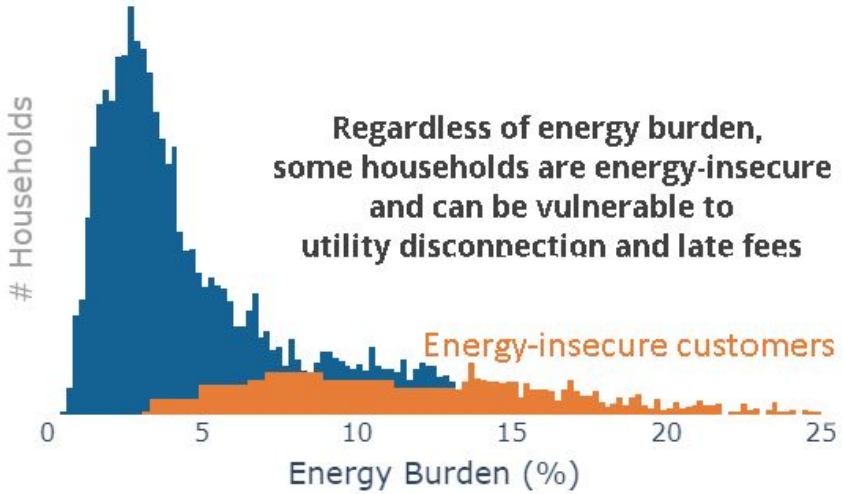
Energy Burden

The primary metric of success is reduction in energy insecurity

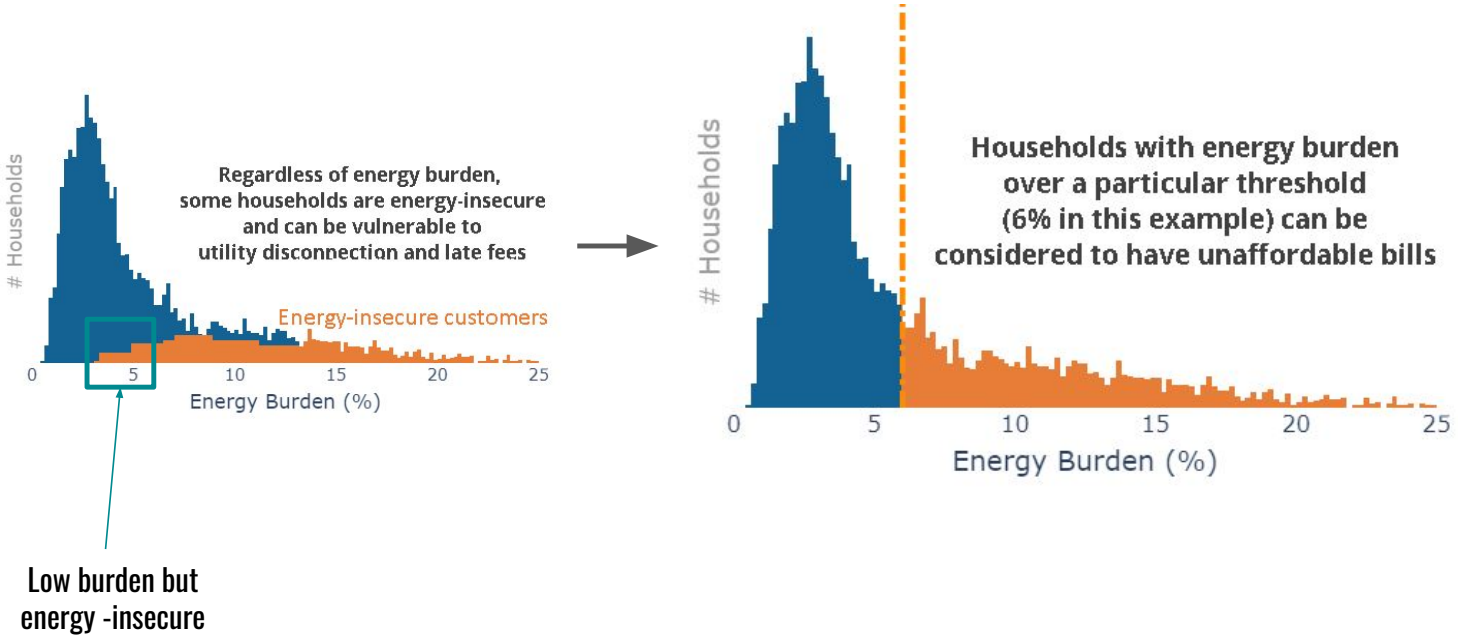
Energy Burden is a Distribution



Energy Insecurity is Harder to Measure



Energy Burden is a Proxy for Energy Insecurity



Definitions

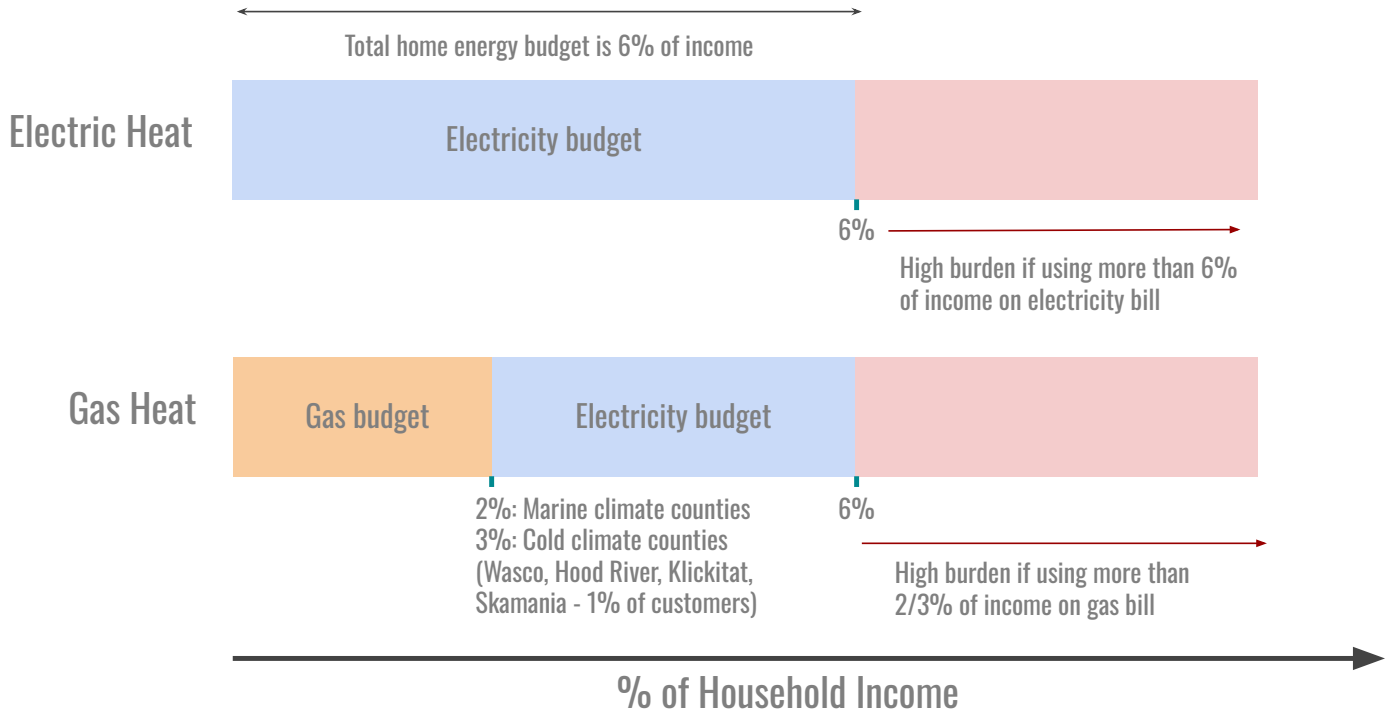
Low-income (Washington):

Households earning under 80% of the area median income (AMI) - Clark county for simplicity

Household Unit Size	Annual Gross Income
1	$66,100
2	$75,550
3	$85,000
4	$94,400
5	$102,000
6	$109,550

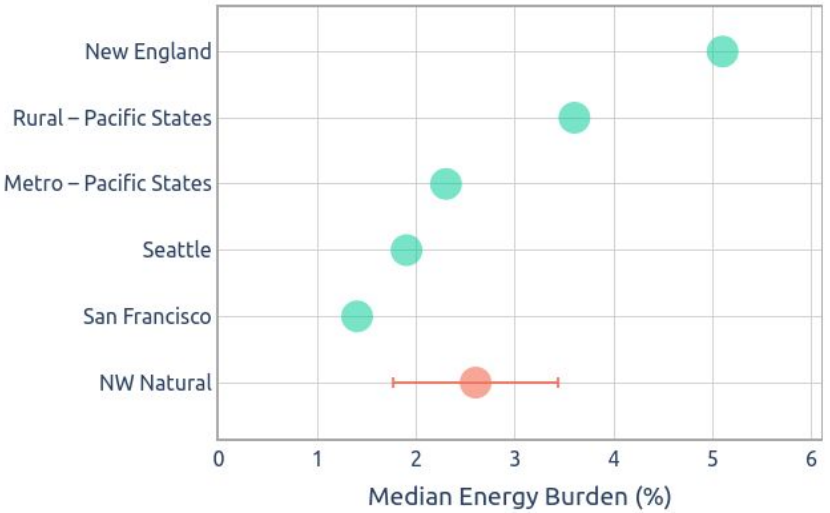
**Most data is reported for the 2023 calendar year. Bills and energy burden are projected for 2024 using 2024 rates and 2023 energy usage. 2024 household incomes are estimated to be 7% over 2023 incomes on average (equal to state median income increase)*

High burden thresholds for multiple fuels



Insights: **Energy Burden**

- ➔ Median total energy burden (~2.6%) is comparable to other metropolitan areas in the Pacific Northwest.
- ➔ Rates are average for the region and NW Natural customers have relatively higher incomes than the general population and experience mostly mild winters.



Insights: **Energy Burden (Washington)**

Number of Occupied Households

~78,000

Low Income Households Under 80% AMI:

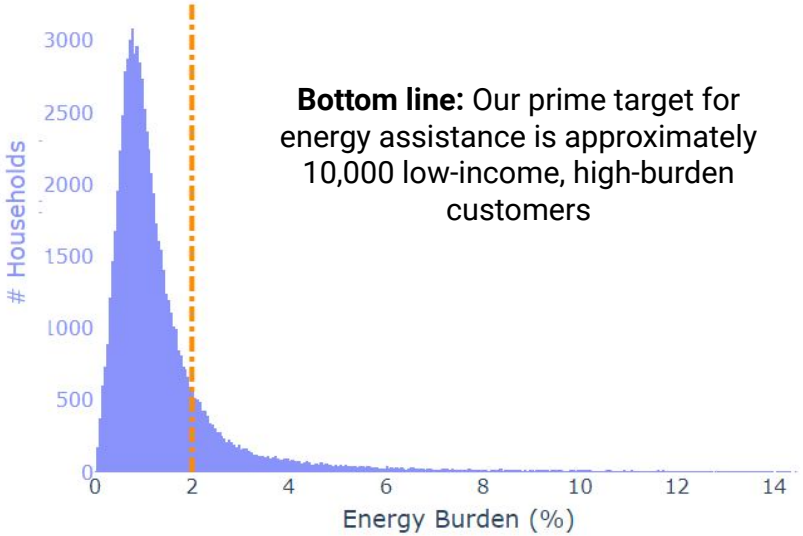
~18k ± 10%

High Burden Households*

~13,000 (all)

~10,000 (LI)

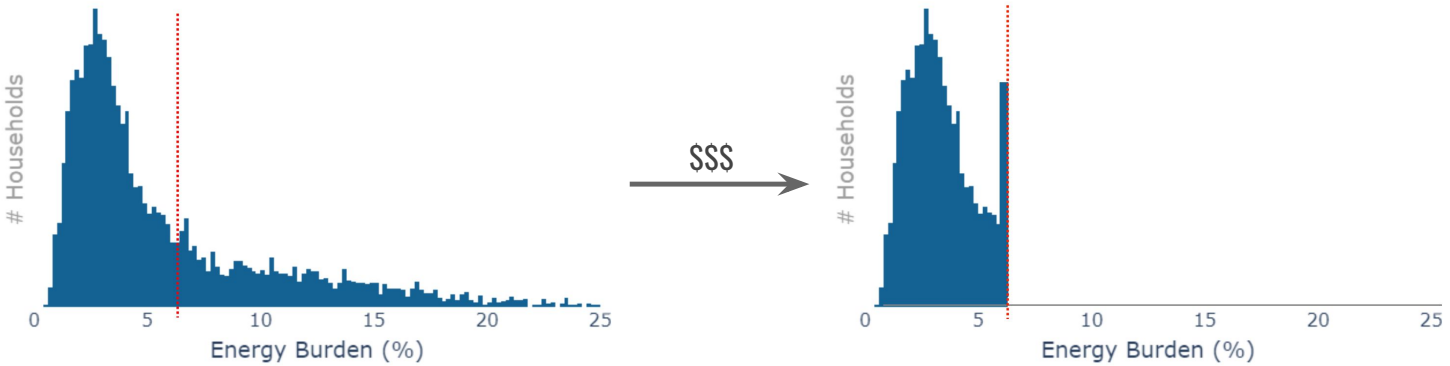
Median Gas Burden
~1% (all)
~2.2% (LI)



Bottom line: Our prime target for energy assistance is approximately 10,000 low-income, high-burden customers

*Energy bills and burden are calculated without factoring in any forms of energy assistance

Energy Assistance Need



Insights: **High-level Assistance Gap**

Low-Income, High Burden Households

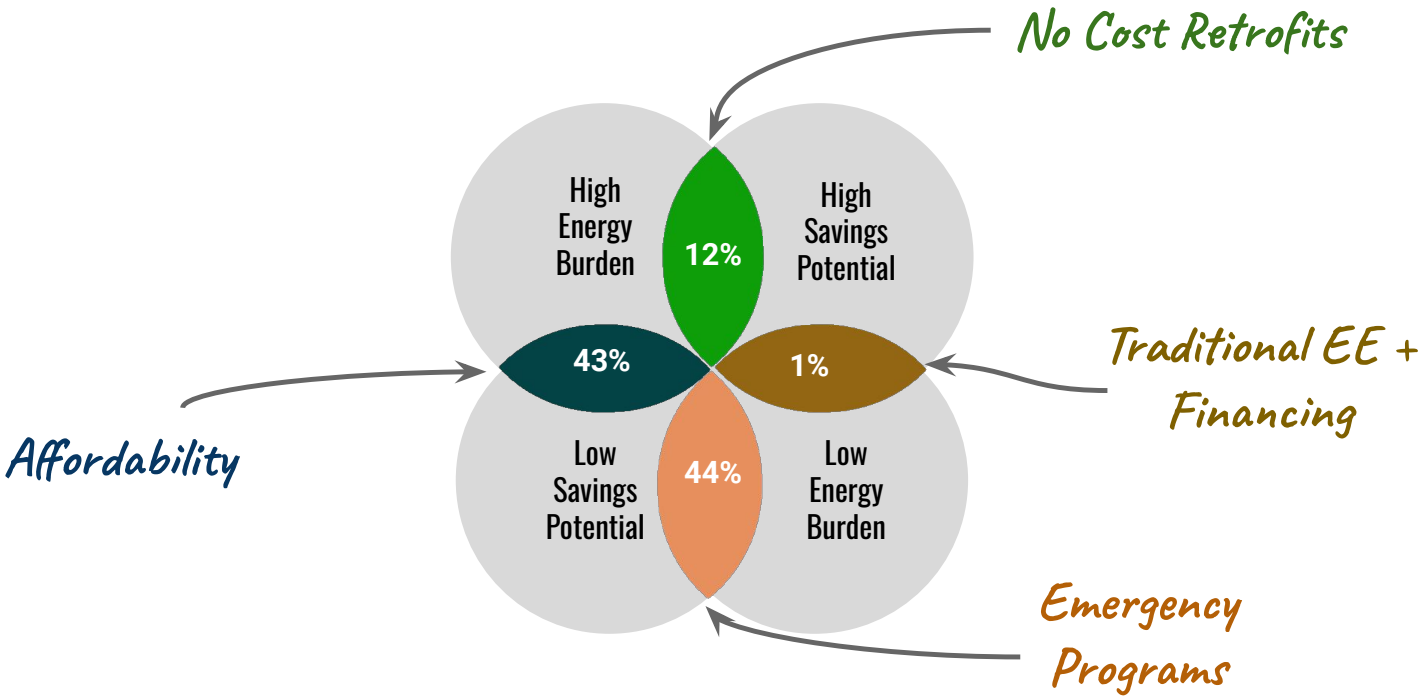
~10,000

Income-eligible only

2024 Projection not including additional program participation:
Bill Discount Program (BDP): $1.8M

➔ At program maturity (year 5+), best practice is to target at least 60-70% of the need available as program funding - barring rate increases, BDP should hit this target in 2025-26 as program enrollment grows.

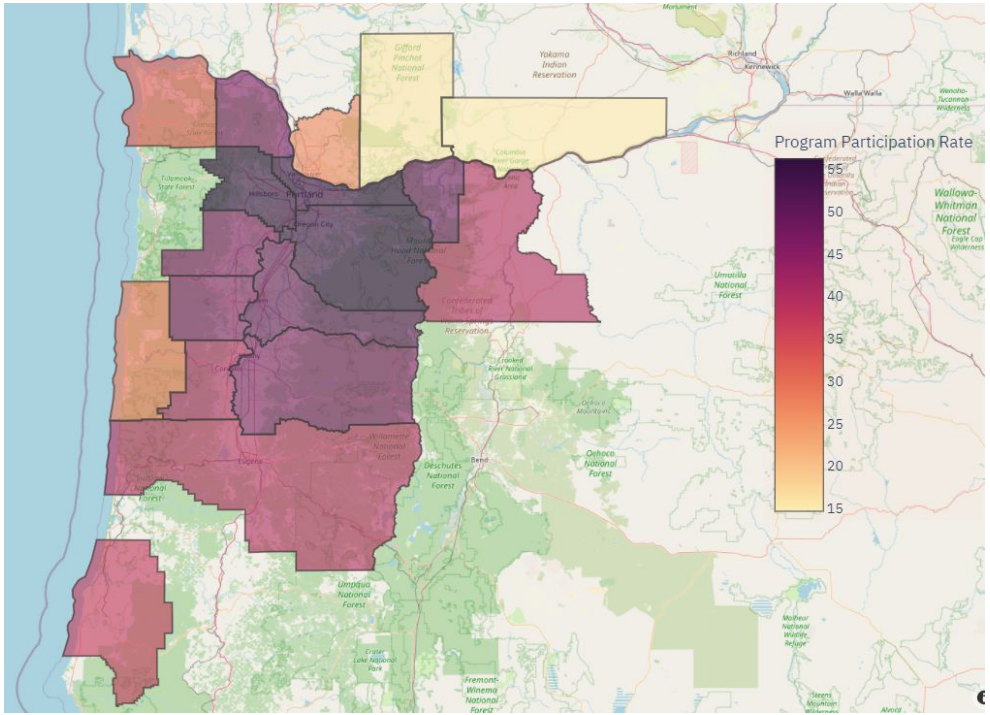
Program Potential (Washington)



Bill Discount Program

Program Participation Rate (Overall)

Recommendation: Washington program is just starting up - focus on general outreach for now, then pivot outreach efforts to Klickitat and Skamania counties in 2025.



Program Saturation Rates (Washington)

Income tier	Estimated number of households	% High-burden	Participation rate
0-60% FPL	1,000	93%	57%
60-120% FPL	3,100	85%	41%
120-150% FPL	1,700	70%	36%
150% FPL- 80%AMI	12,000	42%	16%

Maintain focused outreach efforts on these groups. Target 80% participation by 2028.

Discount Tier Analysis (Washington)

Income tier	Discount Level	Average assistance need as a percent of bill (2024)
0-60% FPL	80%	80%
60-120% FPL	40%	56%
120-150% FPL	20%	40%
150% FPL-80% AMI	15%	18%

Base WA analysis does not include CCA credit and does not include CCA charge for LI households.

Whatever happens to OLGA will likely apply to GREAT as well.

Program Interaction

Discount tier analyses quantify the bill reductions needed to reduce gross customer energy bills to a reasonable percentage of their income. They do not take into account other sources of energy assistance available to low-income households. This is appropriate when a utility uses the discount program as the only type of energy assistance. NW Natural also funds the GREAT program which provide energy assistance grants to eligible customers who apply through a community action agency.

Recommendation:

- *Option 1:* Redesign GREAT.
- *Option 2:* Sunset GREAT and shift funding to BDP.

Outreach Challenges

Challenge:
NW Natural's service territory has a myriad of cultures and ethnicities, a variety of economic backgrounds, urban and rural households and more. NW Natural cannot feasibly become an expert in outreach to every community within its service area.

Recommendation:

Program Navigator Fund: Incentivize local community-based organizations (CBOs) to refer and support customers in applying for the program. These CBOs would serve as the "Program Navigators" would be CBOs that register with NW Natural and would be compensated per successful customer application. Program Navigators would be trained to refer customers to other programs (e.g. LIHEAP, Energy Trust, etc.) in addition to BDP and assist with the application and post-enrolment verification process.

> Pilot estimates: $200k fund, $75 per successful application. Program/pilot may be coordinated jointly with PGE/Pacific Power.

Arrearages and BDP

- NW Natural generally has a low service disconnection rate when considering unique premises (many households may get disconnected multiple times a year)
- 32% of disconnected households are reconnected on the same day and 26% reconnected within one week.
- Very few disconnected households (~100) in past year were likely eligible for energy assistance but didn't participate. **Communication about BDP to customers at risk of disconnection is working well.**

Arrearage Relief

Challenge:
About 10-15% of BDP participants enroll in the program with pre-existing arrears.

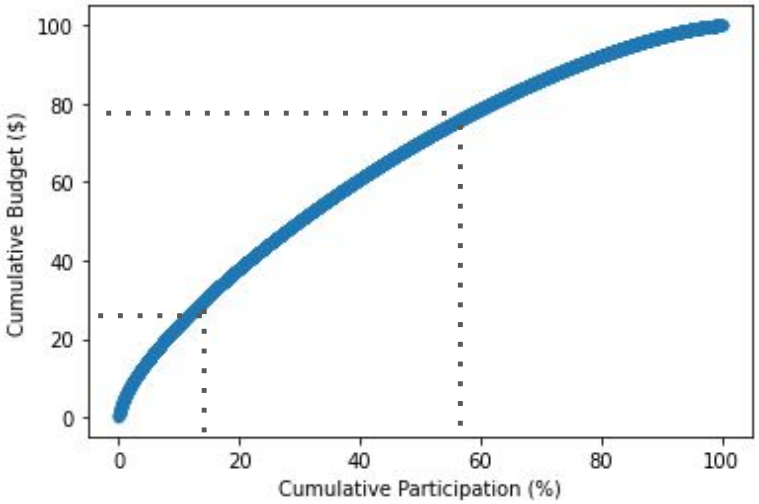
Recommendations:
While some BDP participants may need help with arrears, we are not recommending an Arrearage Management Program (AMP). In our experience, AMPs (which typically require consistent payments from customers in exchange for arrearage matching from a utility) are very onerous to implement, hard to explain to customers and typically have low success rates for customers completing the term of the program (customers do not receive the full arrearage matching because they fall behind on their bills). Most NW Natural customers have relatively small arrears. Instead, we are recommending that NW Natural provide arrearage relief using an immediate, much simpler, and no strings attached approach.

Arrearage relief for program participants: Assess the feasibility and benefit vs. cost of a capped budget arrearage relief program. For simplicity, the program should be made available to BDP participants as a retroactive credit. In other words, the customer's bill discount percent gets applied retroactively for arrears up to a limit (e.g. X% discount on first $1,000 of arrears).

Pilot estimate: $500k arrearage relief fund is likely sufficient to serve the 3,000-4,000 BDP customers who enroll with pre-existing arrears.

Energy Efficiency

Bill Discount Program utilization



Within each income/discount tier:

Top 10% of participants by energy use utilize 21-24% of budget. Their average energy use is 80% higher than the overall average energy use.

Top 50% of participants by energy use utilize 69-72% of budget. Their average energy use is 30% more than the overall average energy use.

Top 10 energy users will receive $3,000+ in 2025

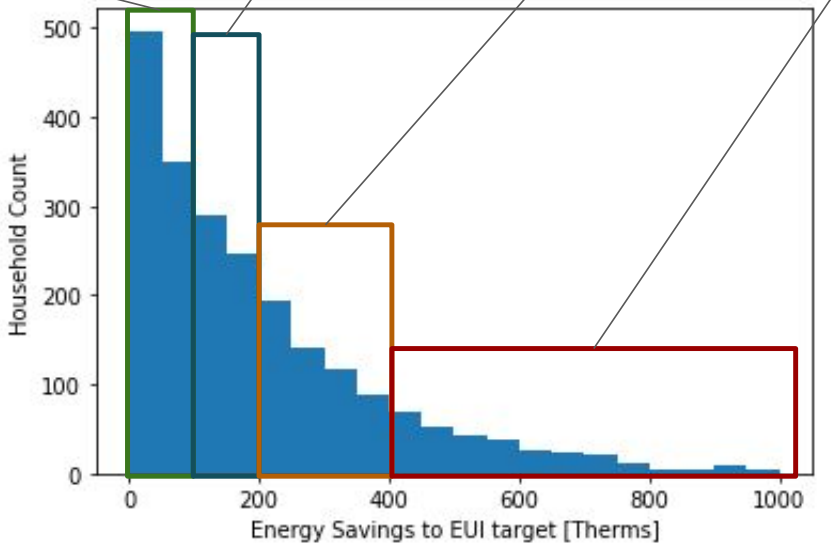
Energy Efficiency Potential (Washington) (2,000 low-income households)

37% Smart thermostats, pipe insulation, furnace tuneups

24% HE water heater/furnace

24% Weatherization

15% Custom / Energy Audits



EUI target = 0.6 Therms/sq.ft

Energy Efficiency Potential

Challenge:
Overall, energy efficiency potential appears to be concentrated in a small segment of low-income customers. High energy users overutilize program funds while the root cause of their high energy burden remains unaddressed. There are 12,000 low-income customers (7,400 BDP participants) who would potentially be good candidates for energy efficiency measures, but existing low-income EE programs serve relatively few households.

Recommendations:

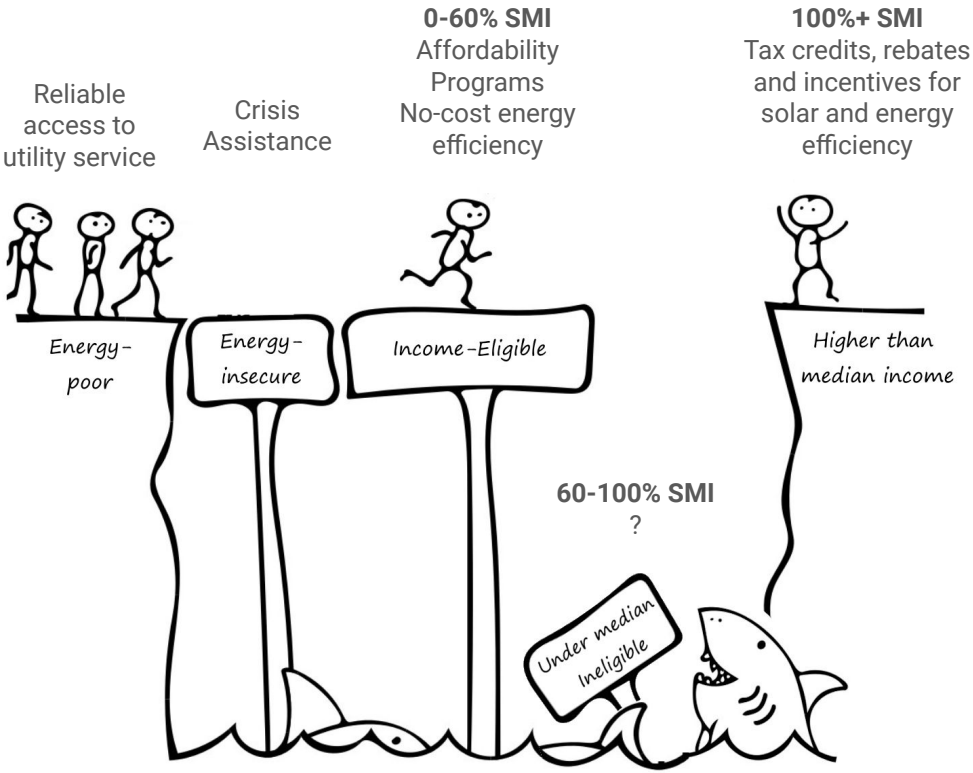
First step towards integrating energy efficiency with BDP is to identify and understand the high use participants.

Energy audit program: Establish a energy audit pilot program (through RFP) that focuses on the top 2,000 or so users in BDP ($1.5M approx. budget). Program should include walkthrough energy audit, ETO and EE credit referrals. List of high priority homes should be provided to program implementer. This program can be designed to be cost-effective through realized savings in BDP discounts.

Unbundled energy efficiency: 35-40% of households could have their energy use reduced to a reasonable level through low-cost measures, without requiring extensive weatherization. Evaluate the feasibility of funding or offering low-cost measures (smart thermostats, pipe insulation, furnace tuneups) and energy education at no-cost to low-income households. This would be most effectively accomplished in collaboration with the Energy Trust of Oregon

The Energy Assistance Hole

The Energy Assistance Hole



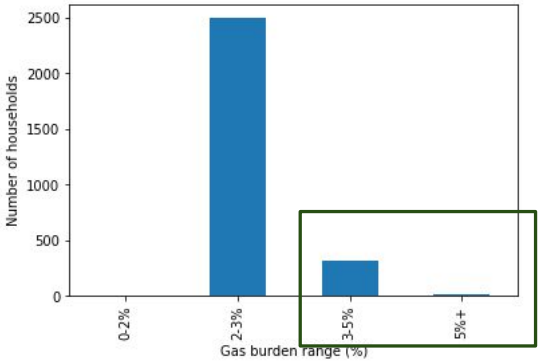
The Energy Assistance Hole (Washington)

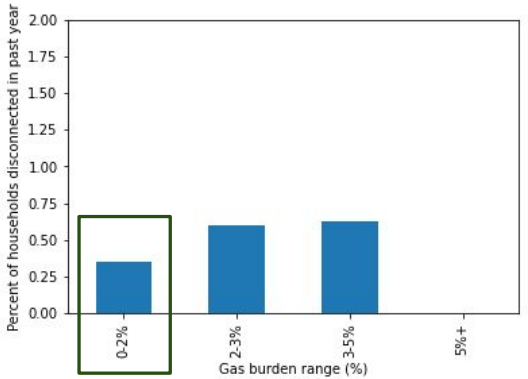
~300 non-low-income households
with a high energy burden >3%

~2,400 borderline (2-3% burden)

Moderate income, high gas use
(1,400 Therms/yr on average)

~200 non-low-income households
at risk of disconnection despite
having a low energy burden





Addressing high-burden, program-ineligible households

Challenge:
There are households that are not eligible for existing programs but may need help improving their bill affordability.

This includes households that:

- Are under the state median income, have a high energy burden, but are ineligible for assistance
- Constrain their energy use due to lack of affordability and lack of program access
- Are **A**sset **L**imited, **I**ncome **C**onstrained, **E**mployed
- Earn above the program income thresholds but under the Self Sufficiency Standard Income

Recommendations:

Customers in this category are high gas users, so discounts and grants do not solve the root causes of their high burden.

Offer no-cost energy weatherization: Expand eligibility for LIEE

Coordination with energy efficiency providers: Work with ETO and CAP agencies to target EE funds at low-income, high burden households. Consider targeted co-marketing campaigns based on data from this assessment.

Other Recommendations

Post-enrolment verification

Challenge:
BDP was designed with self-declared income and the intent was to establish a post-enrolment verification process for 3% of participants in a random draw.

Recommendations:

Targeted verifications: Consider a more targeted verification protocol. Consult with BDP advisory group to determine criteria for initiating a verification (e.g. high property value, own multiple properties, high estimated income).

Potentially use remunerated program navigators to assist customers with responding to the verification request.

Rough estimates of PEV counts

Risk-based: 2,500 (7%) High value homes - 1,100 (3%) of which are in high discount tiers

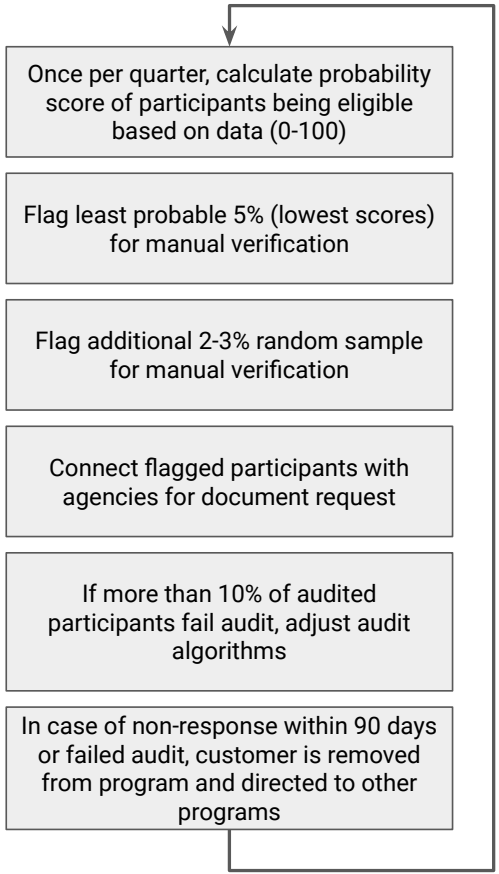
Benefit value-based: 1,700 (5%) receiving over $1,000 from BDP

Audit Protocol for Self-Verification and Auto-Enrollment

The audit process and scoring algorithms are developed and operated within the utility - customer audit lists are shared with agencies.

Data requirements:

- Home values
- Housing type
- Renter/homeowner
- Disconnect/past due notices
- Home location and average neighborhood energy burden
- Participation in other means-tested benefits (optional)
- Estimated customer income range (optional)



Other Issues

Reduce need for reapplication: Allow fixed income customers to reapply every 4-5 years instead of every two.

Communication timing: Biggest marketing pushes should be in September/October **before** high bill season. Include communication about projected winter bills including rate increases and energy efficiency tips to encourage customers to apply early.

Rate design: Evaluate raising the fixed charge with a corresponding decrease in the therm charge. The fixed charge also does not reflect NW Natural's true fixed costs (average of $34 for the residential class). This encourages conservation and solar but low-income customers cannot afford these improvements. Higher volumetric rates are a major trigger for falling behind on bills when a customer receives an unplanned bill during the cold season.

Enrolment target: Use energy assistance need in addition to enrolment as a program metric. Participation rates alone do not reflect whether the program is alleviating energy burden. Set program targets in relation to energy assistance need (similar to Washington state) as opposed to enrolment % targets - this incentivizes targeting the highest need customers vs. just a higher number of participants.

Master-metered buildings

Main Takeaways - Energy Burden Assessment

- NW Natural's customers are relatively higher income and live in a moderate climate. This is reflected in a generally moderate gas burden. Approximately **9% of NW Natural's customers suffer from a high gas burden** (exceeding 2/3% depending on the climate zone)
- The Bill Discount Program (BDP) has been ramping up successfully and along with other assistance programs, is expected to meet **49% of the energy assistance need** for NW Natural's customers in 2024 and 47% of the need in 2025 (including rate increases and proposed discount tiers).
- Recommendations in this assessment are auxiliary components that can be added to NW Natural's energy assistance portfolio to better improve bill affordability:
    - **BDP:** How to deal with the interaction between BDP and OLGA/GREAT to eliminate participants' high energy burden
    - **Arrearages:** How to best serve customers with pre-existing arrears
    - **Energy Efficiency:** How can we leverage energy efficiency for sustained energy burden reduction
    - **Energy assistance hole:** How to best serve customers who have unaffordable bills but are ineligible for assistance programs
    - **Other:** How do we design more equitable rates and target assistance at customers who need it the most

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Cecelia J. Tanaka

EQUITY

Exh. CJT-4

August 29, 2025

Washington

Bill Discount Program

Outreach & Communications Toolkit

Washington | Bill Discount Program

NW Natural®

Enrollments in Washington **reached nearly 8,000** in the first year of the program—that's 8,000 income-eligible households who are now better able to afford their monthly gas bills!

Outreach continues and we are grateful for your support in promoting this important resource.

About | Washington Bill Discount Outreach & Communications Toolkit

NW Natural

NW Natural's bill discount program can save income-eligible customers 15%-80%.

This toolkit includes printable resources, digital materials and customizable content to streamline outreach efforts and integration into existing channels of communication.

Our partners are sharing bill discount information through:

- Check-in calls with homebound seniors
- Newsletters & social media
- Meal deliveries & home weatherization kits
- Tabling at farmer's markets, open houses, community meetings
- Text messages

To learn more or receive hard copies of program materials, contact: CommAffairs@nwnatural.com.

Washington

Bill Discount

Outreach & Communications Toolkit

In this toolkit:

- Program & enrollment details
- Informational links
- Talking points
- Language & graphics for social media, text messages, newsletters, etc.
- QR code
- Toolkit unique URL
- Program brochure & poster

Helpful Links

QR Code Links to program homepage

- Toolkit URL | nwnatural.com/DiscountKit
- NW Natural Bill Discount Homepage
- 2025 Income Guidelines for Washington
- NW Natural Online Application (English)
- Solicitud para el Programa de descuento de facturas residenciales de NW Natural Washington
- Đơn Đăng ký Chương trình Chiết khấu Hóa đơn Tiện ích cho Khách hàng Cư dân Washington của NW Natural
- Заявка на участие в программе скидок по счетам NW Natural Washington
- NW Natural Washington 住宅账单折扣计划申请

Condensed content |

Content & graphics for social media, texts, newsletters, etc.

EN English

Get Bill Discounts

NW Natural can help lower your energy bills.

You may be able to get 15% to 80% off your monthly gas bill with NW Natural's Bill Discount Program.

Learn more at nwnatural.com/BillDiscount

503-226-4211 or 800-422-4012

csst@nwnatural.com

Hashtags:

- #nwnatural
- #billdiscount
- #energybill

ES Español

Obtenga descuentos en las facturas

Obtenga un 15% a 80% de descuento en su factura mensual de gas con el Programa de descuento en facturas naturales de NW.

Usted puede aprender más sobre estos programas en nwnatural.com/BillDiscount, o contáctenos:
503-226-4211 o 800-422-4012, de lunes a viernes, 7 a.m. to 6 p.m.
csst@nwnatural.com

Condensed content | (cont).

Content & graphics for social media, texts, newsletters, etc.

RU русский

Получите скидки на оплату счетов

Получите скидку от 15% до 80% на ежемесячный счет за газ с помощью программы скидок NW Natural Bill.

Вы можете получить дополнительную информацию об этих программах на веб-сайте nwnatural.com/BillDiscount или связаться с нами: 503-226-4211 или 800-422-4012 800-422-4012, с понедельника по пятницу, с 7 a.m. до 18:00 p.m.
csst@nwnatural.com

VI Tiếng Việt

Chiết khấu hóa đơn

Được giảm giá 15% đến 80% hóa đơn khí đốt hàng tháng của bạn với Chương trình Giảm giá Hóa đơn Tự nhiên Tây Bắc..

Quý vị có thể tìm hiểu thêm về các chương trình này tại nwnatural.com/BillDiscount hoặc liên lạc
với chúng tôi.:
503-226-4211 hoặc 800-422-4012 800-422-4012, Thứ Hai đến Thứ Sáu, 7:00 sáng đến 6:00 chiều
csst@nwnatural.com

CN 中国人

获取账单折扣

通过 NW Natural Bill 折扣计划，每月燃气费可享受 15% 至 80% 的折扣。

您可以登录网站 nwnatural.com/BillDiscount 或联系我们，了解更多有关这些计划的信息：
503-226-4211 或 800-422-4012（周一到周五上午 7 点到下午 6 点）
csst@nwnatural.com

Talking Points

Lower your bill

Discounts up to 80% off monthly bills are available.

Enrollment is available to qualifying residential NW Natural customers.

More, not less

It's extra money on top of other energy assistance you may get.

The discount is good for two years. Then you will be contacted to sign up again. NW Natural will remind you before it ends.

Sign up easily

Proof of income is not required to apply. Self-reported figures on household size and average annual income will verify eligibility.

Ways to apply:

- **Online** to fill out a short form
- **Call** and get help over the phone **503-226-4211** or **800-422-4012**
- **Mail** in a completed application

Who is eligible?

Enrollment is available to qualifying residential NW Natural customers.

Discounts are available if your household income is at or below 200% of the federal poverty line (FPL) or 80% of area median income (AMI), whichever is greater. This is approximately $94,000 for a family of four.

Household Income	Bill Discount
0-60% FPL	80%
61-120% FPL	40%
121%-150% FPL	20%
The greater of 151%-200% FPL or 80%AMI	15%

Additional Program Details (cont.)

Discounts are calculated as a percentage of customer's bill and are broken into four tiers.

This table illustrates the impact of the discount for an average annual gas gill of $1,340.

Qualifying Income Threshold	Discount	Annual discount (*average annual gas bill of $1,340)	Total annual bill (after discount)
0-60% FPL	80%	$1,072	$268
61-120%FPL	40%	$536	$804
121 - 150%FPL	20%	$268	$1,072
200% FPL or 80% AMI	15%	$201	$1,139

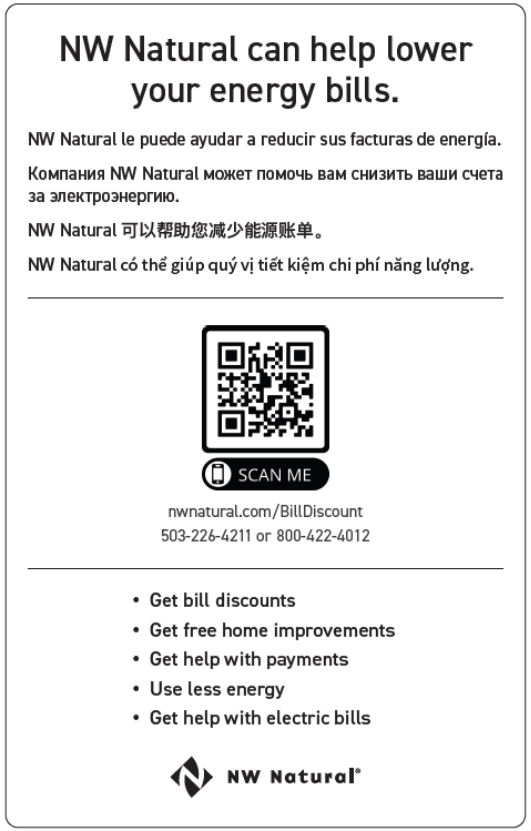
Informational Postcard

For hard copies of the postcard contact:
CommAffairs@nwnatural.com

Poster | Versions & PDF for printing

For easy printing, double-click on the icon to open the poster as a PDF file.

Adobe Acrobat Document



BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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NORTHWEST NATURAL GAS COMPANY

Exhibit of Cecelia J. Tanaka

EQUITY

Exh. CJT-5

August 29, 2025

Published: September 29, 2022

Community and Equity Advisory Group (CEAG) Charter/Operating Guidelines

Background

NW Natural (the Company) has a history of community engagement throughout its service territory and recognizes that improving energy equity is a dynamic and long-standing need. NW Natural supports over 150 community and nonprofit groups in the fields of youth and family resiliency, environmental stewardship, health and human services, and arts and culture.

Energy equity requires expanding access and removing barriers for underserved and overburdened customers. The region is seeing a growth in engagement from community-based organizations as well as increasing awareness by our regulators and policy makers around issues of intersectionality and disparate impacts of energy and climate. These factors, in addition to building upon NW Natural's history of community engagement and commitment to diversity equity and inclusion, have culminated in NW Natural's decision to formulate a Community and Equity Advisory Group.

Purpose

The CEAG is designed to provide NW Natural direct feedback, recommendations, advice, and review on areas related to (a) NW Natural energy system planning and renewable resource development, (b) income-based and arrearage programs, (c) company philanthropic investments, (d) workforce development, and (e) other areas as determined by NW Natural.

The CEAG will have representation from Oregon and Washington to align with the distinct and unique community needs and policy requirements of each state and the areas we serve.

From a place of listening and learning, the Community and Equity Advisory Group (CEAG) seeks out and elevates historically underrepresented voices, perspectives, and lived experiences to advance inclusive practices and institutional actions and bring a racial equity and environmental justice lens to NW Natural's energy and operational planning. Through this deeper community engagement, NW Natural will be positioned to uncover and understand barriers to equitable participation, and, in turn, formulate strategies to address those barriers and center equity in our work ensuring that diversity, equity and inclusion are not merely convenient add-ons, but catalysts for change.

Desired Goals, Outcomes, and Objectives

Deliverables may include drafting recommendations or guidelines for engaging diverse stakeholders, providing concrete feedback and review, and coordinating with other working groups to evaluate recommended strategies for improving energy equity.

Published: September 29, 2022

CEAG Principles

NW Natural operates within five core values: Integrity, Service Ethic, Caring, Safety, and Environmental Stewardship (outlined in detail in NW Natural's Code of Ethics). Reflecting these core values, the NW Natural CEAG will be founded on the principles as listed.

CEAG Principles:

- Integrity
- Transparency
- Openness and Communication
- Accountability (to its Members)

NW Natural Commitments

- Foster an environment which respects and values diversity and inclusiveness
    - Utilize a 3rd party facilitator to establish inaugural charter, processes, methods of communication, and as needed for meeting facilitation, etc.
- Understand and acknowledge the history in which current systems such as energy regulation were formed
- Recognize that serving the Oregon/Washington of today and the Oregon/Washington of the future requires new ways to engage the communities we serve
- Provide clear parameters regarding the decision-making power and/or role of the CEAG throughout the formation and implementation process
- Provide resources to CEAG members to enable understanding of topics as needed
- Commit to an ongoing and iterative learning process.
- Be open to new ideas, and diverse experiences and opinions
- Understand and respect the role of the facilitator
- Be accountable with respect to CEAG feedback and recommendations
    - At each following meeting, NW Natural shall bring back to the CEAG an update on concrete actions, deliverables, etc that were undertaken since the last meeting and under recommendations from the CEAG members
    - NW Natural is open to cocreation of topics for discussion

Representatives from Community-Based Organizations

With the intention to hear from underrepresented voices and experiences, NW Natural is seeking out community-based organizations (CBOs) serving an identity, community, and/or underrepresented population present within the NW Natural service territory who do not currently have a “seat at the table” within energy planning and/or the utility industry. It is up to each CBO to select the correct representative(s) to participate in the CEAG.

Member CBOs are intended to represent a historically underrepresented community or communities. Member CBOs are not intended to represent the beliefs of a single individual. NW Natural will utilize selection criterion that aims to balance diverse representation from both Oregon and Washington. By joining the CEAG, member CBOs are responsible for identifying appropriate representatives to

participate in CEAG activities and ensuring coordination between representatives if more than one staff member is involved.

CEAG Member Commitments

- Participate in scheduled (facilitated) discussions regarding NW Natural's energy system planning, programs, investments, and other topics related to the operations of the Company
- Provide advice, experience, and perspectives from the communities of which the CBO serves, which may include social, economic, racial, tribal, and environmental equity, and assist in identifying best practices/ solutions for improving and expanding equity as a way to inform how NW Natural develops metrics and measures performance
- Understand the regulatory and policy environment in which NW Natural must operate, and to what extent NW Natural has the ability to influence particulars of the energy system and/or planning process
- Commit to an ongoing and iterative learning process
- Be open to new ideas, and diverse experiences and opinions
- Understand and respect the role of the facilitator

CEAG Term of Service

Term of Service:

CEAG participants' terms will run for a length of 2 years with opportunity for renewal. Terms will run (May) to (April) within the year set with the intention of overlapping of membership so that a full turnover is avoided. Members of the inaugural group may be appointed to a three-year term to facilitate such an overlap in membership.

Inaugural Term:

- Year 1: May 2022 – April 2023
- Year 2: May 2023- April 2024
- Year 3 (tentative per each CBO): May 2024- April 2025

Open Positions & Recruitment:

Recruitment will take place each year in the months prior to identified term dates. If a position opens outside of typical recruitment period, NW Natural in consultation with the CEAG and a third-party facilitator may choose whether to fill the position before normal recruitment period.

Calendar and Work Plan for CEAGs

The inaugural CEAG two-year term runs from (May 2022) to (April 2024). During this period, NW Natural anticipates up to 8 meetings across 24 months. CEAG meetings, each with an expected duration of 2-3 hours, depending on the topic(s).

Subsequent CEAG calendars and work plans will be developed by NW Natural and the CEAG.

CEAG Sub-Groups (if applicable):

NW Natural and the CEAG may determine the need for the creation of sub-groups to focus on specific programs and or elements of the energy system planning process.

Roles and Responsibilities

NW Natural:

NW Natural is the convener of the CEAG. The Company provides the services of a third-party facilitator as needed. NW Natural determines final appointments of CBOs to the CEAG and additionally is responsible for final approval of any work plans or activities of the CEAG. The Company is also responsible for ensuring accessibility for members during all CEAG activities.

Community and Equity Advisory Group Members:

The CEAG members must attend meetings, provide direct feedback, advice and recommendations, and reviews of programs and/or materials to the NW Natural team as requested. CEAG members do not need to come to a consensus or have a majority vote in order to provide advice to NW Natural. Members may suggest agenda topics and or areas of focus. Members may designate alternatives from their organization. It is up to each organization to ensure continuity between representatives.

Facilitator(s):

NW Natural will provide a third-party facilitator for inaugural group meetings. The goal of providing facilitator(s) is to help ensure neutral and impartial support to all participants, maintain the integrity of the process, and facilitate communication about the process among participants and other interested parties. The facilitator will work collaboratively with the NW Natural project team to prepare process designs, meeting agendas, materials and final CEAG work products.

Group Conduct/Code of Conduct

CEAG conduct will be governed by the principles of the CEAG and are as follows:

- Integrity
- Transparency
- Openness and Communication
- Accountability (to its Members)

Disagreement and differences of opinion are to be expected, acknowledged, explored, understood, and appreciated. Should conflict arise, it will be addressed with the guidance of the CEAG facilitator. Recurring inappropriate individual behavior may result in an individual being respectfully excused from participation in the CEAG, generally after the following steps have been taken:

- First Notice: A mediated discussion concerning the behavior/disruption/non-conformance between NW Natural, Facilitator/Mediator, and CEAG member
- Opportunity to correct the behavior/disruption/non-conformance
- Second Notice: A mediated discussion concerning the behavior/disruption/non-conformance between NW Natural, third-party Facilitator/Mediator, CEAG member, and CBO leadership
- Opportunity to correct the behavior/disruption/non-conformance

- Continued failure to follow code of conduct will result in removal of the individual CEAG member
- NW Natural and CBO leadership to discuss replacement of member with guidance and input from remaining CEAG members and third-party party facilitator

It is important to note that the above is not a set procedure and the particulars of the individual situation will be considered in how NW Natural proceeds in addressing concerns that may arise.

Compensation

CBOs who have a member serving on the CEAG are provided with an honorarium paid by NW Natural in recognition of their donated time and input. The honorarium is per CBO, per year.

- Year 1: $5,000
- Year 2: $5,000

Operational Guidelines

Meeting Dates and Times:

Meeting dates and times are established in consultation with the group. Meetings take place four times per calendar year, generally meeting, once per quarter.

Quorum Requirement:

There is no quorum requirement; participants present and active at each meeting can continue to work in the absence of others.

Meeting Materials:

Meeting materials may include agendas, reports, resources, and other documentation provided by either NW Natural or members of the CEAG, or facilitator, dependent on topic.

Meeting Location:

Meetings are hosted by NW Natural. Meeting locations are determined by NW Natural in conjunction with CEAG members. The principles of Safety and Inclusion lead all decision making on meeting location determinations. Accessibility accommodations are made as necessary, dependent on the requirement of the meeting location. Hybrid (virtual and in person) meetings may be considered.

Meeting Structure:

To be determined by the inaugural CEAG in conjunction with NW Natural.

Process Documentation:

All CEAG meetings and activities are documented by at least a representative of NW Natural. Further process documentation will be determined as needed in consultation with CEAG members.

Correspondence:

The group may correspond via email, telephone, and/or virtual meeting platforms. NW Natural shall provide a list of correspondence contacts at the start of each CEAG term.

Media, Photography, and Recording:

CEAG participants may speak individually to the media outside of meeting sessions, per the policies of their respective organization, but shall not speak on behalf of the CEAG or NW Natural. Participants may be video recorded, audio recorded and/or photographed by NW Natural or others during the meeting. In these cases, CEAG members are notified in advance when meetings are being video- or audio-recorded. If a member takes issue with any of the above, NW Natural will work with the third-party facilitator to address concerns.

Accessibility:

NW Natural will make the following efforts in order to ensure CEAG meetings and activities are accessible to all CEAG members.

- Provide assistive technology to CEAG members with disabilities, or provide other reasonable accommodations as needed (e.g., large-size print documents, documents formatted for screen readers, etc.).
- Provide language interpretation, as needed/ requested.
- Choose Americans with Disabilities Act (ADA) and transit -accessible venues if meetings are held in person.
- Provide virtual meeting platforms with call-in options to be mindful of limitations in access to technology.

Eligibility for Grants and Resources

NW Natural is seeking strong engagement from local community organizations throughout its service area. It is likely that member organizations engage with NW Natural on multiple fronts across several departments; including, but not limited to the Company's philanthropic giving program, corporate sponsorship offerings, pro bono hospitality services, etc. We welcome this level of engagement and connectivity and the introduction of the CEAG will not change this ethos. The grant programs are an entirely separate processes from CEAG operations and will remain unassociated with CEAG membership and processes. To this end, NW Natural offers the following guidance: participating in -or declining to participate in- the CEAG will not jeopardize, disqualify nor otherwise influence decisions on grant requests, award levels, resource allocations or other offerings.

Confidentiality Agreement

All participants have agreed to a confidentiality through the Participant Agreement. The statement is as follows:

> In order to protect the confidentiality of the community-based organizations (CBOs) and their clients as well as NW Natural customers, all CEAG participants must agree to the following:
>
> - I will not divulge information discussed at meetings, within communications, and/or site visits with anyone except fellow team members, appropriate organization or NW Natural staff, or the third-party Facilitator.

- I will not use privileged information gained as a CEAG member for personal or professional gain.

To create a "culture of candor" and raise awareness, CEAG members are encouraged to disclose and discuss with NW Natural anything that may be potential conflicts of interest relating to matters pertaining to the topics discussed by the group. For example: business relationships with family and friends.

Charter/Guidelines Adoption and/or Amendments

This Charter for the CEAG is considered a living document and as such, a work in progress. The adoption of the inaugural CEAG charter will be achieved through a facilitated discussion and review. The CEAG Charter may be amended consistent with the terms and processes agreed to by the Company and the CEAG. The facilitator will work with the Company and the CEAG to annually evaluate if adjustments to the Charter and Operational Agreements are warranted.

Resources for CEAG Members (attached as Appendices)

- Service Territory Map (Appendix A)

Published: September 29, 2022

Appendix A: NW Natural Service Territory Map

Figure 1 NW Natural Service Territory Map

Published: September 29, 2022

BEFORE THE

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NORTHWEST NATURAL GAS COMPANY

Exhibit of Cecelia J. Tanaka

EQUITY

Exh. CJT-6

August 29, 2025

Community Services Network pdx

Winter Preparedness Fair

Join us for a winter resource fair to learn how to keep yourself, your family, and your home safe and warm this winter season!

NOV 16 2024

PARKROSE HIGH SCHOOL
12003 NE SHAVER ST,
PORTLAND, OR 97220

11AM - 2PM

Winter Coat Giveaway
Infant - Youth Size 12
**while supplies last*

- **NONPROFIT RESOURCES**
- **HEALTHCARE SIGNUP**
- **FAMILY ACTIVITIES**
- **FREE LUNCH**
- **WINTER COATS**
  (INFANT - SIZE 12 YOUTH - LIMIT 2 PER FAMILY)
- **FOOD BOXES**
- **HOME WEATHERIZATION KITS**
- **ENERGY EDUCATION**
- **BILL DISCOUNT OPPORTUNITIES**
- **VACCINATIONS**

In Partnership With:

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We grew up here.

Sponsored by:

THE DPI GROUP
BUSINESS RESULTS WITH SOCIAL IMPACT

CareOregon

COMCAST

Come learn and celebrate with your community!

Community Services Network pdx

Feria de Preparacion para el invierno

ACOMPÁÑENOS EN UNA FERIA DE RECURSOS INVERNALES PARA APRENDER A MANTENERSE A SÍ MISMO, A SU FAMILIA Y A SU HOGAR SEGUROS Y CALIENTES ESTA TEMPORADA DE INVIERNO.

DE NOVIEMBRE **16** de 2024

ESCUELA SECUNDARIA PARKROSE

12003 NE SHAVER ST,
PORTLAND, OR 97220

11AM - 2PM

Regalo de un abrigo de invierno
Infantil - Juvenil Talla 12
hasta agotar existencias

- RECURSOS DE ORGANIZACIONES NO LUCRATIVAS
- INSCRIPCION DECUIDADO DE SALUD
- ACTIVIDADES FAMILIARES
- ALMUERZO GRATIS
- ROPA DE INVIERNO
  (INFANTIL - TALLA JUVENIL 12 - LIMITE 2 POR FAMILIA)
- CAJA DE ALIMENTOS
- KITS DE CLIMATIZACIÓN DE VIVIENDAS
- EDUCACIÓN ENERGÉTICA
- OPORTUNIDADES DE DESCUENTO DE FACTURAS
- VACUNAS

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CareOregon

COMCAST

¡Venga a aprender y celebrar con su comunidad!!

Community Services Network pdx

Зимовий Ярмарок Підготовки

Приєднуйтесь до нас на зимовому ярмарку ресурсів, щоб дізнатися, як зберегти себе, свою сім'ю та ваш дім у безпеці й теплі цієї зими!

ЛИСТОПАДА
16
2024 року

СТАРША ШКОЛА ПАРКРОУЗ
12003 NE SHAVER ST,
PORTLAND, OR 97220

З 11:00 ПО 14:00

Роздача зимових курток
Розміри: дитячі – до розміру 12
** поки є в наявності*

- **РЕСУРСИ ВІД НЕКОМЕРЦІЙНИХ ОРГАНІЗАЦІЙ**
- **РЕЄСТРАЦІЯ НА МЕДИЧНЕ ОБСЛУГОВУВАННЯ**
- **СІМЕЙНІ АКТИВНОСТІ**
- **БЕЗКОШТОВНИЙ ОБІД**
- **ЗИМОВІ КУРТКИ**
  (ДИТЯЧІ РОЗМІРИ ДО 12, НЕ БІЛЬШЕ 2-Х КУРТОК НА РОДИНУ)
- **ПРОДУКТОВІ НАБОРИ**
- **НАБОРИ ДЛЯ УТЕПЛЕННЯ ДОМУ**
- **ОСВІТА З ПИТАНЬ ЕНЕРГОЗБЕРЕЖЕННЯ**
- **МОЖЛИВОСТІ ОТРИМАТИ ЗНИЖКИ НА РАХУНКИ**
- **ВАКЦИНАЦІЯ**
  (ПЕРШІ 30 ОСІБ ОТРИМАЮТЬ БОНУС У РОЗМІРІ 10$)

У партнерстві з:

THE BUREAU OF PLANNING & SUSTAINABILITY

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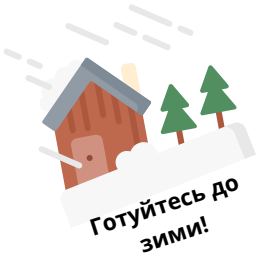

Спонсори:

THE DPI GROUP
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CareOregon

COMCAST

Приходьте вчитися та святкувати разом зі своєю громадою!

Community Services Network pdx

冬季防灾博览会

参与我们的冬季资源博览会，以学习如何在这个冬季保持自己、家人和家中的安全与温暖！

年 11 月
16
2024

PARKROSE HIGH SCHOOL
12003 NE SHAVER ST,
PORTLAND, OR 97220

上午 11 点 - 下午 2 点

冬季外套赠送
婴儿 - 青少年 12 码
*送完即止

- 非营利资源
- 医疗保健注册
- 家庭活动
- 免费午餐
- 冬季外套
  (婴儿 - 12 码青少年 - 每个家庭限 2 件)
- 食品盒
- 家庭御寒套件
- 能源教育
- 账单折扣机会
- 疫苗接种
  (前 30 名可获得 10 美元奖励)

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COMCAST

前来与您的社区一起学习和庆祝吧!

Community Services Network pdx

Hội Chợ Chuẩn Bị cho Mùa Đông

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BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Direct Testimony of Kyle T. Walker

MULTI-YEAR RATE PLAN AND REVENUE REQUIREMENTS

Exh. KTW-1T

August 29, 2025

DIRECT TESTIMONY OF KYLE T. WALKER

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I. INTRODUCTION AND SUMMARY

Q. Please state your name, address, and position with Northwest Natural Gas Company ("NW Natural" or "the Company").

A. My name is Kyle T. Walker. My business address is 250 SW Taylor Street, Portland, Oregon 97204. My current position is Rates/Regulatory Senior Manager in the Rates and Regulatory Affairs Department.

Q. Please state your educational background and experience.

A. I received a Bachelor of Science Degree in Business Administration with an emphasis in Finance from Oregon State University in 2005 and a Master of Business Administration from Willamette University in 2010. In addition, I received an accounting certificate from the University of Washington, and I am a licensed Certified Public Accountant in the State of Oregon with active status and in good standing. Prior to my employment with NW Natural, I held positions at the Bonneville Power Administration ("BPA"), including Risk Analyst, Derivative Accountant, Internal Auditor and Finance Analyst. Prior to BPA, I was a Credit Manager for Wells Fargo. In early 2015, I started at NW Natural as a Rates/Regulatory Analyst and was later promoted to Manager then Senior Manager. In my current role, I am responsible for revenue requirement, regulatory reporting, regulatory strategy, ratemaking, and other regulatory duties as assigned.

Q. Please summarize the multi-year rate plan ("MYRP") sections of your testimony.

A. The MYRP sections of this testimony (Sections II and III) explain NW Natural's MYRP proposal, which is filed to comply with Washington State requirements for extended rate planning and regulatory transparency. The sections outline the

Company's adherence to state law and guidance from the Washington Utilities and Transportation Commission ("Commission" or "WUTC"), describe the MYRP's three-year structure beginning August 1, 2026, and detail methods for setting rates and capital investments. They highlight strategies to safeguard affordability and access to natural gas, implement performance measures, monitor earnings, and support low-income customers. Ultimately, the MYRP testimony demonstrates how the MYRP is designed to ensure regulatory compliance, prudent investment, and accountability to both customers and regulators.

Q. Please summarize the revenue requirements sections of your testimony.

A. The revenue requirements sections of this testimony (Sections IV through XIV) explain the financial adjustments applied to the Test Year and each following rate year (RY1, RY2, and RY3). They describe how restating, pro forma, and provisional adjustments address changes in revenue, expenses, and taxes, and present the rates of return and revenue increases required to reach the Company's targeted financial outcomes. Key references to supporting exhibits and other witnesses' testimonies are also included.

Additionally, the section covers the calculation methodology, including allocation methods and proposed new tariff schedules. These details show how the Company justifies its requested rate changes through clear annual results and the projected revenue increases needed to maintain financial stability across the rate plan.

The section also addresses the Company's proposed deferral amortizations and base rate provisional adjustment rider.

II. MULTI-YEAR RATE PLAN OVERVIEW

Q. Why is NW Natural filing a MYRP?

A. NW Natural is filing a MYRP to comply with RCW 80.28.425(1). Since January 1, 2022, RCW 80.28.425(1) requires natural gas and electric companies to include MYRPs as part of their general rate case filings. NW Natural last filed a Washington general rate on December 18, 2020 and, therefore, NW Natural has included its first MYRP as part of this filing.

Q. What Commission guidance did the Company utilize in preparing its first MYRP?

A. NW Natural utilized the Commission's Used and Useful Policy Statement,[1] which helps clarify how to include future plant in rate base, including incorporating the matching principle. The matching principle is defined in the Used and Useful Policy Statement as "the net effect of including an investment with related offsetting factors."[2]

Additionally, the Commission issued a Policy Statement in Docket U-210590 titled "Interim Policy Statement Addressing Measures and Goals, Targets, Performance Incentives, and Penalty Mechanisms" on April 12, 2024 ("PBR Policy Statement"), which outlines a framework for establishing goals and performance metrics.

Q. What period does NW Natural's MYRP cover?

A. NW Natural is proposing a three-year rate plan with the first rate effective date of August 1, 2026. Rate year one ("RY1") covers August 1, 2026 through July 31, 2027.

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[1] *In the Matter of the Commission Inquiry into the Valuation of Public Service Company Property that Becomes Used and Useful after Rate Effective Date,* Docket U-190531, Policy Statement on Property that Becomes Used and Useful After Rate Effective Date (Jan. 31, 2020) ("Used and Useful Policy Statement").

[2] Used & Useful Policy Statement, fn. 24.

Rate year two ("RY2") covers August 1, 2027 through July 31, 2028. Rate year three ("RY3") covers August 1, 2028 through July 31, 2029.

Q. What adjustments are you making for your MYRP?

A. The Test Year for NW Natural's MYRP is 12 months ending March 31, 2025. Restating adjustments to the Test Year are performed and a pro forma forecast is added for the period between the end of the Test Year (April 1, 2025) and the first rate effective date (August 1, 2026). For RY1, the Company is proposing capital additions through the pro forma period (July 31, 2026) to help mitigate the impact of the MYRP on customer bills. Provisional capital for RY2 and RY3 will be the 12 months ending July 31, 2028, and July 31, 2029, respectively, as demonstrated in Table 1, below.

Table 1 – Pro Forma and Provisional Capital Additions Over MYRP

Pro Forma and Provisional Capital Additions Over Three Year Rate Plan			
Test Year + Pro Forma	Rate Year 1	Rate Year 2	Rate Year 3
Restating: Apr 2024 – March 2025 + Pro Forma: Apr 2025 – July 2026	**RY1 will use EOP July 31, 2026**	+ Provisional: (RY2) Aug 2027* – Jul 2028	+ Provisional: (RY3) Aug 2028* – Jul 2029
Footnotes: *Rate effective date is 8/1 of the corresponding Rate Year e.g. RY1 is 8/1/2026			

Q. Has the Company met all the requirements of RCW 80.28.425?

A. Yes. As discussed in my testimony below and other witnesses' testimony as summarized in Exh. KAR-ZDK-1T, NW Natural has addressed the following items:

A. RCW 80.28.425(1) – Multi-year Rate Plan Requirements and Public Interest Considerations

B. RCW 80.28.425(2) – Low-Income Energy Burden Provisions

C. RCW 80.28.425(3) – Commission Determinations for Property Valuation, Revenues, and Operating Expenses

D. RCW 80.28.425(4) – Commission Authority to Establish Terms and Ensure Just and Reasonable Rates

E. RCW 80.28.425(5) – Binding Commitments and Filing Options for Subsequent Rate Years

F. RCW 80.28.425(6) – Earnings Sharing and Deferral Requirements

G. RCW 80.28.425(7) – Performance Measures and Accountability Standards

III. MULTI-YEAR RATE PLAN PROPOSAL

A. Multi-Year Rate Plan Requirements and Public Interest Considerations

Q. Please describe how NW Natural's MYRP complies with RCW 80.28.425(1).

A. As stated above, RCW 80.28.425(1) requires gas and electric companies to include a MYRP in every general rate case filing. The Commission's consideration of the MYRP is subject to the same standards applicable to other rate filings, including the public interest and fair, just, reasonable, and sufficient rates. In considering the public interest, the Commission may consider such factors including, but not limited to:

> environmental health and greenhouse gas emissions reductions, health and safety concerns, economic development, and equity, to the extent such factors affect the rates, services, and practices of gas or electric company regulated by the commission.[3]

The Company is proposing a three-year plan that is in the public interest and that results in fair, just, reasonable, and sufficient rates. It aligns with the Commission's matching principle, as explained in paragraph 20 of the Commission's Used and Useful Policy Statement, by synchronizing cost recovery with the timing of investments and their associated benefits, ensuring customers pay rates that reflect the costs incurred to serve them.[4] Additionally, the plan incorporates offsetting cost savings from operational efficiencies, retirements, customer contributions, customer growth revenues, and deferred income taxes, helping to mitigate rate impacts while maintaining safe, reliable, and sustainable service that is in the public interest.

Q. Has the Company demonstrated the proposal is in the public interest by discussing environmental health and greenhouse gas emission reductions, health and safety concerns, economic development, and equity?

A. Yes. Direct Testimony provided by Ms. Braun (Exh. HJB-1CT) regarding NW Natural's proposed Vancouver thermal energy network pilot discusses the environmental benefits of the project, including greenhouse gas emissions reductions,

[3] RCW 80.28.425(1).

[4] The Commission generally describes the matching principle as the principle that costs should be matched to offsetting factors and specifically as the net effect of including an investment with related offsetting factors. "In other words, the matching principle requires that all factors affecting a proposed pro forma adjustment (or proposed provisional pro forma adjustment) include pro forma level (or provisional pro forma level) revenue, rate base, and expense." Used and Useful Policy Statement at note 24. The Commission also recognizes that the matching principle is also a generally accepted account concept that requires companies to recognize (match) revenues earned to related expenses in the same period.

the development of downtown Vancouver, and how the project promotes equity by being located in a census tract that is among the most impacted in the State across all metrics of the Washington Environmental Health Disparities Map. Mr. Kizer and Mr. Johnson (Exh. DBK-SSJ-1T) discuss safety-related projects. Ms. Tanaka (Exh. CJT-1T) describes how NW Natural continues to strengthen and incorporate considerations of energy equity and affordability into its day-to-day operations and program offerings to customers, as shown by increasing participation in the Company's Bill Discount Program, expanding our Washington Low-Income Energy Efficiency ("WALIEE") program, and completing our second Energy Burden Assessment, as well as enhancements to several other energy affordability and equity programs.

B. Low-Income Energy Burden Provisions

Q. Please describe the Company's application of RCW 80.28.425(2) regarding low-income customers.

A. Under RCW 80.28.425(2) utilities may recover up to five percent of their annual revenue requirement to fund tariffs reducing energy burden for low-income customers (e.g., bill assistance, or bill discount programs). Rate increases in an MYRP must include an increase in low-income assistance, at least double the rate increase percentage.

For calendar year 2024, the Company collected 2.7 percent of its revenue requirement related to bill assistance and/or the bill discount program, as illustrated in Table 2 below. These income-qualified programs are discussed in detail in the Direct Testimony provided by Ms. Tanaka (Exh. CJT-1T). All of these programs reduce the

energy burden of income-qualified customers and are authorized under tariffs approved by the Commission, consistent with RCW 80.28.425(2).

Table 2 – 2024 Bill Assistance and Bill Discount Program as Percent of Revenue[5]

Bill discount program	$1,937,820	Advice 24-15; UG-240881
GREAT program	$867,320	Advice 24-08; UG-240696
WALIEE program	$115,495	Advice 24-08; UG-240696
Arrearage Management Program	$0	cost recovery to start in 2025 PGA
Income-eligible programs	$2,920,635	
2024 Washington CBR Normalized Revenue	$109,949,935	
Program costs as % of Revenue	2.7%	

Q. What is five percent of the Company's proposed revenue requirement for each year of the MYRP?

A. Five percent of the proposed revenue requirement for RY1, RY2, and RY3 are $6.88 million, $7.35 million, and $7.82 million, respectively.

Q. Please explain the cost recovery approach for the Company's income-qualified programs funding.

A. As illustrated in the table above, the Company's energy affordability programs for income-qualified customers include the residential bill discount program, the Gas Residential Energy Assistance Tariff ("GREAT") program, the WALIEE program, and the Arrearage Management Program ("AMP"). The funding for all of these programs is based on the actual costs incurred for the programs, reflecting the actual uptake of the programs and related administrative costs. These costs are incurred and recorded in a deferred account or a balancing account in the case of the bill discount program.

[5] See electronic Exh. KTW-10.

NW Natural then seeks cost recovery of these accounts annually, usually with the Purchased Gas Adjustment ("PGA") filings made in September. Thus, there is no pre-set budget for these programs; instead, funding for these programs follows the program need and expands as the participation in the programs or administrative costs increase.

Q. How does the funding approach for these programs affect how the Company is addressing income-qualified assistance for its proposed rate increases?

A. As a practical matter, it has been a complex exercise to navigate the provision of RCW 80.28.425(2) requiring an increase in funding for income-qualified programs at an amount at least double the percentage of the rate increase in each year of a MYRP. This is due to the manner in which the funding for these programs operates, as described above. It is difficult to increase funding amounts independent of the actual need of the programs because all of the programs are funded backward-looking to reflect actual costs expended. As a result, increasing funding for these programs will be dependent on increased participation. Both the bill discount program and the AMP will continue to see growth in customer participation due to being early in their history, with the programs beginning in January 2024 and April 2025, respectively. In the case of the bill discount program, increased funding may also be needed if the bill discount percentages are increased. As described in Ms. Tanaka's Direct Testimony (Exh. CJT-1T), an analysis indicates that the current bill discount program discount percentages remain adequate at targeting energy burdens of around 2 percent even with a total rate increase of 35 percent. Thus, the Company is not proposing to change the bill discount percentages in this case. However, if participation in either program causes the costs

of the program to exceed double the percentage of the rate increase in this rate case, NW Natural is supportive of this increase.

The current tariff for the GREAT program does include a soft cap for program costs of $500,000.[6] However, the tariff allows for exceeding the $500,000 upon consultation with the GREAT Advisory Group, and, as described in Ms. Tanaka's Direct Testimony (Exh. CJT-1T), GREAT expenditures have exceeded the threshold for the past two program years. In keeping with the provision in RCW 80.28.425(2), NW Natural is proposing to increase the cap listed in the GREAT tariff by 50 percent, resulting in a cap of $750,000. Note that even with the increase in the cap for GREAT, the cost recovery of the expense for GREAT will continue to reflect the actual spend of the program.

Q. How is NW Natural addressing income-qualified assistance for its proposed rate increases?

A. As described above, the funding for the Company's energy affordability programs typically occurs with the PGA filings each September and reflects the actual spend of the programs, which grows with increased customer participation. NW Natural is therefore proposing to increase the funding for these programs with the PGA filings and not in this rate case. Thus, the required increase of at least double the amount of the residential base rate increase approved will be achieved in the rate effective year of each year in the Company's MYRP. For example, RY1 rates will take effect August

[6] See NW Natural's Washington Tariff Schedule J Gas Residential Energy Assistance Tariff (GREAT) at: https://www.nwnatural.com/-/media/nwnatural/pdfs/wa-tcn/6jai_2024.pdf?rev=9152f758bf2f4500addf30256adc3527&hash=269487404A952B1A49D47673C085D6C6.

1, 2026, and the increase for the Company's income-qualified programs will be filed with the 2026 PGA with rates effective November 1, 2026, and reflect an increase that is double that of the residential rate increase. The funding increase for the programs will reflect increases expected in the bill discount program and AMP as the programs continue to grow. The same follows for the succeeding years of the MYRP. In this way, NW Natural will meet the requirements outlined in RCW 80.28.425(2).

C. Commission Determination for Property Valuation, Revenues, and Operating Expenses

Q. How did the Company decide which property to place in rates for this proceeding?

A. NW Natural referred to both the MYRP statute, specifically RCW 80.28.425(3), and the Commission's Used and Useful Policy Statement for guidance to determine the appropriate property to be included in rates. The Used and Useful Policy Statement states that property must be in service and providing benefits to ratepayers within the rate-effective period, which can extend up to 48 months, and RCW 80.28.425(3) requires the Commission to separately approve rates for each of the individual rate years based on the fair value of the property that goes into service each year.

The Commission allows flexibility in determining fair value by permitting adjustments for property that becomes used and useful after the rate-effective date. However, companies must demonstrate that investments are prudent, used, and useful, and provide proper evidentiary support for cost recovery. The Commission also adopts a retrospective review approach, where rates are subject to refund if projected investments are not used and useful as of the rate effective date, but are nonetheless expected to enter service during the rate year. Additionally, offsetting factors such as

revenue growth or expense reductions must be considered to ensure that rate adjustments are fair, just, and reasonable.

Q. Is the Company proposing to include property in rates that becomes used and useful after the rate-effective date in each rate year?

A. No. For RY1, the Company used plant balances as of July 31, 2026, marking the end of the pro forma period to mitigate the size of the rate increase in RY1. By voluntarily taking regulatory lag for investments entering service during RY1, NW Natural is seeking to limit the size of the RY1 rate increase. In addition, NW Natural is not proposing to include the reasonable cost of construction work in progress in valuing its plant, although the Commission has the discretion to include such costs under RCW 80.04.250(2).

Q. Is the Company providing detailed explanations for increases to rate base?

Yes, the Company has incorporated pro forma and provisional capital adjustments, as detailed in Table 3, below, organized by Company witnesses and categorized according to the Commission's Used and Useful Policy Statement utilizing Large and Distinct, Projected Programmatic, and Short-Lived to align with Commission policy. The amounts in Table 3 below include the total capital additions, not the average of monthly averages ("AMA") that are included within the revenue requirements.

Table 3 – Pro Forma and Provisional Capital Additions by Witness[7]

NW Natural Pro Forma Additions by Witness					
Witness	Large and Discrete	Projected	Programmatic	IT Short Lived [1]	Provisional Total
Moncayo	-	-	1,172,179	-	1,172,179
Fellon	-	-	-	9,949,793	9,949,793
Kizer	1,338,722	16,277,911	15,789,731	-	33,406,363
Pipes	327,472	-	-	-	327,472
Karney	10,279,937	-	-	-	10,279,937
Braun	-	-	-	-	-
Walker	-	-	190,604	-	190,604
RY1 Additions (Apr 2025 - Jul 2026)	**11,946,131**	**16,277,911**	**17,152,514**	**9,949,793**	**55,326,349**

NW Natural Provisional Additions by Witness [2]					
Witness	Large and Discrete	Projected	Programmatic	IT Short Lived [1]	Provisional Total
Moncayo	-	-	889,683	-	889,683
Fellon	-	-	-	18,570,440	18,570,440
Kizer	15,583,137	32,319,761	18,687,903	-	66,590,800
Pipes	175,135	-	-	-	175,135
Karney	3,453,949	-	-	-	3,453,949
Braun	12,829,642	-	-	-	12,829,642
RY2 Additions (Aug 2026 - Jul 2028)	**32,041,862**	**32,319,761**	**19,577,586**	**18,570,440**	**102,509,648**
Moncayo	-	-	1,141,825	-	1,141,825
Fellon	-	-	-	9,242,541	9,242,541
Kizer	22,128,861	20,858,956	7,527,792	-	50,515,608
Pipes	147,076	-	-	-	147,076
Karney	-	-	-	-	-
Braun	-	-	-	-	-
RY3 Additions (Aug 2028 - Jul 2029)	**22,275,937**	**20,858,956**	**8,669,617**	**9,242,541**	**61,047,050**

[1] IT Short-lived may include programmatic and large and discrete
[2] Capital additions that occur in RY1 are included in RY2 rates

Pro forma adjustments reflect capital put in service between the end of the Test Year (April 1, 2025) and the first rate effective date (July 31, 2026). Provisional adjustments reflect all capital additions over the following periods:

- RY2: Capital investments from August 2027 through July 2028
- RY3: Capital investments from August 2028 through July 2029

[7] See electronic confidential Exh. KTW-11C.

As described above, RY1 does not include provisional adjustments, in order to mitigate rate impacts to customers. Instead, the Company is including only those capital investments that are in-service as of the end of the pro forma period (July 31, 2026) in RY1 rates. The Company has also incorporated offsets to revenue, operating and maintenance ("O&M") expenses, retirements that reduce depreciation expense, customer advances, deposits, and deferred taxes to help reduce revenue requirements. The resulting table shows the revenue requirement reductions by rate year.

Table 4 – Revenue Requirement Offsets by Rate Year[8]

	Test Year	Pro Forma	RY 1	RY 2	RY 3
Customer Growth Revenues	$ -	$ (970,547)	$ (338,717)	$ (540,633)	$ (804,921)
O&M Savings	$ (723,087)	$ (11,215)	$ -	$ -	$ -
Retirements	$ -	$ (523,634)	$ (239,978)	$ (562,519)	$ (417,450)
Accumulated Depreciation (Excl. Retirements)	$ (526,347)	$ (1,781,700)	$ -	$ (2,289,253)	$ (1,812,127)
Accumulated Deferred Income Taxes	$ -	$ (83,330)	$ -	$ (141,279)	$ (49,404)
Customer Advances and Deposits	$ (78,462)	$ (185,806)	$ -	$ (153,854)	$ -
Excess Deferred Income Taxes (EDIT)	$ -	$ -	$ (33,140)	$ -	$ -
Revenue Requirement Offsets incl. EDIT	**$ (1,327,896)**	**$ (3,556,233)**	**$ (611,835)**	**$ (3,687,537)**	**$ (3,083,902)**

Q. How is the Company proposing to review RY1 pro forma capital?

A. The Company proposes reviewing pro forma capital for RY1 in a similar manner to the provisional capital review as described below. A Pro Forma Plant Report will be filed within four months of the rate effective date of RY1 (August 1, 2026).

Q. How is the Company proposing to review RY2 and RY3 provisional capital?

A. The Company is proposing an annual retrospective review process for all provisional capital investments as envisioned by the Commission's Used and Useful Policy Statement. Within four months following the end of RY2 and RY3, respectively,[9] NW

[8] See electronic Exh. KTW-12.

[9] As stated above, NW Natural is not proposing to include any provisional capital as part of RY1 rates. Therefore, this process would not be necessary at the end of RY1.

Natural will file a report for utility plant that was placed into service during that rate year, called the Provisional Plant Report.[10] All parties will have the opportunity to review the evidence, conduct discovery, and review provisional plant. Similar to other utility rate cases, parties will have six months to conduct their prudence review for capital set forth in the Company's Provisional Plant Report.[11]

After non-Company parties submit their responses to the Commission, NW Natural will file a petition to amend the final order in this docket in accordance with WAC 480-07-875 by June 1. The petition will indicate whether the parties agree to the proposed rate change or if a dispute exists that would require further process under WAC 480-07-875. If there is no dispute, the petition will specify any changes to the rate year based on updated information or explain that no changes are necessary. The Commission will then issue an Order by July 15 to ensure adequate time to reflect any changes to rates, such as a refund, that would be needed by August 1, the start of the next rate year, or introduce an alternative process.

[10] Cascade Natural Gas filed its provisional plant review four months after its latest rate effective date from UG-240008.

[11] *In the Matter of Washington Utilities and Transportation Commission v. Cascade Natural Gas Corporation,* Docket UG-240008, Order 05, at 21. *"…the Settling parties agreed to require Cascade to "file an annual provisional plant report by April 30th of each year" and provide non-Company parties "six months to review" the prudency of the projects contained in the report*" (Feb. 24, 2025).

Q. How should the Commission view the overall portfolio of capital for each rate year?

A. The pro forma (RY1) and provisional capital additions should be evaluated as a portfolio of projects, not on a project-by-project basis.[12] This treatment captures any unforeseen cost increases or decreases for all capital projects included in the rate year. In addition, this treatment would include any new capital that may not have been included as capital in the rate year due to operational or emergency type situations.

If the total capital additions are below the amount approved by the Commission in the rate year, refunds will be given back to customers, in the appropriate revenue requirement amounts, based on the rate spread established in this case. Furthermore, recovery of capital investment will be capped at the overall plant additions approved by the Commission for each rate year.

Q. What details will be included in the Pro Forma and Provisional Plant Reports?

A. Each annual report will include the following comparison of the actual capital additions versus the Commission-approved capital for that rate year:

A. Actual capital versus authorized capital, with explanations for significant cost variances, defined as variances greater than 10 percent and $500,000 from the authorized amount;

B. Actual in-service date;

[12] *In the Matter of Washington Utilities and Transportation Commission v. Avista Corporation,* Docket UE-240006 & UG-240007, Order 08, at 230. "*Consistent with the Commission's Used and Useful Policy, the provisional plant review process should continue to be conducted on a portfolio basis, with a six-month review period, with consistent classification of plant and naming conventions, and shall not be tracked through a separate tariff at this time"* (Dec. 20, 2024*).*

C. Any material changes to the project descriptions;

D. In the case of significant cost overruns, an update to the project description that includes justification to continue investing in the project;

E. Updated information (if any) on offsetting factors that impact capital; and

F. Detailed description of any material capital projects not approved by the Commission's Final Order.

D. Binding Commitments and Filing Options for Subsequent Rate Years

Q. Please describe the details of RCW 80.28.425(5).

A. Once its MYRP is approved by the Commission, the Company is required to adhere to the terms of such MYRP for the first two rate years. However, for the third year, the Company has the option to file a new MYRP rather than continuing under the existing plan. This provision ensures that while the early years of the MYRP remain fixed, the Commission has authority, as described in RCW 80.28.425(4), to establish conditions and processes for outer rate years as long as the rates are fair, just, reasonable, and sufficient.

Q. Is the Company proposing a process for the third year of the proposed MYRP?

A. Yes. NW Natural is seeking a three-year plan because it best balances the cost of filing rate cases with recovery of investments and expenses over time. However, a three-year plan presents additional uncertainty for the Company compared to a two-year plan. Accordingly, NW Natural proposes a re-evaluation process prior to RY3.

Q. Please describe what you mean by a re-evaluation process.

A. Six months before the rate effective date of RY3 (August 1, 2028), the Company would file to update its revenue requirements for all components, including provisional plant

and O&M expenses, if the revenue requirements are more or less than 25 percent of the original filing, or $2.07 million. This process re-opens the MYRP to make updates that were unforeseen at the time of the original filing.

Q. What would be included in the re-opening filing?

A. The re-opening filing would include justification for revenue requirements changes greater or less than 25 percent from our original filing for RY3 and an updated revenue requirement would be proposed.

Q. What would occur during the four-month re-opening process after NW Natural files?

A. Once NW Natural files revisions to its rate year three revenue requirements, the parties to this case may submit discovery and review the filing. Two months before the rate effective date (June 1, 2028), each party may file a response to this docket with a recommendation and justification to the Commission. NW Natural will file a petition to amend the final order in this docket in accordance with WAC 480-07-875 by June 15, 2028. The Commission would then have five weeks to issue an amended order with updated revenue requirements.

Q. How would the Company implement new rates for RY3?

A. The Company will await the Commission order and submit a compliance filing prior to the rate effective date of RY3 (August 1, 2028).

E. Earnings Sharing and Deferral Requirements

Q. Please describe the details of RCW 80.28.425(6).

A. If a utility's annual commission basis report shows that its reported rate of return exceeds the Commission-authorized rate by more than 0.5 percent for a twelve-month

period, the utility must defer all excess revenues for refunds to customers or another determination by the Commission in a future adjudicative proceeding.

Q. How does the Company propose to address reported rates of return that exceed the Commission-authorized rate by more than 0.5 percent for a twelve-month period?

A. NW Natural currently submits a Commission Basis Report ("CBR") to the Commission by May 1 each year. This report captures the normalized operations over the reporting period and is aligned with the approved adjustments established in the most recent general rate case.

If the CBR reveals earnings more than 0.5 percent above its Commission authorized rate of return, the Company will defer the excess. The deferred amounts will be credited to customers coincident with the following year's PGA filing on an equal percent of margin basis to all customers. This ensures that customers benefit directly from any surplus earnings, in accordance with RCW 80.28.425(6), and allows a process if RY3 has excess earnings.

F. Performance Measures and Accountability Standards

Q. Please describe the details of RCW 80.28.425(7).

A. The Commission must determine performance measures when approving a MYRP for a utility. These measures are used to assess the utility's operations under the MYRP and can be based on proposals from the utility, other parties in the proceeding, or evidence presented during the review. In developing performance measures, incentives, and penalty mechanisms, the Commission may consider a variety of factors, including, but not limited to: lowest reasonable cost planning, affordability, increases

in energy burden, cost of service, customer satisfaction and engagement, service reliability, clean energy or renewable procurement, conservation acquisition, demand-side management expansion, rate stability, timely execution of competitive procurement practices, attainment of state energy and emissions reduction policies, rapid integration of renewable energy resources, and fair compensation of utility employees.[13]

Q. Please describe additional guidance under the Commission's Performance Metrics Policy Statement issued in Docket U-210590.

A. In the PBR Policy Statement issued in Docket U-210590, the Commission provided general guidance and opinions of PBR and established guiding principles, goals and a preferred set of metrics without defining certain terms and calculations for those metrics. Subsequently, on August 2, 2024, the Commission issued its "Policy Statement Addressing Initial Reported Performance Metrics" ("Performance Metrics Policy Statement") wherein the Commission provided a performance framework built around three primary objectives for MYRPs: 1) developing resilient, reliable, and customer-focused distribution systems; 2) enhancing customer affordability; and 3) advancing equity in utility operations, and another goal pending adoption related to supporting environmental improvements. These objectives align with broader state policies and introduce a structured approach to tracking utility progress through measurable outcomes.

[13] *See* PBR Policy Statement at para. 2.

Q. How does the Company address performance metrics in the MYRP?

A. NW Natural's performance metrics reporting is organized around three strategic goals that align with NW Natural's business principles: ensuring a resilient, reliable, and customer-focused distribution grid; promoting customer affordability; and advancing equity in utility operations. The performance measures proposed by NW Natural largely reflect those described and recommended in the Commission's Performance Metrics Policy Statement in Docket U-210590.[14] For a comprehensive discussion and detailed performance metrics, please refer to the Direct Testimony of Ms. Siores in Exh. NCS-1T.

IV. REVENUE REQUIREMENT

Q. Please provide a brief overview of the elements of revenue requirement, and how it is pertinent to a general rate case.

A. The Company's revenue requirement, or cost of service, represents the total annual cost to serve its customers. Costs primarily consist of gas costs (i.e., cost of goods sold), operating and maintenance costs, revenue-related costs, and investment-related costs.

Gas costs include commodity and upstream pipeline costs.[15] Operating and maintenance costs include payroll and other non-capital costs of serving customers. Revenue-related costs, or other taxes, are primarily comprised of franchise taxes, but

[14] *In the Matter of the Proceeding to Develop a Policy Statement Addressing Alternatives to Traditional Cost of Service Rate Making,* Docket U-210590, Policy Statement Addressing Initial Reported Performance Metrics (Aug. 2, 2024).

[15] Although gas and upstream gas supply costs are a major cost for the Company, and form a part of NW Natural's revenue requirement, these costs are recovered through the Company's PGA, and not as part of the Company's base rates, which we seek to modify through this general rate case proceeding.

also include Washington's utility tax, the statutory commission fee, and uncollectible expense. Investment-related costs include the return of investment, or depreciation, and the return on investment, which includes the costs of debt and equity to finance our investments.[16] Federal and State income taxes are also a cost to serve customers. The elements of the revenue requirement are shown below in Table 5.

Table 5 – Elements of Revenue Requirement

Cost of Capital (Debt and Equity)
+ Income Taxes (Federal and State)
+ Other Taxes
+ Depreciation Expense
+ Operating & Maintenance Expense
+ Cost of Gas
= Revenue Requirement

Investment costs are related to the Company's rate base, which include several components, but are primarily net plant. Net plant represents the assets that have been acquired or constructed by the Company for purposes of serving its customers, and which are being financed by the Company. Rate base also includes certain other items that are financed, such as gas inventory in storage, working capital, and leasehold improvements. There are also amounts that are received by the Company that reduce the amount of financing required. The largest of those amounts is deferred income taxes, primarily due to differences in depreciation expense between book accounting and tax accounting. The higher level of tax depreciation expense has historically created a financing benefit by lowering the current income tax liability for the

[16] Investment-related costs also include income and property taxes associated with earnings and plant balances, respectively.

Company. Therefore, I factor in that benefit as a reduction to the total amount of investments, or rate base. The overall rate base, including all these components, represents the amount that requires financing from shareholders and bondholders. Table 6 below shows the elements of rate base.

Table 6 – Elements of Rate Base

Utility Plant in Service:	
	Gross Plant
+	Accumulated Depreciation
=	Net Plant
Other Rate Base Items:	
	Aid in Advance of Construction
+	Customer Deposits
+	Gas Inventory
+	Leasehold Improvements
+	Accumulated Deferred Income Taxes
+	Working Capital
=	Total Other Rate Base Items
Net Plant	
+	**Total Other Rate Base Items**
=	**Total Rate Base**

The aggregation of gas costs, O&M costs, revenue-related costs, and investment-related costs represents the annual amount that is needed to be recovered from the Company's customers. Our incremental revenue requirement is the amount of additional revenue needed over the amount already generated by existing rates, so that the Company can recover its costs and has an opportunity to earn its authorized return on equity ("ROE").

Q. Please walk through the steps taken to compile the revenue requirement proposed in this case for RY1.

A. The first step in the revenue requirement calculation is to determine the amount of revenue that will be generated in RY1 at current rates.[17] To do this, the Company forecasts customers and the average use-per-customer for residential and commercial customers as well as a forecast of usage for current industrial customers.[18] This is done through both restating adjustment via weather normalization as well as pro forma and provisional adjustments to get the correct revenue estimated for RY1.

The second step is to forecast the operating costs and depreciation expense the Company will incur during the pro forma and provisional periods.[19]

The third step is to forecast rate base for the Rate Year. Rate base includes capitalized costs such as utility plant in service, gas inventory, cash working capital, and leasehold improvements offset by accumulated deferred income taxes, aid in advance of construction and customer deposits. Rate base forecasts account for retirements and capital additions.

After these first three steps, we can determine the estimated rate of return on rate base and return on equity in RY1 at current rates. Due to the ROE being below recommended levels using forecasted revenue at current rates, the Company proposes to increase revenues to generate a reasonable return in RY1 after accounting for the

[17] This includes estimated use-per-customer amounts and a forecast of customer counts for the Rate Year.

[18] See Mr. Wyman's Direct Testimony at Exh. RJW-1T.

[19] Operating costs include gas costs, operating and maintenance expense, uncollectible expense, state and federal income tax, property tax, other tax, and depreciation expense. Please see Mr. Davilla's Direct Testimony at Exh. TFD-1CT.

forecasted operating revenues, operating expenses, taxes, return of investment (depreciation expense), and return on investment of Test Year rate base.

The fourth step is to propose a recommended capital structure, cost of debt and cost of equity (ROE) to determine the proposed increase to revenues needed to generate a reasonable rate of return.

Table 7 below shows the steps taken for the proposed increase to revenue requirement:

Table 7 – Revenue Requirement Process Steps

Step 1	**Step 2**	**Step 3**	**Step 4**	**Proposed Increase**
Forecasted Customers and Usage x Current Rates =	Forecast Test Year Operating + Forecast Return of Investment (Depreciation Expense) =	Forecast Capital Additions + Current Rate Base =	Proposed Capital Structure and Proposed Cost of Debt and Equity =	**Incremental Revenue Requirement** + Steps 1-3 =
RY1 Revenue at Current Rates	**Forecasted Expenses for RY1**	**Forecasted Rate Base for RY1**	**Proposed Rate of Return (%) on Rate Base**	**Proposed Rate of Return ($) on Rate Base**

Q. What is the Company's proposed increase to revenue requirement for RY1 highlighting the steps above?

A. The proposed increase to revenue requirement is $25.6 million in RY1, as shown in Table 8 below.

Table 8 – Process Steps with Proposed Increase[20]

Line No.	Test Year at Present Rates	Restating Adjustments (STEP 1 STEP 2)	Test Year Adj. at Present Rates	Pro Forma and Provisional RY 1 Adjustments (STEP 1 STEP 2)	RY1 Adjusted at Present Rates	Proposed RY1 Rate Increase (STEP 4)	RY1 Total
	(a)	(b)	(c)	(d)		(e)	(f)
Revenues	$106,570,987	$3,256,211	$109,827,198	$2,209,080	$112,036,277	**$25,557,744**	$137,594,022
Operating Expenses							
Gas Purchased	$36,014,859	$10,466,590	$46,481,449	$859,248	$47,340,697	$0	$47,340,697
Other Operating & Maintenance Expense	$26,587,783	($1,083,678)	$25,504,105	$4,478,000	$29,982,105	$65,583	$30,047,688
Depreciation Expense	$17,909,187	$650,958	$18,560,145	$1,961,703	$20,521,848	$0	$20,521,848
Taxes							
Federal Income Tax	$2,052,451	($1,582,843)	$469,608	($1,186,510)	($716,902)	$5,125,144	$4,408,242
State Income Tax	$0	$0	$0	$0	$0	$0	$0
Other Taxes	$8,309,308	($29,646)	$8,279,662	$260,008	$8,539,670	$1,086,715	$9,626,385
Total Operating Revenue Deductions	$90,873,588	$8,421,381	$99,294,969	$6,372,449	$105,667,417	$6,277,442	$111,944,860
Net Operating Revenues	$15,697,399	($5,165,170)	$10,532,229	($4,163,369)	$6,368,860	$19,280,302	$25,649,162
		STEP 3		STEP 3			
Average Rate Base							
Utility Plant in Service, Net	$335,446,111	$32,746,611	$368,192,722	$30,305,704	$398,498,427	$398,498,427	$398,498,427
Other Rate Base Items	($52,611,466)	($944,348)	($53,555,814)	($3,181,941)	($56,737,755)	($56,737,755)	($56,737,755)
Total Rate Base	$282,834,645	$31,802,263	$314,636,908	$27,123,764	$341,760,672	$341,760,672	$341,760,672
Rate of Return	5.550%		3.347%		1.864%		7.505%
Return on Common Equity	6.41%		1.81%		-0.96%		10.10%

Q. Please describe how the testimony presented in this rate case establishes NW Natural's revenue requirement within the steps you presented above.

A. Step one is presented by me within this testimony, Exh. KTW-1T.

Step two involves forecasts of operating expenses in the following pieces of testimony:

- Melinda B. Rogers' Direct Testimony (Exh. MBR-1CT) demonstrates NW Natural's costs of labor, including compensation and benefits for our non-bargaining unit employees, bargaining unit employees and executives.

[20] See electronic Exh. KTW-2.

- Cory A. Beck's Direct Testimony (Exh. CAB-1T) describes the costs associated with our customer communications and language access.
- Daniel B. Kizer and Scott S. Johnson's joint Direct Testimony (Exh. DBK-SSJ-1T) describe the operating expenses associated with the Company's safety and other regulatory compliance projects and programs.
- Wayne K. Pipes' Direct Testimony (Exh. WKP-1T) describes the operating expenses associated with the Company's facilities.
- Brian E. Fellon's two pieces of Direct Testimony (Exh. BEF-1CT and Exh. BEF-23HCT) describe the Company's operating expenses related to Information Technology & Services ("IT&S") and the United States Department of Homeland Security's Transportation Security Administration's ("TSA's") security directives, respectively.
- Joe S. Karney's Direct Testimony (Exh. JSK-1T) describes the operating expenses associated with the Company's Meter Modernization Program.
- Tobin F. Davilla's Direct Testimony (Exh. TFD-1CT) describes all other operations and maintenance expense, and the total level of expense the Company will incur in each rate year.
- John J. Spanos' Direct Testimony (Exh. JJS-1T) describes the Company's depreciation study and presents the proposed depreciation rates for RY3 in this case.
- Holly J. Braun's Direct Testimony (Exh. HJB-1CT) describes the proposed thermal energy network project that will begin to be recovered in RY2.

Finally, I describe the Company's income tax expense and the proposed Excess Deferred Income Taxes ("EDIT") amortization resulting from federal income tax reform in 2017.

Step three, related to forecasted rate base, comprises the following testimony:

- Mr. Kizer's and Johnson's Direct Testimony (Exh. DBK-SSJ-1T) describes the capital additions associated with the Company's distribution and storage projects.
- Mr. Pipes' Direct Testimony (Exh. WKP-1T) describes capital additions associated with the Company's facilities.
- Mr. Fellon's Direct Testimonies (Exh. BEF-1CT and Exh. BEF-23HCT) describe the Company's capital additions related to IT&S and TSA's security directives, respectively.
- Mr. Karney's Direct Testimony (Exh. JSK-1T) describes the capital additions associated with the Company's Meter Modernization Program.
- Jorge O. Moncayo's Direct Testimony (Exh. JOM-1T) describes the capital budgeting, management approval and project lifecycles as well as discrete vs. non-discrete capital.
- Ms. Braun's Direct Testimony (Exh. HJB-1CT) describes the proposed thermal energy network project that will begin to be recovered in RY2.

In conjunction with these pieces of testimony, my calculations demonstrate NW Natural's rate base that is used in serving our Washington customers.

Step four, NW Natural's required return on rate base, is established in the following testimonies:

- Brody J. Wilson's Direct Testimony (Exh. BJW-1CT) provides evidence of NW Natural's cost of debt, and the amount of debt and equity the Company uses to finance its investments and operations.
- Jennifer E. Nelson's Direct Testimony (Exh. JEN-1T) provides evidence of the return that NW Natural should pay shareholders to continue to attract their investment in the Company through purchasing common stock.

The proposed increase is the culmination of operating costs, depreciation expense, taxes and the return on rate base less revenue forecasted at current rates for the Rate Year, displayed in Exh. KTW-2.

Q. How are revenue requirements calculated for RY2 and RY3?

A. The process mirrors RY1, but for revenue, the approved rates from RY1 are applied to RY2. Further, the approved rates from RY2 are applied to RY3. As a result, RY2 and RY3 revenue requirements largely depend on RY1, highlighting the need for fair outcomes for both customers and the utility.

V. TEST YEAR RESULTS

Q. What is the purpose of this section of your testimony?

A. The purpose of this section of testimony is to present the Company's financial results for its Washington operations for the Test Year. The Test Year that is being evaluated by the Company to determine the need for a rate increase is the 12-months ended March 31, 2025. The determination of actual results for the Test Year is primarily accomplished by Washington revenue, a state allocation of expense items, as well as the construction of rate base for the period. I will refer to Exh. KTW-3, which I have prepared for the explanation of the Test Year results.

Q. Why was the 12-months ended March 31, 2025, chosen as the Test Year for this rate case?

A. The period was chosen because 1) it provided data that included full quarterly information for accounting purposes, and 2) it was the most recent data available for the preparation of the rate case filed August 29, 2025.

Q. Please describe the components of Exh. KTW-3.

A. Page 1 of the exhibit presents the results of operations for the entire gas utility (i.e., system) for the Test Year in column (a), and the results of operations for Washington in column (b). The Company has two gas utility jurisdictions, Washington and Oregon.

Pages 2 and 3 of Exh. KTW-3 show the allocation of system operations and maintenance ("O&M") expense to Washington and Oregon by Federal Energy Regulatory Commission ("FERC") account. Allocation methodology is discussed later in my testimony.

Page 4 is a listing of all allocation factors used to allocate costs between the Company's two gas utility jurisdictions.

Page 5 displays the income tax calculation for Washington and system in the Test Year. Furthermore, it identifies the book and income tax permanent differences, federal tax credits as well as the amortization of excess deferred income taxes ("EDIT") that arose from the 2017 Tax Cuts and Jobs Act ("TCJA").

Pages 6 and 7 display the Test Year system and Washington rate base, including deferred taxes and other rate base items such as storage gas, customer advances and leasehold improvements.

Page 8 of Exh. KTW-3 shows the cost of capital, including long- and short-term debt and common equity during the Test Year, as well as revenue sensitive costs such as uncollectible expense, Washington utility tax and the WUTC regulatory fee.

Q. Please explain operating revenues and cost of gas on page 1 of Exh. KTW-3.

A. The operating revenues on lines 1 through 4 and the gas cost on line 5 reflect 12-month ended results through March 2025. The revenues for Washington are almost all direct; that is, they are the actual revenues generated from Washington during the 12-month Test Year. The exception is the allocation of utility property rental income under Miscellaneous Revenues, which are allocated between Washington and Oregon. The gas costs for Washington are calculated to correspond precisely to the gas costs collected in billing rates over the period, with inclusion of gas cost deferrals, to ensure the actual costs incurred are presented.

Q. Please explain operating expenses and taxes on page 1 of Exh. KTW-3.

A. Line 6 identifies uncollectible expense and line 7 represents other O&M Expense. There are substantial common costs within O&M expense; therefore, it is necessary for many system amounts to be allocated to both Washington and Oregon.

Line 9 of page 1 represents the environmental expense associated with clean-up activities captured in the Company's Environmental Cost Recovery Mechanism ("ECRM").

Lines 10 and 11 of page 1 represent the federal income taxes and Oregon excise taxes reported for the Test Year on a system and Washington basis. Page 5 of Exh. KTW-3 shows the derivation of the income tax expense for Washington. Utility income before income taxes was used as the basis of the calculation of the Washington

Test Year tax provision, and the interest deduction to that amount was taken as the cost of long-term and short-term debt multiplied by the proportion of rate base supported by the debt components. Additionally, an allocation of permanent tax differences and federal tax credits were included in the provisional calculation, as well as ongoing EDIT amortization.

Line 12 details the system and Washington expenses for property taxes during the Test Year. The Washington amount reflects the direct assignment of property taxes incurred.

Other Taxes on line 13 include franchise taxes, utility tax, and WUTC regulatory fee, which are assigned directly to each jurisdiction. Payroll Taxes are allocated using a payroll factor generated in the O&M expense allocation model that reflects the weighted average of all other cost allocations as they were used for accounts containing payroll expense. Miscellaneous other taxes are almost all directly assigned.

Q. What are the primary differences between income tax expense calculated using only the federal statutory rate of 21 percent and the income tax expense included in the Test Year results?

A. The primary differences result from historical regulatory income tax flow-through items related primarily to tax benefits that were originally flowed through to customers prior to 1981 and the regulatory benefits of EDIT amortization that were established as a result of federal tax reform in 2017.

Q. What are the historical regulatory income tax flow-through items?

A. The historical regulatory flow-through items relate to accelerated income tax depreciation benefits that occurred prior to 1981 and plant removal costs for income

tax. The amortization of these items is included as previously authorized in Docket UG-080546, Order 04, paragraph 16. The amortization is anticipated to conclude in calendar year 2027, and RY1 has been adjusted for the end of this amortization.

Q. What are the regulatory benefits of EDIT, associated with 2017 federal income tax reform, that are included in income tax expense?

A. In Order 06, page 27, paragraph 72 of Docket UG-181053, the Commission concluded that NW Natural's Plant EDIT balance for Washington customers was $14.592 million. This balance began to amortize for the benefit of customers as a reduction of income tax expense at an annual rate of $400 thousand as of November 1, 2019.

The Plant EDIT amortization benefits continue to be provided to customers subject to the timing limitations of the average rate assumption method (ARAM). The Plant EDIT amortization for the benefit of customers as a reduction of income tax expense beginning November 1, 2021, and through the Test Year was $375 thousand annually.

Q. Please explain depreciation and amortization expense and rate base on page 1 of Exh. KTW-3.

A. Depreciation and Amortization on line 14 can be explained in conjunction with the determination of system and Washington Total Rate Base on line 17, which are detailed on pages 6 and 7 of Exh. KTW-3. The allocation methodology of gross plant in rate base applies consistently to the allocation of depreciation and amortization expense and accumulated depreciation in rate base. As with O&M expense, the use of direct assignment is the default approach, and is applicable to the allocation of production, non-storage transmission, and distribution plant. Intangible plant, namely computer

software, is allocated using all customers due to its service to customers generally. Storage and storage transmission plant is allocated on the basis of firm volumes, insofar as it is considered a substitute to pipeline capacity. Compressed Natural Gas and Liquefied Natural Gas refueling facilities (non-storage) are allocated using the 3-factor approach, due to their contribution to various Company activities. General plant is allocated using a 3-factor approach.

The other elements of rate base are 1) cushion gas in storage which, following the storage plant, is allocated on firm volumes; 2) customer advances, which are directly assigned; 3) unamortized, or net, leasehold improvements, which have been allocated on a 3-factor approach for improvements in the Company's 250 Taylor operations center, microwave communication towers and the Company's backup data center; and 4) deferred taxes, which are directly assigned in the case of state deferred taxes and allocated on the basis of percentage of total accumulated depreciation for federal deferred taxes, after grossing up for the effect of state deferred taxes on the federal amount.

Q. Please explain lines 18 and 19 on page 1 of Exh. KTW-3.

A. For system results in column (a) and Washington-specific results in column (b), line 18 represents the overall ROR using the Net Operating Revenue on line 16 divided by the Total Rate Base on line 17. Line 19 is the resulting ROE when the debt cost components of the capital structure are removed from the overall return.

Q. Please describe the allocation methodology used to arrive at the Washington Test Year results summarized in Exh. KTW-3.

A. NW Natural's state allocation methodology for ratemaking has been consistently applied in all Washington and Oregon general rate cases since its original implementation in 2000. The Company's method of allocating costs begins with an initial identification of direct costs, with a direct assignment of those costs to the appropriate jurisdiction. The remaining costs are then considered with respect to specific "drivers," or elements such as volumes or customers that have a causative effect on costs. If a cost is related to a particular driver, it is allocated on that basis. Lastly, if there is a common cost with a mix of drivers, it is allocated on the basis of a multi-part allocation factor, called 3-factor. This 3-factor allocation is composed of the average of 1) the proportion of one jurisdiction's directly assigned gross plant to the system total, 2) the proportion of one jurisdiction's number of customers to the system total, and 3) the proportion of employees directly assigned to the system total.

There are 24 primary allocation factors available for use in assigning O&M expense, as shown on page 4 of Exh. KTW-3[21]. Even though the number is somewhat high when considering the desired simplicity of a method, a review of the nature of the factors shows that most are just refinements of the drivers typically relied on, namely volumes and customers.

System and jurisdictional O&M as shown on pages 2 and 3 of Exh. KTW-3 indicates the total amounts of O&M expense allocated to each state, and the overall

[21] For calculations of allocation factors, see electronic versions of Exh. KTW-3.

percentage of O&M expense allocated to Washington of 10.37 percent. These total O&M expense amounts include uncollectible expense, so when returning to the results of operations on page 1, lines 6 and 7 represent a breakout of the total O&M expense.

VI. TEST YEAR RESTATING ADJUSTMENTS

Q. What is the purpose of this section of your testimony?

A. In this section, I describe the restating adjustments the Company has made to the Test Year results to annualize changes that occurred during the period that are known and measurable. In addition, restating adjustments weather normalize Test Year results. I will refer to Exh. KTW-4, which I have prepared for the explanation of the restating adjustments.

Q. Please describe Exh. KTW-4.

A. Page 1, columns (a) through (k) of Exh. KTW-4 show the individual restating adjustments to Test Year results. Total restating adjustments to Test Year results are in column (l). Page 2 of Exh. KTW-4 displays the federal income tax calculation for each individual restating adjustment in a matching columnar format to page 1.

Q. Please describe the adjustments shown in column (a) on page 1 of Exh. KTW-4.

A. Column (a) on page 1 adjusts the Company's revenues and gas costs for the following items: 1) residential and small commercial usage is normalized to reflect normal weather; 2) usage for industrial and large commercial customers is annualized; 3) delivered volumes are priced to reflect permanent rates currently effective in Washington (Docket UG-200994, effective November 1, 2021 and Docket UG-210974, effective November 1, 2023), and 4) the cost of gas expense is adjusted to reflect the gas costs currently embedded in rates.

Q. Please explain why the normalized volumes are then priced at rates currently effective in Washington.

A. Pricing of the volumes at current rates is done to eliminate the effects of temporary increments in rates and to present revenues and costs at rates which are currently in effect. Due to rates changing during the course of the Test Year, re-pricing is necessary to accurately reflect current rate levels and gas costs for calculating the revenue requirement for RY1.

Q. Please describe how this re-pricing is achieved.

A. The pricing is accomplished by multiplying normalized volumes by the currently effective Washington rates for base, commodity, and pipeline capacity tariff rates. This is performed for all volumes and rates by each individual rate schedule.

Distribution capacity charges and sales service storage charges for large volume non-residential sales and transportation customers are calculated by multiplying the applicable current Maximum Daily Delivery Volume (MDDV) by the currently effective rates for each month of the Test Year.

Customer charges (the fixed portion of a customer's bill) are calculated by multiplying the number of customers by the applicable tariff customer charge. This is performed for all customers and monthly charges by each individual rate schedule. This calculation is performed for each month of the Test Year, and the annual total is added to the result of the normalized volumes pricing to derive the total normalized revenue reflecting current rates.

Q. How are industrial and large commercial customer revenues incorporated into the Test Year?

A. The volumes used for the industrial and large commercial customers for the restating adjustment are the actual volumes consumed during the 12-months ended March 31, 2025.

Q. Please explain how the cost of gas was calculated for the Test Year.

A. The total cost of gas is on page 3 of Exh. KTW-4. Cost of gas for NW Natural can be segmented into demand costs and commodity costs. Demand costs reflect relatively fixed monthly charges that are incurred for pipeline transportation service from domestic and Canadian pipelines. Commodity costs reflect expenses for obtaining physical gas. Each year the Company submits for approval its PGA filing that revises billing rates to include pricing for demand and commodity costs for the upcoming year. The ability to adjust prices on an annual basis for prevailing pricing of gas costs allows for the exclusion of the gas cost pricing issue from general rate cases.

Gas costs were developed using the gas cost rate elements included in the current tariff billing rates for sales rate schedules. This ensures an appropriate level of gas cost in relation to the Test Year normalized revenues.

In summary, pricing normalized volumes at current revenue rates adjusted to exclude temporary increments, and calculating costs built from the gas cost increments that are currently incorporated into those revenue rates, ensure that a precise matching of revenues and gas costs is achieved in the adjustment.

Q. Please explain the other restating adjustments on page 1 of Exh. KTW-4.

A. The adjustment in column (b) serves to set many of the miscellaneous revenue amounts to a three-year average for actual results, using a 12-month ending March time period, to partially remove any anomalies for the items during the Test Year. If the three-year history for an item shows a trend up or down, the most recent year is used as the normal amount. Page 4 of Exh. KTW-4 provides support for the adjustment in column (b).

Column (c) serves to replace the property taxes expenses during the Test Year with the cash amount most recently paid. Page 5 of Exh. KTW-4 provides support for the adjustment in column (c).

Column (d) adjusts uncollectible expenses to reflect the average of the 12-months ended March 31, 2025, March 31, 2024, and March 31, 2023, of actual net write-off percentages. Page 6 of Exh. KTW-4 provides support for the adjustment in column (d).

Column (e) is an adjustment to rate base for working capital, which generates a return on investments in working storage gas inventory and other critical assets necessary to perform the utility function. The Company has continued use of the settled working capital model from its previous general rate proceeding, Docket UG-200994. Page 7 of Exh. KTW-4 displays the adjustment in column (e).

Column (f) adjusts O&M to reflect removal of promotional advertising expenses, the long-term portion of the Company's executive compensation program, and the first year of rate case expenses for regulatory purposes. Furthermore, an increase to full-time employees ("FTEs") to represent the end of the Test Year is also

included. Page 8 of Exh. KTW-4 provides support for the adjustment in column (f), as does the Direct Testimony of Mr. Davilla in Exh. TFD-1CT.

Column (g) adjusts O&M and rate base to include actual ordinary claims for the Test Year, replacing the expense accrual activity that is used for claims reserve accounting. The adjustment also serves to include a three-year average of extraordinary claims. The use of the three-year average is meant to normalize the expense, which corrects for year-to-year anomalies in expense levels. Page 9 of Exh. KTW-4 provides support for the adjustment in column (g).

Column (h) adjusts Environmental Cost Recovery Mechanism (ECRM) expense to remove the expense from the revenue requirement calculation. The ECRM is recovered through a temporary rate for which the revenues associated are removed through the weather normalization adjustment. Page 10 of Exh. KTW-4 provides support for the adjustment in column (h).

Column (i) adjusts depreciation expense and rate base for end of period valuation. The March 2025 depreciation expense amount was multiplied by twelve to annualize the depreciation expense level observed in the last month of the Test Year. The rate base adjustment is the difference between the 13-month average of monthly averages (AMA) and the March 31, 2025, ending period balance. Pages 11 and 12 of Exh. KTW-4 provide support for the adjustment in column (i).

Column (j) adjusts the payroll tax associated with full-time employees (FTEs) at the end of the Test Year. Page 8 of Exh. KTW-4 provides support for the adjustment in column (j).

Column (k) adjusts the Test Year expenses for employee bonuses. The amount accrued during the year is removed and replaced by the three-year average of amounts paid. Page 8 of Exh. KTW-4 provides support for the adjustment in column (k).

Column (l) provides a subtotal of the effects of all the restating adjustments.

VII. ADJUSTED TEST YEAR RESULTS

Q. What is the total effect of the above Test Year restating adjustments on the Company's actual results of operations for the Test Year?

A. Exh. KTW-5 presents the Company's results of operations for the Test Year (column (a)), the resulting restating adjustments described in the previous section (column (b)), and the results for the Test Year normalized and adjusted at present rates (column (c)).

Q. What is the Test Year rate of return and return on common equity after the restating adjustments?

A. Column (c) of Exh. KTW-5, line 17, shows the Company's rate of return of 3.35 percent. Line 18 shows 1.81 percent for the return on common equity (ROE), which is significantly lower than the proposed ROE of 10.1 percent as presented by Ms. Nelson in Exh. JEN-1T.

VIII. TEST YEAR PRO FORMA ADJUSTMENTS

Q. What is the purpose of this section of your testimony?

A. In this section, I describe the pro forma adjustments the Company has made to the Test Year results to include capital, revenues and expenses that will be used and useful or known prior to RY1. I will refer to Exh. KTW-6, which I have prepared for the explanation of the pro forma adjustments.

Q. Please explain each adjustment on page 1 of Exh. KTW-6.

A. Column (m) adjusts revenue to include forecasted customer additions and the revenue they will generate. Pages 2 of Exh. KTW-6 provides support for the adjustment in column (m).

Column (n) adjusts depreciation expenses to an end-of-period annualized amount as of July 31, 2026. The forecasted depreciation expense level for July 2026 was multiplied by twelve for the end of period annualized amount. Page 3 of Exh. KTW-6 provides support for the adjustment in column (n).

Column (o) adjusts utility plant in service and accumulated depreciation for capital that is estimated to be used and useful by the effective date of RY1 (August 1, 2026), but were not complete at the end of the Test Year. Net book value is used for the adjustment at the rate effective date of RY1 and reflects July 31, 2026, balances. Page 4 of Exh. KTW-6 provides support for the adjustment in column (o).

Column (p) adjusts O&M expense that increases between the end of the Test Year and the start of RY1. For more detail, see Mr. Davilla's Direct Testimony, Exh. TFD-1CT. Page 5 of Exh. KTW-6 provides support for the adjustment in column (p).

Column (q) adjusts property tax based on increases in net plant during the pro forma period. Property tax forecasts are derived from an historical four-year relationship between net plant and property taxes paid. Page 5 of Exh. KTW-6 provides support for the adjustment in column (q).

Column (r) adjusts for the inclusion of Mist Recall that is expected to be filed coincident with the 2025-26 PGA. Due to Mist Recall not being included within the Test Year, a pro forma adjustment is needed to ensure the amounts are included in rate

base for RY1. The recall occurred in June 2025. Page 6 of Exh. KTW-6 provides support for the adjustment in Column (r).

Column (s) adjusts O&M and rate base for savings associated with two contract FTE's that will be eliminated due to the Resource Scheduling Optimization Project, as described in Mr. Fellon's Direct Testimony, Exh. BEF-1CT. Page 7 of Exh. KTW-6 and the details further below in my testimony provide support for the adjustment in Column (s).

Column (t) adjusts payroll expense to include the wages for employees given the known and measurable increases that have occurred and will occur due to Consumer Price Index adjustments, bargaining unit contract terms, and step progressions for employees. Pages 5 of Exh. KTW-6 provide support for the adjustment in column (t).

Column (u) provides a subtotal of the effects of all the Test Year pro forma adjustments. Page 8 of Exh. KTW-6 demonstrates the tax effects of the pro forma adjustments.

IX. MULTI-YEAR PROVISIONAL ADJUSTMENTS

Q. What is the purpose of this section of your testimony?

A. In this section, I describe the multi-year provisional adjustments the Company has made for RY1, RY2, and RY3 that will be subject to refund prior to the Pro Forma and Provisional Plant Report review outlined earlier in this testimony. These adjustments include capital, revenue, and expenses that will be used and useful or known within 12 months of each of the rate year's rate effective date. I will refer to Exh. KTW-7, Exh. KTW-8, and Exh. KTW-9, which I have prepared for the explanation of the adjustments.

Q. Please summarize the provisional capital for each of the three rate years.

A. Provisional capital additions represent short-lived assets, programmatic, projected, or large and distinct projects that are included in the Direct Testimony of Mr. Moncayo (Exh. JOM-IT), Mr. Fellon (Exh. BEF-1CT and Exh. BEF-23HCT), Mr. Kizer and Mr. Johnson (Exh. DBK-SSJ-1T), Mr. Pipes (Exh. WKP-1T), Mr. Karney (Exh. JSK-1T), Ms. Braun (Exh. HJB-1CT), and in my testimony (Exh. KTW-1T). Please see Table 4 above, which summarizes pro forma and provisional capital by sponsoring witness.

Q. Do any of the provisional adjustments have offsetting benefits that are included?

A. Yes. Many offsetting benefits have been included within the revenue requirements calculation. A list and description of the offsetting factors below:

- Customer growth revenues are included with current rates for RY1, RY1 rates for RY2, and RY2 rates for RY3, which directly offsets the revenue requirement for those years;
- Direct O&M savings identified;
- Retirements of certain assets have been forecasted based on historical trends which reduces depreciation expense through a reduction of gross plant;
- Accumulated depreciation continues to build every month of the rate year reducing the return on rate base. RY1 uses end of period July 31, 2026, prior to the rate effective date;
- Accumulated deferred income taxes offset rate base, which also reduces the return on rate base;

- Contributions in aid of construction, which represents the amounts new customers pay to help with the cost of construction for connecting to the system, offsets rate base;
- Customer deposits, which are sometimes required for new customers, also reduce rate base; and
- Excess deferred income tax amortization reduces the income taxes owed.

A summary of the offsets for each rate year are included in Table 4, above.

A. RY1 Provisional Adjustments

Q. Please explain the provisional adjustments in Exh. KTW-7.

A. Page 1 of Exh. KTW-7 summarizes the provisional adjustments of revenue, O&M expense, tax expense, and payroll tax expense for RY1.

On page 1, column (v), of Exh. KTW-7, revenues have been updated with forecasted customer additions at current rates. Support for this adjustment can be found on page 2 of KTW-7.

Column (w) of Exh. KTW-7, page 1, represents the O&M adjustment which is related to incremental expense as discussed in Mr. Davilla's Direct Testimony, Exh. TFD-1CT. Support for this adjustment can be found in Exh. KTW-7, page 3.

Column (x) of Exh. KTW-7, page 1, adjusts tax expense, which is associated with an increase in the EDIT credit of $25 thousand per year for a total of $400 thousand. In addition, interest expense associated with the cost of capital, which is deducted from taxable income, is adjusted to reflect a deduction in forecasted interest expense in RY1.

Column (y) adjusts payroll taxes to reflect increased FTEs, CPI adjustments to wages and salaries, and income changes for our bargaining unit employees. Exh. KTW-7, page 3 shows support for this adjustment.

Q. Where are the tax effects shown for the RY1 provisional adjustments?

A. Tax effects are shown on Exh. KTW-7, page 4, for each provisional adjustment.

Q. What is the proposed revenue requirement for RY1?

A. As shown on Exh. KTW-7, page 5, column (g), line 4 proposes a revenue requirement of $137.6 million, or an incremental amount of revenue requirement of $25,557,744, as shown in column (f), line 1. The proposed revenue requirement is based on an ROR on line 17 of column (g) of 7.51 percent and an ROE on line 18 of 10.10 percent. The cost of capital components can be seen in Exh. KTW-7, page 6.

B. RY2 Provisional Adjustments

Q. Please explain the provisional adjustments in Exh. KTW-8.

A. Page 1 of Exh. KTW-8 summarizes the provisional adjustments of revenue, O&M expenses, property tax, depreciation expense, rate base, tax expense, thermal energy network project, and payroll tax expense for RY2.

On page 1, column (a), of Exh. KTW-8, revenues have been updated with forecasted customer additions at RY1 rates. Support for this adjustment can be found on page 2 of Exh. KTW-8.

Column (b) of Exh. KTW-8, page 1, represents the O&M adjustment which is related to incremental expense as discussed in Mr. Davilla's Direct Testimony, Exh. TFD-1CT. Support for this adjustment can be found in Exh. KTW-8, page 3.

Column (c) of Exh. KTW-8, page 1, adjusts property tax to reflect the increase in rate base from the amounts included in RY1. Support for this adjustment can be found in Exh. KTW-8, page 3.

Column (d) of Exh. KTW-8, page 1, adjusts the provisional depreciation expense, which represents expense for the 12 months of RY2. Support for this adjustment can be found in Exh. KTW-8, page 3.

Column (e) of Exh. KTW-8, page 1, adjusts for capital additions on a 13-month AMA basis for rate base. Support for this adjustment can be found in Exh. KTW-8, page 3.

Column (f) of Exh. KTW-8, page 1, represents interest expense associated with the change in cost of capital, which is deducted from taxable income reflecting an increase in forecasted interest expense in RY2.

Column (g) of Exh. KTW-8, page 1, includes the addition of a thermal energy network project that will begin to be recovered in RY2. Support for this adjustment can be found in Exh. KTW-8, page 4.

Column (h) adjusts payroll taxes to reflect increased FTEs, CPI adjustments to wages and salaries, and income changes for our bargaining unit employees. Exh. KTW-8, page 3, shows support for this adjustment.

The overall provisional adjustments for RY2 can be seen in Exh. KTW-8, page 1, column (i).

Q. Where are the tax effects shown for the RY2 provisional adjustments?

A. Tax effects are shown on Exh. KTW-8, page 5, for each provisional adjustment.

Q. What is the proposed revenue requirement for RY2?

A. As shown on Exh. KTW-8, page 6, column (k), line 4 proposes a revenue requirement of $147.0 million, or an incremental amount of revenue requirement of $8,591,015, as shown in column (j), line 1. The proposed revenue requirement is based on an ROR on line 17 of column (g) of 7.62 percent and an ROE on line 18 of 10.20 percent. The cost of capital components can be seen in Exh. KTW-8, page 7.

C. RY3 Provisional Adjustments

Q. Please explain the provisional adjustments in Exh. KTW-9.

A. Page 1 of Exh. KTW-9 summarizes the provisional adjustments of revenue, O&M expenses, property tax, depreciation expense, rate base, tax expense, thermal energy network project, and payroll tax expense for RY3.

On page 1, column (a), of Exh. KTW-9, revenues have been updated with forecasted customer additions at RY2 rates. Support for this adjustment can be found on page 2 of Exh. KTW-9.

Column (b) of Exh. KTW-9, page 1, represents the O&M adjustment, which is related to incremental expense as discussed in Mr. Davilla's testimony, Exh. TFD-1CT. Support for this adjustment can be found in Exh. KTW-9, page 3.

Column (c) of Exh. KTW-9, page 1, adjusts property tax to reflect the increase in rate base from the amounts included in RY2. Support for this adjustment can be found in Exh. KTW-9, page 3.

Column (d) of Exh. KTW-9, page 1, adjusts the provisional depreciation expense which represents expense for the 12 months of RY3. Furthermore, starting at the rate effective date of RY3, the adjustment includes the implementation of the

proposed depreciation study, as sponsored by Mr. Spanos in Exh. JJS-1T. Support for this adjustment can be found in Exh. KTW-9, page 3.

Column (e) of Exh. KTW-9, page 1, adjusts for capital additions on a 13-month AMA basis for rate base. Support for this adjustment can be found in Exh. KTW-9, page 3.

Column (f) of Exh. KTW-9, page 1, represents interest expense associated with the change in cost of capital, which is deducted from taxable income reflecting an increase in forecasted interest expense in RY3.

Column (g) of Exh. KTW-9, page 1, includes a full year of thermal energy network project expenses and rate base, reflecting that it will begin to be recovered in RY2. Support for this adjustment can be found in Exh. KTW-9, page 4.

Column (h) adjusts payroll taxes to reflect increased FTEs, CPI adjustments to wages and salaries ,and income changes for our bargaining unit employees. Exh. KTW-9, page 3 shows support for this adjustment.

The overall provisional adjustments for RY3 can be seen in Exh. KTW-9, page 1, column (i).

Q. Where are the tax effects shown for the RY3 provisional adjustments?

A. Tax effects are shown on Exh. KTW-9, page 5 for each provisional adjustment.

Q. What is the proposed revenue requirement for RY3?

A. As shown on Exh. KTW-9, page 6, column (o), line 4 proposes a revenue requirement of $156.4 million, or an incremental amount of revenue requirement of $8,268,473, as shown in column (n), line 1. The proposed revenue requirement is based on an ROR

on line 17 of column (g) of 7.66 percent and an ROE on line 18 of 10.20 percent. The cost of capital components can be seen in Exh. KTW-9, page 7.

X. TSA SECURITY DIRECTIVE 2 DEFERRAL AMORTIZATION

Q. Did the Company file an accounting petition for the TSA Security Directive 2 described in Exh. BEF-23HCT?

A. Yes. The Company filed a deferral application for the TSA Security Directive 2 on November 17, 2021, which was later docketed as UG-210900. The deferral incorporated start-up O&M costs and ongoing total cost of service, not just operations and maintenance costs. The Commission approved the petition in Order 01 on February 9, 2023.

Q. What is the Company's proposal for amortization?

A. The Company proposes to amortize the start-up O&M costs in a separate temporary adjustment schedule over a three-year period, beginning in RY1. For the cost-of-service deferral, we propose to amortize in a separate temporary rate adjustment schedule over a five-year period beginning in RY3. Both schedules will amortize to all customers on an equal percent of margin basis. Please see Schedule 237 and Schedule 239 for the proposed O&M start-up costs and cost of service deferral, respectively.

Q. Will the Company update Schedule 237 with known costs for the compliance filings to this case?

A. Yes. The Company will update the proposed tariffs to incorporate the June 2026 cost of service balance for the O&M start-up costs, currently estimated at $570 thousand, for the RY1 effective date and each June 30th balance for the remainder of the MYRP.

For the cost-of-service amortization, the Company will incorporate the June 2028 balance to be amortized over a five-year period. The estimated June 2026 balance is $3.2 million.

XI. COVID-19 DEFERRAL AMORTIZATION

Q. Please describe the COVID-19 deferral.

A. The Company filed an accounting petition on March 25, 2020, to defer costs associated with the COVID-19 pandemic for later ratemaking. The Commission issued Order 01 in Docket UG-200264 approving the petition subject to conditions.

Q. What conditions were included in the order?

A. The Commission required NW Natural to reduce its deferral by the amount of reconnection and late payment fee charges actually collected by the Company from January 1 to March 25, 2020, to coincide with the beginning of the deferral period. The Company was also ordered to track and defer operational savings.

Q. What is the Company's COVID-19 deferral balance to be amortized?

A. After the conditions ordered by the Commission were implemented, the Company's COVID-19 deferral balance as of March 31, 2025, per its 2025 1st Quarter COVID-19 Deferred Accounting Report filed in Docket UG-200264, is $1.4 million.

Q. What is the Company's proposal for the COVID-19 deferral amortization?

A. The Company proposes to amortize the balance as of June 30, 2026, to all customers on an equal percent of margin basis over a three-year period. The amortization will occur through a temporary Adjustment Schedule 235 as provided with the other tariffs in this case.

XII. METER MODERNIZATION DEFERRAL AMORTIZATION

Q. Has the Company filed an accounting petition for the Meter Modernization Program?

A. Yes. The Company filed a deferral application on January 4, 2024, which was docketed as UG-240012. The Commission approved the petition in Order 01 on February 22, 2024.

Q. What is the Company's specific proposal regarding the Meter Modernization Program deferral amortization?

A. The Company proposes that the Commission authorize amortization of the June 30, 2026 deferral balance to be amortized to all rate schedules over three years starting August 1, 2026, on an equal percent of margin basis. If the deferral balance continues to increase after June 2026 or June 2027, the additional amount will be amortized over two years from RY2's compliance filing or over one year from RY3's compliance filing. For information about the Meter Modernization Program, please see Mr. Karney's Direct Testimony (Exh. JSK-1T).

Q. What is the estimated deferral balance as of June 30, 2026?

A. The estimated deferral balance as of June 30, 2026, is $548 thousand.

Q. Has the Company proposed a tariff to amortize these costs?

A. Yes. The Company has proposed a tariff (Schedule 236) to incorporate an estimate of the deferred amounts as of June 30, 2026. The Company will update the tariff with known costs as of June 30, 2026, in the compliance filing of this case.

XIII. BASE RATE PROVISIONAL ADJUSTMENT RIDER

Q. What is NW Natural proposing for its base rate provisional adjustment rider?

A. The Company proposes that all provisional capital that is subject to refund be tracked and accounted for on a separate base rate adjustment, Schedule 238, as provided with the tariffs in this case.

Q. What is the purpose of this rider?

A. The rider serves as a cap for base rate amounts that are subject to refund that have the ability to be approved through the Provisional Plant Report. Approved amounts would only occur if capital is placed in service according to the MYRP as described in my testimony above.

Q. What is the procedure for modifying this adjustment schedule when the Commission authorizes provisional capital that was previously subject to refund?

A. Upon the Commission's approval of provisional capital previously designated as subject to refund, the related calculated amounts will be shifted from this schedule to base rates within the relevant rate schedules. If the Company no longer has any provisional capital subject to refund, the per therm amounts for this base rate provisional rider will be set to zero.

Q. What is the process for modifying this adjustment schedule if the Commission were to disallow provisional capital?

A. If the Commission were to determine that provisional capital subject to refund should be disallowed, the Company would calculate the revenue collected from the rate effective date onward and defer these amounts until the earlier of the next rate effective

date of the MYRP or coincident with the PGA. The deferred amounts would then be returned to customers as credits, allocated in accordance with the approved MYRP.

XIV. REVENUE REQUIREMENTS CONCLUSION

Q. Please summarize the results of your analysis and proposed revenue increases for your three-year MYRP.

A. The revenue increase required to allow the Company its requested ROE of 10.1 percent, 10.2 percent, and 10.2 percent for RY1 is $25,557,744, RY2 is $8,591,015, and RY3 is $8,268,473 as shown in column (f), (j) and (n) of Exh. KTW-2, respectively. Columns (e), (i), and (m) represent the normalized and adjusted results for the Company at current rates. The Company's adjusted results including the proposed rate increases are included in in columns (g), (k), and (o) for the three rate years.

Q. Does this conclude your Direct Testimony?

A. Yes.

XV. LIST OF EXHIBITS

Exh. KTW-2	Analysis of Revenue Requirements Results
Exh. KTW-3	Test Year Financial Results
Exh. KTW-4	Test Year Restating Adjustments
Exh. KTW-5	Test Year Adjusted Results
Exh. KTW-6	Test Year Pro Forma Adjustments
Exh. KTW-7	RY1 Provisional Adjustments and Results
Exh. KTW-8	RY2 Provisional Adjustments and Results
Exh. KTW-9	RY3 Provisional Adjustments and Results
Exh. KTW-10	2024 Bill Assistance and Bill Discount Program as Percent of Revenue
Exh. KTW-11C	Pro Forma and Provisional Capital Additions by Witness (Confidential and Redacted)
Exh. KTW-12	Revenue Requirement Offsets by Rate Year

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Kyle T. Walker

MULTI-YEAR RATE PLAN AND REVENUE REQUIREMENTS

Exh. KTW-2

August 29, 2025

NW Natural
Washington Rate Case
Test Year Based on Twelve Months Ended March 31, 2025

Line No.		Test Year Results	Test Year Adjustments	Test Year Adjusted	RY 1 Adjustments	RY 1 Adjusted	Proposed RY 1 Rate Increase	RY 1 at 10.1% Equity Return
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Operating Revenues							
1	**Sale of Gas**	$99,442,515	$7,904,906	$107,347,421	$2,105,584	$109,453,005	$25,557,744	$135,010,749
2	**Transportation**	2,228,562	149,492	2,378,053	103,495	2,481,549		2,481,549
3	**Miscellaneous Revenues**	4,899,911	(4,798,187)	101,724	0	101,724		101,724
4	**Total Operating Revenues**	106,570,987	3,256,211	109,827,198	2,209,080	112,036,277	25,557,744	137,594,022
	Operating Revenue Deductions							
5	**Gas Purchased**	36,014,859	10,466,590	46,481,449	859,248	47,340,697		47,340,697
6	**Uncollectible Accrual for Gas Sales**	219,104	109,651	328,755	5,669	334,423	65,583	400,007
7	**Other Operating & Maintenance Expenses**	25,936,550	(761,200)	25,175,350	4,472,331	29,647,682		29,647,682
8	**Total Operating & Maintenance Expense**	62,170,513	9,815,041	71,985,554	5,337,248	77,322,802	65,583	77,388,385
9	**Environmental Expense**	432,129	(432,129)	0	0	0		0
10	**Federal Income Tax**	2,052,451	(1,582,843)	469,608	(1,186,510)	(716,902)	5,125,144	4,408,242
11	**Property Taxes**	1,864,317	(173,693)	1,690,624	80,119	1,770,743	0	1,770,743
12	**Other Taxes**	6,444,992	144,046	6,589,038	179,889	6,768,927	1,086,715	7,855,642
13	**Depreciation & Amortization**	17,909,187	650,958	18,560,145	1,961,703	20,521,848	0	20,521,848
14	**Total Operating Revenue Deductions**	90,873,588	8,421,381	99,294,969	6,372,449	105,667,417	6,277,442	111,944,860
15	**Net Operating Revenues**	$15,697,399	($5,165,170)	$10,532,229	($4,163,369)	$6,368,860	$19,280,302	$25,649,162
16	**Total Rate Base**	282,834,645	31,802,263	314,636,908	$27,123,764	341,760,672	$0	$341,760,672
17	**Rate of Return**	5.55%		3.35%		1.86%		7.51%
18	**Return on Common Equity**	6.41%		1.81%		-0.96%		10.10%

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Kyle T. Walker

MULTI-YEAR RATE PLAN AND REVENUE REQUIREMENTS

Exh. KTW-3

August 29, 2025

NW Natural
Washington Rate Case
Test Year Based on Twelve Months Ended March 31, 2025

Exh. KTW-3
Page 1

Line No.		System Test Year Results (a)	Washington Test Year Results (b)
	Operating Revenues		
1	**Sale of Gas**	$1,010,795,502	$99,442,515
2	**Transportation**	40,113,284	2,228,562
3	**Miscellaneous Revenues**	25,030,308	4,899,911
4	**Total Operating Revenues**	1,075,939,095	106,570,987
	Operating Revenue Deductions		
5	**Gas Purchased**	395,716,763	36,014,859
6	**Uncollectible Accrual for Gas Sales**	1,808,119	219,104
7	**Other Operating & Maintenance Expenses**	250,401,227	25,936,550
8	**Total Operating & Maintenance Expense**	647,926,109	62,170,513
9	**Environmental Expense**	14,560,448	432,129
10	**Federal Income Tax**	27,031,004	2,052,451
11	**Oregon Excise Tax**	11,984,869	0
12	**Property Taxes**	31,982,610	1,864,317
13	**Other Taxes**	44,300,136	6,444,992
14	**Depreciation & Amortization**	150,603,150	17,909,187
15	**Total Operating Revenue Deductions**	928,388,326	90,873,588
16	**Net Operating Revenues**	$147,550,769	$15,697,399
17	**Total Rate Base**	$2,179,059,625	$282,834,645
18	**Rate of Return**	6.77%	5.55%
18	**Return on Common Equity**	8.66%	6.41%

NW Natural **Exh. KTW-3**
Operations and Maintenance Expense: Allocation of System Amounts **Page 2**
Test Year Based on Twelve Months Ended March 31, 2025

		ACTUAL System	ACTUAL Washington	ACTUAL Oregon
Natural Gas Storage				
Underground Storage Expense				
Operation				
816	**Wells Expense**	984,561	49,491	935,070
818	**Compressor Station Expense**	180,835	19,838	160,997
819	**Compressor Station Fuel**	0	0	0
820	**Measuring and Regulator Station Expense**	5,443,075	369,671	5,073,404
821	**Purification Expense**	0	0	0
Maintenance				
832	**Wells Expense**	619,059	55,908	563,151
834	**Storage Maint. Expense of Compressor Equp**	1,542,426	155,271	1,387,155
	Total Underground Storage Expense	8,769,956	650,179	8,119,777
Other Storage Expense				
Operation				
840	**Supervision and Engineering**	27,546	3,022	24,525
	Total Other Storage Expense	27,546	3,022	24,525
Liquified Natural Gas Expense				
Operation				
844	**Supervision and Engineering**	1,785,547	195,875	1,589,672
845	**LNG Fuel Expense - Credit Liquef Costs**	(48,105)	(5,277)	(42,828)
Maintenance				
847	**Supervision and Engineering**	1,145,041	125,537	1,019,504
	Total Liquified Natural Gas Expense			
	Total Natural Gas Storage	2,882,483	316,134	2,566,349
Transmission Expense				
Operation				
856	**Mains Expense**	1,257,854	15,648	1,242,206
Maintenance				
863	**Maintenance of Mains**	69,712	2	69,710
	Total Transmission Expense	1,327,566	15,650	1,311,915
Distribution Expense				
Operation				
870	**Supervision and Engineering**	3,683,525	293,260	3,390,265
874	**Mains and Services Expense**	23,443,966	2,714,284	20,729,683
875	**Measuring and Regulator Station Expense - General**	518,680	45,895	472,785
877	**Measuring and Regulator Station Expense - City Gate**	730,314	69,740	660,574
878	**Meter and House Regulator Expense**	6,490,306	789,870	5,700,436
879	**Customer Installation Expense**	12,978,581	1,579,022	11,399,559
880	**Other Expense**	3,423,209	346,594	3,076,616
881	**Rents**	344,877	49,159	295,718

NW Natural **Exh. KTW-3**
Operations and Maintenance Expense: Allocation of System Amounts **Page 3**
Test Year Based on Twelve Months Ended March 31, 2025

		ACTUAL System	ACTUAL Washington	ACTUAL Oregon
Maintenance				
885	**Supervision and Engineering**	6,869,570	653,479	6,216,092
887	**Mains**	18,267,884	370,907	17,896,978
889	**Measuring and Regulator Station Expense - General**	2,450,180	228,562	2,221,619
891	**Measuring and Regulator Station Expense - City Gate**	200,608	17,372	183,236
892	**Services**	511,667	62,267	449,400
893	**Meters and House Regulators**	4,229,757	510,763	3,718,994
894	**Other Equipment**	31,367	279	31,088
	Total Distribution Expense	84,174,493	7,731,453	76,443,040
Customer Accounts Expense				
Operation				
901	**Supervision**	2,084,258	253,654	1,830,604
902	**Meter Reading Expenses**	968,517	117,869	850,649
903	**Customer Records and Collection Expense**	21,703,003	2,614,170	19,088,834
904	**Uncollectible Accounts**	1,808,119	219,104	1,589,015
	Total Customer Accounts Expense	26,563,897	3,204,796	23,359,101
Customer Service and Informational				
Operation				
906	**Customer Service and Informational Expense**	1,268,457	154,371	1,114,086
907	**Supervision**	0	0	0
908	**Customer Assistance Expense**	1,951,183	228,649	1,722,534
909	**Customer Information Expense**	2,595,517	315,874	2,279,642
910	**Miscellaneous Customer Service Expense**	182,971	22,579	160,392
	Total Customer Service and Informational	5,998,128	721,473	5,276,654
Sales Expense				
Operation				
911	**Supervision**	211,929	25,792	186,137
912	**Demonstration and Selling Expense**	1,970,340	220,605	1,749,735
913	**Advertising**	830,317	101,050	729,268
916	**Miscellaneous Sales Expense**	0	0	0
	Total Sales Expense	3,012,586	347,446	2,665,140
Administrative and General Expense				
Operation				
920	**Administrative and General Salaries**	55,486,556	6,972,304	48,514,252
921	**Office Supplies and Expense**	45,704,494	5,617,219	40,087,275
922	**Administrative Expenses Transferred - Credit**	(34,788,804)	(4,133,678)	(30,655,126)
924	**Property Insurance Premium**	6,031,383	711,703	5,319,680
925	**Injuries and Damages**	146,292	17,262	129,030
926	**Employee Pensions and Benefits**	18,496,574	1,252,504	17,244,070
928	**Regulatory Commission Expense**	0	0	0
930	**Miscellaneous General Expense**	10,467,926	620,750	9,847,176
931	**Rents**	10,969,506	1,294,004	9,675,502
Maintenance				
935	**Maintenance of General Plant**	6,938,765	813,430	6,125,334
	Total Administrative and General Expense	119,452,691	13,165,500	106,287,191
	Total Operations and Maintenance Expense	**252,209,346**	**26,155,654**	**226,053,692**
	Percent of Total	100.00%	10.37%	89.63%

Note: O&M above excludes amounts that are not intended to be recoverable in ratemaking.
O&M based on Regulatory application of Pension related costs in O&M (costs map to Non-Operating for GAAP).

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Test Year Based on Twelve Months Ended March 31, 2025 **Page 4**
Jurisdictional Allocation Factors

		Oregon	Washington
1	Customers-all	87.830%	12.170%
2	Customers-Residential	87.660%	12.340%
3	Customers-Commercial	89.490%	10.510%
4	Customers-Industrial	92.320%	7.680%
5	Customers-The Dalles	74.840%	25.160%
6	3-factor	88.200%	11.800%
7	firm volumes	89.030%	10.970%
8	sales volumes	89.620%	10.380%
9	sendout volumes	91.320%	8.680%
10	sales/sendout volumes	90.470%	9.530%
11	Payroll	88.883%	11.118%
12	Admin Transfer	87.857%	12.143%
13	Employee Cost	88.984%	11.016%
14	Regulatory	70.000%	30.000%
15	Telemetering	86.792%	13.208%
16	Direct-Wa	0.000%	100.000%
17	Direct-Or	100.000%	0.000%
18	Gross plant direct assign	87.840%	12.160%
19	Transmission	98.756%	1.244%
20	Accumulated Depreciation	88.786%	11.214%
21	Rate Base	87.020%	12.980%
22	Distribution	86.050%	13.950%
23	Perimeter	93.243%	6.757%
24	Environmental Admin Costs	96.680%	3.320%

NW Natural
Test Year Actuals Tax Calculation

Line No.	Washington - Test Year	Amount (a)		
1	**Utility Income before Interest and Taxes**	$17,749,850		
2	**Interest on Historic Average Rate Base**	7,019,956		
3	**Pre-Tax Net Income**	10,729,894		
4	**Permanent Differences**	881,799	11.21%	A/D Factor
5	**Pre Tax Income Adjusted for Permanents**	11,611,693		
6	**Tax Rate**	21.00%		
7	**Federal Income Tax Before Credits**	$2,438,456		
8	**Federal Tax Credits & EDIT Amortization**	(386,005)	11.80%	3-Factor
9	**Federal Income Tax**	$2,052,451		

Line No.	System - Test Year	Amount (a)
1	**Utility Income before Interest and Taxes**	$201,127,090
2	**Interest on Historic Average Rate Base**	51,295,064
3	**Pre-Tax Net Income**	149,832,026
4	**Permanent Differences**	7,863,622
5	**Pre Tax Income Adjusted for Permanents**	157,695,648
6	**State Tax Rate**	7.60%
7	**State Income Tax**	$11,984,869
8	**Pre Tax Income Adj for Perms and State Tax**	145,710,779
9	**Federal Tax Rate**	21.00%
10	**Federal Income Tax Before Credits**	$30,599,264
11	**Federal Tax Credits & EDIT Amortization**	(3,568,260)
12	**Federal Income Tax**	$27,031,004

NW Natural **Exh. KTW-3**
Permanent Tax Differences and Other Tax Inputs **Page 5**

Test Year

System Permanent M-1s	Test Year	RY1	RY2	RY3
Flow Through, Pre-1981 Depreciation	$7,350,000	$7,350,280	$336,897	$0
Flow Through, Pre-1981 Removal Costs	($1,175,000)	($1,175,045)	($53,858)	$0
Meetings and Meals	$542,500	$739,583	$764,583	$789,583
Transportation	$485,000	$531,667	$551,667	$571,667
ESPP Plan Discount	$254,500	$250,000	$250,000	$250,000
AFUDC Equity	$406,622	$654,367	$699,791	$742,618
TOTAL	**$7,863,622**	**$8,350,852**	**$2,549,080**	**$2,353,868**

Other Tax Inputs	Test Year	RY1	RY2	RY3
Federal Research Credit - increase from TCJA (System)	($93,260)	($93,260)	($93,260)	($93,260)
OR EDIT Amortization (Plant and non-Plant)	($3,100,000)	($3,100,000)	($3,100,000)	($3,100,000)
WA EDIT Amortization (Plant) Current	($375,000)			
WA EDIT Amortization (Plant) Proposed		($400,000)	($400,000)	($400,000)
WA EDIT Amortization Provisional Adjustment		($25,000)	$0	$0

NW Natural
Washington Rate Case
Test Year Based on Twelve Months Ended March 31, 2025
Rate Base - System & Washington

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System	March 2024 (a)	April 2024 (b)	May 2024 (c)	June 2024 (d)	July 2024 (e)	August 2024 (f)	September 2024 (g)	October 2024 (h)	November 2024 (i)	December 2024 (j)	January 2025 (k)	February 2025 (l)	March 2025 (m)	13 Month AMA (n)
Gross Plant														
Intangible - Software	300,016,205	302,785,441	303,848,294	304,120,098	312,846,919	315,676,553	335,915,875	343,757,754	343,090,358	344,320,160	344,407,028	344,362,605	353,439,515	326,821,579
Intangible - Other	84,795	84,795	84,795	84,795	84,795	84,795	84,795	84,795	84,795	84,795	84,795	84,795	84,795	84,795
Production	675,198	675,198	675,198	675,198	675,198	675,198	675,198	675,198	675,198	675,198	675,198	675,198	675,198	675,198
Transmission	258,000,793	259,432,251	261,491,196	262,087,197	264,354,637	265,532,990	269,855,535	275,126,387	275,699,048	276,065,800	276,936,573	277,308,384	280,701,741	269,436,772
Distribution	2,880,680,580	2,888,718,030	2,900,036,552	2,924,172,115	2,940,748,209	2,949,279,409	2,961,085,136	2,970,409,705	2,980,282,616	3,004,097,184	3,013,174,020	3,024,628,542	3,042,441,616	2,959,849,385
General	224,219,285	225,107,528	226,021,703	227,615,222	229,256,750	229,833,823	229,916,132	236,658,990	223,922,563	239,079,657	227,064,819	241,817,318	248,414,135	231,050,935
Storage and Storage Transmission	450,753,818	452,167,272	452,038,571	459,786,586	463,073,121	468,365,278	472,974,028	484,559,735	486,336,519	488,500,190	490,541,340	491,674,497	491,659,771	473,435,327
Land & Structures	159,378,335	160,206,109	160,225,304	160,416,869	163,407,521	163,503,520	164,067,144	167,264,095	167,479,787	170,693,715	171,021,464	171,174,647	171,261,018	165,398,321
CNG and LNG Refueling	4,021,208	4,021,208	4,021,208	4,021,884	4,021,884	4,021,884	4,021,884	4,026,517	4,187,797	4,194,090	4,194,206	4,275,379	4,275,379	4,096,353
Total Gross Plant	4,277,830,218	4,293,197,832	4,308,442,821	4,342,979,964	4,378,469,035	4,396,973,449	4,438,595,729	4,482,563,175	4,481,758,682	4,527,710,791	4,528,099,442	4,556,001,366	4,592,953,168	4,430,848,665
Reserve														
Intangible - Software	(85,206,863)	(86,788,786)	(88,349,677)	(94,956,356)	(97,021,893)	(99,712,678)	(101,872,838)	(104,260,157)	(105,594,174)	(107,716,611)	(110,362,883)	(112,922,245)	(115,632,611)	(100,831,503)
Intangible - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Production	(691,036)	(691,036)	(691,036)	(691,036)	(691,036)	(691,036)	(691,036)	(691,036)	(691,036)	(691,036)	(691,036)	(691,036)	(691,036)	(691,036)
Transmission	(50,350,941)	(50,529,002)	(50,599,735)	(50,795,276)	(51,000,126)	(51,172,545)	(51,370,960)	(51,519,349)	(51,750,052)	(52,007,717)	(52,315,226)	(52,541,336)	(52,750,557)	(51,429,339)
Distribution	(1,286,331,411)	(1,290,238,967)	(1,293,652,258)	(1,288,191,940)	(1,292,002,273)	(1,296,133,783)	(1,300,428,593)	(1,289,178,625)	(1,293,457,858)	(1,297,571,424)	(1,302,768,492)	(1,308,229,524)	(1,313,583,477)	(1,295,984,265)
General	(87,757,810)	(89,100,962)	(90,272,703)	(92,988,236)	(94,727,688)	(96,253,782)	(93,773,620)	(95,283,312)	(83,085,026)	(84,432,302)	(85,966,500)	(87,435,414)	(89,023,926)	(90,142,534)
Storage and Storage Transmission	(178,465,808)	(179,264,963)	(180,017,681)	(181,807,650)	(182,711,170)	(183,570,291)	(183,294,192)	(184,176,477)	(185,200,576)	(186,228,909)	(187,262,555)	(188,297,800)	(189,333,608)	(183,810,998)
Land & Structures	(22,060,202)	(22,261,019)	(22,468,553)	(22,990,146)	(23,273,977)	(23,533,623)	(23,794,273)	(24,062,320)	(24,332,695)	(24,606,569)	(24,884,145)	(25,161,006)	(25,437,723)	(23,759,774)
CNG and LNG Refueling	(2,594,997)	(2,602,262)	(2,609,526)	(2,616,791)	(2,624,057)	(2,631,323)	(2,638,589)	(2,645,860)	(2,653,143)	(2,660,603)	(2,668,070)	(2,675,622)	(2,683,261)	(2,638,748)
Total Reserve	(1,713,459,068)	(1,721,476,996)	(1,728,661,168)	(1,735,037,432)	(1,744,052,218)	(1,753,699,060)	(1,757,864,101)	(1,751,817,135)	(1,746,764,560)	(1,755,915,171)	(1,766,918,907)	(1,777,953,982)	(1,789,136,199)	(1,749,288,197)
Storage Gas	22,713,903	22,713,903	22,713,903	22,713,903	22,713,903	22,713,903	22,713,903	22,713,903	22,713,903	22,713,903	22,713,903	22,713,903	22,713,903	22,713,903
Customer Advances	(12,131,943)	(12,509,705)	(12,466,194)	(12,916,847)	(13,224,799)	(13,569,910)	(14,019,811)	(14,571,052)	(15,044,017)	(15,265,024)	(16,422,776)	(16,686,876)	(17,496,124)	(14,292,587)
Leasehold Improvements	25,799,923	25,657,552	25,515,179	25,379,990	25,244,800	25,109,610	24,974,421	24,839,231	24,660,948	24,513,581	24,378,391	24,243,202	24,108,012	24,955,906
Deferred Taxes	(535,878,064)	(535,878,064)	(535,878,064)	(535,878,064)	(535,878,064)	(535,878,064)	(535,878,064)	(535,878,064)	(535,878,064)	(535,878,064)	(535,878,064)	(535,878,064)	(535,878,064)	(535,878,064)
Subtotal Rate Base	2,064,874,969	2,071,704,522	2,079,666,477	2,107,241,514	2,133,272,656	2,141,649,927	2,178,522,076	2,227,850,057	2,231,446,890	2,267,880,015	2,255,971,989	2,272,439,548	2,297,264,696	2,179,059,625

NW Natural
Washington Rate Case
Test Year Based on Twelve Months Ended March 31, 2025
Rate Base - System & Washington

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Washington	March 2024	April 2024	May 2024	June 2024	July 2024	August 2024	September 2024	October 2024	November 2024	December 2024	January 2025	February 2025	March 2025	13 Month AMA
Gross Plant														
Intangible - Software	36,361,964	36,697,595	36,826,413	36,859,356	37,917,047	38,259,998	40,713,004	41,663,440	41,582,551	41,731,603	41,742,132	41,736,748	42,836,869	39,610,775
Intangible - Other	447	447	447	447	447	447	447	447	447	447	447	447	447	447
Production	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission	7,568,821	7,568,821	7,568,821	7,567,361	7,579,506	7,633,948	8,190,206	8,350,224	8,398,916	8,406,312	8,414,873	8,458,478	8,464,620	8,012,849
Distribution	373,922,534	374,784,922	375,430,680	377,643,175	378,628,744	378,334,023	379,431,861	386,538,405	387,829,977	392,408,263	393,398,551	394,192,510	395,911,148	383,628,163
General	26,300,922	26,405,113	26,512,346	26,699,266	26,891,817	26,959,507	26,969,162	27,760,099	26,266,117	28,044,044	26,634,703	28,365,171	29,138,978	27,102,275
Storage and Storage Transmission	45,966,170	46,121,792	46,107,622	46,960,678	47,322,526	47,905,192	48,412,616	49,688,202	49,883,826	50,122,046	50,346,776	50,471,537	50,469,916	48,463,405
Land & Structures	23,428,679	23,549,422	23,552,222	23,580,164	24,016,393	24,030,396	24,112,609	24,578,930	24,610,392	25,079,189	25,126,996	25,149,340	25,161,938	24,306,780
CNG and LNG Refueling	471,688	471,688	471,688	471,767	471,767	471,767	471,767	472,310	491,229	491,967	491,980	501,502	501,502	480,502
Total Gross Plant	514,021,226	515,599,800	516,470,238	519,782,213	522,828,246	523,595,279	528,301,672	539,052,057	539,063,454	546,283,870	546,156,459	548,875,733	552,485,418	531,605,195
Reserve														
Intangible - Software	(10,327,072)	(10,518,801)	(10,707,981)	(11,508,710)	(11,759,053)	(12,085,177)	(12,346,988)	(12,636,331)	(12,770,943)	(13,001,113)	(13,294,778)	(13,577,914)	(13,879,212)	(12,192,578)
Intangible - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission	474,825	480,034	494,618	504,396	508,960	516,460	521,635	528,455	534,312	537,886	537,287	543,672	551,725	518,416
Distribution	(149,577,966)	(150,031,982)	(150,561,191)	(149,374,123)	(149,999,682)	(150,511,990)	(151,116,767)	(151,757,816)	(152,186,000)	(152,852,970)	(153,499,884)	(154,170,780)	(154,833,024)	(151,522,390)
General	(10,303,752)	(10,461,483)	(10,599,208)	(10,917,969)	(11,122,179)	(11,301,395)	(11,010,656)	(11,187,951)	(9,771,011)	(9,942,934)	(10,137,604)	(10,323,611)	(10,524,662)	(10,599,184)
Storage and Storage Transmission	(18,038,865)	(18,121,603)	(18,199,228)	(18,391,055)	(18,485,283)	(18,574,623)	(18,538,976)	(18,630,867)	(18,725,378)	(18,820,247)	(18,915,580)	(19,010,986)	(19,106,467)	(18,582,208)
Land & Structures	(3,223,688)	(3,252,980)	(3,283,251)	(3,359,333)	(3,400,734)	(3,438,607)	(3,476,627)	(3,515,725)	(3,555,163)	(3,595,112)	(3,635,600)	(3,675,984)	(3,716,347)	(3,471,594)
CNG and LNG Refueling	(304,393)	(305,245)	(306,097)	(306,950)	(307,802)	(308,654)	(309,507)	(310,359)	(311,233)	(312,129)	(313,025)	(313,931)	(314,848)	(309,546)
Total Reserve	(191,300,910)	(192,212,060)	(193,162,338)	(193,353,744)	(194,565,774)	(195,703,986)	(196,277,885)	(197,510,594)	(196,785,417)	(197,986,619)	(199,259,185)	(200,529,534)	(201,822,835)	(196,159,084)
Storage Gas	2,491,715	2,491,715	2,491,715	2,491,715	2,491,715	2,491,715	2,491,715	2,491,715	2,491,715	2,491,715	2,491,715	2,491,715	2,491,715	2,491,715
Customer Advances and Deposits	(7,794,021)	(7,876,743)	(7,963,456)	(8,242,373)	(8,287,738)	(8,377,214)	(8,593,069)	(8,789,807)	(8,991,639)	(9,083,338)	(9,497,934)	(9,398,506)	(9,489,599)	(8,645,302)
Leasehold Improvements	3,044,391	3,027,591	3,010,791	2,994,839	2,978,886	2,962,934	2,946,982	2,931,029	2,909,992	2,892,603	2,876,650	2,860,698	2,844,745	2,944,797
Deferred Taxes	(49,402,676)	(49,402,676)	(49,402,676)	(49,402,676)	(49,402,676)	(49,402,676)	(49,402,676)	(49,402,676)	(49,402,676)	(49,402,676)	(49,402,676)	(49,402,676)	(49,402,676)	(49,402,676)
Subtotal Rate Base	271,059,725	271,627,628	271,444,274	274,269,974	276,042,660	275,566,052	279,466,738	288,771,725	289,285,429	295,195,555	293,365,030	294,897,430	297,106,769	282,834,645

NW Natural **Exh. KTW-3**
Test Year Based on Twelve Months Ended March 31, 2025 **Page 8**
Cost of Capital and Revenue Sensitive Calculations

Line No.		Test Year Percent of Total Capital	Average Cost [1]	Weighted Cost
		(a)	(b)	(c)
	Cost of Capital			
1	**Long Term Debt**	50.06%	4.697%	2.351%
2	**Short Term Debt**	2.06%	6.335%	0.131%
3	**Common Stock**	47.87%		
	[1] Actual cost of debt used			
4	**Total**	100.00%		6.982%
	Revenue Sensitive Costs			
5	**Gas Sales**	93.311%		
6	**Transportation**	2.091%		
7	**Other**	4.598%		
8	**Subtotal**	100.000%		
9	**O & M - Uncollectible**	0.257%		
10	**WA Utility Tax**	3.852%		
11	**WUTC Fee**	0.400%		
12	**Total Rev Sensitive Costs Incl Tax**	4.5086%		
13	**Federal Taxable Income**	95.491%		
14	**Federal Income Tax**	20.053%		
15	**Total Income Taxes**	20.053%		
16	**Total Rev Sensitive Costs Incl Tax**	24.562%		
17	**Utility Operating Income**	75.438%		
18	**Net-to-gross factor**	132.559%		
19	**Interest Coordination Factor**	2.482%		
20	**Federal tax rate**	21.000%		
21	**Uncollectible Accounts**	0.257%		

NW Natural
State Allocation Factors
As of March 31, 2025

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	System	Oregon	Washington
Customers			
Total Customers			
March 2024	800,976	703,550	97,426
March 2025	807,426	709,032	98,394
Average	804,201	706,291	97,910
% of System		87.83%	12.17%
Residential Customers			
March 2024	730,555	640,456	90,099
March 2025	736,853	645,903	90,950
Average	733,704	643,180	90,525
% of System		87.66%	12.34%
Commercial Customers			
March 2024	69,461	62,206	7,255
March 2025	69,618	62,249	7,369
Average	69,540	62,228	7,312
% of System		89.49%	10.51%
Industrial Customers			
March 2024	960	888	72
March 2025	955	880	75
Average	958	884	74
% of System		92.32%	7.68%
The Dalles			
March 2024	8,819	6,600	2,219
March 2025	8,822	6,602	2,220
Average	8,821	6,601	2,220
% of System		74.84%	25.16%

NW Natural
State Allocation Factors

Volumes - 12 Months Ended 3/31/25			
Firm Delivered (exclude Unbilled & transportation)	761,170,279	677,703,992	83,466,287
% of System		89.03%	10.97%
Sales Volumes (exclude Unbilled)	814,880,927	730,300,968	84,579,959
% of System		89.62%	10.38%
Sendout Volumes	1,179,776,478	1,077,366,868	102,409,610
% of System		91.32%	8.68%

NW Natural
State Allocation Factors
As of March 31, 2025

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3-factor formula (simple average)

Gross Plant Directly Assigned	87.84%	12.16%
Number of Employees Directly Assigned	88.94%	11.06%
Number of Customers	87.83%	12.17%
Average	88.20%	11.80%

Derivation of factor for 3-factor - Gross Plant Directly Assigned

March 31,2024	**System**	**Oregon**	**Washington**
Intangible - Other	84,795	84,348	447
Production	675,198	675,198	0
Transmission	258,000,793	250,431,972	7,568,821
Distribution	2,880,680,580	2,506,758,046	373,922,534

March 31,2025	**System**	**Oregon**	**Washington**
Intangible - Other	84,795	84,348	447
Production	675,198	675,198	0
Transmission	280,701,741	272,237,120	8,464,620
Distribution	3,042,441,616	2,646,530,468	395,911,148

Average	**System**	**Oregon**	**Washington**
Intangible - Other	84,795	84,348	447
Production	675,198	675,198	0
Transmission	269,351,267	261,334,546	8,016,721
Distribution	2,961,561,098	2,576,644,257	384,916,841
Gross Plant Directly Assigned	3,231,672,358	2,838,738,349	392,934,009
% of System		87.84%	12.16%

NW Natural **KTW-3**
Employees Allocation Factor **Page 11**
Test Year Ending March 31, 2025

3/31/2025	NBU			BU			Total			Directly Assigned	
										OR	WA
Pers. Area/Location	FT	PT	Total	FT	PT	Total	FT	PT	Total		
OR-Albany RC	3	-	3	27	-	27	30	-	30	30	
OR-Appliance Center	3	4	7	1	2	3	4	6	10		
OR-Astoria RC	2	-	2	7	-	7	9	-	9	9	
OR-Coos Bay RC	2	-	2	5	-	5	7	-	7	7	
OR-Eugene RC	5	-	5	31	-	31	36	-	36	36	
OR-Exley	4	-	4	32	-	32	36	-	36	36	
OR-Lincoln City RC	3	-	3	8	-	8	11	-	11	11	
OR-Mist/Miller Station	4	-	4	18	-	18	22	-	22		
OR-Mt Scott RC	6	-	6	41	-	41	47	-	47	47	
OR-Newport LNG	1	-	1	7	1	8	8	1	9		
OR-Headquarters	510	2	512	126	10	136	636	12	648		
OR-Parkrose RC	4	-	4	29	-	29	33	-	33	33	
OR-Portland LNG	1	-	1	6	-	6	7	-	7		
OR-Salem RC	8	-	8	58	4	62	66	4	70	70	
OR-Sherwood OTC	51	-	51	136	-	136	187	-	187	**53**	
OR-Sunset RC	4	-	4	41	-	41	45	-	45	45	
OR-The Dalles RC	2	-	2	8	-	8	10	-	10	8	**2**
OR-Work at Home	2	-	2	-	-	-	2	-	2		
WA-Clark County RC	10	-	10	33	-	33	43	-	43		43
WA-Work at Home	18	1	19	-	-	-	18	1	19		1
AZ-Work at Home	3	-	3	-	-	-	3	-	3		
GA-Work at Home	1	-	1	-	-	-	1	-	1		
ID-Work at Home	2	-	2	-	-	-	2	-	2		
IL-Work at Home	1	-	1	-	-	-	1	-	1		
NV-Work at Home	1	-	1	-	-	-	1	-	1		
TX-Work at Home	1	-	1	-	-	-	1	-	1		
Total	652	7	659	614	17	631	1,266	24	1,290	385	46
										89.33%	10.67%

12/31/2024	NBU			BU			Total			OR	WA
Pers. Area/Location	FT	PT	Total	FT	PT	Total	FT	PT	Total		
OR-Albany RC	3	-	3	26	-	26	29	-	29	29	
OR-Appliance Center	3	4	7	1	2	3	4	6	10		
OR-Astoria RC	2	-	2	8	-	8	10	-	10	10	
OR-Coos Bay RC	2	-	2	4	-	4	6	-	6	6	
OR-Eugene RC	5	-	5	28	-	28	33	-	33	33	
OR-Exley	4	-	4	30	-	30	34	-	34	34	
OR-Lincoln City RC	3	-	3	8	-	8	11	-	11	11	
OR-Mist/Miller Station	4	-	4	18	-	18	22	-	22		
OR-Mt Scott RC	6	-	6	40	-	40	46	-	46	46	
OR-Newport LNG	1	-	1	7	1	8	8	1	9		
OR-Headquarters	504	2	506	129	11	140	633	13	646		
OR-Parkrose RC	3	-	3	29	-	29	32	-	32	32	
OR-Portland LNG	1	-	1	6	-	6	7	-	7		
OR-Salem RC	8	-	8	59	4	63	67	4	71	71	
OR-Sherwood OTC	51	-	51	133	-	133	184	-	184	**53**	
OR-Sunset RC	4	-	4	40	-	40	44	-	44	44	
OR-The Dalles RC	2	-	2	8	-	8	10	-	10	8	**2**
OR-Work at Home	2	-	2	-	-	-	2	-	2		
WA-Clark County RC	10	-	10	34	-	34	44	-	44		44
WA-Work at Home	18	1	19	-	-	-	18	1	19		
AZ-Work at Home	3	-	3	-	-	-	3	-	3		
ID-Work at Home	2	-	2	-	-	-	2	-	2		
TX-Work at Home	1	-	1	-	-	-	1	-	1		
Total	642	7	649	608	18	626	1,250	25	1,275	377	46
										89.13%	10.87%

NW Natural **KTW-3**
Employees Allocation Factor **Page 12**
Test Year Ending March 31, 2025

9/30/2024	NBU			BU			Total				OR	WA
Pers. Area/Location	FT	PT	Total	FT	PT	Total	FT	PT	Total			
OR-Albany RC	3	-	3	27	-	27	30	-	30		30	
OR-Appliance Center	3	4	7	1	2	3	4	6	10	x		
OR-Astoria RC	2	-	2	8	-	8	10	-	10		10	
OR-Coos Bay RC	2	-	2	4	-	4	6	-	6		6	
OR-Eugene RC	5	-	5	28	-	28	33	-	33		33	
OR-Exley	6	-	6	32	-	32	38	-	38		38	
OR-Lincoln City RC	3	-	3	8	-	8	11	-	11		11	
OR-Mist/Miller Station	4	-	4	18	-	18	22	-	22	x		
OR-Mt Scott RC	6	-	6	38	-	38	44	-	44		44	
OR-Newport LNG	1	-	1	7	1	8	8	1	9	x		
OR-Headquarters	494	2	496	134	7	141	628	9	637	x		
OR-Parkrose RC	3	-	3	29	-	29	32	-	32		32	
OR-Portland LNG	1	-	1	6	-	6	7	-	7	x		
OR-Salem RC	8	-	8	61	4	65	69	4	73		73	
OR-Sherwood OTC	51	-	51	130	-	130	181	-	181		**53**	
OR-Sunset RC	3	-	3	41	-	41	44	-	44		44	
OR-The Dalles RC	2	-	2	8	-	8	10	-	10		8	**2**
OR-Work at Home	2	-	2	-	-	-	2	-	2			
WA-Clark County RC	10	-	10	35	-	35	45	-	45			45
WA-Work at Home	19	1	20	-	-	-	19	1	20			
AZ-Work at Home	3	0	3	-	0	0	3	0	3			
ID-Work at Home	2	-	2	-	-	-	2	-	2			
Total	633	7	640	615	14	629	1,248	21	1,269		382	47
											89.04%	10.96%

12/31/2023	NBU			BU			Total				OR	WA
Pers. Area/Location	FT	PT	Total	FT	PT	Total	FT	PT	Total			
OR-Albany RC	3	-	3	26	-	26	29	-	29		29	
OR-Appliance Center	3	4	7	2	2	4	5	6	11	x		
OR-Astoria RC	2	-	2	8	-	8	10	-	10		10	
OR-Coos Bay RC	2	-	2	5	-	5	7	-	7		7	
OR-Eugene RC	5	-	5	28	-	28	33	-	33		33	
OR-Exley	6	-	6	26	-	26	32	-	32		32	
OR-Lincoln City RC	3	-	3	8	-	8	11	-	11		11	
OR-Mist/Miller Station	2	-	2	18	-	18	20	-	20	x		
OR-Mt Scott RC	6	-	6	33	-	33	39	-	39		39	
OR-Newport LNG	1	-	1	7	1	8	8	1	9	x		
OR-Headquarters	464	2	466	133	11	144	597	13	610	x		
OR-Parkrose RC	3	-	3	32	-	32	35	-	35		35	
OR-Portland LNG	1	-	1	6	-	6	7	-	7	x		
OR-Salem RC	8	-	8	58	1	59	66	1	67		67	
OR-Sherwood OTC	47	-	47	126	-	126	173	-	173		**53**	
OR-Sunset RC	3	-	3	37	-	37	40	-	40		40	
OR-The Dalles RC	2	-	2	8	-	8	10	-	10		8	**2**
WA-Clark County RC	7	-	7	38	-	38	45	-	45			45
WA-Work at Home	23	-	23	-	-	-	23	-	23			
AZ-Work at Home	1	0	1	-	0	0	1	0	1			
ID-Work at Home	2	-	2	-	-	-	2	-	2			
Total	594	6	600	599	15	614	1,193	21	1,214		364	47
											88.6%	11.4%

9/30/2023	NBU			BU			Total				OR	WA
Pers. Area/Location	FT	PT	Total	FT	PT	Total	FT	PT	Total			
OR-Albany RC	3	-	3	26	-	26	29	-	29		29	
OR-Appliance Center	3	4	7	1	2	3	4	6	10	x		
OR-Astoria RC	2	-	2	8	-	8	10	-	10		10	
OR-Coos Bay RC	2	-	2	5	-	5	7	-	7		7	
OR-Eugene RC	5	-	5	28	-	28	33	-	33		33	
OR-Exley	6	-	6	27	-	27	33	-	33		33	
OR-Lincoln City RC	3	-	3	8	-	8	11	-	11		11	
OR-Mist/Miller Station	2	-	2	18	-	18	20	-	20	x		
OR-Mt Scott RC	5	-	5	33	-	33	38	-	38		38	
OR-Newport LNG	1	-	1	6	1	7	7	1	8	x		
OR-Headquarters	476	1	477	130	7	137	606	8	614	x		
OR-Parkrose RC	3	-	3	30	-	30	33	-	33		33	
OR-Portland LNG	1	-	1	5	-	5	6	-	6	x		
OR-Salem RC	8	-	8	57	-	57	65	-	65		65	
OR-Sherwood OTC	44	-	44	132	-	132	176	-	176		**53**	
OR-Sunset RC	2	-	2	37	-	37	39	-	39		39	
OR-The Dalles RC	2	-	2	8	-	8	10	-	10		8	**2**
WA-Clark County RC	6	-	6	38	-	38	44	-	44			44
WA-Work at Home	23	-	23	-	-	-	23	-	23			
AZ-Work at Home	1	0	1	0	0	0	1	0	1			
Total	574	5	603	597	10	607	1,171	15	1,210		359	46
											88.6%	11.4%

Summary		OR	WA
March	2025	89.33%	10.67%
December	2024	89.13%	10.87%
September	2024	89.04%	10.96%
December	2023	88.56%	11.44%
September	2023	88.64%	11.36%
	2-Yr Avg	**88.94%**	**11.06%**

NW Natural **KTW-3**
Transmission Factor **Page 13**
Test Year Ending March 31, 2025

				Miles	
1	Oregon	Direct		649.80	
2		less WA SMPE		(4.63)	
3		Net for Factor		645.17	
4			-		
5	Washington	Direct		3.50	
6		SMPE		4.63	
7		Net for Factor		8.13	
8					
9	Total	Direct		653.30	
10		SMPE		-	
11		Net for Factor		653.30	
12					
13					Allocation Factor
14	Oregon			645.17	98.76%
15	Washington			8.13	1.24%
16				653.30	
17					
18				Gross Plant	Miles
19	367.24			17,466,182	11.70
20	367.25			18,613,651	12.00
21	367.26			68,232,676	38.00
22				104,312,509	61.70
23	Oregon Direct			33,000,000	
24	Oregon Direct % of Total			32%	
25	Oregon Direct Miles				19.52
26	Non-Direct Miles				42.18
27	Firm Volumes Factor				10.97%
28	Washington allocation of SMPE				4.63

NW Natural
Telemetering Allocation Factor
Test Year Ending March 31, 2025

AS@PRM	AS@P#	UMACT	UMLNM	UPSTC	UMSTS
17703502000	DART	463236	Customer 1	WA	AC
17703502000	DART	463236	Customer 2	WA	AC
23702009000	DART	563804	Customer 3	WA	AC
23702012000	DART	563806	Customer 4	WA	AC
23711064000	DART	563809	Customer 5	WA	AC
23720046000	DART	563813	Customer 6	WA	AC
23750798000	DART	563820	Customer 7	WA	AC
23031449000	DART	562220	Customer 8	OR	AC
23032521000	DART	562221	Customer 9	OR	AC
23051912000	DART	562222	Customer 10	OR	AC
23110511000	DART	562248	Customer 11	OR	AC
23141698000	DART	562256	Customer 12	OR	AC
23142451000	DART	562259	Customer 13	OR	AC
23150073000	DART	562263	Customer 14	OR	AC
23231138000	DART	3623700	Customer 15	OR	AC
23231455000	DART	562293	Customer 16	OR	AC
23232144000	DART	562303	Customer 17	OR	AC
23232695000	DART	562305	Customer 18	OR	AC
23232906000	DART	562308	Customer 19	OR	AC
23233301000	DART	562310	Customer 20	OR	AC
23233500000	DART	562313	Customer 21	OR	AC
23241770000	DART	2798342	Customer 22	OR	AC
23242066000	DART	562320	Customer 23	OR	AC
23244068000	DART	907289	Customer 24	OR	AC
23260920000	DART	4482316	Customer 25	OR	AC
23261000000	DART	1375593	Customer 26	OR	AC
23272198000	DART	562355	Customer 27	OR	AC
23284210000	DART	1658293	Customer 28	OR	AC
23310990000	DART	560485	Customer 29	OR	AC
23331234000	DART	560513	Customer 30	OR	AC
23340001999	DART	4381029	Customer 31	OR	AC
23341253000	DART	560525	Customer 32	OR	AC
23370008007	DART	560538	Customer 33	OR	AC
23370008007	DART	560538	Customer 34	OR	AC
23410380000	DART	561738	Customer 35	OR	AC
23471600999	DART	561765	Customer 36	OR	AC
23550500000	DART	512042	Customer 37	OR	AC
23605000000	DART	537105	Customer 38	OR	AC
23802030000	DART	3201885	Customer 39	OR	AC
23802487000	DART	1503861	Customer 40	OR	AC
23855000000	DART	2132319	Customer 41	OR	AC
23858669000	DART	565443	Customer 42	OR	AC
23861601000	DART	2053398	Customer 43	OR	AC
23862172000	DART	565456	Customer 44	OR	AC
25027111000	DART	792806	Customer 45	OR	AC
26429370000	DART	1481669	Customer 46	OR	AC
26429373000	DART	1481691	Customer 47	OR	AC
26429380000	DART	1481706	Customer 48	OR	AC
26429660000	DART	1484061	Customer 49	OR	AC
26429689000	DART	1484277	Customer 50	OR	AC
26429692000	DART	1484283	Customer 51	OR	AC
26482119000	DART	1782023	Customer 52	OR	AC
26483027000	DART	1985861	Customer 53	OR	AC

Oregon Telemetering Factor	**86.792%**
Washington Telemetering Factor	**13.208%**
OR Counts	**46**
WA Counts	**7**

NW Natural **KTW-3**
Perimeter Allocation Factor **Page 15**
As of March 31, 2025

FTEs	**Total**	**Oregon**	**Washington**
Astoria	9	9	0
Coos Bay	7	7	0
Lincoln	11	11	0
The Dalles	10	7.5	2.5
	37	**34.5**	**2.5**
		93.243%	**6.757%**

NW Natural **KTW-3**
Environmental Admin Allocation **Page 16**

Washington [1][2]	Oregon
3.320%	96.680%

[1] State allocation determined in UG-181053, per Order No. 06
[2] The Environmental Cost Recovery Mechanism is allocated via the Environmental Admin Allocation, however it does not impact revenue requirements.

NW Natural
Payroll Cost Allocation Factor
Test Year Ending March 31, 2025

$ 150,892,151.35

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						Fiscal Year Period	Amount				Payroll Cost Factor	11.1183%	88.8817%	100.0000%
						Measures	Overall Result				TOTAL	$ 16,776,640.43	$ 134,115,510.92	$ 150,892,151.35
FERC Account	Cost Center	Cost Center Description	GL Account	GL Account Long Name	Chart of Accounts	Ledger	$	SORTER	ALLOCATION FACTOR	ALLOCATION METHOD		WA	OR	SYSTEM
820000	10147	PORTLAND LNG-MEASUR	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	7,806.32	82010147	10.97%	Firm Sales Volumes	$	856.35	$ 6,949.97	$ 7,806.32
820000	10147	PORTLAND LNG-MEASUR	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	165,067.34	82010147	10.97%	Firm Sales Volumes	$	18,107.89	$ 146,959.45	$ 165,067.34
820000	10147	PORTLAND LNG-MEASUR	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	7,945.14	82010147	10.97%	Firm Sales Volumes	$	871.58	$ 7,073.56	$ 7,945.14
820000	10147	PORTLAND LNG-MEASUR	600307	ON CALL ASSIGN. PAY	NWN	F1	11,009.88	82010147	10.97%	Firm Sales Volumes	$	1,207.78	$ 9,802.10	$ 11,009.88
820000	10147	PORTLAND LNG-MEASUR	600500	SALARY BONUS PAYROLL	NWN	F1	0.00	82010147	10.97%	Firm Sales Volumes	$	-	$ -	$ -
820000	10147	PORTLAND LNG-MEASUR	600900	VACATION, SICK & HOL	NWN	F1	27,835.61	82010147	10.97%	Firm Sales Volumes	$	3,053.57	$ 24,782.04	$ 27,835.61
820000	10219	MIST UGS-MEASURE & R	600100	SALARY PAYROLL	NWN	F1	491,962.65	82010219	10.97%	Firm Sales Volumes	$	53,968.30	$ 437,994.35	$ 491,962.65
820000	10219	MIST UGS-MEASURE & R	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	121,378.62	82010219	10.97%	Firm Sales Volumes	$	13,315.23	$ 108,063.39	$ 121,378.62
820000	10219	MIST UGS-MEASURE & R	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	1,291,220.27	82010219	10.97%	Firm Sales Volumes	$	141,646.86	$ 1,149,573.41	$ 1,291,220.27
820000	10219	MIST UGS-MEASURE & R	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	271,340.91	82010219	10.97%	Firm Sales Volumes	$	29,766.10	$ 241,574.81	$ 271,340.91
820000	10219	MIST UGS-MEASURE & R	600307	ON CALL ASSIGN. PAY	NWN	F1	60,100.34	82010219	10.97%	Firm Sales Volumes	$	6,593.01	$ 53,507.33	$ 60,100.34
820000	10219	MIST UGS-MEASURE & R	600500	SALARY BONUS PAYROLL	NWN	F1	0.00	82010219	10.97%	Firm Sales Volumes	$	-	$ -	$ -
820000	10219	MIST UGS-MEASURE & R	600900	VACATION, SICK & HOL	NWN	F1	192,452.14	82010219	10.97%	Firm Sales Volumes	$	21,112.00	$ 171,340.14	$ 192,452.14
832000	10220	MIST UGS - RESERVOIR	600100	SALARY PAYROLL	NWN	F1	219,727.61	83210220	10.97%	Firm Sales Volumes	$	24,104.12	$ 195,623.49	$ 219,727.61
832000	10220	MIST UGS - RESERVOIR	600500	SALARY BONUS PAYROLL	NWN	F1	42,944.76	83210220	10.97%	Firm Sales Volumes	$	4,711.04	$ 38,233.72	$ 42,944.76
840000	10078	GAS CONTROL-GAS STOR	600100	SALARY PAYROLL	NWN	F1	168,851.16	84010078	10.97%	Firm Sales Volumes	$	18,522.97	$ 150,328.19	$ 168,851.16
840000	10078	GAS CONTROL-GAS STOR	600500	SALARY BONUS PAYROLL	NWN	F1	118.49	84010078	10.97%	Firm Sales Volumes	$	13.00	$ 105.49	$ 118.49
844200	10121	NEWPORT LNG - LNG OP	600100	SALARY PAYROLL	NWN	F1	133,272.70	84410121	10.97%	Firm Sales Volumes	$	14,620.02	$ 118,652.68	$ 133,272.70
844200	10121	NEWPORT LNG - LNG OP	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	98,836.09	84410121	10.97%	Firm Sales Volumes	$	10,842.32	$ 87,993.77	$ 98,836.09
844200	10121	NEWPORT LNG - LNG OP	600304	HIGH PAY	NWN	F1	22.96	84410121	10.97%	Firm Sales Volumes	$	2.52	$ 20.44	$ 22.96
844200	10121	NEWPORT LNG - LNG OP	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	543,080.31	84410121	10.97%	Firm Sales Volumes	$	59,575.91	$ 483,504.40	$ 543,080.31
844200	10121	NEWPORT LNG - LNG OP	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	263,509.20	84410121	10.97%	Firm Sales Volumes	$	28,906.96	$ 234,602.24	$ 263,509.20
844200	10121	NEWPORT LNG - LNG OP	600400	P/T HOURLY PAYROLL	NWN	F1	48,494.24	84410121	10.97%	Firm Sales Volumes	$	5,319.82	$ 43,174.42	$ 48,494.24
844200	10121	NEWPORT LNG - LNG OP	600900	VACATION, SICK & HOL	NWN	F1	102,506.13	84410121	10.97%	Firm Sales Volumes	$	11,244.92	$ 91,261.21	$ 102,506.13
844200	10149	PORTLAND LNG - LNG O	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	66,970.19	84410149	10.97%	Firm Sales Volumes	$	7,346.63	$ 59,623.56	$ 66,970.19
844200	10149	PORTLAND LNG - LNG O	600900	VACATION, SICK & HOL	NWN	F1	11,344.87	84410149	10.97%	Firm Sales Volumes	$	1,244.53	$ 10,100.34	$ 11,344.87
847300	10151	PORTLAND LNG - LNG M	600100	SALARY PAYROLL	NWN	F1	145,228.67	84710151	10.97%	Firm Sales Volumes	$	15,931.59	$ 129,297.08	$ 145,228.67
847300	10151	PORTLAND LNG - LNG M	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	16,636.03	84710151	10.97%	Firm Sales Volumes	$	1,824.97	$ 14,811.06	$ 16,636.03
847300	10151	PORTLAND LNG - LNG M	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	265,142.26	84710151	10.97%	Firm Sales Volumes	$	29,086.11	$ 236,056.15	$ 265,142.26
847300	10151	PORTLAND LNG - LNG M	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	9,667.83	84710151	10.97%	Firm Sales Volumes	$	1,060.56	$ 8,607.27	$ 9,667.83
847300	10151	PORTLAND LNG - LNG M	600307	ON CALL ASSIGN. PAY	NWN	F1	29,059.78	84710151	10.97%	Firm Sales Volumes	$	3,187.86	$ 25,871.92	$ 29,059.78
847300	10151	PORTLAND LNG - LNG M	600500	SALARY BONUS PAYROLL	NWN	F1	0.00	84710151	10.97%	Firm Sales Volumes	$	-	$ -	$ -
847300	10151	PORTLAND LNG - LNG M	600900	VACATION, SICK & HOL	NWN	F1	46,887.01	84710151	10.97%	Firm Sales Volumes	$	5,143.50	$ 41,743.51	$ 46,887.01
856000	10360	TRANSMISSION-TRNSMSI	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	41,505.03	85610360	1.24%	Transmission	$	516.33	$ 40,988.70	$ 41,505.03
856000	10360	TRANSMISSION-TRNSMSI	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	1,103,865.35	85610360	1.24%	Transmission	$	13,732.39	$ 1,090,132.96	$ 1,103,865.35
856000	10360	TRANSMISSION-TRNSMSI	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	246,338.64	85610360	1.24%	Transmission	$	3,064.52	$ 243,274.12	$ 246,338.64
856000	10360	TRANSMISSION-TRNSMSI	600307	ON CALL ASSIGN. PAY	NWN	F1	0.00	85610360	1.24%	Transmission	$	-	$ -	$ -
856000	10360	TRANSMISSION-TRNSMSI	600900	VACATION, SICK & HOL	NWN	F1	192,734.67	85610360	1.24%	Transmission	$	2,397.67	$ 190,337.00	$ 192,734.67
870000	10004	SYS OPS-TRNSMSN MAIN	600100	SALARY PAYROLL	NWN	F1	132,320.24	87010004	1.24%	transmission	$	1,646.10	$ 130,674.14	$ 132,320.24
870000	10074	GAS ACQ & PIPE SVCE-	600100	SALARY PAYROLL	NWN	F1	828,514.65	87010074	8.68%	Sendout Volumes	$	71,915.07	$ 756,599.58	$ 828,514.65
870000	10074	GAS ACQ & PIPE SVCE-	600500	SALARY BONUS PAYROLL	NWN	F1	3,681.71	87010074	8.68%	Sendout Volumes	$	319.57	$ 3,362.14	$ 3,681.71
870000	10081	GAS CONTROL-TRNSMSN	600100	SALARY PAYROLL	NWN	F1	1,428,883.46	87010081	8.68%	Sendout Volumes	$	124,027.08	$ 1,304,856.38	$ 1,428,883.46
870000	10081	GAS CONTROL-TRNSMSN	600500	SALARY BONUS PAYROLL	NWN	F1	0.00	87010081	8.68%	Sendout Volumes	$	-	$ -	$ -
874000	10295	CFS-MAINS & SERV-EME	600100	SALARY PAYROLL	NWN	F1	748,449.16	87410295	12.17%	Customers-All	$	91,086.26	$ 657,362.90	$ 748,449.16
874000	10295	CFS-MAINS & SERV-EME	600106	SALARY OVERTIME	NWN	F1	22,450.00	87410295	12.17%	Customers-All	$	2,732.17	$ 19,717.84	$ 22,450.00
874000	10295	CFS-MAINS & SERV-EME	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	33,772.68	87410295	12.17%	Customers-All	$	4,110.14	$ 29,662.54	$ 33,772.68
874000	10295	CFS-MAINS & SERV-EME	600500	SALARY BONUS PAYROLL	NWN	F1	1,088.49	87410295	12.17%	Customers-All	$	132.47	$ 956.02	$ 1,088.49
874000	10365	TRANSMISSION-MAINS &	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	58,399.41	87410365	1.24%	Transmission	$	726.50	$ 57,672.91	$ 58,399.41
874000	10365	TRANSMISSION-MAINS &	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	1,820,979.70	87410365	1.24%	Transmission	$	22,653.48	$ 1,798,326.22	$ 1,820,979.70
874000	10365	TRANSMISSION-MAINS &	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	597,459.76	87410365	1.24%	Transmission	$	7,432.56	$ 590,027.20	$ 597,459.76
874000	10365	TRANSMISSION-MAINS &	600307	ON CALL ASSIGN. PAY	NWN	F1	7,259.55	87410365	1.24%	Transmission	$	90.31	$ 7,169.24	$ 7,259.55
874000	10365	TRANSMISSION-MAINS &	600900	VACATION, SICK & HOL	NWN	F1	311,364.92	87410365	1.24%	Transmission	$	3,873.46	$ 307,491.46	$ 311,364.92
874000	10417	ENGINER SVCES OR-MAI	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	990.56	87410417	0.00%	Direct-OR	$	-	$ 990.56	$ 990.56
874000	10417	ENGINER SVCES OR-MAI	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	333,409.57	87410417	0.00%	Direct-OR	$	-	$ 333,409.57	$ 333,409.57
874000	10417	ENGINER SVCES OR-MAI	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	15,099.98	87410417	0.00%	Direct-OR	$	-	$ 15,099.98	$ 15,099.98
874000	10417	ENGINER SVCES OR-MAI	600900	VACATION, SICK & HOL	NWN	F1	58,790.65	87410417	0.00%	Direct-OR	$	-	$ 58,790.65	$ 58,790.65
874000	10421	ENGINER SVCES OR-MAI	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	1,027.14	87410421	0.00%	Direct-OR	$	-	$ 1,027.14	$ 1,027.14
874000	10421	ENGINER SVCES OR-MAI	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	412,612.97	87410421	0.00%	Direct-OR	$	-	$ 412,612.97	$ 412,612.97
874000	10421	ENGINER SVCES OR-MAI	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	65,390.53	87410421	0.00%	Direct-OR	$	-	$ 65,390.53	$ 65,390.53
874000	10421	ENGINER SVCES OR-MAI	600900	VACATION, SICK & HOL	NWN	F1	73,065.95	87410421	0.00%	Direct-OR	$	-	$ 73,065.95	$ 73,065.95
874000	10480	DISTRIBUTION-MAINS &	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	5,857.02	87410480	12.17%	Customers-All	$	712.80	$ 5,144.22	$ 5,857.02
874000	10480	DISTRIBUTION-MAINS &	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	174,589.77	87410480	12.17%	Customers-All	$	21,247.58	$ 153,342.19	$ 174,589.77
874000	10480	DISTRIBUTION-MAINS &	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	2,875.48	87410480	12.17%	Customers-All	$	349.95	$ 2,525.53	$ 2,875.48
874000	10480	DISTRIBUTION-MAINS &	600307	ON CALL ASSIGN. PAY	NWN	F1	4,165.73	87410480	12.17%	Customers-All	$	506.97	$ 3,658.76	$ 4,165.73
874000	10480	DISTRIBUTION-MAINS &	600900	VACATION, SICK & HOL	NWN	F1	29,854.07	87410480	12.17%	Customers-All	$	3,633.24	$ 26,220.83	$ 29,854.07
874000	10485	DISTRIBUTION-MAINS &	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	852,795.30	87410485	12.17%	Customers-All	$	103,785.19	$ 749,010.11	$ 852,795.30
874000	10485	DISTRIBUTION-MAINS &	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	10,852,791.00	87410485	12.17%	Customers-All	$	1,320,784.66	$ 9,532,006.34	$ 10,852,791.00
874000	10485	DISTRIBUTION-MAINS &	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	1,336,551.17	87410485	12.17%	Customers-All	$	162,658.28	$ 1,173,892.89	$ 1,336,551.17
874000	10485	DISTRIBUTION-MAINS &	600307	ON CALL ASSIGN. PAY	NWN	F1	719,711.67	87410485	12.17%	Customers-All	$	87,588.91	$ 632,122.76	$ 719,711.67
874000	10485	DISTRIBUTION-MAINS &	600500	SALARY BONUS PAYROLL	NWN	F1	0.00	87410485	12.17%	Customers-All	$	-	$ -	$ -
874000	10485	DISTRIBUTION-MAINS &	600900	VACATION, SICK & HOL	NWN	F1	2,004,665.27	87410485	12.17%	Customers-All	$	243,967.76	$ 1,760,697.51	$ 2,004,665.27
874000	10552	CONTRACT SERVICES-MA	600100	SALARY PAYROLL	NWN	F1	131,651.13	87410552	12.17%	Customers-All	$	16,021.94	$ 115,629.19	$ 131,651.13
874000	10554	CONTRACT SERVICES-MA	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	6,024.62	87410554	12.17%	Customers-All	$	733.20	$ 5,291.42	$ 6,024.62
874000	10554	CONTRACT SERVICES-MA	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	134,268.62	87410554	12.17%	Customers-All	$	16,340.49	$ 117,928.13	$ 134,268.62
874000	10554	CONTRACT SERVICES-MA	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	31,998.52	87410554	12.17%	Customers-All	$	3,894.22	$ 28,104.30	$ 31,998.52
874000	10554	CONTRACT SERVICES-MA	600307	ON CALL ASSIGN. PAY	NWN	F1	430.11	87410554	12.17%	Customers-All	$	52.34	$ 377.77	$ 430.11
874000	10554	CONTRACT SERVICES-MA	600900	VACATION, SICK & HOL	NWN	F1	25,373.85	87410554	12.17%	Customers-All	$	3,088.00	$ 22,285.85	$ 25,373.85
874000	10562	OPS TECH SVCES-MAINS	600100	SALARY PAYROLL	NWN	F1	138,120.73	87410562	12.17%	Customers-All	$	16,809.29	$ 121,311.44	$ 138,120.73
874000	10562	OPS TECH SVCES-MAINS	600500	SALARY BONUS PAYROLL	NWN	F1	62.20	87410562	12.17%	Customers-All	$	7.57	$ 54.63	$ 62.20
874000	10573	COMPLIANCE SERV-MAIN	600100	SALARY PAYROLL	NWN	F1	129,428.47	87410573	12.17%	Customers-All	$	15,751.44	$ 113,677.03	$ 129,428.47
874000	10573	COMPLIANCE SERV-MAIN	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	14,525.53	87410573	12.17%	Customers-All	$	1,767.76	$ 12,757.77	$ 14,525.53
874000	10573	COMPLIANCE SERV-MAIN	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	780,841.33	87410573	12.17%	Customers-All	$	95,028.39	$ 685,812.94	$ 780,841.33
874000	10573	COMPLIANCE SERV-MAIN	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	61,449.31	87410573	12.17%	Customers-All	$	7,478.38	$ 53,970.93	$ 61,449.31
874000	10573	COMPLIANCE SERV-MAIN	600307	ON CALL ASSIGN. PAY	NWN	F1	8,336.88	87410573	12.17%	Customers-All	$	1,014.60	$ 7,322.28	$ 8,336.88
874000	10573	COMPLIANCE SERV-MAIN	600500	SALARY BONUS PAYROLL	NWN	F1	124.40	87410573	12.17%	Customers-All	$	15.14	$ 109.26	$ 124.40
874000	10573	COMPLIANCE SERV-MAIN	600900	VACATION, SICK & HOL	NWN	F1	143,910.13	87410573	12.17%	Customers-All	$	17,513.86	$ 126,396.27	$ 143,910.13
874000	11125	CONTRACT SERVICES-MA	600100	SALARY PAYROLL	NWN	F1	103,364.65	87411125	12.17%	Customers-All	$	12,579.48	$ 90,785.17	$ 103,364.65
875000	10009	SYS OPS-DISTRB MSRE&	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	71,118.83	87510009	8.68%	Sendout Volumes	$	6,173.11	$ 64,945.72	$ 71,118.83
875000	10009	SYS OPS-DISTRB MSRE&	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	1,710,744.72	87510009	8.68%	Sendout Volumes	$	148,492.64	$ 1,562,252.08	$ 1,710,744.72
875000	10009	SYS OPS-DISTRB MSRE&	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	262,047.24	87510009	8.68%	Sendout Volumes	$	22,745.70	$ 239,301.54	$ 262,047.24
875000	10009	SYS OPS-DISTRB MSRE&	600307	ON CALL ASSIGN. PAY	NWN	F1	14,711.98	87510009	8.68%	Sendout Volumes	$	1,277.00	$ 13,434.98	$ 14,711.98
875000	10009	SYS OPS-DISTRB MSRE&	600900	VACATION, SICK & HOL	NWN	F1	300,112.35	87510009	8.68%	Sendout Volumes	$	26,049.75	$ 274,062.60	$ 300,112.35
878000	10248	GENERAL MAINT-DISTRB	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	408,263.51	87810248	12.17%	Customers-All	$	49,685.67	$ 358,577.84	$ 408,263.51
878000	10248	GENERAL MAINT-DISTRB	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	30,624.88	87810248	12.17%	Customers-All	$	3,727.05	$ 26,897.83	$ 30,624.88

NW Natural
Payroll Cost Allocation Factor
Test Year Ending March 31, 2025

$ 150,892,151.35

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						Fiscal Year Period	Amount						
						Measures	Overall Result						
FERC Account	Cost Center	Cost Center Description	GL Account	GL Account Long Name	Chart of Accounts	Ledger	$	SORTER	ALLOCATION FACTOR	ALLOCATION METHOD	WA	OR	SYSTEM
								Payroll Cost Factor			11.1183%	88.8817%	100.0000%
								TOTAL			$ 16,776,640.43	$ 134,115,510.92	$ 150,892,151.35
878000	10248	GENERAL MAINT-DISTRB	600900	VACATION, SICK & HOL	NWN	F1	72,488.19	87810248	12.17%	Customers-All	$ 8,821.81	$ 63,666.38	$ 72,488.19
878000	10303	CFS-DISTR MTR&HOU RG	600300	HOURLY PAYROLL	NWN	F1	(1,592,380.82)	87810303	12.17%	Customers-All	$ (193,792.75)	$ (1,398,588.07)	$ (1,592,380.82)
878000	10304	CFS-DISTR MTR&HOU RG	600100	SALARY PAYROLL	NWN	F1	1,837,791.09	87810304	12.17%	Customers-All	$ 223,659.18	$ 1,614,131.91	$ 1,837,791.09
878000	10304	CFS-DISTR MTR&HOU RG	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	9.98	87810304	12.17%	Customers-All	$ 1.21	$ 8.77	$ 9.98
878000	10304	CFS-DISTR MTR&HOU RG	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	385,590.64	87810304	12.17%	Customers-All	$ 46,926.38	$ 338,664.26	$ 385,590.64
878000	10304	CFS-DISTR MTR&HOU RG	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	3,567.39	87810304	12.17%	Customers-All	$ 434.15	$ 3,133.24	$ 3,567.39
878000	10304	CFS-DISTR MTR&HOU RG	600500	SALARY BONUS PAYROLL	NWN	F1	1,979.88	87810304	12.17%	Customers-All	$ 240.95	$ 1,738.93	$ 1,979.88
878000	10304	CFS-DISTR MTR&HOU RG	600900	VACATION, SICK & HOL	NWN	F1	63,453.81	87810304	12.17%	Customers-All	$ 7,722.33	$ 55,731.48	$ 63,453.81
879000	10086	FIELD SERV-CUSTOMER	600100	SALARY PAYROLL	NWN	F1	139,813.04	87910086	12.17%	Customers-All	$ 17,015.25	$ 122,797.79	$ 139,813.04
879000	10086	FIELD SERV-CUSTOMER	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	5,630.12	87910086	12.17%	Customers-All	$ 685.19	$ 4,944.93	$ 5,630.12
879000	10086	FIELD SERV-CUSTOMER	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	365,662.80	87910086	12.17%	Customers-All	$ 44,501.16	$ 321,161.64	$ 365,662.80
879000	10086	FIELD SERV-CUSTOMER	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	34,095.45	87910086	12.17%	Customers-All	$ 4,149.42	$ 29,946.03	$ 34,095.45
879000	10086	FIELD SERV-CUSTOMER	600500	SALARY BONUS PAYROLL	NWN	F1	77.76	87910086	12.17%	Customers-All	$ 9.46	$ 68.30	$ 77.76
879000	10086	FIELD SERV-CUSTOMER	600900	VACATION, SICK & HOL	NWN	F1	66,357.62	87910086	12.17%	Customers-All	$ 8,075.72	$ 58,281.90	$ 66,357.62
879000	10305	CFS-CUST INSTALL-OFF	600100	SALARY PAYROLL	NWN	F1	672,093.30	87910305	12.17%	Customers-All	$ 81,793.75	$ 590,299.55	$ 672,093.30
879000	10305	CFS-CUST INSTALL-OFF	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	7,893.85	87910305	12.17%	Customers-All	$ 960.68	$ 6,933.17	$ 7,893.85
879000	10305	CFS-CUST INSTALL-OFF	600500	SALARY BONUS PAYROLL	NWN	F1	4,262.09	87910305	12.17%	Customers-All	$ 518.70	$ 3,743.39	$ 4,262.09
879000	10305	CFS-CUST INSTALL-OFF	600900	VACATION, SICK & HOL	NWN	F1	1,140.50	87910305	12.17%	Customers-All	$ 138.80	$ 1,001.70	$ 1,140.50
879000	10306	CFS-CUST INSTALL-SER	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	844,787.93	87910306	12.17%	Customers-All	$ 102,810.69	$ 741,977.24	$ 844,787.93
879000	10306	CFS-CUST INSTALL-SER	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	10,374,383.07	87910306	12.17%	Customers-All	$ 1,262,562.42	$ 9,111,820.65	$ 10,374,383.07
879000	10306	CFS-CUST INSTALL-SER	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	910,092.60	87910306	12.17%	Customers-All	$ 110,758.27	$ 799,334.33	$ 910,092.60
879000	10306	CFS-CUST INSTALL-SER	600307	ON CALL ASSIGN. PAY	NWN	F1	297,353.75	87910306	12.17%	Customers-All	$ 36,187.95	$ 261,165.80	$ 297,353.75
879000	10306	CFS-CUST INSTALL-SER	600500	SALARY BONUS PAYROLL	NWN	F1	0.00	87910306	12.17%	Customers-All	$ -	$ -	$ -
879000	10306	CFS-CUST INSTALL-SER	600900	VACATION, SICK & HOL	NWN	F1	1,830,324.66	87910306	12.17%	Customers-All	$ 222,750.51	$ 1,607,574.15	$ 1,830,324.66
879000	10346	RMC-CUST INSTAL-OFFI	600100	SALARY PAYROLL	NWN	F1	3,464,260.68	87910346	12.17%	Customers-All	$ 421,600.52	$ 3,042,660.16	$ 3,464,260.68
879000	10346	RMC-CUST INSTAL-OFFI	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	275.84	87910346	12.17%	Customers-All	$ 33.57	$ 242.27	$ 275.84
879000	10346	RMC-CUST INSTAL-OFFI	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	246,575.61	87910346	12.17%	Customers-All	$ 30,008.25	$ 216,567.36	$ 246,575.61
879000	10346	RMC-CUST INSTAL-OFFI	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	7,002.77	87910346	12.17%	Customers-All	$ 852.24	$ 6,150.53	$ 7,002.77
879000	10346	RMC-CUST INSTAL-OFFI	600500	SALARY BONUS PAYROLL	NWN	F1	74,557.61	87910346	12.17%	Customers-All	$ 9,073.66	$ 65,483.95	$ 74,557.61
879000	10346	RMC-CUST INSTAL-OFFI	600700	HOURLY BONUS PAYROLL	NWN	F1	933.06	87910346	12.17%	Customers-All	$ 113.55	$ 819.51	$ 933.06
879000	10346	RMC-CUST INSTAL-OFFI	600900	VACATION, SICK & HOL	NWN	F1	42,766.99	87910346	12.17%	Customers-All	$ 5,204.74	$ 37,562.25	$ 42,766.99
879000	10555	CONTRACT SERV-CUST I	600100	SALARY PAYROLL	NWN	F1	1,470,061.91	87910555	12.17%	Customers-All	$ 178,906.53	$ 1,291,155.38	$ 1,470,061.91
879000	10555	CONTRACT SERV-CUST I	600500	SALARY BONUS PAYROLL	NWN	F1	4,000.00	87910555	12.17%	Customers-All	$ 486.80	$ 3,513.20	$ 4,000.00
879000	11564	Meter Mod Cust Insta	600100	SALARY PAYROLL	NWN	F1	52,048.91	87911564	12.17%	Customers-All	$ 6,334.35	$ 45,714.56	$ 52,048.91
879000	11564	Meter Mod Cust Insta	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	14,769.12	87911564	12.17%	Customers-All	$ 1,797.40	$ 12,971.72	$ 14,769.12
879000	11564	Meter Mod Cust Insta	600900	VACATION, SICK & HOL	NWN	F1	2,138.42	87911564	12.17%	Customers-All	$ 260.25	$ 1,878.17	$ 2,138.42
880000	10026	SYS OPS-OTHER DISTRI	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	21,036.70	88010026	12.17%	Customers-All	$ 2,560.17	$ 18,476.53	$ 21,036.70
880000	10026	SYS OPS-OTHER DISTRI	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	387,706.30	88010026	12.17%	Customers-All	$ 47,183.86	$ 340,522.44	$ 387,706.30
880000	10026	SYS OPS-OTHER DISTRI	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	120,282.02	88010026	12.17%	Customers-All	$ 14,638.32	$ 105,643.70	$ 120,282.02
880000	10026	SYS OPS-OTHER DISTRI	600307	ON CALL ASSIGN. PAY	NWN	F1	3,697.30	88010026	12.17%	Customers-All	$ 449.96	$ 3,247.34	$ 3,697.30
880000	10026	SYS OPS-OTHER DISTRI	600900	VACATION, SICK & HOL	NWN	F1	67,872.71	88010026	12.17%	Customers-All	$ 8,260.11	$ 59,612.60	$ 67,872.71
880000	10490	DISTRIB-OTHER DISTRI	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	507,219.45	88010490	12.17%	Customers-All	$ 61,728.61	$ 445,490.84	$ 507,219.45
880000	10490	DISTRIB-OTHER DISTRI	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	3,557.74	88010490	12.17%	Customers-All	$ 432.98	$ 3,124.76	$ 3,557.74
880000	10490	DISTRIB-OTHER DISTRI	600900	VACATION, SICK & HOL	NWN	F1	89,983.07	88010490	12.17%	Customers-All	$ 10,950.94	$ 79,032.13	$ 89,983.07
880000	10652	STORES-OTHER DISTRIB	600100	SALARY PAYROLL	NWN	F1	84,123.50	88010652	11.80%	3-factor	$ 9,926.57	$ 74,196.93	$ 84,123.50
880000	10652	STORES-OTHER DISTRIB	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	276.60	88010652	11.80%	3-factor	$ 32.64	$ 243.96	$ 276.60
880000	10652	STORES-OTHER DISTRIB	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	564,850.92	88010652	11.80%	3-factor	$ 66,652.41	$ 498,198.51	$ 564,850.92
880000	10652	STORES-OTHER DISTRIB	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	8,057.80	88010652	11.80%	3-factor	$ 950.82	$ 7,106.98	$ 8,057.80
880000	10652	STORES-OTHER DISTRIB	600307	ON CALL ASSIGN. PAY	NWN	F1	0.00	88010652	11.80%	3-factor	$ -	$ -	$ -
880000	10652	STORES-OTHER DISTRIB	600700	HOURLY BONUS PAYROLL	NWN	F1	419.83	88010652	11.80%	3-factor	$ 49.54	$ 370.29	$ 419.83
880000	10652	STORES-OTHER DISTRIB	600900	VACATION, SICK & HOL	NWN	F1	103,810.07	88010652	11.80%	3-factor	$ 12,249.59	$ 91,560.48	$ 103,810.07
885000	10255	ENGINER SVCES WA-DIS	600100	SALARY PAYROLL	NWN	F1	135,132.50	88510255	100.00%	Direct-WA	$ 135,132.50	$ -	$ 135,132.50
885000	10255	ENGINER SVCES WA-DIS	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	139,127.36	88510255	100.00%	Direct-WA	$ 139,127.36	$ -	$ 139,127.36
885000	10255	ENGINER SVCES WA-DIS	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	459.92	88510255	100.00%	Direct-WA	$ 459.92	$ -	$ 459.92
885000	10255	ENGINER SVCES WA-DIS	600500	SALARY BONUS PAYROLL	NWN	F1	435.41	88510255	100.00%	Direct-WA	$ 435.41	$ -	$ 435.41
885000	10255	ENGINER SVCES WA-DIS	600900	VACATION, SICK & HOL	NWN	F1	26,342.67	88510255	100.00%	Direct-WA	$ 26,342.67	$ -	$ 26,342.67
885000	10368	TRANSMISSION-DISTRB	600100	SALARY PAYROLL	NWN	F1	569,463.28	88510368	1.24%	Transmission	$ 7,084.28	$ 562,379.00	$ 569,463.28
885000	10368	TRANSMISSION-DISTRB	600500	SALARY BONUS PAYROLL	NWN	F1	311.02	88510368	1.24%	Transmission	$ 3.87	$ 307.15	$ 311.02
885000	10429	ENGINEERING SVCES OR	600100	SALARY PAYROLL	NWN	F1	3,847,154.24	88510429	0.00%	Direct-OR	$ -	$ 3,847,154.24	$ 3,847,154.24
885000	10429	ENGINEERING SVCES OR	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	2,835.30	88510429	0.00%	Direct-OR	$ -	$ 2,835.30	$ 2,835.30
885000	10429	ENGINEERING SVCES OR	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	2,044,629.57	88510429	0.00%	Direct-OR	$ -	$ 2,044,629.57	$ 2,044,629.57
885000	10429	ENGINEERING SVCES OR	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	109,630.70	88510429	0.00%	Direct-OR	$ -	$ 109,630.70	$ 109,630.70
885000	10429	ENGINEERING SVCES OR	600307	ON CALL ASSIGN. PAY	NWN	F1	860.22	88510429	0.00%	Direct-OR	$ -	$ 860.22	$ 860.22
885000	10429	ENGINEERING SVCES OR	600500	SALARY BONUS PAYROLL	NWN	F1	8,416.56	88510429	0.00%	Direct-OR	$ -	$ 8,416.56	$ 8,416.56
885000	10429	ENGINEERING SVCES OR	600700	HOURLY BONUS PAYROLL	NWN	F1	811.04	88510429	0.00%	Direct-OR	$ -	$ 811.04	$ 811.04
885000	10429	ENGINEERING SVCES OR	600900	VACATION, SICK & HOL	NWN	F1	357,713.08	88510429	0.00%	Direct-OR	$ -	$ 357,713.08	$ 357,713.08
885000	10435	ENGINER SVCES OR-DIS	600100	SALARY PAYROLL	NWN	F1	0.00	88510435	0.00%	Direct-OR	$ -	$ -	$ -
885000	10444	CODE COMPLIANCE-DIST	600100	SALARY PAYROLL	NWN	F1	519,812.03	88510444	11.80%	3-factor	$ 61,337.82	$ 458,474.21	$ 519,812.03
885000	10444	CODE COMPLIANCE-DIST	600500	SALARY BONUS PAYROLL	NWN	F1	367.27	88510444	11.80%	3-factor	$ 43.34	$ 323.93	$ 367.27
885000	10463	DIR-UTILITY OPS-DIST	600100	SALARY PAYROLL	NWN	F1	183,153.33	88510463	11.80%	3-factor	$ 21,612.09	$ 161,541.24	$ 183,153.33
885000	10463	DIR-UTILITY OPS-DIST	600500	SALARY BONUS PAYROLL	NWN	F1	2,553.19	88510463	11.80%	3-factor	$ 301.28	$ 2,251.91	$ 2,553.19
885000	10495	DISTRIB-DISTRB MAINT	600100	SALARY PAYROLL	NWN	F1	1,960,877.85	88510495	11.80%	3-factor	$ 231,383.59	$ 1,729,494.26	$ 1,960,877.85
885000	10495	DISTRIB-DISTRB MAINT	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	1,046.07	88510495	11.80%	3-factor	$ 123.44	$ 922.63	$ 1,046.07
885000	10495	DISTRIB-DISTRB MAINT	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	36,731.07	88510495	11.80%	3-factor	$ 4,334.27	$ 32,396.80	$ 36,731.07
885000	10495	DISTRIB-DISTRB MAINT	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	2,859.45	88510495	11.80%	3-factor	$ 337.42	$ 2,522.03	$ 2,859.45
885000	10495	DISTRIB-DISTRB MAINT	600500	SALARY BONUS PAYROLL	NWN	F1	222.12	88510495	11.80%	3-factor	$ 26.21	$ 195.91	$ 222.12
885000	10495	DISTRIB-DISTRB MAINT	600900	VACATION, SICK & HOL	NWN	F1	6,094.66	88510495	11.80%	3-factor	$ 719.17	$ 5,375.49	$ 6,094.66
885000	10566	OPS TECH SVCES-DISTR	600100	SALARY PAYROLL	NWN	F1	3,299,731.43	88510566	11.80%	3-factor	$ 389,368.31	$ 2,910,363.12	$ 3,299,731.43
885000	10566	OPS TECH SVCES-DISTR	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	0.00	88510566	11.80%	3-factor	$ -	$ -	$ -
885000	10566	OPS TECH SVCES-DISTR	600500	SALARY BONUS PAYROLL	NWN	F1	3,513.82	88510566	11.80%	3-factor	$ 414.63	$ 3,099.19	$ 3,513.82
885000	10566	OPS TECH SVCES-DISTR	600900	VACATION, SICK & HOL	NWN	F1	0.00	88510566	11.80%	3-factor	$ -	$ -	$ -
885000	10567	OPS TECH SVCES-DISTR	600100	SALARY PAYROLL	NWN	F1	220,853.08	88510567	11.80%	3-factor	$ 26,060.66	$ 194,792.42	$ 220,853.08
885000	10567	OPS TECH SVCES-DISTR	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	61,767.39	88510567	11.80%	3-factor	$ 7,288.55	$ 54,478.84	$ 61,767.39
885000	10567	OPS TECH SVCES-DISTR	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	54.82	88510567	11.80%	3-factor	$ 6.47	$ 48.35	$ 54.82
885000	10567	OPS TECH SVCES-DISTR	600500	SALARY BONUS PAYROLL	NWN	F1	124.41	88510567	11.80%	3-factor	$ 14.68	$ 109.73	$ 124.41
885000	10567	OPS TECH SVCES-DISTR	600900	VACATION, SICK & HOL	NWN	F1	11,327.93	88510567	11.80%	3-factor	$ 1,336.70	$ 9,991.23	$ 11,327.93
885000	10570	DMG PREVENT-DISTRB M	600100	SALARY PAYROLL	NWN	F1	613,752.84	88510570	12.17%	Customers-All	$ 74,693.72	$ 539,059.12	$ 613,752.84
885000	10570	DMG PREVENT-DISTRB M	600500	SALARY BONUS PAYROLL	NWN	F1	333.41	88510570	12.17%	Customers-All	$ 40.58	$ 292.83	$ 333.41
885000	11265	PIPE I-DIST MAIN-SUP	600100	SALARY PAYROLL	NWN	F1	982,292.55	88511265	12.17%	Customers-All	$ 119,545.00	$ 862,747.55	$ 982,292.55
885000	11265	PIPE I-DIST MAIN-SUP	600500	SALARY BONUS PAYROLL	NWN	F1	662.69	88511265	12.17%	Customers-All	$ 80.65	$ 582.04	$ 662.69
887000	10430	ENGINER SERV OR-DIST	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	9,065.66	88710430	0.00%	Direct-OR	$ -	$ 9,065.66	$ 9,065.66
887000	10430	ENGINER SERV OR-DIST	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	774,276.14	88710430	0.00%	Direct-OR	$ -	$ 774,276.14	$ 774,276.14
887000	10430	ENGINER SERV OR-DIST	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	91,286.70	88710430	0.00%	Direct-OR	$ -	$ 91,286.70	$ 91,286.70
887000	10430	ENGINER SERV OR-DIST	600900	VACATION, SICK & HOL	NWN	F1	135,215.61	88710430	0.00%	Direct-OR	$ -	$ 135,215.61	$ 135,215.61
889000	10032	SYS OPS-MAINT-MSRE R	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	0.00	88910032	8.68%	Sendout Volumes	$ -	$ -	$ -
889000	10032	SYS OPS-MAINT-MSRE R	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	97,431.86	88910032	8.68%	Sendout Volumes	$ 8,457.09	$ 88,974.77	$ 97,431.86
889000	10032	SYS OPS-MAINT-MSRE R	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	434.60	88910032	8.68%	Sendout Volumes	$ 37.72	$ 396.88	$ 434.60
889000	10032	SYS OPS-MAINT-MSRE R	600307	ON CALL ASSIGN. PAY	NWN	F1	0.00	88910032	8.68%	Sendout Volumes	$ -	$ -	$ -
889000	10032	SYS OPS-MAINT-MSRE R	600900	VACATION, SICK & HOL	NWN	F1	17,042.21	88910032	8.68%	Sendout Volumes	$ 1,479.26	$ 15,562.95	$ 17,042.21
893000	10039	SYS OPS-MAINT-MTR&HC	600100	SALARY PAYROLL	NWN	F1	131,894.37	89310039	12.17%	Customers-All	$ 16,051.54	$ 115,842.83	$ 131,894.37
893000	10039	SYS OPS-MAINT-MTR&HC	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	4,981.84	89310039	12.17%	Customers-All	$ 606.29	$ 4,375.55	$ 4,981.84
893000	10039	SYS OPS-MAINT-MTR&HC	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	169,123.50	89310039	12.17%	Customers-All	$ 20,582.33	$ 148,541.17	$ 169,123.50
893000	10039	SYS OPS-MAINT-MTR&HC	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	28,818.45	89310039	12.17%	Customers-All	$ 3,507.21	$ 25,311.24	$ 28,818.45
893000	10039	SYS OPS-MAINT-MTR&HC	600307	ON CALL ASSIGN. PAY	NWN	F1	820.43	89310039	12.17%	Customers-All	$ 99.85	$ 720.58	$ 820.43
893000	10039	SYS OPS-MAINT-MTR&HC	600900	VACATION, SICK & HOL	NWN	F1	27,872.02	89310039	12.17%	Customers-All	$ 3,392.02	$ 24,480.00	$ 27,872.02
893000	10043	SYS OPS-MAINT-MTR&HC	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	10,166.92	89310043	12.17%	Customers-All	$ 1,237.31	$ 8,929.61	$ 10,166.92
893000	10043	SYS OPS-MAINT-MTR&HC	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	273,944.04	89310043	12.17%	Customers-All	$ 33,338.99	$ 240,605.05	$ 273,944.04
893000	10043	SYS OPS-MAINT-MTR&HC	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	38,994.90	89310043	12.17%	Customers-All	$ 4,745.68	$ 34,249.22	$ 38,994.90
893000	10043	SYS OPS-MAINT-MTR&HC	600307	ON CALL ASSIGN. PAY	NWN	F1	1,483.77	89310043	12.17%	Customers-All	$ 180.57	$ 1,303.20	$ 1,483.77
893000	10043	SYS OPS-MAINT-MTR&HC	600900	VACATION, SICK & HOL	NWN	F1	49,279.84	89310043	12.17%	Customers-All	$ 5,997.36	$ 43,282.48	$ 49,279.84
893000	10240	METER SHOP-MTR&HOU!	600100	SALARY PAYROLL	NWN	F1	233,469.63	89310240	12.17%	Customers-All	$ 28,413.25	$ 205,056.38	$ 233,469.63
893000	10240	METER SHOP-MTR&HOU!	600500	SALARY BONUS PAYROLL	NWN	F1	139.98	89310240	12.17%	Customers-All	$ 17.04	$ 122.94	$ 139.98
893000	10243	METER SHOP-MTRS&HOL	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	293,095.33	89310243	12.17%	Customers-All	$ 35,669.70	$ 257,425.63	$ 293,095.33
893000	10243	METER SHOP-MTRS&HOL	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	4,938.62	89310243	12.17%	Customers-All	$ 601.03	$ 4,337.59	$ 4,938.62
893000	10243	METER SHOP-MTRS&HOL	600900	VACATION, SICK & HOL	NWN	F1	52,693.90	89310243	12.17%	Customers-All	$ 6,412.85	$ 46,281.05	$ 52,693.90
893000	10374	TRANS-MAINT-MTR&HOL	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	91.75	89310374	1.24%	Transmission	$ 1.14	$ 90.61	$ 91.75
893000	10374	TRANS-MAINT-MTR&HOL	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	81,964.98	89310374	1.24%	Transmission	$ 1,019.67	$ 80,945.31	$ 81,964.98
893000	10374	TRANS-MAINT-MTR&HOL	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	35,959.36	89310374	1.24%	Transmission	$ 447.34	$ 35,512.02	$ 35,959.36
893000	10374	TRANS-MAINT-MTR&HOL	600900	VACATION, SICK & HOL	NWN	F1	14,635.42	89310374	1.24%	Transmission	$ 182.07	$ 14,453.35	$ 14,635.42
893000	10375	TRANS-MAINT-MTR&HOL	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	1,830.00	89310375	1.24%	Transmission	$ 22.77	$ 1,807.23	$ 1,830.00
893000	10375	TRANS-MAINT-MTR&HOL	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	341,295.23	89310375	1.24%	Transmission	$ 4,245.81	$ 337,049.42	$ 341,295.23
893000	10375	TRANS-MAINT-MTR&HOL	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	17,273.85	89310375	1.24%	Transmission	$ 214.89	$ 17,058.96	$ 17,273.85
893000	10375	TRANS-MAINT-MTR&HOL	600900	VACATION, SICK & HOL	NWN	F1	58,539.06	89310375	1.24%	Transmission	$ 728.24	$ 57,810.82	$ 58,539.06
901000	10288	CUST CONTACT CTR-CUS	600100	SALARY PAYROLL	NWN	F1	1,499,556.86	90110288	12.17%	Customers-All	$ 182,496.07	$ 1,317,060.79	$ 1,499,556.86
901000	10288	CUST CONTACT CTR-CUS	600500	SALARY BONUS PAYROLL	NWN	F1	2,646.47	90110288	12.17%	Customers-All	$ 322.08	$ 2,324.39	$ 2,646.47

NW Natural
Payroll Cost Allocation Factor
Test Year Ending March 31, 2025

$ 150,892,151.35

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						Fiscal Year Period	Amount				Payroll Cost Factor	11.1183%	88.8817%	100.0000%
						Measures	Overall Result				TOTAL	$ 16,776,640.43	$ 134,115,510.92	$ 150,892,151.35
FERC Account	Cost Center	Cost Center Description	GL Account	GL Account Long Name	Chart of Accounts	Ledger	$	SORTER	ALLOCATION FACTOR	ALLOCATION METHOD		WA	OR	SYSTEM
902000	10319	CFS-CUST ACCTS OP-ME	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	343,344.69	90210319	12.17%	Customers-All	$	41,785.05	$ 301,559.64	$ 343,344.69
902000	10319	CFS-CUST ACCTS OP-ME	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	1,427.85	90210319	12.17%	Customers-All	$	173.77	$ 1,254.08	$ 1,427.85
902000	10319	CFS-CUST ACCTS OP-ME	600900	VACATION, SICK & HOL	NWN	F1	64,345.50	90210319	12.17%	Customers-All	$	7,830.85	$ 56,514.65	$ 64,345.50
903000	10115	MAJ ACCT SERV-CUST R	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	129.84	90310115	7.68%	Customers-Ind	$	9.97	$ 119.87	$ 129.84
903000	10115	MAJ ACCT SERV-CUST R	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	298,808.26	90310115	7.68%	Customers-Ind	$	22,948.47	$ 275,859.79	$ 298,808.26
903000	10115	MAJ ACCT SERV-CUST R	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	4,131.56	90310115	7.68%	Customers-Ind	$	317.30	$ 3,814.26	$ 4,131.56
903000	10115	MAJ ACCT SERV-CUST R	600900	VACATION, SICK & HOL	NWN	F1	51,555.70	90310115	7.68%	Customers-Ind	$	3,959.48	$ 47,596.22	$ 51,555.70
903000	10290	CUST CONTACT CTR-CUS	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	84,806.84	90310290	12.17%	Customers-All	$	10,320.99	$ 74,485.85	$ 84,806.84
903000	10290	CUST CONTACT CTR-CUS	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	3,861,833.06	90310290	12.17%	Customers-All	$	469,985.08	$ 3,391,847.98	$ 3,861,833.06
903000	10290	CUST CONTACT CTR-CUS	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	380,913.64	90310290	12.17%	Customers-All	$	46,357.19	$ 334,556.45	$ 380,913.64
903000	10290	CUST CONTACT CTR-CUS	600400	P/T HOURLY PAYROLL	NWN	F1	321,752.44	90310290	12.17%	Customers-All	$	39,157.27	$ 282,595.17	$ 321,752.44
903000	10290	CUST CONTACT CTR-CUS	600500	SALARY BONUS PAYROLL	NWN	F1	(500.00)	90310290	12.17%	Customers-All	$	(60.85)	$ (439.15)	$ (500.00)
903000	10290	CUST CONTACT CTR-CUS	600700	HOURLY BONUS PAYROLL	NWN	F1	811.02	90310290	12.17%	Customers-All	$	98.70	$ 712.32	$ 811.02
903000	10290	CUST CONTACT CTR-CUS	600900	VACATION, SICK & HOL	NWN	F1	738,632.79	90310290	12.17%	Customers-All	$	89,891.61	$ 648,741.18	$ 738,632.79
903000	10347	RMC-CUST RECORDS & C	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	66,695.92	90310347	12.17%	Customers-All	$	8,116.89	$ 58,579.03	$ 66,695.92
903000	10347	RMC-CUST RECORDS & C	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	351.79	90310347	12.17%	Customers-All	$	42.81	$ 308.98	$ 351.79
903000	10347	RMC-CUST RECORDS & C	600700	HOURLY BONUS PAYROLL	NWN	F1	311.01	90310347	12.17%	Customers-All	$	37.85	$ 273.16	$ 311.01
903000	10347	RMC-CUST RECORDS & C	600900	VACATION, SICK & HOL	NWN	F1	11,327.42	90310347	12.17%	Customers-All	$	1,378.55	$ 9,948.87	$ 11,327.42
903000	10355	ACCOUNT SERV-CUST RE	600100	SALARY PAYROLL	NWN	F1	365,110.06	90310355	12.17%	Customers-All	$	44,433.89	$ 320,676.17	$ 365,110.06
903000	10355	ACCOUNT SERV-CUST RE	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	124.86	90310355	12.17%	Customers-All	$	15.20	$ 109.66	$ 124.86
903000	10355	ACCOUNT SERV-CUST RE	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	564,485.42	90310355	12.17%	Customers-All	$	68,697.88	$ 495,787.54	$ 564,485.42
903000	10355	ACCOUNT SERV-CUST RE	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	40,135.21	90310355	12.17%	Customers-All	$	4,884.46	$ 35,250.75	$ 40,135.21
903000	10355	ACCOUNT SERV-CUST RE	600500	SALARY BONUS PAYROLL	NWN	F1	124.40	90310355	12.17%	Customers-All	$	15.14	$ 109.26	$ 124.40
903000	10355	ACCOUNT SERV-CUST RE	600900	VACATION, SICK & HOL	NWN	F1	100,381.86	90310355	12.17%	Customers-All	$	12,216.47	$ 88,165.39	$ 100,381.86
903000	10356	ACCOUNT SERV-CUST RE	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	584.64	90310356	12.17%	Customers-All	$	71.15	$ 513.49	$ 584.64
903000	10356	ACCOUNT SERV-CUST RE	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	198,237.44	90310356	12.17%	Customers-All	$	24,125.50	$ 174,111.94	$ 198,237.44
903000	10356	ACCOUNT SERV-CUST RE	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	1,979.18	90310356	12.17%	Customers-All	$	240.87	$ 1,738.31	$ 1,979.18
903000	10356	ACCOUNT SERV-CUST RE	600900	VACATION, SICK & HOL	NWN	F1	33,856.77	90310356	12.17%	Customers-All	$	4,120.37	$ 29,736.40	$ 33,856.77
903000	10357	ACCOUNT SERV-CUST RE	600100	SALARY PAYROLL	NWN	F1	0.00	90310357	12.17%	Customers-All	$	-	$ -	$ -
903000	10357	ACCOUNT SERV-CUST RE	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	206,125.68	90310357	12.17%	Customers-All	$	25,085.50	$ 181,040.18	$ 206,125.68
903000	10357	ACCOUNT SERV-CUST RE	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	7,782.57	90310357	12.17%	Customers-All	$	947.14	$ 6,835.43	$ 7,782.57
903000	10357	ACCOUNT SERV-CUST RE	600500	SALARY BONUS PAYROLL	NWN	F1	(500.00)	90310357	12.17%	Customers-All	$	(60.85)	$ (439.15)	$ (500.00)
903000	10357	ACCOUNT SERV-CUST RE	600700	HOURLY BONUS PAYROLL	NWN	F1	811.04	90310357	12.17%	Customers-All	$	98.70	$ 712.34	$ 811.04
903000	10357	ACCOUNT SERV-CUST RE	600900	VACATION, SICK & HOL	NWN	F1	35,425.23	90310357	12.17%	Customers-All	$	4,311.25	$ 31,113.98	$ 35,425.23
903000	10754	CASH MGMT-CUST RECOI	600100	SALARY PAYROLL	NWN	F1	108,429.10	90310754	12.17%	Customers-All	$	13,195.82	$ 95,233.28	$ 108,429.10
903000	10754	CASH MGMT-CUST RECOI	600500	SALARY BONUS PAYROLL	NWN	F1	93.28	90310754	12.17%	Customers-All	$	11.35	$ 81.93	$ 93.28
903000	10921	CUST ACQ & NEW CONS-	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	55,809.30	90310921	12.17%	Customers-All	$	6,791.99	$ 49,017.31	$ 55,809.30
903000	10921	CUST ACQ & NEW CONS-	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	356.48	90310921	12.17%	Customers-All	$	43.38	$ 313.10	$ 356.48
903000	10921	CUST ACQ & NEW CONS-	600900	VACATION, SICK & HOL	NWN	F1	9,795.69	90310921	12.17%	Customers-All	$	1,192.14	$ 8,603.55	$ 9,795.69
906000	11399	ACCOUNT SERV-CUST SE	600100	SALARY PAYROLL	NWN	F1	98,959.92	90611399	12.17%	Customers-All	$	12,043.42	$ 86,916.50	$ 98,959.92
906000	11399	ACCOUNT SERV-CUST SE	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	672,819.62	90611399	12.17%	Customers-All	$	81,882.15	$ 590,937.47	$ 672,819.62
906000	11399	ACCOUNT SERV-CUST SE	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	1,117.95	90611399	12.17%	Customers-All	$	136.05	$ 981.90	$ 1,117.95
906000	11399	ACCOUNT SERV-CUST SE	600900	VACATION, SICK & HOL	NWN	F1	118,353.67	90611399	12.17%	Customers-All	$	14,403.64	$ 103,950.03	$ 118,353.67
908000	10099	CUST SEG SRVC-CUST A	600100	SALARY PAYROLL	NWN	F1	507,274.28	90810099	7.68%	Customers-Ind	$	38,958.66	$ 468,315.62	$ 507,274.28
908000	10099	CUST SEG SRVC-CUST A	600500	SALARY BONUS PAYROLL	NWN	F1	615.80	90810099	7.68%	Customers-Ind	$	47.29	$ 568.51	$ 615.80
908000	10102	CUST ACQ MRKTG CONV-	600100	SALARY PAYROLL	NWN	F1	319,285.83	90810102	12.17%	Customers-All	$	38,857.09	$ 280,428.74	$ 319,285.83
908000	10102	CUST ACQ MRKTG CONV-	600500	SALARY BONUS PAYROLL	NWN	F1	180.40	90810102	12.17%	Customers-All	$	21.95	$ 158.45	$ 180.40
908000	10103	CUST ACQ MRKTG CONV-	600100	SALARY PAYROLL	NWN	F1	256,783.90	90810103	12.17%	Customers-All	$	31,250.60	$ 225,533.30	$ 256,783.90
908000	10103	CUST ACQ MRKTG CONV-	600500	SALARY BONUS PAYROLL	NWN	F1	205.26	90810103	12.17%	Customers-All	$	24.98	$ 180.28	$ 205.26
908000	10128	RES CONSUMER SERV-CU	600100	SALARY PAYROLL	NWN	F1	123,914.80	90810128	12.34%	Customers-Res	$	15,291.09	$ 108,623.71	$ 123,914.80
908000	10128	RES CONSUMER SERV-CU	600500	SALARY BONUS PAYROLL	NWN	F1	77.76	90810128	12.34%	Customers-Res	$	9.60	$ 68.16	$ 77.76
908000	10136	CUST ACQ SRV CONVS-C	600100	SALARY PAYROLL	NWN	F1	328,733.57	90810136	12.17%	Customers-All	$	40,006.88	$ 288,726.69	$ 328,733.57
908000	10136	CUST ACQ SRV CONVS-C	600500	SALARY BONUS PAYROLL	NWN	F1	62.20	90810136	12.17%	Customers-All	$	7.57	$ 54.63	$ 62.20
908000	10137	CUST ACQ SRV CONVS-C	600100	SALARY PAYROLL	NWN	F1	398,282.93	90810137	12.17%	Customers-All	$	48,471.03	$ 349,811.90	$ 398,282.93
908000	10137	CUST ACQ SRV CONVS-C	600500	SALARY BONUS PAYROLL	NWN	F1	77.76	90810137	12.17%	Customers-All	$	9.46	$ 68.30	$ 77.76
908000	10139	CUST ACQ & NEW CONS-	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	416,897.52	90810139	12.17%	Customers-All	$	50,736.43	$ 366,161.09	$ 416,897.52
908000	10139	CUST ACQ & NEW CONS-	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	4,715.72	90810139	12.17%	Customers-All	$	573.90	$ 4,141.82	$ 4,715.72
908000	10139	CUST ACQ & NEW CONS-	600900	VACATION, SICK & HOL	NWN	F1	73,577.88	90810139	12.17%	Customers-All	$	8,954.43	$ 64,623.45	$ 73,577.88
908000	10161	CUST ACQ MRKTG NEW-C	600100	SALARY PAYROLL	NWN	F1	327,890.54	90810161	12.17%	Customers-All	$	39,904.28	$ 287,986.26	$ 327,890.54
908000	10161	CUST ACQ MRKTG NEW-C	600500	SALARY BONUS PAYROLL	NWN	F1	174.21	90810161	12.17%	Customers-All	$	21.20	$ 153.01	$ 174.21
908000	10162	CUST ACQ MRKTG NEW-C	600100	SALARY PAYROLL	NWN	F1	322,555.05	90810162	12.17%	Customers-All	$	39,254.95	$ 283,300.10	$ 322,555.05
908000	10162	CUST ACQ MRKTG NEW-C	600500	SALARY BONUS PAYROLL	NWN	F1	207.20	90810162	12.17%	Customers-All	$	25.22	$ 181.98	$ 207.20
908000	10457	DIRECTOR-CUST L-CUST	600100	SALARY PAYROLL	NWN	F1	207,012.47	90810457	12.17%	Customers-All	$	25,193.42	$ 181,819.05	$ 207,012.47
908000	10457	DIRECTOR-CUST L-CUST	600500	SALARY BONUS PAYROLL	NWN	F1	108.09	90810457	12.17%	Customers-All	$	13.15	$ 94.94	$ 108.09
909000	10187	CONSMR INFO-WEB SR-I	600100	SALARY PAYROLL	NWN	F1	404,396.38	90910187	12.17%	Customers-All	$	49,215.04	$ 355,181.34	$ 404,396.38
909000	10187	CONSMR INFO-WEB SR-I	600500	SALARY BONUS PAYROLL	NWN	F1	311.02	90910187	12.17%	Customers-All	$	37.85	$ 273.17	$ 311.02
909000	10189	CONSMR INFO-WEB SR-I	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	0.00	90910189	12.17%	Customers-All	$	-	$ -	$ -
909000	10191	CONSMR INFO-WEB SR-I	600100	SALARY PAYROLL	NWN	F1	103,623.09	90910191	12.17%	Customers-All	$	12,610.93	$ 91,012.16	$ 103,623.09
909000	11269	MULTICHANNEL SERVICE	600100	SALARY PAYROLL	NWN	F1	363,467.30	90911269	12.17%	Customers-All	$	44,233.97	$ 319,233.33	$ 363,467.30
909000	11269	MULTICHANNEL SERVICE	600500	SALARY BONUS PAYROLL	NWN	F1	486.56	90911269	12.17%	Customers-All	$	59.21	$ 427.35	$ 486.56
910000	10129	RES CONS SERV-MISC C	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	105,324.94	91010129	12.34%	Customers-Res	$	12,997.10	$ 92,327.84	$ 105,324.94
910000	10129	RES CONS SERV-MISC C	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	380.81	91010129	12.34%	Customers-Res	$	46.99	$ 333.82	$ 380.81
910000	10129	RES CONS SERV-MISC C	600900	VACATION, SICK & HOL	NWN	F1	18,239.10	91010129	12.34%	Customers-Res	$	2,250.70	$ 15,988.40	$ 18,239.10
911000	10176	CONSR RELATIONS-EVT-	600100	SALARY PAYROLL	NWN	F1	110,773.76	91110176	12.17%	Customers-All	$	13,481.17	$ 97,292.59	$ 110,773.76
911000	10176	CONSR RELATIONS-EVT-	600500	SALARY BONUS PAYROLL	NWN	F1	373.22	91110176	12.17%	Customers-All	$	45.42	$ 327.80	$ 373.22
912000	10107	CUST ACQ MRKTG CONV-	600100	SALARY PAYROLL	NWN	F1	95,393.68	91210107	12.17%	Customers-All	$	11,609.41	$ 83,784.27	$ 95,393.68
912000	10107	CUST ACQ MRKTG CONV-	600500	SALARY BONUS PAYROLL	NWN	F1	62.23	91210107	12.17%	Customers-All	$	7.57	$ 54.66	$ 62.23
912000	10108	CUST ACQ MRKTG CONV-	600100	SALARY PAYROLL	NWN	F1	114,439.57	91210108	12.17%	Customers-All	$	13,927.30	$ 100,512.27	$ 114,439.57
912000	10108	CUST ACQ MRKTG CONV-	600500	SALARY BONUS PAYROLL	NWN	F1	55.99	91210108	12.17%	Customers-All	$	6.81	$ 49.18	$ 55.99
912000	10165	CUST ACQ MRKTG NEW-C	600100	SALARY PAYROLL	NWN	F1	195,066.90	91210165	12.17%	Customers-All	$	23,739.64	$ 171,327.26	$ 195,066.90
912000	10165	CUST ACQ MRKTG NEW-C	600500	SALARY BONUS PAYROLL	NWN	F1	112.01	91210165	12.17%	Customers-All	$	13.63	$ 98.38	$ 112.01
912000	10178	CONSR RELATIONS-EVT-	600100	SALARY PAYROLL	NWN	F1	75,999.05	91210178	12.17%	Customers-All	$	9,249.08	$ 66,749.97	$ 75,999.05
912000	10178	CONSR RELATIONS-EVT-	600500	SALARY BONUS PAYROLL	NWN	F1	46.65	91210178	12.17%	Customers-All	$	5.68	$ 40.97	$ 46.65
913000	10195	CONSMR INFO-913 CAT	600100	SALARY PAYROLL	NWN	F1	256,099.35	91310195	12.17%	Customers-All	$	31,167.29	$ 224,932.06	$ 256,099.35
913000	10195	CONSMR INFO-913 CAT	600500	SALARY BONUS PAYROLL	NWN	F1	311.02	91310195	12.17%	Customers-All	$	37.85	$ 273.17	$ 311.02
920000	10117	INTEG RESOURCE PLAN-	600100	SALARY PAYROLL	NWN	F1	489,707.54	92010117	11.80%	3-factor	$	57,785.49	$ 431,922.05	$ 489,707.54
920000	10182	CONSR RELATIONS-EVT-	600100	SALARY PAYROLL	NWN	F1	175,250.44	92010182	12.17%	Customers-All	$	21,327.98	$ 153,922.46	$ 175,250.44
920000	10182	CONSR RELATIONS-EVT-	600500	SALARY BONUS PAYROLL	NWN	F1	108.84	92010182	12.17%	Customers-All	$	13.25	$ 95.59	$ 108.84
920000	10205	OR LOW INCME WTHZN-I	600100	SALARY PAYROLL	NWN	F1	104,761.07	92010205	0.00%	Direct-OR	$	-	$ 104,761.07	$ 104,761.07
920000	10205	OR LOW INCME WTHZN-I	600500	SALARY BONUS PAYROLL	NWN	F1	93.31	92010205	0.00%	Direct-OR	$	-	$ 93.31	$ 93.31
920000	10208	SMART ENERGY-OFFICE	600100	SALARY PAYROLL	NWN	F1	123,394.45	92010208	12.17%	Customers-All	$	15,017.10	$ 108,377.35	$ 123,394.45
920000	10208	SMART ENERGY-OFFICE	600500	SALARY BONUS PAYROLL	NWN	F1	404.29	92010208	12.17%	Customers-All	$	49.20	$ 355.09	$ 404.29
920000	10252	TRANSPORTATION-OFFIC	600100	SALARY PAYROLL	NWN	F1	120,837.52	92010252	11.80%	3-factor	$	14,258.83	$ 106,578.69	$ 120,837.52
920000	10252	TRANSPORTATION-OFFIC	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	485.99	92010252	11.80%	3-factor	$	57.35	$ 428.64	$ 485.99
920000	10252	TRANSPORTATION-OFFIC	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	988,671.45	92010252	11.80%	3-factor	$	116,663.23	$ 872,008.22	$ 988,671.45
920000	10252	TRANSPORTATION-OFFIC	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	44,612.17	92010252	11.80%	3-factor	$	5,264.24	$ 39,347.93	$ 44,612.17
920000	10252	TRANSPORTATION-OFFIC	600500	SALARY BONUS PAYROLL	NWN	F1	93.29	92010252	11.80%	3-factor	$	11.01	$ 82.28	$ 93.29
920000	10252	TRANSPORTATION-OFFIC	600900	VACATION, SICK & HOL	NWN	F1	172,064.07	92010252	11.80%	3-factor	$	20,303.56	$ 151,760.51	$ 172,064.07
920000	10266	IT NETWK LEADER-921	600100	SALARY PAYROLL	NWN	F1	163,593.98	92010266	11.80%	3-factor	$	19,304.09	$ 144,289.89	$ 163,593.98
920000	10266	IT NETWK LEADER-921	600500	SALARY BONUS PAYROLL	NWN	F1	134.90	92010266	11.80%	3-factor	$	15.92	$ 118.98	$ 134.90
920000	10269	IT INFRA TEAM-921	600100	SALARY PAYROLL	NWN	F1	1,721,926.89	92010269	11.80%	3-factor	$	203,187.37	$ 1,518,739.52	$ 1,721,926.89
920000	10269	IT INFRA TEAM-921	600500	SALARY BONUS PAYROLL	NWN	F1	1,548.98	92010269	11.80%	3-factor	$	182.78	$ 1,366.20	$ 1,548.98
920000	10270	IT NTWK TEAM-921	600100	SALARY PAYROLL	NWN	F1	1,049,241.10	92010270	11.80%	3-factor	$	123,810.45	$ 925,430.65	$ 1,049,241.10
920000	10270	IT NTWK TEAM-921	600500	SALARY BONUS PAYROLL	NWN	F1	79.08	92010270	11.80%	3-factor	$	9.33	$ 69.75	$ 79.08
920000	10282	IT SVC DELIVERY-921	600100	SALARY PAYROLL	NWN	F1	1,346,569.04	92010282	11.80%	3-factor	$	158,895.15	$ 1,187,673.89	$ 1,346,569.04
920000	10282	IT SVC DELIVERY-921	600500	SALARY BONUS PAYROLL	NWN	F1	559.82	92010282	11.80%	3-factor	$	66.06	$ 493.76	$ 559.82
920000	10353	BUSINESS SYSS-OFFICE	600100	SALARY PAYROLL	NWN	F1	1,365,762.94	92010353	12.17%	Customers-All	$	166,213.35	$ 1,199,549.59	$ 1,365,762.94
920000	10353	BUSINESS SYSS-OFFICE	600500	SALARY BONUS PAYROLL	NWN	F1	8,533.11	92010353	12.17%	Customers-All	$	1,038.48	$ 7,494.63	$ 8,533.11
920000	10432	ENGINER SVCES OR-OFF	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	136,846.75	92010432	0.00%	Direct-OR	$	-	$ 136,846.75	$ 136,846.75
920000	10432	ENGINER SVCES OR-OFF	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	3,501.25	92010432	0.00%	Direct-OR	$	-	$ 3,501.25	$ 3,501.25
920000	10432	ENGINER SVCES OR-OFF	600500	SALARY BONUS PAYROLL	NWN	F1	(500.00)	92010432	0.00%	Direct-OR	$	-	$ (500.00)	$ (500.00)
920000	10432	ENGINER SVCES OR-OFF	600700	HOURLY BONUS PAYROLL	NWN	F1	811.02	92010432	0.00%	Direct-OR	$	-	$ 811.02	$ 811.02
920000	10432	ENGINER SVCES OR-OFF	600900	VACATION, SICK & HOL	NWN	F1	23,157.36	92010432	0.00%	Direct-OR	$	-	$ 23,157.36	$ 23,157.36
920000	10462	DIRECTOR, TECH SERVI	600100	SALARY PAYROLL	NWN	F1	200,185.24	92010462	12.17%	Customers-All	$	24,362.54	$ 175,822.70	$ 200,185.24
920000	10462	DIRECTOR, TECH SERVI	600500	SALARY BONUS PAYROLL	NWN	F1	2,553.20	92010462	12.17%	Customers-All	$	310.72	$ 2,242.48	$ 2,553.20
920000	10550	BUSINESS ANALYSIS-OF	600100	SALARY PAYROLL	NWN	F1	969,953.63	92010550	12.17%	Customers-All	$	118,043.36	$ 851,910.27	$ 969,953.63
920000	10550	BUSINESS ANALYSIS-OF	600500	SALARY BONUS PAYROLL	NWN	F1	612.64	92010550	12.17%	Customers-All	$	74.56	$ 538.08	$ 612.64
920000	10660	STORES OBS INV - Inv	600500	SALARY BONUS PAYROLL	NWN	F1	(500.00)	92010660	12.17%	Customers-All	$	(60.85)	$ (439.15)	$ (500.00)
920000	10661	PURCHASING-OFFICE ST	600100	SALARY PAYROLL	NWN	F1	1,617,955.87	92010661	11.80%	3-factor	$	190,918.79	$ 1,427,037.08	$ 1,617,955.87
920000	10661	PURCHASING-OFFICE ST	600500	SALARY BONUS PAYROLL	NWN	F1	3,755.78	92010661	11.80%	3-factor	$	443.18	$ 3,312.60	$ 3,755.78
920000	10665	OFFICE SERV-OFFICE S	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	144,479.83	92010665	12.17%	Customers-All	$	17,583.20	$ 126,896.63	$ 144,479.83
920000	10665	OFFICE SERV-OFFICE S	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	893.45	92010665	12.17%	Customers-All	$	108.73	$ 784.72	$ 893.45
920000	10665	OFFICE SERV-OFFICE S	600400	P/T HOURLY PAYROLL	NWN	F1	50,894.97	92010665	12.17%	Customers-All	$	6,193.92	$ 44,701.05	$ 50,894.97
920000	10665	OFFICE SERV-OFFICE S	600900	VACATION, SICK & HOL	NWN	F1	32,792.63	92010665	12.17%	Customers-All	$	3,990.86	$ 28,801.77	$ 32,792.63
920000	10672	EE&LABOR RELATIONS-O	600100	SALARY PAYROLL	NWN	F1	162,829.71	92010672	11.02%	Employee Cost	$	17,937.48	$ 144,892.23	$ 162,829.71

NW Natural
Payroll Cost Allocation Factor
Test Year Ending March 31, 2025

$150,892,151.35

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						Fiscal Year Period Measures	Amount Overall Result				Payroll Cost Factor	11.1183%	88.8817%	100.0000%
											TOTAL	$ 16,776,640.43	$134,115,510.92	$150,892,151.35
FERC Account	Cost Center	Cost Center Description	GL Account	GL Account Long Name	Chart of Accounts	Ledger	$	SORTER	ALLOCATION FACTOR	ALLOCATION METHOD	WA	OR	SYSTEM
920000	10672	EE&LABOR RELATIONS-O	600500	SALARY BONUS PAYROLL	NWN	F1	2,548.34	92010672	11.02%	Employee Cost	$ 280.73	$ 2,267.61	$ 2,548.34
920000	10685	PAYROLL-OFFICE STAFF	600100	SALARY PAYROLL	NWN	F1	144,891.25	92010685	11.02%	Employee Cost	$ 15,961.36	$ 128,929.89	$ 144,891.25
920000	10687	OD & TRAINING-OFFICE	600100	SALARY PAYROLL	NWN	F1	257,196.40	92010687	11.02%	Employee Cost	$ 28,333.01	$ 228,863.39	$ 257,196.40
920000	10687	OD & TRAINING-OFFICE	600500	SALARY BONUS PAYROLL	NWN	F1	124.38	92010687	11.02%	Employee Cost	$ 13.70	$ 110.68	$ 124.38
920000	10690	OD & TRAIN-OFFICE ST	600100	SALARY PAYROLL	NWN	F1	180,375.99	92010690	11.02%	Employee Cost	$ 19,870.40	$ 160,505.59	$ 180,375.99
920000	10690	OD & TRAIN-OFFICE ST	600500	SALARY BONUS PAYROLL	NWN	F1	311.01	92010690	11.02%	Employee Cost	$ 34.26	$ 276.75	$ 311.01
920000	10694	CO SUPPORTED ACTIONS	600500	SALARY BONUS PAYROLL	NWN	F1	857.54	92010694	11.02%	Employee Cost	$ 94.47	$ 763.07	$ 857.54
920000	10705	INF SECUR COMP&QA-O	600100	SALARY PAYROLL	NWN	F1	1,840,980.70	92010705	12.17%	Customers-All	$ 224,047.35	$ 1,616,933.35	$ 1,840,980.70
920000	10705	INF SECUR COMP&QA-O	600500	SALARY BONUS PAYROLL	NWN	F1	14,931.11	92010705	12.17%	Customers-All	$ 1,817.12	$ 13,113.99	$ 14,931.11
920000	10707	IT MAINT-OFFIC-921	600100	SALARY PAYROLL	NWN	F1	455,077.35	92010707	11.80%	3-factor	$ 53,699.13	$ 401,378.22	$ 455,077.35
920000	10707	IT MAINT-OFFIC-921	600500	SALARY BONUS PAYROLL	NWN	F1	118.48	92010707	11.80%	3-factor	$ 13.98	$ 104.50	$ 118.48
920000	10717	IT GAS MGT SYSS-OFFI	600100	SALARY PAYROLL	NWN	F1	1,247,801.63	92010717	11.80%	3-factor	$ 147,240.59	$ 1,100,561.04	$ 1,247,801.63
920000	10717	IT GAS MGT SYSS-OFFI	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	12,425.04	92010717	11.80%	3-factor	$ 1,466.15	$ 10,958.89	$ 12,425.04
920000	10717	IT GAS MGT SYSS-OFFI	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	631,373.99	92010717	11.80%	3-factor	$ 74,502.13	$ 556,871.86	$ 631,373.99
920000	10717	IT GAS MGT SYSS-OFFI	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	64,698.64	92010717	11.80%	3-factor	$ 7,634.44	$ 57,064.20	$ 64,698.64
920000	10717	IT GAS MGT SYSS-OFFI	600500	SALARY BONUS PAYROLL	NWN	F1	1,114.11	92010717	11.80%	3-factor	$ 131.46	$ 982.65	$ 1,114.11
920000	10717	IT GAS MGT SYSS-OFFI	600900	VACATION, SICK & HOL	NWN	F1	113,698.38	92010717	11.80%	3-factor	$ 13,416.41	$ 100,281.97	$ 113,698.38
920000	10727	ENT APPLICATIONS-OFF	600100	SALARY PAYROLL	NWN	F1	3,586,696.36	92010727	12.17%	Customers-All	$ 436,496.08	$ 3,150,160.28	$ 3,586,656.36
920000	10727	ENT APPLICATIONS-OFF	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	438.48	92010727	12.17%	Customers-All	$ 53.36	$ 385.12	$ 438.48
920000	10727	ENT APPLICATIONS-OFF	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	120,759.68	92010727	12.17%	Customers-All	$ 14,696.45	$ 106,063.23	$ 120,759.68
920000	10727	ENT APPLICATIONS-OFF	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	9,394.86	92010727	12.17%	Customers-All	$ 1,143.35	$ 8,251.51	$ 9,394.86
920000	10727	ENT APPLICATIONS-OFF	600500	SALARY BONUS PAYROLL	NWN	F1	14,192.34	92010727	12.17%	Customers-All	$ 1,727.21	$ 12,465.13	$ 14,192.34
920000	10727	ENT APPLICATIONS-OFF	600700	HOURLY BONUS PAYROLL	NWN	F1	93.28	92010727	12.17%	Customers-All	$ 11.35	$ 81.93	$ 93.28
920000	10727	ENT APPLICATIONS-OFF	600900	VACATION, SICK & HOL	NWN	F1	20,940.52	92010727	12.17%	Customers-All	$ 2,548.46	$ 18,392.06	$ 20,940.52
920000	10735	ENT ARCHITECTURE-OFF	600100	SALARY PAYROLL	NWN	F1	992,590.85	92010735	12.17%	Customers-All	$ 120,798.31	$ 871,792.54	$ 992,590.85
920000	10735	ENT ARCHITECTURE-OFF	600500	SALARY BONUS PAYROLL	NWN	F1	370.37	92010735	12.17%	Customers-All	$ 45.07	$ 325.30	$ 370.37
920000	10740	ACCOUNTING-OFFICE921	600100	SALARY PAYROLL	NWN	F1	834,771.38	92010740	11.80%	3-factor	$ 98,503.02	$ 736,268.36	$ 834,771.38
920000	10740	ACCOUNTING-OFFICE921	600500	SALARY BONUS PAYROLL	NWN	F1	238.56	92010740	11.80%	3-factor	$ 28.15	$ 210.41	$ 238.56
920000	10741	TECH ACCTG - 921	600100	SALARY PAYROLL	NWN	F1	344,122.34	92010741	12.17%	Customers-All	$ 41,879.69	$ 302,242.65	$ 344,122.34
920000	10741	TECH ACCTG - 921	600500	SALARY BONUS PAYROLL	NWN	F1	4,155.51	92010741	12.17%	Customers-All	$ 505.73	$ 3,649.78	$ 4,155.51
920000	10745	SARBANES OXLEY-OFFIC	600100	SALARY PAYROLL	NWN	F1	196,917.59	92010745	11.80%	3-factor	$ 23,236.28	$ 173,681.31	$ 196,917.59
920000	10745	SARBANES OXLEY-OFFIC	600500	SALARY BONUS PAYROLL	NWN	F1	0.00	92010745	11.80%	3-factor	$ -	$ -	$ -
920000	10746	SEC REPORTING-921	600100	SALARY PAYROLL	NWN	F1	497,907.33	92010746	11.80%	3-factor	$ 58,753.06	$ 439,154.27	$ 497,907.33
920000	10746	SEC REPORTING-921	600500	SALARY BONUS PAYROLL	NWN	F1	77.01	92010746	11.80%	3-factor	$ 9.09	$ 67.92	$ 77.01
920000	10746	SEC REPORTING-OFFICE	600100	SALARY PAYROLL	NWN	F1	497,907.33	92010746	11.80%	3-factor	$ 58,753.06	$ 439,154.27	$ 497,907.33
920000	10746	SEC REPORTING-OFFICE	600500	SALARY BONUS PAYROLL	NWN	F1	77.01	92010746	11.80%	3-factor	$ 9.09	$ 67.92	$ 77.01
920000	10748	GAS ACCOUNTING-921	600100	SALARY PAYROLL	NWN	F1	571,083.85	92010748	11.80%	3-factor	$ 67,387.89	$ 503,695.96	$ 571,083.85
920000	10748	GAS ACCOUNTING-921	600500	SALARY BONUS PAYROLL	NWN	F1	155.51	92010748	11.80%	3-factor	$ 18.35	$ 137.16	$ 155.51
920000	10748	GAS ACCOUNTING-OFFIC	600100	SALARY PAYROLL	NWN	F1	571,083.85	92010748	11.80%	3-factor	$ 67,387.89	$ 503,695.96	$ 571,083.85
920000	10748	GAS ACCOUNTING-OFFIC	600500	SALARY BONUS PAYROLL	NWN	F1	155.51	92010748	11.80%	3-factor	$ 18.35	$ 137.16	$ 155.51
920000	10750	OPERATIONAL ACCTG-OI	600100	SALARY PAYROLL	NWN	F1	184,444.09	92010750	11.80%	3-factor	$ 21,764.40	$ 162,679.69	$ 184,444.09
920000	10750	OPERATIONAL ACCTG-OI	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	226,126.22	92010750	11.80%	3-factor	$ 26,682.89	$ 199,443.33	$ 226,126.22
920000	10750	OPERATIONAL ACCTG-OI	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	1,637.62	92010750	11.80%	3-factor	$ 193.24	$ 1,444.38	$ 1,637.62
920000	10750	OPERATIONAL ACCTG-OI	600900	VACATION, SICK & HOL	NWN	F1	37,934.65	92010750	11.80%	3-factor	$ 4,476.29	$ 33,458.36	$ 37,934.65
920000	10751	TAX-OFFICE STAFFING	600100	SALARY PAYROLL	NWN	F1	452,258.23	92010751	11.80%	3-factor	$ 53,366.47	$ 398,891.76	$ 452,258.23
920000	10751	TAX-OFFICE STAFFING	600500	SALARY BONUS PAYROLL	NWN	F1	306.68	92010751	11.80%	3-factor	$ 36.19	$ 270.49	$ 306.68
920000	10755	CASH MANAGEMENT-OF	600100	SALARY PAYROLL	NWN	F1	416,612.34	92010755	11.80%	3-factor	$ 49,183.86	$ 367,628.48	$ 416,812.34
920000	10755	CASH MANAGEMENT-OF	600500	SALARY BONUS PAYROLL	NWN	F1	4,882.07	92010755	11.80%	3-factor	$ 576.08	$ 4,305.99	$ 4,882.07
920000	10756	MID OFFICE-OFFICE ST	600100	SALARY PAYROLL	NWN	F1	298,695.73	92010756	11.80%	3-factor	$ 35,246.10	$ 263,449.63	$ 298,695.73
920000	10756	MID OFFICE-OFFICE ST	600500	SALARY BONUS PAYROLL	NWN	F1	208.53	92010756	11.80%	3-factor	$ 24.61	$ 183.92	$ 208.53
920000	10757	CAPITAL ACCOUNTING-G	600100	SALARY PAYROLL	NWN	F1	469,906.86	92010757	11.80%	3-factor	$ 55,449.01	$ 414,457.85	$ 469,906.86
920000	10757	CAPITAL ACCTG 921	600100	SALARY PAYROLL	NWN	F1	469,906.86	92010757	11.80%	3-factor	$ 55,449.01	$ 414,457.85	$ 469,906.86
920000	10758	BUSINESS DEVELOPMEN	600100	SALARY PAYROLL	NWN	F1	813,252.53	92010758	12.17%	Customers-All	$ 98,972.83	$ 714,279.70	$ 813,252.53
920000	10758	BUSINESS DEVELOPMEN	600500	SALARY BONUS PAYROLL	NWN	F1	85,653.37	92010758	12.17%	Customers-All	$ 10,424.02	$ 75,229.35	$ 85,653.37
920000	10759	RENEWABLES-OFFICE ST	600100	SALARY PAYROLL	NWN	F1	1,327,613.96	92010759	12.17%	Customers-All	$ 161,570.62	$ 1,166,043.34	$ 1,327,613.96
920000	10759	RENEWABLES-OFFICE ST	600500	SALARY BONUS PAYROLL	NWN	F1	7,389.63	92010759	12.17%	Customers-All	$ 899.32	$ 6,490.31	$ 7,389.63
920000	10763	FIN PLANNING & BUDGE	600100	SALARY PAYROLL	NWN	F1	900,325.53	92010763	11.80%	3-factor	$ 106,238.41	$ 794,087.12	$ 900,325.53
920000	10763	FIN PLANNING & BUDGE	600500	SALARY BONUS PAYROLL	NWN	F1	35,650.30	92010763	11.80%	3-factor	$ 4,206.74	$ 31,443.56	$ 35,650.30
920000	10765	STRATEGIC PLANNING-O	600100	SALARY PAYROLL	NWN	F1	629,340.09	92010765	11.80%	3-factor	$ 74,262.13	$ 555,077.96	$ 629,340.09
920000	10765	STRATEGIC PLANNING-O	600500	SALARY BONUS PAYROLL	NWN	F1	14,588.77	92010765	11.80%	3-factor	$ 1,721.47	$ 12,867.30	$ 14,588.77
920000	10766	CORP SECRETARY-OFFIC	600100	SALARY PAYROLL	NWN	F1	566,064.87	92010766	11.80%	3-factor	$ 66,795.65	$ 499,269.22	$ 566,064.87
920000	10766	CORP SECRETARY-OFFIC	600500	SALARY BONUS PAYROLL	NWN	F1	14,890.82	92010766	11.80%	3-factor	$ 1,757.12	$ 13,133.70	$ 14,890.82
920000	10775	INVESTOR RELATIONS-O	600100	SALARY PAYROLL	NWN	F1	239,904.75	92010775	11.80%	3-factor	$ 28,308.76	$ 211,595.99	$ 239,904.75
920000	10775	INVESTOR RELATIONS-O	600500	SALARY BONUS PAYROLL	NWN	F1	20,213.39	92010775	11.80%	3-factor	$ 2,385.18	$ 17,828.21	$ 20,213.39
920000	10778	OCC SAFETY-OFFICE ST	600100	SALARY PAYROLL	NWN	F1	898,612.88	92010778	11.02%	Employee Cost	$ 98,992.09	$ 799,620.79	$ 898,612.88
920000	10778	OCC SAFETY-OFFICE ST	600500	SALARY BONUS PAYROLL	NWN	F1	429.46	92010778	11.02%	Employee Cost	$ 47.31	$ 382.15	$ 429.46
920000	10787	LAND OVERHEAD-OFFICE	600100	SALARY PAYROLL	NWN	F1	224,657.57	92010787	11.80%	3-factor	$ 26,509.59	$ 198,147.98	$ 224,657.57
920000	10787	LAND OVERHEAD-OFFICE	600500	SALARY BONUS PAYROLL	NWN	F1	128.86	92010787	11.80%	3-factor	$ 15.21	$ 113.65	$ 128.86
920000	10792	BUSINESS CONT-OFFICE	600100	SALARY PAYROLL	NWN	F1	250,092.38	92010792	11.80%	3-factor	$ 29,510.90	$ 220,581.48	$ 250,092.38
920000	10792	BUSINESS CONT-OFFICE	600500	SALARY BONUS PAYROLL	NWN	F1	168.82	92010792	11.80%	3-factor	$ 19.92	$ 148.90	$ 168.82
920000	10793	CORPORATE SECRT-OFFI	600100	SALARY PAYROLL	NWN	F1	399,198.83	92010793	11.80%	3-factor	$ 47,105.46	$ 352,093.37	$ 399,198.83
920000	10793	CORPORATE SECRT-OFFI	600500	SALARY BONUS PAYROLL	NWN	F1	186.59	92010793	11.80%	3-factor	$ 22.02	$ 164.57	$ 186.59
920000	10794	CORPORATE SECURITY-O	600100	SALARY PAYROLL	NWN	F1	195,448.58	92010794	11.80%	3-factor	$ 23,062.93	$ 172,385.65	$ 195,448.58
920000	10794	CORPORATE SECURITY-O	600500	SALARY BONUS PAYROLL	NWN	F1	152.20	92010794	11.80%	3-factor	$ 17.96	$ 134.24	$ 152.20
920000	10796	PROJECT OFFICE-OFFIC	600100	SALARY PAYROLL	NWN	F1	1,918,029.14	92010796	11.80%	3-factor	$ 226,327.44	$ 1,691,701.70	$ 1,918,029.14
920000	10796	PROJECT OFFICE-OFFIC	600500	SALARY BONUS PAYROLL	NWN	F1	20,155.51	92010796	11.80%	3-factor	$ 2,378.35	$ 17,777.16	$ 20,155.51
920000	10801	CLAIMS OVERHEAD-OFFI	600100	SALARY PAYROLL	NWN	F1	289,804.28	92010801	11.80%	3-factor	$ 34,196.91	$ 255,607.37	$ 289,804.28
920000	10803	PUB POLICY & GVRM AF	600100	SALARY PAYROLL	NWN	F1	908,527.86	92010803	11.80%	3-factor	$ 107,206.29	$ 801,321.57	$ 908,527.86
920000	10803	PUB POLICY & GVRM AF	600500	SALARY BONUS PAYROLL	NWN	F1	16,123.27	92010803	11.80%	3-factor	$ 1,902.55	$ 14,220.72	$ 16,123.27
920000	10807	PHILANTHROPY-OFFICE	600100	SALARY PAYROLL	NWN	F1	95,110.56	92010807	11.80%	3-factor	$ 11,223.05	$ 83,887.51	$ 95,110.56
920000	10807	PHILANTHROPY-OFFICE	600500	SALARY BONUS PAYROLL	NWN	F1	373.22	92010807	11.80%	3-factor	$ 44.04	$ 329.18	$ 373.22
920000	10811	COMM & CIVIC AFFAIRS	600100	SALARY PAYROLL	NWN	F1	253,288.91	92010811	11.80%	3-factor	$ 29,888.09	$ 223,400.82	$ 253,288.91
920000	10811	COMM & CIVIC AFFAIRS	600500	SALARY BONUS PAYROLL	NWN	F1	199.95	92010811	11.80%	3-factor	$ 23.59	$ 176.36	$ 199.95
920000	10814	CORPORATE COMMUNIC	600100	SALARY PAYROLL	NWN	F1	657,639.93	92010814	11.80%	3-factor	$ 77,601.51	$ 580,038.42	$ 657,639.93
920000	10814	CORPORATE COMMUNIC	600500	SALARY BONUS PAYROLL	NWN	F1	108.09	92010814	11.80%	3-factor	$ 12.75	$ 95.34	$ 108.09
920000	10818	REGULATORY AFFAIRS-O	600100	SALARY PAYROLL	NWN	F1	1,804,211.60	92010818	30.00%	Regulatory	$ 541,263.48	$ 1,262,948.12	$ 1,804,211.60
920000	10818	REGULATORY AFFAIRS-O	600106	SALARY OVERTIME	NWN	F1	270.70	92010818	30.00%	Regulatory	$ 81.21	$ 189.49	$ 270.70
920000	10818	REGULATORY AFFAIRS-O	600500	SALARY BONUS PAYROLL	NWN	F1	8,981.60	92010818	30.00%	Regulatory	$ 2,694.48	$ 6,287.12	$ 8,981.60
920000	10818	REGULATORY AFFAIRS-O	600800	SALARY P/T PAYROLL	NWN	F1	5,712.00	92010818	30.00%	Regulatory	$ 1,713.60	$ 3,998.40	$ 5,712.00
920000	10819	LEGAL-OFFICE STAFFIN	600100	SALARY PAYROLL	NWN	F1	1,324,051.35	92010819	11.80%	3-factor	$ 156,238.06	$ 1,167,813.29	$ 1,324,051.35
920000	10819	LEGAL-OFFICE STAFFIN	600500	SALARY BONUS PAYROLL	NWN	F1	58,082.27	92010819	11.80%	3-factor	$ 6,853.71	$ 51,228.56	$ 58,082.27
920000	10846	ENV POLICY AND SUSTN	600100	SALARY PAYROLL	NWN	F1	415,595.37	92010846	11.80%	3-factor	$ 49,040.25	$ 366,555.12	$ 415,595.37
920000	10846	ENV POLICY AND SUSTN	600500	SALARY BONUS PAYROLL	NWN	F1	5,072.27	92010846	11.80%	3-factor	$ 598.53	$ 4,473.74	$ 5,072.27
920000	10846	ENV POLICY AND SUSTN	600800	SALARY P/T PAYROLL	NWN	F1	2,352.00	92010846	11.80%	3-factor	$ 277.54	$ 2,074.46	$ 2,352.00
920000	10857	INTERNAL AUDITING-OF	600100	SALARY PAYROLL	NWN	F1	667,634.06	92010857	11.80%	3-factor	$ 78,780.82	$ 588,853.24	$ 667,634.06
920000	10857	INTERNAL AUDITING-OF	600500	SALARY BONUS PAYROLL	NWN	F1	593.05	92010857	11.80%	3-factor	$ 69.98	$ 523.07	$ 593.05
920000	10857	INTERNAL AUDITING-OF	600800	SALARY P/T PAYROLL	NWN	F1	132,600.05	92010857	11.80%	3-factor	$ 15,646.81	$ 116,953.24	$ 132,600.05
920000	10870	VP, CHF HR&DVRY OFF-	600100	SALARY PAYROLL	NWN	F1	228,024.76	92010870	11.80%	3-factor	$ 26,906.92	$ 201,117.84	$ 228,024.76
920000	10870	VP, CHF HR&DVRY OFF-	600500	SALARY BONUS PAYROLL	NWN	F1	130.92	92010870	11.80%	3-factor	$ 15.45	$ 115.47	$ 130.92
920000	10878	EXEC ASST PAYROLL-OF	600100	SALARY PAYROLL	NWN	F1	591,985.46	92010878	11.80%	3-factor	$ 69,854.28	$ 522,131.18	$ 591,985.46
920000	10878	EXEC ASST PAYROLL-OF	600500	SALARY BONUS PAYROLL	NWN	F1	233.23	92010878	11.80%	3-factor	$ 27.52	$ 205.71	$ 233.23
920000	10879	OFFICERS PAYROLL-OFF	600100	SALARY PAYROLL	NWN	F1	5,236,954.44	92010879	11.80%	3-factor	$ 617,960.62	$ 4,618,993.82	$ 5,236,954.44
920000	10879	OFFICERS PAYROLL-OFF	600500	SALARY BONUS PAYROLL	NWN	F1	184,099.42	92010879	11.80%	3-factor	$ 21,723.73	$ 162,375.69	$ 184,099.42
920000	11127	FACILITIES MGMNT-OFF	600100	SALARY PAYROLL	NWN	F1	76,546.93	92011127	11.80%	3-factor	$ 9,032.54	$ 67,514.39	$ 76,546.93
920000	11127	FACILITIES MGMNT-OFF	600500	SALARY BONUS PAYROLL	NWN	F1	93.28	92011127	11.80%	3-factor	$ 11.01	$ 82.27	$ 93.28
920000	11129	ACCOUNTING RENEWAB	600100	SALARY PAYROLL	NWN	F1	113,900.06	92011129	12.17%	Customers-All	$ 13,861.64	$ 100,038.42	$ 113,900.06
920000	11129	ACCTG RENEWABLES 921	600100	SALARY PAYROLL	NWN	F1	113,900.06	92011129	12.17%	Customers-All	$ 13,861.64	$ 100,038.42	$ 113,900.06
920000	11425	INF SECUR COMP&QA-SE	600100	SALARY PAYROLL	NWN	F1	337,096.07	92011425	12.17%	Customers-All	$ 41,024.59	$ 296,071.48	$ 337,096.07
920000	11426	INF SECUR COMP&QA-CI	600100	SALARY PAYROLL	NWN	F1	144,130.05	92011426	12.17%	Customers-All	$ 17,540.63	$ 126,589.42	$ 144,130.05
920000	11427	IT GAS MGT SYSS-PIPE	600100	SALARY PAYROLL	NWN	F1	270,483.43	92011427	12.17%	Customers-All	$ 32,917.83	$ 237,565.60	$ 270,483.43
920000	11428	IT GAS MGT SYSS-COMM	600100	SALARY PAYROLL	NWN	F1	33,468.76	92011428	12.17%	Customers-All	$ 4,073.15	$ 29,395.61	$ 33,468.76
920000	11428	IT GAS MGT SYSS-COMM	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	4,986.24	92011428	12.17%	Customers-All	$ 606.83	$ 4,379.41	$ 4,986.24
920000	11428	IT GAS MGT SYSS-COMM	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	236,561.40	92011428	12.17%	Customers-All	$ 28,789.52	$ 207,771.88	$ 236,561.40
920000	11428	IT GAS MGT SYSS-COMM	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	9,281.82	92011428	12.17%	Customers-All	$ 1,129.60	$ 8,152.22	$ 9,281.82
920000	11428	IT GAS MGT SYSS-COMM	600900	VACATION, SICK & HOL	NWN	F1	37,501.56	92011428	12.17%	Customers-All	$ 4,563.94	$ 32,937.62	$ 37,501.56
920000	11429	ENT APPLICATIONS-SAP	600100	SALARY PAYROLL	NWN	F1	468,692.52	92011429	12.17%	Customers-All	$ 57,034.77	$ 411,615.75	$ 468,650.52
920000	11430	ENT APPLICATIONS-COM	600100	SALARY PAYROLL	NWN	F1	280,435.69	92011430	12.17%	Customers-All	$ 34,129.02	$ 246,306.67	$ 280,435.69
920000	11430	ENT APPLICATIONS-COM	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	38.00	92011430	12.17%	Customers-All	$ 4.62	$ 33.38	$ 38.00
920000	11430	ENT APPLICATIONS-COM	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	37,088.00	92011430	12.17%	Customers-All	$ 4,513.61	$ 32,574.39	$ 37,088.00
920000	11430	ENT APPLICATIONS-COM	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	4,448.00	92011430	12.17%	Customers-All	$ 541.32	$ 3,906.68	$ 4,448.00
920000	11430	ENT APPLICATIONS-COM	600900	VACATION, SICK & HOL	NWN	F1	5,405.12	92011430	12.17%	Customers-All	$ 657.80	$ 4,747.32	$ 5,405.12
920000	11431	ENT APPLICATIONS-CIS	600100	SALARY PAYROLL	NWN	F1	256,633.39	92011431	12.17%	Customers-All	$ 31,232.28	$ 225,401.11	$ 256,633.39
920000	11432	ENT APPLICATIONS-DB/	600100	SALARY PAYROLL	NWN	F1	194,622.53	92011432	12.17%	Customers-All	$ 23,685.56	$ 170,936.97	$ 194,622.53
75037	75037	PERFRM-OFFIC NON-RE	600100	SALARY PAYROLL	NWN	F1	3,331,528.03	92075037	11.12%	Payroll	$ 370,382.63	$ 2,961,145.40	$ 3,331,528.03
920000	80026	PERFORMANCE-OFFICE S	600500	SALARY BONUS PAYROLL	NWN	F1	1,333,167.08	92080026	11.02%	Employee Cost	$ 146,863.02	$ 1,186,304.06	$ 1,333,167.08
920000	80037	SEVERANCE-OFFICE STA	600100	SALARY PAYROLL	NWN	F1	457,700.32	92080037	11.02%	Employee Cost	$ 50,420.72	$ 407,279.60	$ 457,700.32
922000	80128	ADMIN TRANSFER-N. MI	600100	SALARY PAYROLL	NWN	F1	(80,767.47)	92280128	12.14%	Admin Tran	$ (9,807.43)	$ (70,960.04)	$ (80,767.47)
926000	10668	EMPLOYMENT-E PENSIC	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	522,683.15	92610668	11.02%	Employee Cost	$ 57,579.30	$ 465,103.85	$ 522,683.15
926000	10668	EMPLOYMENT-EE PENSIC	600106	SALARY OVERTIME	NWN	F1	12.30	92610668	11.02%	Employee Cost	$ 1.35	$ 10.95	$ 12.30
926000	10674	EE&LABOR REL-EE PENS	600100	SALARY PAYROLL	NWN	F1	247,717.01	92610674	11.02%	Employee Cost	$ 27,288.75	$ 220,428.26	$ 247,717.01
926000	10674	EE&LABOR REL-EE PENS	600500	SALARY BONUS PAYROLL	NWN	F1	811.02	92610674	11.02%	Employee Cost	$ 89.34	$ 721.68	$ 811.02
926000	10678	BENEFITS-EE PENSION	600100	SALARY PAYROLL	NWN	F1	291,383.23	92610678	11.02%	Employee Cost	$ 32,099.07	$ 259,284.16	$ 291,383.23
926000	10678	BENEFITS-EE PENSION	600500	SALARY BONUS PAYROLL	NWN	F1	935.42	92610678	11.02%	Employee Cost	$ 103.05	$ 832.37	$ 935.42
926000	10678	BENEFITS-EE PENSION	600800	SALARY P/T PAYROLL	NWN	F1	112,918.12	92610678	11.02%	Employee Cost	$ 12,439.17	$ 100,478.95	$ 112,918.12
926000	10686	PAYROLL-EE PENSION &	600100	SALARY PAYROLL	NWN	F1	314,609.34	92610686	11.12%	payroll	$ 34,976.69	$ 279,632.65	$ 314,609.34
926000	10686	PAYROLL-EE PENSION &	600500	SALARY BONUS PAYROLL	NWN	F1	93.29	92610686	11.12%	payroll	$ 10.37	$ 82.92	$ 93.29
926000	10699	CO SUPPORT ACTIONS-E	600100	SALARY PAYROLL	NWN	F1	67,903.92	92610699	11.02%	Employee Cost	$ 7,480.36	$ 60,423.56	$ 67,903.92
926000	10699	CO SUPPORT ACTIONS-E	600500	SALARY BONUS PAYROLL	NWN	F1	7,000.00	92610699	11.02%	Employee Cost	$ 771.13	$ 6,228.87	$ 7,000.00
926000	10700	DATA & PROJ MGMT-EE	600100	SALARY PAYROLL	NWN	F1	90,915.05	92610700	11.02%	Employee Cost	$ 10,015.29	$ 80,899.76	$ 90,915.05
926000	10701	COMP & ADMIN-EE PENS	600100	SALARY PAYROLL	NWN	F1	561,649.91	92610701	11.02%	Employee Cost	$ 61,871.92	$ 499,777.99	$ 561,649.91
926000	10701	COMP & ADMIN-EE PENS	600500	SALARY BONUS PAYROLL	NWN	F1	120.10	92610701	11.02%	Employee Cost	$ 13.23	$ 106.87	$ 120.10
926000	10799	PROJECT OFFICE-EE PE	600100	SALARY PAYROLL	NWN	F1	102,450.04	92610799	11.02%	Employee Cost	$ 11,286.00	$ 91,164.04	$ 102,450.04
926000	80023	POH ADJUSTMENTS-EE P	600900	VACATION, SICK & HOL	NWN	F1	(208,083.76)	92680023	11.02%	Employee Cost	$ (22,922.72)	$ (185,161.04)	$ (208,083.76)
932000	10466	LEGACY ENV PROG-MAIN	600100	SALARY PAY

NW Natural
Employee Cost Allocation Factor
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												Employee Cost Factor		11.0161%		88.9839%	
												TOTAL Incldg Construction Wages		$ 24,992,324.25		$201,877,797.67	$226,870,121.92
												Add: Direct/Indirect Construction Wages		$ 9,163,030.26		$ 75,383,928.20	$ 84,546,958.47
												TOTAL		$ 15,829,293.98		$126,493,869.47	$142,323,163.45
							$ 142,323,163.45										
					Fiscal Year Period		Amount										
					Measures		Overall Result										
FERC Account	Cost Center	Cost Center Description	GL Account	GL Account Long Name	Chart of Accounts	Ledger	$	SORTER	ALLOCATION FACTOR	ALLOCATION METHOD		WA		OR		SYSTEM
820000	1014:	PORTLAND LNG-MEASUR	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	7,806.32	82010147	10.97%	Firm Sales Volumes	$	856.35	$	6,949.97	$	7,806.32
820000	1014:	PORTLAND LNG-MEASUR	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	165,067.34	82010147	10.97%	Firm Sales Volumes	$	18,107.89	$	146,959.45	$	165,067.34
820000	1014:	PORTLAND LNG-MEASUR	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	7,945.14	82010147	10.97%	Firm Sales Volumes	$	871.58	$	7,073.56	$	7,945.14
820000	1014:	PORTLAND LNG-MEASUR	600307	ON CALL ASSIGN. PAY	NWN	F1	11,009.88	82010147	10.97%	Firm Sales Volumes	$	1,207.78	$	9,802.10	$	11,009.88
820000	1014:	PORTLAND LNG-MEASUR	600500	SALARY BONUS PAYROLL	NWN	F1	0.00	82010147	10.97%	Firm Sales Volumes	$	-	$	-	$	-
820000	1014:	PORTLAND LNG-MEASUR	600900	VACATION, SICK & HOL	NWN	F1	27,835.61	82010147	10.97%	Firm Sales Volumes	$	3,053.57	$	24,782.04	$	27,835.61
820000	1021:	MIST UGS-MEASURE & R	600100	SALARY PAYROLL	NWN	F1	491,962.65	82010219	10.97%	Firm Sales Volumes	$	53,968.30	$	437,994.35	$	491,962.65
820000	1021:	MIST UGS-MEASURE & R	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	121,378.62	82010219	10.97%	Firm Sales Volumes	$	13,315.23	$	108,063.39	$	121,378.62
820000	1021:	MIST UGS-MEASURE & R	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	1,291,220.27	82010219	10.97%	Firm Sales Volumes	$	141,646.86	$	1,149,573.41	$	1,291,220.27
820000	1021:	MIST UGS-MEASURE & R	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	271,340.91	82010219	10.97%	Firm Sales Volumes	$	29,766.10	$	241,574.81	$	271,340.91
820000	1021:	MIST UGS-MEASURE & R	600307	ON CALL ASSIGN. PAY	NWN	F1	60,100.34	82010219	10.97%	Firm Sales Volumes	$	6,593.01	$	53,507.33	$	60,100.34
820000	1021:	MIST UGS-MEASURE & R	600500	SALARY BONUS PAYROLL	NWN	F1	0.00	82010219	10.97%	Firm Sales Volumes	$	-	$	-	$	-
820000	1021:	MIST UGS-MEASURE & R	600900	VACATION, SICK & HOL	NWN	F1	192,452.14	82010219	10.97%	Firm Sales Volumes	$	21,112.00	$	171,340.14	$	192,452.14
832000	1022:	MIST UGS - RESERVOIR	600100	SALARY PAYROLL	NWN	F1	219,727.61	83210220	10.97%	Firm Sales Volumes	$	24,104.12	$	195,623.49	$	219,727.61
832000	1022:	MIST UGS - RESERVOIR	600500	SALARY BONUS PAYROLL	NWN	F1	42,944.76	83210220	10.97%	Firm Sales Volumes	$	4,711.04	$	38,233.72	$	42,944.76
840000	1007:	GAS CONTROL-GAS STOR	600100	SALARY PAYROLL	NWN	F1	168,851.16	84010078	10.97%	Firm Sales Volumes	$	18,522.97	$	150,328.19	$	168,851.16
840000	1007:	GAS CONTROL-GAS STOR	600500	SALARY BONUS PAYROLL	NWN	F1	118.49	84010078	10.97%	Firm Sales Volumes	$	13.00	$	105.49	$	118.49
844200	1012:	NEWPORT LNG - LNG OP	600100	SALARY PAYROLL	NWN	F1	133,272.70	84410121	10.97%	Firm Sales Volumes	$	14,620.02	$	118,652.68	$	133,272.70
844200	1012:	NEWPORT LNG - LNG OP	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	98,836.09	84410121	10.97%	Firm Sales Volumes	$	10,842.32	$	87,993.77	$	98,836.09
844200	1012:	NEWPORT LNG - LNG OP	600304	HIGH PAY	NWN	F1	22.96	84410121	10.97%	Firm Sales Volumes	$	2.52	$	20.44	$	22.96
844200	1012:	NEWPORT LNG - LNG OP	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	543,080.31	84410121	10.97%	Firm Sales Volumes	$	59,575.91	$	483,504.40	$	543,080.31
844200	1012:	NEWPORT LNG - LNG OP	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	263,509.20	84410121	10.97%	Firm Sales Volumes	$	28,906.96	$	234,602.24	$	263,509.20
844200	1012:	NEWPORT LNG - LNG OP	600400	P/T HOURLY PAYROLL	NWN	F1	48,494.24	84410121	10.97%	Firm Sales Volumes	$	5,319.82	$	43,174.42	$	48,494.24
844200	1012:	NEWPORT LNG - LNG OP	600900	VACATION, SICK & HOL	NWN	F1	102,506.13	84410121	10.97%	Firm Sales Volumes	$	11,244.92	$	91,261.21	$	102,506.13
844200	1014:	PORTLAND LNG - LNG O	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	66,970.19	84410149	10.97%	Firm Sales Volumes	$	7,346.63	$	59,623.56	$	66,970.19
844200	1014:	PORTLAND LNG - LNG O	600900	VACATION, SICK & HOL	NWN	F1	11,344.87	84410149	10.97%	Firm Sales Volumes	$	1,244.53	$	10,100.34	$	11,344.87
847300	1015:	PORTLAND LNG - LNG M	600100	SALARY PAYROLL	NWN	F1	145,228.67	84710151	10.97%	Firm Sales Volumes	$	15,931.59	$	129,297.08	$	145,228.67
847300	1015:	PORTLAND LNG - LNG M	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	16,636.03	84710151	10.97%	Firm Sales Volumes	$	1,824.97	$	14,811.06	$	16,636.03
847300	1015:	PORTLAND LNG - LNG M	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	265,142.26	84710151	10.97%	Firm Sales Volumes	$	29,086.11	$	236,056.15	$	265,142.26
847300	1015:	PORTLAND LNG - LNG M	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	9,667.83	84710151	10.97%	Firm Sales Volumes	$	1,060.56	$	8,607.27	$	9,667.83
847300	1015:	PORTLAND LNG - LNG M	600307	ON CALL ASSIGN. PAY	NWN	F1	29,059.78	84710151	10.97%	Firm Sales Volumes	$	3,187.86	$	25,871.92	$	29,059.78
847300	1015:	PORTLAND LNG - LNG M	600500	SALARY BONUS PAYROLL	NWN	F1	0.00	84710151	10.97%	Firm Sales Volumes	$	-	$	-	$	-
847300	1015:	PORTLAND LNG - LNG M	600900	VACATION, SICK & HOL	NWN	F1	46,887.01	84710151	10.97%	Firm Sales Volumes	$	5,143.50	$	41,743.51	$	46,887.01
856000	1036:	TRANSMISSION-TRNSMS	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	41,505.03	85610360	1.24%	Transmission	$	516.33	$	40,988.70	$	41,505.03
856000	1036:	TRANSMISSION-TRNSMS	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	1,103,865.35	85610360	1.24%	Transmission	$	13,732.39	$	1,090,132.96	$	1,103,865.35
856000	1036:	TRANSMISSION-TRNSMS	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	246,338.64	85610360	1.24%	Transmission	$	3,064.52	$	243,274.12	$	246,338.64
856000	1036:	TRANSMISSION-TRNSMS	600307	ON CALL ASSIGN. PAY	NWN	F1	0.00	85610360	1.24%	Transmission	$	-	$	-	$	-
856000	1036:	TRANSMISSION-TRNSMS	600900	VACATION, SICK & HOL	NWN	F1	192,734.67	85610360	1.24%	Transmission	$	2,397.67	$	190,337.00	$	192,734.67
870000	1000:	SYS OPS-TRNSMSN MAIN	600100	SALARY PAYROLL	NWN	F1	132,320.24	87010004	1.24%	transmission	$	1,646.10	$	130,674.14	$	132,320.24
870000	1007:	GAS ACQ & PIPE SVCE-	600100	SALARY PAYROLL	NWN	F1	828,514.65	87010074	8.68%	Sendout Volumes	$	71,915.07	$	756,599.58	$	828,514.65
870000	1007:	GAS ACQ & PIPE SVCE-	600500	SALARY BONUS PAYROLL	NWN	F1	3,681.71	87010074	8.68%	Sendout Volumes	$	319.57	$	3,362.14	$	3,681.71
870000	1008:	GAS CONTROL-TRNSMSN	600100	SALARY PAYROLL	NWN	F1	1,428,883.46	87010081	8.68%	Sendout Volumes	$	124,027.08	$	1,304,856.38	$	1,428,883.46
870000	1008:	GAS CONTROL-TRNSMSN	600500	SALARY BONUS PAYROLL	NWN	F1	0.00	87010081	8.68%	Sendout Volumes	$	-	$	-	$	-
874000	1029:	CFS-MAINS & SERV-EME	600100	SALARY PAYROLL	NWN	F1	748,449.16	87410295	12.17%	Customers-All	$	91,086.26	$	657,362.90	$	748,449.16
874000	1029:	CFS-MAINS & SERV-EME	600106	SALARY OVERTIME	NWN	F1	22,450.00	87410295	12.17%	Customers-All	$	2,732.17	$	19,717.84	$	22,450.00
874000	1029:	CFS-MAINS & SERV-EME	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	33,772.68	87410295	12.17%	Customers-All	$	4,110.14	$	29,662.54	$	33,772.68
874000	1029:	CFS-MAINS & SERV-EME	600500	SALARY BONUS PAYROLL	NWN	F1	1,088.49	87410295	12.17%	Customers-All	$	132.47	$	956.02	$	1,088.49
874000	1036:	TRANSMISSION-MAINS &	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	58,399.41	87410365	1.24%	Transmission	$	726.50	$	57,672.91	$	58,399.41
874000	1036:	TRANSMISSION-MAINS &	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	1,820,979.70	87410365	1.24%	Transmission	$	22,653.48	$	1,798,326.22	$	1,820,979.70
874000	1036:	TRANSMISSION-MAINS &	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	597,459.76	87410365	1.24%	Transmission	$	7,432.56	$	590,027.20	$	597,459.76
874000	1036:	TRANSMISSION-MAINS &	600307	ON CALL ASSIGN. PAY	NWN	F1	7,259.55	87410365	1.24%	Transmission	$	90.31	$	7,169.24	$	7,259.55
874000	1036:	TRANSMISSION-MAINS &	600900	VACATION, SICK & HOL	NWN	F1	311,364.92	87410365	1.24%	Transmission	$	3,873.46	$	307,491.46	$	311,364.92
874000	1041:	ENGINEER SVCES OR-MAI	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	990.56	87410417	0.00%	Direct-OR	$	-	$	990.56	$	990.56
874000	1041:	ENGINEER SVCES OR-MAI	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	333,409.57	87410417	0.00%	Direct-OR	$	-	$	333,409.57	$	333,409.57
874000	1041:	ENGINEER SVCES OR-MAI	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	15,099.98	87410417	0.00%	Direct-OR	$	-	$	15,099.98	$	15,099.98
874000	1041:	ENGINEER SVCES OR-MAI	600900	VACATION, SICK & HOL	NWN	F1	58,790.65	87410417	0.00%	Direct-OR	$	-	$	58,790.65	$	58,790.65
874000	1042:	ENGINEER SVCES OR-MAI	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	1,027.14	87410421	0.00%	Direct-OR	$	-	$	1,027.14	$	1,027.14
874000	1042:	ENGINEER SVCES OR-MAI	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	412,612.97	87410421	0.00%	Direct-OR	$	-	$	412,612.97	$	412,612.97
874000	1042:	ENGINEER SVCES OR-MAI	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	65,390.53	87410421	0.00%	Direct-OR	$	-	$	65,390.53	$	65,390.53
874000	1042:	ENGINEER SVCES OR-MAI	600900	VACATION, SICK & HOL	NWN	F1	73,065.95	87410421	0.00%	Direct-OR	$	-	$	73,065.95	$	73,065.95
874000	1048:	DISTRIBUTION-MAINS &	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	5,857.02	87410480	12.17%	Customers-All	$	712.80	$	5,144.22	$	5,857.02
874000	1048:	DISTRIBUTION-MAINS &	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	174,589.77	87410480	12.17%	Customers-All	$	21,247.58	$	153,342.19	$	174,589.77
874000	1048:	DISTRIBUTION-MAINS &	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	2,875.48	87410480	12.17%	Customers-All	$	349.95	$	2,525.53	$	2,875.48
874000	1048:	DISTRIBUTION-MAINS &	600307	ON CALL ASSIGN. PAY	NWN	F1	4,165.73	87410480	12.17%	Customers-All	$	506.97	$	3,658.76	$	4,165.73
874000	1048:	DISTRIBUTION-MAINS &	600900	VACATION, SICK & HOL	NWN	F1	29,854.07	87410480	12.17%	Customers-All	$	3,633.24	$	26,220.83	$	29,854.07
874000	1048:	DISTRIBUTION-MAINS &	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	852,795.30	87410485	12.17%	Customers-All	$	103,785.19	$	749,010.11	$	852,795.30
874000	1048:	DISTRIBUTION-MAINS &	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	10,852,791.00	87410485	12.17%	Customers-All	$	1,320,784.66	$	9,532,006.34	$	10,852,791.00
874000	1048:	DISTRIBUTION-MAINS &	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	1,336,551.17	87410485	12.17%	Customers-All	$	162,658.28	$	1,173,892.89	$	1,336,551.17
874000	1048:	DISTRIBUTION-MAINS &	600307	ON CALL ASSIGN. PAY	NWN	F1	719,711.67	87410485	12.17%	Customers-All	$	87,588.91	$	632,122.76	$	719,711.67
874000	1048:	DISTRIBUTION-MAINS &	600500	SALARY BONUS PAYROLL	NWN	F1	0.00	87410485	12.17%	Customers-All	$	-	$	-	$	-
874000	1048:	DISTRIBUTION-MAINS &	600900	VACATION, SICK & HOL	NWN	F1	2,004,665.27	87410485	12.17%	Customers-All	$	243,967.76	$	1,760,697.51	$	2,004,665.27
874000	1055:	CONTRACT SERVICES-MA	600100	SALARY PAYROLL	NWN	F1	131,651.13	87410552	12.17%	Customers-All	$	16,021.94	$	115,629.19	$	131,651.13
874000	1055:	CONTRACT SERVICES-MA	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	6,024.62	87410554	12.17%	Customers-All	$	733.20	$	5,291.42	$	6,024.62
874000	1055:	CONTRACT SERVICES-MA	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	134,268.62	87410554	12.17%	Customers-All	$	16,340.49	$	117,928.13	$	134,268.62
874000	1055:	CONTRACT SERVICES-MA	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	31,998.52	87410554	12.17%	Customers-All	$	3,894.22	$	28,104.30	$	31,998.52
874000	1055:	CONTRACT SERVICES-MA	600307	ON CALL ASSIGN. PAY	NWN	F1	430.11	87410554	12.17%	Customers-All	$	52.34	$	377.77	$	430.11
874000	1055:	CONTRACT SERVICES-MA	600900	VACATION, SICK & HOL	NWN	F1	25,373.85	87410554	12.17%	Customers-All	$	3,088.00	$	22,285.85	$	25,373.85
874000	1056:	OPS TECH SVCES-MAINS	600100	SALARY PAYROLL	NWN	F1	138,120.73	87410562	12.17%	Customers-All	$	16,809.29	$	121,311.44	$	138,120.73
874000	1056:	OPS TECH SVCES-MAINS	600500	SALARY BONUS PAYROLL	NWN	F1	62.20	87410562	12.17%	Customers-All	$	7.57	$	54.63	$	62.20
874000	1057:	COMPLIANCE SERV-MAIN	600100	SALARY PAYROLL	NWN	F1	129,428.47	87410573	12.17%	Customers-All	$	15,751.44	$	113,677.03	$	129,428.47
874000	1057:	COMPLIANCE SERV-MAIN	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	14,525.53	87410573	12.17%	Customers-All	$	1,767.76	$	12,757.77	$	14,525.53
874000	1057:	COMPLIANCE SERV-MAIN	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	780,841.33	87410573	12.17%	Customers-All	$	95,028.39	$	685,812.94	$	780,841.33
874000	1057:	COMPLIANCE SERV-MAIN	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	61,449.31	87410573	12.17%	Customers-All	$	7,478.38	$	53,970.93	$	61,449.31
874000	1057:	COMPLIANCE SERV-MAIN	600307	ON CALL ASSIGN. PAY	NWN	F1	8,336.88	87410573	12.17%	Customers-All	$	1,014.60	$	7,322.28	$	8,336.88
874000	1057:	COMPLIANCE SERV-MAIN	600500	SALARY BONUS PAYROLL	NWN	F1	124.40	87410573	12.17%	Customers-All	$	15.14	$	109.26	$	124.40
874000	1057:	COMPLIANCE SERV-MAIN	600900	VACATION, SICK & HOL	NWN	F1	143,910.13	87410573	12.17%	Customers-All	$	17,513.86	$	126,396.27	$	143,910.13
874000	1112:	CONTRACT SERVICES-MA	600100	SALARY PAYROLL	NWN	F1	103,364.65	87411125	12.17%	Customers-All	$	12,579.48	$	90,785.17	$	103,364.65
875000	1000:	SYS OPS-DISTRB MSRE&	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	71,118.83	87510009	8.68%	Sendout Volumes	$	6,173.11	$	64,945.72	$	71,118.83
875000	1000:	SYS OPS-DISTRB MSRE&	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	1,710,744.72	87510009	8.68%	Sendout Volumes	$	148,492.64	$	1,562,252.08	$	1,710,744.72
875000	1000:	SYS OPS-DISTRB MSRE&	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	262,047.24	87510009	8.68%	Sendout Volumes	$	22,745.70	$	239,301.54	$	262,047.24
875000	1000:	SYS OPS-DISTRB MSRE&	600307	ON CALL ASSIGN. PAY	NWN	F1	14,711.98	87510009	8.68%	Sendout Volumes	$	1,277.00	$	13,434.98	$	14,711.98
875000	1000:	SYS OPS-DISTRB MSRE&	600900	VACATION, SICK & HOL	NWN	F1	300,112.35	87510009	8.68%	Sendout Volumes	$	26,049.75	$	274,062.60	$	300,112.35
878000	1024:	GENERAL MAINT-DISTRB	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	408,263.51	87810248	12.17%	Customers-All	$	49,685.67	$	358,577.84	$	408,263.51
878000	1024:	GENERAL MAINT-DISTRB	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	30,624.88	87810248	12.17%	Customers-All	$	3,727.05	$	26,897.83	$	30,624.88
878000	1024:	GENERAL MAINT-DISTRB	600900	VACATION, SICK & HOL	NWN	F1	72,488.19	87810248	12.17%	Customers-All	$	8,821.81	$	63,666.38	$	72,488.19
878000	1030:	CFS-DISTR MTR&HOU RC	600300	HOURLY PAYROLL	NWN	F1	(1,592,380.82)	87810303	12.17%	Customers-All	$	(193,792.75)	$	(1,398,588.07)	$	(1,592,380.82)
878000	1030:	CFS-DISTR MTR&HOU RC	600100	SALARY PAYROLL	NWN	F1	1,837,791.09	87810304	12.17%	Customers-All	$	223,659.18	$	1,614,131.91	$	1,837,791.09
878000	1030:	CFS-DISTR MTR&HOU RC	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	9.98	87810304	12.17%	Customers-All	$	1.21	$	8.77	$	9.98
878000	1030:	CFS-DISTR MTR&HOU RC	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	385,590.64	87810304	12.17%	Customers-All	$	46,926.38	$	338,664.26	$	385,590.64
878000	1030:	CFS-DISTR MTR&HOU RC	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	3,567.39	87810304	12.17%	Customers-All	$	434.15	$	3,133.24	$	3,567.39
878000	1030:	CFS-DISTR MTR&HOU RC	600500	SALARY BONUS PAYROLL	NWN	F1	1,979.88	87810304	12.17%	Customers-All	$	240.95	$	1,738.93	$	1,979.88
878000	1030:	CFS-DISTR MTR&HOU RC	600900	VACATION, SICK & HOL	NWN	F1	63,453.81	87810304	12.17%	Customers-All	$	7,722.33	$	55,731.48	$	63,453.81
879000	1008:	FIELD SERV-CUSTOMER	600100	SALARY PAYROLL	NWN	F1	139,813.04	87910086	12.17%	Customers-All	$	17,015.25	$	122,797.79	$	139,813.04
879000	1008:	FIELD SERV-CUSTOMER	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	5,630.12	87910086	12.17%	Customers-All	$	685.19	$	4,944.93	$	5,630.12
879000	1008:	FIELD SERV-CUSTOMER	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	365,662.80	87910086	12.17%	Customers-All	$	44,501.16	$	321,161.64	$	365,662.80
879000	1008:	FIELD SERV-CUSTOMER	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	34,095.45	87910086	12.17%	Customers-All	$	4,149.42	$	29,946.03	$	34,095.45
879000	1008:	FIELD SERV-CUSTOMER	600500	SALARY BONUS PAYROLL	NWN	F1	77.76	87910086	12.17%	Customers-All	$	9.46	$	68.30	$	77.76
879000	1008:	FIELD SERV-CUSTOMER	600900	VACATION, SICK & HOL	NWN	F1	66,357.62	87910086	12.17%	Customers-All	$	8,075.72	$	58,281.90	$	66,357.62
879000	1030:	CFS-CUST INSTALL-OFF	600100	SALARY PAYROLL	NWN	F1	672,093.30	87910305	12.17%	Customers-All	$	81,793.75	$	590,299.55	$	672,093.30
879000	1030:	CFS-CUST INSTALL-OFF	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	7,893.85	87910305	12.17%	Customers-All	$	960.68	$	6,933.17	$	7,893.85
879000	1030:	CFS-CUST INSTALL-OFF	600500	SALARY BONUS PAYROLL	NWN	F1	4,262.09	87910305	12.17%	Customers-All	$	518.70	$	3,743.39	$	4,262.09
879000	1030:	CFS-CUST INSTALL-OFF	600900	VACATION, SICK & HOL	NWN	F1	1,140.50	87910305	12.17%	Customers-All	$	138.80	$	1,001.70	$	1,140.50
879000	1030:	CFS-CUST INSTALL-SER	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	844,787.93	87910306	12.17%	Customers-All	$	102,810.69	$	741,977.24	$	844,787.93
879000	1030:	CFS-CUST INSTALL-SER	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	10,374,383.07	87910306	12.17%	Customers-All	$	1,262,562.42	$	9,111,820.65	$	10,374,383.07
879000	1030:	CFS-CUST INSTALL-SER	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	910,092.60	87910306	12.17%	Customers-All	$	110,758.27	$	799,334.33	$	910,092.60
879000	1030:	CFS-CUST INSTALL-SER	600307	ON CALL ASSIGN. PAY	NWN	F1	297,353.75	87910306	12.17%	Customers-All	$	36,187.95	$	261,165.80	$	297,353.75
879000	1030:	CFS-CUST INSTALL-SER	600500	SALARY BONUS PAYROLL	NWN	F1	0.00	87910306	12.17%	Customers-All	$	-	$	-	$	-
879000	1030:	CFS-CUST INSTALL-SER	600900	VACATION, SICK & HOL	NWN	F1	1,830,324.66	87910306	12.17%	Customers-All	$	222,750.51	$	1,607,574.15	$	1,830,324.66
879000	1034:	RMC-CUST INSTAL-OFFI	600100	SALARY PAYROLL	NWN	F1	3,464,260.68	87910346	12.17%	Customers-All	$	421,600.52	$	3,042,660.16	$	3,464,260.68
879000	1034:	RMC-CUST INSTAL-OFFI	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	275.84	87910346	12.17%	Customers-All	$	33.57	$	242.27	$	275.84
879000	1034:	RMC-CUST INSTAL-OFFI	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	246,575.61	87910346	12.17%	Customers-All	$	30,008.25	$	216,567.36	$	246,575.61
879000	1034:	RMC-CUST INSTAL-OFFI	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	7,002.77	87910346	12.17%	Customers-All	$	852.24	$	6,150.53	$	7,002.77
879000	1034:	RMC-CUST INSTAL-OFFI	600500	SALARY BONUS PAYROLL	NWN	F1	74,557.61	87910346	12.17%	Customers-All	$	9,073.66	$	65,483.95	$	74,557.61
879000	1034:	RMC-CUST INSTAL-OFFI	600700	HOURLY BONUS PAYROLL	NWN	F1	933.06	87910346	12.17%	Customers-All	$	113.55	$	819.51	$	933.06
879000	1034:	RMC-CUST INSTAL-OFFI	600900	VACATION, SICK & HOL	NWN	F1	42,766.99	87910346	12.17%	Customers-All	$	5,204.74	$	37,562.25	$	42,766.99
879000	1055:	CONTRACT SERV-CUST I	600100	SALARY PAYROLL	NWN	F1	1,470,061.91	87910555	12.17%	Customers-All	$	178,906.53	$	1,291,155.38	$	1,470,061.91
879000	1055:	CONTRACT SERV-CUST I	600500	SALARY BONUS PAYROLL	NWN	F1	4,000.00	87910555	12.17%	Customers-All	$	486.80	$	3,513.20	$	4,000.00
879000	1156:	Meter Mod Cust Insta	600100	SALARY PAYROLL	NWN	F1	52,048.91	87911564	12.17%	Customers-All	$	6,334.35	$	45,714.56	$	52,048.91
879000	1156:	Meter Mod Cust Insta	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	14,769.12	87911564	12.17%	Customers-All	$	1,797.40	$	12,971.72	$	14,769.12
879000	1156:	Meter Mod Cust Insta	600900	VACATION, SICK & HOL	NWN	F1	2,138.42	87911564	12.17%	Customers-All	$	260.25	$	1,878.17	$	2,138.42
880000	1002:	SYS OPS-OTHER DISTRI	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	21,036.70	88010026	12.17%	Customers-All	$	2,560.17	$	18,476.53	$	21,036.70
880000	1002:	SYS OPS-OTHER DISTRI	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	387,706.30	88010026	12.17%	Customers-All	$	47,183.86

NW Natural
Employee Cost Allocation Factor
Test Year Ending March 31, 2025

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							$ 142,323,163.45				Employee Cost Factor	11.0161%	88.9839%		
											TOTAL Incldg Construction Wages	$ 24,992,324.25	$201,877,797.67		$226,870,121.92
											Add: Direct/Indirect Construction Wages	$ 9,163,030.26	$ 75,383,928.20		$ 84,546,958.47
											TOTAL	$ 15,829,293.98	$126,493,869.47		$142,323,163.45
						Fiscal Year Period	Amount								
						Measures	Overall Result								
FERC Account	Cost Center	Cost Center Description	GL Account	GL Account Long Name	Chart of Accounts	Ledger	$	SORTER	ALLOCATION FACTOR	ALLOCATION METHOD	WA	OR	SYSTEM
880000	1065:	STORES-OTHER DISTRIB	600700	HOURLY BONUS PAYROLL	NWN	F1	419.83	88010652	11.80%	3-factor	$ 49.54	$ 370.29	$ 419.83
880000	1065:	STORES-OTHER DISTRIB	600900	VACATION, SICK & HOL	NWN	F1	103,810.07	88010652	11.80%	3-factor	$ 12,249.59	$ 91,560.48	$ 103,810.07
885000	1025:	ENGINEER SVCES WA-DIS	600100	SALARY PAYROLL	NWN	F1	135,132.50	88510255	100.00%	Direct-WA	$ 135,132.50	$ -	$ 135,132.50
885000	1025:	ENGINEER SVCES WA-DIS	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	139,127.36	88510255	100.00%	Direct-WA	$ 139,127.36	$ -	$ 139,127.36
885000	1025:	ENGINEER SVCES WA-DIS	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	459.92	88510255	100.00%	Direct-WA	$ 459.92	$ -	$ 459.92
885000	1025:	ENGINEER SVCES WA-DIS	600500	SALARY BONUS PAYROLL	NWN	F1	435.41	88510255	100.00%	Direct-WA	$ 435.41	$ -	$ 435.41
885000	1025:	ENGINEER SVCES WA-DIS	600900	VACATION, SICK & HOL	NWN	F1	26,342.67	88510255	100.00%	Direct-WA	$ 26,342.67	$ -	$ 26,342.67
885000	1036:	TRANSMISSION-DISTRB	600100	SALARY PAYROLL	NWN	F1	569,463.28	88510368	1.24%	Transmission	$ 7,084.28	$ 562,379.00	$ 569,463.28
885000	1036:	TRANSMISSION-DISTRB	600500	SALARY BONUS PAYROLL	NWN	F1	311.02	88510368	1.24%	Transmission	$ 3.87	$ 307.15	$ 311.02
885000	1042:	ENGINEERING SVCES OR	600100	SALARY PAYROLL	NWN	F1	3,847,154.24	88510429	0.00%	Direct-OR	$ -	$ 3,847,154.24	$ 3,847,154.24
885000	1042:	ENGINEERING SVCES OR	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	2,835.30	88510429	0.00%	Direct-OR	$ -	$ 2,835.30	$ 2,835.30
885000	1042:	ENGINEERING SVCES OR	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	2,044,629.57	88510429	0.00%	Direct-OR	$ -	$ 2,044,629.57	$ 2,044,629.57
885000	1042:	ENGINEERING SVCES OR	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	109,630.70	88510429	0.00%	Direct-OR	$ -	$ 109,630.70	$ 109,630.70
885000	1042:	ENGINEERING SVCES OR	600307	ON CALL ASSIGN. PAY	NWN	F1	860.22	88510429	0.00%	Direct-OR	$ -	$ 860.22	$ 860.22
885000	1042:	ENGINEERING SVCES OR	600500	SALARY BONUS PAYROLL	NWN	F1	8,416.56	88510429	0.00%	Direct-OR	$ -	$ 8,416.56	$ 8,416.56
885000	1042:	ENGINEERING SVCES OR	600700	HOURLY BONUS PAYROLL	NWN	F1	811.04	88510429	0.00%	Direct-OR	$ -	$ 811.04	$ 811.04
885000	1042:	ENGINEERING SVCES OR	600900	VACATION, SICK & HOL	NWN	F1	357,713.08	88510429	0.00%	Direct-OR	$ -	$ 357,713.08	$ 357,713.08
885000	1043:	ENGINEER SVCES OR-DIS	600100	SALARY PAYROLL	NWN	F1	-	88510435	0.00%	Direct-OR	$ -	$ -	$ -
885000	1044:	CODE COMPLIANCE-DIST	600100	SALARY PAYROLL	NWN	F1	519,812.03	88510444	11.80%	3-factor	$ 61,337.82	$ 458,474.21	$ 519,812.03
885000	1044:	CODE COMPLIANCE-DIST	600500	SALARY BONUS PAYROLL	NWN	F1	367.27	88510444	11.80%	3-factor	$ 43.34	$ 323.93	$ 367.27
885000	1046:	DIR-UTILITY OPS-DIST	600100	SALARY PAYROLL	NWN	F1	183,153.33	88510463	11.80%	3-factor	$ 21,612.09	$ 161,541.24	$ 183,153.33
885000	1046:	DIR-UTILITY OPS-DIST	600500	SALARY BONUS PAYROLL	NWN	F1	2,553.19	88510463	11.80%	3-factor	$ 301.28	$ 2,251.91	$ 2,553.19
885000	1049:	DISTRIB-DISTRB MAINT	600100	SALARY PAYROLL	NWN	F1	1,960,877.85	88510495	11.80%	3-factor	$ 231,383.59	$ 1,729,494.26	$ 1,960,877.85
885000	1049:	DISTRIB-DISTRB MAINT	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	1,046.07	88510495	11.80%	3-factor	$ 123.44	$ 922.63	$ 1,046.07
885000	1049:	DISTRIB-DISTRB MAINT	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	36,731.07	88510495	11.80%	3-factor	$ 4,334.27	$ 32,396.80	$ 36,731.07
885000	1049:	DISTRIB-DISTRB MAINT	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	2,859.45	88510495	11.80%	3-factor	$ 337.42	$ 2,522.03	$ 2,859.45
885000	1049:	DISTRIB-DISTRB MAINT	600500	SALARY BONUS PAYROLL	NWN	F1	222.12	88510495	11.80%	3-factor	$ 26.21	$ 195.91	$ 222.12
885000	1049:	DISTRIB-DISTRB MAINT	600900	VACATION, SICK & HOL	NWN	F1	6,094.66	88510495	11.80%	3-factor	$ 719.17	$ 5,375.49	$ 6,094.66
885000	1056:	OPS TECH SVCES-DISTR	600100	SALARY PAYROLL	NWN	F1	3,299,731.43	88510566	11.80%	3-factor	$ 389,368.31	$ 2,910,363.12	$ 3,299,731.43
885000	1056:	OPS TECH SVCES-DISTR	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	0.00	88510566	11.80%	3-factor	$ -	$ -	$ -
885000	1056:	OPS TECH SVCES-DISTR	600500	SALARY BONUS PAYROLL	NWN	F1	3,513.82	88510566	11.80%	3-factor	$ 414.63	$ 3,099.19	$ 3,513.82
885000	1056:	OPS TECH SVCES-DISTR	600900	VACATION, SICK & HOL	NWN	F1	0.00	88510566	11.80%	3-factor	$ -	$ -	$ -
885000	1056:	OPS TECH SVCES-DISTR	600100	SALARY PAYROLL	NWN	F1	220,853.08	88510567	11.80%	3-factor	$ 26,060.66	$ 194,792.42	$ 220,853.08
885000	1056:	OPS TECH SVCES-DISTR	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	61,767.39	88510567	11.80%	3-factor	$ 7,288.55	$ 54,478.84	$ 61,767.39
885000	1056:	OPS TECH SVCES-DISTR	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	54.82	88510567	11.80%	3-factor	$ 6.47	$ 48.35	$ 54.82
885000	1056:	OPS TECH SVCES-DISTR	600500	SALARY BONUS PAYROLL	NWN	F1	124.41	88510567	11.80%	3-factor	$ 14.68	$ 109.73	$ 124.41
885000	1056:	OPS TECH SVCES-DISTR	600900	VACATION, SICK & HOL	NWN	F1	11,327.93	88510567	11.80%	3-factor	$ 1,336.70	$ 9,991.23	$ 11,327.93
885000	1057I	DMG PREVENT-DISTRB M	600100	SALARY PAYROLL	NWN	F1	613,752.84	88510570	12.17%	Customers-All	$ 74,693.72	$ 539,059.12	$ 613,752.84
885000	1057I	DMG PREVENT-DISTRB M	600500	SALARY BONUS PAYROLL	NWN	F1	333.41	88510570	12.17%	Customers-All	$ 40.58	$ 292.83	$ 333.41
885000	1126:	PIPE I-DIST MAIN-SUP	600100	SALARY PAYROLL	NWN	F1	982,292.55	88511265	12.17%	Customers-All	$ 119,545.00	$ 862,747.55	$ 982,292.55
885000	1126:	PIPE I-DIST MAIN-SUP	600500	SALARY BONUS PAYROLL	NWN	F1	662.69	88511265	12.17%	Customers-All	$ 80.65	$ 582.04	$ 662.69
887000	1043:	ENGINEER SERV OR-DIST	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	9,065.66	88710430	0.00%	Direct-OR	$ -	$ 9,065.66	$ 9,065.66
887000	1043:	ENGINEER SERV OR-DIST	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	774,276.14	88710430	0.00%	Direct-OR	$ -	$ 774,276.14	$ 774,276.14
887000	1043:	ENGINEER SERV OR-DIST	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	91,286.70	88710430	0.00%	Direct-OR	$ -	$ 91,286.70	$ 91,286.70
887000	1043:	ENGINEER SERV OR-DIST	600900	VACATION, SICK & HOL	NWN	F1	135,215.61	88710430	0.00%	Direct-OR	$ -	$ 135,215.61	$ 135,215.61
889000	1003:	SYS OPS-MAINT-MSRE R	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	0.00	88910032	8.68%	Sendout Volumes	$ -	$ -	$ -
889000	1003:	SYS OPS-MAINT-MSRE R	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	97,431.86	88910032	8.68%	Sendout Volumes	$ 8,457.09	$ 88,974.77	$ 97,431.86
889000	1003:	SYS OPS-MAINT-MSRE R	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	434.60	88910032	8.68%	Sendout Volumes	$ 37.72	$ 396.88	$ 434.60
889000	1003:	SYS OPS-MAINT-MSRE R	600307	ON CALL ASSIGN. PAY	NWN	F1	0.00	88910032	8.68%	Sendout Volumes	$ -	$ -	$ -
889000	1003:	SYS OPS-MAINT-MSRE R	600900	VACATION, SICK & HOL	NWN	F1	17,042.21	88910032	8.68%	Sendout Volumes	$ 1,479.26	$ 15,562.95	$ 17,042.21
893000	1003I	SYS OPS-MAINT-MTR&H	600100	SALARY PAYROLL	NWN	F1	131,894.37	89310039	12.17%	Customers-All	$ 16,051.54	$ 115,842.83	$ 131,894.37
893000	1003I	SYS OPS-MAINT-MTR&H	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	4,981.84	89310039	12.17%	Customers-All	$ 606.29	$ 4,375.55	$ 4,981.84
893000	1003I	SYS OPS-MAINT-MTR&H	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	169,123.50	89310039	12.17%	Customers-All	$ 20,582.33	$ 148,541.17	$ 169,123.50
893000	1003I	SYS OPS-MAINT-MTR&H	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	28,818.45	89310039	12.17%	Customers-All	$ 3,507.21	$ 25,311.24	$ 28,818.45
893000	1003I	SYS OPS-MAINT-MTR&H	600307	ON CALL ASSIGN. PAY	NWN	F1	820.43	89310039	12.17%	Customers-All	$ 99.85	$ 720.58	$ 820.43
893000	1003I	SYS OPS-MAINT-MTR&H	600900	VACATION, SICK & HOL	NWN	F1	27,872.02	89310039	12.17%	Customers-All	$ 3,392.02	$ 24,480.00	$ 27,872.02
893000	1004:	SYS OPS-MAINT-MTR&H	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	10,166.92	89310043	12.17%	Customers-All	$ 1,237.31	$ 8,929.61	$ 10,166.92
893000	1004:	SYS OPS-MAINT-MTR&H	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	273,944.04	89310043	12.17%	Customers-All	$ 33,338.99	$ 240,605.05	$ 273,944.04
893000	1004:	SYS OPS-MAINT-MTR&H	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	38,994.90	89310043	12.17%	Customers-All	$ 4,745.68	$ 34,249.22	$ 38,994.90
893000	1004:	SYS OPS-MAINT-MTR&H	600307	ON CALL ASSIGN. PAY	NWN	F1	1,483.77	89310043	12.17%	Customers-All	$ 180.57	$ 1,303.20	$ 1,483.77
893000	1004:	SYS OPS-MAINT-MTR&H	600900	VACATION, SICK & HOL	NWN	F1	49,279.84	89310043	12.17%	Customers-All	$ 5,997.36	$ 43,282.48	$ 49,279.84
893000	1024:	METER SHOP-MTR&HOL	600100	SALARY PAYROLL	NWN	F1	233,469.63	89310240	12.17%	Customers-All	$ 28,413.25	$ 205,056.38	$ 233,469.63
893000	1024:	METER SHOP-MTR&HOL	600500	SALARY BONUS PAYROLL	NWN	F1	139.98	89310240	12.17%	Customers-All	$ 17.04	$ 122.94	$ 139.98
893000	1024:	METER SHOP-MTRS&HO	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	293,095.33	89310243	12.17%	Customers-All	$ 35,669.70	$ 257,425.63	$ 293,095.33
893000	1024:	METER SHOP-MTRS&HO	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	4,938.62	89310243	12.17%	Customers-All	$ 601.03	$ 4,337.59	$ 4,938.62
893000	1024:	METER SHOP-MTRS&HO	600900	VACATION, SICK & HOL	NWN	F1	52,693.90	89310243	12.17%	Customers-All	$ 6,412.85	$ 46,281.05	$ 52,693.90
893000	1037:	TRANS-MAINT-MTR&HO	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	91.75	89310374	1.24%	Transmission	$ 1.14	$ 90.61	$ 91.75
893000	1037:	TRANS-MAINT-MTR&HO	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	81,964.98	89310374	1.24%	Transmission	$ 1,019.67	$ 80,945.31	$ 81,964.98
893000	1037:	TRANS-MAINT-MTR&HO	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	35,959.36	89310374	1.24%	Transmission	$ 447.34	$ 35,512.02	$ 35,959.36
893000	1037:	TRANS-MAINT-MTR&HO	600900	VACATION, SICK & HOL	NWN	F1	14,635.42	89310374	1.24%	Transmission	$ 182.07	$ 14,453.35	$ 14,635.42
893000	1037:	TRANS-MAINT-MTR&HO	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	1,830.00	89310375	1.24%	Transmission	$ 22.77	$ 1,807.23	$ 1,830.00
893000	1037:	TRANS-MAINT-MTR&HO	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	341,295.23	89310375	1.24%	Transmission	$ 4,245.81	$ 337,049.42	$ 341,295.23
893000	1037:	TRANS-MAINT-MTR&HO	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	17,273.85	89310375	1.24%	Transmission	$ 214.89	$ 17,058.96	$ 17,273.85
893000	1037:	TRANS-MAINT-MTR&HO	600900	VACATION, SICK & HOL	NWN	F1	58,539.06	89310375	1.24%	Transmission	$ 728.24	$ 57,810.82	$ 58,539.06
901000	1028I	CUST CONTACT CTR-CUS	600100	SALARY PAYROLL	NWN	F1	1,499,556.86	90110288	12.17%	Customers-All	$ 182,496.07	$ 1,317,060.79	$ 1,499,556.86
901000	1028I	CUST CONTACT CTR-CUS	600500	SALARY BONUS PAYROLL	NWN	F1	2,646.47	90110288	12.17%	Customers-All	$ 322.08	$ 2,324.39	$ 2,646.47
902000	1031I	CFS-CUST ACCTS OP-ME	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	343,344.69	90210319	12.17%	Customers-All	$ 41,785.05	$ 301,559.64	$ 343,344.69
902000	1031I	CFS-CUST ACCTS OP-ME	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	1,427.85	90210319	12.17%	Customers-All	$ 173.77	$ 1,254.08	$ 1,427.85
902000	1031I	CFS-CUST ACCTS OP-ME	600900	VACATION, SICK & HOL	NWN	F1	64,345.50	90210319	12.17%	Customers-All	$ 7,830.85	$ 56,514.65	$ 64,345.50
903000	1011I	MAJ ACCT SERV-CUST R	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	129.84	90310115	7.68%	Customers-Ind	$ 9.97	$ 119.87	$ 129.84
903000	1011I	MAJ ACCT SERV-CUST R	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	298,808.26	90310115	7.68%	Customers-Ind	$ 22,948.47	$ 275,859.79	$ 298,808.26
903000	1011I	MAJ ACCT SERV-CUST R	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	4,131.56	90310115	7.68%	Customers-Ind	$ 317.30	$ 3,814.26	$ 4,131.56
903000	1011I	MAJ ACCT SERV-CUST R	600900	VACATION, SICK & HOL	NWN	F1	51,555.70	90310115	7.68%	Customers-Ind	$ 3,959.48	$ 47,596.22	$ 51,555.70
903000	1029I	CUST CONTACT CTR-CUS	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	84,806.84	90310290	12.17%	Customers-All	$ 10,320.99	$ 74,485.85	$ 84,806.84
903000	1029I	CUST CONTACT CTR-CUS	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	3,861,833.06	90310290	12.17%	Customers-All	$ 469,985.08	$ 3,391,847.98	$ 3,861,833.06
903000	1029I	CUST CONTACT CTR-CUS	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	380,913.64	90310290	12.17%	Customers-All	$ 46,357.19	$ 334,556.45	$ 380,913.64
903000	1029I	CUST CONTACT CTR-CUS	600400	P/T HOURLY PAYROLL	NWN	F1	321,752.44	90310290	12.17%	Customers-All	$ 39,157.27	$ 282,595.17	$ 321,752.44
903000	1029I	CUST CONTACT CTR-CUS	600500	SALARY BONUS PAYROLL	NWN	F1	(500.00)	90310290	12.17%	Customers-All	$ (60.85)	$ (439.15)	$ (500.00)
903000	1029I	CUST CONTACT CTR-CUS	600700	HOURLY BONUS PAYROLL	NWN	F1	811.02	90310290	12.17%	Customers-All	$ 98.70	$ 712.32	$ 811.02
903000	1029I	CUST CONTACT CTR-CUS	600900	VACATION, SICK & HOL	NWN	F1	738,632.79	90310290	12.17%	Customers-All	$ 89,891.61	$ 648,741.18	$ 738,632.79
903000	1034:	RMC-CUST RECORDS & C	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	66,695.92	90310347	12.17%	Customers-All	$ 8,116.89	$ 58,579.03	$ 66,695.92
903000	1034:	RMC-CUST RECORDS & C	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	351.79	90310347	12.17%	Customers-All	$ 42.81	$ 308.98	$ 351.79
903000	1034:	RMC-CUST RECORDS & C	600700	HOURLY BONUS PAYROLL	NWN	F1	311.01	90310347	12.17%	Customers-All	$ 37.85	$ 273.16	$ 311.01
903000	1034:	RMC-CUST RECORDS & C	600900	VACATION, SICK & HOL	NWN	F1	11,327.42	90310347	12.17%	Customers-All	$ 1,378.55	$ 9,948.87	$ 11,327.42
903000	1035:	ACCOUNT SERV-CUST RE	600100	SALARY PAYROLL	NWN	F1	365,110.06	90310355	12.17%	Customers-All	$ 44,433.89	$ 320,676.17	$ 365,110.06
903000	1035:	ACCOUNT SERV-CUST RE	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	124.86	90310355	12.17%	Customers-All	$ 15.20	$ 109.66	$ 124.86
903000	1035:	ACCOUNT SERV-CUST RE	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	564,485.42	90310355	12.17%	Customers-All	$ 68,697.88	$ 495,787.54	$ 564,485.42
903000	1035:	ACCOUNT SERV-CUST RE	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	40,135.21	90310355	12.17%	Customers-All	$ 4,884.46	$ 35,250.75	$ 40,135.21
903000	1035:	ACCOUNT SERV-CUST RE	600500	SALARY BONUS PAYROLL	NWN	F1	124.40	90310355	12.17%	Customers-All	$ 15.14	$ 109.26	$ 124.40
903000	1035:	ACCOUNT SERV-CUST RE	600900	VACATION, SICK & HOL	NWN	F1	100,381.86	90310355	12.17%	Customers-All	$ 12,216.47	$ 88,165.39	$ 100,381.86
903000	1035I	ACCOUNT SERV-CUST RE	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	584.64	90310356	12.17%	Customers-All	$ 71.15	$ 513.49	$ 584.64
903000	1035I	ACCOUNT SERV-CUST RE	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	198,237.44	90310356	12.17%	Customers-All	$ 24,125.50	$ 174,111.94	$ 198,237.44
903000	1035I	ACCOUNT SERV-CUST RE	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	1,979.18	90310356	12.17%	Customers-All	$ 240.87	$ 1,738.31	$ 1,979.18
903000	1035I	ACCOUNT SERV-CUST RE	600900	VACATION, SICK & HOL	NWN	F1	33,856.77	90310356	12.17%	Customers-All	$ 4,120.37	$ 29,736.40	$ 33,856.77
903000	1035:	ACCOUNT SERV-CUST RE	600100	SALARY PAYROLL	NWN	F1	0.00	90310357	12.17%	Customers-All	$ -	$ -	$ -
903000	1035:	ACCOUNT SERV-CUST RE	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	206,125.68	90310357	12.17%	Customers-All	$ 25,085.50	$ 181,040.18	$ 206,125.68
903000	1035:	ACCOUNT SERV-CUST RE	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	7,782.57	90310357	12.17%	Customers-All	$ 947.14	$ 6,835.43	$ 7,782.57
903000	1035:	ACCOUNT SERV-CUST RE	600500	SALARY BONUS PAYROLL	NWN	F1	(500.00)	90310357	12.17%	Customers-All	$ (60.85)	$ (439.15)	$ (500.00)
903000	1035:	ACCOUNT SERV-CUST RE	600700	HOURLY BONUS PAYROLL	NWN	F1	811.04	90310357	12.17%	Customers-All	$ 98.70	$ 712.34	$ 811.04
903000	1035:	ACCOUNT SERV-CUST RE	600900	VACATION, SICK & HOL	NWN	F1	35,425.23	90310357	12.17%	Customers-All	$ 4,311.25	$ 31,113.98	$ 35,425.23
903000	1075:	CASH MGMT-CUST RECO	600100	SALARY PAYROLL	NWN	F1	108,429.10	90310754	12.17%	Customers-All	$ 13,195.82	$ 95,233.28	$ 108,429.10
903000	1075:	CASH MGMT-CUST RECO	600500	SALARY BONUS PAYROLL	NWN	F1	93.28	90310754	12.17%	Customers-All	$ 11.35	$ 81.93	$ 93.28
903000	1092:	CUST ACQ & NEW CONS	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	55,809.30	90310921	12.17%	Customers-All	$ 6,791.99	$ 49,017.31	$ 55,809.30
903000	1092:	CUST ACQ & NEW CONS	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	356.48	90310921	12.17%	Customers-All	$ 43.38	$ 313.10	$ 356.48
903000	1092:	CUST ACQ & NEW CONS	600900	VACATION, SICK & HOL	NWN	F1	9,795.69	90310921	12.17%	Customers-All	$ 1,192.14	$ 8,603.55	$ 9,795.69
906000	1139I	ACCOUNT SERV-CUST SE	600100	SALARY PAYROLL	NWN	F1	98,959.92	90611399	12.17%	Customers-All	$ 12,043.42	$ 86,916.50	$ 98,959.92
906000	1139I	ACCOUNT SERV-CUST SE	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	672,819.62	90611399	12.17%	Customers-All	$ 81,882.15	$ 590,937.47	$ 672,819.62
906000	1139I	ACCOUNT SERV-CUST SE	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	1,117.95	90611399	12.17%	Customers-All	$ 136.05	$ 981.90	$ 1,117.95
906000	1139I	ACCOUNT SERV-CUST SE	600900	VACATION, SICK & HOL	NWN	F1	118,353.67	90611399	12.17%	Customers-All	$ 14,403.64	$ 103,950.03	$ 118,353.67
908000	1009I	CUST SEG SRVC-CUST A	600100	SALARY PAYROLL	NWN	F1	507,274.28	90810099	7.68%	Customers-Ind	$ 38,958.66	$ 468,315.62	$ 507,274.28
908000	1009I	CUST SEG SRVC-CUST A	600500	SALARY BONUS PAYROLL	NWN	F1	615.80	90810099	7.68%	Customers-Ind	$ 47.29	$ 568.51	$ 615.80
908000	1010:	CUST ACQ MRKTG CONV	600100	SALARY PAYROLL	NWN	F1	319,285.83	90810102	12.17%	Customers-All	$ 38,857.09	$ 280,428.74	$ 319,285.83
908000	1010:	CUST ACQ MRKTG CONV	600500	SALARY BONUS PAYROLL	NWN	F1	180.40	90810102	12.17%	Customers-All	$ 21.95	$ 158.45	$ 180.40
908000	1010:	CUST ACQ MRKTG CONV	600100	SALARY PAYROLL	NWN	F1	256,783.90	90810103	12.17%	Customers-All	$ 31,250.60	$ 225,533.30	$ 256,783.90
908000	1010:	CUST ACQ MRKTG CONV	600500	SALARY BONUS PAYROLL	NWN	F1	205.26	90810103	12.17%	Customers-All	$ 24.98	$ 180.28	$ 205.26
908000	1012:	RES CONSUMER SERV-CL	600100	SALARY PAYROLL	NWN	F1	123,914.80	90810128	12.34%	Customers-Res	$ 15,291.09	$ 108,623.71	$ 123,914.80
908000	1012:	RES CONSUMER SERV-CL	600500	SALARY BONUS PAYROLL	NWN	F1	77.76	90810128	12.34%	Customers-Res	$ 9.60	$ 68.16	$ 77.76
908000	1013I	CUST ACQ SRV CONVS-C	600100	SALARY PAYROLL	NWN	F1	328,733.57	90810136	12.17%	Customers-All	$ 40,006.88	$ 288,726.69	$ 328,733.57
908000	1013I	CUST ACQ SRV CONVS-C	600500	SALARY BONUS PAYROLL	NWN	F1	62.20	90810136	12.17%	Customers-All	$ 7.57	$ 54.63	$ 62.20
908000	1013:	CUST ACQ SRV CONVS-C	600100	SALARY PAYROLL	NWN	F1	398,282.93	90810137	12.17%	Customers-All	$ 48,471.03	$ 349,811.90	$ 398,282.93
908000	1013:	CUST ACQ SRV CONVS-C	600500	SALARY BONUS PAYROLL	NWN	F1	77.76	90810137	12.17%	Customers-All	$ 9.46	$ 68.30	$ 77.76
908000	1013I	CUST ACQ & NEW CONS	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	416,897.52	90810139	12.17%	Customers-All	$ 50,736.43	$ 366,161.09	$ 416,897.52
908000	1013I	CUST ACQ & NEW CONS	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	4,715.72	90810139	12.17%	Customers-All	$ 573.90	$ 4,141.82	$ 4,715.72
908000	1013I	CUST ACQ & NEW CONS	600900	VACATION, SICK & HOL	NWN	F1	73,577.88	90810139	12.17%	Customers-All	$ 8,954.43	$ 64,623.45	$ 73,577.88
908000	1016:	CUST ACQ MRKTG NEW-	600100	SALARY PAYROLL	NWN	F1	327,890.54	90810161	12.17%	Customers-All	$ 39,904.28	$ 287,986.26	$ 327,890.54
908000	1016:	CUST ACQ MRKTG NEW-	600500	SALARY BONUS PAYROLL	NWN	F1	174.21	90810161	12.17%	Customers-All	$ 21.20	$ 153.01	$ 174.21
908000	1016:	CUST ACQ MRKTG NEW-	600100	SALARY PAYROLL	NWN	F1	322,555.05	90810162	12.17%	Customers-All	$ 39,254.95	$ 283,300.10	$ 322,555.05
908000	1016:	CUST ACQ MRKTG NEW-	600500	SALARY BONUS PAYROLL	NWN	F1	207.20	90810162	12.17%	Customers-All	$ 25.22	$ 181.98	$ 207.20
908000	1045:	DIRECTOR-CUST I-CUST	600100	SALARY PAYROLL	NWN	F1	207,012.47	90810457	12.17%	Customers-All	$ 25,193.42	$ 181,819.05	$ 207,012.47
908000	1045:	DIRECTOR-CUST I-CUST	600500	SALARY BONUS PAYROLL	NWN	F1	108.09	90810457	12.17%	Customers-All	$ 13.15

NW Natural
Emoluvee Cost Allocation Factor
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							$ 142,323,163.45				Emoluvee Cost Factor		11.0161%		88.9839%		
											TOTAL Incldg Construction Wages	$	24,993,234.25	$	201,677,797.67	$	226,670,121.92
											Add Direct/Indirect Construction Wages	$	9,163,030.26	$	75,385,928.20	$	84,548,958.47
											TOTAL	$	15,829,293.98	$	126,493,869.47	$	142,323,163.45
				Fiscal Year Period			Amount										
				Measures			Overall Result										
FERC Account	Cost Center	Cost Center Description	GL Account	GL Account Long Name	Chart of Accounts	Ledger	$	SORTER	ALLOCATION FACTOR	ALLOCATION METHOD		WA		OR		SYSTEM
9110000	10176	CONSR RELATIONS-EVT-	600500	SALARY BONUS PAYROLL	NWN	F1	373.22	91110176	12.17%	Customers-All	$	45.42	$	327.80	$	373.22
9120000	10101	CUST ACQ MRKTG CONV	600500	SALARY PAYROLL	NWN	F1	95,393.68	91210107	12.17%	Customers-All	$	11,609.41	$	83,784.27	$	95,393.68
9120000	10101	CUST ACQ MRKTG CONV	600500	SALARY BONUS PAYROLL	NWN	F1	62.23	91210107	12.17%	Customers-All	$	7.57	$	54.66	$	62.23
9120000	10103	CUST ACQ MRKTG CONV	600500	SALARY BONUS PAYROLL	NWN	F1	114,439.57	91210108	12.17%	Customers-All	$	13,927.30	$	100,512.27	$	114,439.57
9120000	10103	CUST ACQ MRKTG CONV	600500	SALARY BONUS PAYROLL	NWN	F1	55.99	91210108	12.17%	Customers-All	$	6.81	$	49.18	$	55.99
9120000	10161	CUST ACQ MRKTG NEW-	600100	SALARY PAYROLL	NWN	F1	195,066.90	91210165	12.17%	Customers-All	$	23,739.64	$	171,327.26	$	195,066.90
9120000	10161	CUST ACQ MRKTG NEW-	600500	SALARY BONUS PAYROLL	NWN	F1	112.01	91210165	12.17%	Customers-All	$	13.63	$	98.38	$	112.01
9120000	10171	CONSR RELATIONS-EVT-	600100	SALARY PAYROLL	NWN	F1	75,999.05	91210178	12.17%	Customers-All	$	9,249.08	$	66,749.97	$	75,999.05
9120000	10171	CONSR RELATIONS-EVT-	600500	SALARY BONUS PAYROLL	NWN	F1	40.65	91210178	12.17%	Customers-All	$	5.68	$	40.97	$	46.65
9130000	10191	CONSMR INFO-913 CAT	600100	SALARY PAYROLL	NWN	F1	256,099.35	91310195	12.17%	Customers-All	$	31,167.29	$	224,932.06	$	256,099.35
9130000	10191	CONSMR INFO-913 CAT	600500	SALARY BONUS PAYROLL	NWN	F1	311.02	91310195	12.17%	Customers-All	$	37.85	$	273.17	$	311.02
9200000	10111	INTEG RESOURCE PLAN-	600100	SALARY PAYROLL	NWN	F1	489,707.54	92001117	11.80%	3-factor	$	57,785.49	$	431,922.05	$	489,707.54
9200000	10161	CONSR RELATIONS-EVT-	600100	SALARY PAYROLL	NWN	F1	175,250.44	92001182	12.17%	Customers-All	$	21,327.98	$	153,922.46	$	175,250.44
9200000	10161	CONSR RELATIONS-EVT-	600500	SALARY BONUS PAYROLL	NWN	F1	108.84	92001182	12.17%	Customers-All	$	13.25	$	95.59	$	108.84
9200000	10201	OR LOW INCME WTHDN	600100	SALARY PAYROLL	NWN	F1	104,761.07	92001205	0.00%	Direct-OR	$	-	$	104,761.07	$	104,761.07
9200000	10201	OR LOW INCME WTHDN	600500	SALARY BONUS PAYROLL	NWN	F1	93.31	92001205	0.00%	Direct-OR	$	-	$	93.31	$	93.31
9200000	10203	SMART ENERGY-OFFICE	600100	SALARY PAYROLL	NWN	F1	123,394.45	92001208	12.17%	Customers-All	$	15,017.10	$	108,377.35	$	123,394.45
9200000	10203	SMART ENERGY-OFFICE	600500	SALARY BONUS PAYROLL	NWN	F1	404.29	92001208	12.17%	Customers-All	$	49.20	$	355.09	$	404.29
9200000	10251	TRANSPORTATION-OFFIC	600100	SALARY PAYROLL	NWN	F1	120,837.02	92001252	11.80%	3-factor	$	14,258.83	$	106,578.69	$	120,837.52
9200000	10251	TRANSPORTATION-OFFIC	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	485.99	92001252	11.80%	3-factor	$	57.35	$	428.64	$	485.99
9200000	10251	TRANSPORTATION-OFFIC	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	988,671.45	92001252	11.80%	3-factor	$	116,663.23	$	872,008.22	$	988,671.45
9200000	10251	TRANSPORTATION-OFFIC	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	44,612.17	92001252	11.80%	3-factor	$	5,264.24	$	39,347.93	$	44,612.17
9200000	10251	TRANSPORTATION-OFFIC	600500	SALARY BONUS PAYROLL	NWN	F1	93.29	92001252	11.80%	3-factor	$	11.01	$	82.28	$	93.29
9200000	10251	TRANSPORTATION-OFFIC	600900	VACATION, SICK & HOL	NWN	F1	172,064.07	92001252	11.80%	3-factor	$	20,303.56	$	151,760.51	$	172,064.07
9200000	10261	IT NETWK LEADER-921	600100	SALARY PAYROLL	NWN	F1	163,393.98	92001266	11.80%	3-factor	$	19,304.09	$	144,289.89	$	163,593.98
9200000	10261	IT NETWK LEADER-921	600500	SALARY BONUS PAYROLL	NWN	F1	134.50	92001266	11.80%	3-factor	$	15.92	$	118.98	$	134.90
9200000	10261	IT INFRA TEAM-921	600100	SALARY PAYROLL	NWN	F1	1,721,926.89	92001269	11.80%	3-factor	$	203,187.37	$	1,518,739.52	$	1,721,926.89
9200000	10261	IT INFRA TEAM-921	600500	SALARY BONUS PAYROLL	NWN	F1	1,548.98	92001269	11.80%	3-factor	$	182.78	$	1,366.20	$	1,548.98
9200000	10271	IT NTWK TEAM-921	600100	SALARY PAYROLL	NWN	F1	1,049,241.10	92001270	11.80%	3-factor	$	123,810.45	$	925,430.65	$	1,049,241.10
9200000	10271	IT NTWK TEAM-921	600500	SALARY BONUS PAYROLL	NWN	F1	79.08	92001270	11.80%	3-factor	$	9.33	$	69.75	$	79.08
9200000	10281	IT SVC DELIVERY-921	600100	SALARY PAYROLL	NWN	F1	1,346,569.04	92001282	11.80%	3-factor	$	158,895.15	$	1,187,673.89	$	1,346,569.04
9200000	10281	IT SVC DELIVERY-921	600500	SALARY BONUS PAYROLL	NWN	F1	559.62	92001282	11.80%	3-factor	$	66.06	$	493.76	$	559.82
9200000	10351	BUSINESS SYS5-OFFICE	600100	SALARY PAYROLL	NWN	F1	1,365,762.94	92001353	12.17%	Customers-All	$	166,213.35	$	1,199,549.59	$	1,365,762.94
9200000	10351	BUSINESS SYS5-OFFICE	600500	SALARY BONUS PAYROLL	NWN	F1	8,533.11	92001353	12.17%	Customers-All	$	1,038.48	$	7,494.63	$	8,533.11
9200000	10411	ENGINEER SVCES OR-OFF	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	138,846.75	92001432	0.00%	Direct-OR	$	-	$	138,846.75	$	138,846.75
9200000	10411	ENGINEER SVCES OR-OFF	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	3,501.25	92001432	0.00%	Direct-OR	$	-	$	3,501.25	$	3,501.25
9200000	10411	ENGINEER SVCES OR-OFF	600500	SALARY BONUS PAYROLL	NWN	F1	(500.00)	92001432	0.00%	Direct-OR	$	-	$	(500.00)	$	(500.00)
9200000	10411	ENGINEER SVCES OR-OFF	600900	HOURLY BONUS PAYROLL	NWN	F1	811.02	92001432	0.00%	Direct-OR	$	-	$	811.02	$	811.02
9200000	10411	ENGINEER SVCES OR-OFF	600900	VACATION, SICK & HOL	NWN	F1	23,157.36	92001432	0.00%	Direct-OR	$	-	$	23,157.36	$	23,157.36
9200000	10461	DIRECTOR, TECH SERVI	600100	SALARY PAYROLL	NWN	F1	200,185.24	92001462	12.17%	Customers-All	$	24,362.54	$	175,822.70	$	200,185.24
9200000	10461	DIRECTOR, TECH SERVI	600500	SALARY BONUS PAYROLL	NWN	F1	2,553.20	92001462	12.17%	Customers-All	$	310.72	$	2,242.48	$	2,553.20
9200000	10551	BUSINESS ANALYSIS-OF	600100	SALARY PAYROLL	NWN	F1	969,953.63	92001550	12.17%	Customers-All	$	118,043.36	$	851,910.27	$	969,953.63
9200000	10551	BUSINESS ANALYSIS-OF	600500	SALARY BONUS PAYROLL	NWN	F1	612.64	92001550	12.17%	Customers-All	$	74.56	$	538.08	$	612.64
9200000	10661	STORES OBS INV - Inv	600500	SALARY BONUS PAYROLL	NWN	F1	(500.00)	92001660	12.17%	Customers-All	$	(60.85)	$	(439.15)	$	(500.00)
9200000	10661	PURCHASING-OFFICE ST	600100	SALARY PAYROLL	NWN	F1	1,427,037.08	92001661	11.80%	3-factor	$	190,918.79	$	1,427,037.08	$	1,617,955.87
9200000	10661	PURCHASING-OFFICE ST	600500	SALARY BONUS PAYROLL	NWN	F1	3,755.78	92001661	11.80%	3-factor	$	443.18	$	3,312.60	$	3,755.78
9200000	10681	OFFICE SERV-OFFICE S	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	144,479.83	92001665	12.17%	Customers-All	$	17,583.20	$	126,896.63	$	144,479.83
9200000	10681	OFFICE SERV-OFFICE S	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	893.45	92001665	12.17%	Customers-All	$	108.73	$	784.72	$	893.45
9200000	10681	OFFICE SERV-OFFICE S	600400	P/T HOURLY PAYROLL	NWN	F1	50,894.97	92001665	12.17%	Customers-All	$	6,193.92	$	44,701.05	$	50,894.97
9200000	10681	OFFICE SERV-OFFICE S	600900	VACATION, SICK & HOL	NWN	F1	32,792.63	92001665	12.17%	Customers-All	$	3,990.86	$	28,801.77	$	32,792.63
9200000	10701	INF SECUR COMP&QA-O	600100	SALARY PAYROLL	NWN	F1	1,840,980.70	92001705	12.17%	Customers-All	$	224,047.35	$	1,616,933.35	$	1,840,980.70
9200000	10701	INF SECUR COMP&QA-O	600500	SALARY BONUS PAYROLL	NWN	F1	14,931.11	92001705	12.17%	Customers-All	$	1,817.12	$	13,113.99	$	14,931.11
9200000	10701	IT MAINT-OFFIC-921	600100	SALARY PAYROLL	NWN	F1	455,077.35	92001707	11.80%	3-factor	$	53,699.13	$	401,378.22	$	455,077.35
9200000	10701	IT MAINT-OFFIC-921	600500	SALARY BONUS PAYROLL	NWN	F1	118.48	92001707	11.80%	3-factor	$	13.98	$	104.50	$	118.48
9200000	10711	IT GAS MGT SYS5-OFFI	600100	SALARY PAYROLL	NWN	F1	1,247,801.63	92001717	11.80%	3-factor	$	147,240.59	$	1,100,561.04	$	1,247,801.63
9200000	10711	IT GAS MGT SYS5-OFFI	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	12,425.04	92001717	11.80%	3-factor	$	1,466.15	$	10,958.89	$	12,425.04
9200000	10711	IT GAS MGT SYS5-OFFI	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	631,373.99	92001717	11.80%	3-factor	$	74,502.13	$	556,871.86	$	631,373.99
9200000	10711	IT GAS MGT SYS5-OFFI	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	64,668.64	92001717	11.80%	3-factor	$	7,634.44	$	57,064.20	$	64,698.64
9200000	10711	IT GAS MGT SYS5-OFFI	600500	SALARY BONUS PAYROLL	NWN	F1	1,114.11	92001717	11.80%	3-factor	$	131.46	$	982.65	$	1,114.11
9200000	10711	IT GAS MGT SYS5-OFFI	600900	VACATION, SICK & HOL	NWN	F1	113,668.38	92001717	11.80%	3-factor	$	13,416.41	$	100,281.97	$	113,698.38
9200000	10721	ENT APPLICATIONS-OFF	600100	SALARY PAYROLL	NWN	F1	3,586,656.36	92001727	12.17%	Customers-All	$	436,496.08	$	3,150,160.28	$	3,586,656.36
9200000	10721	ENT APPLICATIONS-OFF	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1	438.48	92001727	12.17%	Customers-All	$	53.36	$	385.12	$	438.48
9200000	10721	ENT APPLICATIONS-OFF	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	120,759.68	92001727	12.17%	Customers-All	$	14,696.45	$	106,063.23	$	120,759.68
9200000	10721	ENT APPLICATIONS-OFF	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	9,394.86	92001727	12.17%	Customers-All	$	1,143.35	$	8,251.51	$	9,394.86
9200000	10721	ENT APPLICATIONS-OFF	600500	SALARY BONUS PAYROLL	NWN	F1	14,162.36	92001727	12.17%	Customers-All	$	1,727.21	$	12,465.13	$	14,192.34
9200000	10721	ENT APPLICATIONS-OFF	600700	HOURLY BONUS PAYROLL	NWN	F1	93.28	92001727	12.17%	Customers-All	$	11.35	$	81.93	$	93.28
9200000	10721	ENT APPLICATIONS-OFF	600900	VACATION, SICK & HOL	NWN	F1	20,940.52	92001727	12.17%	Customers-All	$	2,548.46	$	18,392.06	$	20,940.52
9200000	10731	ENT ARCHITECTURE-OFF	600100	SALARY PAYROLL	NWN	F1	992,590.85	92001735	12.17%	Customers-All	$	120,798.11	$	871,792.54	$	992,590.85
9200000	10731	ENT ARCHITECTURE-OFF	600500	SALARY BONUS PAYROLL	NWN	F1	370.37	92001735	12.17%	Customers-All	$	45.07	$	325.30	$	370.37
9200000	10741	ACCOUNTING-OFFICE92	600100	SALARY PAYROLL	NWN	F1	834,771.38	92001740	11.80%	3-factor	$	98,503.02	$	736,268.36	$	834,771.38
9200000	10741	ACCOUNTING-OFFICE92	600500	SALARY BONUS PAYROLL	NWN	F1	238.58	92001740	11.80%	3-factor	$	28.15	$	210.41	$	238.56
9200000	10741	TECH ACCTG - 921	600100	SALARY PAYROLL	NWN	F1	344,122.34	92001741	12.17%	Customers-All	$	41,879.69	$	302,242.65	$	344,122.34
9200000	10741	TECH ACCTG - 921	600500	SALARY BONUS PAYROLL	NWN	F1	4,155.51	92001741	12.17%	Customers-All	$	505.73	$	3,649.78	$	4,155.51
9200000	10741	SARBANES OXLEY-OFFIC	600100	SALARY PAYROLL	NWN	F1	196,917.59	92001745	11.80%	3-factor	$	23,236.28	$	175,681.31	$	196,917.59
9200000	10741	SARBANES OXLEY-OFFIC	600500	SALARY BONUS PAYROLL	NWN	F1	0.00	92001745	11.80%	3-factor	$	-	$	-	$	-
9200000	10741	SEC REPORTING-921	600100	SALARY PAYROLL	NWN	F1	497,907.33	92001746	11.80%	3-factor	$	58,753.06	$	439,154.27	$	497,907.33
9200000	10741	SEC REPORTING-921	600500	SALARY BONUS PAYROLL	NWN	F1	77.01	92001746	11.80%	3-factor	$	9.09	$	67.92	$	77.01
9200000	10741	SEC REPORTING-OFFICE	600100	SALARY PAYROLL	NWN	F1	497,907.33	92001746	11.80%	3-factor	$	58,753.06	$	439,154.27	$	497,907.33
9200000	10741	SEC REPORTING-OFFICE	600500	SALARY BONUS PAYROLL	NWN	F1	77.01	92001746	11.80%	3-factor	$	9.09	$	67.92	$	77.01
9200000	10741	GAS ACCOUNTING-921	600100	SALARY PAYROLL	NWN	F1	571,093.85	92001748	11.80%	3-factor	$	67,387.89	$	503,695.96	$	571,083.85
9200000	10741	GAS ACCOUNTING-921	600500	SALARY BONUS PAYROLL	NWN	F1	155.51	92001748	11.80%	3-factor	$	18.35	$	137.16	$	155.51
9200000	10741	GAS ACCOUNTING-OFFIC	600100	SALARY PAYROLL	NWN	F1	571,093.85	92001748	11.80%	3-factor	$	67,387.89	$	503,695.96	$	571,083.85
9200000	10741	GAS ACCOUNTING-OFFIC	600500	SALARY BONUS PAYROLL	NWN	F1	155.51	92001748	11.80%	3-factor	$	18.35	$	137.16	$	155.51
9200000	10751	OPERATIONAL ACCTG-OI	600100	SALARY PAYROLL	NWN	F1	184,444.08	92001750	11.80%	3-factor	$	21,764.40	$	162,679.69	$	184,444.09
9200000	10751	OPERATIONAL ACCTG-OI	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1	226,126.22	92001750	11.80%	3-factor	$	26,682.89	$	199,443.33	$	226,126.22
9200000	10751	OPERATIONAL ACCTG-OI	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1	1,637.62	92001750	11.80%	3-factor	$	193.24	$	1,444.38	$	1,637.62
9200000	10751	OPERATIONAL ACCTG-OI	600900	VACATION, SICK & HOL	NWN	F1	37,504.65	92001750	11.80%	3-factor	$	4,476.29	$	33,458.36	$	37,934.65
9200000	10751	TAX-OFFICE STAFFING	600100	SALARY PAYROLL	NWN	F1	452,258.23	92001751	11.80%	3-factor	$	53,366.47	$	398,891.76	$	452,258.23
9200000	10751	TAX-OFFICE STAFFING	600500	SALARY BONUS PAYROLL	NWN	F1	306.68	92001751	11.80%	3-factor	$	36.19	$	270.49	$	306.68
9200000	10751	CASH MANAGEMENT-OF	600100	SALARY PAYROLL	NWN	F1	416,812.34	92001755	11.80%	3-factor	$	49,183.86	$	367,628.48	$	416,812.34
9200000	10751	CASH MANAGEMENT-OF	600500	SALARY BONUS PAYROLL	NWN	F1	4,882.07	92001755	11.80%	3-factor	$	576.08	$	4,305.99	$	4,882.07
9200000	10751	MID OFFICE-OFFICE ST	600100	SALARY PAYROLL	NWN	F1	298,695.73	92001756	11.80%	3-factor	$	35,246.10	$	263,449.63	$	298,695.73
9200000	10751	MID OFFICE-OFFICE ST	600500	SALARY BONUS PAYROLL	NWN	F1	208.03	92001756	11.80%	3-factor	$	24.61	$	183.92	$	208.53
9200000	10751	CAPITAL ACCOUNTING-C	600100	SALARY PAYROLL	NWN	F1	469,906.86	92001757	11.80%	3-factor	$	55,449.01	$	414,457.85	$	469,906.86
9200000	10751	CAPITAL ACCTG 921	600100	SALARY PAYROLL	NWN	F1	469,906.86	92001757	11.80%	3-factor	$	55,449.01	$	414,457.85	$	469,906.86
9200000	10751	BUSINESS DEVELOPMENT	600100	SALARY PAYROLL	NWN	F1	813,252.53	92001758	12.17%	Customers-All	$	98,972.83	$	714,279.70	$	813,252.53
9200000	10751	BUSINESS DEVELOPMENT	600500	SALARY BONUS PAYROLL	NWN	F1	85,653.27	92001758	12.17%	Customers-All	$	10,424.02	$	75,229.35	$	85,653.37
9200000	10751	RENEWABLES-OFFICE ST	600100	SALARY PAYROLL	NWN	F1	1,327,613.98	92001759	12.17%	Customers-All	$	161,570.62	$	1,166,043.34	$	1,327,613.96
9200000	10751	RENEWABLES-OFFICE ST	600500	SALARY BONUS PAYROLL	NWN	F1	7,389.63	92001759	12.17%	Customers-All	$	899.32	$	6,490.31	$	7,389.63
9200000	10761	FIN PLANNING & BUDGE	600100	SALARY PAYROLL	NWN	F1	900,305.03	92001763	11.80%	3-factor	$	106,238.41	$	794,087.12	$	900,325.53
9200000	10761	FIN PLANNING & BUDGE	600500	SALARY BONUS PAYROLL	NWN	F1	35,650.30	92001763	11.80%	3-factor	$	4,206.74	$	31,443.56	$	35,650.30
9200000	10761	STRATEGIC PLANNING-O	600100	SALARY PAYROLL	NWN	F1	629,340.09	92001765	11.80%	3-factor	$	74,262.13	$	555,077.96	$	629,340.09
9200000	10761	STRATEGIC PLANNING-O	600500	SALARY BONUS PAYROLL	NWN	F1	14,588.77	92001765	11.80%	3-factor	$	1,721.47	$	12,867.30	$	14,588.77
9200000	10761	CORP SECRETARY-OFFIC	600100	SALARY PAYROLL	NWN	F1	588,064.87	92001766	11.80%	3-factor	$	69,395.65	$	489,269.22	$	568,064.87
9200000	10761	CORP SECRETARY-OFFIC	600500	SALARY BONUS PAYROLL	NWN	F1	14,890.82	92001766	11.80%	3-factor	$	1,757.12	$	13,133.70	$	14,890.82
9200000	10771	INVESTOR RELATIONS-O	600100	SALARY PAYROLL	NWN	F1	239,904.75	92001775	11.80%	3-factor	$	28,308.76	$	211,595.99	$	239,904.75
9200000	10771	INVESTOR RELATIONS-O	600500	SALARY BONUS PAYROLL	NWN	F1	20,213.39	92001775	11.80%	3-factor	$	2,385.18	$	17,828.21	$	20,213.39
9200000	10781	LAND OVERHEAD-OFFICE	600100	SALARY PAYROLL	NWN	F1	224,657.17	92001787	11.80%	3-factor	$	26,509.59	$	198,147.58	$	224,657.17
9200000	10781	LAND OVERHEAD-OFFICE	600500	SALARY BONUS PAYROLL	NWN	F1	128.86	92001787	11.80%	3-factor	$	15.21	$	113.65	$	128.86
9200000	10791	BUSINESS CONT-OFFICE	600100	SALARY PAYROLL	NWN	F1	250,092.38	92001792	11.80%	3-factor	$	29,510.90	$	220,581.48	$	250,092.38
9200000	10791	BUSINESS CONT-OFFICE	600500	SALARY BONUS PAYROLL	NWN	F1	168.82	92001792	11.80%	3-factor	$	19.92	$	148.90	$	168.82
9200000	10791	CORPORATE SECRT-OFFI	600100	SALARY PAYROLL	NWN	F1	399,198.93	92001793	11.80%	3-factor	$	47,105.46	$	352,093.37	$	399,198.83
9200000	10791	CORPORATE SECRT-OFFI	600500	SALARY BONUS PAYROLL	NWN	F1	186.59	92001793	11.80%	3-factor	$	22.02	$	164.57	$	186.59
9200000	10791	CORPORATE SECURITY-C	600100	SALARY PAYROLL	NWN	F1	195,448.58	92001794	11.80%	3-factor	$	23,062.93	$	172,385.65	$	195,448.58
9200000	10791	CORPORATE SECURITY-C	600500	SALARY BONUS PAYROLL	NWN	F1	152.20	92001794	11.80%	3-factor	$	17.96	$	134.24	$	152.20
9200000	10791	PROJECT OFFICE-OFFIC	600100	SALARY PAYROLL	NWN	F1	1,918,029.14	92001796	11.80%	3-factor	$	226,327.44	$	1,691,701.70	$	1,918,029.14
9200000	10791	PROJECT OFFICE-OFFIC	600500	SALARY BONUS PAYROLL	NWN	F1	20,155.51	92001796	11.80%	3-factor	$	2,378.35	$	17,777.16	$	20,155.51
9200000	10801	CLAIMS OVERHEAD-OFFI	600100	SALARY PAYROLL	NWN	F1	289,804.28	92001801	11.80%	3-factor	$	34,196.91	$	255,607.37	$	289,804.28
9200000	10801	PUB POLICY & GVRM AF	600100	SALARY PAYROLL	NWN	F1	908,527.86	92001803	11.80%	3-factor	$	107,206.29	$	801,321.57	$	908,527.86
9200000	10801	PUB POLICY & GVRM AF	600500	SALARY BONUS PAYROLL	NWN	F1	16,123.27	92001803	11.80%	3-factor	$	1,902.55	$	14,220.72	$	16,123.27
9200000	10801	PHILANTHROPY-OFFICE	600100	SALARY PAYROLL	NWN	F1	95,110.56	92001807	11.80%	3-factor	$	11,223.05	$	83,887.51	$	95,110.56
9200000	10801	PHILANTHROPY-OFFICE	600500	SALARY BONUS PAYROLL	NWN	F1	373.22	92001807	11.80%	3-factor	$	44.04	$	329.18	$	373.22
9200000	10811	COMM & CIVIC AFFAIRS	600100	SALARY PAYROLL	NWN	F1	253,288.91	92001811	11.80%	3-factor	$	29,888.09	$	223,400.82	$	253,288.91
9200000	10811	COMM & CIVIC AFFAIRS	600500	SALARY BONUS PAYROLL	NWN	F1	199.95	92001811	11.80%	3-factor	$	23.59	$	176.36	$	199.95
9200000	10831	CORPORATE COMMUNIC	600100	SALARY PAYROLL	NWN	F1	657,639.93	92001814	11.80%	3-factor	$	77,601.51	$	580,038.42	$	657,639.93
9200000	10831	CORPORATE COMMUNIC	600500	SALARY BONUS PAYROLL	NWN	F1	108.09	92001814	11.80%	3-factor	$	12.75	$	95.34	$	108.09
9200000	10831	REGULATORY AFFAIRS-O	600500	SALARY PAYROLL	NWN	F1	1,804,211.60	92001818	30.00%	Regulatory	$	541,263.48	$	1,262,948.12	$	1,804,211.60
9200000	10831	REGULATORY AFFAIRS-O	600506	SALARY OVERTIME	NWN	F1	270.70	92001818	30.00%	Regulatory	$	81.21	$	189.49	$	270.70
9200000	10831	REGULATORY AFFAIRS-O	600508	SALARY BONUS PAYROLL	NWN	F1	8,981.60	92001818	30.00%	Regulatory	$	2,694.48	$	6,287.12	$	8,981.60
9200000	10831	REGULATORY AFFAIRS-O	600800	SALARY P/T PAYROLL	NWN	F1	5,712.00	92001818	30.00%	Regulatory	$	1,713.60	$	3,998.40	$	5,712.00
9200000	10831	LEGAL-OFFICE STAFFIN	600100	SALARY PAYROLL	NWN	F1	1,324,051.35	92001819	11.80%	3-factor	$	156,238.06	$	1,167,813.29	$	1,324,051.35
9200000	10831	LEGAL-OFFICE STAFFIN	600500	SALARY BONUS PAYROLL	NWN	F1	58,082.27	92001819	11.80%	3-factor	$	6,853.71	$	51,228.56	$	58,082.27
9200000	10841	ENV POLICY AND SUSTN	600100	SALARY PAYROLL	NWN	F1	415,595.37	92001846	11.80%	3-factor	$	49,040.25	$	366,555.12	$	415,595.37
9200000	10841	ENV POLICY AND SUSTN	600500	SALARY BONUS PAYROLL	NWN	F1	5,072.27	92001846	11.80%	3-factor	$	598.53	$	4,473.74	$	5,072.27
9200000	10841	ENV POLICY AND SUSTN	600800	SALARY P/T PAYROLL	NWN	F1	2,352.00	92001846	11.80%	3-factor	$	277.54	$	2,074.46	$	2,352.00
9200000	10851	INTERNAL AUDITING-OF	600100	SALARY PAYROLL	NWN	F1	667,634.06	92001857	11.80%	3-factor	$	78,780.82	$	588,853.24	$	667,634.06
9200000	10851	INTERNAL AUDITING-OF	600500	SALARY BONUS PAYROLL	NWN	F1	593.05	92001857	11.80%	3-factor	$	69.98	$	523.07	$	593.05

NW Natural
Admin Transfer Allocation Factor
Test Year Ending March 31, 2025

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$ 71,068,305.98

							Fiscal Year Period Measures	Amount Overall Result				Admin Transfer Factor TOTAL	12.1429% $ 8,629,765.83	87.8571% $ 62,438,540.15	$ 71,068,305.98
FERC Account	Cost Center	Cost Center Description	GL Account	GL Account Long Name	Chart of Accounts	Ledger		$	SORTER	ALLOCATION FACTOR	ALLOCATION METHOD		WA	OR	SYSTEM
911000	10176	CONSR RELATIONS-EVT-	600100	SALARY PAYROLL	NWN	F1		110,773.76	91110176	12.17%	Customers-All	$	13,481.17	$ 97,292.59	$ 110,773.76
911000	10176	CONSR RELATIONS-EVT-	600500	SALARY BONUS PAYROLL	NWN	F1		373.22	91110176	12.17%	Customers-All	$	45.42	$ 327.80	$ 373.22
911000	10176	CONSR RELATIONS-EVT-	601100	EDUCATION	NWN	F1		595.00	91110176	12.17%	Customers-All	$	72.41	$ 522.59	$ 595.00
911000	10176	CONSR RELATIONS-EVT-	602466	P CARD UNCODED CHARG	NWN	F1		0.00	91110176	12.17%	Customers-All	$	-	$ -	$ -
911000	10176	CONSR RELATIONS-EVT-	604700	PARKING	NWN	F1		0.00	91110176	12.17%	Customers-All	$	-	$ -	$ -
911000	10176	CONSR RELATIONS-EVT-	607700	SMALL TOOLS	NWN	F1		0.00	91110176	12.17%	Customers-All	$	-	$ -	$ -
911000	10176	CONSR RELATIONS-EVT-	613100	CONFERENCE TRAVEL	NWN	F1		505.61	91110176	12.17%	Customers-All	$	61.53	$ 444.08	$ 505.61
911000	10176	CONSR RELATIONS-EVT-	622000	EMPLOYEE AWARDS	NWN	F1		923.40	91110176	12.17%	Customers-All	$	112.38	$ 811.02	$ 923.40
911000	10176	CONSR RELATIONS-EVT-	680105	SALARY REGULAR-2nd secondary outlin	NWN	F1		46,989.85	91110176	12.17%	Customers-All	$	5,718.66	$ 41,271.19	$ 46,989.85
912000	10104	CUST ACQ MRKTG CONV-	602800	POSTAGE	NWN	F1		3,051.08	91210104	12.17%	Customers-All	$	371.32	$ 2,679.76	$ 3,051.08
912000	10104	CUST ACQ MRKTG CONV-	603200	BOOKS AND MAGAZINES	NWN	F1		14.95	91210104	12.17%	Customers-All	$	1.82	$ 13.13	$ 14.95
912000	10104	CUST ACQ MRKTG CONV-	603300	REFRESHMENTS	NWN	F1		0.00	91210104	12.17%	Customers-All	$	-	$ -	$ -
912000	10104	CUST ACQ MRKTG CONV-	604600	DEALER RELATIONS	NWN	F1		500.07	91210104	12.17%	Customers-All	$	60.86	$ 439.21	$ 500.07
912000	10104	CUST ACQ MRKTG CONV-	605100	PROFESSIONAL SERVICE	NWN	F1		3,450.00	91210104	12.17%	Customers-All	$	419.87	$ 3,030.14	$ 3,450.00
912000	10104	CUST ACQ MRKTG CONV-	612100	MEALS AND ENTERTAIN	NWN	F1		76.74	91210104	12.17%	Customers-All	$	9.34	$ 67.40	$ 76.74
912000	10107	CUST ACQ MRKTG CONV-	600100	SALARY PAYROLL	NWN	F1		95,393.68	91210107	12.17%	Customers-All	$	11,609.41	$ 83,784.27	$ 95,393.68
912000	10107	CUST ACQ MRKTG CONV-	600500	SALARY BONUS PAYROLL	NWN	F1		62.23	91210107	12.17%	Customers-All	$	7.57	$ 54.66	$ 62.23
912000	10107	CUST ACQ MRKTG CONV-	602466	P CARD UNCODED CHARG	NWN	F1		0.00	91210107	12.17%	Customers-All	$	-	$ -	$ -
912000	10107	CUST ACQ MRKTG CONV-	680105	SALARY REGULAR-2nd secondary outlin	NWN	F1		(150,829.88)	91210107	12.17%	Customers-All	$	(18,356.00)	$ (132,473.88)	$ (150,829.88)
912000	10108	CUST ACQ MRKTG CONV-	600100	SALARY PAYROLL	NWN	F1		114,439.57	91210108	12.17%	Customers-All	$	13,927.30	$ 100,512.27	$ 114,439.57
912000	10108	CUST ACQ MRKTG CONV-	600500	SALARY BONUS PAYROLL	NWN	F1		55.99	91210108	12.17%	Customers-All	$	6.81	$ 49.18	$ 55.99
912000	10108	CUST ACQ MRKTG CONV-	601100	EDUCATION	NWN	F1		399.00	91210108	12.17%	Customers-All	$	48.56	$ 350.44	$ 399.00
912000	10108	CUST ACQ MRKTG CONV-	602466	P CARD UNCODED CHARG	NWN	F1		0.00	91210108	12.17%	Customers-All	$	-	$ -	$ -
912000	10108	CUST ACQ MRKTG CONV-	680105	SALARY REGULAR-2nd secondary outlin	NWN	F1		382,444.72	91210108	12.17%	Customers-All	$	46,543.52	$ 335,901.20	$ 382,444.72
912000	10109	CUST ACQ MRK CONV-DE	607000	REBATES	NWN	F1		125,029.98	91210109	12.34%	Customers-Res	$	15,428.70	$ 109,601.28	$ 125,029.98
912000	10130	RES CONSUMER SERV-DE	603000	OFFICE SUPPLIES	NWN	F1		0.00	91210130	12.34%	Customers-Res	$	-	$ -	$ -
912000	10130	RES CONSUMER SERV-DE	603200	BOOKS AND MAGAZINES	NWN	F1		0.00	91210130	12.34%	Customers-Res	$	-	$ -	$ -
912000	10131	RES CONSUMER SERV-DE	605300	CUSTOMER RECOVERY	NWN	F1		0.00	91210131	12.34%	Customers-Res	$	-	$ -	$ -
912000	10163	CUST ACQ MRKTG NEW-D	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1		63.19	91210163	12.17%	Customers-All	$	7.69	$ 55.50	$ 63.19
912000	10163	CUST ACQ MRKTG NEW-D	602466	P CARD UNCODED CHARG	NWN	F1		(195.60)	91210163	12.17%	Customers-All	$	(23.80)	$ (171.80)	$ (195.60)
912000	10163	CUST ACQ MRKTG NEW-D	603200	BOOKS AND MAGAZINES	NWN	F1		1,610.00	91210163	12.17%	Customers-All	$	195.94	$ 1,414.06	$ 1,610.00
912000	10163	CUST ACQ MRKTG NEW-D	604600	DEALER RELATIONS	NWN	F1		8,303.84	91210163	12.17%	Customers-All	$	1,010.58	$ 7,293.26	$ 8,303.84
912000	10163	CUST ACQ MRKTG NEW-D	604700	PARKING	NWN	F1		31.20	91210163	12.17%	Customers-All	$	3.80	$ 27.40	$ 31.20
912000	10163	CUST ACQ MRKTG NEW-D	612100	MEALS AND ENTERTAIN	NWN	F1		269.33	91210163	12.17%	Customers-All	$	32.78	$ 236.55	$ 269.33
912000	10165	CUST ACQ MRKTG NEW-D	600100	SALARY PAYROLL	NWN	F1		195,066.90	91210165	12.17%	Customers-All	$	23,739.64	$ 171,327.26	$ 195,066.90
912000	10165	CUST ACQ MRKTG NEW-D	600500	SALARY BONUS PAYROLL	NWN	F1		112.01	91210165	12.17%	Customers-All	$	13.63	$ 98.38	$ 112.01
912000	10165	CUST ACQ MRKTG NEW-D	601100	EDUCATION	NWN	F1		59.00	91210165	12.17%	Customers-All	$	7.18	$ 51.82	$ 59.00
912000	10165	CUST ACQ MRKTG NEW-D	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1		2,171.07	91210165	12.17%	Customers-All	$	264.22	$ 1,906.85	$ 2,171.07
912000	10165	CUST ACQ MRKTG NEW-D	602466	P CARD UNCODED CHARG	NWN	F1		(70.59)	91210165	12.17%	Customers-All	$	(8.59)	$ (62.00)	$ (70.59)
912000	10165	CUST ACQ MRKTG NEW-D	603300	REFRESHMENTS	NWN	F1		52.00	91210165	12.17%	Customers-All	$	6.33	$ 45.67	$ 52.00
912000	10165	CUST ACQ MRKTG NEW-D	604600	DEALER RELATIONS	NWN	F1		150.61	91210165	12.17%	Customers-All	$	18.33	$ 132.28	$ 150.61
912000	10165	CUST ACQ MRKTG NEW-D	604700	PARKING	NWN	F1		4.50	91210165	12.17%	Customers-All	$	0.55	$ 3.95	$ 4.50
912000	10165	CUST ACQ MRKTG NEW-D	612100	MEALS AND ENTERTAIN	NWN	F1		433.09	91210165	12.17%	Customers-All	$	52.71	$ 380.38	$ 433.09
912000	10165	CUST ACQ MRKTG NEW-D	680105	SALARY REGULAR-2nd secondary outlin	NWN	F1		(84,329.82)	91210165	12.17%	Customers-All	$	(10,262.94)	$ (74,066.88)	$ (84,329.82)
912000	10166	CUST ACQ MRKTG NEW-D	680105	SALARY REGULAR-2nd secondary outlin	NWN	F1		46,341.81	91210166	12.17%	Customers-All	$	5,639.80	$ 40,702.01	$ 46,341.81
912000	10177	CONSR REL-EVT-HOMSHW	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1		152.76	91210177	12.34%	Customers-Res	$	18.85	$ 133.91	$ 152.76
912000	10177	CONSR REL-EVT-HOMSHW	602466	P CARD UNCODED CHARG	NWN	F1		0.00	91210177	12.34%	Customers-Res	$	-	$ -	$ -
912000	10177	CONSR REL-EVT-HOMSHW	604700	PARKING	NWN	F1		0.00	91210177	12.34%	Customers-Res	$	-	$ -	$ -
912000	10177	CONSR REL-EVT-HOMSHW	607500	CORPORATE IDENTITY	NWN	F1		45,000.00	91210177	12.34%	Customers-Res	$	5,553.00	$ 39,447.00	$ 45,000.00
912000	10177	CONSR REL-EVT-HOMSHW	612100	MEALS AND ENTERTAIN	NWN	F1		38.90	91210177	12.34%	Customers-Res	$	4.80	$ 34.10	$ 38.90
912000	10177	CONSR REL-EVT-HOMSHW	613200	BUSINESS TRAVEL	NWN	F1		213.21	91210177	12.34%	Customers-Res	$	26.31	$ 186.90	$ 213.21
912000	10178	CONSR RELATIONS-EVT-	600100	SALARY PAYROLL	NWN	F1		75,999.05	91210178	12.17%	Customers-All	$	9,249.08	$ 66,749.97	$ 75,999.05
912000	10178	CONSR RELATIONS-EVT-	600500	SALARY BONUS PAYROLL	NWN	F1		46.65	91210178	12.17%	Customers-All	$	5.68	$ 40.97	$ 46.65
912000	10178	CONSR RELATIONS-EVT-	601400	MATERIALS	NWN	F1		38.08	91210178	12.17%	Customers-All	$	4.63	$ 33.45	$ 38.08
912000	10178	CONSR RELATIONS-EVT-	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1		456.04	91210178	12.17%	Customers-All	$	55.50	$ 400.54	$ 456.04
912000	10178	CONSR RELATIONS-EVT-	601700	EQUIPMENT	NWN	F1		0.00	91210178	12.17%	Customers-All	$	-	$ -	$ -
912000	10178	CONSR RELATIONS-EVT-	602100	OTHER CONTRACT WORK	NWN	F1		27,399.78	91210178	12.17%	Customers-All	$	3,334.55	$ 24,065.23	$ 27,399.78
912000	10178	CONSR RELATIONS-EVT-	602466	P CARD UNCODED CHARG	NWN	F1		4,835.53	91210178	12.17%	Customers-All	$	588.48	$ 4,247.05	$ 4,835.53
912000	10178	CONSR RELATIONS-EVT-	603000	OFFICE SUPPLIES	NWN	F1		0.00	91210178	12.17%	Customers-All	$	-	$ -	$ -
912000	10178	CONSR RELATIONS-EVT-	603300	REFRESHMENTS	NWN	F1		14.25	91210178	12.17%	Customers-All	$	1.73	$ 12.52	$ 14.25
912000	10178	CONSR RELATIONS-EVT-	604600	DEALER RELATIONS	NWN	F1		20,469.39	91210178	12.17%	Customers-All	$	2,491.12	$ 17,978.27	$ 20,469.39
912000	10178	CONSR RELATIONS-EVT-	604700	PARKING	NWN	F1		6.45	91210178	12.17%	Customers-All	$	0.78	$ 5.67	$ 6.45
912000	10178	CONSR RELATIONS-EVT-	604800	LAUNDRY	NWN	F1		272.86	91210178	12.17%	Customers-All	$	33.21	$ 239.65	$ 272.86
912000	10178	CONSR RELATIONS-EVT-	605100	PROFESSIONAL SERVICE	NWN	F1		70,366.37	91210178	12.17%	Customers-All	$	8,563.59	$ 61,802.78	$ 70,366.37
912000	10178	CONSR RELATIONS-EVT-	605200	ADVERTISING	NWN	F1		710.00	91210178	12.17%	Customers-All	$	86.41	$ 623.59	$ 710.00
912000	10178	CONSR RELATIONS-EVT-	606200	PERMITS AND FEES	NWN	F1		216.00	91210178	12.17%	Customers-All	$	26.29	$ 189.71	$ 216.00
912000	10178	CONSR RELATIONS-EVT-	607500	CORPORATE IDENTITY	NWN	F1		255,230.35	91210178	12.17%	Customers-All	$	31,061.53	$ 224,168.82	$ 255,230.35
912000	10178	CONSR RELATIONS-EVT-	612100	MEALS AND ENTERTAIN	NWN	F1		132.74	91210178	12.17%	Customers-All	$	16.15	$ 116.59	$ 132.74
912000	10178	CONSR RELATIONS-EVT-	680105	SALARY REGULAR-2nd secondary outlin	NWN	F1		(115,513.93)	91210178	12.17%	Customers-All	$	(14,058.05)	$ (101,455.88)	$ (115,513.93)
912000	10179	CONSR RELATIONS-EVT-	601100	EDUCATION	NWN	F1		74.99	91210179	12.17%	Customers-All	$	9.13	$ 65.86	$ 74.99
912000	10179	CONSR RELATIONS-EVT-	601400	MATERIALS	NWN	F1		22,947.43	91210179	12.17%	Customers-All	$	2,792.70	$ 20,154.73	$ 22,947.43
912000	10179	CONSR RELATIONS-EVT-	601401	MATERIALS - CONS INV	NWN	F1		0.00	91210179	12.17%	Customers-All	$	-	$ -	$ -
912000	10179	CONSR RELATIONS-EVT-	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1		31.18	91210179	12.17%	Customers-All	$	3.79	$ 27.39	$ 31.18
912000	10179	CONSR RELATIONS-EVT-	601900	DUES/MEMBERSHIP	NWN	F1		260.00	91210179	12.17%	Customers-All	$	31.64	$ 228.36	$ 260.00
912000	10179	CONSR RELATIONS-EVT-	602100	OTHER CONTRACT WORK	NWN	F1		1,368.88	91210179	12.17%	Customers-All	$	166.59	$ 1,202.29	$ 1,368.88
912000	10179	CONSR RELATIONS-EVT-	602466	P CARD UNCODED CHARG	NWN	F1		0.00	91210179	12.17%	Customers-All	$	-	$ -	$ -
912000	10179	CONSR RELATIONS-EVT-	602800	POSTAGE	NWN	F1		233.32	91210179	12.17%	Customers-All	$	28.40	$ 204.92	$ 233.32
912000	10179	CONSR RELATIONS-EVT-	603000	OFFICE SUPPLIES	NWN	F1		19.31	91210179	12.17%	Customers-All	$	2.35	$ 16.96	$ 19.31
912000	10179	CONSR RELATIONS-EVT-	603300	REFRESHMENTS	NWN	F1		0.00	91210179	12.17%	Customers-All	$	-	$ -	$ -
912000	10179	CONSR RELATIONS-EVT-	603400	TOOL EXPENSE	NWN	F1		87.99	91210179	12.17%	Customers-All	$	10.71	$ 77.28	$ 87.99
912000	10179	CONSR RELATIONS-EVT-	604100	PAYSTATION COMMISSIO	NWN	F1		0.00	91210179	12.17%	Customers-All	$	-	$ -	$ -
912000	10179	CONSR RELATIONS-EVT-	604600	DEALER RELATIONS	NWN	F1		378.67	91210179	12.17%	Customers-All	$	46.08	$ 332.59	$ 378.67
912000	10179	CONSR RELATIONS-EVT-	604601	PARTNER HOSPITALITY	NWN	F1		(90.42)	91210179	12.17%	Customers-All	$	(11.00)	$ (79.42)	$ (90.42)
912000	10179	CONSR RELATIONS-EVT-	604700	PARKING	NWN	F1		12.00	91210179	12.17%	Customers-All	$	1.46	$ 10.54	$ 12.00
912000	10179	CONSR RELATIONS-EVT-	604800	LAUNDRY	NWN	F1		929.18	91210179	12.17%	Customers-All	$	113.08	$ 816.10	$ 929.18
912000	10179	CONSR RELATIONS-EVT-	604900	UNIFORMS	NWN	F1		1,139.42	91210179	12.17%	Customers-All	$	138.67	$ 1,000.75	$ 1,139.42
912000	10179	CONSR RELATIONS-EVT-	606200	PERMITS AND FEES	NWN	F1		36.00	91210179	12.17%	Customers-All	$	4.38	$ 31.62	$ 36.00
912000	10179	CONSR RELATIONS-EVT-	607700	SMALL TOOLS	NWN	F1		196.14	91210179	12.17%	Customers-All	$	23.87	$ 172.27	$ 196.14
912000	10179	CONSR RELATIONS-EVT-	608100	SUBCRIPTION SERVICES	NWN	F1		2,544.00	91210179	12.17%	Customers-All	$	309.60	$ 2,234.40	$ 2,544.00
912000	10179	CONSR RELATIONS-EVT-	680105	SALARY REGULAR-2nd secondary outlin	NWN	F1		121,167.07	91210179	12.17%	Customers-All	$	14,746.03	$ 106,421.04	$ 121,167.07
912000	10180	CONSR REL-EVT-SHOWHM	601400	MATERIALS	NWN	F1		38.36	91210180	12.34%	Customers-Res	$	4.73	$ 33.63	$ 38.36
912000	10180	CONSR REL-EVT-SHOWHM	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1		429.47	91210180	12.34%	Customers-Res	$	53.00	$ 376.47	$ 429.47
912000	10180	CONSR REL-EVT-SHOWHM	602100	OTHER CONTRACT WORK	NWN	F1		7,421.32	91210180	12.34%	Customers-Res	$	915.79	$ 6,505.53	$ 7,421.32
912000	10180	CONSR REL-EVT-SHOWHM	602466	P CARD UNCODED CHARG	NWN	F1		0.00	91210180	12.34%	Customers-Res	$	-	$ -	$ -
912000	10180	CONSR REL-EVT-SHOWHM	604600	DEALER RELATIONS	NWN	F1		3,432.85	91210180	12.34%	Customers-Res	$	423.61	$ 3,009.24	$ 3,432.85
912000	10180	CONSR REL-EVT-SHOWHM	604601	PARTNER HOSPITALITY	NWN	F1		0.00	91210180	12.34%	Customers-Res	$	-	$ -	$ -
912000	10180	CONSR REL-EVT-SHOWHM	604800	LAUNDRY	NWN	F1		167.76	91210180	12.34%	Customers-Res	$	20.70	$ 147.06	$ 167.76
912000	10180	CONSR REL-EVT-SHOWHM	607500	CORPORATE IDENTITY	NWN	F1		4,940.00	91210180	12.34%	Customers-Res	$	609.60	$ 4,330.40	$ 4,940.00
912000	10180	CONSR REL-EVT-SHOWHM	612100	MEALS AND ENTERTAIN	NWN	F1		(361.67)	91210180	12.34%	Customers-Res	$	(44.63)	$ (317.04)	$ (361.67)
912000	10181	CONSR RELATION-EVT-D	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1		199.32	91210181	12.17%	Customers-All	$	24.26	$ 175.06	$ 199.32
912000	10181	CONSR RELATION-EVT-D	602100	OTHER CONTRACT WORK	NWN	F1		8,118.81	91210181	12.17%	Customers-All	$	988.06	$ 7,130.75	$ 8,118.81
912000	10181	CONSR RELATION-EVT-D	602466	P CARD UNCODED CHARG	NWN	F1		(0.00)	91210181	12.17%	Customers-All	$	(0.00)	$ (0.00)	$ (0.00)
912000	10181	CONSR RELATION-EVT-D	602800	POSTAGE	NWN	F1		59.04	91210181	12.17%	Customers-All	$	7.19	$ 51.85	$ 59.04
912000	10181	CONSR RELATION-EVT-D	603100	PRINTING	NWN	F1		409.75	91210181	12.17%	Customers-All	$	49.87	$ 359.88	$ 409.75
912000	10181	CONSR RELATION-EVT-D	603300	REFRESHMENTS	NWN	F1		(9.50)	91210181	12.17%	Customers-All	$	(1.16)	$ (8.34)	$ (9.50)
912000	10181	CONSR RELATION-EVT-D	603400	TOOL EXPENSE	NWN	F1		0.00	91210181	12.17%	Customers-All	$	-	$ -	$ -
912000	10181	CONSR RELATION-EVT-D	604600	DEALER RELATIONS	NWN	F1		13,493.23	91210181	12.17%	Customers-All	$	1,642.13	$ 11,851.10	$ 13,493.23
912000	10181	CONSR RELATION-EVT-D	604601	PARTNER HOSPITALITY	NWN	F1		10.36	91210181	12.17%	Customers-All	$	1.26	$ 9.10	$ 10.36
912000	10181	CONSR RELATION-EVT-D	604800	LAUNDRY	NWN	F1		0.00	91210181	12.17%	Customers-All	$	-	$ -	$ -
912000	10181	CONSR RELATION-EVT-D	605100	PROFESSIONAL SERVICE	NWN	F1		66,537.37	91210181	12.17%	Customers-All	$	8,097.60	$ 58,439.77	$ 66,537.37
912000	10181	CONSR RELATION-EVT-D	605200	ADVERTISING	NWN	F1		25.00	91210181	12.17%	Customers-All	$	3.04	$ 21.96	$ 25.00
912000	10181	CONSR RELATION-EVT-D	606200	PERMITS AND FEES	NWN	F1		102.00	91210181	12.17%	Customers-All	$	12.41	$ 89.59	$ 102.00
912000	10181	CONSR RELATION-EVT-D	607500	CORPORATE IDENTITY	NWN	F1		5,185.84	91210181	12.17%	Customers-All	$	631.12	$ 4,554.72	$ 5,185.84
912000	10181	CONSR RELATION-EVT-D	612100	MEALS AND ENTERTAIN	NWN	F1		43.10	91210181	12.17%	Customers-All	$	5.25	$ 37.85	$ 43.10
912000	10181	CONSR RELATION-EVT-D	612200	TRAVEL IN TERRITORY	NWN	F1		276.95	91210181	12.17%	Customers-All	$	33.70	$ 243.25	$ 276.95
912000	10181	CONSR RELATION-EVT-D	680105	SALARY REGULAR-2nd secondary outlin	NWN	F1		80,135.23	91210181	12.17%	Customers-All	$	9,752.46	$ 70,382.77	$ 80,135.23
912000	10185	CONSR REL EVT-ST DRM	601400	MATERIALS	NWN	F1		38.28	91210185	0.00%	Direct-OR	$	-	$ 38.28	$ 38.28
912000	10185	CONSR REL EVT-ST DRM	601401	MATERIALS - CONS INV	NWN	F1		(0.03)	91210185	0.00%	Direct-OR	$	-	$ (0.03)	$ (0.03)
912000	10185	CONSR REL EVT-ST DRM	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1		312.50	91210185	0.00%	Direct-OR	$	-	$ 312.50	$ 312.50
912000	10185	CONSR REL EVT-ST DRM	602100	OTHER CONTRACT WORK	NWN	F1		8,171.52	91210185	0.00%	Direct-OR	$	-	$ 8,171.52	$ 8,171.52
912000	10185	CONSR REL EVT-ST DRM	602466	P CARD UNCODED CHARG	NWN	F1		7.00	91210185	0.00%	Direct-OR	$	-	$ 7.00	$ 7.00
912000	10185	CONSR REL EVT-ST DRM	603000	OFFICE SUPPLIES	NWN	F1		115.79	91210185	0.00%	Direct-OR	$	-	$ 115.79	$ 115.79
912000	10185	CONSR REL EVT-ST DRM	604600	DEALER RELATIONS	NWN	F1		1,420.21	91210185	0.00%	Direct-OR	$	-	$ 1,420.21	$ 1,420.21
912000	10185	CONSR REL EVT-ST DRM	604601	PARTNER HOSPITALITY	NWN	F1		0.00	91210185	0.00%	Direct-OR	$	-	$ -	$ -
912000	10185	CONSR REL EVT-ST DRM	612100	MEALS AND ENTERTAIN	NWN	F1		0.00	91210185	0.00%	Direct-OR	$	-	$ -	$ -
912000	10459	DIRECTOR-CUST L-DEMO	680105	SALARY REGULAR-2nd secondary outlin	NWN	F1		56,767.11	91210459	12.17%	Customers-All	$	6,908.56	$ 49,858.55	$ 56,767.11
912000	10460	DIRECTOR-CUST L-DEMO	680105	SALARY REGULAR-2nd secondary outlin	NWN	F1		56,767.11	91210460	12.17%	Customers-All	$	6,908.56	$ 49,858.55	$ 56,767.11
912000	75000	CUST ACQ MRKTG NEW-N	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1		379.89	91275000	12.17%	Customers-All	$	46.23	$ 333.66	$ 379.89
912000	75000	CUST ACQ MRKTG NEW-N	602466	P CARD UNCODED CHARG	NWN	F1		0.00	91275000	12.17%	Customers-All	$	-	$ -	$ -
912000	75000	CUST ACQ MRKTG NEW-N	604600	DEALER RELATIONS	NWN	F1		36,595.34	91275000	12.17%	Customers-All	$	4,453.65	$ 32,141.69	$ 36,595.34
912000	75000	CUST ACQ MRKTG NEW-N	605100	PROFESSIONAL SERVICE	NWN	F1		63,075.00	91275000	12.17%	Customers-All	$	7,676.23	$ 55,398.77	$ 63,075.00
912000	75000	CUST ACQ MRKTG NEW-N	612100	MEALS AND ENTERTAIN	NWN	F1		410.03	91275000	12.17%	Customers-All	$	49.90	$ 360.13	$ 410.03
912000	75000	CUST ACQ MRKTG NEW-N	624100	BUILDER SIGNS	NWN	F1		3,389.00	91275000	12.17%	Customers-All	$	412.44	$ 2,976.56	$ 3,389.00
912000	75002	CUST ACQ MRKTG CONV-	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1		0.00	91275002	12.17%	Customers-All	$	-	$ -	$ -
912000	75002	CUST ACQ MRKTG CONV-	601900	DUES/MEMBERSHIP	NWN	F1		1,000.00	91275002	12.17%	Customers-All	$	121.70	$ 878.30	$ 1,000.00
912000	75002	CUST ACQ MRKTG CONV-	602466	P CARD UNCODED CHARG	NWN	F1		222.38	91275002	12.17%	Customers-All	$	27.06	$ 195.32	$ 222.38
912000	75002	CUST ACQ MRKTG CONV-	602800	POSTAGE	NWN	F1		45,000.00	91275002	12.17%	Customers-All	$	5,476.50	$ 39,523.50	$ 45,000.00
912000	75002	CUST ACQ MRKTG CONV-	603000	OFFICE SUPPLIES	NWN	F1		5.00	91275002	12.17%	Customers-All	$	0.61	$ 4.39	$ 5.00
912000	75002	CUST ACQ MRKTG CONV-	603300	REFRESHMENTS	NWN	F1		26.17	91275002	12.17%	Customers-All	$	3.18	$ 22.99	$ 26.17
912000	75002	CUST ACQ MRKTG CONV-	604600	DEALER RELATIONS	NWN	F1		12,024.67	91275002	12.17%	Customers-All	$	1,463.40	$ 10,561.27	$ 12,024.67
912000	75002	CUST ACQ MRKTG CONV-	604700	PARKING	NWN	F1		2.60	91275002	12.17%	Customers-All	$	0.32	$ 2.28	$ 2.60
912000	75002	CUST ACQ MRKTG CONV-	605100	PROFESSIONAL SERVICE	NWN	F1		195.00	91275002	12.17%	Customers-All	$	23.73	$ 171.27	$ 195.00
912000	75002	CUST ACQ MRKTG CONV-	612100	MEALS AND ENTERTAIN	NWN	F1		284.81	91275002	12.17%	Customers-All	$	34.66	$ 250.15	$ 284.81
912000	75002	CUST ACQ MRKTG CONV-	622000	EMPLOYEE AWARDS	NWN	F1		2,123.40	91275002	12.17%	Customers-All	$	258.42	$ 1,864.98	$ 2,123.40

NW Natural
Admin Transfer Allocation Factor
Test Year Ending March 31, 2025

$ 71,068,305.98

						Fiscal Year Period	Amount
						Measures	Overall Result
FERC Account	Cost Center	Cost Center Description	GL Account	GL Account Long Name	Chart of Accounts	Ledger	$
912000	75002	CUST ACQ MRKTG CONVI-	680105	SALARY REGULAR-2nd secondary outlin	NWN	P1	281.06
921000	10075	GAS ACQ & PIPE SVCE-	605100	PROFESSIONAL SERVICE	NWN	P1	25,660.89
921000	10095	FIELD SERVICES-OFFIC	601600	TRANSPORTATION	NWN	P1	6,786.00
921000	10117	INTEG RESOURCE PLAN-	601100	EDUCATION	NWN	P1	4,178.00
921000	10117	INTEG RESOURCE PLAN-	601400	MATERIALS	NWN	P1	69.93
921000	10117	INTEG RESOURCE PLAN-	601900	DUES/MEMBERSHIP	NWN	P1	2,700.00
921000	10117	INTEG RESOURCE PLAN-	602466	P CARD UNCODED CHARG	NWN	P1	664.40
921000	10117	INTEG RESOURCE PLAN-	603000	OFFICE SUPPLIES	NWN	P1	46.36
921000	10117	INTEG RESOURCE PLAN-	603300	REFRESHMENTS	NWN	P1	4.29
921000	10117	INTEG RESOURCE PLAN-	605100	PROFESSIONAL SERVICE	NWN	P1	289,555.63
921000	10117	INTEG RESOURCE PLAN-	606500	UNLEADED FUEL	NWN	P1	60.41
921000	10117	INTEG RESOURCE PLAN-	607500	CORPORATE IDENTITY	NWN	P1	3,200.00
921000	10117	INTEG RESOURCE PLAN-	612100	MEALS AND ENTERTAIN	NWN	P1	58.98
921000	10117	INTEG RESOURCE PLAN-	613100	CONFERENCE TRAVEL	NWN	P1	4,102.83
921000	10117	INTEG RESOURCE PLAN-	622000	EMPLOYEE AWARDS	NWN	P1	10.00
921000	10182	CONSR RELATIONS-EVT-	601400	MATERIALS	NWN	P1	272.07
921000	10182	CONSR RELATIONS-EVT-	602100	OTHER CONTRACT WORK	NWN	P1	1,344.17
921000	10182	CONSR RELATIONS-EVT-	602466	P CARD UNCODED CHARG	NWN	P1	118.70
921000	10182	CONSR RELATIONS-EVT-	604801	PARTNER HOSPITALITY	NWN	P1	0.00
921000	10182	CONSR RELATIONS-EVT-	612100	MEALS AND ENTERTAIN	NWN	P1	0.00
921000	10205	OR LOW INCME WTHZN-O	601100	EDUCATION	NWN	P1	0.00
921000	10205	OR LOW INCME WTHZN-O	602466	P CARD UNCODED CHARG	NWN	P1	(1,318.00)
921000	10205	OR LOW INCME WTHZN-O	603300	REFRESHMENTS	NWN	P1	125.40
921000	10205	OR LOW INCME WTHZN-O	604700	PARKING	NWN	P1	4.20
921000	10205	OR LOW INCME WTHZN-O	612100	MEALS AND ENTERTAIN	NWN	P1	713.53
921000	10205	OR LOW INCME WTHZN-O	613100	CONFERENCE TRAVEL	NWN	P1	5,341.29
921000	10205	OR LOW INCME WTHZN-O	613200	BUSINESS TRAVEL	NWN	P1	439.94
921000	10237	City of PDX-CNG Schw	602100	OTHER CONTRACT WORK	NWN	P1	0.00
921000	10252	TRANSPORTATION-OFFIC	601400	MATERIALS	NWN	P1	119.80
921000	10252	TRANSPORTATION-OFFIC	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	P1	3,416.75
921000	10252	TRANSPORTATION-OFFIC	601600	TRANSPORTATION	NWN	P1	114.79
921000	10252	TRANSPORTATION-OFFIC	601900	DUES/MEMBERSHIP	NWN	P1	150.00
921000	10252	TRANSPORTATION-OFFIC	602466	P CARD UNCODED CHARG	NWN	P1	(611.38)
921000	10252	TRANSPORTATION-OFFIC	603000	OFFICE SUPPLIES	NWN	P1	0.00
921000	10252	TRANSPORTATION-OFFIC	603400	TOOL EXPENSE	NWN	P1	0.00
921000	10252	TRANSPORTATION-OFFIC	604700	PARKING	NWN	P1	0.00
921000	10252	TRANSPORTATION-OFFIC	605500	REPAIRS AND MAINT	NWN	P1	1,604.00
921000	10252	TRANSPORTATION-OFFIC	605800	MEAL TICKETS	NWN	P1	117.60
921000	10252	TRANSPORTATION-OFFIC	612100	MEALS AND ENTERTAIN	NWN	P1	276.71
921000	10252	TRANSPORTATION-OFFIC	613100	CONFERENCE TRAVEL	NWN	P1	0.00
921000	10252	TRANSPORTATION-OFFIC	681500	MILEAGE REIMBURSEMNT	NWN	P1	(726.88)
921000	10252	TRANSPORTATION-OFFIC	685800	MEAL TICKETS SECONDARY	NWN	P1	(94.40)
921000	10266	IT NETWK LEADER-921	601401	MATERIALS - CONS INV	NWN	P1	0.00
921000	10266	IT NETWK LEADER-921	602100	OTHER CONTRACT WORK	NWN	P1	202,661.98
921000	10266	IT NETWK LEADER-921	602466	P CARD UNCODED CHARG	NWN	P1	58.50
921000	10266	IT NETWK LEADER-921	602700	TELEPHONE	NWN	P1	0.00
921000	10266	IT NETWK LEADER-921	602800	POSTAGE	NWN	P1	20.18
921000	10266	IT NETWK LEADER-921	603000	OFFICE SUPPLIES	NWN	P1	195.84
921000	10266	IT NETWK LEADER-921	605900	HARDWARE MAINT	NWN	P1	965.80
921000	10266	IT NETWK LEADER-921	612100	MEALS AND ENTERTAIN	NWN	P1	181.78
921000	10266	IT NETWK LEADER-921	622000	EMPLOYEE AWARDS	NWN	P1	700.00
921000	10268	NTWK CTRL SYS-OFFICE	602700	TELEPHONE	NWN	P1	0.00
921000	10268	NTWK CTRL SYS-OFFICE	606300	CELLULAR PHONES	NWN	P1	702,460.98
921000	10269	IT INFRA TEAM-921	601100	EDUCATION	NWN	P1	31,555.63
921000	10269	IT INFRA TEAM-921	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	P1	1,303.94
921000	10269	IT INFRA TEAM-921	602000	OTHER CONTRACT WORK	NWN	P1	102,580.45
921000	10269	IT INFRA TEAM-921	602100	OTHER CONTRACT WORK	NWN	P1	107,557.08
921000	10269	IT INFRA TEAM-921	602466	P CARD UNCODED CHARG	NWN	P1	(9,128.49)
921000	10269	IT INFRA TEAM-921	602800	POSTAGE	NWN	P1	40.56
921000	10269	IT INFRA TEAM-921	603000	OFFICE SUPPLIES	NWN	P1	10.94
921000	10269	IT INFRA TEAM-921	603200	BOOKS AND MAGAZINES	NWN	P1	0.00
921000	10269	IT INFRA TEAM-921	604700	PARKING	NWN	P1	275.40
921000	10269	IT INFRA TEAM-921	605600	SOFTWARE MAINT	NWN	P1	29,612.97
921000	10269	IT INFRA TEAM-921	607700	SMALL TOOLS	NWN	P1	2,816.34
921000	10269	IT INFRA TEAM-921	612100	MEALS AND ENTERTAIN	NWN	P1	589.84
921000	10269	IT INFRA TEAM-921	613200	BUSINESS TRAVEL	NWN	P1	2,756.62
921000	10269	IT INFRA TEAM-921	622000	EMPLOYEE AWARDS	NWN	P1	1,800.00
921000	10270	IT NTWK TEAM-921	601100	EDUCATION	NWN	P1	106.99
921000	10270	IT NTWK TEAM-921	601400	MATERIALS	NWN	P1	(1,570.02)
921000	10270	IT NTWK TEAM-921	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	P1	4,013.72
921000	10270	IT NTWK TEAM-921	601700	EQUIPMENT	NWN	P1	580.21
921000	10270	IT NTWK TEAM-921	601900	DUES/MEMBERSHIP	NWN	P1	960.82
921000	10270	IT NTWK TEAM-921	602466	P CARD UNCODED CHARG	NWN	P1	356.24
921000	10270	IT NTWK TEAM-921	602700	TELEPHONE	NWN	P1	35.16
921000	10270	IT NTWK TEAM-921	602800	POSTAGE	NWN	P1	164.51
921000	10270	IT NTWK TEAM-921	603200	BOOKS AND MAGAZINES	NWN	P1	289.65
921000	10270	IT NTWK TEAM-921	604700	PARKING	NWN	P1	1,508.00
921000	10270	IT NTWK TEAM-921	604900	UNIFORMS	NWN	P1	90.00
921000	10270	IT NTWK TEAM-921	605500	REPAIRS AND MAINT	NWN	P1	745.00
921000	10270	IT NTWK TEAM-921	605900	HARDWARE MAINT	NWN	P1	0.00
921000	10270	IT NTWK TEAM-921	606200	PERMITS AND FEES	NWN	P1	840.00
921000	10270	IT NTWK TEAM-921	606500	UNLEADED FUEL	NWN	P1	0.00
921000	10270	IT NTWK TEAM-921	608100	SUBCRIPTION SERVICES	NWN	P1	11,624.55
921000	10270	IT NTWK TEAM-921	612100	MEALS AND ENTERTAIN	NWN	P1	1,128.89
921000	10270	IT NTWK TEAM-921	613100	CONFERENCE TRAVEL	NWN	P1	1,429.79
921000	10270	IT NTWK TEAM-921	613200	BUSINESS TRAVEL	NWN	P1	3,916.15
921000	10270	IT NTWK TEAM-921	622000	EMPLOYEE AWARDS	NWN	P1	1,000.00
921000	10271	IT TELECELL/TV-921	602300	RENTS AND LEASES	NWN	P1	10.00
921000	10271	IT TELECELL/TV-921	602600	UTILITIES	NWN	P1	542.88
921000	10271	IT TELECELL/TV-921	602700	TELEPHONE	NWN	P1	1,321,256.64
921000	10271	IT TELECELL/TV-921	606300	CELLULAR PHONES	NWN	P1	187,036.29
921000	10282	IT SVC DELIVERY-921	601100	EDUCATION	NWN	P1	9,400.00
921000	10282	IT SVC DELIVERY-921	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	P1	4,984.12
921000	10282	IT SVC DELIVERY-921	601700	EQUIPMENT	NWN	P1	1,218.00
921000	10282	IT SVC DELIVERY-921	602000	OFFICE CONTRACT WORK	NWN	P1	40,298.85
921000	10282	IT SVC DELIVERY-921	602100	OTHER CONTRACT WORK	NWN	P1	5,525.00
921000	10282	IT SVC DELIVERY-921	602466	P CARD UNCODED CHARG	NWN	P1	(4,750.46)
921000	10282	IT SVC DELIVERY-921	602700	TELEPHONE	NWN	P1	2,874.94
921000	10282	IT SVC DELIVERY-921	602800	POSTAGE	NWN	P1	7,942.27
921000	10282	IT SVC DELIVERY-921	603000	OFFICE SUPPLIES	NWN	P1	0.00
921000	10282	IT SVC DELIVERY-921	603100	PRINTING	NWN	P1	248.65
921000	10282	IT SVC DELIVERY-921	603200	BOOKS AND MAGAZINES	NWN	P1	692.38
921000	10282	IT SVC DELIVERY-921	604700	PARKING	NWN	P1	18.00
921000	10282	IT SVC DELIVERY-921	605600	SOFTWARE MAINT	NWN	P1	3,904.84
921000	10282	IT SVC DELIVERY-921	605900	HARDWARE MAINT	NWN	P1	35,572.42
921000	10282	IT SVC DELIVERY-921	606300	CELLULAR PHONES	NWN	P1	3,440.50
921000	10282	IT SVC DELIVERY-921	612100	MEALS AND ENTERTAIN	NWN	P1	336.79
921000	10282	IT SVC DELIVERY-921	612200	TRAVEL IN TERRITORY	NWN	P1	423.73
921000	10282	IT SVC DELIVERY-921	613100	CONFERENCE TRAVEL	NWN	P1	3,365.75
921000	10282	IT SVC DELIVERY-921	613200	BUSINESS TRAVEL	NWN	P1	1,867.71
921000	10282	IT SVC DELIVERY-921	622000	EMPLOYEE AWARDS	NWN	P1	1,075.00
921000	10293	CUST CONTACT CENTER-	605100	PROFESSIONAL SERVICE	NWN	P1	(36,750.00)
921000	10293	CUST CONTACT CENTER-	612100	MEALS AND ENTERTAIN	NWN	P1	50.00
921000	10348	RMC-OFFICE STAFFING	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	P1	0.00
921000	10348	RMC-OFFICE STAFFING	612100	MEALS AND ENTERTAIN	NWN	P1	0.00
921000	10353	BUSINESS SYSS-OFFICE	601100	EDUCATION	NWN	P1	838.95
921000	10353	BUSINESS SYSS-OFFICE	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	P1	770.71
921000	10353	BUSINESS SYSS-OFFICE	602466	P CARD UNCODED CHARG	NWN	P1	0.00
921000	10353	BUSINESS SYSS-OFFICE	603000	OFFICE SUPPLIES	NWN	P1	99.10
921000	10353	BUSINESS SYSS-OFFICE	603300	REFRESHMENTS	NWN	P1	79.22
921000	10353	BUSINESS SYSS-OFFICE	612100	MEALS AND ENTERTAIN	NWN	P1	759.01
921000	10353	BUSINESS SYSS-OFFICE	612200	TRAVEL IN TERRITORY	NWN	P1	0.00
921000	10353	BUSINESS SYSS-OFFICE	613100	CONFERENCE TRAVEL	NWN	P1	1,714.54
921000	10353	BUSINESS SYSS-OFFICE	613200	BUSINESS TRAVEL	NWN	P1	0.00
921000	10353	BUSINESS SYSS-OFFICE	622000	EMPLOYEE AWARDS	NWN	P1	773.40
921000	10358	ACCOUNT SERVICES-OFF	602000	OFFICE CONTRACT WORK	NWN	P1	578.39
921000	10358	ACCOUNT SERVICES-OFF	602800	POSTAGE	NWN	P1	29.19
921000	10432	ENGINER SVCES OR-OFF	601700	EQUIPMENT	NWN	P1	496.42
921000	10432	ENGINER SVCES OR-OFF	602100	OTHER CONTRACT WORK	NWN	P1	0.00
921000	10432	ENGINER SVCES OR-OFF	603100	PRINTING	NWN	P1	(4,999.68)
921000	10450	EE PROTECT EQUIP-OFF	604900	UNIFORMS	NWN	P1	600,301.73
921000	10451	EE PROTECTION EQUIP-	604900	UNIFORMS	NWN	P1	72,140.72
921000	10451	EE PROTECTION EQUIP-	604950	CLOTHING	NWN	P1	90,564.74
921000	10452	EE PROTECTION EQUIP-	601700	EQUIPMENT	NWN	P1	490.49
921000	10452	EE PROTECTION EQUIP-	602466	P CARD UNCODED CHARG	NWN	P1	0.00
921000	10452	EE PROTECTION EQUIP-	604900	UNIFORMS	NWN	P1	177.00
921000	10452	EE PROTECTION EQUIP-	604950	CLOTHING	NWN	P1	10,690.68
921000	10455	EE PROTECT EQUIP-OFF	604900	UNIFORMS	NWN	P1	4,231.90
921000	10455	EE PROTECT EQUIP-OFF	604950	CLOTHING	NWN	P1	1,266.39
921000	10462	DIRECTOR, TECH SERVI	601100	EDUCATION	NWN	P1	0.00
921000	10462	DIRECTOR, TECH SERVI	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	P1	926.22
921000	10462	DIRECTOR, TECH SERVI	602466	P CARD UNCODED CHARG	NWN	P1	0.00
921000	10462	DIRECTOR, TECH SERVI	603000	OFFICE SUPPLIES	NWN	P1	68.95
921000	10462	DIRECTOR, TECH SERVI	603300	REFRESHMENTS	NWN	P1	94.38
921000	10462	DIRECTOR, TECH SERVI	604700	PARKING	NWN	P1	14.30
921000	10462	DIRECTOR, TECH SERVI	606300	CELLULAR PHONES	NWN	P1	0.99
921000	10462	DIRECTOR, TECH SERVI	612100	MEALS AND ENTERTAIN	NWN	P1	991.64
921000	10462	DIRECTOR, TECH SERVI	613200	BUSINESS TRAVEL	NWN	P1	655.01
921000	10462	DIRECTOR, TECH SERVI	622000	EMPLOYEE AWARDS	NWN	P1	794.18
921000	10509	DISTRIBUTION-OFFICE	604900	UNIFORMS	NWN	P1	0.00

			Admin Transfer Factor	12.1429%
			TOTAL	$ 8,629,765.83

SORTER	ALLOCATION FACTOR	ALLOCATION METHOD	WA	OR	SYSTEM
91275002	12.17%	Customers-All	$ 34.21	$ 246.85	$ 281.06
92110075	8.68%	Sendout Volumes	$ 2,227.37	$ 23,433.52	$ 25,660.89
92110095	12.17%	Customers-All	$ 825.86	$ 5,960.14	$ 6,786.00
92110117	11.80%	3-factor	$ 493.00	$ 3,685.00	$ 4,178.00
92110117	11.80%	3-factor	$ 8.25	$ 61.68	$ 69.93
92110117	11.80%	3-factor	$ 318.60	$ 2,381.40	$ 2,700.00
92110117	11.80%	3-factor	$ 78.40	$ 586.00	$ 664.40
92110117	11.80%	3-factor	$ 5.47	$ 40.89	$ 46.36
92110117	11.80%	3-factor	$ 0.51	$ 3.78	$ 4.29
92110117	11.80%	3-factor	$ 34,167.59	$ 255,388.24	$ 289,555.83
92110117	11.80%	3-factor	$ 7.13	$ 53.28	$ 60.41
92110117	11.80%	3-factor	$ 377.60	$ 2,822.40	$ 3,200.00
92110117	11.80%	3-factor	$ 6.96	$ 52.02	$ 58.98
92110117	11.80%	3-factor	$ 484.13	$ 3,618.70	$ 4,102.83
92110117	11.80%	3-factor	$ 1.18	$ 8.82	$ 10.00
92110182	12.17%	Customers-All	$ 33.11	$ 238.96	$ 272.07
92110182	12.17%	Customers-All	$ 163.59	$ 1,180.58	$ 1,344.17
92110182	12.17%	Customers-All	$ 14.45	$ 104.25	$ 118.70
92110182	12.17%	Customers-All	$ -	$ -	$ -
92110182	12.17%	Customers-All	$ -	$ -	$ -
92110205	0.00%	direct-or	$ -	$ -	$ -
92110205	0.00%	direct-or	$ -	$ (1,318.00)	$ (1,318.00)
92110205	0.00%	direct-or	$ -	$ 125.40	$ 125.40
92110205	0.00%	direct-or	$ -	$ 4.20	$ 4.20
92110205	0.00%	direct-or	$ -	$ 713.53	$ 713.53
92110205	0.00%	direct-or	$ -	$ 5,341.29	$ 5,341.29
92110205	0.00%	direct-or	$ -	$ 439.94	$ 439.94
92110237	0.00%	Direct-OR	$ -	$ -	$ -
92110252	11.80%	3-factor	$ 14.14	$ 105.66	$ 119.80
92110252	11.80%	3-factor	$ 403.18	$ 3,013.57	$ 3,416.75
92110252	11.80%	3-factor	$ 13.55	$ 101.24	$ 114.79
92110252	11.80%	3-factor	$ 17.70	$ 132.30	$ 150.00
92110252	11.80%	3-factor	$ (72.14)	$ (539.24)	$ (611.38)
92110252	11.80%	3-factor	$ -	$ -	$ -
92110252	11.80%	3-factor	$ -	$ -	$ -
92110252	11.80%	3-factor	$ -	$ -	$ -
92110252	11.80%	3-factor	$ 189.27	$ 1,414.73	$ 1,604.00
92110252	11.80%	3-factor	$ 13.88	$ 103.72	$ 117.60
92110252	11.80%	3-factor	$ 32.65	$ 244.06	$ 276.71
92110252	11.80%	3-factor	$ -	$ -	$ -
92110252	11.80%	3-factor	$ (85.77)	$ (641.11)	$ (726.88)
92110252	11.80%	3-factor	$ (11.14)	$ (83.26)	$ (94.40)
92110266	11.80%	3-factor	$ -	$ -	$ -
92110266	11.80%	3-factor	$ 23,914.11	$ 178,747.87	$ 202,661.98
92110266	11.80%	3-factor	$ 6.90	$ 51.60	$ 58.50
92110266	11.80%	3-factor	$ -	$ -	$ -
92110266	11.80%	3-factor	$ 2.38	$ 17.80	$ 20.18
92110266	11.80%	3-factor	$ 23.11	$ 172.73	$ 195.84
92110266	11.80%	3-factor	$ 113.96	$ 851.84	$ 965.80
92110266	11.80%	3-factor	$ 21.45	$ 160.33	$ 181.78
92110266	11.80%	3-factor	$ 82.60	$ 617.40	$ 700.00
92110268	11.80%	3-factor	$ -	$ -	$ -
92110268	11.80%	3-factor	$ 82,890.40	$ 619,570.58	$ 702,460.98
92110269	11.80%	3-factor	$ 3,723.56	$ 27,832.07	$ 31,555.63
92110269	11.80%	3-factor	$ 153.86	$ 1,150.08	$ 1,303.94
92110269	11.80%	3-factor	$ 12,104.49	$ 90,475.96	$ 102,580.45
92110269	11.80%	3-factor	$ 12,691.74	$ 94,865.34	$ 107,557.08
92110269	11.80%	3-factor	$ (1,077.16)	$ (8,051.33)	$ (9,128.49)
92110269	11.80%	3-factor	$ 4.79	$ 35.77	$ 40.56
92110269	11.80%	3-factor	$ 1.29	$ 9.65	$ 10.94
92110269	11.80%	3-factor	$ -	$ -	$ -
92110269	11.80%	3-factor	$ 32.50	$ 242.90	$ 275.40
92110269	11.80%	3-factor	$ 3,494.33	$ 26,118.64	$ 29,612.97
92110269	11.80%	3-factor	$ 332.33	$ 2,484.01	$ 2,816.34
92110269	11.80%	3-factor	$ 69.60	$ 520.24	$ 589.84
92110269	11.80%	3-factor	$ 325.28	$ 2,431.34	$ 2,756.62
92110269	11.80%	3-factor	$ 212.40	$ 1,587.60	$ 1,800.00
92110270	11.80%	3-factor	$ 12.62	$ 94.37	$ 106.99
92110270	11.80%	3-factor	$ (185.26)	$ (1,384.76)	$ (1,570.02)
92110270	11.80%	3-factor	$ 473.62	$ 3,540.10	$ 4,013.72
92110270	11.80%	3-factor	$ 68.46	$ 511.75	$ 580.21
92110270	11.80%	3-factor	$ 113.38	$ 847.44	$ 960.82
92110270	11.80%	3-factor	$ 42.04	$ 314.20	$ 356.24
92110270	11.80%	3-factor	$ 4.15	$ 31.01	$ 35.16
92110270	11.80%	3-factor	$ 19.41	$ 145.10	$ 164.51
92110270	11.80%	3-factor	$ 34.18	$ 255.47	$ 289.65
92110270	11.80%	3-factor	$ 177.94	$ 1,330.06	$ 1,508.00
92110270	11.80%	3-factor	$ 10.62	$ 79.38	$ 90.00
92110270	11.80%	3-factor	$ 87.91	$ 657.09	$ 745.00
92110270	11.80%	3-factor	$ -	$ -	$ -
92110270	11.80%	3-factor	$ 99.12	$ 740.88	$ 840.00
92110270	11.80%	3-factor	$ -	$ -	$ -
92110270	11.80%	3-factor	$ 1,371.70	$ 10,252.85	$ 11,624.55
92110270	11.80%	3-factor	$ 133.21	$ 995.68	$ 1,128.89
92110270	11.80%	3-factor	$ 168.72	$ 1,261.07	$ 1,429.79
92110270	11.80%	3-factor	$ 462.11	$ 3,454.04	$ 3,916.15
92110270	11.80%	3-factor	$ 118.00	$ 882.00	$ 1,000.00
92110271	11.80%	3-factor	$ 1.18	$ 8.82	$ 10.00
92110271	11.80%	3-factor	$ 64.06	$ 478.82	$ 542.88
92110271	11.80%	3-factor	$ 155,908.28	$ 1,165,348.36	$ 1,321,256.64
92110271	11.80%	3-factor	$ 22,070.28	$ 164,966.01	$ 187,036.29
92110282	11.80%	3-factor	$ 1,109.20	$ 8,290.80	$ 9,400.00
92110282	11.80%	3-factor	$ 588.13	$ 4,395.99	$ 4,984.12
92110282	11.80%	3-factor	$ 143.72	$ 1,074.28	$ 1,218.00
92110282	11.80%	3-factor	$ 4,755.26	$ 35,543.59	$ 40,298.85
92110282	11.80%	3-factor	$ 651.95	$ 4,873.05	$ 5,525.00
92110282	11.80%	3-factor	$ (560.55)	$ (4,189.91)	$ (4,750.46)
92110282	11.80%	3-factor	$ 339.24	$ 2,535.70	$ 2,874.94
92110282	11.80%	3-factor	$ 937.19	$ 7,005.08	$ 7,942.27
92110282	11.80%	3-factor	$ -	$ -	$ -
92110282	11.80%	3-factor	$ 29.34	$ 219.31	$ 248.65
92110282	11.80%	3-factor	$ 81.70	$ 610.68	$ 692.38
92110282	11.80%	3-factor	$ 2.12	$ 15.88	$ 18.00
92110282	11.80%	3-factor	$ 460.77	$ 3,444.07	$ 3,904.84
92110282	11.80%	3-factor	$ 4,197.55	$ 31,374.87	$ 35,572.42
92110282	11.80%	3-factor	$ 405.98	$ 3,034.52	$ 3,440.50
92110282	11.80%	3-factor	$ 39.74	$ 297.05	$ 336.79
92110282	11.80%	3-factor	$ 50.00	$ 373.73	$ 423.73
92110282	11.80%	3-factor	$ 397.16	$ 2,968.59	$ 3,365.75
92110282	11.80%	3-factor	$ 220.39	$ 1,647.32	$ 1,867.71
92110282	11.80%	3-factor	$ 126.85	$ 948.15	$ 1,075.00
92110293	12.17%	Customers-All	$ (4,472.48)	$ (32,277.53)	$ (36,750.00)
92110293	12.17%	Customers-All	$ 6.09	$ 43.92	$ 50.00
92110348	12.17%	Customers-All	$ -	$ -	$ -
92110348	12.17%	Customers-All	$ -	$ -	$ -
92110353	12.17%	Customers-All	$ 102.10	$ 736.85	$ 838.95
92110353	12.17%	Customers-All	$ 93.80	$ 676.91	$ 770.71
92110353	12.17%	Customers-All	$ -	$ -	$ -
92110353	12.17%	Customers-All	$ 12.06	$ 87.04	$ 99.10
92110353	12.17%	Customers-All	$ 9.64	$ 69.58	$ 79.22
92110353	12.17%	Customers-All	$ 92.37	$ 666.64	$ 759.01
92110353	12.17%	Customers-All	$ -	$ -	$ -
92110353	12.17%	Customers-All	$ 208.66	$ 1,505.88	$ 1,714.54
92110353	12.17%	Customers-All	$ -	$ -	$ -
92110353	12.17%	Customers-All	$ 94.12	$ 679.28	$ 773.40
92110358	12.17%	Customers-All	$ 70.39	$ 508.00	$ 578.39
92110358	12.17%	Customers-All	$ 3.55	$ 25.64	$ 29.19
92110432	0.00%	Direct-OR	$ -	$ 496.42	$ 496.42
92110432	0.00%	Direct-OR	$ -	$ -	$ -
92110432	0.00%	Direct-OR	$ -	$ (4,999.68)	$ (4,999.68)
92110450	11.02%	Employee Cost	$ 66,129.84	$ 534,171.89	$ 600,301.73
92110451	11.02%	Employee Cost	$ 7,947.09	$ 64,193.63	$ 72,140.72
92110451	11.02%	Employee Cost	$ 9,976.70	$ 80,588.04	$ 90,564.74
92110452	11.02%	Employee Cost	$ 54.03	$ 436.46	$ 490.49
92110452	11.02%	Employee Cost	$ -	$ -	$ -
92110452	11.02%	Employee Cost	$ 19.50	$ 157.50	$ 177.00
92110452	11.02%	Employee Cost	$ 1,177.70	$ 9,512.98	$ 10,690.68
92110455	11.02%	Employee Cost	$ 466.19	$ 3,765.71	$ 4,231.90
92110455	11.02%	Employee Cost	$ 139.51	$ 1,126.88	$ 1,266.39
92110462	12.17%	Customers-All	$ -	$ -	$ -
92110462	12.17%	Customers-All	$ 112.72	$ 813.50	$ 926.22
92110462	12.17%	Customers-All	$ -	$ -	$ -
92110462	12.17%	Customers-All	$ 8.39	$ 60.56	$ 68.95
92110462	12.17%	Customers-All	$ 11.49	$ 82.89	$ 94.38
92110462	12.17%	Customers-All	$ 1.74	$ 12.56	$ 14.30
92110462	12.17%	Customers-All	$ 0.12	$ 0.87	$ 0.99
92110462	12.17%	Customers-All	$ 120.68	$ 870.96	$ 991.64
92110462	12.17%	Customers-All	$ 79.71	$ 575.30	$ 655.01
92110462	12.17%	Customers-All	$ 96.65	$ 697.53	$ 794.18
92110509	12.17%	Customers-All	$ -	$ -	$ -

			Admin Transfer Factor	87.8571%
			TOTAL	$ 62,438,540.15

$ 71,068,305.98

NW Natural
Admin Transfer Allocation Factor
Test Year Ending March 31, 2025

$ 71,068,305.98

						Fiscal Year Period	Amount			Admin Transfer Factor	12.1429%	87.8571%	
						Measures	Overall Result			TOTAL	$ 8,629,765.83	$ 62,438,540.15	$ 71,068,305.98
FERC Account	Cost Center	Cost Center Description	GL Account	GL Account Long Name	Chart of Accounts	Ledger	$	SORTER	ALLOCATION FACTOR	ALLOCATION METHOD	WA	OR	SYSTEM
921000	10550	BUSINESS ANALYSIS-OF	601100	EDUCATION	NWN	F1	5,902.00	92110550	12.17%	Customers-All	$ 718.27	$ 5,183.73	$ 5,902.00
921000	10550	BUSINESS ANALYSIS-OF	601900	DUES/MEMBERSHIP	NWN	F1	255.00	92110550	12.17%	Customers-All	$ 31.03	$ 223.97	$ 255.00
921000	10550	BUSINESS ANALYSIS-OF	602466	P CARD UNCODED CHARG	NWN	F1	(238.08)	92110550	12.17%	Customers-All	$ (28.97)	$ (209.11)	$ (238.08)
921000	10550	BUSINESS ANALYSIS-OF	603200	BOOKS AND MAGAZINES	NWN	F1	56.26	92110550	12.17%	Customers-All	$ 6.85	$ 49.41	$ 56.26
921000	10550	BUSINESS ANALYSIS-OF	603300	REFRESHMENTS	NWN	F1	434.85	92110550	12.17%	Customers-All	$ 52.92	$ 381.93	$ 434.85
921000	10550	BUSINESS ANALYSIS-OF	604700	PARKING	NWN	F1	120.00	92110550	12.17%	Customers-All	$ 14.60	$ 105.40	$ 120.00
921000	10550	BUSINESS ANALYSIS-OF	605100	PROFESSIONAL SERVICE	NWN	F1	0.00	92110550	12.17%	Customers-All	$ -	$ -	$ -
921000	10550	BUSINESS ANALYSIS-OF	612100	MEALS AND ENTERTAIN	NWN	F1	1,572.70	92110550	12.17%	Customers-All	$ 191.40	$ 1,381.30	$ 1,572.70
921000	10550	BUSINESS ANALYSIS-OF	613100	CONFERENCE TRAVEL	NWN	F1	2,249.58	92110550	12.17%	Customers-All	$ 273.77	$ 1,975.81	$ 2,249.58
921000	10550	BUSINESS ANALYSIS-OF	613200	BUSINESS TRAVEL	NWN	F1	136.67	92110550	12.17%	Customers-All	$ 16.66	$ 120.21	$ 136.87
921000	10550	BUSINESS ANALYSIS-OF	622000	EMPLOYEE AWARDS	NWN	F1	750.00	92110550	12.17%	Customers-All	$ 91.28	$ 658.73	$ 750.00
921000	10589	250TAYLOR-FAC-OFFICE	605100	PROFESSIONAL SERVICE	NWN	F1	403,734.23	92110589	11.80%	3-factor	$ 47,640.64	$ 356,093.59	$ 403,734.23
921000	10590	250TAYLOR-FAC-OFFICE	604700	PARKING	NWN	F1	148,145.58	92110590	11.80%	3-factor	$ 17,481.18	$ 130,664.40	$ 148,145.58
921000	10598	FAC MGMNT-OFFICE STA	602300	RENTS AND LEASES	NWN	F1	43,692.63	92110598	11.80%	3-factor	$ 5,155.73	$ 38,536.90	$ 43,692.63
921000	10598	FAC MGMNT-OFFICE STA	602360	ROU UTIL LEA RENT EX	NWN	F1	39,862.43	92110598	11.80%	3-factor	$ 4,703.77	$ 35,158.66	$ 39,862.43
921000	10598	FAC MGMNT-OFFICE STA	602365	ROU UTIL LEASE INTEREST EXPENSE	NWN	F1	230,437.57	92110598	11.80%	3-factor	$ 27,191.63	$ 203,245.94	$ 230,437.57
921000	10598	FAC MGMNT-OFFICE STA	605100	PROFESSIONAL SERVICE	NWN	F1	15,500.00	92110598	11.80%	3-factor	$ 1,829.00	$ 13,671.00	$ 15,500.00
921000	10599	FAC MGMNT-OFFICE STA	602600	UTILITIES	NWN	F1	5,953.27	92110599	11.80%	3-factor	$ 702.49	$ 5,250.78	$ 5,953.27
921000	10616	MTSCOTT-FACILITIES-O	602100	OTHER CONTRACT WORK	NWN	F1	488.80	92110616	0.00%	Direct-OR	$ -	$ 488.80	$ 488.80
921000	10620	PARKROSE-FAC-OFFICE	602100	OTHER CONTRACT WORK	NWN	F1	350.00	92110620	0.00%	Direct-OR	$ -	$ 350.00	$ 350.00
921000	10646	NEWPORT-FAC-OFFICE S	605500	REPAIRS AND MAINT	NWN	F1	(6,851.00)	92110646	0.00%	Direct-OR	$ -	$ (6,851.00)	$ (6,851.00)
921000	10656	STORES-OFFICE STAFFI	601400	MATERIALS	NWN	F1	3,412.17	92110656	11.80%	3-factor	$ 402.64	$ 3,009.53	$ 3,412.17
921000	10656	STORES-OFFICE STAFFI	601401	MATERIALS - CONS INV	NWN	F1	833.71	92110656	11.80%	3-factor	$ 98.38	$ 735.33	$ 833.71
921000	10656	STORES-OFFICE STAFFI	601600	TRANSPORTATION	NWN	F1	3,633.24	92110656	11.80%	3-factor	$ 428.72	$ 3,204.52	$ 3,633.24
921000	10656	STORES-OFFICE STAFFI	601700	EQUIPMENT	NWN	F1	4,163.88	92110656	11.80%	3-factor	$ 491.34	$ 3,672.54	$ 4,163.88
921000	10656	STORES-OFFICE STAFFI	602100	OTHER CONTRACT WORK	NWN	F1	0.75	92110656	11.80%	3-factor	$ 0.09	$ 0.66	$ 0.75
921000	10656	STORES-OFFICE STAFFI	602466	P CARD UNCODED CHARG	NWN	F1	0.00	92110656	11.80%	3-factor	$ -	$ -	$ -
921000	10656	STORES-OFFICE STAFFI	602800	POSTAGE	NWN	F1	1,385.09	92110656	11.80%	3-factor	$ 163.44	$ 1,221.65	$ 1,385.09
921000	10656	STORES-OFFICE STAFFI	603000	OFFICE SUPPLIES	NWN	F1	14.35	92110656	11.80%	3-factor	$ 1.69	$ 12.66	$ 14.35
921000	10656	STORES-OFFICE STAFFI	604950	CLOTHING	NWN	F1	140.03	92110656	11.80%	3-factor	$ 16.52	$ 123.51	$ 140.03
921000	10656	STORES-OFFICE STAFFI	605100	PROFESSIONAL SERVICE	NWN	F1	28,923.02	92110656	11.80%	3-factor	$ 3,412.92	$ 25,510.10	$ 28,923.02
921000	10656	STORES-OFFICE STAFFI	622000	EMPLOYEE AWARDS	NWN	F1	675.00	92110656	11.80%	3-factor	$ 79.65	$ 595.35	$ 675.00
921000	10656	STORES-OFFICE STAFFI	681500	MILEAGE REIMBURSEMNT	NWN	F1	1.89	92110656	11.80%	3-factor	$ 0.22	$ 1.67	$ 1.89
921000	10656	STORES-OFFICE STAFFI	685800	MEAL TICKETS SECONDARY	NWN	F1	27.31	92110656	11.80%	3-factor	$ 3.22	$ 24.09	$ 27.31
921000	10657	STORES - Inventory D	609100	INVENTORY DIFF	NWN	F1	276,440.81	92110657	11.80%	3-factor	$ 32,620.02	$ 243,820.79	$ 276,440.81
921000	10660	STORES OBS INV - Inv	601400	MATERIALS	NWN	F1	112.40	92110660	11.80%	3-factor	$ 13.26	$ 99.14	$ 112.40
921000	10660	STORES OBS INV - Inv	601401	MATERIALS - CONS INV	NWN	F1	30,423.04	92110660	11.80%	3-factor	$ 3,589.92	$ 26,833.12	$ 30,423.04
921000	10660	STORES OBS INV - Inv	601402	MATERIALS - CONS PIPE	NWN	F1	11,387.97	92110660	11.80%	3-factor	$ 1,343.78	$ 10,044.19	$ 11,387.97
921000	10660	STORES OBS INV - Inv	601403	MAT CONS -PIPE SCRAP	NWN	F1	76.51	92110660	11.80%	3-factor	$ 9.03	$ 67.48	$ 76.51
921000	10660	STORES OBS INV - Inv	606800	INVENTORY ADJUSTMENT	NWN	F1	(2,932.12)	92110660	11.80%	3-factor	$ (345.99)	$ (2,586.13)	$ (2,932.12)
921000	10661	PURCHASNG-OFFICE ST	601100	EDUCATION	NWN	F1	425.00	92110661	11.80%	3-factor	$ 50.15	$ 374.85	$ 425.00
921000	10661	PURCHASNG-OFFICE ST	601401	MATERIALS - CONS INV	NWN	F1	0.00	92110661	11.80%	3-factor	$ -	$ -	$ -
921000	10661	PURCHASNG-OFFICE ST	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	182.24	92110661	11.80%	3-factor	$ 21.50	$ 160.74	$ 182.24
921000	10661	PURCHASNG-OFFICE ST	601900	DUES/MEMBERSHIP	NWN	F1	27,925.00	92110661	11.80%	3-factor	$ 3,295.15	$ 24,629.85	$ 27,925.00
921000	10661	PURCHASNG-OFFICE ST	602000	OFFICE CONTRACT WORK	NWN	F1	168,862.08	92110661	11.80%	3-factor	$ 19,925.73	$ 148,936.35	$ 168,862.08
921000	10661	PURCHASNG-OFFICE ST	602100	OTHER CONTRACT WORK	NWN	F1	0.00	92110661	11.80%	3-factor	$ -	$ -	$ -
921000	10661	PURCHASNG-OFFICE ST	602466	P CARD UNCODED CHARG	NWN	F1	(170.70)	92110661	11.80%	3-factor	$ (20.14)	$ (150.56)	$ (170.70)
921000	10661	PURCHASNG-OFFICE ST	602800	POSTAGE	NWN	F1	90.03	92110661	11.80%	3-factor	$ 10.62	$ 79.41	$ 90.03
921000	10661	PURCHASNG-OFFICE ST	603100	PRINTING	NWN	F1	0.00	92110661	11.80%	3-factor	$ -	$ -	$ -
921000	10661	PURCHASNG-OFFICE ST	603200	BOOKS AND MAGAZINES	NWN	F1	49.98	92110661	11.80%	3-factor	$ 5.90	$ 44.08	$ 49.98
921000	10661	PURCHASNG-OFFICE ST	603300	REFRESHMENTS	NWN	F1	132.31	92110661	11.80%	3-factor	$ 15.61	$ 116.70	$ 132.31
921000	10661	PURCHASNG-OFFICE ST	604700	PARKING	NWN	F1	36.00	92110661	11.80%	3-factor	$ 4.25	$ 31.75	$ 36.00
921000	10661	PURCHASNG-OFFICE ST	604950	CLOTHING	NWN	F1	0.00	92110661	11.80%	3-factor	$ -	$ -	$ -
921000	10661	PURCHASNG-OFFICE ST	605100	PROFESSIONAL SERVICE	NWN	F1	206,084.77	92110661	11.80%	3-factor	$ 24,318.00	$ 181,766.77	$ 206,084.77
921000	10661	PURCHASNG-OFFICE ST	605600	SOFTWARE MAINT	NWN	F1	10,644.00	92110661	11.80%	3-factor	$ 1,255.99	$ 9,388.01	$ 10,644.00
921000	10661	PURCHASNG-OFFICE ST	606500	UNLEADED FUEL	NWN	F1	0.00	92110661	11.80%	3-factor	$ -	$ -	$ -
921000	10661	PURCHASNG-OFFICE ST	612100	MEALS AND ENTERTAIN	NWN	F1	135.89	92110661	11.80%	3-factor	$ 16.04	$ 119.85	$ 135.89
921000	10661	PURCHASNG-OFFICE ST	613200	BUSINESS TRAVEL	NWN	F1	0.00	92110661	11.80%	3-factor	$ -	$ -	$ -
921000	10661	PURCHASNG-OFFICE ST	622000	EMPLOYEE AWARDS	NWN	F1	1,920.65	92110661	11.80%	3-factor	$ 226.64	$ 1,694.01	$ 1,920.65
921000	10663	OFFICE SERVICES-OFFI	601400	MATERIALS	NWN	F1	3,819.37	92110663	11.80%	3-factor	$ 450.69	$ 3,368.68	$ 3,819.37
921000	10663	OFFICE SERVICES-OFFI	601600	TRANSPORTATION	NWN	F1	(2,262.00)	92110663	11.80%	3-factor	$ (266.92)	$ (1,995.08)	$ (2,262.00)
921000	10663	OFFICE SERVICES-OFFI	601700	EQUIPMENT	NWN	F1	8,464.40	92110663	11.80%	3-factor	$ 998.80	$ 7,465.60	$ 8,464.40
921000	10663	OFFICE SERVICES-OFFI	602300	RENTS AND LEASES	NWN	F1	1,066.90	92110663	11.80%	3-factor	$ 125.89	$ 941.01	$ 1,066.90
921000	10663	OFFICE SERVICES-OFFI	602466	P CARD UNCODED CHARG	NWN	F1	0.00	92110663	11.80%	3-factor	$ -	$ -	$ -
921000	10663	OFFICE SERVICES-OFFI	602800	POSTAGE	NWN	F1	45,549.89	92110663	11.80%	3-factor	$ 5,374.89	$ 40,175.00	$ 45,549.89
921000	10663	OFFICE SERVICES-OFFI	603000	OFFICE SUPPLIES	NWN	F1	8,699.34	92110663	11.80%	3-factor	$ 1,026.52	$ 7,672.82	$ 8,699.34
921000	10663	OFFICE SERVICES-OFFI	603200	BOOKS AND MAGAZINES	NWN	F1	70.55	92110663	11.80%	3-factor	$ 8.32	$ 62.23	$ 70.55
921000	10663	OFFICE SERVICES-OFFI	603600	COPIER LEASE/MAINT	NWN	F1	25,359.89	92110663	11.80%	3-factor	$ 2,992.47	$ 22,367.42	$ 25,359.89
921000	10663	OFFICE SERVICES-OFFI	606200	PERMIT AND FEES	NWN	F1	182.00	92110663	11.80%	3-factor	$ 21.48	$ 160.52	$ 182.00
921000	10663	OFFICE SERVICES-OFFI	608100	SUBCRIPTION SERVICES	NWN	F1	14.79	92110663	11.80%	3-factor	$ 1.75	$ 13.04	$ 14.79
921000	10663	OFFICE SERVICES-OFFI	612100	MEALS AND ENTERTAIN	NWN	F1	419.66	92110663	11.80%	3-factor	$ 49.52	$ 370.14	$ 419.66
921000	10663	OFFICE SERVICES-OFFI	622000	EMPLOYEE AWARDS	NWN	F1	475.00	92110663	11.80%	3-factor	$ 56.05	$ 418.95	$ 475.00
921000	10664	OFFICE SERV-OFFICE S	603100	PRINTING	NWN	F1	55,632.99	92110664	11.80%	3-factor	$ 6,564.69	$ 49,068.30	$ 55,632.99
921000	10664	OFFICE SERV-OFFICE S	605100	PROFESSIONAL SERVICE	NWN	F1	75.00	92110664	11.80%	3-factor	$ 8.85	$ 66.15	$ 75.00
921000	10665	OFFICE SERV-OFFICE S	601400	MATERIALS	NWN	F1	3,308.35	92110665	11.80%	3-factor	$ 390.39	$ 2,917.96	$ 3,308.35
921000	10665	OFFICE SERV-OFFICE S	601401	MATERIALS - CONS INV	NWN	F1	0.00	92110665	11.80%	3-factor	$ -	$ -	$ -
921000	10665	OFFICE SERV-OFFICE S	602300	RENTS AND LEASES	NWN	F1	1,296.00	92110665	11.80%	3-factor	$ 152.93	$ 1,143.07	$ 1,296.00
921000	10665	OFFICE SERV-OFFICE S	602466	P CARD UNCODED CHARG	NWN	F1	0.00	92110665	11.80%	3-factor	$ -	$ -	$ -
921000	10665	OFFICE SERV-OFFICE S	602800	POSTAGE	NWN	F1	3,062.45	92110665	11.80%	3-factor	$ 361.37	$ 2,701.08	$ 3,062.45
921000	10665	OFFICE SERV-OFFICE S	603000	OFFICE SUPPLIES	NWN	F1	0.00	92110665	11.80%	3-factor	$ -	$ -	$ -
921000	10665	OFFICE SERV-OFFICE S	603100	PRINTING	NWN	F1	1,595.38	92110665	11.80%	3-factor	$ 188.25	$ 1,407.13	$ 1,595.38
921000	10665	OFFICE SERV-OFFICE S	603200	BOOKS AND MAGAZINES	NWN	F1	23.98	92110665	11.80%	3-factor	$ 2.83	$ 21.15	$ 23.98
921000	10665	OFFICE SERV-OFFICE S	604100	PAYSTATION COMMISSIO	NWN	F1	0.00	92110665	11.80%	3-factor	$ -	$ -	$ -
921000	10665	OFFICE SERV-OFFICE S	604950	CLOTHING	NWN	F1	163.41	92110665	11.80%	3-factor	$ 19.28	$ 144.13	$ 163.41
921000	10665	OFFICE SERV-OFFICE S	605100	PROFESSIONAL SERVICE	NWN	F1	59,897.19	92110665	11.80%	3-factor	$ 7,067.87	$ 52,829.32	$ 59,897.19
921000	10665	OFFICE SERV-OFFICE S	605800	MEAL TICKETS	NWN	F1	0.00	92110665	11.80%	3-factor	$ -	$ -	$ -
921000	10665	OFFICE SERV-OFFICE S	606200	PERMITS AND FEES	NWN	F1	800.00	92110665	11.80%	3-factor	$ 94.40	$ 705.60	$ 800.00
921000	10665	OFFICE SERV-OFFICE S	612100	MEALS AND ENTERTAIN	NWN	F1	240.79	92110665	11.80%	3-factor	$ 28.41	$ 212.38	$ 240.79
921000	10665	OFFICE SERV-OFFICE S	622000	EMPLOYEE AWARDS	NWN	F1	75.00	92110665	11.80%	3-factor	$ 8.85	$ 66.15	$ 75.00
921000	10667	EMPLOYMENT-OFFICE ST	605100	PROFESSIONAL SERVICE	NWN	F1	71,859.47	92110667	11.80%	3-factor	$ 8,479.42	$ 63,380.05	$ 71,859.47
921000	10667	EMPLOYMENT-OFFICE ST	605200	ADVERTISING	NWN	F1	19,903.44	92110667	11.80%	3-factor	$ 2,348.61	$ 17,554.83	$ 19,903.44
921000	10667	EMPLOYMENT-OFFICE ST	612100	MEALS AND ENTERTAIN	NWN	F1	129.63	92110667	11.80%	3-factor	$ 15.30	$ 114.33	$ 129.63
921000	10671	DRUG & ALCOHOL-OFFIC	601400	MATERIALS	NWN	F1	0.00	92110671	11.02%	Employee Cost	$ -	$ -	$ -
921000	10671	DRUG & ALCOHOL-OFFIC	601900	DUES/MEMBERSHIP	NWN	F1	66.00	92110671	11.02%	Employee Cost	$ 7.27	$ 58.73	$ 66.00
921000	10671	DRUG & ALCOHOL-OFFIC	602100	OTHER CONTRACT WORK	NWN	F1	36,080.18	92110671	11.02%	Employee Cost	$ 3,974.63	$ 32,105.55	$ 36,080.18
921000	10671	DRUG & ALCOHOL-OFFIC	602466	P CARD UNCODED CHARG	NWN	F1	2,068.42	92110671	11.02%	Employee Cost	$ 227.86	$ 1,840.56	$ 2,068.42
921000	10671	DRUG & ALCOHOL-OFFIC	605100	PROFESSIONAL SERVICE	NWN	F1	289.50	92110671	11.02%	Employee Cost	$ 31.89	$ 257.61	$ 289.50
921000	10672	EE&LABOR RELATIONS-O	601100	EDUCATION	NWN	F1	2,149.10	92110672	11.02%	Employee Cost	$ 236.75	$ 1,912.35	$ 2,149.10
921000	10672	EE&LABOR RELATIONS-O	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	0.00	92110672	11.02%	Employee Cost	$ -	$ -	$ -
921000	10672	EE&LABOR RELATIONS-O	601900	DUES/MEMBERSHIP	NWN	F1	697.00	92110672	11.02%	Employee Cost	$ 76.78	$ 620.22	$ 697.00
921000	10672	EE&LABOR RELATIONS-O	602100	OTHER CONTRACT WORK	NWN	F1	302.40	92110672	11.02%	Employee Cost	$ 33.31	$ 269.09	$ 302.40
921000	10672	EE&LABOR RELATIONS-O	602466	P CARD UNCODED CHARG	NWN	F1	266.33	92110672	11.02%	Employee Cost	$ 29.34	$ 236.99	$ 266.33
921000	10672	EE&LABOR RELATIONS-O	603000	OFFICE SUPPLIES	NWN	F1	75.00	92110672	11.02%	Employee Cost	$ 8.26	$ 66.74	$ 75.00
921000	10672	EE&LABOR RELATIONS-O	603100	PRINTING	NWN	F1	10,587.67	92110672	11.02%	Employee Cost	$ 1,166.35	$ 9,421.32	$ 10,587.67
921000	10672	EE&LABOR RELATIONS-O	603200	BOOKS AND MAGAZINES	NWN	F1	298.09	92110672	11.02%	Employee Cost	$ 32.84	$ 265.25	$ 298.09
921000	10672	EE&LABOR RELATIONS-O	603300	REFRESHMENTS	NWN	F1	1,749.15	92110672	11.02%	Employee Cost	$ 192.69	$ 1,556.46	$ 1,749.15
921000	10672	EE&LABOR RELATIONS-O	604700	PARKING	NWN	F1	4.00	92110672	11.02%	Employee Cost	$ 0.44	$ 3.56	$ 4.00
921000	10672	EE&LABOR RELATIONS-O	605100	PROFESSIONAL SERVICE	NWN	F1	4,849.50	92110672	11.02%	Employee Cost	$ 534.23	$ 4,315.27	$ 4,849.50
921000	10672	EE&LABOR RELATIONS-O	612100	MEALS AND ENTERTAIN	NWN	F1	657.00	92110672	11.02%	Employee Cost	$ 72.38	$ 584.62	$ 657.00
921000	10672	EE&LABOR RELATIONS-O	613100	CONFERENCE TRAVEL	NWN	F1	0.00	92110672	11.02%	Employee Cost	$ -	$ -	$ -
921000	10672	EE&LABOR RELATIONS-O	622000	EMPLOYEE AWARDS	NWN	F1	313.90	92110672	11.02%	Employee Cost	$ 34.58	$ 279.32	$ 313.90
921000	10685	PAYROLL-OFFICE STAFF	602466	P CARD UNCODED CHARG	NWN	F1	204.80	92110685	11.12%	Payroll	$ 22.77	$ 182.03	$ 204.80
921000	10685	PAYROLL-OFFICE STAFF	603100	PRINTING	NWN	F1	9,420.25	92110685	11.12%	Payroll	$ 1,047.30	$ 8,372.95	$ 9,420.25
921000	10685	PAYROLL-OFFICE STAFF	603800	TAXES	NWN	F1	52.55	92110685	11.12%	Payroll	$ 5.84	$ 46.71	$ 52.55
921000	10685	PAYROLL-OFFICE STAFF	605600	SOFTWARE MAINT	NWN	F1	99.00	92110685	11.12%	Payroll	$ 11.01	$ 87.99	$ 99.00
921000	10685	PAYROLL-OFFICE STAFF	622000	EMPLOYEE AWARDS	NWN	F1	410.80	92110685	11.12%	Payroll	$ 45.67	$ 365.13	$ 410.80
921000	10687	OD & TRAINING-OFFICE	601100	EDUCATION	NWN	F1	5,432.95	92110687	11.02%	Employee Cost	$ 598.50	$ 4,834.45	$ 5,432.95
921000	10687	OD & TRAINING-OFFICE	601400	MATERIALS	NWN	F1	0.00	92110687	11.02%	Employee Cost	$ -	$ -	$ -
921000	10687	OD & TRAINING-OFFICE	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	221.77	92110687	11.02%	Employee Cost	$ 24.43	$ 197.34	$ 221.77
921000	10687	OD & TRAINING-OFFICE	601900	DUES/MEMBERSHIP	NWN	F1	782.00	92110687	11.02%	Employee Cost	$ 86.15	$ 695.85	$ 782.00
921000	10687	OD & TRAINING-OFFICE	602466	P CARD UNCODED CHARG	NWN	F1	338.30	92110687	11.02%	Employee Cost	$ 37.27	$ 301.03	$ 338.30
921000	10687	OD & TRAINING-OFFICE	602800	POSTAGE	NWN	F1	25.00	92110687	11.02%	Employee Cost	$ 2.75	$ 22.25	$ 25.00
921000	10687	OD & TRAINING-OFFICE	603000	OFFICE SUPPLIES	NWN	F1	65.85	92110687	11.02%	Employee Cost	$ 7.25	$ 58.60	$ 65.85
921000	10687	OD & TRAINING-OFFICE	603100	PRINTING	NWN	F1	0.00	92110687	11.02%	Employee Cost	$ -	$ -	$ -
921000	10687	OD & TRAINING-OFFICE	603200	BOOKS AND MAGAZINES	NWN	F1	19.00	92110687	11.02%	Employee Cost	$ 2.09	$ 16.91	$ 19.00
921000	10687	OD & TRAINING-OFFICE	603300	REFRESHMENTS	NWN	F1	0.00	92110687	11.02%	Employee Cost	$ -	$ -	$ -
921000	10687	OD & TRAINING-OFFICE	604800	LAUNDRY	NWN	F1	111.53	92110687	11.02%	Employee Cost	$ 12.29	$ 99.24	$ 111.53
921000	10687	OD & TRAINING-OFFICE	605100	PROFESSIONAL SERVICE	NWN	F1	21,105.00	92110687	11.02%	Employee Cost	$ 2,324.95	$ 18,780.05	$ 21,105.00
921000	10687	OD & TRAINING-OFFICE	612100	MEALS AND ENTERTAIN	NWN	F1	690.32	92110687	11.02%	Employee Cost	$ 76.05	$ 614.27	$ 690.32
921000	10687	OD & TRAINING-OFFICE	613100	CONFERENCE TRAVEL	NWN	F1	384.97	92110687	11.02%	Employee Cost	$ 42.41	$ 342.56	$ 384.97
921000	10687	OD & TRAINING-OFFICE	613200	BUSINESS TRAVEL	NWN	F1	819.34	92110687	11.02%	Employee Cost	$ 90.26	$ 729.08	$ 819.34
921000	10687	OD & TRAINING-OFFICE	622000	EMPLOYEE AWARDS	NWN	F1	2,327.80	92110687	11.02%	Employee Cost	$ 256.43	$ 2,071.37	$ 2,327.80
921000	10688	OD & TRAINING-OFFICE	605100	PROFESSIONAL SERVICE	NWN	F1	45,875.00	92110688	11.02%	Employee Cost	$ 5,053.64	$ 40,821.36	$ 45,875.00
921000	10689	OD & TRAIN-OFFICE ST	601100	EDUCATION	NWN	F1	20,750.00	92110689	11.02%	Employee Cost	$ 2,285.84	$ 18,464.16	$ 20,750.00
921000	10689	OD & TRAIN-OFFICE ST	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	4.55	92110689	11.02%	Employee Cost	$ 0.50	$ 4.05	$ 4.55
921000	10689	OD & TRAIN-OFFICE ST	602100	OTHER CONTRACT WORK	NWN	F1	0.00	92110689	11.02%	Employee Cost	$ -	$ -	$ -
921000	10689	OD & TRAIN-OFFICE ST	604800	LAUNDRY	NWN	F1	0.00	92110689	11.02%	Employee Cost	$ -	$ -	$ -
921000	10689	OD & TRAIN-OFFICE ST	605100	PROFESSIONAL SERVICE	NWN	F1	10,200.00	92110689	11.02%	Employee Cost	$ 1,123.64	$ 9,076.36	$ 10,200.00
921000	10689	OD & TRAIN-OFFICE ST	612100	MEALS AND ENTERTAIN	NWN	F1	360.95	92110689	11.02%	Employee Cost	$ 39.76	$ 321.19	$ 360.95
921000	10690	OD & TRAIN-OFFICE ST	602466	P CARD UNCODED CHARG	NWN	F1	199.97	92110690	11.02%	Employee Cost	$ 22.03	$ 177.94	$ 199.97
921000	10690	OD & TRAIN-OFFICE ST	602800	POSTAGE	NWN	F1	75.00	92110690	11.02%	Employee Cost	$ 8.26	$ 66.74	$ 75.00
921000	10690	OD & TRAIN-OFFICE ST	603000	OFFICE SUPPLIES	NWN	F1	216.46	92110690	11.02%	Employee Cost	$ 23.85	$ 192.61	$ 216.46
921000	10690	OD & TRAIN-OFFICE ST	603300	REFRESHMENTS	NWN	F1	267.60	92110690	11.02%	Employee Cost	$ 29.48	$ 238.12	$ 267.60
921000	10690	OD & TRAIN-OFFICE ST	605100	PROFESSIONAL SERVICE	NWN	F1	9,685.70	92110690	11.02%	Employee Cost	$ 1,066.99	$ 8,618.71	$ 9,685.70
921000	10690	OD & TRAIN-OFFICE ST	613200	BUSINESS TRAVEL	NWN	F1	0.00	92110690	11.02%	Employee Cost	$ -	$ -	$ -
921000	10690	OD & TRAIN-OFFICE ST	622000	EMPLOYEE AWARDS	NWN	F1	951.15	92110690	11.02%	Employee Cost	$ 104.78	$ 846.37	$ 951.15
921000	10693	OD & TRAINING-Manage	601400	MATERIALS	NWN	F1	146.65	92110693	11.02%	Employee Cost	$ 16.16	$ 130.49	$ 146.65
921000	10693	OD & TRAINING-Manage	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	10.85	92110693	11.02%	Employee Cost	$ 1.20	$ 9.65	$ 10.85
921000	10693	OD & TRAINING-Manage	602100	OTHER CONTRACT WORK	NWN	F1	979.45	92110693	11.02%	Employee Cost	$ 107.90	$ 871.55	$ 979.45
921000	10693	OD & TRAINING-Manage	602466	P CARD UNCODED CHARG	NWN	F1	1,866.74	92110693	11.02%	Employee Cost	$ 205.64	$ 1,661.10	$ 1,866.74

NW Natural
Admin Transfer Allocation Factor
Test Year Ending March 31, 2025

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$ 71,068,305.98

						Fiscal Year Period	Amount							
						Measures	Overall Result							
FERC Account	Cost Center	Cost Center Description	GL Account	GL Account Long Name	Chart of Accounts	Ledger	$	SORTER	ALLOCATION FACTOR	ALLOCATION METHOD	WA	OR	SYSTEM
										Admin Transfer Factor	12.1429%	87.8571%	
										TOTAL	$ 8,629,765.83	$ 62,438,540.15	$ 71,068,305.98
921000	10693	OD & TRAINING-Manage	603000	OFFICE SUPPLIES	NWN	F1	1,940.63	92110693	11.02%	Employee Cost	$ 213.78	$ 1,726.85	$ 1,940.63
921000	10693	OD & TRAINING-Manage	604901	PARTNER HOSPITALITY	NWN	F1	5.76	92110693	11.02%	Employee Cost	$ 0.63	$ 5.13	$ 5.76
921000	10693	OD & TRAINING-Manage	605100	PROFESSIONAL SERVICE	NWN	F1	69,831.89	92110693	11.02%	Employee Cost	$ 7,692.75	$ 62,139.14	$ 69,831.89
921000	10693	OD & TRAINING-Manage	606200	PERMITS AND FEES	NWN	F1	34.00	92110693	11.02%	Employee Cost	$ 3.75	$ 30.25	$ 34.00
921000	10693	OD & TRAINING-Manage	612100	MEALS AND ENTERTAIN	NWN	F1	1,195.82	92110693	11.02%	Employee Cost	$ 131.73	$ 1,064.09	$ 1,195.82
921000	10694	CO SUPPORTED ACTIONS	601100	EDUCATION	NWN	F1	873.20	92110694	11.02%	Employee Cost	$ 96.19	$ 777.01	$ 873.20
921000	10694	CO SUPPORTED ACTIONS	601400	MATERIALS	NWN	F1	580.26	92110694	11.02%	Employee Cost	$ 63.92	$ 516.34	$ 580.26
921000	10694	CO SUPPORTED ACTIONS	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	22.61	92110694	11.02%	Employee Cost	$ 2.49	$ 20.12	$ 22.61
921000	10694	CO SUPPORTED ACTIONS	601900	DUES/MEMBERSHIP	NWN	F1	10,000.00	92110694	11.02%	Employee Cost	$ 1,101.61	$ 8,898.39	$ 10,000.00
921000	10694	CO SUPPORTED ACTIONS	602466	P CARD UNCODED CHARG	NWN	F1	5.18	92110694	11.02%	Employee Cost	$ 0.57	$ 4.61	$ 5.18
921000	10694	CO SUPPORTED ACTIONS	602800	POSTAGE	NWN	F1	167.05	92110694	11.02%	Employee Cost	$ 18.40	$ 148.65	$ 167.05
921000	10694	CO SUPPORTED ACTIONS	603000	OFFICE SUPPLIES	NWN	F1	1,424.70	92110694	11.02%	Employee Cost	$ 156.95	$ 1,267.75	$ 1,424.70
921000	10694	CO SUPPORTED ACTIONS	603100	PRINTING	NWN	F1	76.00	92110694	11.02%	Employee Cost	$ 8.37	$ 67.63	$ 76.00
921000	10694	CO SUPPORTED ACTIONS	603200	BOOKS AND MAGAZINES	NWN	F1	30.28	92110694	11.02%	Employee Cost	$ 3.34	$ 26.94	$ 30.28
921000	10694	CO SUPPORTED ACTIONS	603300	REFRESHMENTS	NWN	F1	3,395.56	92110694	11.02%	Employee Cost	$ 374.06	$ 3,021.50	$ 3,395.56
921000	10694	CO SUPPORTED ACTIONS	604600	DEALER RELATIONS	NWN	F1	13.39	92110694	11.02%	Employee Cost	$ 1.48	$ 11.91	$ 13.39
921000	10694	CO SUPPORTED ACTIONS	604800	LAUNDRY	NWN	F1	13.30	92110694	11.02%	Employee Cost	$ 1.47	$ 11.83	$ 13.30
921000	10694	CO SUPPORTED ACTIONS	604900	UNIFORMS	NWN	F1	548.75	92110694	11.02%	Employee Cost	$ 60.45	$ 488.30	$ 548.75
921000	10694	CO SUPPORTED ACTIONS	604950	CLOTHING	NWN	F1	106.70	92110694	11.02%	Employee Cost	$ 11.75	$ 94.95	$ 106.70
921000	10694	CO SUPPORTED ACTIONS	605100	PROFESSIONAL SERVICE	NWN	F1	2,492.78	92110694	11.02%	Employee Cost	$ 274.61	$ 2,218.17	$ 2,492.78
921000	10694	CO SUPPORTED ACTIONS	605200	ADVERTISING	NWN	F1	10,000.00	92110694	11.02%	Employee Cost	$ 1,101.61	$ 8,898.39	$ 10,000.00
921000	10694	CO SUPPORTED ACTIONS	607500	CORPORATE IDENTITY	NWN	F1	0.00	92110694	11.02%	Employee Cost	$ -	$ -	$ -
921000	10694	CO SUPPORTED ACTIONS	608100	SUBSCRIPTION SERVICES	NWN	F1	90.49	92110694	11.02%	Employee Cost	$ 9.97	$ 80.52	$ 90.49
921000	10694	CO SUPPORTED ACTIONS	612100	MEALS AND ENTERTAIN	NWN	F1	1,109.42	92110694	11.02%	Employee Cost	$ 122.21	$ 987.21	$ 1,109.42
921000	10694	CO SUPPORTED ACTIONS	622000	EMPLOYEE AWARDS	NWN	F1	1,597.17	92110694	11.02%	Employee Cost	$ 175.95	$ 1,421.22	$ 1,597.17
921000	10695	CO SUPP ACT-OFFICE S	605100	PROFESSIONAL SERVICE	NWN	F1	(5,000.00)	92110695	11.02%	Employee Cost	$ (550.81)	$ (4,449.20)	$ (5,000.00)
921000	10703	COMP & ADMIN-OFFICE	601400	MATERIALS	NWN	F1	0.00	92110703	11.02%	Employee Cost	$ -	$ -	$ -
921000	10703	COMP & ADMIN-OFFICE	612100	MEALS AND ENTERTAIN	NWN	F1	159.64	92110703	11.02%	Employee Cost	$ 17.59	$ 142.05	$ 159.64
921000	10705	INF SECUR COMP&QA-OF	601100	EDUCATION	NWN	F1	4,635.00	92110705	12.17%	Customers-All	$ 564.08	$ 4,070.92	$ 4,635.00
921000	10705	INF SECUR COMP&QA-OF	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	77.72	92110705	12.17%	Customers-All	$ 9.46	$ 68.26	$ 77.72
921000	10705	INF SECUR COMP&QA-OF	601700	EQUIPMENT	NWN	F1	282.85	92110705	12.17%	Customers-All	$ 34.42	$ 248.43	$ 282.85
921000	10705	INF SECUR COMP&QA-OF	601900	DUES/MEMBERSHIP	NWN	F1	781.45	92110705	12.17%	Customers-All	$ 95.10	$ 686.35	$ 781.45
921000	10705	INF SECUR COMP&QA-OF	602000	OFFICE CONTRACT WORK	NWN	F1	197,410.80	92110705	12.17%	Customers-All	$ 24,024.89	$ 173,385.91	$ 197,410.80
921000	10705	INF SECUR COMP&QA-OF	602100	OTHER CONTRACT WORK	NWN	F1	1,165,330.57	92110705	12.17%	Customers-All	$ 141,820.73	$ 1,023,509.84	$ 1,165,330.57
921000	10705	INF SECUR COMP&QA-OF	602466	P CARD UNCODED CHARG	NWN	F1	570.38	92110705	12.17%	Customers-All	$ 69.42	$ 500.96	$ 570.38
921000	10705	INF SECUR COMP&QA-OF	602800	POSTAGE	NWN	F1	33.96	92110705	12.17%	Customers-All	$ 4.13	$ 29.83	$ 33.96
921000	10705	INF SECUR COMP&QA-OF	603000	OFFICE SUPPLIES	NWN	F1	26.00	92110705	12.17%	Customers-All	$ 3.16	$ 22.84	$ 26.00
921000	10705	INF SECUR COMP&QA-OF	603200	BOOKS AND MAGAZINES	NWN	F1	62.66	92110705	12.17%	Customers-All	$ 7.63	$ 55.03	$ 62.66
921000	10705	INF SECUR COMP&QA-OF	603300	REFRESHMENTS	NWN	F1	53.20	92110705	12.17%	Customers-All	$ 6.47	$ 46.73	$ 53.20
921000	10705	INF SECUR COMP&QA-OF	604700	PARKING	NWN	F1	18.75	92110705	12.17%	Customers-All	$ 2.28	$ 16.47	$ 18.75
921000	10705	INF SECUR COMP&QA-OF	605100	PROFESSIONAL SERVICE	NWN	F1	0.00	92110705	12.17%	Customers-All	$ -	$ -	$ -
921000	10705	INF SECUR COMP&QA-OF	605600	SOFTWARE MAINT	NWN	F1	0.00	92110705	12.17%	Customers-All	$ -	$ -	$ -
921000	10705	INF SECUR COMP&QA-OF	606200	PERMITS AND FEES	NWN	F1	0.00	92110705	12.17%	Customers-All	$ -	$ -	$ -
921000	10705	INF SECUR COMP&QA-OF	606801	PLANT TRANSFERS	NWN	F1	69.36	92110705	12.17%	Customers-All	$ 8.44	$ 60.92	$ 69.36
921000	10705	INF SECUR COMP&QA-OF	612100	MEALS AND ENTERTAIN	NWN	F1	962.80	92110705	12.17%	Customers-All	$ 117.17	$ 845.63	$ 962.80
921000	10705	INF SECUR COMP&QA-OF	613100	CONFERENCE TRAVEL	NWN	F1	1,795.58	92110705	12.17%	Customers-All	$ 218.52	$ 1,577.06	$ 1,795.58
921000	10705	INF SECUR COMP&QA-OF	613200	BUSINESS TRAVEL	NWN	F1	5,473.23	92110705	12.17%	Customers-All	$ 666.09	$ 4,807.14	$ 5,473.23
921000	10705	INF SECUR COMP&QA-OF	622000	EMPLOYEE AWARDS	NWN	F1	2,470.79	92110705	12.17%	Customers-All	$ 300.70	$ 2,170.09	$ 2,470.79
921000	10707	IT MAINT-OFFIC-921	601401	MATERIALS - CONS INV	NWN	F1	17.76	92110707	11.80%	3-factor	$ 2.10	$ 15.66	$ 17.76
921000	10707	IT MAINT-OFFIC-921	602000	OFFICE CONTRACT WORK	NWN	F1	20,107.50	92110707	11.80%	3-factor	$ 2,372.69	$ 17,734.82	$ 20,107.50
921000	10707	IT MAINT-OFFIC-921	602100	OTHER CONTRACT WORK	NWN	F1	2,238,835.14	92110707	11.80%	3-factor	$ 264,182.55	$ 1,974,652.59	$ 2,238,835.14
921000	10707	IT MAINT-OFFIC-921	602466	P CARD UNCODED CHARG	NWN	F1	(1,651.98)	92110707	11.80%	3-factor	$ (194.93)	$ (1,457.05)	$ (1,651.98)
921000	10707	IT MAINT-OFFIC-921	603000	OFFICE SUPPLIES	NWN	F1	919.46	92110707	11.80%	3-factor	$ 108.50	$ 810.96	$ 919.46
921000	10707	IT MAINT-OFFIC-921	603300	REFRESHMENTS	NWN	F1	197.68	92110707	11.80%	3-factor	$ 23.33	$ 174.35	$ 197.68
921000	10707	IT MAINT-OFFIC-921	605100	PROFESSIONAL SERVICE	NWN	F1	976,191.55	92110707	11.80%	3-factor	$ 115,190.60	$ 861,000.95	$ 976,191.55
921000	10707	IT MAINT-OFFIC-921	605600	SOFTWARE MAINT	NWN	F1	752,423.61	92110707	11.80%	3-factor	$ 88,785.99	$ 663,637.62	$ 752,423.61
921000	10707	IT MAINT-OFFIC-921	605900	HARDWARE MAINT	NWN	F1	322,920.42	92110707	11.80%	3-factor	$ 38,104.61	$ 284,815.81	$ 322,920.42
921000	10707	IT MAINT-OFFIC-921	612100	MEALS AND ENTERTAIN	NWN	F1	5,035.00	92110707	11.80%	3-factor	$ 594.13	$ 4,440.87	$ 5,035.00
921000	10707	IT MAINT-OFFIC-921	613200	BUSINESS TRAVEL	NWN	F1	0.00	92110707	11.80%	3-factor	$ -	$ -	$ -
921000	10707	IT MAINT-OFFIC-921	622000	EMPLOYEE AWARDS	NWN	F1	106.50	92110707	11.80%	3-factor	$ 12.57	$ 93.93	$ 106.50
921000	10710	IT MAINT- NONCLD-921	601400	MATERIALS	NWN	F1	12.00	92110710	11.80%	3-factor	$ 1.42	$ 10.58	$ 12.00
921000	10710	IT MAINT- NONCLD-921	602100	OTHER CONTRACT WORK	NWN	F1	0.00	92110710	11.80%	3-factor	$ -	$ -	$ -
921000	10710	IT MAINT- NONCLD-921	602800	POSTAGE	NWN	F1	177.84	92110710	11.80%	3-factor	$ 20.99	$ 156.85	$ 177.84
921000	10710	IT MAINT- NONCLD-921	605100	PROFESSIONAL SERVICE	NWN	F1	35,350.00	92110710	11.80%	3-factor	$ 4,171.30	$ 31,178.70	$ 35,350.00
921000	10710	IT MAINT- NONCLD-921	605600	SOFTWARE MAINT	NWN	F1	8,130,388.51	92110710	11.80%	3-factor	$ 959,385.84	$ 7,171,002.67	$ 8,130,388.51
921000	10710	IT MAINT- NONCLD-921	605900	HARDWARE MAINT	NWN	F1	1,044,881.74	92110710	11.80%	3-factor	$ 123,296.05	$ 921,585.69	$ 1,044,881.74
921000	10710	IT MAINT- NONCLD-921	606801	PLANT TRANSFERS	NWN	F1	4,277.94	92110710	11.80%	3-factor	$ 504.80	$ 3,773.14	$ 4,277.94
921000	10711	IT MAINT- CLOUD-921	602000	OFFICE CONTRACT WORK	NWN	F1	14,682.42	92110711	11.80%	3-factor	$ 1,732.53	$ 12,949.89	$ 14,682.42
921000	10711	IT MAINT- CLOUD-921	602100	OTHER CONTRACT WORK	NWN	F1	0.00	92110711	11.80%	3-factor	$ -	$ -	$ -
921000	10711	IT MAINT- CLOUD-921	602466	P CARD UNCODED CHARG	NWN	F1	0.00	92110711	11.80%	3-factor	$ -	$ -	$ -
921000	10711	IT MAINT- CLOUD-921	605600	SOFTWARE MAINT	NWN	F1	7,327,425.54	92110711	11.80%	3-factor	$ 864,636.21	$ 6,462,789.33	$ 7,327,425.54
921000	10711	IT MAINT- CLOUD-921	608100	SUBCRIPTION SERVICES	NWN	F1	684.00	92110711	11.80%	3-factor	$ 80.71	$ 603.29	$ 684.00
921000	10714	INFRASTR-OFFICE STAF	601100	EDUCATION	NWN	F1	3,000.00	92110714	11.80%	3-factor	$ 354.00	$ 2,646.00	$ 3,000.00
921000	10714	INFRASTR-OFFICE STAF	605600	SOFTWARE MAINT	NWN	F1	9,085.50	92110714	11.80%	3-factor	$ 1,072.09	$ 8,013.41	$ 9,085.50
921000	10717	IT GAS MGT SYSS-OFFI	601100	EDUCATION	NWN	F1	16,240.90	92110717	11.80%	3-factor	$ 1,916.43	$ 14,324.47	$ 16,240.90
921000	10717	IT GAS MGT SYSS-OFFI	601400	MATERIALS	NWN	F1	13,058.52	92110717	11.80%	3-factor	$ 1,540.91	$ 11,517.61	$ 13,058.52
921000	10717	IT GAS MGT SYSS-OFFI	601401	MATERIALS - CONS INV	NWN	F1	360.15	92110717	11.80%	3-factor	$ 42.50	$ 317.65	$ 360.15
921000	10717	IT GAS MGT SYSS-OFFI	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	463.84	92110717	11.80%	3-factor	$ 54.73	$ 409.11	$ 463.84
921000	10717	IT GAS MGT SYSS-OFFI	601600	TRANSPORTATION	NWN	F1	9,930.18	92110717	11.80%	3-factor	$ 1,171.76	$ 8,758.42	$ 9,930.18
921000	10717	IT GAS MGT SYSS-OFFI	601700	EQUIPMENT	NWN	F1	4,775.12	92110717	11.80%	3-factor	$ 563.46	$ 4,211.66	$ 4,775.12
921000	10717	IT GAS MGT SYSS-OFFI	602100	OTHER CONTRACT WORK	NWN	F1	0.00	92110717	11.80%	3-factor	$ -	$ -	$ -
921000	10717	IT GAS MGT SYSS-OFFI	602302	TOOLS AND EQUIP RENT	NWN	F1	404.00	92110717	11.80%	3-factor	$ 47.67	$ 356.33	$ 404.00
921000	10717	IT GAS MGT SYSS-OFFI	602466	P CARD UNCODED CHARG	NWN	F1	(4,847.10)	92110717	11.80%	3-factor	$ (571.96)	$ (4,275.14)	$ (4,847.10)
921000	10717	IT GAS MGT SYSS-OFFI	602600	UTILITIES	NWN	F1	536.06	92110717	11.80%	3-factor	$ 63.26	$ 472.80	$ 536.06
921000	10717	IT GAS MGT SYSS-OFFI	602700	TELEPHONE	NWN	F1	0.00	92110717	11.80%	3-factor	$ -	$ -	$ -
921000	10717	IT GAS MGT SYSS-OFFI	602800	POSTAGE	NWN	F1	44.34	92110717	11.80%	3-factor	$ 5.23	$ 39.11	$ 44.34
921000	10717	IT GAS MGT SYSS-OFFI	603000	OFFICE SUPPLIES	NWN	F1	155.63	92110717	11.80%	3-factor	$ 18.36	$ 137.27	$ 155.63
921000	10717	IT GAS MGT SYSS-OFFI	603200	BOOKS AND MAGAZINES	NWN	F1	607.05	92110717	11.80%	3-factor	$ 71.63	$ 535.42	$ 607.05
921000	10717	IT GAS MGT SYSS-OFFI	603300	REFRESHMENTS	NWN	F1	90.40	92110717	11.80%	3-factor	$ 10.67	$ 79.73	$ 90.40
921000	10717	IT GAS MGT SYSS-OFFI	603400	TOOL EXPENSE	NWN	F1	1,381.28	92110717	11.80%	3-factor	$ 162.99	$ 1,218.29	$ 1,381.28
921000	10717	IT GAS MGT SYSS-OFFI	604700	PARKING	NWN	F1	407.55	92110717	11.80%	3-factor	$ 48.09	$ 359.46	$ 407.55
921000	10717	IT GAS MGT SYSS-OFFI	604950	CLOTHING	NWN	F1	0.00	92110717	11.80%	3-factor	$ -	$ -	$ -
921000	10717	IT GAS MGT SYSS-OFFI	605000	LEGAL FEES	NWN	F1	0.00	92110717	11.80%	3-factor	$ -	$ -	$ -
921000	10717	IT GAS MGT SYSS-OFFI	605600	SOFTWARE MAINT	NWN	F1	1,507.91	92110717	11.80%	3-factor	$ 177.93	$ 1,329.98	$ 1,507.91
921000	10717	IT GAS MGT SYSS-OFFI	605800	MEAL TICKETS	NWN	F1	1,309.20	92110717	11.80%	3-factor	$ 154.49	$ 1,154.71	$ 1,309.20
921000	10717	IT GAS MGT SYSS-OFFI	606100	SECURITY	NWN	F1	300.00	92110717	11.80%	3-factor	$ 35.40	$ 264.60	$ 300.00
921000	10717	IT GAS MGT SYSS-OFFI	606200	PERMITS AND FEES	NWN	F1	0.00	92110717	11.80%	3-factor	$ -	$ -	$ -
921000	10717	IT GAS MGT SYSS-OFFI	606300	CELLULAR PHONES	NWN	F1	157.98	92110717	11.80%	3-factor	$ 18.64	$ 139.34	$ 157.98
921000	10717	IT GAS MGT SYSS-OFFI	606500	UNLEADED FUEL	NWN	F1	195.95	92110717	11.80%	3-factor	$ 23.12	$ 172.83	$ 195.95
921000	10717	IT GAS MGT SYSS-OFFI	607700	SMALL TOOLS	NWN	F1	2,072.52	92110717	11.80%	3-factor	$ 244.56	$ 1,827.96	$ 2,072.52
921000	10717	IT GAS MGT SYSS-OFFI	612100	MEALS AND ENTERTAIN	NWN	F1	597.19	92110717	11.80%	3-factor	$ 70.47	$ 526.72	$ 597.19
921000	10717	IT GAS MGT SYSS-OFFI	612200	TRAVEL IN TERRITORY	NWN	F1	31.10	92110717	11.80%	3-factor	$ 3.67	$ 27.43	$ 31.10
921000	10717	IT GAS MGT SYSS-OFFI	613100	CONFERENCE TRAVEL	NWN	F1	690.29	92110717	11.80%	3-factor	$ 81.45	$ 608.84	$ 690.29
921000	10717	IT GAS MGT SYSS-OFFI	613200	BUSINESS TRAVEL	NWN	F1	5,806.91	92110717	11.80%	3-factor	$ 685.22	$ 5,121.69	$ 5,806.91
921000	10717	IT GAS MGT SYSS-OFFI	622000	EMPLOYEE AWARDS	NWN	F1	2,775.00	92110717	11.80%	3-factor	$ 327.45	$ 2,447.55	$ 2,775.00
921000	10717	IT GAS MGT SYSS-OFFI	685800	MEAL TICKETS SECONDARY	NWN	F1	(920.40)	92110717	11.80%	3-factor	$ (108.61)	$ (811.79)	$ (920.40)
921000	10727	ENT APPLICATIONS-OFF	601100	EDUCATION	NWN	F1	16,878.00	92110727	12.17%	Customers-All	$ 2,054.05	$ 14,823.95	$ 16,878.00
921000	10727	ENT APPLICATIONS-OFF	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	0.00	92110727	12.17%	Customers-All	$ -	$ -	$ -
921000	10727	ENT APPLICATIONS-OFF	601900	DUES/MEMBERSHIP	NWN	F1	3,100.00	92110727	12.17%	Customers-All	$ 377.27	$ 2,722.73	$ 3,100.00
921000	10727	ENT APPLICATIONS-OFF	602000	OFFICE CONTRACT WORK	NWN	F1	367,778.30	92110727	12.17%	Customers-All	$ 44,758.62	$ 323,019.68	$ 367,778.30
921000	10727	ENT APPLICATIONS-OFF	602100	OTHER CONTRACT WORK	NWN	F1	2,279,222.47	92110727	12.17%	Customers-All	$ 277,381.37	$ 2,001,841.10	$ 2,279,222.47
921000	10727	ENT APPLICATIONS-OFF	602466	P CARD UNCODED CHARG	NWN	F1	240.88	92110727	12.17%	Customers-All	$ 29.32	$ 211.56	$ 240.88
921000	10727	ENT APPLICATIONS-OFF	602700	TELEPHONE	NWN	F1	8.00	92110727	12.17%	Customers-All	$ 0.97	$ 7.03	$ 8.00
921000	10727	ENT APPLICATIONS-OFF	603000	OFFICE SUPPLIES	NWN	F1	72.69	92110727	12.17%	Customers-All	$ 8.85	$ 63.84	$ 72.69
921000	10727	ENT APPLICATIONS-OFF	603200	BOOKS AND MAGAZINES	NWN	F1	1,200.00	92110727	12.17%	Customers-All	$ 146.04	$ 1,053.96	$ 1,200.00
921000	10727	ENT APPLICATIONS-OFF	603300	REFRESHMENTS	NWN	F1	283.52	92110727	12.17%	Customers-All	$ 34.50	$ 249.02	$ 283.52
921000	10727	ENT APPLICATIONS-OFF	604700	PARKING	NWN	F1	0.00	92110727	12.17%	Customers-All	$ -	$ -	$ -
921000	10727	ENT APPLICATIONS-OFF	605000	LEGAL FEES	NWN	F1	18,505.00	92110727	12.17%	Customers-All	$ 2,252.06	$ 16,252.94	$ 18,505.00
921000	10727	ENT APPLICATIONS-OFF	605100	PROFESSIONAL SERVICE	NWN	F1	(38,841.15)	92110727	12.17%	Customers-All	$ (4,726.97)	$ (34,114.18)	$ (38,841.15)
921000	10727	ENT APPLICATIONS-OFF	605600	SOFTWARE MAINT	NWN	F1	11,879.00	92110727	12.17%	Customers-All	$ 1,445.67	$ 10,433.33	$ 11,879.00
921000	10727	ENT APPLICATIONS-OFF	605800	MEAL TICKETS	NWN	F1	118.00	92110727	12.17%	Customers-All	$ 14.36	$ 103.64	$ 118.00
921000	10727	ENT APPLICATIONS-OFF	606200	PERMITS AND FEES	NWN	F1	4.00	92110727	12.17%	Customers-All	$ 0.49	$ 3.51	$ 4.00
921000	10727	ENT APPLICATIONS-OFF	606801	PLANT TRANSFERS	NWN	F1	3,048.96	92110727	12.17%	Customers-All	$ 371.06	$ 2,677.90	$ 3,048.96
921000	10727	ENT APPLICATIONS-OFF	608100	SUBCRIPTION SERVICES	NWN	F1	0.00	92110727	12.17%	Customers-All	$ -	$ -	$ -
921000	10727	ENT APPLICATIONS-OFF	612100	MEALS AND ENTERTAIN	NWN	F1	1,484.73	92110727	12.17%	Customers-All	$ 180.69	$ 1,304.04	$ 1,484.73
921000	10727	ENT APPLICATIONS-OFF	613100	CONFERENCE TRAVEL	NWN	F1	3,930.89	92110727	12.17%	Customers-All	$ 478.39	$ 3,452.50	$ 3,930.89
921000	10727	ENT APPLICATIONS-OFF	613200	BUSINESS TRAVEL	NWN	F1	484.40	92110727	12.17%	Customers-All	$ 58.95	$ 425.45	$ 484.40
921000	10727	ENT APPLICATIONS-OFF	622000	EMPLOYEE AWARDS	NWN	F1	4,995.78	92110727	12.17%	Customers-All	$ 607.99	$ 4,387.79	$ 4,995.78
921000	10735	ENT ARCHTECTURE-OFF	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	244.30	92110735	12.17%	Customers-All	$ 29.73	$ 214.57	$ 244.30
921000	10735	ENT ARCHTECTURE-OFF	601900	DUES/MEMBERSHIP	NWN	F1	22,906.00	92110735	12.17%	Customers-All	$ 2,787.66	$ 20,118.34	$ 22,906.00
921000	10735	ENT ARCHTECTURE-OFF	602000	OFFICE CONTRACT WORK	NWN	F1	124,884.00	92110735	12.17%	Customers-All	$ 15,198.38	$ 109,685.62	$ 124,884.00
921000	10735	ENT ARCHTECTURE-OFF	602100	OTHER CONTRACT WORK	NWN	F1	301,292.80	92110735	12.17%	Customers-All	$ 36,667.33	$ 264,625.47	$ 301,292.80
921000	10735	ENT ARCHTECTURE-OFF	602466	P CARD UNCODED CHARG	NWN	F1	0.00	92110735	12.17%	Customers-All	$ -	$ -	$ -
921000	10735	ENT ARCHTECTURE-OFF	604700	PARKING	NWN	F1	17.00	92110735	12.17%	Customers-All	$ 2.07	$ 14.93	$ 17.00
921000	10735	ENT ARCHTECTURE-OFF	605100	PROFESSIONAL SERVICE	NWN	F1	61,810.85	92110735	12.17%	Customers-All	$ 7,522.38	$ 54,288.47	$ 61,810.85
921000	10735	ENT ARCHTECTURE-OFF	606500	UNLEADED FUEL	NWN	F1	46.41	92110735	12.17%	Customers-All	$ 5.65	$ 40.76	$ 46.41
921000	10735	ENT ARCHTECTURE-OFF	606801	PLANT TRANSFERS	NWN	F1	10,335.56	92110735	12.17%	Customers-All	$ 1,257.84	$ 9,077.72	$ 10,335.56
921000	10735	ENT ARCHTECTURE-OFF	612100	MEALS AND ENTERTAIN	NWN	F1	347.96	92110735	12.17%	Customers-All	$ 42.35	$ 305.61	$ 347.96
921000	10735	ENT ARCHTECTURE-OFF	613200	BUSINESS TRAVEL	NWN	F1	0.00	92110735	12.17%	Customers-All	$ -	$ -	$ -
921000	10735	ENT ARCHTECTURE-OFF	622000	EMPLOYEE AWARDS	NWN	F1	484.79	92110735	12.17%	Customers-All	$ 59.00	$ 425.79	$ 484.79
921000	10739	CYBERSE STAYGOOD-921	602000	OFFICE CONTRACT WORK	NWN	F1	20,658.75	92110739	12.17%	Customers-All	$ 2,514.17	$ 18,144.58	$ 20,658.75
921000	10739	CYBERSE STAYGOOD-921	602100	OTHER CONTRACT WORK	NWN	F1	83,625.00	92110739	12.17%	Customers-All	$ 10,177.16	$ 73,447.84	$ 83,625.00
921000	10739	CYBERSE STAYGOOD-921	605000	LEGAL FEES	NWN	F1	55,086.75	92110739	12.17%	Customers-All	$ 6,704.06	$ 48,382.69	$ 55,086.75
921000	10739	CYBERSE STAYGOOD-921	605100	PROFESSIONAL SERVICE	NWN	F1	6,619.80	92110739	12.17%	Customers-All	$ 805.63	$ 5,814.17	$ 6,619.80
921000	10739	CYBERSE STAYGOOD-921	605600	SOFTWARE MAINT	NWN	F1	(81,215.80)	92110739	12.17%	Customers-All	$ (9,883.96)	$ (71,331.84)	$ (81,215.80)
921000	10740	ACCOUNTING-OFFICE921	601100	EDUCATION	NWN	F1	2,937.00	92110740	11.80%	3-factor	$ 346.57	$ 2,590.43	$ 2,937.00
921000	10740	ACCOUNTING-OFFICE921	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	238.52	92110740	11.80%	3-factor	$ 28.15	$ 210.37	$ 238.52
921000	10740	ACCOUNTING-OFFICE921	601900	DUES/MEMBERSHIP	NWN	F1	1,386.71	92110740	11.80%	3-factor	$ 163.63	$ 1,223.08	$ 1,386.71
921000	10740	ACCOUNTING-OFFICE921	602000	OFFICE CONTRACT WORK	NWN	F1	188,515.74	92110740	11.80%	3-factor	$ 22,244.86	$ 166,270.88	$ 188,515.74
921000	10740	ACCOUNTING-OFFICE921	602466	P CARD UNCODED CHARG	NWN	F1	(5,585.26)	92110740	11.80%	3-factor	$ (659.06)	$ (4,926.20)	$ (5,585.26)

NW Natural
Admin Transfer Allocation Factor
Test Year Ending March 31, 2025

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$ 71,068,305.98

						Fiscal Year Period	Amount			Admin Transfer Factor	12.1429%	87.8571%	
						Measures	Overall Result			TOTAL	$ 8,629,765.83	$ 62,438,540.15	$ 71,068,305.98
FERC Account	Cost Center	Cost Center Description	GL Account	GL Account Long Name	Chart of Accounts	Ledger	$	SORTER	ALLOCATION FACTOR	ALLOCATION METHOD	WA	OR	SYSTEM
921000	10740	ACCOUNTING-OFFICE921	602500	BANK CHARGES	NWN	P1	(181,375.76)	92110740	11.80%	3-factor	$ (21,402.34)	$ (159,973.42)	$ (181,375.76)
921000	10740	ACCOUNTING-OFFICE921	602800	POSTAGE	NWN	P1	27.23	92110740	11.80%	3-factor	$ 3.21	$ 24.02	$ 27.23
921000	10740	ACCOUNTING-OFFICE921	603000	OFFICE SUPPLIES	NWN	P1	37.39	92110740	11.80%	3-factor	$ 4.41	$ 32.98	$ 37.39
921000	10740	ACCOUNTING-OFFICE921	603300	REFRESHMENTS	NWN	P1	129.45	92110740	11.80%	3-factor	$ 15.28	$ 114.17	$ 129.45
921000	10740	ACCOUNTING-OFFICE921	604700	PARKING	NWN	P1	335.40	92110740	11.80%	3-factor	$ 39.58	$ 295.87	$ 335.45
921000	10740	ACCOUNTING-OFFICE921	605100	PROFESSIONAL SERVICE	NWN	P1	168,217.92	92110740	11.80%	3-factor	$ 19,849.71	$ 148,368.21	$ 168,217.92
921000	10740	ACCOUNTING-OFFICE921	606200	PERMITS AND FEES	NWN	P1	128.50	92110740	11.80%	3-factor	$ 15.16	$ 113.34	$ 128.50
921000	10740	ACCOUNTING-OFFICE921	606500	UNLEADED FUEL	NWN	P1	25.17	92110740	11.80%	3-factor	$ 2.97	$ 22.20	$ 25.17
921000	10740	ACCOUNTING-OFFICE921	612100	MEALS AND ENTERTAIN	NWN	P1	1,236.62	92110740	11.80%	3-factor	$ 145.92	$ 1,090.70	$ 1,236.62
921000	10740	ACCOUNTING-OFFICE921	613100	CONFERENCE TRAVEL	NWN	P1	5,756.86	92110740	11.80%	3-factor	$ 679.31	$ 5,077.55	$ 5,756.86
921000	10740	ACCOUNTING-OFFICE921	622000	EMPLOYEE AWARDS	NWN	P1	2,708.80	92110740	11.80%	3-factor	$ 319.64	$ 2,389.16	$ 2,708.80
921000	10740	ACCOUNTING-OFFICE921	622200	NON EMPLOYEE GIFTS	NWN	P1	4.99	92110740	11.80%	3-factor	$ 0.59	$ 4.40	$ 4.99
921000	10741	TECH ACCT G - 921	601100	EDUCATION	NWN	P1	1,077.00	92110741	11.80%	3-factor	$ 127.09	$ 949.91	$ 1,077.00
921000	10741	TECH ACCT G - 921	601900	DUES/MEMBERSHIP	NWN	P1	0.00	92110741	11.80%	3-factor	$ -	$ -	$ -
921000	10741	TECH ACCT G - 921	602466	P CARD UNCODED CHARG	NWN	P1	370.00	92110741	11.80%	3-factor	$ 43.66	$ 326.34	$ 370.00
921000	10741	TECH ACCT G - 921	605100	PROFESSIONAL SERVICE	NWN	P1	106,590.00	92110741	11.80%	3-factor	$ 12,577.62	$ 94,012.38	$ 106,590.00
921000	10741	TECH ACCT G - 921	605600	SOFTWARE MAINT	NWN	P1	0.00	92110741	11.80%	3-factor	$ -	$ -	$ -
921000	10741	TECH ACCT G - 921	608100	SUBSCRIPTION SERVICES	NWN	P1	60.00	92110741	11.80%	3-factor	$ 7.08	$ 52.92	$ 60.00
921000	10741	TECH ACCT G - 921	622000	EMPLOYEE AWARDS	NWN	P1	320.65	92110741	11.80%	3-factor	$ 37.86	$ 282.99	$ 320.85
921000	10745	SARBANES OXLEY-OFFIC	601100	EDUCATION	NWN	P1	2,813.00	92110745	11.80%	3-factor	$ 331.93	$ 2,481.07	$ 2,813.00
921000	10745	SARBANES OXLEY-OFFIC	601900	DUES/MEMBERSHIP	NWN	P1	255.00	92110745	11.80%	3-factor	$ 30.09	$ 224.91	$ 255.00
921000	10745	SARBANES OXLEY-OFFIC	602000	OFFICE CONTRACT WORK	NWN	P1	75,285.00	92110745	11.80%	3-factor	$ 8,883.63	$ 66,401.37	$ 75,285.00
921000	10745	SARBANES OXLEY-OFFIC	602466	P CARD UNCODED CHARG	NWN	P1	0.00	92110745	11.80%	3-factor	$ -	$ -	$ -
921000	10745	SARBANES OXLEY-OFFIC	602800	POSTAGE	NWN	P1	0.00	92110745	11.80%	3-factor	$ -	$ -	$ -
921000	10745	SARBANES OXLEY-OFFIC	605100	PROFESSIONAL SERVICE	NWN	P1	1,544,160.00	92110745	11.80%	3-factor	$ 182,210.88	$ 1,361,949.12	$ 1,544,160.00
921000	10745	SARBANES OXLEY-OFFIC	605600	SOFTWARE MAINT	NWN	P1	69,057.24	92110745	11.80%	3-factor	$ 8,148.75	$ 60,908.49	$ 69,057.24
921000	10745	SARBANES OXLEY-OFFIC	613100	CONFERENCE TRAVEL	NWN	P1	579.11	92110745	11.80%	3-factor	$ 68.33	$ 510.78	$ 579.11
921000	10745	SARBANES OXLEY-OFFIC	622000	EMPLOYEE AWARDS	NWN	P1	370.85	92110745	11.80%	3-factor	$ 43.76	$ 327.09	$ 370.85
921000	10746	SEC REPORTING-921	601100	EDUCATION	NWN	P1	718.00	92110746	11.80%	3-factor	$ 84.72	$ 633.28	$ 718.00
921000	10746	SEC REPORTING-921	601900	DUES/MEMBERSHIP	NWN	P1	510.00	92110746	11.80%	3-factor	$ 60.18	$ 449.82	$ 510.00
921000	10746	SEC REPORTING-921	602466	P CARD UNCODED CHARG	NWN	P1	0.00	92110746	11.80%	3-factor	$ -	$ -	$ -
921000	10746	SEC REPORTING-921	604700	PARKING	NWN	P1	9.95	92110746	11.80%	3-factor	$ 1.17	$ 8.78	$ 9.95
921000	10746	SEC REPORTING-921	605100	PROFESSIONAL SERVICE	NWN	P1	177,000.00	92110746	11.80%	3-factor	$ 20,886.00	$ 156,114.00	$ 177,000.00
921000	10746	SEC REPORTING-921	605600	SOFTWARE MAINT	NWN	P1	47,656.88	92110746	11.80%	3-factor	$ 5,623.51	$ 42,033.37	$ 47,656.88
921000	10746	SEC REPORTING-921	612100	MEALS AND ENTERTAIN	NWN	P1	69.00	92110746	11.80%	3-factor	$ 8.14	$ 60.86	$ 69.00
921000	10746	SEC REPORTING-921	622000	EMPLOYEE AWARDS	NWN	P1	475.80	92110746	11.80%	3-factor	$ 56.14	$ 419.66	$ 475.80
921000	10746	SEC REPORTING-OFFICE	601100	EDUCATION	NWN	P1	718.00	92110746	11.80%	3-factor	$ 84.72	$ 633.28	$ 718.00
921000	10746	SEC REPORTING-OFFICE	601900	DUES/MEMBERSHIP	NWN	P1	510.00	92110746	11.80%	3-factor	$ 60.18	$ 449.82	$ 510.00
921000	10746	SEC REPORTING-OFFICE	602466	P CARD UNCODED CHARG	NWN	P1	0.00	92110746	11.80%	3-factor	$ -	$ -	$ -
921000	10746	SEC REPORTING-OFFICE	604700	PARKING	NWN	P1	9.95	92110746	11.80%	3-factor	$ 1.17	$ 8.78	$ 9.95
921000	10746	SEC REPORTING-OFFICE	605100	PROFESSIONAL SERVICE	NWN	P1	177,000.00	92110746	11.80%	3-factor	$ 20,886.00	$ 156,114.00	$ 177,000.00
921000	10746	SEC REPORTING-OFFICE	605600	SOFTWARE MAINT	NWN	P1	47,656.88	92110746	11.80%	3-factor	$ 5,623.51	$ 42,033.37	$ 47,656.88
921000	10746	SEC REPORTING-OFFICE	612100	MEALS AND ENTERTAIN	NWN	P1	69.00	92110746	11.80%	3-factor	$ 8.14	$ 60.86	$ 69.00
921000	10746	SEC REPORTING-OFFICE	622000	EMPLOYEE AWARDS	NWN	P1	475.80	92110746	11.80%	3-factor	$ 56.14	$ 419.66	$ 475.80
921000	10748	GAS ACCOUNTING-921	601100	EDUCATION	NWN	P1	718.00	92110748	11.80%	3-factor	$ 84.72	$ 633.28	$ 718.00
921000	10748	GAS ACCOUNTING-921	601900	DUES/MEMBERSHIP	NWN	P1	510.00	92110748	11.80%	3-factor	$ 60.18	$ 449.82	$ 510.00
921000	10748	GAS ACCOUNTING-921	605100	PROFESSIONAL SERVICE	NWN	P1	38,460.60	92110748	11.80%	3-factor	$ 4,538.35	$ 33,922.25	$ 38,460.60
921000	10748	GAS ACCOUNTING-921	612100	MEALS AND ENTERTAIN	NWN	P1	0.00	92110748	11.80%	3-factor	$ -	$ -	$ -
921000	10748	GAS ACCOUNTING-921	622000	EMPLOYEE AWARDS	NWN	P1	785.70	92110748	11.80%	3-factor	$ 92.71	$ 692.99	$ 785.70
921000	10748	GAS ACCOUNTING-OFFIC	601100	EDUCATION	NWN	P1	718.00	92110748	11.80%	3-factor	$ 84.72	$ 633.28	$ 718.00
921000	10748	GAS ACCOUNTING-OFFIC	601900	DUES/MEMBERSHIP	NWN	P1	510.00	92110748	11.80%	3-factor	$ 60.18	$ 449.82	$ 510.00
921000	10748	GAS ACCOUNTING-OFFIC	605100	PROFESSIONAL SERVICE	NWN	P1	38,460.60	92110748	11.80%	3-factor	$ 4,538.35	$ 33,922.25	$ 38,460.60
921000	10748	GAS ACCOUNTING-OFFIC	612100	MEALS AND ENTERTAIN	NWN	P1	0.00	92110748	11.80%	3-factor	$ -	$ -	$ -
921000	10748	GAS ACCOUNTING-OFFIC	622000	EMPLOYEE AWARDS	NWN	P1	785.70	92110748	11.80%	3-factor	$ 92.71	$ 692.99	$ 785.70
921000	10750	OPERATIONAL ACCT G-OF	601900	DUES/MEMBERSHIP	NWN	P1	240.00	92110750	11.80%	3-factor	$ 28.32	$ 211.68	$ 240.00
921000	10750	OPERATIONAL ACCT G-OF	602000	OFFICE CONTRACT WORK	NWN	P1	106,875.30	92110750	11.80%	3-factor	$ 12,611.29	$ 94,264.01	$ 106,875.30
921000	10750	OPERATIONAL ACCT G-OF	602100	OTHER CONTRACT WORK	NWN	P1	0.00	92110750	11.80%	3-factor	$ -	$ -	$ -
921000	10750	OPERATIONAL ACCT G-OF	602466	P CARD UNCODED CHARG	NWN	P1	246.49	92110750	11.80%	3-factor	$ 29.09	$ 217.40	$ 246.49
921000	10750	OPERATIONAL ACCT G-OF	603000	OFFICE SUPPLIES	NWN	P1	27.55	92110750	11.80%	3-factor	$ 3.25	$ 24.30	$ 27.55
921000	10750	OPERATIONAL ACCT G-OF	605100	PROFESSIONAL SERVICE	NWN	P1	46,000.00	92110750	11.80%	3-factor	$ 5,428.00	$ 40,572.00	$ 46,000.00
921000	10750	OPERATIONAL ACCT G-OF	605600	SOFTWARE MAINT	NWN	P1	0.00	92110750	11.80%	3-factor	$ -	$ -	$ -
921000	10750	OPERATIONAL ACCT G-OF	622000	EMPLOYEE AWARDS	NWN	P1	481.70	92110750	11.80%	3-factor	$ 56.84	$ 424.86	$ 481.70
921000	10751	TAX-OFFICE STAFFING	601100	EDUCATION	NWN	P1	673.99	92110751	11.80%	3-factor	$ 79.53	$ 594.46	$ 673.99
921000	10751	TAX-OFFICE STAFFING	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	P1	0.00	92110751	11.80%	3-factor	$ -	$ -	$ -
921000	10751	TAX-OFFICE STAFFING	601900	DUES/MEMBERSHIP	NWN	P1	1,505.00	92110751	11.80%	3-factor	$ 177.59	$ 1,327.41	$ 1,505.00
921000	10751	TAX-OFFICE STAFFING	602100	OTHER CONTRACT WORK	NWN	P1	992.50	92110751	11.80%	3-factor	$ 117.12	$ 875.39	$ 992.50
921000	10751	TAX-OFFICE STAFFING	602466	P CARD UNCODED CHARG	NWN	P1	4,447.41	92110751	11.80%	3-factor	$ 524.79	$ 3,922.62	$ 4,447.41
921000	10751	TAX-OFFICE STAFFING	602800	POSTAGE	NWN	P1	9.68	92110751	11.80%	3-factor	$ 1.14	$ 8.54	$ 9.68
921000	10751	TAX-OFFICE STAFFING	604700	PARKING	NWN	P1	0.00	92110751	11.80%	3-factor	$ -	$ -	$ -
921000	10751	TAX-OFFICE STAFFING	605100	PROFESSIONAL SERVICE	NWN	P1	53,249.00	92110751	11.80%	3-factor	$ 6,283.38	$ 46,965.62	$ 53,249.00
921000	10751	TAX-OFFICE STAFFING	605600	SOFTWARE MAINT	NWN	P1	85,263.32	92110751	11.80%	3-factor	$ 10,061.07	$ 75,202.25	$ 85,263.32
921000	10751	TAX-OFFICE STAFFING	612100	MEALS AND ENTERTAIN	NWN	P1	0.00	92110751	11.80%	3-factor	$ -	$ -	$ -
921000	10751	TAX-OFFICE STAFFING	613100	CONFERENCE TRAVEL	NWN	P1	0.00	92110751	11.80%	3-factor	$ -	$ -	$ -
921000	10751	TAX-OFFICE STAFFING	622000	EMPLOYEE AWARDS	NWN	P1	300.00	92110751	11.80%	3-factor	$ 35.40	$ 264.60	$ 300.00
921000	10752	TAX-OFFICE STAFFING	601401	MATERIALS - CONS INV	NWN	P1	4.17	92110752	11.80%	3-factor	$ 0.49	$ 3.68	$ 4.17
921000	10755	CASH MANAGEMENT-OFFI	602466	P CARD UNCODED CHARG	NWN	P1	158.44	92110755	11.80%	3-factor	$ 18.70	$ 139.74	$ 158.44
921000	10755	CASH MANAGEMENT-OFFI	602500	BANK CHARGES	NWN	P1	680,550.31	92110755	11.80%	3-factor	$ 80,304.94	$ 600,245.37	$ 680,550.31
921000	10755	CASH MANAGEMENT-OFFI	602800	POSTAGE	NWN	P1	153.40	92110755	11.80%	3-factor	$ 18.10	$ 135.30	$ 153.40
921000	10755	CASH MANAGEMENT-OFFI	605100	PROFESSIONAL SERVICE	NWN	P1	780,841.62	92110755	11.80%	3-factor	$ 92,139.31	$ 688,702.31	$ 780,841.62
921000	10755	CASH MANAGEMENT-OFFI	612100	MEALS AND ENTERTAIN	NWN	P1	89.44	92110755	11.80%	3-factor	$ 10.55	$ 78.89	$ 89.44
921000	10755	CASH MANAGEMENT-OFFI	613200	BUSINESS TRAVEL	NWN	P1	771.41	92110755	11.80%	3-factor	$ 91.03	$ 680.38	$ 771.41
921000	10756	MID OFFICE-OFFICE ST	601900	DUES/MEMBERSHIP	NWN	P1	257.01	92110756	11.80%	3-factor	$ 30.33	$ 226.68	$ 257.01
921000	10756	MID OFFICE-OFFICE ST	602466	P CARD UNCODED CHARG	NWN	P1	768.77	92110756	11.80%	3-factor	$ 90.71	$ 678.06	$ 768.77
921000	10756	MID OFFICE-OFFICE ST	603200	BOOKS AND MAGAZINES	NWN	P1	1,224.10	92110756	11.80%	3-factor	$ 144.44	$ 1,079.66	$ 1,224.10
921000	10756	MID OFFICE-OFFICE ST	604700	PARKING	NWN	P1	0.00	92110756	11.80%	3-factor	$ -	$ -	$ -
921000	10756	MID OFFICE-OFFICE ST	605100	PROFESSIONAL SERVICE	NWN	P1	304,243.10	92110756	11.80%	3-factor	$ 35,900.69	$ 268,342.41	$ 304,243.10
921000	10756	MID OFFICE-OFFICE ST	612100	MEALS AND ENTERTAIN	NWN	P1	112.00	92110756	11.80%	3-factor	$ 13.22	$ 98.78	$ 112.00
921000	10756	MID OFFICE-OFFICE ST	622000	EMPLOYEE AWARDS	NWN	P1	150.00	92110756	11.80%	3-factor	$ 17.70	$ 132.30	$ 150.00
921000	10757	CAPITAL ACCOUNTING-O	622000	EMPLOYEE AWARDS	NWN	P1	525.80	92110757	11.80%	3-factor	$ 62.04	$ 463.76	$ 525.80
921000	10757	CAPITAL ACCTG 921	622000	EMPLOYEE AWARDS	NWN	P1	525.80	92110757	11.80%	3-factor	$ 62.04	$ 463.76	$ 525.80
921000	10758	BUSINESS DEVELOPMENT	601200	AUTO ALLOWANCE	NWN	P1	6,000.00	92110758	12.17%	Customers-All	$ 730.20	$ 5,269.80	$ 6,000.00
921000	10758	BUSINESS DEVELOPMENT	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	P1	122.61	92110758	12.17%	Customers-All	$ 14.92	$ 107.69	$ 122.61
921000	10758	BUSINESS DEVELOPMENT	601900	DUES/MEMBERSHIP	NWN	P1	2,029.60	92110758	12.17%	Customers-All	$ 247.00	$ 1,782.60	$ 2,029.60
921000	10758	BUSINESS DEVELOPMENT	602466	P CARD UNCODED CHARG	NWN	P1	1,409.00	92110758	12.17%	Customers-All	$ 171.48	$ 1,237.52	$ 1,409.00
921000	10758	BUSINESS DEVELOPMENT	603300	REFRESHMENTS	NWN	P1	221.80	92110758	12.17%	Customers-All	$ 26.99	$ 194.81	$ 221.80
921000	10758	BUSINESS DEVELOPMENT	604700	PARKING	NWN	P1	618.20	92110758	12.17%	Customers-All	$ 75.23	$ 542.97	$ 618.20
921000	10758	BUSINESS DEVELOPMENT	605000	LEGAL FEES	NWN	P1	0.00	92110758	12.17%	Customers-All	$ -	$ -	$ -
921000	10758	BUSINESS DEVELOPMENT	606500	UNLEADED FUEL	NWN	P1	0.00	92110758	12.17%	Customers-All	$ -	$ -	$ -
921000	10758	BUSINESS DEVELOPMENT	612100	MEALS AND ENTERTAIN	NWN	P1	1,995.78	92110758	12.17%	Customers-All	$ 242.89	$ 1,752.89	$ 1,995.78
921000	10758	BUSINESS DEVELOPMENT	613100	CONFERENCE TRAVEL	NWN	P1	0.00	92110758	12.17%	Customers-All	$ -	$ -	$ -
921000	10758	BUSINESS DEVELOPMENT	613200	BUSINESS TRAVEL	NWN	P1	19,004.33	92110758	12.17%	Customers-All	$ 2,312.83	$ 16,691.50	$ 19,004.33
921000	10758	BUSINESS DEVELOPMENT	622000	EMPLOYEE AWARDS	NWN	P1	410.95	92110758	12.17%	Customers-All	$ 50.01	$ 360.94	$ 410.95
921000	10759	RENEWABLES-OFFICE ST	601100	EDUCATION	NWN	P1	8,111.48	92110759	12.17%	Customers-All	$ 987.17	$ 7,124.31	$ 8,111.48
921000	10759	RENEWABLES-OFFICE ST	601400	MATERIALS	NWN	P1	240.00	92110759	12.17%	Customers-All	$ 29.21	$ 210.79	$ 240.00
921000	10759	RENEWABLES-OFFICE ST	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	P1	2,834.87	92110759	12.17%	Customers-All	$ 345.00	$ 2,489.87	$ 2,834.87
921000	10759	RENEWABLES-OFFICE ST	601600	TRANSPORTATION	NWN	P1	0.00	92110759	12.17%	Customers-All	$ -	$ -	$ -
921000	10759	RENEWABLES-OFFICE ST	601900	DUES/MEMBERSHIP	NWN	P1	550.00	92110759	12.17%	Customers-All	$ 66.94	$ 483.07	$ 550.00
921000	10759	RENEWABLES-OFFICE ST	602000	OFFICE CONTRACT WORK	NWN	P1	0.00	92110759	12.17%	Customers-All	$ -	$ -	$ -
921000	10759	RENEWABLES-OFFICE ST	602400	MISCELLANEOUS	NWN	P1	200,000.00	92110759	12.17%	Customers-All	$ 24,340.00	$ 175,660.00	$ 200,000.00
921000	10759	RENEWABLES-OFFICE ST	602466	P CARD UNCODED CHARG	NWN	P1	(1,161.15)	92110759	12.17%	Customers-All	$ (141.31)	$ (1,019.84)	$ (1,161.15)
921000	10759	RENEWABLES-OFFICE ST	602700	TELEPHONE	NWN	P1	8.00	92110759	12.17%	Customers-All	$ 0.97	$ 7.03	$ 8.00
921000	10759	RENEWABLES-OFFICE ST	602800	POSTAGE	NWN	P1	0.00	92110759	12.17%	Customers-All	$ -	$ -	$ -
921000	10759	RENEWABLES-OFFICE ST	603000	OFFICE SUPPLIES	NWN	P1	281.78	92110759	12.17%	Customers-All	$ 34.29	$ 247.49	$ 281.78
921000	10759	RENEWABLES-OFFICE ST	603100	PRINTING	NWN	P1	68.15	92110759	12.17%	Customers-All	$ 8.29	$ 59.86	$ 68.15
921000	10759	RENEWABLES-OFFICE ST	603300	REFRESHMENTS	NWN	P1	98.25	92110759	12.17%	Customers-All	$ 11.96	$ 86.29	$ 98.25
921000	10759	RENEWABLES-OFFICE ST	604700	PARKING	NWN	P1	641.31	92110759	12.17%	Customers-All	$ 78.05	$ 563.26	$ 641.31
921000	10759	RENEWABLES-OFFICE ST	604950	CLOTHING	NWN	P1	224.69	92110759	12.17%	Customers-All	$ 27.34	$ 197.35	$ 224.69
921000	10759	RENEWABLES-OFFICE ST	605000	LEGAL FEES	NWN	P1	0.00	92110759	12.17%	Customers-All	$ -	$ -	$ -
921000	10759	RENEWABLES-OFFICE ST	605100	PROFESSIONAL SERVICE	NWN	P1	224,214.19	92110759	12.17%	Customers-All	$ 27,286.87	$ 196,927.32	$ 224,214.19
921000	10759	RENEWABLES-OFFICE ST	605600	SOFTWARE MAINT	NWN	P1	432.00	92110759	12.17%	Customers-All	$ 52.57	$ 379.43	$ 432.00
921000	10759	RENEWABLES-OFFICE ST	606200	PERMITS AND FEES	NWN	P1	25.25	92110759	12.17%	Customers-All	$ 3.07	$ 22.18	$ 25.25
921000	10759	RENEWABLES-OFFICE ST	606500	UNLEADED FUEL	NWN	P1	462.34	92110759	12.17%	Customers-All	$ 56.27	$ 406.07	$ 462.34
921000	10759	RENEWABLES-OFFICE ST	607500	CORPORATE IDENTITY	NWN	P1	1,250.00	92110759	12.17%	Customers-All	$ 152.13	$ 1,097.88	$ 1,250.00
921000	10759	RENEWABLES-OFFICE ST	608411	SHARED SERVICES COSTS SECONDARY	NWN	P1	12,954.06	92110759	12.17%	Customers-All	$ 1,576.51	$ 11,377.55	$ 12,954.06
921000	10759	RENEWABLES-OFFICE ST	612100	MEALS AND ENTERTAIN	NWN	P1	5,274.42	92110759	12.17%	Customers-All	$ 641.90	$ 4,632.52	$ 5,274.42
921000	10759	RENEWABLES-OFFICE ST	612200	TRAVEL IN TERRITORY	NWN	P1	0.00	92110759	12.17%	Customers-All	$ -	$ -	$ -
921000	10759	RENEWABLES-OFFICE ST	613100	CONFERENCE TRAVEL	NWN	P1	16,589.72	92110759	12.17%	Customers-All	$ 2,018.97	$ 14,570.75	$ 16,589.72
921000	10759	RENEWABLES-OFFICE ST	613200	BUSINESS TRAVEL	NWN	P1	18,169.52	92110759	12.17%	Customers-All	$ 2,211.23	$ 15,958.29	$ 18,169.52
921000	10759	RENEWABLES-OFFICE ST	622000	EMPLOYEE AWARDS	NWN	P1	1,255.60	92110759	12.17%	Customers-All	$ 152.81	$ 1,102.79	$ 1,255.60
921000	10761	RENEWABLES-OFFICE ST	602466	P CARD UNCODED CHARG	NWN	P1	1,988.68	92110761	12.17%	Customers-All	$ 242.02	$ 1,746.66	$ 1,988.68
921000	10761	RENEWABLES-OFFICE ST	605100	PROFESSIONAL SERVICE	NWN	P1	(301.00)	92110761	12.17%	Customers-All	$ (36.63)	$ (264.37)	$ (301.00)
921000	10763	FIN PLANNING & BUDGE	601100	EDUCATION	NWN	P1	474.00	92110763	11.80%	3-factor	$ 55.93	$ 418.07	$ 474.00
921000	10763	FIN PLANNING & BUDGE	601900	DUES/MEMBERSHIP	NWN	P1	80.00	92110763	11.80%	3-factor	$ 9.44	$ 70.56	$ 80.00
921000	10763	FIN PLANNING & BUDGE	602100	OTHER CONTRACT WORK	NWN	P1	0.00	92110763	11.80%	3-factor	$ -	$ -	$ -
921000	10763	FIN PLANNING & BUDGE	602466	P CARD UNCODED CHARG	NWN	P1	(159.50)	92110763	11.80%	3-factor	$ (18.82)	$ (140.68)	$ (159.50)
921000	10763	FIN PLANNING & BUDGE	603000	OFFICE SUPPLIES	NWN	P1	213.89	92110763	11.80%	3-factor	$ 25.24	$ 188.65	$ 213.89
921000	10763	FIN PLANNING & BUDGE	603300	REFRESHMENTS	NWN	P1	242.50	92110763	11.80%	3-factor	$ 28.62	$ 213.89	$ 242.50
921000	10763	FIN PLANNING & BUDGE	604700	PARKING	NWN	P1	72.00	92110763	11.80%	3-factor	$ 8.50	$ 63.50	$ 72.00
921000	10763	FIN PLANNING & BUDGE	605100	PROFESSIONAL SERVICE	NWN	P1	0.00	92110763	11.80%	3-factor	$ -	$ -	$ -
921000	10763	FIN PLANNING & BUDGE	612100	MEALS AND ENTERTAIN	NWN	P1	1,055.24	92110763	11.80%	3-factor	$ 124.52	$ 930.72	$ 1,055.24
921000	10763	FIN PLANNING & BUDGE	613100	CONFERENCE TRAVEL	NWN	P1	778.01	92110763	11.80%	3-factor	$ 91.81	$ 686.20	$ 778.01
921000	10763	FIN PLANNING & BUDGE	613200	BUSINESS TRAVEL	NWN	P1	0.00	92110763	11.80%	3-factor	$ -	$ -	$ -
921000	10763	FIN PLANNING & BUDGE	622000	EMPLOYEE AWARDS	NWN	P1	1,677.85	92110763	11.80%	3-factor	$ 197.99	$ 1,479.86	$ 1,677.85
921000	10765	STRATEGIC PLANNING-O	601100	EDUCATION	NWN	P1	275.00	92110765	11.80%	3-factor	$ 32.45	$ 242.55	$ 275.00
921000	10765	STRATEGIC PLANNING-O	601200	AUTO ALLOWANCE	NWN	P1	6,300.00	92110765	11.80%	3-factor	$ 743.40	$ 5,556.60	$ 6,300.00
921000	10765	STRATEGIC PLANNING-O	601900	DUES/MEMBERSHIP	NWN	P1	1,099.00	92110765	11.80%	3-factor	$ 129.68	$ 969.32	$ 1,099.00
921000	10765	STRATEGIC PLANNING-O	602466	P CARD UNCODED CHARG	NWN	P1	(715.40)	92110765	11.80%	3-factor	$ (84.42)	$ (630.98)	$ (715.40)
921000	10765	STRATEGIC PLANNING-O	603000	OFFICE SUPPLIES	NWN	P1	112.06	92110765	11.80%	3-factor	$ 13.22	$ 98.84	$ 112.06
921000	10765	STRATEGIC PLANNING-O	603100	PRINTING	NWN	P1	1,724.50	92110765	11.80%	3-factor	$ 203.49	$ 1,521.01	$ 1,724.50
921000	10765	STRATEGIC PLANNING-O	603200	BOOKS AND MAGAZINES	NWN	P1	2,483.99	92110765	11.80%	3-factor	$ 293.11	$ 2,190.88	$ 2,483.99

NW Natural
Admin Transfer Allocation Factor
Test Year Ending March 31, 2025

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$ 71,068,305.98

							Fiscal Year Period	Amount			Admin Transfer Factor	12.1429%	87.8571%		
							Measures	Overall Result			TOTAL	$ 8,629,765.83	$ 62,438,540.15	$ 71,068,305.98	TRUE
FERC Account	Cost Center	Cost Center Description	GL Account	GL Account Long Name	Chart of Accounts	Ledger		$	SORTER	ALLOCATION FACTOR	ALLOCATION METHOD	WA	OR	SYSTEM	
921000	10765	STRATEGIC PLANNING-O	603300	REFRESHMENTS	NWN	F1		12.47	92110765	11.80%	3-factor	$ 1.47	$ 11.00	$ 12.47	
921000	10765	STRATEGIC PLANNING-O	604700	PARKING	NWN	F1		185.44	92110765	11.80%	3-factor	$ 19.52	$ 145.92	$ 165.44	
921000	10765	STRATEGIC PLANNING-O	605100	PROFESSIONAL SERVICE	NWN	F1		27,278.10	92110765	11.80%	3-factor	$ 3,218.82	$ 24,059.28	$ 27,278.10	
921000	10765	STRATEGIC PLANNING-O	606500	UNLEADED FUEL	NWN	F1		60.74	92110765	11.80%	3-factor	$ 7.17	$ 53.57	$ 60.74	
921000	10765	STRATEGIC PLANNING-O	612100	MEALS AND ENTERTAIN	NWN	F1		1,076.74	92110765	11.80%	3-factor	$ 127.06	$ 949.68	$ 1,076.74	
921000	10765	STRATEGIC PLANNING-O	613100	CONFERENCE TRAVEL	NWN	F1		2,839.36	92110765	11.80%	3-factor	$ 335.04	$ 2,504.32	$ 2,839.36	
921000	10765	STRATEGIC PLANNING-O	613200	BUSINESS TRAVEL	NWN	F1		84.00	92110765	11.80%	3-factor	$ 9.91	$ 74.09	$ 84.00	
921000	10765	STRATEGIC PLANNING-O	622000	EMPLOYEE AWARDS	NWN	F1		764.58	92110765	11.80%	3-factor	$ 90.22	$ 674.36	$ 764.58	
921000	10766	CORP SECRETARY-OFFIC	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1		47.57	92110766	11.80%	3-factor	$ 5.61	$ 41.96	$ 47.57	
921000	10766	CORP SECRETARY-OFFIC	601900	DUES/MEMBERSHIP	NWN	F1		19,330.00	92110766	11.80%	3-factor	$ 2,280.94	$ 17,049.06	$ 19,330.00	
921000	10766	CORP SECRETARY-OFFIC	602466	P CARD UNCODED CHARG	NWN	F1		(0.00)	92110766	11.80%	3-factor	$ (0.00)	$ (0.00)	$ (0.00)	
921000	10766	CORP SECRETARY-OFFIC	602800	POSTAGE	NWN	F1		1,446.92	92110766	11.80%	3-factor	$ 170.74	$ 1,276.18	$ 1,446.92	
921000	10766	CORP SECRETARY-OFFIC	605000	LEGAL FEES	NWN	F1		3,447.50	92110766	11.80%	3-factor	$ 406.81	$ 3,040.70	$ 3,447.50	
921000	10766	CORP SECRETARY-OFFIC	605100	PROFESSIONAL SERVICE	NWN	F1		22,659.63	92110766	11.80%	3-factor	$ 2,673.84	$ 19,985.79	$ 22,659.63	
921000	10766	CORP SECRETARY-OFFIC	607500	CORPORATE IDENTITY	NWN	F1		112.00	92110766	11.80%	3-factor	$ 13.22	$ 98.78	$ 112.00	
921000	10766	CORP SECRETARY-OFFIC	612100	MEALS AND ENTERTAIN	NWN	F1		56.41	92110766	11.80%	3-factor	$ 6.66	$ 49.75	$ 56.41	
921000	10774	CORP ETHICS & COMPL-	605100	PROFESSIONAL SERVICE	NWN	F1		50,436.99	92110774	11.80%	3-factor	$ 5,951.56	$ 44,485.43	$ 50,436.99	
921000	10775	INVESTOR RELATIONS-O	601100	EDUCATION	NWN	F1		1,599.00	92110775	11.80%	3-factor	$ 188.68	$ 1,410.32	$ 1,599.00	
921000	10775	INVESTOR RELATIONS-O	601900	DUES/MEMBERSHIP	NWN	F1		259.95	92110775	11.80%	3-factor	$ 30.68	$ 229.28	$ 259.96	
921000	10775	INVESTOR RELATIONS-O	602466	P CARD UNCODED CHARG	NWN	F1		218.89	92110775	11.80%	3-factor	$ 25.83	$ 193.06	$ 218.89	
921000	10775	INVESTOR RELATIONS-O	602700	TELEPHONE	NWN	F1		104.00	92110775	11.80%	3-factor	$ 12.27	$ 91.73	$ 104.00	
921000	10775	INVESTOR RELATIONS-O	602800	POSTAGE	NWN	F1		4,523.09	92110775	11.80%	3-factor	$ 533.72	$ 3,989.37	$ 4,523.09	
921000	10775	INVESTOR RELATIONS-O	603000	OFFICE SUPPLIES	NWN	F1		79.98	92110775	11.80%	3-factor	$ 9.44	$ 70.54	$ 79.98	
921000	10775	INVESTOR RELATIONS-O	603100	PRINTING	NWN	F1		72,696.00	92110775	11.80%	3-factor	$ 8,578.13	$ 64,117.87	$ 72,696.00	
921000	10775	INVESTOR RELATIONS-O	603200	BOOKS AND MAGAZINES	NWN	F1		490.91	92110775	11.80%	3-factor	$ 57.93	$ 432.98	$ 490.91	
921000	10775	INVESTOR RELATIONS-O	604700	PARKING	NWN	F1		462.00	92110775	11.80%	3-factor	$ 54.52	$ 407.48	$ 462.00	
921000	10775	INVESTOR RELATIONS-O	605100	PROFESSIONAL SERVICE	NWN	F1		243,422.98	92110775	11.80%	3-factor	$ 28,723.91	$ 214,699.07	$ 243,422.98	
921000	10775	INVESTOR RELATIONS-O	605600	SOFTWARE MAINT	NWN	F1		7,354.56	92110775	11.80%	3-factor	$ 867.84	$ 6,486.72	$ 7,354.56	
921000	10775	INVESTOR RELATIONS-O	612100	MEALS AND ENTERTAIN	NWN	F1		(868.80)	92110775	11.80%	3-factor	$ (102.52)	$ (766.28)	$ (868.80)	
921000	10775	INVESTOR RELATIONS-O	613100	CONFERENCE TRAVEL	NWN	F1		6,508.82	92110775	11.80%	3-factor	$ 768.04	$ 5,740.78	$ 6,508.82	
921000	10775	INVESTOR RELATIONS-O	613200	BUSINESS TRAVEL	NWN	F1		13,688.47	92110775	11.80%	3-factor	$ 1,615.24	$ 12,073.23	$ 13,688.47	
921000	10775	INVESTOR RELATIONS-O	622000	EMPLOYEE AWARDS	NWN	F1		1,339.70	92110775	11.80%	3-factor	$ 158.08	$ 1,181.62	$ 1,339.70	
921000	10775	INVESTOR RELATIONS-O	622200	NON EMPLOYEE GIFTS	NWN	F1		83.00	92110775	11.80%	3-factor	$ 9.79	$ 73.21	$ 83.00	
921000	10778	OCC SAFETY-OFFICE ST	601100	EDUCATION	NWN	F1		5,044.95	92110778	11.02%	Employee Cost	$ 555.76	$ 4,489.19	$ 5,044.95	
921000	10778	OCC SAFETY-OFFICE ST	601400	MATERIALS	NWN	F1		7,205.83	92110778	11.02%	Employee Cost	$ 793.80	$ 6,412.03	$ 7,205.83	
921000	10778	OCC SAFETY-OFFICE ST	601401	MATERIALS - CONS INV	NWN	F1		3,138.68	92110778	11.02%	Employee Cost	$ 345.76	$ 2,792.92	$ 3,138.68	
921000	10778	OCC SAFETY-OFFICE ST	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1		0.00	92110778	11.02%	Employee Cost	$ -	$ -	$ -	
921000	10778	OCC SAFETY-OFFICE ST	601700	EQUIPMENT	NWN	F1		1,650.60	92110778	11.02%	Employee Cost	$ 181.83	$ 1,468.77	$ 1,650.60	
921000	10778	OCC SAFETY-OFFICE ST	601900	DUES/MEMBERSHIP	NWN	F1		3,348.00	92110778	11.02%	Employee Cost	$ 368.82	$ 2,979.18	$ 3,348.00	
921000	10778	OCC SAFETY-OFFICE ST	602100	OTHER CONTRACT WORK	NWN	F1		224,970.56	92110778	11.02%	Employee Cost	$ 24,782.98	$ 200,187.58	$ 224,970.56	
921000	10778	OCC SAFETY-OFFICE ST	602466	P CARD UNCODED CHARG	NWN	F1		3,381.21	92110778	11.02%	Employee Cost	$ 372.48	$ 3,008.73	$ 3,381.21	
921000	10778	OCC SAFETY-OFFICE ST	602700	TELEPHONE	NWN	F1		0.00	92110778	11.02%	Employee Cost	$ -	$ -	$ -	
921000	10778	OCC SAFETY-OFFICE ST	602800	POSTAGE	NWN	F1		125.95	92110778	11.02%	Employee Cost	$ 13.87	$ 112.08	$ 125.95	
921000	10778	OCC SAFETY-OFFICE ST	603000	OFFICE SUPPLIES	NWN	F1		85.98	92110778	11.02%	Employee Cost	$ 9.47	$ 76.51	$ 85.98	
921000	10778	OCC SAFETY-OFFICE ST	603200	BOOKS AND MAGAZINES	NWN	F1		195.85	92110778	11.02%	Employee Cost	$ 21.58	$ 174.27	$ 195.85	
921000	10778	OCC SAFETY-OFFICE ST	603300	REFRESHMENTS	NWN	F1		244.46	92110778	11.02%	Employee Cost	$ 26.93	$ 217.53	$ 244.46	
921000	10778	OCC SAFETY-OFFICE ST	603400	TOOL EXPENSE	NWN	F1		75.81	92110778	11.02%	Employee Cost	$ 8.35	$ 67.46	$ 75.81	
921000	10778	OCC SAFETY-OFFICE ST	604700	PARKING	NWN	F1		246.80	92110778	11.02%	Employee Cost	$ 27.19	$ 219.61	$ 246.80	
921000	10778	OCC SAFETY-OFFICE ST	604900	UNIFORMS	NWN	F1		99,999.96	92110778	11.02%	Employee Cost	$ 11,016.10	$ 88,983.86	$ 99,999.96	
921000	10778	OCC SAFETY-OFFICE ST	605100	PROFESSIONAL SERVICE	NWN	F1		54,761.42	92110778	11.02%	Employee Cost	$ 6,032.57	$ 48,728.85	$ 54,761.42	
921000	10778	OCC SAFETY-OFFICE ST	605500	REPAIRS AND MAINT	NWN	F1		0.00	92110778	11.02%	Employee Cost	$ -	$ -	$ -	
921000	10778	OCC SAFETY-OFFICE ST	606200	PERMITS AND FEES	NWN	F1		0.00	92110778	11.02%	Employee Cost	$ -	$ -	$ -	
921000	10778	OCC SAFETY-OFFICE ST	606500	UNLEADED FUEL	NWN	F1		25.78	92110778	11.02%	Employee Cost	$ 2.84	$ 22.94	$ 25.78	
921000	10778	OCC SAFETY-OFFICE ST	612100	MEALS AND ENTERTAIN	NWN	F1		1,141.39	92110778	11.02%	Employee Cost	$ 125.74	$ 1,015.65	$ 1,141.39	
921000	10778	OCC SAFETY-OFFICE ST	612200	TRAVEL IN TERRITORY	NWN	F1		3,884.65	92110778	11.02%	Employee Cost	$ 427.94	$ 3,456.71	$ 3,884.65	
921000	10778	OCC SAFETY-OFFICE ST	613100	CONFERENCE TRAVEL	NWN	F1		854.43	92110778	11.02%	Employee Cost	$ 94.12	$ 760.31	$ 854.43	
921000	10778	OCC SAFETY-OFFICE ST	613200	BUSINESS TRAVEL	NWN	F1		(217.65)	92110778	11.02%	Employee Cost	$ (23.98)	$ (193.67)	$ (217.65)	
921000	10778	OCC SAFETY-OFFICE ST	622000	EMPLOYEE AWARDS	NWN	F1		139,042.15	92110778	11.02%	Employee Cost	$ 15,317.02	$ 123,725.13	$ 139,042.15	
921000	10779	OCC SAFETY-OFFICE ST	605100	PROFESSIONAL SERVICE	NWN	F1		165.00	92110779	11.02%	Employee Cost	$ 18.18	$ 146.82	$ 165.00	
921000	10785	OCCUPATIONAL SAFETY-	603000	OFFICE SUPPLIES	NWN	F1		52.49	92110785	12.17%	Customers-All	$ 6.39	$ 46.10	$ 52.49	
921000	10787	LAND OVERHEAD-OFFICE	601100	EDUCATION	NWN	F1		468.46	92110787	11.80%	3-factor	$ 55.28	$ 413.18	$ 468.46	
921000	10787	LAND OVERHEAD-OFFICE	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1		367.50	92110787	11.80%	3-factor	$ 43.37	$ 324.14	$ 367.50	
921000	10787	LAND OVERHEAD-OFFICE	601900	DUES/MEMBERSHIP	NWN	F1		1,384.14	92110787	11.80%	3-factor	$ 163.33	$ 1,220.81	$ 1,384.14	
921000	10787	LAND OVERHEAD-OFFICE	602466	P CARD UNCODED CHARG	NWN	F1		(1,434.45)	92110787	11.80%	3-factor	$ (169.27)	$ (1,265.18)	$ (1,434.45)	
921000	10787	LAND OVERHEAD-OFFICE	602800	POSTAGE	NWN	F1		161.15	92110787	11.80%	3-factor	$ 19.02	$ 142.13	$ 161.15	
921000	10787	LAND OVERHEAD-OFFICE	603100	PRINTING	NWN	F1		505.97	92110787	11.80%	3-factor	$ 59.70	$ 446.27	$ 505.97	
921000	10787	LAND OVERHEAD-OFFICE	603900	INSURANCE	NWN	F1		1,928.36	92110787	11.80%	3-factor	$ 227.55	$ 1,700.81	$ 1,928.36	
921000	10787	LAND OVERHEAD-OFFICE	606200	PERMITS AND FEES	NWN	F1		21,343.28	92110787	11.80%	3-factor	$ 2,518.51	$ 18,824.77	$ 21,343.28	
921000	10787	LAND OVERHEAD-OFFICE	612100	MEALS AND ENTERTAIN	NWN	F1		199.17	92110787	11.80%	3-factor	$ 23.50	$ 175.67	$ 199.17	
921000	10787	LAND OVERHEAD-OFFICE	613200	BUSINESS TRAVEL	NWN	F1		2,097.24	92110787	11.80%	3-factor	$ 247.47	$ 1,849.77	$ 2,097.24	
921000	10787	LAND OVERHEAD-OFFICE	622000	EMPLOYEE AWARDS	NWN	F1		90.00	92110787	11.80%	3-factor	$ 10.62	$ 79.38	$ 90.00	
921000	10792	BUSINESS CONT-OFFICE	601100	EDUCATION	NWN	F1		2,510.95	92110792	11.80%	3-factor	$ 296.29	$ 2,214.66	$ 2,510.95	
921000	10792	BUSINESS CONT-OFFICE	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1		558.11	92110792	11.80%	3-factor	$ 65.86	$ 492.25	$ 558.11	
921000	10792	BUSINESS CONT-OFFICE	601900	DUES/MEMBERSHIP	NWN	F1		199.91	92110792	11.80%	3-factor	$ 23.59	$ 176.32	$ 199.91	
921000	10792	BUSINESS CONT-OFFICE	602466	P CARD UNCODED CHARG	NWN	F1		275.50	92110792	11.80%	3-factor	$ 32.51	$ 242.99	$ 275.50	
921000	10792	BUSINESS CONT-OFFICE	603000	OFFICE SUPPLIES	NWN	F1		91.40	92110792	11.80%	3-factor	$ 10.79	$ 80.61	$ 91.40	
921000	10792	BUSINESS CONT-OFFICE	603100	PRINTING	NWN	F1		16.45	92110792	11.80%	3-factor	$ 2.18	$ 16.27	$ 18.45	
921000	10792	BUSINESS CONT-OFFICE	603200	BOOKS AND MAGAZINES	NWN	F1		46.95	92110792	11.80%	3-factor	$ 5.54	$ 41.41	$ 46.95	
921000	10792	BUSINESS CONT-OFFICE	603300	REFRESHMENTS	NWN	F1		0.00	92110792	11.80%	3-factor	$ -	$ -	$ -	
921000	10792	BUSINESS CONT-OFFICE	604700	PARKING	NWN	F1		11.00	92110792	11.80%	3-factor	$ 1.30	$ 9.70	$ 11.00	
921000	10792	BUSINESS CONT-OFFICE	606200	PERMITS AND FEES	NWN	F1		0.00	92110792	11.80%	3-factor	$ -	$ -	$ -	
921000	10792	BUSINESS CONT-OFFICE	612100	MEALS AND ENTERTAIN	NWN	F1		162.10	92110792	11.80%	3-factor	$ 19.13	$ 142.97	$ 162.10	
921000	10792	BUSINESS CONT-OFFICE	612200	TRAVEL IN TERRITORY	NWN	F1		219.66	92110792	11.80%	3-factor	$ 25.92	$ 193.74	$ 219.66	
921000	10792	BUSINESS CONT-OFFICE	613100	CONFERENCE TRAVEL	NWN	F1		394.98	92110792	11.80%	3-factor	$ 46.61	$ 348.37	$ 394.98	
921000	10792	BUSINESS CONT-OFFICE	613200	BUSINESS TRAVEL	NWN	F1		0.00	92110792	11.80%	3-factor	$ -	$ -	$ -	
921000	10793	CORPORATE SECRT-OFFI	601100	EDUCATION	NWN	F1		1,390.00	92110793	11.80%	3-factor	$ 164.02	$ 1,225.98	$ 1,390.00	
921000	10793	CORPORATE SECRT-OFFI	601400	MATERIALS	NWN	F1		157.24	92110793	11.80%	3-factor	$ 18.55	$ 138.69	$ 157.24	
921000	10793	CORPORATE SECRT-OFFI	601600	TRANSPORTATION	NWN	F1		33,985.67	92110793	11.80%	3-factor	$ 4,010.31	$ 29,975.36	$ 33,985.67	
921000	10793	CORPORATE SECRT-OFFI	601700	EQUIPMENT	NWN	F1		3,448.09	92110793	11.80%	3-factor	$ 406.87	$ 3,041.22	$ 3,448.09	
921000	10793	CORPORATE SECRT-OFFI	601900	DUES/MEMBERSHIP	NWN	F1		709.00	92110793	11.80%	3-factor	$ 83.66	$ 625.34	$ 709.00	
921000	10793	CORPORATE SECRT-OFFI	602100	OTHER CONTRACT WORK	NWN	F1		106,277.07	92110793	11.80%	3-factor	$ 12,540.69	$ 93,736.38	$ 106,277.07	
921000	10793	CORPORATE SECRT-OFFI	602466	P CARD UNCODED CHARG	NWN	F1		1,294.74	92110793	11.80%	3-factor	$ 152.78	$ 1,141.96	$ 1,294.74	
921000	10793	CORPORATE SECRT-OFFI	602800	POSTAGE	NWN	F1		20.98	92110793	11.80%	3-factor	$ 2.48	$ 18.50	$ 20.98	
921000	10793	CORPORATE SECRT-OFFI	603000	OFFICE SUPPLIES	NWN	F1		959.78	92110793	11.80%	3-factor	$ 113.25	$ 846.53	$ 959.78	
921000	10793	CORPORATE SECRT-OFFI	603100	PRINTING	NWN	F1		118.97	92110793	11.80%	3-factor	$ 14.04	$ 104.93	$ 118.97	
921000	10793	CORPORATE SECRT-OFFI	603200	BOOKS AND MAGAZINES	NWN	F1		221.18	92110793	11.80%	3-factor	$ 26.10	$ 195.08	$ 221.18	
921000	10793	CORPORATE SECRT-OFFI	603300	REFRESHMENTS	NWN	F1		114.04	92110793	11.80%	3-factor	$ 13.46	$ 100.58	$ 114.04	
921000	10793	CORPORATE SECRT-OFFI	603400	TOOL EXPENSE	NWN	F1		146.91	92110793	11.80%	3-factor	$ 17.34	$ 129.57	$ 146.91	
921000	10793	CORPORATE SECRT-OFFI	603900	INSURANCE	NWN	F1		0.00	92110793	11.80%	3-factor	$ -	$ -	$ -	
921000	10793	CORPORATE SECRT-OFFI	604700	PARKING	NWN	F1		182.00	92110793	11.80%	3-factor	$ 21.48	$ 160.52	$ 182.00	
921000	10793	CORPORATE SECRT-OFFI	605500	REPAIRS AND MAINT	NWN	F1		0.00	92110793	11.80%	3-factor	$ -	$ -	$ -	
921000	10793	CORPORATE SECRT-OFFI	606100	SECURITY	NWN	F1		283,433.10	92110793	11.80%	3-factor	$ 33,445.11	$ 249,987.99	$ 283,433.10	
921000	10793	CORPORATE SECRT-OFFI	606200	PERMITS AND FEES	NWN	F1		713.00	92110793	11.80%	3-factor	$ 84.13	$ 628.87	$ 713.00	
921000	10793	CORPORATE SECRT-OFFI	606500	UNLEADED FUEL	NWN	F1		4.27	92110793	11.80%	3-factor	$ 0.50	$ 3.77	$ 4.27	
921000	10793	CORPORATE SECRT-OFFI	607700	SMALL TOOLS	NWN	F1		35.47	92110793	11.80%	3-factor	$ 4.19	$ 31.28	$ 35.47	
921000	10793	CORPORATE SECRT-OFFI	612100	MEALS AND ENTERTAIN	NWN	F1		1,537.33	92110793	11.80%	3-factor	$ 181.40	$ 1,355.93	$ 1,537.33	
921000	10793	CORPORATE SECRT-OFFI	613100	CONFERENCE TRAVEL	NWN	F1		1,971.62	92110793	11.80%	3-factor	$ 232.65	$ 1,738.97	$ 1,971.62	
921000	10793	CORPORATE SECRT-OFFI	613200	BUSINESS TRAVEL	NWN	F1		1,227.00	92110793	11.80%	3-factor	$ 144.79	$ 1,082.21	$ 1,227.00	
921000	10793	CORPORATE SECRT-OFFI	622000	EMPLOYEE AWARDS	NWN	F1		372.10	92110793	11.80%	3-factor	$ 43.91	$ 328.19	$ 372.10	
921000	10793	CORPORATE SECRT-OFFI	622200	NON EMPLOYEE GIFTS	NWN	F1		111.90	92110793	11.80%	3-factor	$ 13.20	$ 98.70	$ 111.90	
921000	10794	CORPORATE SECURITY-O	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1		123.28	92110794	11.80%	3-factor	$ 14.55	$ 108.73	$ 123.28	
921000	10794	CORPORATE SECURITY-O	601900	DUES/MEMBERSHIP	NWN	F1		100.00	92110794	11.80%	3-factor	$ 11.80	$ 88.20	$ 100.00	
921000	10794	CORPORATE SECURITY-O	603000	OFFICE SUPPLIES	NWN	F1		214.63	92110794	11.80%	3-factor	$ 25.33	$ 189.30	$ 214.63	
921000	10794	CORPORATE SECURITY-O	603300	REFRESHMENTS	NWN	F1		15.30	92110794	11.80%	3-factor	$ 1.81	$ 13.49	$ 15.30	
921000	10794	CORPORATE SECURITY-O	605600	SOFTWARE MAINT	NWN	F1		540.00	92110794	11.80%	3-factor	$ 63.72	$ 476.28	$ 540.00	
921000	10794	CORPORATE SECURITY-O	606200	PERMITS AND FEES	NWN	F1		525.00	92110794	11.80%	3-factor	$ 61.95	$ 463.05	$ 525.00	
921000	10794	CORPORATE SECURITY-O	612100	MEALS AND ENTERTAIN	NWN	F1		32.45	92110794	11.80%	3-factor	$ 3.83	$ 28.62	$ 32.45	
921000	10794	CORPORATE SECURITY-O	622000	EMPLOYEE AWARDS	NWN	F1		620.85	92110794	11.80%	3-factor	$ 73.26	$ 547.59	$ 620.85	
921000	10796	PROJECT OFFICE-OFFIC	601100	EDUCATION	NWN	F1		2,493.99	92110796	11.80%	3-factor	$ 294.29	$ 2,199.70	$ 2,493.99	
921000	10796	PROJECT OFFICE-OFFIC	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1		899.81	92110796	11.80%	3-factor	$ 106.18	$ 793.63	$ 899.81	
921000	10796	PROJECT OFFICE-OFFIC	601600	TRANSPORTATION	NWN	F1		(2,262.00)	92110796	11.80%	3-factor	$ (266.92)	$ (1,995.08)	$ (2,262.00)	
921000	10796	PROJECT OFFICE-OFFIC	601900	DUES/MEMBERSHIP	NWN	F1		85,995.00	92110796	11.80%	3-factor	$ 10,147.41	$ 75,847.59	$ 85,995.00	
921000	10796	PROJECT OFFICE-OFFIC	602000	OFFICE CONTRACT WORK	NWN	F1		0.00	92110796	11.80%	3-factor	$ -	$ -	$ -	
921000	10796	PROJECT OFFICE-OFFIC	602100	OTHER CONTRACT WORK	NWN	F1		8,161.31	92110796	11.80%	3-factor	$ 963.03	$ 7,198.28	$ 8,161.31	
921000	10796	PROJECT OFFICE-OFFIC	602466	P CARD UNCODED CHARG	NWN	F1		(1,936.81)	92110796	11.80%	3-factor	$ (228.54)	$ (1,708.27)	$ (1,936.81)	
921000	10796	PROJECT OFFICE-OFFIC	603000	OFFICE SUPPLIES	NWN	F1		44.00	92110796	11.80%	3-factor	$ 5.19	$ 38.81	$ 44.00	
921000	10796	PROJECT OFFICE-OFFIC	603200	BOOKS AND MAGAZINES	NWN	F1		0.00	92110796	11.80%	3-factor	$ -	$ -	$ -	
921000	10796	PROJECT OFFICE-OFFIC	604700	PARKING	NWN	F1		0.00	92110796	11.80%	3-factor	$ -	$ -	$ -	
921000	10796	PROJECT OFFICE-OFFIC	605100	PROFESSIONAL SERVICE	NWN	F1		225,074.44	92110796	11.80%	3-factor	$ 26,558.78	$ 198,515.66	$ 225,074.44	
921000	10796	PROJECT OFFICE-OFFIC	605600	SOFTWARE MAINT	NWN	F1		900.33	92110796	11.80%	3-factor	$ 106.24	$ 794.09	$ 900.33	
921000	10796	PROJECT OFFICE-OFFIC	606500	UNLEADED FUEL	NWN	F1		25.83	92110796	11.80%	3-factor	$ 3.05	$ 22.78	$ 25.83	
921000	10796	PROJECT OFFICE-OFFIC	606801	PLANT TRANSFERS	NWN	F1		330,297.59	92110796	11.80%	3-factor	$ 38,975.12	$ 291,322.47	$ 330,297.59	
921000	10796	PROJECT OFFICE-OFFIC	612100	MEALS AND ENTERTAIN	NWN	F1		2,618.52	92110796	11.80%	3-factor	$ 308.99	$ 2,309.53	$ 2,618.52	
921000	10796	PROJECT OFFICE-OFFIC	613100	CONFERENCE TRAVEL	NWN	F1		701.96	92110796	11.80%	3-factor	$ 82.83	$ 619.13	$ 701.96	
921000	10796	PROJECT OFFICE-OFFIC	613200	BUSINESS TRAVEL	NWN	F1		1,669.46	92110796	11.80%	3-factor	$ 197.00	$ 1,472.46	$ 1,669.46	
921000	10796	PROJECT OFFICE-OFFIC	622000	EMPLOYEE AWARDS	NWN	F1		1,627.45	92110796	11.80%	3-factor	$ 192.04	$ 1,435.41	$ 1,627.45	
921000	10796	PROJECT OFFICE-OFFIC	681500	MILEAGE REIMBURSEMNT	NWN	F1		(690.47)	92110796	11.80%	3-factor	$ (81.48)	$ (608.99)	$ (690.47)	
921000	10801	CLAIMS OVERHEAD-OFFI	601600	TRANSPORTATION	NWN	F1		(24,882.00)	92110801	11.80%	3-factor	$ (2,936.08)	$ (21,945.92)	$ (24,882.00)	
921000	10801	CLAIMS OVERHEAD-OFFI	601900	DUES/MEMBERSHIP	NWN	F1		0.00	92110801	11.80%	3-factor	$ -	$ -	$ -	
921000	10801	CLAIMS OVERHEAD-OFFI	602466	P CARD UNCODED CHARG	NWN	F1		186.59	92110801	11.80%	3-factor	$ 22.02	$ 164.57	$ 186.59	
921000	10801	CLAIMS OVERHEAD-OFFI	602700	TELEPHONE	NWN	F1		0.30	92110801	11.80%	3-factor	$ 0.04	$ 0.26	$ 0.30	
921000	10801	CLAIMS OVERHEAD-OFFI	602800	POSTAGE	NWN	F1		9.00	92110801	11.80%	3-factor	$ 1.06	$ 7.94	$ 9.00	
921000	10801	CLAIMS OVERHEAD-OFFI	603000	OFFICE SUPPLIES	NWN	F1		74.89	92110801	11.80%	3-factor	$ 8.84	$ 66.05	$ 74.89	
921000	10801	CLAIMS OVERHEAD-OFFI	603100	PRINTING	NWN	F1		5.50	92110801	11.80%	3-factor	$ 0.65	$ 4.85	$ 5.50	
921000	10801	CLAIMS OVERHEAD-OFFI	603200	BOOKS AND MAGAZINES	NWN	F1		0.00	92110801	11.80%	3-factor	$ -	$ -	$ -	
921000	10801	CLAIMS OVERHEAD-OFFI	603300	REFRESHMENTS	NWN	F1		235.55	92110801	11.80%	3-factor	$ 27.79	$ 207.76	$ 235.55	
921000	10801	CLAIMS OVERHEAD-OFFI	605100	PROFESSIONAL SERVICE	NWN	F1		7.50	92110801	11.80%	3-factor	$ 0.89	$ 6.62	$ 7.50	
921000	10801	CLAIMS OVERHEAD-OFFI	606200	PERMITS AND FEES	NWN	F1		217.60	92110801	11.80%	3-factor	$ 25.68	$ 191.92	$ 217.60	
921000	10801	CLAIMS OVERHEAD-OFFI	612100	MEALS AND ENTERTAIN	NWN	F1		274.35	92110801	11.80%	3-factor	$ 32.37	$ 241.98

NW Natural
Admin Transfer Allocation Factor
Test Year Ending March 31, 2025

$ 71,068,305.98

							Fiscal Year Period	Amount
							Measures	Overall Result
FERC Account	Cost Center	Cost Center Description	GL Account	GL Account Long Name	Chart of Accounts	Ledger	$	
921000	10801	CLAIMS OVERHEAD-OFFI	624200	CLAIMS & ACCRUALS	NWN	P1	0.00	
921000	10803	PUB POLICY & GVRM AF	601100	EDUCATION	NWN	P1	163.50	
921000	10803	PUB POLICY & GVRM AF	601400	MATERIALS	NWN	P1	773.00	
921000	10803	PUB POLICY & GVRM AF	601401	MATERIALS - CONS INV	NWN	P1	0.00	
921000	10803	PUB POLICY & GVRM AF	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	P1	571.07	
921000	10803	PUB POLICY & GVRM AF	601700	EQUIPMENT	NWN	P1	88.26	
921000	10803	PUB POLICY & GVRM AF	601900	DUES/MEMBERSHIP	NWN	P1	153,888.68	
921000	10803	PUB POLICY & GVRM AF	602466	P CARD UNCODED CHARG	NWN	P1	(2,551.85)	
921000	10803	PUB POLICY & GVRM AF	603000	OFFICE SUPPLIES	NWN	P1	118.43	
921000	10803	PUB POLICY & GVRM AF	603200	BOOKS AND MAGAZINES	NWN	P1	1,650.26	
921000	10803	PUB POLICY & GVRM AF	603300	REFRESHMENTS	NWN	P1	244.36	
921000	10803	PUB POLICY & GVRM AF	604700	PARKING	NWN	P1	184.02	
921000	10803	PUB POLICY & GVRM AF	605100	PROFESSIONAL SERVICE	NWN	P1	12,000.00	
921000	10803	PUB POLICY & GVRM AF	606500	UNLEADED FUEL	NWN	P1	25.05	
921000	10803	PUB POLICY & GVRM AF	607500	CORPORATE IDENTITY	NWN	P1	25,496.76	
921000	10803	PUB POLICY & GVRM AF	608100	SUBCRIPTION SERVICES	NWN	P1	92.97	
921000	10803	PUB POLICY & GVRM AF	612100	MEALS AND ENTERTAIN	NWN	P1	1,251.66	
921000	10803	PUB POLICY & GVRM AF	613100	CONFERENCE TRAVEL	NWN	P1	0.00	
921000	10803	PUB POLICY & GVRM AF	613200	BUSINESS TRAVEL	NWN	P1	818.49	
921000	10803	PUB POLICY & GVRM AF	622000	EMPLOYEE AWARDS	NWN	P1	809.75	
921000	10803	PUB POLICY & GVRM AF	622200	NON EMPLOYEE GIFTS	NWN	P1	237.35	
921000	10807	PHILANTHROPY-OFFICE	601900	DUES/MEMBERSHIP	NWN	P1	3,500.00	
921000	10807	PHILANTHROPY-OFFICE	602466	P CARD UNCODED CHARG	NWN	P1	905.65	
921000	10807	PHILANTHROPY-OFFICE	603000	OFFICE SUPPLIES	NWN	P1	359.39	
921000	10807	PHILANTHROPY-OFFICE	603300	REFRESHMENTS	NWN	P1	39.68	
921000	10807	PHILANTHROPY-OFFICE	604700	PARKING	NWN	P1	92.00	
921000	10807	PHILANTHROPY-OFFICE	605100	PROFESSIONAL SERVICE	NWN	P1	75,033.65	
921000	10807	PHILANTHROPY-OFFICE	607500	CORPORATE IDENTITY	NWN	P1	19.20	
921000	10807	PHILANTHROPY-OFFICE	608100	SUBCRIPTION SERVICES	NWN	P1	498.00	
921000	10807	PHILANTHROPY-OFFICE	612100	MEALS AND ENTERTAIN	NWN	P1	89.76	
921000	10807	PHILANTHROPY-OFFICE	622000	EMPLOYEE AWARDS	NWN	P1	155.00	
921000	10811	COMM & CIVIC AFFAIRS	601100	EDUCATION	NWN	P1	3,250.00	
921000	10811	COMM & CIVIC AFFAIRS	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	P1	2,623.78	
921000	10811	COMM & CIVIC AFFAIRS	601900	DUES/MEMBERSHIP	NWN	P1	120,519.80	
921000	10811	COMM & CIVIC AFFAIRS	602100	OTHER CONTRACT WORK	NWN	P1	0.00	
921000	10811	COMM & CIVIC AFFAIRS	602466	P CARD UNCODED CHARG	NWN	P1	12,020.41	
921000	10811	COMM & CIVIC AFFAIRS	602800	POSTAGE	NWN	P1	21.69	
921000	10811	COMM & CIVIC AFFAIRS	603000	OFFICE SUPPLIES	NWN	P1	235.70	
921000	10811	COMM & CIVIC AFFAIRS	603100	PRINTING	NWN	P1	0.00	
921000	10811	COMM & CIVIC AFFAIRS	603200	BOOKS AND MAGAZINES	NWN	P1	99.00	
921000	10811	COMM & CIVIC AFFAIRS	603300	REFRESHMENTS	NWN	P1	94.79	
921000	10811	COMM & CIVIC AFFAIRS	604700	PARKING	NWN	P1	367.55	
921000	10811	COMM & CIVIC AFFAIRS	605100	PROFESSIONAL SERVICE	NWN	P1	0.00	
921000	10811	COMM & CIVIC AFFAIRS	606200	PERMITS AND FEES	NWN	P1	0.00	
921000	10811	COMM & CIVIC AFFAIRS	607500	CORPORATE IDENTITY	NWN	P1	0.00	
921000	10811	COMM & CIVIC AFFAIRS	608100	SUBCRIPTION SERVICES	NWN	P1	0.00	
921000	10811	COMM & CIVIC AFFAIRS	612100	MEALS AND ENTERTAIN	NWN	P1	294.85	
921000	10811	COMM & CIVIC AFFAIRS	612200	TRAVEL IN TERRITORY	NWN	P1	320.67	
921000	10811	COMM & CIVIC AFFAIRS	613200	BUSINESS TRAVEL	NWN	P1	635.42	
921000	10811	COMM & CIVIC AFFAIRS	622000	EMPLOYEE AWARDS	NWN	P1	554.83	
921000	10814	CORPORATE COMMUNICAT	601400	MATERIALS	NWN	P1	722.50	
921000	10814	CORPORATE COMMUNICAT	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	P1	102.97	
921000	10814	CORPORATE COMMUNICAT	601900	DUES/MEMBERSHIP	NWN	P1	803.82	
921000	10814	CORPORATE COMMUNICAT	602466	P CARD UNCODED CHARG	NWN	P1	(2,633.96)	
921000	10814	CORPORATE COMMUNICAT	602700	TELEPHONE	NWN	P1	8.00	
921000	10814	CORPORATE COMMUNICAT	603000	OFFICE SUPPLIES	NWN	P1	288.00	
921000	10814	CORPORATE COMMUNICAT	603100	PRINTING	NWN	P1	6,889.78	
921000	10814	CORPORATE COMMUNICAT	603200	BOOKS AND MAGAZINES	NWN	P1	2,816.75	
921000	10814	CORPORATE COMMUNICAT	603300	REFRESHMENTS	NWN	P1	307.84	
921000	10814	CORPORATE COMMUNICAT	604700	PARKING	NWN	P1	1.70	
921000	10814	CORPORATE COMMUNICAT	604950	CLOTHING	NWN	P1	484.80	
921000	10814	CORPORATE COMMUNICAT	605100	PROFESSIONAL SERVICE	NWN	P1	78,989.56	
921000	10814	CORPORATE COMMUNICAT	605200	ADVERTSING	NWN	P1	1,750.00	
921000	10814	CORPORATE COMMUNICAT	605600	SOFTWARE MAINT	NWN	P1	1,188.00	
921000	10814	CORPORATE COMMUNICAT	607500	CORPORATE IDENTITY	NWN	P1	4,000.00	
921000	10814	CORPORATE COMMUNICAT	612100	MEALS AND ENTERTAIN	NWN	P1	1,111.82	
921000	10814	CORPORATE COMMUNICAT	613200	BUSINESS TRAVEL	NWN	P1	1,631.40	
921000	10814	CORPORATE COMMUNICAT	622000	EMPLOYEE AWARDS	NWN	P1	100.00	
921000	10814	CORPORATE COMMUNICAT	622200	NON EMPLOYEE GIFTS	NWN	P1	87.50	
921000	10818	REGULATORY AFFAIRS-O	601100	EDUCATION	NWN	P1	3,844.26	
921000	10818	REGULATORY AFFAIRS-O	601400	MATERIALS	NWN	P1	40.00	
921000	10818	REGULATORY AFFAIRS-O	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	P1	62.31	
921000	10818	REGULATORY AFFAIRS-O	601900	DUES/MEMBERSHIP	NWN	P1	1,420.06	
921000	10818	REGULATORY AFFAIRS-O	602466	P CARD UNCODED CHARG	NWN	P1	645.23	
921000	10818	REGULATORY AFFAIRS-O	602700	TELEPHONE	NWN	P1	8.00	
921000	10818	REGULATORY AFFAIRS-O	602800	POSTAGE	NWN	P1	347.75	
921000	10818	REGULATORY AFFAIRS-O	603000	OFFICE SUPPLIES	NWN	P1	212.87	
921000	10818	REGULATORY AFFAIRS-O	603100	PRINTING	NWN	P1	3,228.28	
921000	10818	REGULATORY AFFAIRS-O	603200	BOOKS AND MAGAZINES	NWN	P1	1,323.96	
921000	10818	REGULATORY AFFAIRS-O	603300	REFRESHMENTS	NWN	P1	9.25	
921000	10818	REGULATORY AFFAIRS-O	604700	PARKING	NWN	P1	232.00	
921000	10818	REGULATORY AFFAIRS-O	605100	PROFESSIONAL SERVICE	NWN	P1	491,771.74	
921000	10818	REGULATORY AFFAIRS-O	605200	ADVERTSING	NWN	P1	4,984.05	
921000	10818	REGULATORY AFFAIRS-O	606500	UNLEADED FUEL	NWN	P1	32.81	
921000	10818	REGULATORY AFFAIRS-O	607500	CORPORATE IDENTITY	NWN	P1	4,650.00	
921000	10818	REGULATORY AFFAIRS-O	612100	MEALS AND ENTERTAIN	NWN	P1	2,604.20	
921000	10818	REGULATORY AFFAIRS-O	612200	TRAVEL IN TERRITORY	NWN	P1	530.15	
921000	10818	REGULATORY AFFAIRS-O	613100	CONFERENCE TRAVEL	NWN	P1	5,271.85	
921000	10818	REGULATORY AFFAIRS-O	613200	BUSINESS TRAVEL	NWN	P1	2,090.04	
921000	10818	REGULATORY AFFAIRS-O	622000	EMPLOYEE AWARDS	NWN	P1	1,253.65	
921000	10819	LEGAL-OFFICE STAFFIN	601100	EDUCATION	NWN	P1	300.00	
921000	10819	LEGAL-OFFICE STAFFIN	601200	AUTO ALLOWANCE	NWN	P1	12,600.00	
921000	10819	LEGAL-OFFICE STAFFIN	601900	DUES/MEMBERSHIP	NWN	P1	19,307.67	
921000	10819	LEGAL-OFFICE STAFFIN	602100	OTHER CONTRACT WORK	NWN	P1	14,995.45	
921000	10819	LEGAL-OFFICE STAFFIN	602466	P CARD UNCODED CHARG	NWN	P1	1,724.58	
921000	10819	LEGAL-OFFICE STAFFIN	603000	OFFICE SUPPLIES	NWN	P1	238.37	
921000	10819	LEGAL-OFFICE STAFFIN	603200	BOOKS AND MAGAZINES	NWN	P1	0.00	
921000	10819	LEGAL-OFFICE STAFFIN	603300	REFRESHMENTS	NWN	P1	317.32	
921000	10819	LEGAL-OFFICE STAFFIN	604700	PARKING	NWN	P1	81.90	
921000	10819	LEGAL-OFFICE STAFFIN	605000	LEGAL FEES	NWN	P1	(8,133.40)	
921000	10819	LEGAL-OFFICE STAFFIN	605100	PROFESSIONAL SERVICE	NWN	P1	2,110.08	
921000	10819	LEGAL-OFFICE STAFFIN	606200	PERMITS AND FEES	NWN	P1	0.00	
921000	10819	LEGAL-OFFICE STAFFIN	606500	UNLEADED FUEL	NWN	P1	96.12	
921000	10819	LEGAL-OFFICE STAFFIN	612100	MEALS AND ENTERTAIN	NWN	P1	13.64	
921000	10819	LEGAL-OFFICE STAFFIN	612200	TRAVEL IN TERRITORY	NWN	P1	24.62	
921000	10819	LEGAL-OFFICE STAFFIN	613100	CONFERENCE TRAVEL	NWN	P1	0.00	
921000	10819	LEGAL-OFFICE STAFFIN	613200	BUSINESS TRAVEL	NWN	P1	2,608.36	
921000	10819	LEGAL-OFFICE STAFFIN	622000	EMPLOYEE AWARDS	NWN	P1	463.90	
921000	10820	LEGAL-OFFICE STAFFIN	605000	LEGAL FEES	NWN	P1	84,375.50	
921000	10820	LEGAL-OFFICE STAFFIN	605500	REPAIRS AND MAINT	NWN	P1	41,012.50	
921000	10822	LEGAL FEES BIZ DEV-O	605000	LEGAL FEES	NWN	P1	123,120.18	
921000	10822	LEGAL FEES BIZ DEV-O	605100	PROFESSIONAL SERVICE	NWN	P1	0.00	
921000	10823	CORP SEC LEGAL FEES-	602800	POSTAGE	NWN	P1	0.00	
921000	10823	CORP SEC LEGAL FEES-	606200	PERMITS AND FEES	NWN	P1	836.06	
921000	10824	CORP SEC LEGAL FEES	605000	LEGAL FEES	NWN	P1	27,751.80	
921000	10825	CORP SEC LEGAL FEES-	605000	LEGAL FEES	NWN	P1	65,052.00	
921000	10826	CORP SEC LEGAL FEES-	605000	LEGAL FEES	NWN	P1	52,678.20	
921000	10827	CORP SEC LEGAL FEES-	605000	LEGAL FEES	NWN	P1	202,142.03	
921000	10828	LEGAL FEES-HR-OFFICE	605000	LEGAL FEES	NWN	P1	41,003.00	
921000	10829	LEGAL FEES-HR-OFFICE	605000	LEGAL FEES	NWN	P1	105,118.50	
921000	10830	LEGAL FEES-HR-EMPLOY	605000	LEGAL FEES	NWN	P1	38,703.60	
921000	10831	LEGAL FEES-RATES-OFF	605000	LEGAL FEES	NWN	P1	746,508.90	
921000	10832	LEGAL FEES-RATES-OFF	605000	LEGAL FEES	NWN	P1	46,782.18	
921000	10833	LEGAL FEES-RATES-OFF	605000	LEGAL FEES	NWN	P1	0.00	
921000	10835	LEGAL FEES-RISK-OFFI	605000	LEGAL FEES	NWN	P1	1,765,322.37	
921000	10836	LEGAL FEES-RISK-OFFI	605000	LEGAL FEES	NWN	P1	980.00	
921000	10838	LEGAL FEES-RISK-OFFI	605000	LEGAL FEES	NWN	P1	0.00	
921000	10839	LEGAL FEES - RISK -	605000	LEGAL FEES	NWN	P1	37,692.00	
921000	10840	LEGAL FEES-RISK-OFFI	605000	LEGAL FEES	NWN	P1	0.00	
921000	10843	CORP SEC TAX - Tax	605000	LEGAL FEES	NWN	P1	542.00	
921000	10844	LEGAL FEES GAS SPLY-	605000	LEGAL FEES	NWN	P1	76,237.10	
921000	10845	LEGAL FEES GAS SU-	605000	LEGAL FEES	NWN	P1	315.00	
921000	10846	ENV POLICY AND SUSTN	601100	EDUCATION	NWN	P1	2,860.00	
921000	10846	ENV POLICY AND SUSTN	601400	MATERIALS	NWN	P1	846.94	
921000	10846	ENV POLICY AND SUSTN	601401	MATERIALS - CONS INV	NWN	P1	0.00	
921000	10846	ENV POLICY AND SUSTN	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	P1	375.20	
921000	10846	ENV POLICY AND SUSTN	601900	DUES/MEMBERSHIP	NWN	P1	148,427.75	
921000	10846	ENV POLICY AND SUSTN	602100	OTHER CONTRACT WORK	NWN	P1	0.00	
921000	10846	ENV POLICY AND SUSTN	602466	P CARD UNCODED CHARG	NWN	P1	(1,295.79)	
921000	10846	ENV POLICY AND SUSTN	602700	TELEPHONE	NWN	P1	0.00	
921000	10846	ENV POLICY AND SUSTN	603000	OFFICE SUPPLIES	NWN	P1	466.44	
921000	10846	ENV POLICY AND SUSTN	603300	REFRESHMENTS	NWN	P1	942.72	
921000	10846	ENV POLICY AND SUSTN	603800	TAXES	NWN	P1	25.25	
921000	10846	ENV POLICY AND SUSTN	604700	PARKING	NWN	P1	457.25	
921000	10846	ENV POLICY AND SUSTN	604800	LAUNDRY	NWN	P1	88.10	
921000	10846	ENV POLICY AND SUSTN	605100	PROFESSIONAL SERVICE	NWN	P1	17,733.75	
921000	10846	ENV POLICY AND SUSTN	606500	UNLEADED FUEL	NWN	P1	44.91	
921000	10846	ENV POLICY AND SUSTN	607500	CORPORATE IDENTITY	NWN	P1	8,847.86	
921000	10846	ENV POLICY AND SUSTN	608100	SUBCRIPTION SERVICES	NWN	P1	1,713.00	
921000	10846	ENV POLICY AND SUSTN	612100	MEALS AND ENTERTAIN	NWN	P1	1,847.36	

			Admin Transfer Factor	12.1429%	87.8571%	
			TOTAL	$ 8,629,765.83	$ 62,438,540.15	$ 71,068,305.98
SORTER	ALLOCATION FACTOR	ALLOCATION METHOD	WA	OR	SYSTEM
92110801	11.80%	3-factor	$ -	$ -	$ -
92110803	11.80%	3-factor	$ 19.29	$ 144.21	$ 163.50
92110803	11.80%	3-factor	$ 91.21	$ 681.79	$ 773.00
92110803	11.80%	3-factor	$ -	$ -	$ -
92110803	11.80%	3-factor	$ 67.39	$ 503.68	$ 571.07
92110803	11.80%	3-factor	$ 10.41	$ 77.85	$ 88.26
92110803	11.80%	3-factor	$ 18,158.86	$ 135,729.82	$ 153,888.68
92110803	11.80%	3-factor	$ (301.12)	$ (2,250.73)	$ (2,551.85)
92110803	11.80%	3-factor	$ 13.97	$ 104.46	$ 118.43
92110803	11.80%	3-factor	$ 194.73	$ 1,455.53	$ 1,650.26
92110803	11.80%	3-factor	$ 28.83	$ 215.53	$ 244.36
92110803	11.80%	3-factor	$ 21.71	$ 162.31	$ 184.02
92110803	11.80%	3-factor	$ 1,416.00	$ 10,584.00	$ 12,000.00
92110803	11.80%	3-factor	$ 2.96	$ 22.09	$ 25.05
92110803	11.80%	3-factor	$ 3,008.62	$ 22,488.14	$ 25,496.76
92110803	11.80%	3-factor	$ 10.97	$ 82.00	$ 92.97
92110803	11.80%	3-factor	$ 147.70	$ 1,103.96	$ 1,251.66
92110803	11.80%	3-factor	$ -	$ -	$ -
92110803	11.80%	3-factor	$ 96.58	$ 721.91	$ 818.49
92110803	11.80%	3-factor	$ 95.55	$ 714.20	$ 809.75
92110803	11.80%	3-factor	$ 28.01	$ 209.34	$ 237.35
92110807	12.17%	Customers-All	$ 425.95	$ 3,074.05	$ 3,500.00
92110807	12.17%	Customers-All	$ 110.22	$ 795.43	$ 905.65
92110807	12.17%	Customers-All	$ 43.74	$ 315.65	$ 359.39
92110807	12.17%	Customers-All	$ 4.83	$ 34.85	$ 39.68
92110807	12.17%	Customers-All	$ 11.20	$ 80.80	$ 92.00
92110807	12.17%	Customers-All	$ 9,131.60	$ 65,902.05	$ 75,033.65
92110807	12.17%	Customers-All	$ 2.34	$ 16.86	$ 19.20
92110807	12.17%	Customers-All	$ 60.61	$ 437.39	$ 498.00
92110807	12.17%	Customers-All	$ 10.92	$ 78.84	$ 89.76
92110807	12.17%	Customers-All	$ 18.86	$ 136.14	$ 155.00
92110811	12.17%	Customers-All	$ 395.53	$ 2,854.48	$ 3,250.00
92110811	12.17%	Customers-All	$ 319.31	$ 2,304.47	$ 2,623.78
92110811	12.17%	Customers-All	$ 14,667.26	$ 105,852.54	$ 120,519.80
92110811	12.17%	Customers-All	$ -	$ -	$ -
92110811	12.17%	Customers-All	$ 1,462.88	$ 10,557.53	$ 12,020.41
92110811	12.17%	Customers-All	$ 2.64	$ 19.05	$ 21.69
92110811	12.17%	Customers-All	$ 28.68	$ 207.02	$ 235.70
92110811	12.17%	Customers-All	$ -	$ -	$ -
92110811	12.17%	Customers-All	$ 12.05	$ 86.95	$ 99.00
92110811	12.17%	Customers-All	$ 11.54	$ 83.25	$ 94.79
92110811	12.17%	Customers-All	$ 44.73	$ 322.82	$ 367.55
92110811	12.17%	Customers-All	$ -	$ -	$ -
92110811	12.17%	Customers-All	$ -	$ -	$ -
92110811	12.17%	Customers-All	$ -	$ -	$ -
92110811	12.17%	Customers-All	$ -	$ -	$ -
92110811	12.17%	Customers-All	$ 35.88	$ 258.97	$ 294.85
92110811	12.17%	Customers-All	$ 39.03	$ 281.64	$ 320.67
92110811	12.17%	Customers-All	$ 77.33	$ 558.09	$ 635.42
92110811	12.17%	Customers-All	$ 67.52	$ 487.31	$ 554.83
92110814	12.17%	Customers-All	$ 87.93	$ 634.57	$ 722.50
92110814	12.17%	Customers-All	$ 12.53	$ 90.44	$ 102.97
92110814	12.17%	Customers-All	$ 97.82	$ 706.00	$ 803.82
92110814	12.17%	Customers-All	$ (320.55)	$ (2,313.41)	$ (2,633.96)
92110814	12.17%	Customers-All	$ 0.97	$ 7.03	$ 8.00
92110814	12.17%	Customers-All	$ 35.05	$ 252.95	$ 288.00
92110814	12.17%	Customers-All	$ 838.49	$ 6,051.29	$ 6,889.78
92110814	12.17%	Customers-All	$ 342.80	$ 2,473.95	$ 2,816.75
92110814	12.17%	Customers-All	$ 37.46	$ 270.38	$ 307.84
92110814	12.17%	Customers-All	$ 0.21	$ 1.49	$ 1.70
92110814	12.17%	Customers-All	$ 59.00	$ 425.80	$ 484.80
92110814	12.17%	Customers-All	$ 9,613.03	$ 69,376.53	$ 78,989.56
92110814	12.17%	Customers-All	$ 212.98	$ 1,537.03	$ 1,750.00
92110814	12.17%	Customers-All	$ 144.58	$ 1,043.42	$ 1,188.00
92110814	12.17%	Customers-All	$ 486.80	$ 3,513.20	$ 4,000.00
92110814	12.17%	Customers-All	$ 135.31	$ 976.51	$ 1,111.82
92110814	12.17%	Customers-All	$ 198.54	$ 1,432.86	$ 1,631.40
92110814	12.17%	Customers-All	$ 12.17	$ 87.83	$ 100.00
92110814	12.17%	Customers-All	$ 10.65	$ 76.85	$ 87.50
92110818	30.00%	Regulatory	$ 1,153.28	$ 2,690.98	$ 3,844.26
92110818	30.00%	Regulatory	$ 12.00	$ 28.00	$ 40.00
92110818	30.00%	Regulatory	$ 18.69	$ 43.62	$ 62.31
92110818	30.00%	Regulatory	$ 426.02	$ 994.04	$ 1,420.06
92110818	30.00%	Regulatory	$ 193.57	$ 451.66	$ 645.23
92110818	30.00%	Regulatory	$ 2.40	$ 5.60	$ 8.00
92110818	30.00%	Regulatory	$ 104.33	$ 243.43	$ 347.75
92110818	30.00%	Regulatory	$ 63.86	$ 149.01	$ 212.87
92110818	30.00%	Regulatory	$ 968.48	$ 2,259.80	$ 3,228.28
92110818	30.00%	Regulatory	$ 397.19	$ 926.77	$ 1,323.96
92110818	30.00%	Regulatory	$ 2.78	$ 6.48	$ 9.25
92110818	30.00%	Regulatory	$ 69.60	$ 162.40	$ 232.00
92110818	30.00%	Regulatory	$ 147,531.52	$ 344,240.22	$ 491,771.74
92110818	30.00%	Regulatory	$ 1,495.22	$ 3,488.84	$ 4,984.05
92110818	30.00%	Regulatory	$ 9.84	$ 22.97	$ 32.81
92110818	30.00%	Regulatory	$ 1,395.00	$ 3,255.00	$ 4,650.00
92110818	30.00%	Regulatory	$ 781.26	$ 1,822.94	$ 2,604.20
92110818	30.00%	Regulatory	$ 159.05	$ 371.11	$ 530.15
92110818	30.00%	Regulatory	$ 1,581.56	$ 3,690.30	$ 5,271.85
92110818	30.00%	Regulatory	$ 627.01	$ 1,463.03	$ 2,090.04
92110818	30.00%	Regulatory	$ 376.10	$ 877.56	$ 1,253.65
92110819	11.80%	3-factor	$ 35.40	$ 264.60	$ 300.00
92110819	11.80%	3-factor	$ 1,486.80	$ 11,113.20	$ 12,600.00
92110819	11.80%	3-factor	$ 2,278.31	$ 17,029.36	$ 19,307.67
92110819	11.80%	3-factor	$ 1,769.46	$ 13,225.99	$ 14,995.45
92110819	11.80%	3-factor	$ 203.50	$ 1,521.08	$ 1,724.58
92110819	11.80%	3-factor	$ 28.13	$ 210.24	$ 238.37
92110819	11.80%	3-factor	$ -	$ -	$ -
92110819	11.80%	3-factor	$ 37.44	$ 279.88	$ 317.32
92110819	11.80%	3-factor	$ 9.66	$ 72.24	$ 81.90
92110819	11.80%	3-factor	$ (959.75)	$ (7,173.74)	$ (8,133.49)
92110819	11.80%	3-factor	$ 248.99	$ 1,861.09	$ 2,110.08
92110819	11.80%	3-factor	$ -	$ -	$ -
92110819	11.80%	3-factor	$ 11.34	$ 84.78	$ 96.12
92110819	11.80%	3-factor	$ 1.61	$ 12.03	$ 13.64
92110819	11.80%	3-factor	$ 2.91	$ 21.71	$ 24.62
92110819	11.80%	3-factor	$ -	$ -	$ -
92110819	11.80%	3-factor	$ 307.79	$ 2,300.57	$ 2,608.36
92110819	11.80%	3-factor	$ 54.74	$ 409.16	$ 463.90
92110820	11.80%	3-factor	$ 9,956.31	$ 74,419.19	$ 84,375.50
92110820	11.80%	3-factor	$ 4,839.48	$ 36,173.03	$ 41,012.50
92110822	11.80%	3-factor	$ 14,528.18	$ 108,592.00	$ 123,120.18
92110822	11.80%	3-factor	$ -	$ -	$ -
92110823	11.80%	3-factor	$ -	$ -	$ -
92110823	11.80%	3-factor	$ 98.66	$ 737.40	$ 836.06
92110824	11.80%	3-factor	$ 3,274.71	$ 24,477.09	$ 27,751.80
92110825	11.80%	3-factor	$ 7,676.14	$ 57,375.86	$ 65,052.00
92110826	11.80%	3-factor	$ 6,216.03	$ 46,462.17	$ 52,678.20
92110827	11.80%	3-factor	$ 23,852.76	$ 178,289.27	$ 202,142.03
92110828	11.02%	Employee Cost	$ 4,516.93	$ 36,486.07	$ 41,003.00
92110829	11.02%	Employee Cost	$ 11,579.96	$ 93,538.54	$ 105,118.50
92110830	11.02%	Employee Cost	$ 4,263.63	$ 34,439.97	$ 38,703.60
92110831	30.00%	Regulatory	$ 223,952.67	$ 522,556.23	$ 746,508.90
92110832	30.00%	Regulatory	$ 14,034.65	$ 32,747.53	$ 46,782.18
92110833	30.00%	Regulatory	$ -	$ -	$ -
92110835	11.80%	3-factor	$ 208,308.04	$ 1,557,014.33	$ 1,765,322.37
92110836	11.80%	3-factor	$ 113.28	$ 846.72	$ 960.00
92110838	11.80%	3-factor	$ -	$ -	$ -
92110839	11.80%	3-factor	$ 4,447.66	$ 33,244.34	$ 37,692.00
92110840	11.80%	3-factor	$ -	$ -	$ -
92110843	11.80%	3-factor	$ 63.96	$ 478.04	$ 542.00
92110844	11.80%	3-factor	$ 8,995.98	$ 67,241.12	$ 76,237.10
92110845	11.80%	3-factor	$ 37.17	$ 277.83	$ 315.00
92110846	11.80%	3-factor	$ 337.48	$ 2,522.52	$ 2,860.00
92110846	11.80%	3-factor	$ 99.94	$ 747.00	$ 846.94
92110846	11.80%	3-factor	$ -	$ -	$ -
92110846	11.80%	3-factor	$ 44.27	$ 330.93	$ 375.20
92110846	11.80%	3-factor	$ 17,514.47	$ 130,913.28	$ 148,427.75
92110846	11.80%	3-factor	$ -	$ -	$ -
92110846	11.80%	3-factor	$ (152.90)	$ (1,142.89)	$ (1,295.79)
92110846	11.80%	3-factor	$ -	$ -	$ -
92110846	11.80%	3-factor	$ 55.04	$ 411.40	$ 466.44
92110846	11.80%	3-factor	$ 111.24	$ 831.48	$ 942.72
92110846	11.80%	3-factor	$ 2.98	$ 22.27	$ 25.25
92110846	11.80%	3-factor	$ 53.96	$ 403.29	$ 457.25
92110846	11.80%	3-factor	$ 10.40	$ 77.70	$ 88.10
92110846	11.80%	3-factor	$ 2,092.58	$ 15,641.17	$ 17,733.75
92110846

NW Natural
Admin Transfer Allocation Factor
Test Year Ending March 31, 2025

$ 71,068,305.98

						Fiscal Year Period	Amount									
						Measures	Overall Result				Admin Transfer Factor		12.1429%		87.8571%	
											TOTAL	$ 8,629,765.83		$ 62,438,540.15		$ 71,068,305.98
FERC Account	Cost Center	Cost Center Description	GL Account	GL Account Long Name	Chart of Accounts	Ledger	$	SORTER	ALLOCATION FACTOR	ALLOCATION METHOD		WA		OR		SYSTEM
921000	10846	ENV POLICY AND SUSTN	613100	CONFERENCE TRAVEL	NWN	F1	13,656.66	92110846	11.80%	3-factor	$	1,611.49	$	12,045.17	$	13,656.66
921000	10846	ENV POLICY AND SUSTN	613200	BUSINESS TRAVEL	NWN	F1	3,332.11	92110846	11.80%	3-factor	$	393.19	$	2,938.92	$	3,332.11
921000	10846	ENV POLICY AND SUSTN	622000	EMPLOYEE AWARDS	NWN	F1	1,394.42	92110846	11.80%	3-factor	$	164.54	$	1,229.88	$	1,394.42
921000	10846	ENV POLICY AND SUSTN	622200	NON EMPLOYEE GIFTS	NWN	F1	4,458.26	92110846	11.80%	3-factor	$	526.07	$	3,932.19	$	4,458.26
921000	10853	RISK AND LAND-OFFICE	602000	OFFICE CONTRACT WORK	NWN	F1	95,683.50	92110853	11.80%	3-factor	$	11,290.65	$	84,392.85	$	95,683.50
921000	10853	RISK AND LAND-OFFICE	602466	P CARD UNCODED CHARG	NWN	F1	0.00	92110853	11.80%	3-factor	$	-	$	-	$	-
921000	10853	RISK AND LAND-OFFICE	602700	TELEPHONE	NWN	F1	114.72	92110853	11.80%	3-factor	$	13.54	$	101.18	$	114.72
921000	10853	RISK AND LAND-OFFICE	602800	POSTAGE	NWN	F1	8.50	92110853	11.80%	3-factor	$	1.00	$	7.50	$	8.50
921000	10853	RISK AND LAND-OFFICE	605100	PROFESSIONAL SERVICE	NWN	F1	10.00	92110853	11.80%	3-factor	$	1.18	$	8.82	$	10.00
921000	10854	TREASURY-OFFICE STAF	602000	OFFICE CONTRACT WORK	NWN	F1	0.00	92110854	11.80%	3-factor	$	-	$	-	$	-
921000	10854	TREASURY-OFFICE STAF	605100	PROFESSIONAL SERVICE	NWN	F1	0.00	92110854	11.80%	3-factor	$	-	$	-	$	-
921000	10855	CEO-OFFICE STAFF EXP	601100	EDUCATION	NWN	F1	5,540.00	92110855	11.80%	3-factor	$	653.72	$	4,886.28	$	5,540.00
921000	10855	CEO-OFFICE STAFF EXP	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	1,142.59	92110855	11.80%	3-factor	$	134.83	$	1,007.76	$	1,142.59
921000	10855	CEO-OFFICE STAFF EXP	601900	DUES/MEMBERSHIP	NWN	F1	2,472.88	92110855	11.80%	3-factor	$	291.80	$	2,181.08	$	2,472.88
921000	10855	CEO-OFFICE STAFF EXP	602466	P CARD UNCODED CHARG	NWN	F1	(1,171.20)	92110855	11.80%	3-factor	$	(138.20)	$	(1,033.00)	$	(1,171.20)
921000	10855	CEO-OFFICE STAFF EXP	602700	TELEPHONE	NWN	F1	253.90	92110855	11.80%	3-factor	$	29.96	$	223.94	$	253.90
921000	10855	CEO-OFFICE STAFF EXP	603000	OFFICE SUPPLIES	NWN	F1	8.50	92110855	11.80%	3-factor	$	1.00	$	7.50	$	8.50
921000	10855	CEO-OFFICE STAFF EXP	603200	BOOKS AND MAGAZINES	NWN	F1	229.00	92110855	11.80%	3-factor	$	27.02	$	201.98	$	229.00
921000	10855	CEO-OFFICE STAFF EXP	604700	PARKING	NWN	F1	985.90	92110855	11.80%	3-factor	$	116.34	$	869.56	$	985.90
921000	10855	CEO-OFFICE STAFF EXP	605600	LEGAL FEES	NWN	F1	12,116.50	92110855	11.80%	3-factor	$	1,429.75	$	10,686.75	$	12,116.50
921000	10855	CEO-OFFICE STAFF EXP	605600	SOFTWARE MAINT	NWN	F1	14.99	92110855	11.80%	3-factor	$	1.77	$	13.22	$	14.99
921000	10855	CEO-OFFICE STAFF EXP	612100	MEALS AND ENTERTAIN	NWN	F1	10,224.87	92110855	11.80%	3-factor	$	1,206.53	$	9,018.34	$	10,224.87
921000	10855	CEO-OFFICE STAFF EXP	612200	TRAVEL IN TERRITORY	NWN	F1	991.98	92110855	11.80%	3-factor	$	117.05	$	874.93	$	991.98
921000	10855	CEO-OFFICE STAFF EXP	613100	CONFERENCE TRAVEL	NWN	F1	3,133.59	92110855	11.80%	3-factor	$	369.76	$	2,763.83	$	3,133.59
921000	10855	CEO-OFFICE STAFF EXP	613200	BUSINESS TRAVEL	NWN	F1	12,577.55	92110855	11.80%	3-factor	$	1,484.15	$	11,093.40	$	12,577.55
921000	10855	CEO-OFFICE STAFF EXP	622000	EMPLOYEE AWARDS	NWN	F1	4,027.90	92110855	11.80%	3-factor	$	475.29	$	3,552.61	$	4,027.90
921000	10855	CEO-OFFICE STAFF EXP	622200	NON EMPLOYEE GIFTS	NWN	F1	2,979.25	92110855	11.80%	3-factor	$	351.55	$	2,627.70	$	2,979.25
921000	10857	INTERNAL AUDITING-OF	601100	EDUCATION	NWN	F1	7,380.00	92110857	11.80%	3-factor	$	870.84	$	6,509.16	$	7,380.00
921000	10857	INTERNAL AUDITING-OF	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	85.40	92110857	11.80%	3-factor	$	10.08	$	75.32	$	85.40
921000	10857	INTERNAL AUDITING-OF	601700	EQUIPMENT	NWN	F1	219.89	92110857	11.80%	3-factor	$	25.95	$	193.94	$	219.89
921000	10857	INTERNAL AUDITING-OF	601800	FURNITURE	NWN	F1	149.98	92110857	11.80%	3-factor	$	17.70	$	132.28	$	149.98
921000	10857	INTERNAL AUDITING-OF	601900	DUES/MEMBERSHIP	NWN	F1	3,915.00	92110857	11.80%	3-factor	$	461.97	$	3,453.03	$	3,915.00
921000	10857	INTERNAL AUDITING-OF	602000	OFFICE CONTRACT WORK	NWN	F1	0.00	92110857	11.80%	3-factor	$	-	$	-	$	-
921000	10857	INTERNAL AUDITING-OF	602466	P CARD UNCODED CHARG	NWN	F1	134.90	92110857	11.80%	3-factor	$	15.92	$	118.98	$	134.90
921000	10857	INTERNAL AUDITING-OF	603000	OFFICE SUPPLIES	NWN	F1	293.56	92110857	11.80%	3-factor	$	34.64	$	258.92	$	293.56
921000	10857	INTERNAL AUDITING-OF	603100	PRINTING	NWN	F1	74.70	92110857	11.80%	3-factor	$	8.81	$	65.89	$	74.70
921000	10857	INTERNAL AUDITING-OF	603200	BOOKS AND MAGAZINES	NWN	F1	0.00	92110857	11.80%	3-factor	$	-	$	-	$	-
921000	10857	INTERNAL AUDITING-OF	603300	REFRESHMENTS	NWN	F1	232.82	92110857	11.80%	3-factor	$	27.47	$	205.35	$	232.82
921000	10857	INTERNAL AUDITING-OF	604800	LAUNDRY	NWN	F1	63.85	92110857	11.80%	3-factor	$	7.53	$	56.32	$	63.85
921000	10857	INTERNAL AUDITING-OF	605100	PROFESSIONAL SERVICE	NWN	F1	8,235.00	92110857	11.80%	3-factor	$	971.73	$	7,263.27	$	8,235.00
921000	10857	INTERNAL AUDITING-OF	605600	SOFTWARE MAINT	NWN	F1	12,267.68	92110857	11.80%	3-factor	$	1,447.59	$	10,820.09	$	12,267.68
921000	10857	INTERNAL AUDITING-OF	606200	PERMITS AND FEES	NWN	F1	16.37	92110857	11.80%	3-factor	$	1.93	$	14.44	$	16.37
921000	10857	INTERNAL AUDITING-OF	612100	MEALS AND ENTERTAIN	NWN	F1	1,205.82	92110857	11.80%	3-factor	$	142.29	$	1,063.53	$	1,205.82
921000	10857	INTERNAL AUDITING-OF	613100	CONFERENCE TRAVEL	NWN	F1	5,560.76	92110857	11.80%	3-factor	$	656.17	$	4,904.59	$	5,560.76
921000	10857	INTERNAL AUDITING-OF	613200	BUSINESS TRAVEL	NWN	F1	1,772.98	92110857	11.80%	3-factor	$	209.21	$	1,563.77	$	1,772.98
921000	10857	INTERNAL AUDITING-OF	622000	EMPLOYEE AWARDS	NWN	F1	1,565.97	92110857	11.80%	3-factor	$	184.78	$	1,381.19	$	1,565.97
921000	10860	PRESIDENT - OFFIC EX	601100	EDUCATION	NWN	F1	49.00	92110860	11.80%	3-factor	$	5.78	$	43.22	$	49.00
921000	10860	PRESIDENT - OFFIC EX	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	277.38	92110860	11.80%	3-factor	$	32.73	$	244.65	$	277.38
921000	10860	PRESIDENT - OFFIC EX	602100	OTHER CONTRACT WORK	NWN	F1	424.00	92110860	11.80%	3-factor	$	50.03	$	373.97	$	424.00
921000	10860	PRESIDENT - OFFIC EX	602466	P CARD UNCODED CHARG	NWN	F1	4,923.00	92110860	11.80%	3-factor	$	580.91	$	4,342.09	$	4,923.00
921000	10860	PRESIDENT - OFFIC EX	602700	TELEPHONE	NWN	F1	27.95	92110860	11.80%	3-factor	$	3.30	$	24.65	$	27.95
921000	10860	PRESIDENT - OFFIC EX	603000	OFFICE SUPPLIES	NWN	F1	245.36	92110860	11.80%	3-factor	$	28.95	$	216.41	$	245.36
921000	10860	PRESIDENT - OFFIC EX	603200	BOOKS AND MAGAZINES	NWN	F1	3,076.10	92110860	11.80%	3-factor	$	362.98	$	2,713.12	$	3,076.10
921000	10860	PRESIDENT - OFFIC EX	603300	REFRESHMENTS	NWN	F1	2,423.07	92110860	11.80%	3-factor	$	285.92	$	2,137.15	$	2,423.07
921000	10860	PRESIDENT - OFFIC EX	603800	TAXES	NWN	F1	2.32	92110860	11.80%	3-factor	$	0.27	$	2.05	$	2.32
921000	10860	PRESIDENT - OFFIC EX	604700	PARKING	NWN	F1	158.00	92110860	11.80%	3-factor	$	18.64	$	139.36	$	158.00
921000	10860	PRESIDENT - OFFIC EX	604800	LAUNDRY	NWN	F1	109.62	92110860	11.80%	3-factor	$	12.94	$	96.68	$	109.62
921000	10860	PRESIDENT - OFFIC EX	612100	MEALS AND ENTERTAIN	NWN	F1	1,734.01	92110860	11.80%	3-factor	$	204.61	$	1,529.40	$	1,734.01
921000	10860	PRESIDENT - OFFIC EX	612200	TRAVEL IN TERRITORY	NWN	F1	281.06	92110860	11.80%	3-factor	$	33.17	$	247.89	$	281.06
921000	10860	PRESIDENT - OFFIC EX	613100	CONFERENCE TRAVEL	NWN	F1	2,888.71	92110860	11.80%	3-factor	$	352.67	$	2,636.04	$	2,988.71
921000	10860	PRESIDENT - OFFIC EX	613200	BUSINESS TRAVEL	NWN	F1	2,252.79	92110860	11.80%	3-factor	$	265.83	$	1,986.96	$	2,252.79
921000	10860	PRESIDENT - OFFIC EX	622000	EMPLOYEE AWARDS	NWN	F1	675.00	92110860	11.80%	3-factor	$	79.65	$	595.35	$	675.00
921000	10861	VP & CORPORATE SECTY	601100	EDUCATION	NWN	F1	0.00	92110861	11.80%	3-factor	$	-	$	-	$	-
921000	10861	VP & CORPORATE SECTY	601900	DUES/MEMBERSHIP	NWN	F1	3,753.00	92110861	11.80%	3-factor	$	442.85	$	3,310.15	$	3,753.00
921000	10861	VP & CORPORATE SECTY	602466	P CARD UNCODED CHARG	NWN	F1	4,651.97	92110861	11.80%	3-factor	$	548.93	$	4,103.04	$	4,651.97
921000	10861	VP & CORPORATE SECTY	602700	TELEPHONE	NWN	F1	48.00	92110861	11.80%	3-factor	$	5.66	$	42.34	$	48.00
921000	10861	VP & CORPORATE SECTY	602800	POSTAGE	NWN	F1	188.98	92110861	11.80%	3-factor	$	22.30	$	166.68	$	188.98
921000	10861	VP & CORPORATE SECTY	603000	OFFICE SUPPLIES	NWN	F1	571.32	92110861	11.80%	3-factor	$	67.42	$	503.90	$	571.32
921000	10861	VP & CORPORATE SECTY	603200	BOOKS AND MAGAZINES	NWN	F1	1,217.16	92110861	11.80%	3-factor	$	143.62	$	1,073.54	$	1,217.16
921000	10861	VP & CORPORATE SECTY	603300	REFRESHMENTS	NWN	F1	0.00	92110861	11.80%	3-factor	$	-	$	-	$	-
921000	10861	VP & CORPORATE SECTY	605000	LEGAL FEES	NWN	F1	10.00	92110861	11.80%	3-factor	$	1.18	$	8.82	$	10.00
921000	10861	VP & CORPORATE SECTY	605100	PROFESSIONAL SERVICE	NWN	F1	5,850.00	92110861	11.80%	3-factor	$	690.30	$	5,159.70	$	5,850.00
921000	10861	VP & CORPORATE SECTY	606300	CELLULAR PHONES	NWN	F1	1,785.00	92110861	11.80%	3-factor	$	210.63	$	1,574.37	$	1,785.00
921000	10861	VP & CORPORATE SECTY	608100	SUBCRIPTION SERVICES	NWN	F1	1,699.97	92110861	11.80%	3-factor	$	200.58	$	1,499.29	$	1,699.87
921000	10861	VP & CORPORATE SECTY	612100	MEALS AND ENTERTAIN	NWN	F1	1,051.00	92110861	11.80%	3-factor	$	124.02	$	926.98	$	1,051.00
921000	10861	VP & CORPORATE SECTY	613100	CONFERENCE TRAVEL	NWN	F1	2,095.83	92110861	11.80%	3-factor	$	247.31	$	1,848.52	$	2,095.83
921000	10861	VP & CORPORATE SECTY	613200	BUSINESS TRAVEL	NWN	F1	0.00	92110861	11.80%	3-factor	$	-	$	-	$	-
921000	10861	VP & CORPORATE SECTY	622000	EMPLOYEE AWARDS	NWN	F1	1,065.65	92110861	11.80%	3-factor	$	125.75	$	939.90	$	1,065.65
921000	10862	EVP, CHIEF FIN OFF -	601100	EDUCATION	NWN	F1	2,451.70	92110862	11.80%	3-factor	$	289.30	$	2,162.40	$	2,451.70
921000	10862	EVP, CHIEF FIN OFF -	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	97.82	92110862	11.80%	3-factor	$	11.54	$	86.28	$	97.82
921000	10862	EVP, CHIEF FIN OFF -	602466	P CARD UNCODED CHARG	NWN	F1	2,595.39	92110862	11.80%	3-factor	$	306.26	$	2,289.13	$	2,595.39
921000	10862	EVP, CHIEF FIN OFF -	602700	TELEPHONE	NWN	F1	15.00	92110862	11.80%	3-factor	$	1.77	$	13.23	$	15.00
921000	10862	EVP, CHIEF FIN OFF -	603000	OFFICE SUPPLIES	NWN	F1	29.99	92110862	11.80%	3-factor	$	3.54	$	26.45	$	29.99
921000	10862	EVP, CHIEF FIN OFF -	604700	PARKING	NWN	F1	245.00	92110862	11.80%	3-factor	$	28.91	$	216.09	$	245.00
921000	10862	EVP, CHIEF FIN OFF -	604950	CLOTHING	NWN	F1	159.99	92110862	11.80%	3-factor	$	18.88	$	141.11	$	159.99
921000	10862	EVP, CHIEF FIN OFF -	605100	PROFESSIONAL SERVICE	NWN	F1	48,356.48	92110862	11.80%	3-factor	$	5,706.06	$	42,650.42	$	48,356.48
921000	10862	EVP, CHIEF FIN OFF -	612100	MEALS AND ENTERTAIN	NWN	F1	889.76	92110862	11.80%	3-factor	$	104.99	$	784.77	$	889.76
921000	10862	EVP, CHIEF FIN OFF -	612200	TRAVEL IN TERRITORY	NWN	F1	3,132.59	92110862	11.80%	3-factor	$	369.65	$	2,762.94	$	3,132.59
921000	10862	EVP, CHIEF FIN OFF -	613100	CONFERENCE TRAVEL	NWN	F1	1,811.15	92110862	11.80%	3-factor	$	213.72	$	1,597.43	$	1,811.15
921000	10862	EVP, CHIEF FIN OFF -	613200	BUSINESS TRAVEL	NWN	F1	7,122.51	92110862	11.80%	3-factor	$	840.46	$	6,282.05	$	7,122.51
921000	10862	EVP, CHIEF FIN OFF -	622000	EMPLOYEE AWARDS	NWN	F1	250.00	92110862	11.80%	3-factor	$	29.50	$	220.50	$	250.00
921000	10864	VP, CAO, CONT&TREAS-	601100	EDUCATION	NWN	F1	5,694.00	92110864	11.80%	3-factor	$	671.89	$	5,022.11	$	5,694.00
921000	10864	VP, CAO, CONT&TREAS-	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	362.76	92110864	11.80%	3-factor	$	42.81	$	319.95	$	362.76
921000	10864	VP, CAO, CONT&TREAS-	601900	DUES/MEMBERSHIP	NWN	F1	605.00	92110864	11.80%	3-factor	$	71.39	$	533.61	$	605.00
921000	10864	VP, CAO, CONT&TREAS-	602466	P CARD UNCODED CHARG	NWN	F1	(3,643.26)	92110864	11.80%	3-factor	$	(429.91)	$	(3,213.37)	$	(3,643.28)
921000	10864	VP, CAO, CONT&TREAS-	602700	TELEPHONE	NWN	F1	120.00	92110864	11.80%	3-factor	$	14.16	$	105.84	$	120.00
921000	10864	VP, CAO, CONT&TREAS-	602800	POSTAGE	NWN	F1	0.00	92110864	11.80%	3-factor	$	-	$	-	$	-
921000	10864	VP, CAO, CONT&TREAS-	603200	BOOKS AND MAGAZINES	NWN	F1	0.00	92110864	11.80%	3-factor	$	-	$	-	$	-
921000	10864	VP, CAO, CONT&TREAS-	604700	PARKING	NWN	F1	633.95	92110864	11.80%	3-factor	$	74.81	$	559.14	$	633.95
921000	10864	VP, CAO, CONT&TREAS-	606500	UNLEADED FUEL	NWN	F1	51.10	92110864	11.80%	3-factor	$	6.03	$	45.07	$	51.10
921000	10864	VP, CAO, CONT&TREAS-	608100	SUBCRIPTION SERVICES	NWN	F1	467.88	92110864	11.80%	3-factor	$	55.21	$	412.67	$	467.88
921000	10864	VP, CAO, CONT&TREAS-	612100	MEALS AND ENTERTAIN	NWN	F1	1,056.58	92110864	11.80%	3-factor	$	124.68	$	931.90	$	1,056.58
921000	10864	VP, CAO, CONT&TREAS-	613100	CONFERENCE TRAVEL	NWN	F1	11,390.27	92110864	11.80%	3-factor	$	1,344.05	$	10,046.22	$	11,390.27
921000	10864	VP, CAO, CONT&TREAS-	613200	BUSINESS TRAVEL	NWN	F1	5,507.17	92110864	11.80%	3-factor	$	649.85	$	4,857.32	$	5,507.17
921000	10864	VP, CAO, CONT&TREAS-	622000	EMPLOYEE AWARDS	NWN	F1	1,548.99	92110864	11.80%	3-factor	$	182.78	$	1,366.21	$	1,548.99
921000	10865	VP GS SPLY & UTL SS	601100	EDUCATION	NWN	F1	500.00	92110865	11.80%	3-factor	$	59.00	$	441.00	$	500.00
921000	10865	VP GS SPLY & UTL SS	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	1,352.15	92110865	11.80%	3-factor	$	159.55	$	1,192.60	$	1,352.15
921000	10865	VP GS SPLY & UTL SS	602466	P CARD UNCODED CHARG	NWN	F1	294.10	92110865	11.80%	3-factor	$	34.70	$	259.40	$	294.10
921000	10865	VP GS SPLY & UTL SS	603300	REFRESHMENTS	NWN	F1	0.00	92110865	11.80%	3-factor	$	-	$	-	$	-
921000	10865	VP GS SPLY & UTL SS	604700	PARKING	NWN	F1	50.00	92110865	11.80%	3-factor	$	5.90	$	44.10	$	50.00
921000	10865	VP GS SPLY & UTL SS	605100	PROFESSIONAL SERVICE	NWN	F1	6,148.89	92110865	11.80%	3-factor	$	725.57	$	5,423.32	$	6,148.89
921000	10865	VP GS SPLY & UTL SS	606200	PERMITS AND FEES	NWN	F1	0.00	92110865	11.80%	3-factor	$	-	$	-	$	-
921000	10865	VP GS SPLY & UTL SS	612100	MEALS AND ENTERTAIN	NWN	F1	20.87	92110865	11.80%	3-factor	$	2.46	$	18.41	$	20.87
921000	10865	VP GS SPLY & UTL SS	612200	TRAVEL IN TERRITORY	NWN	F1	152.20	92110865	11.80%	3-factor	$	17.96	$	134.24	$	152.20
921000	10865	VP GS SPLY & UTL SS	613100	CONFERENCE TRAVEL	NWN	F1	943.13	92110865	11.80%	3-factor	$	111.29	$	831.84	$	943.13
921000	10865	VP GS SPLY & UTL SS	613200	BUSINESS TRAVEL	NWN	F1	733.06	92110865	11.80%	3-factor	$	86.50	$	646.56	$	733.06
921000	10865	VP GS SPLY & UTL SS	622000	EMPLOYEE AWARDS	NWN	F1	940.00	92110865	11.80%	3-factor	$	110.92	$	829.08	$	940.00
921000	10866	VP, I.T. & CIO-OFFIC	601100	EDUCATION	NWN	F1	0.00	92110866	11.80%	3-factor	$	-	$	-	$	-
921000	10866	VP, I.T. & CIO-OFFIC	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	90.30	92110866	11.80%	3-factor	$	10.66	$	79.64	$	90.30
921000	10866	VP, I.T. & CIO-OFFIC	601900	DUES/MEMBERSHIP	NWN	F1	120.00	92110866	11.80%	3-factor	$	14.16	$	105.84	$	120.00
921000	10866	VP, I.T. & CIO-OFFIC	602466	P CARD UNCODED CHARG	NWN	F1	0.00	92110866	11.80%	3-factor	$	-	$	-	$	-
921000	10866	VP, I.T. & CIO-OFFIC	603000	OFFICE SUPPLIES	NWN	F1	53.98	92110866	11.80%	3-factor	$	6.37	$	47.61	$	53.98
921000	10866	VP, I.T. & CIO-OFFIC	603200	BOOKS AND MAGAZINES	NWN	F1	54.31	92110866	11.80%	3-factor	$	6.41	$	47.90	$	54.31
921000	10866	VP, I.T. & CIO-OFFIC	603300	REFRESHMENTS	NWN	F1	1,451.53	92110866	11.80%	3-factor	$	171.28	$	1,280.25	$	1,451.53
921000	10866	VP, I.T. & CIO-OFFIC	605100	PROFESSIONAL SERVICE	NWN	F1	105,500.00	92110866	11.80%	3-factor	$	12,449.00	$	93,051.00	$	105,500.00
921000	10866	VP, I.T. & CIO-OFFIC	612100	MEALS AND ENTERTAIN	NWN	F1	97.75	92110866	11.80%	3-factor	$	11.53	$	86.22	$	97.75
921000	10866	VP, I.T. & CIO-OFFIC	613100	CONFERENCE TRAVEL	NWN	F1	0.00	92110866	11.80%	3-factor	$	-	$	-	$	-
921000	10866	VP, I.T. & CIO-OFFIC	622000	EMPLOYEE AWARDS	NWN	F1	1,818.99	92110866	11.80%	3-factor	$	214.64	$	1,604.35	$	1,818.99
921000	10867	VP, CHIEF PAA & SUSTA	601100	EDUCATION	NWN	F1	8,780.00	92110867	11.80%	3-factor	$	1,036.04	$	7,743.96	$	8,780.00
921000	10867	VP, CHIEF PAA & SUSTA	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	313.56	92110867	11.80%	3-factor	$	37.00	$	276.56	$	313.56
921000	10867	VP, CHIEF PAA & SUSTA	601900	DUES/MEMBERSHIP	NWN	F1	5,497.93	92110867	11.80%	3-factor	$	648.76	$	4,849.17	$	5,497.93
921000	10867	VP, CHIEF PAA & SUSTA	602466	P CARD UNCODED CHARG	NWN	F1	(5,430.83)	92110867	11.80%	3-factor	$	(640.84)	$	(4,789.99)	$	(5,430.83)
921000	10867	VP, CHIEF PAA & SUSTA	602700	TELEPHONE	NWN	F1	231.87	92110867	11.80%	3-factor	$	27.36	$	204.51	$	231.87
921000	10867	VP, CHIEF PAA & SUSTA	602800	POSTAGE	NWN	F1	46.51	92110867	11.80%	3-factor	$	5.49	$	41.02	$	46.51
921000	10867	VP, CHIEF PAA & SUSTA	603000	OFFICE SUPPLIES	NWN	F1	69.20	92110867	11.80%	3-factor	$	8.17	$	61.03	$	69.20
921000	10867	VP, CHIEF PAA & SUSTA	603200	BOOKS AND MAGAZINES	NWN	F1	716.93	92110867	11.80%	3-factor	$	84.60	$	632.33	$	716.93
921000	10867	VP, CHIEF PAA & SUSTA	603300	REFRESHMENTS	NWN	F1	474.57	92110867	11.80%	3-factor	$	56.00	$	418.57	$	474.57
921000	10867	VP, CHIEF PAA & SUSTA	604700	PARKING	NWN	F1	288.60	92110867	11.80%	3-factor	$	34.05	$	254.55	$	288.60
921000	10867	VP, CHIEF PAA & SUSTA	606500	UNLEADED FUEL	NWN	F1	34.26	92110867	11.80%	3-factor	$	4.04	$	30.22	$	34.26
921000	10867	VP, CHIEF PAA & SUSTA	608100	SUBCRIPTION SERVICES	NWN	F1	45.00	92110867	11.80%	3-factor	$	5.31	$	39.69	$	45.00
921000	10867	VP, CHIEF PAA & SUSTA	612100	MEALS AND ENTERTAIN	NWN	F1	1,567.20	92110867	11.80%	3-factor	$	184.93	$	1,382.27	$	1,567.20
921000	10867	VP, CHIEF PAA & SUSTA	613100	CONFERENCE TRAVEL	NWN	F1	10,118.44	92110867	11.80%	3-factor	$	1,193.98	$	8,924.46	$	10,118.44
921000	10867	VP, CHIEF PAA & SUSTA	613200	BUSINESS TRAVEL	NWN	F1	4,018.55	92110867	11.80%	3-factor	$	474.19	$	3,544.36	$	4,018.55
921000	10867	VP, CHIEF PAA & SUSTA	622000	EMPLOYEE AWARDS	NWN	F1	1,912.92	92110867	11.80%	3-factor	$	225.72	$	1,687.20	$	1,912.92
921000	10869	SR VP & GEN COUNSEL-	601100	EDUCATION	NWN	F1	3,898.00	92110869	11.80%	3-factor	$	459.96	$	3,438.04	$	3,898.00
921000	10869	SR VP & GEN COUNSEL-	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	45.89	92110869	11.80%	3-factor	$	5.42	$	40.47	$	45.89
921000	10869	SR VP & GEN COUNSEL-	601900	DUES/MEMBERSHIP	NWN	F1	3,569.22	92110869

NW Natural
Admin Transfer Allocation Factor
Test Year Ending March 31, 2025

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$ 71,068,305.98

						Fiscal Year Period Measures	Amount Overall Result				Admin Transfer Factor	12.1429%	87.8571%	
											TOTAL	$ 8,629,765.83	$ 62,438,540.15	$ 71,068,305.98
FERC Account	Cost Center	Cost Center Description	GL Account	GL Account Long Name	Chart of Accounts	Ledger	$	SORTER	ALLOCATION FACTOR	ALLOCATION METHOD		WA	OR	SYSTEM
921000	10869	SR VP & GEN COUNSEL-	602800	POSTAGE	NWN	F1	152.68	92110869	11.80%	3-factor	$	18.02	$ 134.66	$ 152.68
921000	10869	SR VP & GEN COUNSEL-	603000	OFFICE SUPPLIES	NWN	F1	562.11	92110869	11.80%	3-factor	$	66.33	$ 495.78	$ 562.11
921000	10869	SR VP & GEN COUNSEL-	603200	BOOKS AND MAGAZINES	NWN	F1	170.00	92110869	11.80%	3-factor	$	20.06	$ 149.94	$ 170.00
921000	10869	SR VP & GEN COUNSEL-	603300	REFRESHMENTS	NWN	F1	407.23	92110869	11.80%	3-factor	$	48.05	$ 359.18	$ 407.23
921000	10869	SR VP & GEN COUNSEL-	604700	PARKING	NWN	F1	109.45	92110869	11.80%	3-factor	$	12.92	$ 96.53	$ 109.45
921000	10869	SR VP & GEN COUNSEL-	605100	PROFESSIONAL SERVICE	NWN	F1	288,628.25	92110869	11.80%	3-factor	$	34,058.13	$ 254,570.12	$ 288,628.25
921000	10869	SR VP & GEN COUNSEL-	605900	HARDWARE MAINT	NWN	F1	67.98	92110869	11.80%	3-factor	$	8.02	$ 59.96	$ 67.98
921000	10869	SR VP & GEN COUNSEL-	606300	CELLULAR PHONES	NWN	F1	8.00	92110869	11.80%	3-factor	$	0.94	$ 7.06	$ 8.00
921000	10869	SR VP & GEN COUNSEL-	606500	UNLEADED FUEL	NWN	F1	46.85	92110869	11.80%	3-factor	$	5.53	$ 41.32	$ 46.85
921000	10869	SR VP & GEN COUNSEL-	612100	MEALS AND ENTERTAIN	NWN	F1	2,167.62	92110869	11.80%	3-factor	$	255.78	$ 1,911.84	$ 2,167.62
921000	10869	SR VP & GEN COUNSEL-	612200	TRAVEL IN TERRITORY	NWN	F1	0.00	92110869	11.80%	3-factor	$	-	$ -	$ -
921000	10869	SR VP & GEN COUNSEL-	613100	CONFERENCE TRAVEL	NWN	F1	8,447.13	92110869	11.80%	3-factor	$	996.76	$ 7,450.37	$ 8,447.13
921000	10869	SR VP & GEN COUNSEL-	622000	EMPLOYEE AWARDS	NWN	F1	3,119.38	92110869	11.80%	3-factor	$	368.09	$ 2,751.29	$ 3,119.38
921000	10869	SR VP & GEN COUNSEL-	622200	NON EMPLOYEE GIFTS	NWN	F1	151.20	92110869	11.80%	3-factor	$	17.84	$ 133.36	$ 151.20
921000	10870	VP, CHF HR&DIRY OFF-	601100	EDUCATION	NWN	F1	425.00	92110870	11.80%	3-factor	$	50.15	$ 374.85	$ 425.00
921000	10870	VP, CHF HR&DIRY OFF-	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	246.22	92110870	11.80%	3-factor	$	29.05	$ 217.17	$ 246.22
921000	10870	VP, CHF HR&DIRY OFF-	601900	DUES/MEMBERSHIP	NWN	F1	14,950.00	92110870	11.80%	3-factor	$	1,764.10	$ 13,185.90	$ 14,950.00
921000	10870	VP, CHF HR&DIRY OFF-	602466	P CARD UNCODED CHARG	NWN	F1	1,679.47	92110870	11.80%	3-factor	$	198.18	$ 1,481.29	$ 1,679.47
921000	10870	VP, CHF HR&DIRY OFF-	603000	OFFICE SUPPLIES	NWN	F1	502.25	92110870	11.80%	3-factor	$	59.27	$ 442.98	$ 502.25
921000	10870	VP, CHF HR&DIRY OFF-	603200	BOOKS AND MAGAZINES	NWN	F1	32.63	92110870	11.80%	3-factor	$	3.85	$ 28.78	$ 32.63
921000	10870	VP, CHF HR&DIRY OFF-	603300	REFRESHMENTS	NWN	F1	25.55	92110870	11.80%	3-factor	$	3.01	$ 22.54	$ 25.55
921000	10870	VP, CHF HR&DIRY OFF-	604700	PARKING	NWN	F1	64.00	92110870	11.80%	3-factor	$	7.55	$ 56.45	$ 64.00
921000	10870	VP, CHF HR&DIRY OFF-	604800	LAUNDRY	NWN	F1	195.81	92110870	11.80%	3-factor	$	23.11	$ 172.70	$ 195.81
921000	10870	VP, CHF HR&DIRY OFF-	605100	PROFESSIONAL SERVICE	NWN	F1	0.00	92110870	11.80%	3-factor	$	-	$ -	$ -
921000	10870	VP, CHF HR&DIRY OFF-	605600	SOFTWARE MAINT	NWN	F1	2,880.00	92110870	11.80%	3-factor	$	339.84	$ 2,540.16	$ 2,880.00
921000	10870	VP, CHF HR&DIRY OFF-	606200	PERMITS AND FEES	NWN	F1	2,295.00	92110870	11.80%	3-factor	$	270.81	$ 2,024.19	$ 2,295.00
921000	10870	VP, CHF HR&DIRY OFF-	608100	SUBCRIPTION SERVICES	NWN	F1	9,250.00	92110870	11.80%	3-factor	$	1,091.50	$ 8,158.50	$ 9,250.00
921000	10870	VP, CHF HR&DIRY OFF-	612100	MEALS AND ENTERTAIN	NWN	F1	957.41	92110870	11.80%	3-factor	$	112.97	$ 844.44	$ 957.41
921000	10870	VP, CHF HR&DIRY OFF-	612200	TRAVEL IN TERRITORY	NWN	F1	0.00	92110870	11.80%	3-factor	$	-	$ -	$ -
921000	10870	VP, CHF HR&DIRY OFF-	613100	CONFERENCE TRAVEL	NWN	F1	1,465.53	92110870	11.80%	3-factor	$	172.93	$ 1,292.60	$ 1,465.53
921000	10870	VP, CHF HR&DIRY OFF-	622000	EMPLOYEE AWARDS	NWN	F1	1,425.00	92110870	11.80%	3-factor	$	168.15	$ 1,256.85	$ 1,425.00
921000	10870	VP, CHF HR&DIRY OFF-	622200	NON EMPLOYEE GIFTS	NWN	F1	0.00	92110870	11.80%	3-factor	$	-	$ -	$ -
921000	10872	CEO-OFFIC EXP	601100	EDUCATION	NWN	F1	2,490.00	92110872	11.80%	3-factor	$	293.82	$ 2,196.18	$ 2,490.00
921000	10872	CEO-OFFIC EXP	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	934.14	92110872	11.80%	3-factor	$	110.23	$ 823.91	$ 934.14
921000	10872	CEO-OFFIC EXP	601900	DUES/MEMBERSHIP	NWN	F1	467.88	92110872	11.80%	3-factor	$	55.21	$ 412.67	$ 467.88
921000	10872	CEO-OFFIC EXP	602466	P CARD UNCODED CHARG	NWN	F1	(2,879.50)	92110872	11.80%	3-factor	$	(339.78)	$ (2,539.72)	$ (2,879.50)
921000	10872	CEO-OFFIC EXP	602700	TELEPHONE	NWN	F1	176.00	92110872	11.80%	3-factor	$	20.77	$ 155.23	$ 176.00
921000	10872	CEO-OFFIC EXP	602800	POSTAGE	NWN	F1	12.39	92110872	11.80%	3-factor	$	1.46	$ 10.93	$ 12.39
921000	10872	CEO-OFFIC EXP	603200	BOOKS AND MAGAZINES	NWN	F1	190.00	92110872	11.80%	3-factor	$	22.42	$ 167.58	$ 190.00
921000	10872	CEO-OFFIC EXP	604700	PARKING	NWN	F1	508.65	92110872	11.80%	3-factor	$	60.02	$ 448.63	$ 508.65
921000	10872	CEO-OFFIC EXP	605100	PROFESSIONAL SERVICE	NWN	F1	8,558.01	92110872	11.80%	3-factor	$	1,009.85	$ 7,548.16	$ 8,558.01
921000	10872	CEO-OFFIC EXP	612100	MEALS AND ENTERTAIN	NWN	F1	7,697.14	92110872	11.80%	3-factor	$	908.26	$ 6,788.88	$ 7,697.14
921000	10872	CEO-OFFIC EXP	612200	TRAVEL IN TERRITORY	NWN	F1	994.98	92110872	11.80%	3-factor	$	117.41	$ 877.57	$ 994.98
921000	10872	CEO-OFFIC EXP	613100	CONFERENCE TRAVEL	NWN	F1	8,887.49	92110872	11.80%	3-factor	$	1,048.72	$ 7,838.77	$ 8,887.49
921000	10872	CEO-OFFIC EXP	613200	BUSINESS TRAVEL	NWN	F1	9,152.35	92110872	11.80%	3-factor	$	1,079.98	$ 8,072.37	$ 9,152.35
921000	10872	CEO-OFFIC EXP	622000	EMPLOYEE AWARDS	NWN	F1	568.49	92110872	11.80%	3-factor	$	67.08	$ 501.41	$ 568.49
921000	10875	GEN ADMIN STAFF-OFFI	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	59.93	92110875	11.80%	3-factor	$	7.07	$ 52.86	$ 59.93
921000	10875	GEN ADMIN STAFF-OFFI	602100	OTHER CONTRACT WORK	NWN	F1	217.00	92110875	11.80%	3-factor	$	25.61	$ 191.39	$ 217.00
921000	10875	GEN ADMIN STAFF-OFFI	602466	P CARD UNCODED CHARG	NWN	F1	5,484.19	92110875	11.80%	3-factor	$	647.13	$ 4,837.06	$ 5,484.19
921000	10875	GEN ADMIN STAFF-OFFI	602800	POSTAGE	NWN	F1	364.91	92110875	11.80%	3-factor	$	43.06	$ 321.85	$ 364.91
921000	10875	GEN ADMIN STAFF-OFFI	603000	OFFICE SUPPLIES	NWN	F1	5,156.36	92110875	11.80%	3-factor	$	608.45	$ 4,547.91	$ 5,156.36
921000	10875	GEN ADMIN STAFF-OFFI	603100	PRINTING	NWN	F1	3,538.44	92110875	11.80%	3-factor	$	417.54	$ 3,120.90	$ 3,538.44
921000	10875	GEN ADMIN STAFF-OFFI	603200	BOOKS AND MAGAZINES	NWN	F1	41.64	92110875	11.80%	3-factor	$	4.91	$ 36.73	$ 41.64
921000	10875	GEN ADMIN STAFF-OFFI	603300	REFRESHMENTS	NWN	F1	183.49	92110875	11.80%	3-factor	$	21.65	$ 161.84	$ 183.49
921000	10875	GEN ADMIN STAFF-OFFI	604700	PARKING	NWN	F1	5.00	92110875	11.80%	3-factor	$	0.59	$ 4.41	$ 5.00
921000	10875	GEN ADMIN STAFF-OFFI	604800	LAUNDRY	NWN	F1	0.00	92110875	11.80%	3-factor	$	-	$ -	$ -
921000	10875	GEN ADMIN STAFF-OFFI	605100	PROFESSIONAL SERVICE	NWN	F1	40.00	92110875	11.80%	3-factor	$	4.72	$ 35.28	$ 40.00
921000	10875	GEN ADMIN STAFF-OFFI	606200	PERMITS AND FEES	NWN	F1	1.08	92110875	11.80%	3-factor	$	0.13	$ 0.95	$ 1.08
921000	10875	GEN ADMIN STAFF-OFFI	608100	SUBCRIPTION SERVICES	NWN	F1	0.00	92110875	11.80%	3-factor	$	-	$ -	$ -
921000	10875	GEN ADMIN STAFF-OFFI	612100	MEALS AND ENTERTAIN	NWN	F1	4,809.15	92110875	11.80%	3-factor	$	567.48	$ 4,241.67	$ 4,809.15
921000	10875	GEN ADMIN STAFF-OFFI	612200	TRAVEL IN TERRITORY	NWN	F1	0.00	92110875	11.80%	3-factor	$	-	$ -	$ -
921000	10875	GEN ADMIN STAFF-OFFI	613200	BUSINESS TRAVEL	NWN	F1	0.00	92110875	11.80%	3-factor	$	-	$ -	$ -
921000	10875	GEN ADMIN STAFF-OFFI	622000	EMPLOYEE AWARDS	NWN	F1	16,510.01	92110875	11.80%	3-factor	$	1,948.18	$ 14,561.83	$ 16,510.01
921000	10875	GEN ADMIN STAFF-OFFI	622100	EMPLOYEE AWRDS MLS &	NWN	F1	0.00	92110875	11.80%	3-factor	$	-	$ -	$ -
921000	10875	GEN ADMIN STAFF-OFFI	622200	NON EMPLOYEE GIFTS	NWN	F1	115.48	92110875	11.80%	3-factor	$	13.63	$ 101.85	$ 115.48
921000	10878	EXEC ASST PAYROLL-OF	602466	P CARD UNCODED CHARG	NWN	F1	23.99	92110878	11.80%	3-factor	$	2.83	$ 21.16	$ 23.99
921000	10879	OFFICERS PAYROLL-OFF	601100	EDUCATION	NWN	F1	2,250.00	92110879	11.12%	Payroll	$	250.14	$ 1,999.86	$ 2,250.00
921000	10879	OFFICERS PAYROLL-OFF	601200	AUTO ALLOWANCE	NWN	F1	4,725.00	92110879	11.12%	Payroll	$	525.30	$ 4,199.70	$ 4,725.00
921000	10879	OFFICERS PAYROLL-OFF	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	0.00	92110879	11.12%	Payroll	$	-	$ -	$ -
921000	10879	OFFICERS PAYROLL-OFF	601900	DUES/MEMBERSHIP	NWN	F1	599.00	92110879	11.12%	Payroll	$	66.59	$ 532.41	$ 599.00
921000	10879	OFFICERS PAYROLL-OFF	602466	P CARD UNCODED CHARG	NWN	F1	1,850.53	92110879	11.12%	Payroll	$	205.73	$ 1,644.80	$ 1,850.53
921000	10879	OFFICERS PAYROLL-OFF	602700	TELEPHONE	NWN	F1	0.00	92110879	11.12%	Payroll	$	-	$ -	$ -
921000	10879	OFFICERS PAYROLL-OFF	603200	BOOKS AND MAGAZINES	NWN	F1	194.97	92110879	11.12%	Payroll	$	21.68	$ 173.29	$ 194.97
921000	10879	OFFICERS PAYROLL-OFF	605100	PROFESSIONAL SERVICE	NWN	F1	55,415.52	92110879	11.12%	Payroll	$	6,160.82	$ 49,254.70	$ 55,415.52
921000	10879	OFFICERS PAYROLL-OFF	612100	MEALS AND ENTERTAIN	NWN	F1	0.00	92110879	11.12%	Payroll	$	-	$ -	$ -
921000	10879	OFFICERS PAYROLL-OFF	612200	TRAVEL IN TERRITORY	NWN	F1	1,270.70	92110879	11.12%	Payroll	$	141.27	$ 1,129.43	$ 1,270.70
921000	10879	OFFICERS PAYROLL-OFF	613100	CONFERENCE TRAVEL	NWN	F1	0.00	92110879	11.12%	Payroll	$	-	$ -	$ -
921000	10879	OFFICERS PAYROLL-OFF	613200	BUSINESS TRAVEL	NWN	F1	792.11	92110879	11.12%	Payroll	$	88.06	$ 704.05	$ 792.11
921000	10884	GENERAL CORPORATE-OF	601900	DUES/MEMBERSHIP	NWN	F1	26,761.65	92110884	11.80%	3-factor	$	3,157.87	$ 23,603.78	$ 26,761.65
921000	10884	GENERAL CORPORATE-OF	605100	PROFESSIONAL SERVICE	NWN	F1	103,885.47	92110884	11.80%	3-factor	$	12,258.49	$ 91,626.98	$ 103,885.47
921000	10923	VP, ENGN & UTIL OPS	601100	EDUCATION	NWN	F1	0.00	92110923	11.80%	3-factor	$	-	$ -	$ -
921000	10923	VP, ENGN & UTIL OPS	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	1,820.22	92110923	11.80%	3-factor	$	214.79	$ 1,605.43	$ 1,820.22
921000	10923	VP, ENGN & UTIL OPS	601900	DUES/MEMBERSHIP	NWN	F1	2,125.00	92110923	11.80%	3-factor	$	250.75	$ 1,874.25	$ 2,125.00
921000	10923	VP, ENGN & UTIL OPS	602466	P CARD UNCODED CHARG	NWN	F1	1,021.26	92110923	11.80%	3-factor	$	120.51	$ 900.75	$ 1,021.26
921000	10923	VP, ENGN & UTIL OPS	602700	TELEPHONE	NWN	F1	16.00	92110923	11.80%	3-factor	$	1.89	$ 14.11	$ 16.00
921000	10923	VP, ENGN & UTIL OPS	603000	OFFICE SUPPLIES	NWN	F1	127.16	92110923	11.80%	3-factor	$	15.00	$ 112.16	$ 127.16
921000	10923	VP, ENGN & UTIL OPS	603300	REFRESHMENTS	NWN	F1	10,206.57	92110923	11.80%	3-factor	$	1,204.38	$ 9,002.19	$ 10,206.57
921000	10923	VP, ENGN & UTIL OPS	604700	PARKING	NWN	F1	216.85	92110923	11.80%	3-factor	$	25.59	$ 191.26	$ 216.85
921000	10923	VP, ENGN & UTIL OPS	612100	MEALS AND ENTERTAIN	NWN	F1	399.92	92110923	11.80%	3-factor	$	47.19	$ 352.73	$ 399.92
921000	10923	VP, ENGN & UTIL OPS	612200	TRAVEL IN TERRITORY	NWN	F1	753.00	92110923	11.80%	3-factor	$	88.85	$ 664.15	$ 753.00
921000	10923	VP, ENGN & UTIL OPS	613100	CONFERENCE TRAVEL	NWN	F1	2,296.43	92110923	11.80%	3-factor	$	270.98	$ 2,025.45	$ 2,296.43
921000	10923	VP, ENGN & UTIL OPS	613200	BUSINESS TRAVEL	NWN	F1	1,438.76	92110923	11.80%	3-factor	$	169.77	$ 1,268.99	$ 1,438.76
921000	10923	VP, ENGN & UTIL OPS	622000	EMPLOYEE AWARDS	NWN	F1	1,103.99	92110923	11.80%	3-factor	$	130.27	$ 973.72	$ 1,103.99
921000	10923	VP, ENGN & UTIL OPS	622200	NON EMPLOYEE GIFTS	NWN	F1	493.74	92110923	11.80%	3-factor	$	58.26	$ 435.48	$ 493.74
921000	11126	VP RATES AND REG OFF	601100	EDUCATION	NWN	F1	3,090.00	92111126	11.80%	3-factor	$	364.62	$ 2,725.38	$ 3,090.00
921000	11126	VP RATES AND REG OFF	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	63.00	92111126	11.80%	3-factor	$	7.43	$ 55.57	$ 63.00
921000	11126	VP RATES AND REG OFF	601900	DUES/MEMBERSHIP	NWN	F1	349.93	92111126	11.80%	3-factor	$	41.29	$ 308.64	$ 349.93
921000	11126	VP RATES AND REG OFF	602466	P CARD UNCODED CHARG	NWN	F1	364.78	92111126	11.80%	3-factor	$	43.04	$ 321.74	$ 364.78
921000	11126	VP RATES AND REG OFF	602700	TELEPHONE	NWN	F1	40.00	92111126	11.80%	3-factor	$	4.72	$ 35.28	$ 40.00
921000	11126	VP RATES AND REG OFF	603000	OFFICE SUPPLIES	NWN	F1	0.00	92111126	11.80%	3-factor	$	-	$ -	$ -
921000	11126	VP RATES AND REG OFF	603200	BOOKS AND MAGAZINES	NWN	F1	749.88	92111126	11.80%	3-factor	$	88.49	$ 661.39	$ 749.88
921000	11126	VP RATES AND REG OFF	603300	REFRESHMENTS	NWN	F1	193.49	92111126	11.80%	3-factor	$	22.83	$ 170.66	$ 193.49
921000	11126	VP RATES AND REG OFF	604700	PARKING	NWN	F1	287.00	92111126	11.80%	3-factor	$	33.87	$ 253.13	$ 287.00
921000	11126	VP RATES AND REG OFF	612100	MEALS AND ENTERTAIN	NWN	F1	1,574.43	92111126	11.80%	3-factor	$	185.78	$ 1,388.65	$ 1,574.43
921000	11126	VP RATES AND REG OFF	613100	CONFERENCE TRAVEL	NWN	F1	5,301.39	92111126	11.80%	3-factor	$	625.56	$ 4,675.83	$ 5,301.39
921000	11126	VP RATES AND REG OFF	613200	BUSINESS TRAVEL	NWN	F1	0.00	92111126	11.80%	3-factor	$	-	$ -	$ -
921000	11126	VP RATES AND REG OFF	622000	EMPLOYEE AWARDS	NWN	F1	1,150.68	92111126	11.80%	3-factor	$	135.78	$ 1,014.90	$ 1,150.68
921000	11127	FACILITIES MGMNT-OFF	602466	P CARD UNCODED CHARG	NWN	F1	37.83	92111127	11.80%	3-factor	$	4.46	$ 33.37	$ 37.83
921000	11129	ACCOUNTING RENEWABLE	601100	EDUCATION	NWN	F1	359.00	92111129	12.17%	Customers-All	$	43.69	$ 315.31	$ 359.00
921000	11129	ACCOUNTING RENEWABLE	601900	DUES/MEMBERSHIP	NWN	F1	255.00	92111129	12.17%	Customers-All	$	31.03	$ 223.97	$ 255.00
921000	11129	ACCTG RENEWABLES 921	601100	EDUCATION	NWN	F1	359.00	92111129	12.17%	Customers-All	$	43.69	$ 315.31	$ 359.00
921000	11129	ACCTG RENEWABLES 921	601900	DUES/MEMBERSHIP	NWN	F1	255.00	92111129	12.17%	Customers-All	$	31.03	$ 223.97	$ 255.00
921000	11132	LEGAL FEES-OFFICE ST	605000	LEGAL FEES	NWN	F1	209,524.55	92111132	11.80%	3-factor	$	24,723.90	$ 184,800.65	$ 209,524.55
921000	11133	LEGAL FEES PROCURMEN	605000	LEGAL FEES	NWN	F1	286,441.50	92111133	11.80%	3-factor	$	33,800.10	$ 252,641.40	$ 286,441.50
921000	11134	RECORDS MANAGEMENT-O	601900	DUES/MEMBERSHIP	NWN	F1	175.00	92111134	11.80%	3-factor	$	20.65	$ 154.35	$ 175.00
921000	11134	RECORDS MANAGEMENT-O	602100	OTHER CONTRACT WORK	NWN	F1	154,283.65	92111134	11.80%	3-factor	$	18,205.47	$ 136,078.18	$ 154,283.65
921000	11134	RECORDS MANAGEMENT-O	602466	P CARD UNCODED CHARG	NWN	F1	0.00	92111134	11.80%	3-factor	$	-	$ -	$ -
921000	11134	RECORDS MANAGEMENT-O	603300	REFRESHMENTS	NWN	F1	90.20	92111134	11.80%	3-factor	$	10.64	$ 79.56	$ 90.20
921000	11261	CORP SEC LEGAL FEES-	605000	LEGAL FEES	NWN	F1	0.00	92111261	11.80%	3-factor	$	-	$ -	$ -
921000	11262	LEGAL FEES PROCURMEN	605000	LEGAL FEES	NWN	F1	58,603.85	92111262	11.80%	3-factor	$	6,915.25	$ 51,688.60	$ 58,603.85
921000	11262	LEGAL FEES PROCURMEN	606000	PENSION CONTRIBUTION	NWN	F1	0.00	92111262	11.80%	3-factor	$	-	$ -	$ -
921000	11263	LEGAL FEES GAS SPLY-	605000	LEGAL FEES	NWN	F1	20,339.82	92111263	11.80%	3-factor	$	2,400.10	$ 17,939.72	$ 20,339.82
921000	11425	INF SECUR COMP&QA-SE	601100	EDUCATION	NWN	F1	0.00	92111425	12.17%	Customers-All	$	-	$ -	$ -
921000	11425	INF SECUR COMP&QA-SE	602100	OTHER CONTRACT WORK	NWN	F1	0.00	92111425	12.17%	Customers-All	$	-	$ -	$ -
921000	11425	INF SECUR COMP&QA-SE	602466	P CARD UNCODED CHARG	NWN	F1	84.96	92111425	12.17%	Customers-All	$	10.34	$ 74.62	$ 84.96
921000	11425	INF SECUR COMP&QA-SE	603200	BOOKS AND MAGAZINES	NWN	F1	171.00	92111425	12.17%	Customers-All	$	20.81	$ 150.19	$ 171.00
921000	11425	INF SECUR COMP&QA-SE	603300	REFRESHMENTS	NWN	F1	11.00	92111425	12.17%	Customers-All	$	1.34	$ 9.66	$ 11.00
921000	11425	INF SECUR COMP&QA-SE	606801	PLANT TRANSFERS	NWN	F1	0.00	92111425	12.17%	Customers-All	$	-	$ -	$ -
921000	11425	INF SECUR COMP&QA-SE	612100	MEALS AND ENTERTAIN	NWN	F1	0.00	92111425	12.17%	Customers-All	$	-	$ -	$ -
921000	11425	INF SECUR COMP&QA-SE	613200	BUSINESS TRAVEL	NWN	F1	797.55	92111425	12.17%	Customers-All	$	97.06	$ 700.49	$ 797.55
921000	11426	INF SECUR COMP&QA-CO	603300	REFRESHMENTS	NWN	F1	13.50	92111426	12.17%	Customers-All	$	1.64	$ 11.86	$ 13.50
921000	11427	IT GAS MGT SYSS-PIPE	601100	EDUCATION	NWN	F1	2,544.90	92111427	11.80%	3-factor	$	300.30	$ 2,244.60	$ 2,544.90
921000	11427	IT GAS MGT SYSS-PIPE	601400	MATERIALS	NWN	F1	0.00	92111427	11.80%	3-factor	$	-	$ -	$ -
921000	11427	IT GAS MGT SYSS-PIPE	601401	MATERIALS - CONS INV	NWN	F1	167.81	92111427	11.80%	3-factor	$	19.80	$ 148.01	$ 167.81
921000	11427	IT GAS MGT SYSS-PIPE	602100	OTHER CONTRACT WORK	NWN	F1	25,600.00	92111427	11.80%	3-factor	$	3,020.80	$ 22,579.20	$ 25,600.00
921000	11427	IT GAS MGT SYSS-PIPE	602466	P CARD UNCODED CHARG	NWN	F1	145.13	92111427	11.80%	3-factor	$	17.13	$ 128.00	$ 145.13
921000	11427	IT GAS MGT SYSS-PIPE	603000	OFFICE SUPPLIES	NWN	F1	58.50	92111427	11.80%	3-factor	$	6.90	$ 51.60	$ 58.50
921000	11427	IT GAS MGT SYSS-PIPE	603400	TOOL EXPENSE	NWN	F1	119.99	92111427	11.80%	3-factor	$	14.16	$ 105.83	$ 119.99
921000	11427	IT GAS MGT SYSS-PIPE	604700	PARKING	NWN	F1	38.20	92111427	11.80%	3-factor	$	4.51	$ 33.69	$ 38.20
921000	11427	IT GAS MGT SYSS-PIPE	612100	MEALS AND ENTERTAIN	NWN	F1	94.04	92111427	11.80%	3-factor	$	11.10	$ 82.94	$ 94.04
921000	11427	IT GAS MGT SYSS-PIPE	612200	TRAVEL IN TERRITORY	NWN	F1	24.07	92111427	11.80%	3-factor	$	2.84	$ 21.23	$ 24.07
921000	11428	IT GAS MGT SYSS-COMM	601100	EDUCATION	NWN	F1	405.80	92111428	12.17%	Customers-All	$	49.39	$ 356.41	$ 405.80
921000	11428	IT GAS MGT SYSS-COMM	601400	MATERIALS	NWN	F1	4,409.78	92111428	12.17%	Customers-All	$	536.67	$ 3,873.11	$ 4,409.78
921000	11428	IT GAS MGT SYSS-COMM	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	492.00	92111428	12.17%	Customers-All	$	59.88	$ 432.12	$ 492.00
921000	11428	IT GAS MGT SYSS-COMM	601700	EQUIPMENT	NWN	F1	119.98	92111428	12.17%	Customers-All	$	14.60	$ 105.38	$ 119.98
921000	11428	IT GAS MGT SYSS-COMM	602466	P CARD UNCODED CHARG	NWN	F1	2,148.70	92111428	12.17%	Customers-All	$	261.50	$ 1,887.20	$ 2,148.70
921000	11428	IT GAS MGT SYSS-COMM	602800	POSTAGE	NWN	F1	27.74	92111428	12.17%	Customers-All	$	3.38	$ 24.36	$ 27.74
921000	11428	IT GAS MGT SYSS-COMM	603000	OFFICE SUPPLIES	NWN	F1	34.27	92111428	12.17%	Customers-All	$	4.17	$ 30.10	$ 34.27
921000	11428	IT GAS MGT SYSS-COMM	603200	BOOKS AND MAGAZINES	NWN	F1	0.00	92111428	12.17%	Customers-All	$	-	$ -	$ -
921000	11428	IT GAS MGT SYSS-COMM	603300	REFRESHMENTS	NWN	F1	219.93	92111428	12.17%	Customers-All	$	26.77	$ 193.16	$ 219.93

NW Natural
Admin Transfer Allocation Factor
Test Year Ending March 31, 2025

$ 71,068,305.98

FERC Account	Cost Center	Cost Center Description	GL Account	GL Account Long Name	Chart of Accounts	Fiscal Year Period / Measures	Amount / Overall Result	SORTER	ALLOCATION FACTOR	ALLOCATION METHOD	Admin Transfer Factor / TOTAL	12.1429% / $ 8,629,765.83 WA	87.8571% / $ 62,438,540.15 OR	$ 71,068,305.98 SYSTEM
							$							
921000	11428	IT GAS MGT SYSS-COMM	603400	TOOL EXPENSE	NWN	F1	52.19	92111428	12.17%	Customers-All	$ 6.35	$ 45.84	$ 52.19	
921000	11428	IT GAS MGT SYSS-COMM	604700	PARKING	NWN	F1	0.00	92111428	12.17%	Customers-All	$ -	$ -	$ -	
921000	11428	IT GAS MGT SYSS-COMM	605500	REPAIRS AND MAINT	NWN	F1	0.00	92111428	12.17%	Customers-All	$ -	$ -	$ -	
921000	11428	IT GAS MGT SYSS-COMM	605800	MEAL TICKETS	NWN	F1	588.00	92111428	12.17%	Customers-All	$ 71.56	$ 516.44	$ 588.00	
921000	11428	IT GAS MGT SYSS-COMM	606500	UNLEADED FUEL	NWN	F1	80.52	92111428	12.17%	Customers-All	$ 9.80	$ 70.72	$ 80.52	
921000	11428	IT GAS MGT SYSS-COMM	607700	SMALL TOOLS	NWN	F1	296.55	92111428	12.17%	Customers-All	$ 36.09	$ 260.46	$ 296.55	
921000	11428	IT GAS MGT SYSS-COMM	613200	BUSINESS TRAVEL	NWN	F1	773.55	92111428	12.17%	Customers-All	$ 94.14	$ 679.41	$ 773.55	
921000	11428	IT GAS MGT SYSS-COMM	685800	MEAL TICKETS SECONDARY	NWN	F1	(472.00)	92111428	12.17%	Customers-All	$ (57.44)	$ (414.56)	$ (472.00)	
921000	11429	ENT APPLICATIONS-SAP	602466	P CARD UNCODED CHARG	NWN	F1	1,837.30	92111429	12.17%	Customers-All	$ 223.60	$ 1,613.70	$ 1,837.30	
921000	11429	ENT APPLICATIONS-SAP	606200	PERMITS AND FEES	NWN	F1	820.00	92111429	12.17%	Customers-All	$ 99.79	$ 720.21	$ 820.00	
921000	11429	ENT APPLICATIONS-SAP	612100	MEALS AND ENTERTAIN	NWN	F1	0.00	92111429	12.17%	Customers-All	$ -	$ -	$ -	
921000	11429	ENT APPLICATIONS-SAP	613200	BUSINESS TRAVEL	NWN	F1	0.00	92111429	12.17%	Customers-All	$ -	$ -	$ -	
921000	11430	ENT APPLICATIONS-COM	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	259.70	92111430	12.17%	Customers-All	$ 31.61	$ 228.09	$ 259.70	
921000	11430	ENT APPLICATIONS-COM	602466	P CARD UNCODED CHARG	NWN	F1	70.00	92111430	12.17%	Customers-All	$ 8.52	$ 61.48	$ 70.00	
921000	11430	ENT APPLICATIONS-COM	603300	REFRESHMENTS	NWN	F1	8.88	92111430	12.17%	Customers-All	$ 1.08	$ 7.80	$ 8.88	
921000	11430	ENT APPLICATIONS-COM	604700	PARKING	NWN	F1	20.41	92111430	12.17%	Customers-All	$ 2.48	$ 17.93	$ 20.41	
921000	11430	ENT APPLICATIONS-COM	605800	MEAL TICKETS	NWN	F1	88.20	92111430	12.17%	Customers-All	$ 10.73	$ 77.47	$ 88.20	
921000	11430	ENT APPLICATIONS-COM	612100	MEALS AND ENTERTAIN	NWN	F1	83.28	92111430	12.17%	Customers-All	$ 10.14	$ 73.14	$ 83.28	
921000	11430	ENT APPLICATIONS-COM	613100	CONFERENCE TRAVEL	NWN	F1	274.73	92111430	12.17%	Customers-All	$ 33.43	$ 241.30	$ 274.73	
921000	11430	ENT APPLICATIONS-COM	613200	BUSINESS TRAVEL	NWN	F1	0.00	92111430	12.17%	Customers-All	$ -	$ -	$ -	
921000	11431	ENT APPLICATIONS-CIS	602466	P CARD UNCODED CHARG	NWN	F1	47.90	92111431	12.17%	Customers-All	$ 5.83	$ 42.07	$ 47.90	
921000	11431	ENT APPLICATIONS-CIS	603300	REFRESHMENTS	NWN	F1	10.25	92111431	12.17%	Customers-All	$ 1.25	$ 9.00	$ 10.25	
921000	11431	ENT APPLICATIONS-CIS	613200	BUSINESS TRAVEL	NWN	F1	0.00	92111431	12.17%	Customers-All	$ -	$ -	$ -	
921000	11541	ENT APPLICAT-DR/AEDP	602100	OTHER CONTRACT WORK	NWN	F1	36,694.40	92111541	12.17%	Customers-All	$ 4,465.71	$ 32,228.69	$ 36,694.40	
921000	11541	ENT APPLICAT-DR/AEDP	605600	SOFTWARE MAINT	NWN	F1	10,760.77	92111541	12.17%	Customers-All	$ 1,309.59	$ 9,451.18	$ 10,760.77	
921000	75004	CORP COMMUNICATIONS-	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	81.22	92175004	11.80%	3-factor	$ 9.58	$ 71.64	$ 81.22	
921000	75004	CORP COMMUNICATIONS-	602466	P CARD UNCODED CHARG	NWN	F1	(81.22)	92175004	11.80%	3-factor	$ (9.58)	$ (71.64)	$ (81.22)	
921000	75006	UNFORESEEN EVENTS-UN	602100	OTHER CONTRACT WORK	NWN	F1	0.00	92175006	11.80%	3-factor	$ -	$ -	$ -	
921000	75006	UNFORESEEN EVENTS-UN	602400	MISCELLANEOUS	NWN	F1	(89,775.11)	92175006	11.80%	3-factor	$ (10,593.46)	$ (79,181.65)	$ (89,775.11)	
921000	75006	UNFORESEEN EVENTS-UN	624200	CLAIMS & ACCRUALS	NWN	F1	5,717.66	92175006	11.80%	3-factor	$ 674.68	$ 5,042.98	$ 5,717.66	
921000	75008	GEN ADMIN STAFF-UNRE	601400	MATERIALS	NWN	F1	24.16	92175008	11.80%	3-factor	$ 2.85	$ 21.31	$ 24.16	
921000	75008	GEN ADMIN STAFF-UNRE	602466	P CARD UNCODED CHARG	NWN	F1	0.00	92175008	11.80%	3-factor	$ -	$ -	$ -	
921000	75008	GEN ADMIN STAFF-UNRE	603300	REFRESHMENTS	NWN	F1	236.29	92175008	11.80%	3-factor	$ 27.88	$ 208.41	$ 236.29	
921000	75008	GEN ADMIN STAFF-UNRE	612100	MEALS AND ENTERTAIN	NWN	F1	1,056.10	92175008	11.80%	3-factor	$ 124.62	$ 931.48	$ 1,056.10	
921000	75009	CEO-UNRECOVERA	602466	P CARD UNCODED CHARG	NWN	F1	(1,865.73)	92175009	11.80%	3-factor	$ (220.16)	$ (1,645.57)	$ (1,865.73)	
921000	75009	CEO-UNRECOVERA	612100	MEALS AND ENTERTAIN	NWN	F1	2,021.08	92175009	11.80%	3-factor	$ 238.49	$ 1,782.59	$ 2,021.08	
921000	75009	CEO-UNRECOVERA	613100	CONFERENCE TRAVEL	NWN	F1	4,027.33	92175009	11.80%	3-factor	$ 475.22	$ 3,552.11	$ 4,027.33	
921000	75009	CEO-UNRECOVERA	613200	BUSINESS TRAVEL	NWN	F1	4,903.39	92175009	11.80%	3-factor	$ 578.60	$ 4,324.79	$ 4,903.39	
921000	75010	VP-CH PA&SUSTAIN-UN	601100	EDUCATION	NWN	F1	10.00	92175010	11.80%	3-factor	$ 1.18	$ 8.82	$ 10.00	
921000	75010	VP-CH PA&SUSTAIN-UN	602466	P CARD UNCODED CHARG	NWN	F1	1,638.40	92175010	11.80%	3-factor	$ 193.33	$ 1,445.07	$ 1,638.40	
921000	75010	VP-CH PA&SUSTAIN-UN	603300	REFRESHMENTS	NWN	F1	175.00	92175010	11.80%	3-factor	$ 20.65	$ 154.35	$ 175.00	
921000	75010	VP-CH PA&SUSTAIN-UN	612100	MEALS AND ENTERTAIN	NWN	F1	908.54	92175010	11.80%	3-factor	$ 107.21	$ 801.33	$ 908.54	
921000	75010	VP-CH PA&SUSTAIN-UN	613100	CONFERENCE TRAVEL	NWN	F1	3,030.20	92175010	11.80%	3-factor	$ 357.56	$ 2,672.64	$ 3,030.20	
921000	75010	VP-CH PA&SUSTAIN-UN	613200	BUSINESS TRAVEL	NWN	F1	0.00	92175010	11.80%	3-factor	$ -	$ -	$ -	
921000	75011	EVP-CHIEF FIN OFF-UN	602466	P CARD UNCODED CHARG	NWN	F1	274.53	92175011	11.80%	3-factor	$ 32.39	$ 242.14	$ 274.53	
921000	75011	EVP-CHIEF FIN OFF-UN	612100	MEALS AND ENTERTAIN	NWN	F1	225.60	92175011	11.80%	3-factor	$ 26.62	$ 198.98	$ 225.60	
921000	75011	EVP-CHIEF FIN OFF-UN	613100	CONFERENCE TRAVEL	NWN	F1	1,419.01	92175011	11.80%	3-factor	$ 167.44	$ 1,251.57	$ 1,419.01	
921000	75011	EVP-CHIEF FIN OFF-UN	613200	BUSINESS TRAVEL	NWN	F1	2,987.98	92175011	11.80%	3-factor	$ 352.58	$ 2,635.40	$ 2,987.98	
921000	75013	CEO-UNRECOV EXP	602466	P CARD UNCODED CHARG	NWN	F1	(700.17)	92175013	11.80%	3-factor	$ (82.62)	$ (617.55)	$ (700.17)	
921000	75013	CEO-UNRECOV EXP	612100	MEALS AND ENTERTAIN	NWN	F1	6,204.47	92175013	11.80%	3-factor	$ 732.13	$ 5,472.34	$ 6,204.47	
921000	75013	CEO-UNRECOV EXP	613100	CONFERENCE TRAVEL	NWN	F1	363.02	92175013	11.80%	3-factor	$ 42.84	$ 320.18	$ 363.02	
921000	75013	CEO-UNRECOV EXP	613200	BUSINESS TRAVEL	NWN	F1	3,745.81	92175013	11.80%	3-factor	$ 442.01	$ 3,303.80	$ 3,745.81	
921000	75018	LEGAL FEES-RISK-UNRE	605000	LEGAL FEES	NWN	F1	13,598.85	92175018	11.80%	3-factor	$ 1,604.66	$ 11,994.19	$ 13,598.85	
921000	75019	SR VP & GEN COUNSEL-	602466	P CARD UNCODED CHARG	NWN	F1	0.00	92175019	11.80%	3-factor	$ -	$ -	$ -	
921000	75019	SR VP & GEN COUNSEL-	612100	MEALS AND ENTERTAIN	NWN	F1	605.41	92175019	11.80%	3-factor	$ 71.44	$ 533.97	$ 605.41	
921000	75019	SR VP & GEN COUNSEL-	613100	CONFERENCE TRAVEL	NWN	F1	3,104.24	92175019	11.80%	3-factor	$ 366.30	$ 2,737.94	$ 3,104.24	
921000	75020	VP, CAO, CONT&TREAS-	602466	P CARD UNCODED CHARG	NWN	F1	(1,799.57)	92175020	11.80%	3-factor	$ (212.35)	$ (1,587.22)	$ (1,799.57)	
921000	75020	VP, CAO, CONT&TREAS-	612100	MEALS AND ENTERTAIN	NWN	F1	72.05	92175020	11.80%	3-factor	$ 8.50	$ 63.55	$ 72.05	
921000	75020	VP, CAO, CONT&TREAS-	613100	CONFERENCE TRAVEL	NWN	F1	1,227.73	92175020	11.80%	3-factor	$ 144.87	$ 1,082.86	$ 1,227.73	
921000	75020	VP, CAO, CONT&TREAS-	613200	BUSINESS TRAVEL	NWN	F1	1,418.57	92175020	11.80%	3-factor	$ 167.39	$ 1,251.18	$ 1,418.57	
921000	75022	INVESTOR RELATIONS-U	602466	P CARD UNCODED CHARG	NWN	F1	(1,799.57)	92175022	11.80%	3-factor	$ (212.35)	$ (1,587.22)	$ (1,799.57)	
921000	75022	INVESTOR RELATIONS-U	613100	CONFERENCE TRAVEL	NWN	F1	381.00	92175022	11.80%	3-factor	$ 44.96	$ 336.04	$ 381.00	
921000	75022	INVESTOR RELATIONS-U	613200	BUSINESS TRAVEL	NWN	F1	1,418.57	92175022	11.80%	3-factor	$ 167.39	$ 1,251.18	$ 1,418.57	
921000	75023	VP & CORPORATE SEC-U	613100	CONFERENCE TRAVEL	NWN	F1	1,793.37	92175023	11.80%	3-factor	$ 211.62	$ 1,581.75	$ 1,793.37	
921000	75026	LEGAL FEES-RATES-NON	605000	LEGAL FEES	NWN	F1	(16,189.00)	92175026	30.00%	Regulatory	$ (4,856.70)	$ (11,332.30)	$ (16,189.00)	
921000	75027	PRESIDENT- UNRECOVER	602466	P CARD UNCODED CHARG	NWN	F1	2,830.91	92175027	11.80%	3-factor	$ 334.05	$ 2,496.86	$ 2,830.91	
921000	75027	PRESIDENT- UNRECOVER	603200	BOOKS AND MAGAZINES	NWN	F1	2,150.00	92175027	11.80%	3-factor	$ 253.70	$ 1,896.30	$ 2,150.00	
921000	75027	PRESIDENT- UNRECOVER	603300	REFRESHMENTS	NWN	F1	1,110.20	92175027	11.80%	3-factor	$ 131.00	$ 979.20	$ 1,110.20	
921000	75027	PRESIDENT- UNRECOVER	612100	MEALS AND ENTERTAIN	NWN	F1	76.45	92175027	11.80%	3-factor	$ 9.02	$ 67.43	$ 76.45	
921000	75027	PRESIDENT- UNRECOVER	613100	CONFERENCE TRAVEL	NWN	F1	584.10	92175027	11.80%	3-factor	$ 68.92	$ 515.18	$ 584.10	
921000	75027	PRESIDENT- UNRECOVER	613200	BUSINESS TRAVEL	NWN	F1	1,484.40	92175027	11.80%	3-factor	$ 175.16	$ 1,309.24	$ 1,484.40	
921000	75029	VP, CHF HR&DVRY OFF-	602466	P CARD UNCODED CHARG	NWN	F1	22.50	92175029	11.80%	3-factor	$ 2.66	$ 19.85	$ 22.50	
921000	75029	VP, CHF HR&DVRY OFF-	612100	MEALS AND ENTERTAIN	NWN	F1	34.62	92175029	11.80%	3-factor	$ 4.09	$ 30.53	$ 34.62	
921000	75029	VP, CHF HR&DVRY OFF-	613100	CONFERENCE TRAVEL	NWN	F1	1,013.20	92175029	11.80%	3-factor	$ 119.56	$ 893.64	$ 1,013.20	
921000	75030	VP RATES AND REG NON	602466	P CARD UNCODED CHARG	NWN	F1	(525.05)	92175030	30.00%	regulatory	$ (157.52)	$ (367.54)	$ (525.05)	
921000	75030	VP RATES AND REG NON	603300	REFRESHMENTS	NWN	F1	0.00	92175030	30.00%	regulatory	$ -	$ -	$ -	
921000	75030	VP RATES AND REG NON	612100	MEALS AND ENTERTAIN	NWN	F1	533.94	92175030	30.00%	regulatory	$ 160.18	$ 373.76	$ 533.94	
921000	75030	VP RATES AND REG NON	613100	CONFERENCE TRAVEL	NWN	F1	2,898.81	92175030	30.00%	regulatory	$ 869.64	$ 2,029.17	$ 2,898.81	
921000	75030	VP RATES AND REG NON	613200	BUSINESS TRAVEL	NWN	F1	0.00	92175030	30.00%	regulatory	$ -	$ -	$ -	
921000	75031	CONSR RELATIONS-NONR	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	7.37	92175031	12.17%	Customers-All	$ 0.90	$ 6.47	$ 7.37	
921000	75031	CONSR RELATIONS-NONR	602100	OTHER CONTRACT WORK	NWN	F1	4,483.35	92175031	12.17%	Customers-All	$ 545.62	$ 3,937.73	$ 4,483.35	
921000	75031	CONSR RELATIONS-NONR	602466	P CARD UNCODED CHARG	NWN	F1	0.00	92175031	12.17%	Customers-All	$ -	$ -	$ -	
921000	75031	CONSR RELATIONS-NONR	603300	REFRESHMENTS	NWN	F1	75.95	92175031	12.17%	Customers-All	$ 9.24	$ 66.71	$ 75.95	
921000	75031	CONSR RELATIONS-NONR	604600	DEALER RELATIONS	NWN	F1	702.23	92175031	12.17%	Customers-All	$ 85.46	$ 616.77	$ 702.23	
921000	75031	CONSR RELATIONS-NONR	607500	CORPORATE IDENTITY	NWN	F1	6,926.34	92175031	12.17%	Customers-All	$ 842.94	$ 6,083.40	$ 6,926.34	
921000	75031	CONSR RELATIONS-NONR	612100	MEALS AND ENTERTAIN	NWN	F1	1,300.00	92175031	12.17%	Customers-All	$ 158.21	$ 1,141.79	$ 1,300.00	
921000	75032	STRATEGIC PLAN-NONRE	601900	DUES/MEMBERSHIP	NWN	F1	225.00	92175032	11.80%	3-factor	$ 26.55	$ 198.45	$ 225.00	
921000	75032	STRATEGIC PLAN-NONRE	602466	P CARD UNCODED CHARG	NWN	F1	0.00	92175032	11.80%	3-factor	$ -	$ -	$ -	
921000	75032	STRATEGIC PLAN-NONRE	605100	PROFESSIONAL SERVICE	NWN	F1	80,462.50	92175032	11.80%	3-factor	$ 9,494.58	$ 70,967.93	$ 80,462.50	
921000	80037	SEVERANCE-OFFICE STA	605100	PROFESSIONAL SERVICE	NWN	F1	13,000.00	92180037	11.80%	3-factor	$ 1,534.00	$ 11,466.00	$ 13,000.00	
924000	10789	INS-PROPERTY INS-LIA	602800	POSTAGE	NWN	F1	44.34	92410789	11.80%	3-factor	$ 5.23	$ 39.11	$ 44.34	
924000	10789	INS-PROPERTY INS-LIA	603900	INSURANCE	NWN	F1	6,031,338.57	92410789	11.80%	3-factor	$ 711,697.95	$ 5,319,640.62	$ 6,031,338.57	
931000	10183	CONSR RELATIONS-EVT	602300	RENTS AND LEASES	NWN	F1	0.00	93110183	11.80%	3-factor	$ -	$ -	$ -	
931000	10183	CONSR RELATIONS-EVT	602360	ROU UTIL LEA RENT EX	NWN	F1	34,663.05	93110183	11.80%	3-factor	$ 4,090.24	$ 30,572.81	$ 34,663.05	
931000	10183	CONSR RELATIONS-EVT	602365	ROU UTIL LEASE INTEREST EXPENSE	NWN	F1	3,088.95	93110183	11.80%	3-factor	$ 364.50	$ 2,724.45	$ 3,088.95	
931000	10272	IT RENTS AMORT	604402	AMORTIZATION	NWN	F1	32,998.98	93110272	11.80%	3-factor	$ 3,893.88	$ 29,105.10	$ 32,998.98	
931000	10273	IT RADIO TOWER-931	602300	RENTS AND LEASES	NWN	F1	33,541.50	93110273	11.80%	3-factor	$ 3,957.90	$ 29,583.60	$ 33,541.50	
931000	10273	IT RADIO TOWER-931	602360	ROU UTIL LEA RENT EX	NWN	F1	31,333.72	93110273	11.80%	3-factor	$ 3,697.38	$ 27,636.34	$ 31,333.72	
931000	10273	IT RADIO TOWER-931	602365	ROU UTIL LEASE INTEREST EXPENSE	NWN	F1	5,725.96	93110273	11.80%	3-factor	$ 675.66	$ 5,050.30	$ 5,725.96	
931000	10274	IT DATA LEASE	602360	ROU UTIL LEA RENT EX	NWN	F1	117,843.59	93110274	11.80%	3-factor	$ 13,905.54	$ 103,938.05	$ 117,843.59	
931000	10274	IT DATA LEASE	602362	NON-LEASE COMP EXP	NWN	F1	43,795.27	93110274	11.80%	3-factor	$ 5,167.84	$ 38,627.43	$ 43,795.27	
931000	10274	IT DATA LEASE	602365	ROU UTIL LEASE INTEREST EXPENSE	NWN	F1	1,586.58	93110274	11.80%	3-factor	$ 187.22	$ 1,399.36	$ 1,586.58	
931000	10591	250TAYLOR-FACILITIES	601400	MATERIALS	NWN	F1	2,251.61	93110591	11.80%	3-factor	$ 265.69	$ 1,985.92	$ 2,251.61	
931000	10591	250TAYLOR-FACILITIES	601401	MATERIALS - CONS INV	NWN	F1	475.99	93110591	11.80%	3-factor	$ 56.17	$ 419.82	$ 475.99	
931000	10591	250TAYLOR-FACILITIES	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1	3.85	93110591	11.80%	3-factor	$ 0.45	$ 3.40	$ 3.85	
931000	10591	250TAYLOR-FACILITIES	601700	EQUIPMENT	NWN	F1	2,446.86	93110591	11.80%	3-factor	$ 288.73	$ 2,158.13	$ 2,446.86	
931000	10591	250TAYLOR-FACILITIES	601800	FURNITURE	NWN	F1	22,149.06	93110591	11.80%	3-factor	$ 2,613.59	$ 19,535.47	$ 22,149.06	
931000	10591	250TAYLOR-FACILITIES	602100	OTHER CONTRACT WORK	NWN	F1	2,993.89	93110591	11.80%	3-factor	$ 353.28	$ 2,640.61	$ 2,993.89	
931000	10591	250TAYLOR-FACILITIES	602362	NON-LEASE COMP EXP	NWN	F1	2,159,318.96	93110591	11.80%	3-factor	$ 254,799.64	$ 1,904,519.32	$ 2,159,318.96	
931000	10591	250TAYLOR-FACILITIES	602466	P CARD UNCODED CHARG	NWN	F1	0.00	93110591	11.80%	3-factor	$ -	$ -	$ -	
931000	10591	250TAYLOR-FACILITIES	603000	OFFICE SUPPLIES	NWN	F1	4,995.16	93110591	11.80%	3-factor	$ 589.43	$ 4,405.73	$ 4,995.16	
931000	10591	250TAYLOR-FACILITIES	604400	AMORTIZATION	NWN	F1	1,444,914.31	93110591	11.80%	3-factor	$ 170,499.89	$ 1,274,414.42	$ 1,444,914.31	
931000	10591	250TAYLOR-FACILITIES	604600	DEALER RELATIONS	NWN	F1	115.42	93110591	11.80%	3-factor	$ 13.62	$ 101.80	$ 115.42	
931000	10591	250TAYLOR-FACILITIES	604601	PARTNER HOSPITALITY	NWN	F1	23.87	93110591	11.80%	3-factor	$ 2.82	$ 21.05	$ 23.87	
931000	10591	250TAYLOR-FACILITIES	604700	PARKING	NWN	F1	4.80	93110591	11.80%	3-factor	$ 0.57	$ 4.23	$ 4.80	
931000	10591	250TAYLOR-FACILITIES	604800	LAUNDRY	NWN	F1	157.10	93110591	11.80%	3-factor	$ 18.54	$ 138.56	$ 157.10	
931000	10591	250TAYLOR-FACILITIES	605500	REPAIRS AND MAINT	NWN	F1	90,321.80	93110591	11.80%	3-factor	$ 10,657.97	$ 79,663.83	$ 90,321.80	
931000	10591	250TAYLOR-FACILITIES	612100	MEALS AND ENTERTAIN	NWN	F1	133.53	93110591	11.80%	3-factor	$ 15.76	$ 117.77	$ 133.53	
931000	10591	250TAYLOR-FACILITIES	622000	EMPLOYEE AWARDS	NWN	F1	850.00	93110591	11.80%	3-factor	$ 100.30	$ 749.70	$ 850.00	
931000	10591	250TAYLOR-FACILITIES	680305	HOURLY REGULAR-SECONDARY	NWN	F1	15,582.98	93110591	11.80%	3-factor	$ 1,838.79	$ 13,744.19	$ 15,582.98	
931000	10591	250TAYLOR-FACILITIES	680306	HOURLY OT PAY-SECONDARY	NWN	F1	250.68	93110591	11.80%	3-factor	$ 29.58	$ 221.10	$ 250.68	
931000	10592	250TAYLOR-FAC-RENTS-	602360	ROU UTIL LEA RENT EX	NWN	F1	(67,495.94)	93110592	11.80%	3-factor	$ (7,964.52)	$ (59,531.42)	$ (67,495.94)	
931000	10592	250TAYLOR-FAC-RENTS-	602365	ROU UTIL LEASE INTEREST EXPENSE	NWN	F1	6,703,264.12	93110592	11.80%	3-factor	$ 790,985.17	$ 5,912,278.95	$ 6,703,264.12	
931000	10592	250TAYLOR-FAC-RENTS-	604400	AMORTIZATION	NWN	F1	22,234.71	93110592	11.80%	3-factor	$ 2,623.70	$ 19,611.01	$ 22,234.71	
931000	10600	FACILITIES MGMNT - R	604400	AMORTIZATION	NWN	F1	69,635.34	93110600	11.80%	3-factor	$ 8,216.97	$ 61,418.37	$ 69,635.34	
931000	10624	SHERWOOD-FACILITIES	602300	RENTS AND LEASES	NWN	F1	7,895.03	93110624	11.80%	3-factor	$ 931.61	$ 6,963.42	$ 7,895.03	
931000	10624	SHERWOOD-FACILITIES	602360	ROU UTIL LEA RENT EX	NWN	F1	117,537.41	93110624	11.80%	3-factor	$ 13,869.41	$ 103,668.00	$ 117,537.41	
931000	10624	SHERWOOD-FACILITIES	602362	NON-LEASE COMP EXP	NWN	F1	49,139.52	93110624	11.80%	3-factor	$ 5,798.46	$ 43,341.06	$ 49,139.52	
931000	10624	SHERWOOD-FACILITIES	602365	ROU UTIL LEASE INTEREST EXPENSE	NWN	F1	12,358.19	93110624	11.80%	3-factor	$ 1,458.27	$ 10,899.92	$ 12,358.19	
931000	10637	CENTRAL - FACILITIES	602100	OTHER CONTRACT WORK	NWN	F1	2,957.80	93110637	0.00%	Direct-OR	$ -	$ 2,957.80	$ 2,957.80	
931000	10637	CENTRAL - FACILITIES	605500	REPAIRS AND MAINT	NWN	F1	412.62	93110637	0.00%	Direct-OR	$ -	$ 412.62	$ 412.62	
932000	10053	SYS OPS-MAINT OF GEN	601400	MATERIALS	NWN	F1	8,329.98	93210053	8.68%	Sendout Volumes	$ 723.04	$ 7,606.94	$ 8,329.98	
932000	10053	SYS OPS-MAINT OF GEN	601401	MATERIALS - CONS INV	NWN	F1	298.89	93210053	8.68%	Sendout Volumes	$ 25.94	$ 272.95	$ 298.89	
932000	10053	SYS OPS-MAINT OF GEN	601700	EQUIPMENT	NWN	F1	11,522.87	93210053	8.68%	Sendout Volumes	$ 1,000.19	$ 10,522.68	$ 11,522.87	
932000	10053	SYS OPS-MAINT OF GEN	602100	OTHER CONTRACT WORK	NWN	F1	1,273.65	93210053	8.68%	Sendout Volumes	$ 110.55	$ 1,163.10	$ 1,273.65	
932000	10053	SYS OPS-MAINT OF GEN	602466	P CARD UNCODED CHARG	NWN	F1	(71.84)	93210053	8.68%	Sendout Volumes	$ (6.24)	$ (65.60)	$ (71.84)	
932000	10053	SYS OPS-MAINT OF GEN	605500	REPAIRS AND MAINT	NWN	F1	150.89	93210053	8.68%	Sendout Volumes	$ 13.10	$ 137.79	$ 150.89	
932000	10053	SYS OPS-MAINT OF GEN	605900	HARDWARE MAINT	NWN	F1	71.84	93210053	8.68%	Sendout Volumes	$ 6.24	$ 65.60	$ 71.84	
932000	10053	SYS OPS-MAINT OF GEN	680301	HOURLY DBL TIME PAY	NWN	F1	2,072.50	93210053	8.68%	Sendout Volumes	$ 179.89	$ 1,892.61	$ 2,072.50	
932000	10053	SYS OPS-MAINT OF GEN	680305	HOURLY REGULAR-SECONDARY	NWN	F1	195,800.73	93210053	8.68%	Sendout Volumes	$ 16,995.50	$ 178,805.23	$ 195,800.73	
932000	10053	SYS OPS-MAINT OF GEN	680306	HOURLY OT PAY-SECONDARY	NWN	F1	37,610.77	93210053	8.68%	Sendout Volumes	$ 3,264.61	$ 34,346.16	$ 37,610.77	
932000	10053	SYS OPS-MAINT OF GEN	685800	MEAL TICKETS SECONDARY	NWN	F1	354.00	93210053	8.68%	Sendout Volumes	$ 30.73	$ 323.27	$ 354.00	
932000	10054	SYS OPS-MAINT OF GEN	601700	EQUIPMENT	NWN	F1	242.21	93210054	8.68%	Sendout Volumes	$ 21.02	$ 221.19	$ 242.21	
932000	10054	SYS OPS-MAINT OF GEN	680105	SALARY REGULAR-2nd secondary outlin	NWN	F1	0.00	93210054	8.68%	Sendout Volumes	$ -	$ -	$ -	
932000	10054	SYS OPS-MAINT OF GEN	680305	HOURLY REGULAR-SECONDARY	NWN	F1	4,949.71	93210054	8.68%	Sendout Volumes	$ 429.63	$ 4,520.08	$ 4,949.71	
932000	10054	SYS OPS-MAINT OF GEN	680306	HOURLY OT PAY-SECONDARY	NWN	F1	0.00	93210054	8.68%	Sendout Volumes	$ -	$ -	$ -	
932000	10055	SYS OPS-MAINT OF GEN	602100	OTHER CONTRACT WORK	NWN	F1	82.16	93210055	8.68%	Sendout Volumes	$ 7.13	$ 75.03	$ 82.16	
932000	10055	SYS OPS-MAINT OF GEN	680301	HOURLY DBL TIME PAY	NWN	F1	122.96	93210055	8.68%	Sendout Volumes	$ 10.67	$ 112.29	$ 122.96

NW Natural
Admin Transfer Allocation Factor
Test Year Ending March 31, 2025

$ 71,068,305.98

FERC Account	Cost Center	Cost Center Description	GL Account	GL Account Long Name	Chart of Accounts	Ledger	Fiscal Year Period / Measures	Amount / Overall Result	SORTER	ALLOCATION FACTOR	ALLOCATION METHOD	Admin Transfer Factor TOTAL 12.1429%	WA 87.8571%	OR	SYSTEM
								$				$ 8,629,765.83	$ 62,438,540.15		$ 71,068,305.98
932000	10055	SYS OPS-MAINT OF GEN	685800	MEAL TICKETS SECONDARY	NWN	F1		118.00	93210055	8.68%	Sendout Volumes	$ 10.24	$ 107.76	$ 118.00	
932000	10056	SYS OPS-MAINT OF GEN	601700	EQUIPMENT	NWN	F1		2,652.37	93210056	8.68%	Sendout Volumes	$ 230.23	$ 2,422.14	$ 2,652.37	
932000	10056	SYS OPS-MAINT OF GEN	602100	OTHER CONTRACT WORK	NWN	F1		0.00	93210056	8.68%	Sendout Volumes	$ -	$ -	$ -	
932000	10056	SYS OPS-MAINT OF GEN	680301	HOURLY DBL TIME PAY	NWN	F1		64.38	93210056	8.68%	Sendout Volumes	$ 5.59	$ 58.79	$ 64.38	
932000	10056	SYS OPS-MAINT OF GEN	680305	HOURLY REGULAR-SECONDARY	NWN	F1		38,895.83	93210056	8.68%	Sendout Volumes	$ 3,376.16	$ 35,519.67	$ 38,895.83	
932000	10056	SYS OPS-MAINT OF GEN	680306	HOURLY OT PAY-SECONDARY	NWN	F1		15,244.39	93210056	8.68%	Sendout Volumes	$ 1,323.21	$ 13,921.18	$ 15,244.39	
932000	10056	SYS OPS-MAINT OF GEN	685800	MEAL TICKETS SECONDARY	NWN	F1		401.20	93210056	8.68%	Sendout Volumes	$ 34.82	$ 366.38	$ 401.20	
932000	10153	PORTLAND LNG-MAINT O	602600	UTILITIES	NWN	F1		495.15	93210153	10.97%	Firm Sales Volumes	$ 54.32	$ 440.83	$ 495.15	
932000	10184	CONSR RELATIONS-EVT-	601400	MATERIALS	NWN	F1		2,234.80	93210184	12.17%	Customers-All	$ 271.98	$ 1,962.82	$ 2,234.80	
932000	10184	CONSR RELATIONS-EVT-	601401	MATERIALS - CONS INV	NWN	F1		1,000.24	93210184	12.17%	Customers-All	$ 121.73	$ 878.51	$ 1,000.24	
932000	10184	CONSR RELATIONS-EVT-	601402	MATERIALS -CONS PIPE	NWN	F1		11.81	93210184	12.17%	Customers-All	$ 1.44	$ 10.37	$ 11.81	
932000	10184	CONSR RELATIONS-EVT-	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1		152.79	93210184	12.17%	Customers-All	$ 18.59	$ 134.20	$ 152.79	
932000	10184	CONSR RELATIONS-EVT-	601600	TRANSPORTATION	NWN	F1		(4,146.24)	93210184	12.17%	Customers-All	$ (504.60)	$ (3,641.64)	$ (4,146.24)	
932000	10184	CONSR RELATIONS-EVT-	601700	EQUIPMENT	NWN	F1		16,905.05	93210184	12.17%	Customers-All	$ 2,057.34	$ 14,847.71	$ 16,905.05	
932000	10184	CONSR RELATIONS-EVT-	602100	OTHER CONTRACT WORK	NWN	F1		13,963.50	93210184	12.17%	Customers-All	$ 1,699.36	$ 12,264.14	$ 13,963.50	
932000	10184	CONSR RELATIONS-EVT-	602302	TOOLS AND EQUIP RENT	NWN	F1		700.00	93210184	12.17%	Customers-All	$ 85.19	$ 614.81	$ 700.00	
932000	10184	CONSR RELATIONS-EVT-	602466	P CARD UNCODED CHARG	NWN	F1		8,185.35	93210184	12.17%	Customers-All	$ 996.16	$ 7,189.19	$ 8,185.35	
932000	10184	CONSR RELATIONS-EVT-	602600	UTILITIES	NWN	F1		0.00	93210184	12.17%	Customers-All	$ -	$ -	$ -	
932000	10184	CONSR RELATIONS-EVT-	603000	OFFICE SUPPLIES	NWN	F1		198.76	93210184	12.17%	Customers-All	$ 24.19	$ 174.57	$ 198.76	
932000	10184	CONSR RELATIONS-EVT-	604600	DEALER RELATIONS	NWN	F1		14.19	93210184	12.17%	Customers-All	$ 1.73	$ 12.46	$ 14.19	
932000	10184	CONSR RELATIONS-EVT-	604800	LAUNDRY	NWN	F1		40.55	93210184	12.17%	Customers-All	$ 4.93	$ 35.62	$ 40.55	
932000	10184	CONSR RELATIONS-EVT-	604900	UNIFORMS	NWN	F1		863.63	93210184	12.17%	Customers-All	$ 105.10	$ 758.53	$ 863.63	
932000	10184	CONSR RELATIONS-EVT-	607700	SMALL TOOLS	NWN	F1		199.98	93210184	12.17%	Customers-All	$ 24.34	$ 175.64	$ 199.98	
932000	10184	CONSR RELATIONS-EVT-	608100	SUBSCRIPTION SERVICES	NWN	F1		100.00	93210184	12.17%	Customers-All	$ 12.17	$ 87.83	$ 100.00	
932000	10184	CONSR RELATIONS-EVT-	612100	MEALS AND ENTERTAIN	NWN	F1		106.97	93210184	12.17%	Customers-All	$ 13.02	$ 93.95	$ 106.97	
932000	10184	CONSR RELATIONS-EVT-	680105	SALARY REGULAR-2nd secondary outlin	NWN	F1		34,343.65	93210184	12.17%	Customers-All	$ 4,179.62	$ 30,164.03	$ 34,343.65	
932000	10244	METR SHOP-MAINT OF G	603100	PRINTING	NWN	F1		3,266.34	93210244	12.17%	Customers-All	$ 397.51	$ 2,868.83	$ 3,266.34	
932000	10244	METR SHOP-MAINT OF G	680105	SALARY REGULAR-2nd secondary outlin	NWN	F1		39,515.32	93210244	12.17%	Customers-All	$ 4,809.01	$ 34,706.31	$ 39,515.32	
932000	10276	IT RENTS	602300	RENTS AND LEASES	NWN	F1		8,210.20	93210276	11.80%	3-factor	$ 968.80	$ 7,241.40	$ 8,210.20	
932000	10276	IT RENTS	602360	ROU UTIL LEA RENT EX	NWN	F1		25,337.34	93210276	11.80%	3-factor	$ 2,989.81	$ 22,347.53	$ 25,337.34	
932000	10276	IT RENTS	602365	ROU UTIL LEASE INTEREST EXPENSE	NWN	F1		10,492.26	93210276	11.80%	3-factor	$ 1,238.09	$ 9,254.17	$ 10,492.26	
932000	10277	IT RADIO TOWER-932	601700	EQUIPMENT	NWN	F1		1.74	93210277	11.80%	3-factor	$ 0.21	$ 1.53	$ 1.74	
932000	10277	IT RADIO TOWER-932	602300	RENTS AND LEASES	NWN	F1		1,630.00	93210277	11.80%	3-factor	$ 192.34	$ 1,437.66	$ 1,630.00	
932000	1027:	IT RADIO TOWER-932	602360	ROU UTIL LEA RENT EX	NWN	F1		16,754.52	93210277	11.80%	3-factor	$ 1,977.03	$ 14,777.49	$ 16,754.52	
932000	1027:	IT RADIO TOWER-932	602362	NON-LEASE COMP EXP	NWN	F1		1,038.28	93210277	11.80%	3-factor	$ 122.52	$ 915.76	$ 1,038.28	
932000	1027:	IT RADIO TOWER-932	602365	ROU UTIL LEASE INTEREST EXPENSE	NWN	F1		3,766.80	93210277	11.80%	3-factor	$ 444.48	$ 3,322.32	$ 3,766.80	
932000	1027:	IT RADIO TOWER-932	680305	HOURLY REGULAR-SECONDARY	NWN	F1		169.20	93210277	11.80%	3-factor	$ 19.97	$ 149.23	$ 169.20	
932000	1039:	TRANSMISS-MAINT OF G	680305	HOURLY REGULAR-SECONDARY	NWN	F1		232.73	93210391	1.24%	Transmission	$ 2.90	$ 229.83	$ 232.73	
932000	1046:	LEGACY ENV PROG-MAIN	600100	SALARY PAYROLL	NWN	F1		291,521.07	93210466	11.80%	3-factor	$ 34,399.49	$ 257,121.58	$ 291,521.07	
932000	1046:	LEGACY ENV PROG-MAIN	600500	SALARY BONUS PAYROLL	NWN	F1		45,229.10	93210466	11.80%	3-factor	$ 5,337.03	$ 39,892.07	$ 45,229.10	
932000	1046:	LEGACY ENV PROG-MAIN	601100	EDUCATION	NWN	F1		35.00	93210466	11.80%	3-factor	$ 4.13	$ 30.87	$ 35.00	
932000	1046:	LEGACY ENV PROG-MAIN	601400	MATERIALS	NWN	F1		0.00	93210466	11.80%	3-factor	$ -	$ -	$ -	
932000	1046:	LEGACY ENV PROG-MAIN	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1		16.08	93210466	11.80%	3-factor	$ 1.90	$ 14.18	$ 16.08	
932000	1046:	LEGACY ENV PROG-MAIN	601900	DUES/MEMBERSHIP	NWN	F1		595.00	93210466	11.80%	3-factor	$ 70.21	$ 524.79	$ 595.00	
932000	1046:	LEGACY ENV PROG-MAIN	602100	OTHER CONTRACT WORK	NWN	F1		0.00	93210466	11.80%	3-factor	$ -	$ -	$ -	
932000	1046:	LEGACY ENV PROG-MAIN	602466	P CARD UNCODED CHARG	NWN	F1		(235.60)	93210466	11.80%	3-factor	$ (27.80)	$ (207.80)	$ (235.60)	
932000	1046:	LEGACY ENV PROG-MAIN	603000	OFFICE SUPPLIES	NWN	F1		242.60	93210466	11.80%	3-factor	$ 28.63	$ 213.97	$ 242.60	
932000	1046:	LEGACY ENV PROG-MAIN	603100	PRINTING	NWN	F1		0.00	93210466	11.80%	3-factor	$ -	$ -	$ -	
932000	1046:	LEGACY ENV PROG-MAIN	604700	PARKING	NWN	F1		23.13	93210466	11.80%	3-factor	$ 2.73	$ 20.40	$ 23.13	
932000	1046:	LEGACY ENV PROG-MAIN	605100	PROFESSIONAL SERVICE	NWN	F1		0.00	93210466	11.80%	3-factor	$ -	$ -	$ -	
932000	1046:	LEGACY ENV PROG-MAIN	612100	MEALS AND ENTERTAIN	NWN	F1		351.66	93210466	11.80%	3-factor	$ 41.50	$ 310.16	$ 351.66	
932000	1046:	LEGACY ENV PROG-MAIN	612200	TRAVEL IN TERRITORY	NWN	F1		3.00	93210466	11.80%	3-factor	$ 0.35	$ 2.65	$ 3.00	
932000	1046:	LEGACY ENV PROG-MAIN	613200	BUSINESS TRAVEL	NWN	F1		20.00	93210466	11.80%	3-factor	$ 2.36	$ 17.64	$ 20.00	
932000	1046:	LEGACY ENV PROG-MAIN	622000	EMPLOYEE AWARDS	NWN	F1		201.05	93210466	11.80%	3-factor	$ 23.72	$ 177.33	$ 201.05	
932000	1051:	DISTRIBUTION-MAINT O	601600	TRANSPORTATION	NWN	F1		6,750.00	93210510	0.00%	Direct-OR	$ -	$ 6,750.00	$ 6,750.00	
932000	1059:	2SDTAYLOR-MAINT OF G	601700	FURNITURE	NWN	F1		6,722.18	93210593	11.80%	3-factor	$ 793.22	$ 5,928.96	$ 6,722.18	
932000	1059:	2SDTAYLOR-MAINT OF G	602000	OFFICE CONTRACT WORK	NWN	F1		41,472.00	93210593	11.80%	3-factor	$ 4,893.70	$ 36,578.30	$ 41,472.00	
932000	1059:	2SDTAYLOR-MAINT OF G	602100	OTHER CONTRACT WORK	NWN	F1		426,670.26	93210593	11.80%	3-factor	$ 50,347.09	$ 376,323.17	$ 426,670.26	
932000	1059:	2SDTAYLOR-MAINT OF G	602106	ENVIRONMENTAL	NWN	F1		7,818.06	93210593	11.80%	3-factor	$ 922.53	$ 6,895.53	$ 7,818.06	
932000	1059:	2SDTAYLOR-MAINT OF G	602400	MISCELANEOUS	NWN	F1		8,589.11	93210593	11.80%	3-factor	$ 1,013.51	$ 7,575.60	$ 8,589.11	
932000	1059:	2SDTAYLOR-MAINT OF G	602600	UTILITIES	NWN	F1		300,794.96	93210593	11.80%	3-factor	$ 35,493.81	$ 265,301.15	$ 300,794.96	
932000	1059:	2SDTAYLOR-MAINT OF G	603000	OFFICE SUPPLIES	NWN	F1		10,977.69	93210593	11.80%	3-factor	$ 1,295.37	$ 9,682.32	$ 10,977.69	
932000	1059:	2SDTAYLOR-MAINT OF G	604700	PARKING	NWN	F1		303,438.68	93210593	11.80%	3-factor	$ 35,805.76	$ 267,632.92	$ 303,438.68	
932000	1059:	2SDTAYLOR-MAINT OF G	605100	PROFESSIONAL SERVICE	NWN	F1		125.00	93210593	11.80%	3-factor	$ 14.75	$ 110.25	$ 125.00	
932000	1059:	2SDTAYLOR-MAINT OF G	605500	REPAIRS AND MAINT	NWN	F1		18,326.83	93210593	11.80%	3-factor	$ 2,162.57	$ 16,164.26	$ 18,326.83	
932000	1059:	2SDTAYLOR-MAINT OF G	606100	SECURITY	NWN	F1		25,348.07	93210593	11.80%	3-factor	$ 2,991.07	$ 22,357.00	$ 25,348.07	
932000	1059:	2SDTAYLOR-MAINT OF G	606200	PERMITS AND FEES	NWN	F1		63.00	93210593	11.80%	3-factor	$ 7.43	$ 55.57	$ 63.00	
932000	1059:	2SDTAYLOR-MAINT OF G	612100	MEALS AND ENTERTAIN	NWN	F1		49.50	93210593	11.80%	3-factor	$ 5.84	$ 43.66	$ 49.50	
932000	1059:	2SDTAYLOR-MAINT OF G	602466	P CARD UNCODED CHARG	NWN	F1		176.19	93210594	11.80%	3-factor	$ 20.79	$ 155.40	$ 176.19	
932000	1060:	FACILITIES MGMNT-MAI	600100	SALARY PAYROLL	NWN	F1		330,702.99	93210601	11.80%	3-factor	$ 39,022.95	$ 291,680.04	$ 330,702.99	
932000	1060:	FACILITIES MGMNT-MAI	600301	HOURLY DOUBLE PAY-PRIMARY	NWN	F1		2,558.64	93210601	11.80%	3-factor	$ 301.92	$ 2,256.72	$ 2,558.64	
932000	1060:	FACILITIES MGMNT-MAI	600305	HOURLY REGULAR PAY-PRIMARY	NWN	F1		221,094.04	93210601	11.80%	3-factor	$ 26,089.10	$ 195,004.94	$ 221,094.04	
932000	1060:	FACILITIES MGMNT-MAI	600306	HOURLY OVERTIME PAY-PRIMARY	NWN	F1		49,997.65	93210601	11.80%	3-factor	$ 5,899.72	$ 44,097.93	$ 49,997.65	
932000	1060:	FACILITIES MGMNT-MAI	600500	SALARY BONUS PAYROLL	NWN	F1		59.82	93210601	11.80%	3-factor	$ 7.06	$ 52.76	$ 59.82	
932000	1060:	FACILITIES MGMNT-MAI	600700	HOURLY BONUS PAYROLL	NWN	F1		1,167.58	93210601	11.80%	3-factor	$ 137.77	$ 1,029.81	$ 1,167.58	
932000	1060:	FACILITIES MGMNT-MAI	600900	VACATION, SICK & HOL	NWN	F1		38,123.65	93210601	11.80%	3-factor	$ 4,498.59	$ 33,625.06	$ 38,123.65	
932000	1060:	FACILITIES MGMNT-MAI	601100	EDUCATION	NWN	F1		475.00	93210601	11.80%	3-factor	$ 56.05	$ 418.95	$ 475.00	
932000	1060:	FACILITIES MGMNT-MAI	601400	MATERIALS	NWN	F1		9,002.71	93210601	11.80%	3-factor	$ 1,062.32	$ 7,940.39	$ 9,002.71	
932000	1060:	FACILITIES MGMNT-MAI	601401	MATERIALS - CONS INV	NWN	F1		2,315.80	93210601	11.80%	3-factor	$ 273.26	$ 2,042.54	$ 2,315.80	
932000	1060:	FACILITIES MGMNT-MAI	601402	MATERIALS -CONS PIPE	NWN	F1		0.00	93210601	11.80%	3-factor	$ -	$ -	$ -	
932000	1060:	FACILITIES MGMNT-MAI	601500	MILEAGE/PER DIEMS REIMBURSENT	NWN	F1		4,408.00	93210601	11.80%	3-factor	$ 520.14	$ 3,887.86	$ 4,408.00	
932000	1060:	FACILITIES MGMNT-MAI	601600	TRANSPORTATION	NWN	F1		8,143.20	93210601	11.80%	3-factor	$ 960.90	$ 7,182.30	$ 8,143.20	
932000	1060:	FACILITIES MGMNT-MAI	601700	EQUIPMENT	NWN	F1		38,659.34	93210601	11.80%	3-factor	$ 4,561.80	$ 34,097.54	$ 38,659.34	
932000	1060:	FACILITIES MGMNT-MAI	601800	FURNITURE	NWN	F1		981.71	93210601	11.80%	3-factor	$ 115.84	$ 865.87	$ 981.71	
932000	1060:	FACILITIES MGMNT-MAI	601900	DUES/MEMBERSHIP	NWN	F1		553.00	93210601	11.80%	3-factor	$ 65.25	$ 487.75	$ 553.00	
932000	1060:	FACILITIES MGMNT-MAI	602100	OTHER CONTRACT WORK	NWN	F1		132.50	93210601	11.80%	3-factor	$ 15.64	$ 116.87	$ 132.50	
932000	1060:	FACILITIES MGMNT-MAI	602466	P CARD UNCODED CHARG	NWN	F1		(1,485.05)	93210601	11.80%	3-factor	$ (175.24)	$ (1,309.81)	$ (1,485.05)	
932000	1060:	FACILITIES MGMNT-MAI	602800	POSTAGE	NWN	F1		694.35	93210601	11.80%	3-factor	$ 81.93	$ 612.42	$ 694.35	
932000	1060:	FACILITIES MGMNT-MAI	603000	OFFICE SUPPLIES	NWN	F1		149,171.15	93210601	11.80%	3-factor	$ 17,602.20	$ 131,568.95	$ 149,171.15	
932000	1060:	FACILITIES MGMNT-MAI	603100	PRINTING	NWN	F1		803.79	93210601	11.80%	3-factor	$ 94.85	$ 708.94	$ 803.79	
932000	1060:	FACILITIES MGMNT-MAI	603200	BOOKS AND MAGAZINES	NWN	F1		485.17	93210601	11.80%	3-factor	$ 57.25	$ 427.92	$ 485.17	
932000	1060:	FACILITIES MGMNT-MAI	603300	REFRESHMENTS	NWN	F1		812.29	93210601	11.80%	3-factor	$ 95.85	$ 716.44	$ 812.29	
932000	1060:	FACILITIES MGMNT-MAI	603400	TOOL EXPENSE	NWN	F1		685.95	93210601	11.80%	3-factor	$ 80.94	$ 605.01	$ 685.95	
932000	1060:	FACILITIES MGMNT-MAI	604700	PARKING	NWN	F1		47.80	93210601	11.80%	3-factor	$ 5.64	$ 42.16	$ 47.80	
932000	1060:	FACILITIES MGMNT-MAI	605500	REPAIRS AND MAINT	NWN	F1		22,319.03	93210601	11.80%	3-factor	$ 2,633.65	$ 19,685.38	$ 22,319.03	
932000	1060:	FACILITIES MGMNT-MAI	605800	MEAL TICKETS	NWN	F1		553.60	93210601	11.80%	3-factor	$ 65.32	$ 488.28	$ 553.60	
932000	1060:	FACILITIES MGMNT-MAI	606200	PERMITS AND FEES	NWN	F1		3,762.16	93210601	11.80%	3-factor	$ 443.93	$ 3,318.23	$ 3,762.16	
932000	1060:	FACILITIES MGMNT-MAI	606500	UNLEADED FUEL	NWN	F1		83.95	93210601	11.80%	3-factor	$ 9.91	$ 74.04	$ 83.95	
932000	1060:	FACILITIES MGMNT-MAI	607700	SMALL TOOLS	NWN	F1		1,203.86	93210601	11.80%	3-factor	$ 142.06	$ 1,061.80	$ 1,203.86	
932000	1060:	FACILITIES MGMNT-MAI	612100	MEALS AND ENTERTAIN	NWN	F1		137.67	93210601	11.80%	3-factor	$ 16.25	$ 121.42	$ 137.67	
932000	1060:	FACILITIES MGMNT-MAI	612200	TRAVEL IN TERRITORY	NWN	F1		1,944.43	93210601	11.80%	3-factor	$ 229.44	$ 1,714.99	$ 1,944.43	
932000	1060:	FACILITIES MGMNT-MAI	613200	BUSINESS TRAVEL	NWN	F1		4,308.25	93210601	11.80%	3-factor	$ 508.37	$ 3,799.88	$ 4,308.25	
932000	1060:	FACILITIES MGMNT-MAI	622000	EMPLOYEE AWARDS	NWN	F1		28.95	93210601	11.80%	3-factor	$ 3.42	$ 25.53	$ 28.95	
932000	1060:	FACILITIES MGMNT-MAI	680305	HOURLY REGULAR-SECONDARY	NWN	F1		(3,827.75)	93210601	11.80%	3-factor	$ (451.67)	$ (3,376.08)	$ (3,827.75)	
932000	1060:	FACILITIES MGMNT-MAI	680306	HOURLY OT PAY-SECONDARY	NWN	F1		(152.03)	93210601	11.80%	3-factor	$ (17.94)	$ (134.09)	$ (152.03)	
932000	1060:	FACILITIES MGMNT-MAI	602100	OTHER CONTRACT WORK	NWN	F1		41,659.53	93210602	11.80%	3-factor	$ 4,915.82	$ 36,743.71	$ 41,659.53	
932000	1060:	FACILITIES MGMNT-MAI	602600	UTILITIES	NWN	F1		43,290.16	93210602	11.80%	3-factor	$ 5,108.24	$ 38,181.92	$ 43,290.16	
932000	1060:	FACILITIES MGMNT-MAI	605500	REPAIRS AND MAINT	NWN	F1		3,750.51	93210602	11.80%	3-factor	$ 442.56	$ 3,307.95	$ 3,750.51	
932000	1060:	FACILITIES MGMT-MAIN	601400	MATERIALS	NWN	F1		0.00	93210603	11.80%	3-factor	$ -	$ -	$ -	
932000	1060:	FACILITIES MGMT-MAIN	602600	UTILITIES	NWN	F1		310.24	93210606	11.80%	3-factor	$ 36.61	$ 273.63	$ 310.24	
932000	1060:	FACILITIES MGMT-MAIN	680301	HOURLY DBL TIME PAY	NWN	F1		249.44	93210606	11.80%	3-factor	$ 29.43	$ 220.01	$ 249.44	
932000	1060:	FACILITIES MGMT-MAIN	685800	MEAL TICKETS SECONDARY	NWN	F1		23.60	93210606	11.80%	3-factor	$ 2.78	$ 20.82	$ 23.60	
932000	1060:	FACILITIES MGMT-MAIN	602100	OTHER CONTRACT WORK	NWN	F1		7,384.45	93210607	11.80%	3-factor	$ 871.37	$ 6,513.08	$ 7,384.45	
932000	1060:	FACILITIES MGMT-MAIN	602600	UTILITIES	NWN	F1		70,801.75	93210607	11.80%	3-factor	$ 8,354.61	$ 62,447.14	$ 70,801.75	
932000	1060:	FACILITIES MGMT-MAIN	602600	UTILITIES	NWN	F1		223.14	93210608	11.80%	3-factor	$ 26.33	$ 196.81	$ 223.14	
932000	1060:	FACILITIES MGMT-MAIN	602600	UTILITIES	NWN	F1		50,793.82	93210609	11.80%	3-factor	$ 5,993.67	$ 44,800.15	$ 50,793.82	
932000	1060:	FACILITIES MGMT-MAIN	602800	POSTAGE	NWN	F1		0.00	93210609	11.80%	3-factor	$ -	$ -	$ -	
932000	1061:	FACILITIES MGMT-MAIN	602600	UTILITIES	NWN	F1		28.15	93210610	11.80%	3-factor	$ 3.32	$ 24.83	$ 28.15	
932000	1061:	FACILITIES MGMT-MAIN	602600	UTILITIES	NWN	F1		4,895.77	93210611	11.80%	3-factor	$ 577.70	$ 4,318.07	$ 4,895.77	
932000	1061:	FACILITIES MGMT-MAIN	602600	UTILITIES	NWN	F1		93,515.07	93210612	11.80%	3-factor	$ 11,034.78	$ 82,480.29	$ 93,515.07	
932000	1061:	MTSCOTT-FAC- MAINT G	601100	EDUCATION	NWN	F1		2,495.00	93210617	0.00%	direct-or	$ -	$ 2,495.00	$ 2,495.00	
932000	1061:	MTSCOTT-FAC- MAINT G	602100	OTHER CONTRACT WORK	NWN	F1		16,977.39	93210617	0.00%	direct-or	$ -	$ 16,977.39	$ 16,977.39	
932000	1061:	MTSCOTT-FAC- MAINT G	602600	UTILITIES	NWN	F1		58,802.35	93210617	0.00%	direct-or	$ -	$ 58,802.35	$ 58,802.35	
932000	1061:	MTSCOTT-FAC- MAINT G	605500	REPAIRS AND MAINT	NWN	F1		5,666.96	93210617	0.00%	direct-or	$ -	$ 5,666.96	$ 5,666.96	
932000	1061:	MTSCOTT-FAC- MAINT G	606100	SECURITY	NWN	F1		500.00	93210617	0.00%	direct-or	$ -	$ 500.00	$ 500.00	
932000	1061:	ASTORIA-FAC-MAINT GE	602100	OTHER CONTRACT WORK	NWN	F1		35,423.38	93210618	0.00%	Direct-OR	$ -	$ 35,423.38	$ 35,423.38	
932000	1061:	ASTORIA-FAC-MAINT GE	602600	UTILITIES	NWN	F1		27,097.04	93210618	0.00%	Direct-OR	$ -	$ 27,097.04	$ 27,097.04	
932000	1061:	ASTORIA-FAC-MAINT GE	603000	OFFICE SUPPLIES	NWN	F1		0.00	93210618	0.00%	Direct-OR	$ -	$ -	$ -	
932000	1061:	ASTORIA-FAC-MAINT GE	605500	REPAIRS AND MAINT	NWN	F1		4,199.29	93210618	0.00%	Direct-OR	$ -	$ 4,199.29	$ 4,199.29	
932000	1061:	PARKROSE-FAC-MAINT G	602100	OTHER CONTRACT WORK	NWN	F1		25,652.80	93210619	0.00%	Direct-OR	$ -	$ 25,652.80	$ 25,652.80	
932000	1061:	PARKROSE-FAC-MAINT G	602600	UTILITIES	NWN	F1		38,112.31	93210619	0.00%	Direct-OR	$ -	$ 38,112.31	$ 38,112.31	
932000	1061:	PARKROSE-FAC-MAINT G	603000	OFFICE SUPPLIES	NWN	F1		0.00	93210619	0.00%	Direct-OR	$ -	$ -	$ -	
932000	1061:	PARKROSE-FAC-MAINT G	605000	LEGAL FEES	NWN	F1		0.00	93210619	0.00%	Direct-OR	$ -	$ -	$ -	
932000	1061:	PARKROSE-FAC-MAINT G	605500	REPAIRS AND MAINT	NWN	F1		1,972.00	93210619	0.00%	Direct-OR	$ -	$ 1,972.00	$ 1,972.00	
932000	1061:	PARKROSE-FAC-MAINT G	606100	SECURITY	NWN	F1		5,144.00	93210619	0.00%	Direct-OR	$ -	$ 5,144.00	$ 5,144.00	
932000	1061:	PARKROSE-FAC-MAINT G	606200	PERMITS AND FEES	NWN	F1		338.00	93210619	0.00%	Direct-OR	$ -	$ 338.00	$ 338.00	
932000	1062:	LINC CITY-FAC-MAINT	602100	OTHER CONTRACT WORK	NWN	F1		22,052.92	93210621	0.00%	direct-or	$ -	$ 22,052.92	$ 22,052.92	
932000	1062:	LINC CITY-FAC-MAINT	602600	UTILITIES	NWN	F1		21,350.96	93210621	0.00%	direct-or	$ -	$ 21,350.96	$ 21,350.96	
932000	1062:	LINC CITY-FAC-MAINT	603000	OFFICE SUPPLIES	NWN	F1		0.00	93210621	0.00%	direct-or	$ -	$ -	$ -	
932000	1062:	LINC CITY-FAC-MAINT	605500	REPAIRS AND MAINT	NWN	F1		445.00	93210621	0.00%	direct-or	$ -	$ 445.00	$ 445.00	
932000	1062:	LINC CITY-FAC-MAINT	606100	SECURITY	NWN	F1		0.00	93210621	0.00%	direct-or	$ -	$ -	$ -	
932000	1062:	LINC CITY-FAC-MAINT	602100	OTHER CONTRACT WORK	NWN	F1		84.21	93210622	0.00%	direct-or	$ -	$ 84.21	$ 84.21	
932000	1062:	LINC CITY-FAC-MAINT	604700	PARKING	NWN	F1		3,224.10	93210623	0.00%	direct-or	$ -	$ 3,224.10	$ 3,224.10	
932000	1062:	SHERWOOD-FAC-MAINT G	601400	MATERIALS	NWN	F1		417.98	93210625	11.80%	3-factor	$ 49.32	$ 368.66	$ 417.98	
932000	1062:	SHERWOOD-FAC-MAINT G	601401	MATERIALS - CONS INV	NWN	F1		7,680.64	93210625	11.80%	3-factor	$ 906.32	$ 6,774.32	$ 7,680.64	
932000	1062:	SHERWOOD-FAC-MAINT G	601700	EQUIPMENT	NWN	F1		2,130.28	93210625	11.80%	3-factor	$ 251.37	$ 1,878.91	$ 2,130.28	
932000	1062:	SHERWOOD-FAC-MAINT G	601800	FURNITURE	NWN	F1		780.00	93210625	11.80%	3-factor	$ 92.04	$ 687.96	$ 780.00	
932000	1062:	SHERWOOD-FAC-MAINT G	602100	OTHER CONTRACT WORK	NWN	F1		322,685.25	93210625	11.80%	3-factor	$ 38,076.86	$ 284,608.39	$ 322,685.25	
932000

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Kyle T. Walker

MULTI-YEAR RATE PLAN AND REVENUE REQUIREMENTS

Exh. KTW-4

August 29, 2025

NW Natural
Adjustments to Test Year and RY1
Test Year Based on Twelve Months Ended March 31, 2025
RY1 Based on Twelve Months Ended July 31, 2027

Exh. KTW-4
Page 1

Line No.		Restating Weather Normalized Gas Sales & Purchases (a)	Restating Misc Revenues Adjustment (b)	Restating Property Tax Adjustment (c)	Restating Uncollectible Accounts Adjustment (d)	Restating Working Capital Adjustment (e)	Restating O&M Adjustment (f)	Restating Claims Adjustment (g)	Restating ECRM Adjustment (h)	Restating EOP RB & Depr. Adjustment (i)	Restating Payroll Tax Adjustment (j)	Restating Capital Bonus Adjustment (k)	Total Test Year Restating Total Restating Adjustments (l)
	Operating Revenues												
1	Sale of Gas	$7,904,906	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,904,906
2	Transportation	149,492	0	0	0	0	0	0	0	0	0	0	149,492
3	Miscellaneous Revenues		(4,798,187)	0	0	0	0	0	0	0	0	0	(4,798,187)
4	Total Operating Revenues	8,054,397	(4,798,187)	0	0	0	0	0	0	0	0	0	3,256,211
	Operating Revenue Deductions												
5	Gas Purchased	10,466,590	0	0	0	0	0	0	0	0	0	0	10,466,590
6	Uncollectible Accrual	20,668	(12,313)	0	101,295	0	0	0	0	0	0	0	109,651
7	Other Operating & Maintenance Expenses	0	0	0	0	0	(748,810)	(12,390)	0	0	0	0	(761,200)
8	Total Operating & Maintenance Expense	10,487,258	(12,313)	0	101,295	0	(748,810)	(12,390)	0	0	0	0	9,815,041
9	Environmental Expense	0	0	0	0	0	0	0	(432,129)	0	0	0	(432,129)
10	Federal Income Tax	(582,820)	(962,190)	36,475	(21,272)	(91,798)	157,250	2,602	90,747	(211,090)	(1,174)	427	(1,582,843)
11	Property Taxes	0	0	(173,693)	0	0	0	0	0	0	0	0	(173,693)
12	Other Taxes	342,473	(204,019)	0	0	0	0	0	0	0	5,592	0	144,046
13	Depreciation & Amortization	0	0	0	0	0	0	0	0	650,958	0	0	650,958
14	Total Operating Revenue Deductions	10,246,911	(1,178,521)	(137,218)	80,023	(91,798)	(591,560)	(9,788)	(341,382)	439,868	4,418	427	8,421,381
15	Net Operating Revenues	(2,192,514)	(3,619,665)	137,218	(80,023)	91,798	591,560	9,788	341,382	(439,868)	(4,418)	(427)	(5,165,170)
	Average Rate Base												
16	Utility Plant in Service	0	0	0	0	17,612,042	0	0	0	20,880,223	0	(81,903)	38,410,362
17	Accumulated Depreciation	0	0	0	0	0	0	0	0	(5,663,751)	0	0	(5,663,751)
18	Net Utility Plant	0	0	0	0	17,612,042	0	0	0	15,216,472	0	(81,903)	32,746,611
19	Storage Gas	0	0	0	0	0	0	0	0	0	0	0	0
20	Customer Contributions	0	0	0	0	0	0	0	0	(844,297)	0	0	(844,297)
21	Leasehold Improvements	0	0	0	0	0	0	0	0	(100,052)	0	0	(100,052)
22	Accumulated Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0
23	Total Rate Base	0	0	0	0	17,612,042	0	0	0	14,272,124	0	(81,903)	31,802,263
24	Interest Coordination	0	0	0	0	437,131	0	0	0	354,234	0	(2,033)	789,332
25	Estimated Revenue Requirement	2,906,374	4,798,192	(181,895)	106,078	1,508,355	(784,165)	(12,975)	(452,533)	1,904,008	5,857	(7,014)	9,790,283

Northwest Natural Gas Company
Adjustments to Test Period
RY1 Based on Twelve Months Ended July 31, 2027
($000)

Exh. KTW-4
Page 2

Line No.	Income Tax Calculations	Weather Normalized Gas Sales & Purchases	Misc Revenues Adjustment	Property Tax Adjustment	Uncollectible Accounts Adjustment	Working Capital Adjustment	O&M Adjustment	Claims Adjustment	ECRM Adjustment	EOP RB & Depr. Adjustment	Tax Adjustment	Capital Bonus Adjustment	Total Restating Adjustments
		(a)	(b)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Book Revenues	8,054,397	(4,798,187)	0	0	0	0	0	0	0	0	0	3,256,211
2	Book Expenses before Deprec. & Interest	10,829,731	(216,331)	(173,693)	101,295	0	(748,810)	(12,390)	(432,129)	0	5,592	0	9,353,265
3	State Tax Depreciation	0	0	0	0	0	0	0	0	650,958	0	0	650,958
4	Interest Expense (Income)	0	0	0	0	437,131	0	0	0	354,234	0	(2,033)	789,332
5	Book/Tax Differences (Sched. M)	0	0	0	0	0	0	0	0	0	0	0	0
6	Federal Taxable Income	(2,775,334)	(4,581,855)	173,693	(101,295)	(437,131)	748,810	12,390	432,129	(1,005,192)	(5,592)	2,033	(7,537,345)
7	Federal Income Tax [1]	(582,820)	(962,190)	36,475	(21,272)	(91,798)	157,250	2,602	90,747	(211,090)	(1,174)	427	(1,582,843)
8	ITC/EDIT	0	0	0	0	0	0	0	0	0	0	0	0
9	Current Federal Tax	(582,820)	(962,190)	36,475	(21,272)	(91,798)	157,250	2,602	90,747	(211,090)	(1,174)	427	(1,582,843)
10	Deferred Income Tax - Federal	0	0	0	0	0	0	0	0	0	0	0	0
11	Deferred Income Tax - State	0	0	0	0	0	0	0	0	0	0	0	0
12	ITC Restored (Deferred)	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Federal Tax	(582,820)	(962,190)	36,475	(21,272)	(91,798)	157,250	2,602	90,747	(211,090)	(1,174)	427	(1,582,843)

NW Natural
RY1 Based on Twelve Months Ended July 31, 2027
Weather Normalized Gas Sales and Purchases Adjustment

Exh. KTW-4
Page 3

		Actual			Normalized Test Year			
	Revenues	Therm Deliveries	Average Class Price Per Therm	Revenues and Margin	Therm Deliveries	Average Class Price Per Therm	Revenues and Margin	Test Year Adjustment
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Sales Volumes and Revenues							
1	Residential	54,592,965	1.25033	$68,259,082	59,110,125	1.24265	$73,453,136	
2	Commercial	25,916,000	1.10256	$28,574,039	27,761,753	1.10501	$30,676,903	
3	Industrial Firm	2,957,322	0.81572	$2,412,358	2,804,325	0.88293	$2,476,023	
4	Interruptible	1,113,672	0.60534	$674,145	1,113,672	0.66569	$741,359	
5	Total Sales of Gas Revenues	84,579,959		$99,919,624	90,789,875		$107,347,421	$7,427,797
6	Unbilled amounts	(359,624)		($477,109)			$0	$477,109
	Transportation Volumes and Revenues							
7	Firm	9,981,792		$1,384,781	8,601,031	0.16944	$1,457,389	
8	Interruptible	7,847,859		$843,781	10,089,812	0.09125	$920,664	
9	Special Contracts - Firm	0		$0	0	n/a	$0	
10	Total Transportation	17,829,651		$2,228,562	18,690,842		$2,378,053	$149,492
11	Total Deliveries and Revenues	102,049,986		$101,671,076	109,480,717		$109,725,474	$8,054,397
	Gas Costs							
12	Demand Charges (Net of Deferral)			$8,204,267			$8,904,428	
13	Commodity Charges (Net of Deferral)			35,867,341			37,577,021	
14	Commodity and Demand Amortizations			(8,056,748)			0	
15	Total Cost of Gas			$36,014,859			$46,481,449	$10,466,590
16	Total Margin			$65,656,217			$63,244,025	($2,412,193)

NW Natural **Exh. KTW-4**
Washington Rate Case **Page 4**
Test Year Based on Twelve Months Ended March 31, 2025
Restating Adjustment to Miscellaneous Revenues

Line No.		Actual (a)	Normalized (b)	Adjustment (c)
1	Revenue & Technical Adjustment Amortizations	$4,666,968	$0	($4,666,968)
2	Subtotal	$4,666,968	$0	($4,666,968)
	Other Miscellaneous Revenues			
3	LATE PAYMENT CHARGE	$123,120	$42,040	($81,081)
4	AUTOMATED PAYMENT CHARGE	$0	$0	$0
5	FIELD COLLECTION CHARGES	$305	($160)	($465)
6	RECONN CHG-CR-AFTER OFFICE H	$0	$0	$0
7	RECONN CHG-CR-DURING OFFICE	($2,910)	($2,910)	$0
8	RECONN CHG-SEAS-AFTER OFFICE	$0	$0	$0
9	RECONN CHG-SEAS-DURING OFFIC	$0	$0	$0
10	DELINQ RECONNECT FEE	$0	$0	$0
11	RETURNED CHECK CHARGE	$74,145	$21,460	($52,685)
12	METER RENTALS	$18,205	$6,047	($12,158)
13	OTHER GAS REV - MISC	$10,114	$25,283	$15,170
14	Non-AMR Read Charge	$0	$0	$0
15	SUMMARY BILLS SVCS	$0	$0	$0
16	NON-AMR Install/Remove Charge	$0	$0	$0
17	CURTAILMENT UNAUTH TA	$0	$0	$0
18	Subtotal	$222,979	$91,760	($131,219)
19	RENT FROM GAS PROPERTY-RENT - UTILITY PR	$9,972	$9,972	$0
20	Total	$4,899,919	$101,732	($4,798,187)

NW Natural **Exh. KTW-4**
Test Year Restating Adjustment **Page 5**
Property Tax Adjustment

Line No.		Test Year Expense (a)
1	**Property Taxes - Test Period Expense**	$1,864,317
2	**Property Taxes - Paid**	$1,690,624
3	**Restating Adjustment**	($173,693)
	Net Utility Plant in Service	
	December 31, 2025	$372,855,971
	December 31, 2024	$348,297,252
	December 31, 2023	$311,818,807
	December 31, 2022	$288,557,693
	Property Tax	
	2025	1,690,624
	2024	1,452,177
	2023	1,483,515
	2022	1,481,696
	Ratio of Property Tax to Net Utility Plant in Service	
	2025	0.45%
	2024	0.42%
	2023	0.48%
	2022	0.51%
	AVERAGE	0.46%

NW Natural
Test Year Restating Adjustment
Uncollectible Accounts Adjustment

Exh. KTW-4
Page 6

Line No.		2023-2025 Total	12 Months Ended March 31 [1] 2025 Actual	2024 Actual	2023 Actual
		(a)	(b)	(c)	(d)
	Gas Revenues				
1	**Residential**	$1,988,760,418	$662,328,949	$646,322,685	$680,108,784
2	**Commercial**	915,159,514	$302,503,783	$290,399,190	$322,256,541
3	**Industrial**	101,767,183	$32,541,771	$32,286,278	$36,939,134
4	**Interruptible**	98,360,868	$29,408,582	$29,454,878	$39,497,408
5	**Total**	3,104,047,983	1,026,783,086	998,463,031	1,078,801,866
	Net Write-Offs				
6	**Residential**	5,484,695	1,439,823	1,543,905	2,500,967
7	**Commercial**	1,196,247	447,087	395,931	353,230
8	**Industrial**	1,284,301	1,476	1,281,520	1,305
9	**Interruptible**	-	0	0	0
10	**Total**	7,965,243	1,888,385	3,221,355	2,855,503
	Write-Off % - 3-Year Average				
11	**Residential**	0.276%	0.217%	0.239%	0.368%
12	**Commercial**	0.131%	0.148%	0.136%	0.110%
13	**Industrial**	1.262%	0.005%	3.969%	0.004%
14	**Interruptible**	0.000%	0.000%	0.000%	0.000%
15	**Weighted Total [2]**	0.257%	0.184%	0.323%	0.265%
	Normalized Uncollectible				
16	**Residential**	$1,826,601			
17	**Commercial**	395,417			
18	**Industrial**	410,677			
19	**Interruptible**	0			
20	**Total**	$2,632,695			
21	**Allocation Factor (Customers - All)**	12.17%			
22	**Washington Normalized Amount**	$320,399			
23	**Washington Allocation of Accrued Amount**	$219,104			
24	**Adjustment (Normalized less Accrued)**	$101,295			

[1] Weighted uncollectible rate of 0.257%

NW Natural **Exh. KTW-4**
Test Year Restating Adjustment **Page 7**
Working Capital Adjustment

		Amount
1	**Current Working Capital Assets**	$358,093,886
2	**Current Working Capital Liabilities**	($196,160,063)
3	**Net Working Capital**	$161,933,823
4		
5	**WA Allocation**	10.88%
6		
7	**Total Working Capital Adjustment**	$17,612,042

NW Natural **Exh. KTW-4**
Test Year Restating Adjustments **Page 8**
O&M, Other Tax Items, and Capital Adjustment

Line No.	O&M Items	Adjustment Amount
1	FERC 913 Removal	($101,050)
2	SERP and SRIP Removal	($227,492)
3	LTIP Removal	($112,840)
4	Stock Expense Removal	($249,103)
5	Rate Case Expense Adjustment	($148,523)
6	FTE Adjustment (Incl. Payroll Tax)	$256,438
7	O&M Annual Incentive Removal	($166,239)
8	Total	**($748,810)**

Line No.	Other Tax Items	Adjustment Amount
1	Payroll Taxes	$5,592

Line No.	Capital Items	Adjustment Amount
1	Capital Annual Incentive Removal	($81,903)

NW Natural **Exh. KTW-4**
Test Year Restating Adjustment **Page 9**
Claims Expense Adjustment

Line No.		O&M Expense (a)	Construction (b)
1	**Expensed during Test period**	$129,574	$57,255
	Normalized Expenses		
2	**Actual Claims - Ordinary (Paid)**	24,574	57,255
3	**3-Year Average Claims - Extraordinary 1/**	0	0
4	**Subtotal**	24,574	57,255
5	**Adjustment - System (line 4 - line 1)**	(105,000)	0
6	**Allocation to Washington (O&M on 3-factor, const on gross plant)**	11.80%	12.16%
7	**Adjustment**	($12,390)	$0

1/	**Extraordinary Claims**	TME March
	TME 3/31/23	0
	TME 3/31/24	0
	TME 3/31/25	0
	3-Year Average	0

NW Natural
Test Year Restating Adjustment
Enviromental Cost Recovery Mechanism (ECRM) Adjustment

Exh. KTW-4
Page 10

Line No.		Test Year Expense (a)
1	**ECRM - Test Period Expense**	$432,129
2	**Restating Adjustment**	($432,129)
3	**Total Impact to Revenue Requirement**	$0.00

NW Natural
Test Year Restating and Proforma Adjustment

Exh. KTW-4
Page 11

Line No.		Depreciation Expense (a)
1	**Depreciation Expense (TME 3/31/2025)**	$17,909,187
2	**Depreciation Expense (Period Ending 3/31/2025)**	$18,560,145
3	**Restating Adjustment**	$650,958

NW Natural
Restating and Proforma End of Period Rate Base Adjustments

Line No.		Restating Adjustment for Period Ending March 31, 2025					
		Utility Plant in Service	Accumulated Depreciation	Storage Gas	Customer Contributions	Leasehold Improvements	Accumulated Deferred Income Taxes
		(a)	(b)	(c)	(d)	(e)	(f)
1	**13 mo. AMA of Test Year**	531,605,195	(196,159,084)	2,491,715	(8,645,302)	2,944,797	(49,402,676)
2	**End of Period March 31, 2025**	552,485,418	(201,822,835)	2,491,715	(9,489,599)	2,844,745	(49,402,676)
3	**Adjustment**	$20,880,223	($5,663,751)	$0	($844,297)	($100,052)	$0

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Kyle T. Walker

MULTI-YEAR RATE PLAN AND REVENUE REQUIREMENTS

Exh. KTW-5

August 29, 2025

NW Natural **Exh. KTW-5**
Washington Rate Case **Page 1**
Test Year Based on Twelve Months Ended March 31, 2025

Line No.		Test Year Results (a)	Test Year Adjustments (b)	Test Year Adjusted (c)
	Operating Revenues			
1	**Sale of Gas**	$99,442,515	$7,904,906	$107,347,421
2	**Transportation**	2,228,562	149,492	2,378,053
3	**Miscellaneous Revenues**	4,899,911	(4,798,187)	101,724
4	**Total Operating Revenues**	106,570,987	3,256,211	109,827,198
	Operating Revenue Deductions			
5	**Gas Purchased**	36,014,859	10,466,590	46,481,449
6	**Uncollectible Accrual for Gas Sales**	219,104	109,651	328,755
7	**Other Operating & Maintenance Expenses**	25,936,550	(761,200)	25,175,350
8	**Total Operating & Maintenance Expense**	62,170,513	9,815,041	71,985,554
9	**Environmental Expense**	432,129	(432,129)	0
10	**Federal Income Tax**	2,052,451	(1,582,843)	469,608
11	**Property Taxes**	1,864,317	(173,693)	1,690,624
12	**Other Taxes**	6,444,992	144,046	6,589,038
13	**Depreciation & Amortization**	17,909,187	650,958	18,560,145
14	**Total Operating Revenue Deductions**	90,873,588	8,421,381	99,294,969
15	**Net Operating Revenues**	$15,697,399	($5,165,170)	$10,532,229
16	**Total Rate Base**	282,834,645	31,802,263	314,636,908
17	**Rate of Return**	5.55%		3.35%
18	**Return on Common Equity**	6.41%		1.81%

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Kyle T. Walker

MULTI-YEAR RATE PLAN AND REVENUE REQUIREMENTS

Exh. KTW-6

August 29, 2025

NW Natural
Adjustments to Test Year and RY1
Test Year Based on Twelve Months Ended March 31, 2025
RY1 Based on Twelve Months Ended July 31, 2027

Exh. KTW-6
Page 1

Line No.		Pro Forma Customer Growth Adjustment	Pro Forma EOP Depreciation Exp. Adjustment	Pro Forma EOP (7/31/26) Rate Base Adjustment	Pro Forma O&M TTM (7/31/26) Adjustment	Pro Forma Property Tax Adjustment	Pro Forma Mist Recall Adjustment	Pro Forma Savings Adjustment	Pro Forma Payroll Tax Adjustment	Total Yr1 Pro Forma Total Pro Forma Adjustments
		(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)
	Operating Revenues									
1	Sale of Gas	$1,569,850	$0	$0	$0	$0	$0	$0	$0	$1,569,850
2	Transportation	105,569	0	0	0	0	0	0	0	105,569
3	Miscellaneous Revenues	0	0	0	0	0	0	0	0	0
4	Total Operating Revenues	1,675,419	0	0	0	0	0	0		1,675,419
	Operating Revenue Deductions									
5	Gas Purchased	673,093	0	0	0	0	0	0	0	673,093
6	Uncollectible Accrual	4,299	0	0	0	0	0	0	0	4,299
7	Other Operating & Maintenance Expenses	0	0	0	2,863,128	0	0	(10,710)	0	2,852,419
8	Total Operating & Maintenance Expense	677,392	0	0	2,863,128	0	0	(10,710)	0	3,529,811
9	Environmental Expense	0	0	0	0	0	0	0	0	0
10	Federal Income Tax	194,625	(411,196)	(141,102)	(601,257)	(16,825)	(1,182)	2,397	(9,902)	(984,442)
11	Property Taxes	0	0	0	0	80,119	0	0	0	80,119
12	Other Taxes	71,239	0	0	0	0	0	0	47,153	118,392
13	Depreciation & Amortization	0	1,958,078	0	0	0	3,625	0	0	1,961,703
14	Total Operating Revenue Deductions	943,256	1,546,882	(141,102)	2,261,871	63,294	2,443	(8,313)	37,251	4,705,583
15	Net Operating Revenues	732,163	(1,546,882)	141,102	(2,261,871)	(63,294)	(2,443)	8,313	(37,251)	(3,030,165)
	Average Rate Base									
16	Utility Plant in Service	0	0	49,315,540	0	0	190,604	(28,478)	0	49,477,666
17	Accumulated Depreciation	0	0	(19,092,710)	0	0	(79,252)		0	(19,171,962)
18	Net Utility Plant	0	0	30,222,830	0	0	111,352	(28,478)	0	30,305,704
19	Storage Gas	0	0	0	0	0	0	0	0	0
20	Customer Contributions	0	0	(1,999,366)	0	0	0	0	0	(1,999,366)
21	Leasehold Improvements	0	0	(255,238)	0	0	0	0	0	(255,238)
22	Accumulated Deferred Income Taxes	0	0	(896,663)	0	0	(30,673)	0	0	(927,336)
23	Total Rate Base	0	0	27,071,562	0	0	80,679	(28,478)	0	27,123,764
24	Interest Coordination	0	0	671,916	0	0	2,002	(707)	0	638,493
25	Estimated Revenue Requirement	(970,547)	2,050,532	2,506,185	2,998,314	83,902	11,265	(13,852)	49,380	6,715,178

NW Natural
RY1 Based on Twelve Months Ended July 31, 2027
Weather Normalized Gas Sales and Purchases Adjustment

Exh. KTW-6
Page 2

	Revenues	Normalized Test Year: Therm Deliveries	Normalized Test Year: Average Class Price Per Therm	Normalized Test Year: Revenues and Margin	Test Year Adjustment	Pro Forma Adjustment
		(d)	(e)	(f)	(g)	(g)
	Sales Volumes and Revenues					
1	Residential	59,110,125	1.24265	$73,453,136		
2	Commercial	27,761,753	1.10501	$30,676,903		
3	Industrial Firm	2,804,325	0.88293	$2,476,023		
4	Interruptible	1,113,672	0.66569	$741,359		
5	Total Sales of Gas Revenues	90,789,875		$107,347,421	$7,427,797	$1,569,850
6	Unbilled amounts			$0	$477,109	
	Transportation Volumes and Revenues					
7	Firm	8,601,031	0.16944	$1,457,389		
8	Interruptible	10,089,812	0.09125	$920,664		
9	Special Contracts - Firm	0	n/a	$0		
10	Total Transportation	18,690,842		$2,378,053	$149,492	$105,569
11	Total Deliveries and Revenues	109,480,717		$109,725,474	$8,054,397	$1,675,419
	Gas Costs					
12	Demand Charges (Net of Deferral)			$8,904,428		
13	Commodity Charges (Net of Deferral)			37,577,021		
14	Commodity and Demand Amortizations			0		
15	Total Cost of Gas			$46,481,449	$10,466,590	$673,093
16	Total Margin			$63,244,025	($2,412,193)	$1,002,326

NW Natural
Test Year Restating and Proforma Adjustment

Exh. KTW-6
Page 3

Line No.		Depreciation Expense (a)
1	**Depreciation Expense (TME 3/31/2025)**	$17,909,187
2	**Depreciation Expense (Period Ending 3/31/2025)**	$18,560,145
3	**Restating Adjustment**	$650,958
4	**Depreciation Expense (Period Ending 7/31/2026) [1]**	20,518,223
5	**Proforma Adjustment**	$1,958,078

[1] Based on gross plant at July 31, 2026

NW Natural
Proforma End of Period Rate Base Adjustments

Exh. KTW-6
Page 4

Line No.		Pro Forma Adjustment for Period Ending July 31, 2026					
		Utility Plant in Service	Accumulated Depreciation	Storage Gas	Customer Contributions	Leasehold Improvements	Accumulated Deferred Income Taxes
		(a)	(b)	(c)	(d)	(e)	(f)
1	**End of Period March 31, 2025**	552,485,418	(201,822,835)	2,491,715	(9,489,599)	2,844,745	(49,402,676)
2	**End of Period July 31, 2026**	601,800,958	(220,915,545)	2,491,715	(11,488,965)	2,589,507	(50,299,339)
3	**Adjustment**	$49,315,540	($19,092,710)	$0	($1,999,366)	($255,238)	($896,663)

NW Natural
Proforma and Provisional Adjustments
Washington Post Test-Year Capital Projects

Exh. KTW-6
Page 5

Line No.		Pro Forma Adj. Pro Forma (a)
1	**Addition to Gross Plant (AMA Basis)**	See KTW-6 p4
2	**Addition to Accumulated Depreciation (AMA Basis)**	See KTW-6 p4
3	**Addition to Accumulated Deferred Income Taxes**	($896,663)
4	**Addition to O&M**	$2,863,128
5	**Addition to Property Taxes**	$80,119
6	**Addition to Depreciation Expense**	See KTW-6 p3
7	**Addition to Payroll Taxes**	$47,153
8	**Storage Gas**	See KTW-6 p4
9	**Customer Contributions**	See KTW-6 p4
10	**Leasehold Improvements**	See KTW-6 p4

NW Natural **Exh. KTW-6**
Proforma Adjustment **Page 6**
Mist Recall Rate Base and Depreciation Expense Adjustment

Line No.		Amount
1	**Adjustment to Gross Plant**	$ 190,604
2	**Adjustment to Accumulated Depreciation**	$ (79,252)
3	**Adjustment to Depreciation Expense**	$3,625

NW Natural
Pro Forma Adjustment
Savings

Exh. KTW-6
Page 7

Line No.		Expense (a)
1	**Resource Scheduling Optimization Project**	($88,000)
2	**Washington Allocation**	12.17%
3	**Pro Forma Expense Adjustment**	($10,710)

		Capital (b)
1	**Resource Scheduling Optimization Project**	($234,000)
2	**Washington Allocation**	12.17%
3	**Pro Forma Capital Adjustment**	($28,478)

Northwest Natural Gas Company
Adjustments to Test Period
RY1 Based on Twelve Months Ended July 31, 2027
($000)

Exh. KTW-6
Page 8

Line No.	Income Tax Calculations	Weather Normalized Gas Sales & Purchases	Misc Revenues Adjustment	Property Tax Adjustment	Uncollectible Accounts Adjustment	Working Capital Adjustment	O&M Adjustment	Claims Adjustment	Customer Growth Adjustment	EOP Depreciation Exp. Adjustment	EOP (7/31/26) Rate Base Adjustment	O&M TTM (7/31/26) Adjustment	Property Tax Adjustment	Mist Recall Adjustment	Savings Adjustment	Payroll Tax Adjustment	Total Pro Forma Adjustments
		(a)	(b)	(d)	(e)	(f)	(g)	(h)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
1	Book Revenues	8,054,397	(4,798,187)	0	0	0	0	0	1,675,419	0	0	0	0	0	0	0	1,675,419
2	Book Expenses before Deprec. & Interest	10,829,731	(216,331)	(173,693)	101,295	0	(748,810)	(12,390)	748,631	0	0	2,863,128	80,119	0	(10,710)	47,153	3,728,322
3	State Tax Depreciation	0	0	0	0	0	0	0	0	1,958,078	0	0	0	3,625	0	0	1,961,703
4	Interest Expense (Income)	0	0	0	0	437,131	0	0	0	0	671,916	0	0	2,002	(707)	0	673,211
5	Book/Tax Differences (Sched. M)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Federal Taxable Income	(2,775,334)	(4,581,855)	173,693	(101,295)	(437,131)	748,810	12,390	926,788	(1,958,078)	(671,916)	(2,863,128)	(80,119)	(5,627)	11,417	(47,153)	(4,687,818)
7	Federal Income Tax [1]	(582,820)	(962,190)	36,475	(21,272)	(91,798)	157,250	2,602	194,625	(411,196)	(141,102)	(601,257)	(16,825)	(1,182)	2,397	(9,902)	(984,442)
8	ITC/EDIT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Current Federal Tax	(582,820)	(962,190)	36,475	(21,272)	(91,798)	157,250	2,602	194,625	(411,196)	(141,102)	(601,257)	(16,825)	(1,182)	2,397	(9,902)	(984,442)
10	Deferred Income Tax - Federal	0	0	0	0	0	0	0	0	0	0	0	0	(30,673)	0	0	(30,673)
11	Deferred Income Tax - State	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	ITC Restored (Deferred)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Federal Tax	(582,820)	(962,190)	36,475	(21,272)	(91,798)	157,250	2,602	194,625	(411,196)	(141,102)	(601,257)	(16,825)	(31,855)	2,397	(9,902)	(1,015,115)

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Kyle T. Walker

MULTI-YEAR RATE PLAN AND REVENUE REQUIREMENTS

Exh. KTW-7

August 29, 2025

NW Natural
Adjustments to Test Year and RY1
Test Year Based on Twelve Months Ended March 31, 2025
RY1 Based on Twelve Months Ended July 31, 2027

Line No.		Provisional Customer Growth Adjustment (v)	Provisional O&M Expense Adjustment (w)	Provisional Tax Expense Adjustment (x)	Provisional Payroll Tax Adjustment (y)	Total Yr1 Provisional Total Year 1 Provisional Adj. (z)
	Operating Revenues					
1	**Sale of Gas**	$535,735	$0	$0	$0	$535,735
2	**Transportation**	(2,074)	0	0	0	($2,074)
3	**Miscellaneous Revenues**	0	0	0	0	$0
4	**Total Operating Revenues**	533,661	0	0	0	533,661
	Operating Revenue Deductions					
5	**Gas Purchased**	186,155	0	0	0	186,155
6	**Uncollectible Accrual**	1,369	0	0	0	1,369
7	**Other Operating & Maintenance Expenses**	0	1,619,913	0	0	1,619,913
8	**Total Operating & Maintenance Expense**	187,524	1,619,913	0	0	1,807,437
9	**Environmental Expense**	0	0	0	0	0
10	**Federal Income Tax**	67,924	(340,182)	78,339	(8,149)	(202,068)
11	**Property Taxes**	0	0	0	0	0
12	**Other Taxes**	22,691	0	0	38,805	61,497
13	**Depreciation & Amortization**					0
14	**Total Operating Revenue Deductions**	278,140	1,279,731	78,339	30,656	1,666,866
15	**Net Operating Revenues**	255,521	(1,279,731)	(78,339)	(30,656)	(1,133,205)
	Average Rate Base					
16	**Utility Plant in Service**	0	0	0	0	0
17	**Accumulated Depreciation**	0	0	0	0	0
18	**Net Utility Plant**	0	0	0	0	0
						0
19	**Storage Gas**	0	0	0	0	0
20	**Customer Contributions**	0	0	0	0	0
21	**Leasehold Improvements**	0	0	0	0	0
22	**Accumulated Deferred Income Taxes**	0	0	0	0	0
23	**Total Rate Base**	0	0	0	0	0
24	**Interest Coordination**	0	0	(437,454)	0	(437,454)
						0
25	**Estimated Revenue Requirement**	(338,717)	1,696,398	103,845	40,638	1,502,165

NW Natural
RY1 Based on Twelve Months Ended July 31, 2027
Weather Normalized Gas Sales and Purchases Adjustment

Exh. KTW-7
Page 2

	Revenues	Normalized RY 1 Therm Deliveries (d)	Normalized RY 1 Average Class Price Per Therm (e)	Normalized RY 1 Revenues and Margin (f)	RY 1 Adjustment (g)
	Sales Volumes and Revenues				
1	Residential	60,104,871	1.24480	$74,818,389	
2	Commercial	28,425,313	1.10395	$31,380,199	
3	Industrial Firm	2,794,487	0.89207	$2,492,891	
4	Interruptible	1,144,860	0.66517	$761,525	
5	Total Sales of Gas Revenues	92,469,530		$109,453,005	$535,735
6	Unbilled amounts				
	Transportation Volumes and Revenues				
7	Firm	8,661,699	0.15659	$1,356,365	
8	Interruptible	10,039,111	0.11208	$1,125,184	
9	Special Contracts - Firm	0	n/a	$0	
10	Total Transportation	18,700,809		$2,481,549	($2,074)
11	Total Deliveries and Revenues	111,170,340		$111,934,553	
	Gas Costs				
12	Demand Charges (Net of Deferral)			$9,068,479	
13	Commodity Charges (Net of Deferral)			38,272,218	
14	Commodity and Demand Amortizations			0	
15	Total Cost of Gas			$47,340,697	$186,155
16	Total Margin			$64,593,856	

NW Natural
Proforma and Provisional Adjustments
Washington Post Test-Year Capital Projects

Exh. KTW-7
Page 3

Line No.		Provisional Adjustments RY 1
1	Addition to Gross Plant (AMA Basis)	-
2	Addition to Accumulated Depreciation (AMA Basis)	-
3	Addition to Accumulated Deferred Income Taxes	-
4	Addition to O&M	$1,619,913
5	Addition to Property Taxes	$ -
6	Addition to Depreciation Expense	$ -
7	Addition to Payroll Taxes	$ 38,805
8	Storage Gas	$ -
9	Customer Contributions	$ -
10	Leasehold Improvements	$ -

Northwest Natural Gas Company
Adjustments to Test Period
RY1 Based on Twelve Months Ended July 31, 2027
($000)

Exh. KTW-7
Page 4

Line No.	Income Tax Calculations	Customer Growth Adjustment	O&M Expense Adjustment	Tax Expense Adjustment	Payroll Tax Adjustment	Total Yr1 Provisional Adjustments
		(w)	(x)	(y)	(z)	(aa)
1	Book Revenues	533,661	0	0	0	533,661
2	Book Expenses before Deprec. & Interest	210,216	1,619,913	0	38,805	1,868,934
3	State Tax Depreciation	0	0	0	0	0
4	Interest Expense (Income)	0	0	(437,454)	0	(437,454)
5	Book/Tax Differences (Sched. M)	0	0	54,636	0	54,636
6	Federal Taxable Income	323,445	(1,619,913)	492,090	(38,805)	(843,183)
7	Federal Income Tax [1]	67,924	(340,182)	103,339	(8,149)	(177,068)
8	ITC/EDIT	0	0	(25,000)	0	(25,000)
9	Current Federal Tax	67,924	(340,182)	78,339	(8,149)	(202,068)
10	Deferred Income Tax - Federal	0	0	0	0	0
11	Deferred Income Tax - State	0	0	0	0	0
12	ITC Restored (Deferred)	0	0	0	0	0
13	Total Federal Tax	67,924	(340,182)	78,339	(8,149)	(202,068)

NW Natural
Washington Rate Case
Test Year Based on Twelve Months Ended March 31, 2025

Line No.		Test Year Results	Test Year Adjustments	Test Year Adjusted	RY 1 Adjustments	RY 1 Adjusted	Proposed RY 1 Rate Increase	RY 1 at 10.1% Equity Return
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Operating Revenues							
1	**Sale of Gas**	$99,442,515	$7,904,906	$107,347,421	$2,105,584	$109,453,005	$25,557,744	$135,010,749
2	**Transportation**	2,228,562	149,492	2,378,053	103,495	2,481,549		2,481,549
3	**Miscellaneous Revenues**	4,899,911	(4,798,187)	101,724	0	101,724		101,724
4	**Total Operating Revenues**	106,570,987	3,256,211	109,827,198	2,209,080	112,036,277	25,557,744	137,594,022
	Operating Revenue Deductions							
5	**Gas Purchased**	36,014,859	10,466,590	46,481,449	859,248	47,340,697		47,340,697
6	**Uncollectible Accrual for Gas Sales**	219,104	109,651	328,755	5,669	334,423	65,583	400,007
7	**Other Operating & Maintenance Expenses**	25,936,550	(761,200)	25,175,350	4,472,331	29,647,682		29,647,682
8	**Total Operating & Maintenance Expense**	62,170,513	9,815,041	71,985,554	5,337,248	77,322,802	65,583	77,388,385
9	**Environmental Expense**	432,129	(432,129)	0	0	0		0
10	**Federal Income Tax**	2,052,451	(1,582,843)	469,608	(1,186,510)	(716,902)	5,125,144	4,408,242
11	**Property Taxes**	1,864,317	(173,693)	1,690,624	80,119	1,770,743	0	1,770,743
12	**Other Taxes**	6,444,992	144,046	6,589,038	179,889	6,768,927	1,086,715	7,855,642
13	**Depreciation & Amortization**	17,909,187	650,958	18,560,145	1,961,703	20,521,848	0	20,521,848
14	**Total Operating Revenue Deductions**	90,873,588	8,421,381	99,294,969	6,372,449	105,667,417	6,277,442	111,944,860
15	**Net Operating Revenues**	$15,697,399	($5,165,170)	$10,532,229	($4,163,369)	$6,368,860	$19,280,302	$25,649,162
16	**Total Rate Base**	282,834,645	31,802,263	314,636,908	$27,123,764	341,760,672	$0	$341,760,672
17	**Rate of Return**	5.55%		3.35%		1.86%		7.51%
18	**Return on Common Equity**	6.41%		1.81%		-0.96%		10.10%

NW Natural **Exh. KTW-7**
RY1 Based on Twelve Months Ended July 31, 2027 **Page 6**
Cost of Capital and Revenue Sensitive Calculations

Line No.		Year 1 Percent of Total Capital (a)	Average Cost (b)	Weighted Cost (c)
	Cost of Capital			
1	**Long Term Debt**	48.00%	4.779%	2.294%
2	**Short Term Debt**	1.00%	6.040%	0.060%
3	**Common Stock**	51.00%	10.100%	5.151%
	[1] Actual cost of debt used			
4	**Total**	100.00%		7.505%
	Revenue Sensitive Costs			
5	**Gas Sales**	97.694%		
6	**Transportation**	2.215%		
7	**Other**	0.091%		
8	**Subtotal**	100.000%		
9	**O & M - Uncollectible**	0.257%		
10	**WA Utility Tax**	3.852%		
11	**WUTC Fee**	0.400%		
12	**Total Rev Sensitive Costs Incl Tax**	4.5086%		
13	**Federal Taxable Income**	95.491%		
14	**Federal Income Tax**	20.053%		
15	**Total Income Taxes**	20.053%		
16	**Total Rev Sensitive Costs Incl Tax**	24.562%		
17	**Utility Operating Income**	75.438%		
18	**Net-to-gross factor**	132.559%		
19	**Interest Coordination Factor**	2.354%		
20	**Federal tax rate**	21.000%		
21	**Uncollectible Accounts**	0.257%		

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Kyle T. Walker

MULTI-YEAR RATE PLAN AND REVENUE REQUIREMENTS

Exh. KTW-8

August 29, 2025

NW Natural
Provisional Adjustments to RY2
RY2 Based on Twelve Months Ended July 31, 2028

Exh. KTW-8
Page 1

Line No.		Provisional Customer Growth Adjustment (a)	Provisional O&M Expense Adjustment (b)	Provisional Property Tax Adjustment (c)	Provisional Depreciation Expense Adjustment (d)	Provisional AMA Rate Base Adjustment (e)	Provisional Tax Expense Adjustment (f)	Provisional TENs Adjustment (g)	Provisional Payroll Tax Adjustment (h)	Total Yr2 Provisional Total Year 2 Provisional Adj. (i)
	Operating Revenues									
1	**Sale of Gas**	201,701	0	0	0	0	0	0	0	201,701
2	**Transportation**	653,989	0	0	0	0	0	0	0	653,989
3	**Miscellaneous Revenues**									0
4	**Total Operating Revenues**	855,691	0	0	0	0	0	0	0	855,691
	Operating Revenue Deductions									
5	**Gas Purchased**	300,854	0	0	0	0	0	0	0	300,854
6	**Uncollectible Accrual**	2,196	0	0	0	0	0	0	0	2,196
7	**Other Operating & Maintenance Expenses**	0	1,816,848	0	0	0	0	9,528	0	1,826,376
8	**Total Operating & Maintenance Expense**	303,050	1,816,848	0	0	0	0	9,528	0	2,129,425
9	**Federal Income Tax**	108,414	(381,538)	(50,327)	(572,446)	(194,222)	(184,710)	(55,155)	(8,549)	(1,338,533)
10	**Property Taxes**	0	0	239,652	0	0	0	0	0	239,652
11	**Other Taxes**	36,384	0	0	0	0	0	0	40,709	77,093
12	**Depreciation & Amortization**	0	0	0	2,725,934	0	0	75,534	0	2,801,469
13	**Total Operating Revenue Deductions**	447,848	1,435,310	189,325	2,153,488	(194,222)	(184,710)	29,907	32,160	3,909,105
14	**Net Operating Revenues**	407,843	(1,435,310)	(189,325)	(2,153,488)	194,222	184,710	(29,907)	(32,160)	(3,053,415)
	Average Rate Base									
15	**Utility Plant in Service**	0	0	0	0	65,831,600	0	1,476,917	0	67,308,517
16	**Accumulated Depreciation**	0	0	0	0	(24,219,429)	0	(6,295)	0	(24,225,724)
17	**Net Utility Plant**	0	0	0	0	41,612,171	0	1,470,623	0	43,082,793
18	**Storage Gas**	0	0	0	0	0	0	0	0	0
19	**Customer Contributions**	0	0	0	0	(1,628,134)	0	0	0	(1,628,134)
20	**Leasehold Improvements**	0	0	0	0	(287,143)	0	0	0	(287,143)
21	**Accumulated Deferred Income Taxes**	0	0	0	0	(1,495,066)	0	0	0	(1,495,066)
22	**Total Rate Base**	0	0	0	0	38,201,828	0	1,470,623	0	39,672,450
23	**Interest Coordination**	0	0	0	0	924,866	228,980	35,604	0	1,189,450
24	**Estimated Revenue Requirement**	(540,633)	1,902,633	250,967	2,854,643	3,602,825	(244,850)	188,250	42,630	8,056,466

NW Natural
RY2 Based on Twelve Months Ended July 31, 2028
Weather Normalized Gas Sales and Purchases Adjustment

Exh. KTW-8
Page 2

		Normalized RY 2		
		Average Class Price Per Therm	Revenues and Margin	RY 2 Adjustment
	Revenues	(e)	(f)	(g)
	Sales Volumes and Revenues			
1	Residential	1.53224	$92,799,044	
2	Commercial	1.35748	$38,780,340	
3	Industrial Firm	0.99976	$2,782,697	
4	Interruptible	0.74595	$850,369	
5	Total Sales of Gas Revenues		$135,212,451	$201,701
6	Unbilled amounts			
	Transportation Volumes and Revenues			
7	Firm	0.19951	$1,714,565	
8	Interruptible	0.14270	$1,420,973	
9	Special Contracts - Firm	n/a	$0	
10	Total Transportation		$3,135,538	$653,989
11	Total Deliveries and Revenues		$138,347,988	
	Gas Costs			
12	Demand Charges (Net of Deferral)		$9,126,742	
13	Commodity Charges (Net of Deferral)		38,514,809	
14	Commodity and Demand Amortizations		0	
15	Total Cost of Gas		$47,641,551	$300,854
16	Total Margin		$90,706,437	

NW Natural
Proforma and Provisional Adjustments
Washington Post Test-Year Capital Projects

Exh. KTW-8
Page 3

Line No.		Provisional Adjustments RY 2
1	**Addition to Gross Plant (AMA Basis)**	65,831,600
2	**Addition to Accumulated Depreciation (AMA Basis)**	24,219,429
3	**Addition to Accumulated Deferred Income Taxes**	($1,495,066)
4	**Addition to O&M**	$1,816,848
5	**Addition to Property Taxes**	$239,652
6	**Addition to Depreciation Expense**	$ 2,725,934
7	**Addition to Payroll Taxes**	$ 40,709
8	**Storage Gas**	$ -
9	**Customer Contributions**	$ (1,628,134)
10	**Leasehold Improvements**	$ (287,143)

NW Natural **Exh. KTW-8**
RY2/RY3 Provisional Adjustment **Page 4**
Thermal Energy Network's (TENs)

Line No.		TENs RY2 Cost of Service [1]
		(a)
	Expenses:	
	Other Operating & Maintenance Expenses	$9,528
	Depreciation Expense	$75,534
	Average Rate Base:	
	Utility Plant in Service	$1,476,917
	Accumulated Depreciation	($6,295)
	Net Utility Plant	$1,470,623
	Investment Tax Credits	($29,815)

[1] Rate base reflects a 13-mo AMA basis.

Northwest Natural Gas Company
Adjustments to Test Period
RY2 Based on Twelve Months Ended July 31, 2027
($000)

Exh. KTW-8
Page 5

Line No.	Income Tax Calculations	Customer Growth Adjustment	O&M Expense Adjustment	Property Tax Adjustment	Depreciation Expense Adjustment	AMA Rate Base Adjustment	Tax Expense Adjustment	TENs Adjustment	Payroll Tax Adjustment	Total Yr2 Provisional Adjustments
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Book Revenues	855,691	0	0	0	0	0	0	0	855,691
2	Book Expenses before Deprec. & Interest	339,434	1,816,848	239,652	0	0	0	9,528	40,709	2,446,170
3	State Tax Depreciation	0	0	0	2,725,934	0	0	75,534	0	2,801,469
4	Interest Expense (Income)	0	0	0	0	924,866	228,980	35,604	0	1,189,450
5	Book/Tax Differences (Sched. M)	0	0	0	0	0	(650,590)	0	0	(650,590)
6	Federal Taxable Income	516,257	(1,816,848)	(239,652)	(2,725,934)	(924,866)	(879,570)	(120,666)	(40,709)	(6,231,988)
7	Federal Income Tax [1]	108,414	(381,538)	(50,327)	(572,446)	(194,222)	(184,710)	(25,340)	(8,549)	(1,308,718)
8	ITC/EDIT	0	0	0	0	0	0	(29,815)	0	(29,815)
9	Current Federal Tax	108,414	(381,538)	(50,327)	(572,446)	(194,222)	(184,710)	(55,155)	(8,549)	(1,338,533)
10	Deferred Income Tax - Federal	0	0	0	0	0	0	0	0	0
11	Deferred Income Tax - State	0	0	0	0	0	0	0	0	0
12	ITC Restored (Deferred)	0	0	0	0	0	0	0	0	0
13	Total Federal Tax	108,414	(381,538)	(50,327)	(572,446)	(194,222)	(184,710)	(55,155)	(8,549)	(1,338,533)

NW Natural
Washington Rate Case
Test Year Based on Twelve Months Ended March 31, 2025

Exh. KTW-8
Page 6

Line No.		Test Year Results	Test Year Adjustments	Test Year Adjusted	RY 1 Adjustments	RY 1 Adjusted	Proposed RY 1 Rate Increase	RY 1 at 10.1% Equity Return	RY2 Adjustments	RY2 Adjusted	Proposed Year 2 Rate Increase	RY2 at 10.2% Equity Return
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Operating Revenues											
1	**Sale of Gas**	$99,442,515	$7,904,906	$107,347,421	$2,105,584	$109,453,005	$25,557,744	$135,010,749	$201,701	$135,212,451	$8,591,015	$143,803,466
2	**Transportation**	2,228,562	149,492	2,378,053	103,495	2,481,549		2,481,549	653,989	3,135,538		3,135,538
3	**Miscellaneous Revenues**	4,899,911	(4,798,187)	101,724	0	101,724		101,724	0	101,724		101,724
4	**Total Operating Revenues**	106,570,987	3,256,211	109,827,198	2,209,080	112,036,277	25,557,744	137,594,022	855,691	138,449,713	8,591,015	147,040,728
	Operating Revenue Deductions											
5	**Gas Purchased**	36,014,859	10,466,590	46,481,449	859,248	47,340,697		47,340,697	300,854	47,641,551		47,641,551
6	**Uncollectible Accrual for Gas Sales**	219,104	109,651	328,755	5,669	334,423	65,583	400,007	2,196	402,202	22,045	424,248
7	**Other Operating & Maintenance Expenses**	25,936,550	(761,200)	25,175,350	4,472,331	29,647,682		29,647,682	1,826,376	31,474,057		31,474,057
8	**Total Operating & Maintenance Expense**	62,170,513	9,815,041	71,985,554	5,337,248	77,322,802	65,583	77,388,385	2,129,425	79,517,811	22,045	79,539,856
9	**Environmental Expense**	432,129	(432,129)	0	0	0		0	0	0		0
10	**Federal Income Tax**	2,052,451	(1,582,843)	469,608	(1,186,510)	(716,902)	5,125,144	4,408,242	(1,338,533)	3,069,709	1,722,773	4,792,481
11	**Property Taxes**	1,864,317	(173,693)	1,690,624	80,119	1,770,743	0	1,770,743	239,652	2,010,395	0	2,010,395
12	**Other Taxes**	6,444,992	144,046	6,589,038	179,889	6,768,927	1,086,715	7,855,642	77,093	7,932,735	365,290	8,298,025
13	**Depreciation & Amortization**	17,909,187	650,958	18,560,145	1,961,703	20,521,848	0	20,521,848	2,801,469	23,323,317	0	23,323,317
14	**Total Operating Revenue Deductions**	90,873,588	8,421,381	99,294,969	6,372,449	105,667,417	6,277,442	111,944,860	3,909,105	115,853,965	2,110,108	117,964,073
15	**Net Operating Revenues**	$15,697,399	($5,165,170)	$10,532,229	($4,163,369)	$6,368,860	$19,280,302	$25,649,162	($3,053,415)	$22,595,748	$6,480,907	$29,076,655
16	**Total Rate Base**	282,834,645	31,802,263	314,636,908	$27,123,764	341,760,672	$0	$341,760,672	$39,672,450	$381,433,122	$0	$381,433,122
17	**Rate of Return**	5.55%		3.35%		1.86%		7.51%		5.92%		7.62%
18	**Return on Common Equity**	6.41%		1.81%		-0.96%		10.10%		6.87%		10.20%

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Kyle T. Walker

MULTI-YEAR RATE PLAN AND REVENUE REQUIREMENTS

Exh. KTW-9

August 29, 2025

NW Natural
Adjustments to RY3
RY3 Based on Twelve Months Ended July 31, 2029

Exh. KTW-9
Page 1

Line No.		Provisional Customer Growth Adjustment (a)	Provisional O&M Expense Adjustment (b)	Provisional Property Tax Adjustment (c)	Provisional Depreciation Expense Adjustment (d)	Provisional AMA Rate Base Adjustment (e)	Provisional Tax Expense Adjustment (f)	Provisional TENs Adjustment (g)	Provisional Payroll Tax Adjustment (h)	Total Yr3 Provisional Total Year 3 Provisional Adj. (i)
	Operating Revenues									
1	**Sale of Gas**	864,647	0	0	0	0	0	0	0	864,647
2	**Transportation**	271,621	0	0	0	0	0	0	0	271,621
3	**Miscellaneous Revenues**									0
4	**Total Operating Revenues**	1,136,268	0	0	0	0	0	0	0	1,136,268
										0
	Operating Revenue Deductions									0
5	**Gas Purchased**	316,409	0	0	0	0	0	0	0	316,409
6	**Uncollectible Accrual**	2,916	0	0	0	0	0	0	0	2,916
7	**Other Operating & Maintenance Expenses**	0	946,359	0	0	0	0	47,703	0	994,062
8	**Total Operating & Maintenance Expense**	319,325	946,359	0	0	0	0	47,703	0	1,313,386
9	**Federal Income Tax**	161,412	(198,735)	(34,748)	(694,909)	(161,257)	(35,035)	(215,826)	(8,968)	(1,188,066)
10	**Property Taxes**	0	0	165,465	0	0	0	0	0	165,465
11	**Other Taxes**	48,314	0	0	0	0	0	0	42,705	91,019
12	**Depreciation & Amortization**	0	0	0	3,309,092	0	0	378,188	0	3,687,280
13	**Total Operating Revenue Deductions**	529,051	747,624	130,717	2,614,183	(161,257)	(35,035)	210,066	33,737	4,069,085
14	**Net Operating Revenues**	607,217	(747,624)	(130,717)	(2,614,183)	161,257	35,035	(210,066)	(33,737)	(2,932,817)
	Average Rate Base									
15	**Utility Plant in Service**	0	0	0	0	50,502,549	0	10,351,916	0	60,854,465
16	**Accumulated Depreciation**	0	0	0	0	(18,799,784)	0	(333,997)	0	(19,133,781)
17	**Net Utility Plant**	0	0	0	0	31,702,764	0	10,017,919	0	41,720,684
18	**Storage Gas**	0	0	0	0	0	0	0	0	0
19	**Customer Contributions**	0	0	0	0	237,997	0	0	0	237,997
20	**Leasehold Improvements**	0	0	0	0	(191,429)	0	0	0	(191,429)
21	**Accumulated Deferred Income Taxes**	0	0	0	0	(521,647)	0	0	0	(521,647)
22	**Total Rate Base**	0	0	0	0	31,227,685	0	10,017,919	0	41,245,605
23	**Interest Coordination**	0	0	0	0	767,889	144,945	246,341	0	970,922
24	**Estimated Revenue Requirement**	(804,921)	991,042	173,277	3,465,335	2,957,519	(46,442)	1,295,815	44,722	8,076,346

NW Natural
RY3 Based on Twelve Months Ended July 31, 2029
Weather Normalized Gas Sales and Purchases Adjustment

Exh. KTW-9
Page 2

	Revenues	Normalized RY 3 Therm Deliveries	Normalized RY 3 Average Class Price Per Therm	Normalized RY 3 Revenues and Margin	RY 3 Adjustment
		(d)	(e)	(f)	(g)
	Sales Volumes and Revenues				
1	Residential	61,034,105	1.62984	$99,475,652	
2	Commercial	28,740,118	1.44096	$41,413,475	
3	Industrial Firm	2,767,058	1.04822	$2,900,482	
4	Interruptible	1,133,987	0.77470	$878,504	
5	Total Sales of Gas Revenues	93,675,268		$144,668,113	$864,647
6	Unbilled amounts				
	Transportation Volumes and Revenues				
7	Firm	8,504,257	0.21912	$1,863,495	
8	Interruptible	9,857,430	0.15660	$1,543,664	
9	Special Contracts - Firm	0	n/a	$0	
10	Total Transportation	18,361,687		$3,407,159	$271,621
11	Total Deliveries and Revenues	112,036,955		$148,075,272	
	Gas Costs				
12	Demand Charges (Net of Deferral)			$9,186,701	
13	Commodity Charges (Net of Deferral)			38,771,259	
14	Commodity and Demand Amortizations			0	
15	Total Cost of Gas			$47,957,960	$316,409
16	Total Margin			$100,117,312	

NW Natural
Proforma and Provisional Adjustments
Washington Post Test-Year Capital Projects

Exh. KTW-9
Page 3

Line No.		Provisional Adjustment RY 3
1	**Addition to Gross Plant (AMA Basis)**	$50,502,549
2	**Addition to Accumulated Depreciation (AMA Basis)**	$18,799,784
3	**Addition to Accumulated Deferred Income Taxes**	($521,647)
4	**Addition to O&M**	$946,359
5	**Addition to Property Taxes**	$165,465
6	**Addition to Depreciation Expense**	$ 3,309,092
7	**Addition to Payroll Taxes**	$ 42,705
8	**Storage Gas**	$ -
9	**Customer Contributions**	$ 237,997
10	**Leasehold Improvements**	$ (191,429)

NW Natural **Exh. KTW-9**
RY2/RY3 Provisional Adjustment **Page 4**
Thermal Energy Network's (TENs)

Line No.		TENs RY3 Cost of Service [1] (a)
	Expenses:	
	Other Operating & Maintenance Expenses	$57,231
	Depreciation Expense	$453,722
	Average Rate Base:	
	Utility Plant in Service	$11,828,834
	Accumulated Depreciation	($340,292)
	Net Utility Plant	$11,488,542
	Investment Tax Credits	($104,472)

[1] Rate base reflects a 13-mo AMA basis.

Northwest Natural Gas Company
Provisional Adjustments to RY3
RY3 Based on Twelve Months Ended July 31, 2029
($000)

Exh. KTW-9
Page 5

Line No.	Income Tax Calculations	Customer Growth Adjustment	O&M Expense Adjustment	Property Tax Adjustment	Depreciation Expense Adjustment	AMA Rate Base Adjustment	Tax Expense Adjustment	TENs Adjustment	Payroll Tax Adjustment	Total Yr3 Provisional Adjustments
1	**Book Revenues**	1,136,268	0	0	0	0	0	0	0	1,136,268
2	**Book Expenses before Deprec. & Interest**	367,639	946,359	165,465	0	0	0	47,703	42,705	1,569,871
3	**State Tax Depreciation**	0	0	0	3,309,092	0	0	378,188	0	3,687,280
4	**Interest Expense (Income)**	0	0	0	0	767,889	144,945	246,341	0	1,159,175
5	**Book/Tax Differences (Sched. M)**	0	0	0	0	0	(21,890)	0	0	(21,890)
6	**Federal Taxable Income**	768,629	(946,359)	(165,465)	(3,309,092)	(767,889)	(166,835)	(672,232)	(42,705)	(5,301,947)
7	**Federal Income Tax [1]**	161,412	(198,735)	(34,748)	(694,909)	(161,257)	(35,035)	(141,169)	(8,968)	(1,113,409)
8	**ITC/EDIT**	0	0	0	0	0	0	(74,657)	0	(74,657)
9	**Current Federal Tax**	161,412	(198,735)	(34,748)	(694,909)	(161,257)	(35,035)	(215,826)	(8,968)	(1,188,066)
										0
10	**Deferred Income Tax - Federal**	0	0	0	0	0	0	0	0	0
11	**Deferred Income Tax - State**	0	0	0	0	0	0	0	0	0
12	**ITC Restored (Deferred)**	0	0	0	0	0	0	0	0	0
13	**Total Federal Tax**	161,412	(198,735)	(34,748)	(694,909)	(161,257)	(35,035)	(215,826)	(8,968)	(1,188,066)

NW Natural
Washington Rate Case
Test Year Based on Twelve Months Ended March 31, 2025

Exh. KTW-9
Page 6

Line No.		Test Year Results	Test Year Adjustments	Test Year Adjusted	RY 1 Adjustments	RY 1 Adjusted	Proposed RY 1 Rate Increase	RY 1 at 10.1% Equity Return	RY2 Adjustments	RY2 Adjusted	Proposed Year 2 Rate Increase	RY2 at 10.2% Equity Return	RY3 Adjustments	RY3 Adjusted	Proposed Year 3 Rate Increase	RY3 at 10.2% Equity Return
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Operating Revenues															
1	**Sale of Gas**	$99,442,515	$7,904,906	$107,347,421	$2,105,584	$109,453,005	$25,557,744	$135,010,749	$201,701	$135,212,451	$8,591,015	$143,803,466	$864,647	$144,668,113	$8,268,473	$152,936,586
2	**Transportation**	2,228,562	149,492	2,378,053	103,495	2,481,549		2,481,549	653,989	3,135,538		3,135,538	271,621	3,407,159		3,407,159
3	**Miscellaneous Revenues**	4,899,911	(4,798,187)	101,724	0	101,724		101,724	0	101,724		101,724	0	101,724		101,724
4	**Total Operating Revenues**	106,570,987	3,256,211	109,827,198	2,209,080	112,036,277	25,557,744	137,594,022	855,691	138,449,713	8,591,015	147,040,728	1,136,268	148,176,996	8,268,473	156,445,469
	Operating Revenue Deductions															
5	**Gas Purchased**	36,014,859	10,466,590	46,481,449	859,248	47,340,697		47,340,697	300,854	47,641,551		47,641,551	316,409	47,957,960		47,957,960
6	**Uncollectible Accrual for Gas Sales**	219,104	109,651	328,755	5,669	334,423	65,583	400,007	2,196	402,202	22,045	424,248	2,916	427,163	21,218	448,381
7	**Other Operating & Maintenance Expenses**	25,936,550	(761,200)	25,175,350	4,472,331	29,647,682		29,647,682	1,826,376	31,474,057		31,474,057	994,062	32,468,119		32,468,119
8	**Total Operating & Maintenance Expense**	62,170,513	9,815,041	71,985,554	5,337,248	77,322,802	65,583	77,388,385	2,129,425	79,517,811	22,045	79,539,856	1,313,386	80,853,242	21,218	80,874,460
9	**Environmental Expense**	432,129	(432,129)	0	0	0		0	0	0		0	0	0		0
10	**Federal Income Tax**	2,052,451	(1,582,843)	469,608	(1,186,510)	(716,902)	5,125,144	4,408,242	(1,338,533)	3,069,709	1,722,773	4,792,481	(1,188,066)	3,604,416	1,658,093	5,262,509
11	**Property Taxes**	1,864,317	(173,693)	1,690,624	80,119	1,770,743	0	1,770,743	239,652	2,010,395	0	2,010,395	165,465	2,175,860	0	2,175,860
12	**Other Taxes**	6,444,992	144,046	6,589,038	179,889	6,768,927	1,086,715	7,855,642	77,093	7,932,735	365,290	8,298,025	91,019	8,389,044	351,575	8,740,619
13	**Depreciation & Amortization**	17,909,187	650,958	18,560,145	1,961,703	20,521,848	0	20,521,848	2,801,469	23,323,317	0	23,323,317	3,687,280	27,010,596	0	27,010,596
14	**Total Operating Revenue Deductions**	90,873,588	8,421,381	99,294,969	6,372,449	105,667,417	6,277,442	111,944,860	3,909,105	115,853,965	2,110,108	117,964,073	4,069,085	122,033,158	2,030,886	124,064,044
15	**Net Operating Revenues**	$15,697,399	($5,165,170)	$10,532,229	($4,163,369)	$6,368,860	$19,280,302	$25,649,162	($3,053,415)	$22,595,748	$6,480,907	$29,076,655	($2,932,817)	$26,143,838	$6,237,587	$32,381,425
16	**Total Rate Base**	282,834,645	31,802,263	314,636,908	$27,123,764	341,760,672	$0	$341,760,672	$39,672,450	$381,433,122	$0	$381,433,122	$41,245,605	$422,678,727	$0	$422,678,727
17	**Rate of Return**	5.55%		3.35%		1.86%		7.51%		5.92%		7.62%		6.19%		7.66%
18	**Return on Common Equity**	6.41%		1.81%		-0.96%		10.10%		6.87%		10.20%		7.31%		10.20%

NW Natural **Exh. KTW-9**
RY3 Based on Twelve Months Ended July 31, 2029 **Page 7**
Cost of Capital and Revenue Sensitive Calculations

Line No.		Year 3 Percent of Total Capital (a)	Average Cost (b)	Weighted Cost (c)
	Cost of Capital			
1	**Long Term Debt**	48.00%	5.005%	2.402%
2	**Short Term Debt**	1.00%	5.675%	0.057%
3	**Common Stock**	51.00%	10.200%	5.202%
	[1] Actual cost of debt used			
4	**Total**	100.00%		7.661%
	Revenue Sensitive Costs			
5	**Gas Sales**	97.632%		
6	**Transportation**	2.299%		
7	**Other**	0.069%		
8	**Subtotal**	100.000%		
9	**O & M - Uncollectible**	0.257%		
10	**WA Utility Tax**	3.852%		
11	**WUTC Fee**	0.400%		
12	**Total Rev Sensitive Costs Incl Tax**	4.5086%		
13	**Federal Taxable Income**	95.491%		
14	**Federal Income Tax**	20.053%		
15	**Total Income Taxes**	20.053%		
16	**Total Rev Sensitive Costs Incl Tax**	24.562%		
17	**Utility Operating Income**	75.438%		
18	**Net-to-gross factor**	132.559%		
19	**Interest Coordination Factor**	2.459%		
20	**Federal tax rate**	21.000%		
21	**Uncollectible Accounts**	0.257%		

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Kyle T. Walker

MULTI-YEAR RATE PLAN AND REVENUE REQUIREMENTS

Exh. KTW-10

August 29, 2025

NW Natural **Exh. KTW-10**

2024 Bill Assistance and Bill Discount Program as Percent of Revenue

Bill discount program	$1,937,820	Advice 24-15; UG-240881
GREAT program	$867,320	Advice 24-08; UG-240696
WALIEE program	$115,495	Advice 24-08; UG-240696
Arrearage Management Program	$0	cost recovery to start in 2025 PGA
Income-eligible programs	$2,920,635	
2024 Washington CBR Normalized Revenue	$109,949,935	UG-250296 filed 4/29/2025
Program costs as % of Revenue	2.7%	

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Kyle T. Walker

MULTI-YEAR RATE PLAN AND REVENUE REQUIREMENTS

Exh. KTW-11C

REDACTED VERSION

August 29, 2025

THIS EXHIBIT IS BEING FILED IN ITS NATIVE EXCEL FORMAT. IT CONTAINS CONFIDENTIAL INFORMATION UNDER WAC 480-07-160. NO REDACTED VERSION EXISTS.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Direct Testimony of Natasha C. Siores

PERFORMANCE-BASED RATEMAKING METRICS

Exh. NCS-1T

August 29, 2025

DIRECT TESTIMONY OF NATASHA C. SIORES

Table of Contents

I. Introduction and Summary 2

II. Proposed Measures 3

III. List of Exhibits 11

I. INTRODUCTION AND SUMMARY

Q. Please state your name and position at Northwest Natural Gas Company ("NW Natural" or "the Company").

A. My name is Natasha C. Siores. My title is Senior Manager, Regulatory Affairs.

Q. Please describe your education and employment background.

A. I earned my Bachelor of Science degree in Commerce (Accountancy honors program) from DePaul University in Chicago and am an Illinois Registered Certified Public Accountant.

My utility work experience includes more than 16 years with NW Natural and then more than 5 years with PacifiCorp. At NW Natural, I worked on regulatory compliance, regulatory policy strategy, revenue requirement, regulatory mechanisms, regulatory accounting and reporting, and development of rate filings. At PacifiCorp, I worked on revenue requirement, state regulatory proceedings, and regulatory affairs. I previously have testified in proceedings before the Public Utility Commission of Oregon and the Washington Utilities and Transportation Commission ("Commission" or "WUTC").

In my current position at NW Natural, my primary responsibilities include oversight of regulatory compliance and regulatory filings, coordination of the Company's participation in regulatory policy proceedings in its state jurisdictions, management of the Company's tariffs, administration of the Company's regulatory compliance system, and oversight of energy equity and affordability strategy.

Q. Please summarize the purpose of your testimony.

A. The purpose of my testimony is to provide the proposed performance measures that NW Natural proposes to track and report as required by RCW.80.28.425(7).

II. PROPOSED MEASURES

Q. Please explain the need for performance measures.

A. As briefly discussed in the Direct Testimony of Kyle T. Walker (Exh. KTW-1T), the applicable rules regarding multi-year rate plans require that the Commission determine a set of performance measures that will be used to assess a utility operating under a multi-year rate plan.[1]

Q. Please describe the performance measures NW Natural is proposing.

A. Consistent with the guidance in the Commission's Proceeding to Develop a Policy Statement Addressing Alternatives to Traditional Cost of Service Rate Making, docketed as U-210590, NW Natural's proposed performance measures reflect three strategic goals that align with NW Natural's business principles: ensuring a resilient, reliable, and customer-focused distribution grid; promoting customer affordability; and advancing equity in utility operations. Specifically, NW Natural proposes to track and report the performance measures listed below. The performance metric areas and goals listed in the first column largely reflect the framework used in the U-210590 docket.

[1] RCW. 80.28.425(7).

Table 1- Proposed Performance Measures

Commission-Ordered Multi-Year Rate Plan Metrics	
Area	**Measure**
Operational Efficiency	Operations and maintenance expense divided by operating revenue
Operational Efficiency	Operating revenue divided by AMA total rate base and Operating revenue divided by EOP total rate base
Operational Efficiency	Current assets divided by current liabilities
Earnings	Net income divided by operating revenue
Earnings	Retained earnings divided by total equity
Affordability	Average annual bill impacts
Energy Burden	Average annual bill divided by median income by census tract
Commission Initial Reported Performance Metrics	
Goal	**Measure**
Resilient, reliable, and customer-focused distribution system	**Emergency response time**: Average and median length (in minutes) from customer call to arrival of field tech in response to emergency, separately reported for Named and Non-named Communities.
Customer Affordability	**Arrearages:** Number of customers in arrears by period and total amount of arrearages by month, by class, measured by census tract to include 30+, 60+, and 90+ days in arrears.
Customer Affordability	**Energy burden:** Annual residential bill divided by area median income by census tract for all customers, comparing outcomes in Named and Non-named Communities. The number and percentage of customers experiencing high energy burden by census tract.
Customer Affordability	**Utility assistance program effectiveness:** On an annual basis, utility customer-funded assistance funds dispersed divided by total available customer-funded assistance received, as well as the percentage of estimated low-income needs met with dispersed funds.

Commission Initial Reported Performance Metrics	
Goal	**Measure**
Customer Affordability	**Customer participation in assistance programs:** The number and percentage of estimated low-income customers who participate in one or more customer-funded energy assistance programs that actively lowers energy burden, both aggregated and by census tract; and separately the number and percentage of estimated low-income population enrolled in a utility bill discount program and total amount of discount applied annually.
Customer Affordability	**Annual utility revenues and rate impacts:** Annual revenue from base rates approved in most recent MYRP by customer class; Total incremental or decremental revenue from all approved rate adjustments, excluding those authorized by the MYRP, occurring during the reporting year separated by schedule and customer class providing the calendar month and percentage of the change for each schedule; Net bill revenue (annual) by schedule.

Q. How did NW Natural decide on these performance measures?

A. These performance measures largely reflect those described and recommended in the Commission's Policy Statement in docket U-210590.[2]

Q. Were there measures from the Policy Statement that are not included in NW Natural's proposal?

A. Yes, NW Natural has not included measures for workforce diversity or supplier diversity. NW Natural has policies promoting workforce diversity and supplier diversity, and the Company tracks our progress for these measures. NW Natural provides insights on these metrics through a publicly available document, NW Natural

[2] *In the Matter of the Proceeding to Develop a Policy Statement Addressing Alternatives to Traditional Cost of Service Rate Making,* Docket U-210590, Policy Statement Addressing Initial Reported Performance Metrics (Aug. 2, 2024).

Holding Company's Community and Sustainability Report, included as Exh. NCS-2.[3] NW Natural strives to be an employer of choice to effectively compete for a talented workforce and to be a thoughtful and informed purchasing partner. The Company is proud of its current results in these areas, as reported in its Community and Sustainability Report, which provides examples and illustrates how NW Natural strives to advance diversity of its employees and suppliers. For example, NW Natural publishes data on the race, ethnicity, and gender of our employee base and board of directors.[4] Additionally, NW Natural provides information about the number of goods and services purchased from culturally or racially diverse-, woman-, or veteran-owned businesses.[5] However, NW Natural has concerns with including these measures. First, while I am not a lawyer, my understanding of RCW 80.28.425(7) is that it did not enumerate workforce and supplier diversity as a performance measure, incentive, or penalty for the Commission to consider. While the statute does not limit the Commission to consider only the enumerated measures, NW Natural is concerned how its internal workforce and supplier diversity practices will be used by the Commission as a means to "assess a utility operating under a multi-year rate plan" as contemplated in the Commission's Policy Statement. This concern is amplified when or if these performance measures evolve into performance *incentive* measures establishing incentives or penalties based on the diversity of our workforce and suppliers, as has

[3] NW Natural Holding Company's Community and Sustainability Report is available at this link: https://s23.q4cdn.com/611156738/files/doc_downloads/2024/12/20/ESG_2023_Report_Combined_fnl_b.pdf.

[4] Exh. NCS-2 at 50.

[5] Exh. NCS-2 at 52.

been contemplated in the U-210590 policy docket. For these reasons, NW Natural does not propose the workforce and supplier diversity measures from the Policy Statement.

Q. Are there aspects of the performance measures that are important to highlight?

A. Yes. While the description and calculation of the measures are intuitive to understand, NW Natural would like to highlight the disparity that gas utilities face in defining "Named Communities." The Commission provided guidance in its Policy Statement that "…Named Communities shall include both Highly Impacted Communities and Vulnerable Populations as defined in the Clean Energy Transformation Act (CETA) of 2019."[6]

Q. How will the Company determine Highly Impacted Communities for use in its performance metrics?

A. Highly Impacted Communities have been defined by CETA as "…a community designated by the department of health based on cumulative impact analyses in RCW 19.405.140 or a community located in census tracts that are fully or partially on "Indian country" as defined in 18 U.S.C Sec. 1151."[7] NW Natural understands that the Washington Department of Health has provided a health disparities map for electric utilities in the State to identify the highly impacted communities in their service territories. The map even includes a drop-down list for the utilities to filter the census

[6] *In the Matter of the Proceeding to Develop a Policy Statement Addressing Alternatives to Traditional Cost of Service Rate Making,* Docket U-210590, Policy Statement Addressing Initial Reported Performance Metrics, at para. 13 (Aug. 2, 2024).

[7] RCW 19.405.020(22).

tracts applicable to their service territory.[8] NW Natural notes that such assistance for this data does not exist for gas utilities. For purposes of determining highly impacted communities for NW Natural's performance measures, the Company is using those census tracts located in the counties of the service territory that the Department of Health's health disparities map and data indicate are highly impacted communities.

Q. How will the Company determine Vulnerable Populations for use in its performance metrics?

A. The term Vulnerable Populations is defined by CETA as those "communities that experience a disproportionate cumulative risk from environmental burdens due to: a) adverse socioeconomic factors, including unemployment, high housing and transportation costs relative to income, access to food and health care, and linguistic isolation; and b) sensitivity factors, such as low birth weight and higher rates of hospitalization."[9] For purposes of determining Vulnerable Populations for its performance measures, NW Natural is using those census tracts that were identified as being a disadvantaged community in the Energy Burden Assessment ("EBA") that was completed for the Company by Empower Dataworks in 2024. The EBA identified disadvantaged communities by using the disadvantaged community flag in the U.S. Environmental Protection Agency's ("EPA") environmental justice screen ("EJ Screen") dataset, which was the EPA's screening and mapping tool that utilized national datasets for environmental and socioeconomic indicators.

[8] See Washington Environmental Health Disparities Map | Washington State Department of Health last accessed July 27, 2025. A map filtered on the counties in the Company's service territory is included as Exh. NCS-3.

[9] RCW 19.405.020(39).

Q. Please summarize what the Company is proposing to use for Named Communities.

A. NW Natural proposes to use Named Communities in compliance with the Commission's policy statement, which includes both Highly Impacted Communities and Vulnerable Populations. As explained above, for Highly Impacted Communities, NW Natural will include those census tracts located in the counties of the service territory that the Department of Health's health disparities map indicated as highly impacted. Also, for Vulnerable Populations, the Company will include those census tracts identified in its 2024 EBA as being a disadvantaged community. The table below summarizes these census tracts. The shaded census tracts indicate those that are common between Vulnerable Populations and Highly Impacted Communities.

NW Natural Named Communities Census Tracts	
Vulnerable Populations (EBA EJ Screen)	**Highly Impacted (WA Dept of Health)**
53011040706	53011040507
53011041005	53011040509
53011041010	53011040808
53011041104	53011041009
53011041108	53011041010
53011041111	53011041104
53011041313	53011041112
53011041600	53011041201
53011041700	53011041205
53011041800	53011041318
53011042300	53011041320
53011042400	53011041323
53011042700	53011041332
53039950200	53011041333
	53011042000
	53011043100

Q. Are there additional factors in determining the performance measures the Company is considering?

A. Yes. On May 5, 2025, notice was provided that the Commission commenced Phase 2 of the U-210590 policy docket. The Phase 2 work plan released by the Commission will include opportunities for comments and workshops establishing principles and expectations for performance incentive mechanisms. NW Natural has already actively participated in this policy docket and will continue to do so. As the Company learns more about how the reporting performance metrics are being discussed, calculated and used by utilities, stakeholders and the Commission, NW Natural will inform its own calculations and considerations of performance measures and may adjust those proposed in this docket accordingly.

Q. How will NW Natural report these performance measures?

A. As indicated in the Commission's policy statement, if approved, these performance measures will be reported as an appendix to NW Natural's annual Commission Basis Report.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

III. LIST OF EXHIBITS

Exh. NCS-2	NW Natural Holdings 2023 Community and Sustainability Report
Exh. NCS-3	Washington Department of Health – Health Disparities Map

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Natasha C. Siores

PERFORMANCE-BASED RATEMAKING METRICS

Exh. NCS-2

August 29, 2025

2023 Community and Sustainability Report

NW Natural HOLDINGS™

Leading with integrity.
Caring for people.
Innovating for the future.

TABLE OF CONTENTS

This report describes our progress on significant areas undertaken by our business including sustainability, community, governance issues, and includes disclosures from the SASB framework. It is divided into the following sections:

About NW Natural Holdings

NW Natural

- Safety & Reliability
- Environmental Stewardship
- Customers & Community
- People & Culture

NW Natural Water

NW Natural Renewables

Governance

Appendix

- 2023 Sustainability Accounting Standards Board (SASB)
- 2023 NW Natural Workforce Statistics
- 2023 American Gas Association (AGA) Voluntary Reporting Tool
- 2023 NW Natural Environmental Data
- 2023 Additional Statistics
- 2023 Environmental Memberships & Associations

Forward-Looking Statements

To Our Stakeholders

NW Natural Holdings CEO David H. Anderson at Portland Headquarters.

Recently, we celebrated our 165th anniversary. Since our founding in 1859 and our very first days as a gas light company that illuminated the streets of Portland, Oregon, we have continued to hold to our Pacific Northwest ethos of respecting the beauty of our region, supporting its dynamic and diverse economy, and helping the communities we serve grow and thrive.

Every year, we work toward lower-carbon and renewable energy solutions for the benefit of our customers and our shared environment. In 2023, NW Natural began operation of its second renewable natural gas (RNG) facility under the landmark Oregon Senate Bill 98, and NW Natural Renewables completed construction on two RNG facilities. We continued to explore hydrogen technology and performed a successful 20% hydrogen blend test at our Sherwood, Oregon utility operations and training center. We believe NW Natural Holdings has an important role to play in a sustainable energy future, and we are continuing our education, innovation, and efforts related to energy efficiency to serve our communities.

Safety is our greatest responsibility, and in 2023 we had one of the lowest numbers of workplace injuries in nearly two decades. As we grow, we consistently look for ways to increase the safety of our employees and customers. For example, NW Natural Water completed a major upgrade to our Sunriver Water Wastewater Treatment Plant, now allowing the utility to treat an average of 1.5 million gallons of water each day and bringing the water quality of the plant to the Oregon Department of Environmental Quality's highest standard.

I am so proud of the work we did to support our customers, communities, and employees. Our Community and Equity Advisory Group worked with and learned from community organizations to further our efforts to make energy equitable and accessible to everyone we serve. Because of our employees' service ethic, our gas utility was ranked second in the West for large utilities by J.D. Power's Gas Utility Residential Customer Satisfaction Study for the 20th time. Integrity is our foundation, and it informs how we serve our customers, operate our business, treat our colleagues, and engage with the community. I am particularly proud that, for the third year in a row, we were recognized as one of the World's Most Ethical Companies® by Ethisphere early in 2024.

These successes would not be possible without the hard work and passion of our 1,400 employees who embody the core values of NW Natural Holdings every day. Our 2023 Community & Sustainability Report is a celebration of successes across NW Natural Holdings. Our future is bright, and I am eager to see each business lead with integrity and caring while serving our customers and communities far into the future.

David H. Anderson
NW Natural Holdings CEO

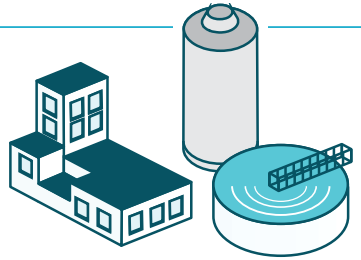
Not to be used for investment purposes—see NW Natural and NW Natural Holdings most recent Form 10-Ks as updated by the most recent quarterly and periodic reports for information relevant to investment decisions.

About NW Natural Holdings

NW Natural Holdings, based in Portland, Oregon, owns NW Natural Gas Company, NW Natural Water Company, NW Natural Renewables Holdings and other business interests. In 2023 we entered a new stage of growth, continuing our commitment to environmental stewardship efforts and delivering essential energy and services safely and reliably with great care.

OVER 165 YEARS

doing business as a respected energy provider in the Pacific Northwest



MORE THAN 180,000

people in the Pacific Northwest, Arizona, and Texas depend on us for clean, safe water, and we provide wastewater utility services to approximately 20,000 connections

APPROXIMATELY 2 MILLION PEOPLE

in more than 140 communities depend on us to deliver the energy and essential services they need to heat their homes, cook their meals and keep their businesses running

800,000 METERS

providing energy in Oregon and Southwest Washington

1,400 EMPLOYEES

serving customers safely and reliably every day

KEY INITIATIVES

Pursuing a renewable, **carbon-neutral future** for our gas utility

Expanding and investing in our **water and wastewater** utility business

Investing in **renewable energy** and the transition to a decarbonized future for a variety of sectors

Not to be used for investment purposes—see NW Natural and NW Natural Holdings most recent Form 10-Ks as updated by the most recent quarterly and periodic reports for information relevant to investment decisions.

Our Mission

We provide safe, reliable, and affordable utility services and renewable energy in a sustainable way to better the lives of the communities we serve.

Our Vision

Lead in service excellence, innovation and environmental stewardship by harnessing our passion for customers.

Our Values

Since 1859, NW Natural Holdings has been a respected energy provider in the Pacific Northwest. We have maintained this reputation by keeping our five core values at the center of everything we do.

INTEGRITY

We will display integrity in everything we do by being honest, ethical and true to our word. We will always choose to do the right thing, even when it is the harder path.

SAFETY

Safety is paramount in all aspects of our operations, infrastructure and workplaces. We are committed to superior training and protective, healthy work practices to ensure we all return home safely. We strive to educate our employees, partners, customers, and our communities about safety.

CARING

We are committed to respecting and caring about each other. We value teamwork, collaboration, and strong individual contributions. We believe a diverse, equitable and inclusive culture, and involvement in the communities we serve, is essential to our collective success.

SERVICE ETHIC

We are driven by a desire to serve our customers and each other and go the extra mile to solve problems. We take pride in our service excellence.

ENVIRONMENTAL STEWARDSHIP

We are committed to a decarbonized and more sustainable future through energy efficiency, water conservation, and expanding the supply of renewable resources we provide.

Not to be used for investment purposes—see NW Natural and NW Natural Holdings most recent Form 10-Ks as updated by the most recent quarterly and periodic reports for information relevant to investment decisions.

2023 Highlights & Awards

2ND
renewable natural gas facility began operations

CONTINUED
to operate one of the tightest, most up-to-date systems in the nation

3RD
year in a row of one of the lowest numbers of workplace injuries in nearly two decades

#2
in the West ranking by residential customers in J.D. Power survey for 20 years running

$1.0M
contributed to nonprofit organizations

89%
of surveyed employees are proud to work for NW Natural

HIGHEST
board gender diversity recognition from 50/50 Women on Boards

4
water and wastewater utilities acquired

ENTERED
the water operations and maintenance services business

2
renewable natural gas facilities constructed for competitive RNG business

2023 WORLD'S MOST ETHICAL COMPANIES® ETHISPHERE 2-TIME HONOREE

Ethisphere® Institute's 2022 and 2023 World's Most Ethical Companies®

2023 MOST TRUSTED UTILITY BRAND escalent RESIDENTIAL CUSTOMERS

2023 Escalent Most Trusted Utility Brand

50/50 WOMEN ON BOARDS

50/50 Women on Boards – Highest distinction for Gender Balanced board

J.D. POWER

TOP 2 IN THE WEST
in residential customer satisfaction

Not to be used for investment purposes—see NW Natural and NW Natural Holdings most recent Form 10-Ks as updated by the most recent quarterly and periodic reports for information relevant to investment decisions.

NW Natural HOLDINGS™

NW Natural®

Safety & Reliability

Safe, reliable delivery of natural gas is our greatest responsibility to our customers, employees, and the communities we serve. Safety guides everything we do.

Not to be used for investment purposes—see NW Natural and NW Natural Holdings most recent Form 10-Ks as updated by the most recent quarterly and periodic reports for information relevant to investment decisions.

Safety Highlights

ZERO

reportable information security breaches

Continued to achieve a low damage rate with the lowest rate in our history in 2023

2023 FEDERAL REPORTS

ZERO

- Reportable pipeline incidents
- Corrective action orders
- Notices of probable violation

OUR MODERN SYSTEM

- No known cast iron pipes since 2000, no known bare steel pipes since 2015
- Leading the industry with one of the lowest ratios of leaks per 100 miles of pipeline in 2023

ONE OF THE LOWEST ANNUAL NUMBER OF WORKPLACE INJURIES SINCE 2004

NEARLY 75% OF TRANSMISSION PIPELINE INSPECTED

- 2.5 times the rate required by regulations
- 88% of inspections performed through inline assessment

Not to be used for investment purposes—see NW Natural and NW Natural Holdings most recent Form 10-Ks as updated by the most recent quarterly and periodic reports for information relevant to investment decisions.

NW Natural®

Our Tight, Modern System

In the mid-1980s, we worked with our public utility commissions in Oregon and Washington state to proactively create a pipeline replacement program. In 2000 we became one of the first companies in the country to eliminate known cast iron pipes, and by 2015 we replaced all known cast iron and bare steel pipe. We believe we are the first pure-play local distribution company to completely remove these legacy pipelines. That legacy continues—NW Natural had one of the lowest ratios of leaks per mile of distribution pipe in 2023 among U.S. natural gas utilities.[1]

We work to vigilantly manage our assets, which include about 700 miles of transmission pipelines and approximately 14,300 miles of distribution pipeline. Our asset management processes include:

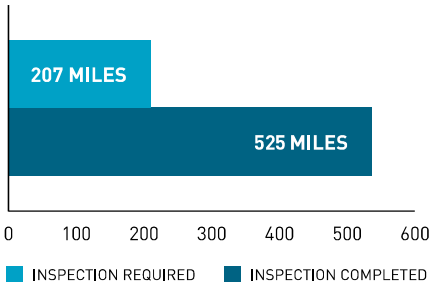
- Comprehensive training for operations employees
- Proactive monitoring, preventative maintenance, corrective and accelerated actions
- Regular asset monitoring and auditing
- Risk assessments
- Systems and processes to help us promptly identify and repair potential issues

In 2023, we performed safety inspections on our transmission system at about 2.5 times the rate required by federal and state regulations.

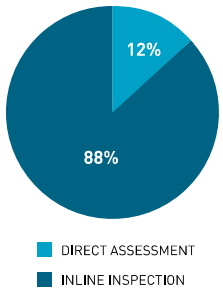
We inspect our transmission system with a combination of direct assessments and technologically advanced inline inspection. At the end of 2023, we had inspected nearly 75% of our transmission system, primarily through inline inspection—a superior method, as it can assess pipeline integrity from inside the pipe.

NW Natural consistently leads the industry in one of the lowest number of leaks per mile of distribution pipeline. We plan to perform a leak survey of each gas distribution main at least every five years and survey 20% of mains every year. We also work to perform leakage and atmospheric corrosion surveys every three years on residential service lines. In 2023, we expanded our classification of business districts, raising the bar on the federal requirement to perform these inspections annually. We use Supervisory Control and Data Acquisition (SCADA) and telemetry to monitor the system in real time and transmit data from remote sources. This powerful technology makes it possible to quickly identify operational issues, even in remote locations.

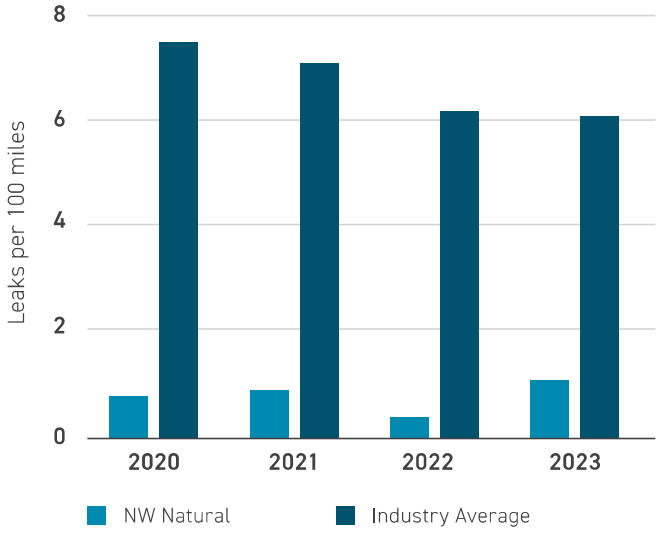
Inspected More Miles Than Required



Used Most Modern Inspection Approach Majority of Time



Leading the Industry with Low Number of Leaks[1]



[1] Based on Annual DOT Report Data for natural gas operators reporting more than 7,000 miles of distribution main.

Not to be used for investment purposes—see NW Natural and NW Natural Holdings most recent Form 10-Ks as updated by the most recent quarterly and periodic reports for information relevant to investment decisions.

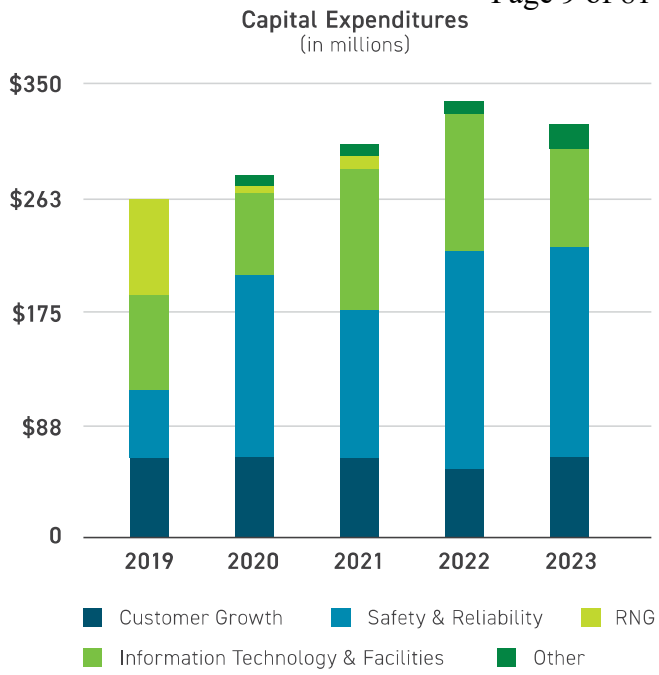
Investing in Safety Improvements

We're continually investing in the safety and reliability of our natural gas infrastructure. In 2023, NW Natural invested more than $315 million[2] to complete a range of projects to support safety, reliability, growth, and investments in technology. Those investments included system reinforcement projects, maintaining our valuable storage facilities, renovations at several of our service centers including seismic upgrades, and critical upgrades related to information technology to ensure we can continue serving our customers well into the future.

Damage Prevention

Digging by third-party contractors is the biggest cause of damages to NW Natural pipelines. Preventing these damages protects public safety, prevents interruptions in gas service and helps reduce pipeline emissions. NW Natural began comprehensive efforts to address this issue in 2006, working with our state regulators to implement more rigorous dig laws, and providing training and intervention to help contractors excavate safely. Since then, damages due to digging have declined by over 75%.

In 2023, we focused on reducing damages related to insufficient one-call notification practices, where excavation happens without proper locates for utility lines. We proactively communicated with and educated excavators on the locate request process, as well as created a field-accessible reporting procedure to alert damage prevention specialists to potential issues. The average damages related to insufficient one-call notification practices from 2018-2022 dropped by about 20% in 2023.



[2] Cap-ex is on an accrual basis and includes cloud-based software.

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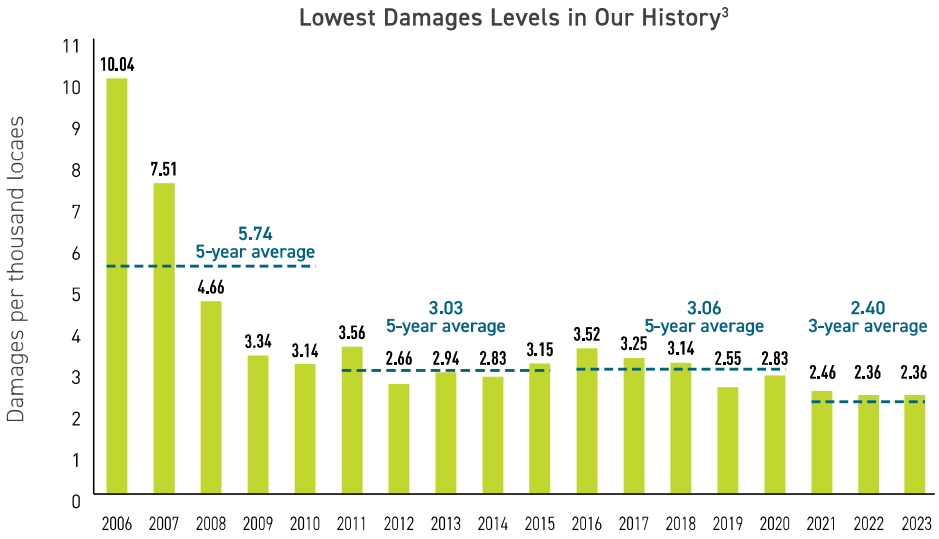

[3] DOT, 2023.

In 2023, NW Natural once again had a historically low damage rate, tying our achievement in 2022.

We continued to maintain our lowest annual damage rate in 2023 as we refined our risk-based locate response program. State-of-the-art technology makes it possible to evaluate every locate request to identify the riskiest excavations. This data-driven approach helps us understand where the risk of damage is highest so we can effectively prioritize and intervene where necessary.

Our specialists engaged third-party excavators on high-risk interventions by:

- Contacting individual excavators prior to the project start date to discuss the scope of work, dig laws, best practices and the location of NW Natural facilities
- Meeting the excavator on-site to perform jobsite assessments
- Providing a point of contact and support for the excavator on that jobsite and any future jobsites
- Offering trainings tailored to the kind of work each contractor does

We also continued a robust multimedia campaign, in Spanish and English, reminding landscapers, contractors and homeowners how to avoid damaging lines. Excavators or homeowners can call 811 or use the free NW Natural safety app to have utility lines located before digging.

NW Natural is a member of the Common Ground Alliance's Damage Prevention Institute, an association committed to promoting public safety and effective damage prevention practices through partnership and collaboration. The Damage Prevention Institute acquired the Gold Shovel Association in 2023. NW Natural obtained Gold Shovel Certification in 2021 and 2022, a credential recognizing NW Natural's efforts to take specific, comprehensive actions to prevent underground infrastructure damages.

NW Natural recognized for outstanding emergency management in community

In 2023, NW Natural was presented with the Oregon Emergency Management Association's Innovation, Collaboration and Service Award, recognizing outstanding contributions in the field of emergency management. This honor is given annually to an organization that has made a significant contribution to the field of emergency management and to Oregon communities focusing on underserved populations. The honor was bestowed on NW Natural because of our longstanding Get Ready campaign, which since 2012 has worked with and supported local fire departments, law enforcement, first responder agencies, and emergency preparedness organizations. At Get Ready events, we provide critical educational materials on emergency and disaster preparedness. In 2023, we joined with first responder agencies and hosted seven different events attended by more than 5,000 people.

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Excess Flow Valves

We are installing excess flow valves (EFVs), which can automatically stop the flow of natural gas to a home or business if the service line is damaged by a seismic disturbance or other catastrophic event. We're installing EFVs on new service lines and planning to retrofit EFVs on existing service lines meeting certain specifications. By the end of 2023, we had installed more than 302,000 EFVs on about 40% of the service lines in our system, which compares to an industry average of 27%.[4]

Taking System Safety to the Next Level

To help prevent safety issues, our employees performed approximately 200,000 proactive field visits in 2023. We operate a 24/7 emergency hotline that enables us to promptly dispatch responders when there's a problem, and our NW Natural safety app connects customers to our 24-hour emergency line with one click. On average, we respond to damage and odor calls across our service territory in about 30 minutes or less.

NW Natural leverages new technologies and best practices to help keep our employees, our system, and the public safe. For example, we're active in the American Gas Association (AGA) Best Practices Program, a voluntary peer review forum for local natural gas utilities across the U.S. to share information on safety and reliability and support safety management efforts at the industry level. In 2023 we were a partner company in the U.S. Environmental Protection Agency's (EPA) Natural Gas STAR Program. The EPA launched the voluntary partnership with natural gas operators in 1993 to achieve important reductions in methane emissions.

Our commitment to safety extends beyond adhering to regulatory mandates. Our Pipeline Safety Management System (PSMS) is not a required program, we do it voluntarily. It provides a holistic framework for our employees to manage risk and promote continuous improvement of safety practices. PSMS engages all employees, from frontline workers to executives, in advancing the program's ultimate goal of reducing pipeline incidents to zero. We've continued to enhance our PSMS program by strengthening NW Natural's existing safety programs and integrating them into our PSMS. We also enhanced our documentation for safety-related processes, as well as increased training using our event-learning program.

[4] Pipeline and Hazardous Materials Safety Administration data for natural gas distribution companies with more than 400,000 service lines.

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NW Natural®

Reliability & Resilience

Approximately 2 million people depend on us to deliver the energy and essential services they need to heat their homes, cook their meals, and keep their businesses running. NW Natural has developed a risk-based method for determining how to provide this energy to customers without interruption, both now and over the long term, even when demand is at its highest. This is done through a process of evaluating different energy-demand scenarios and resource-acquisition strategies, as outlined in our Integrated Resource Plan (IRP).

We conduct this involved analytical process to help maintain adequate gas supply to meet customer needs every day across the year (energy planning) and during the coldest days we might experience (system capacity planning). To help lower costs for our customers and mitigate the risk of interruptions to our natural gas supply, we:

- Purchase natural gas from geographically varied sources
- Maintain a diversified portfolio of supply contracts
- Own and contract with natural gas storage facilities

Our expertise in resource and energy planning will continue to be essential as we transition to renewable fuels for the pipeline.

NW Natural has abundant storage capacity in or near our service area—a unique and valuable resource for reliable energy delivery.

We expect to meet about 54% of our projected peak day energy requirement with gas from storage in or near our service area. Underground gas stored at our facility near Mist, Oregon holds sufficient capacity to supply natural gas to the Portland metro area for approximately one month during an average winter.

PROVIDING POWER DURING WINTER STORMS AND TIMES OF NEED

Frigid temperatures that hit the Pacific Northwest during the week of January 13-19, 2024 resulted in record-breaking natural gas deliveries on our system. Through careful planning, hard work and dedication, our field crews and operations teams kept the gas flowing safely for about 2 million people in the region, many of whom were without power but could still rely on direct use of natural gas in appliances like gas fireplaces, water heaters, stoves, and generators. On January 13, a record breaking 8 million therms of gas were delivered to homes and businesses, about 100,000 more therms than our last record in December 2022 and double our average daily winter send out. Our system storage facility in Mist, Oregon supported the entire region and hit a new record when it provided 4.5 million therms of gas on January 13. That's equivalent to serving 630,000 residential customers in a day. Meeting the moment in January was a result of disciplined investments in the system over many decades.

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Resilient Infrastructure & Operations

Maintaining the resilience of the U.S. energy system is imperative. Compared with above-ground infrastructure, the underground gas delivery system is less vulnerable to disruptive events from extreme weather such as hurricanes and snowstorms. Our modern pipes are also designed to withstand stress from ground movement associated with earthquakes, landslides, and other natural disasters. A study by Portland State University's Center for Public Service suggests the natural gas system can be a crucial resource in the event of a major disaster that disrupts power to the Pacific Northwest.[5]

We take measures so that in the event of a disaster we can continue to operate critical business functions, including gas control and emergency response. We build and upgrade our operations facilities to function in the event of a disaster so we can continue to operate these critical business activities.

- Our Portland headquarters is designed to remain operational after an earthquake. We completed construction of another NW Natural building that is designed to be operational after a large-scale seismic event. New resource centers in Vancouver, Washington and Lincoln City, Oregon are built to Level 4 seismic standards, which apply to structures that are most critical to resilience.
- We continued to upgrade our facilities in 2023 as part of the company's Long-Range Facilities Strategic Plan for building resilient, energy-efficient structures.
- NW Natural uses FEMA's National Incident Management System and Incident Command System (ICS) to manage emergency situations that could disrupt our operations. The ICS is designed to address any hazard, whether it be a natural disaster, a pandemic, a technology issue, a cybersecurity incident, or an event such as major damage caused by third-party excavation.

[5] Portland State University, Renewable/Compressed Natural Gas (R/CNG) for Transportation System Resilience, 2019

Cybersecurity

We prioritize cybersecurity to protect our critical systems and customer data. Our vigorous cybersecurity program continued to be a significant and growing piece of our investment portfolio. About 3% of our total capital expenditures in 2023 were related to cybersecurity and about 19% were information technology (IT) related. We continue to maintain processes and controls guided by the National Institute of Standards and Technology (NIST) Cybersecurity Framework. NW Natural's commitment to cybersecurity encompasses our third-party partners. We manage third-party cybersecurity risks by asking detailed questions, reviewing independent assessments, requiring incident reporting, and ongoing monitoring. In 2023, we were not materially impacted by any information security breach of a third party. Our cybersecurity activities are supported and overseen at the highest levels of the company and the audit committee of our board.

NW Natural had zero known reportable[6] information security breaches in 2023

With significant new investments to enhance cybersecurity protocols, systems, and staff, we continued to incorporate IT best practices in 2023. This included expanding our IT teams, implementing new security processes and products, and onboarding new partners for managed services and 24/7 monitoring and detection.

Cybersecurity highlights for 2023 include:

- Continued to implement our five-year cybersecurity roadmap
- Performed successful penetration tests, threat hunting, tabletop exercises, and other programs
- Launched an incentive-based employee competition that recognizes the team with the strongest performance on phishing tests

[6] For the purposes of this report, reportable information security breaches are those that are required to be reported to the Securities and Exchange Commission or the public generally

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Cybersecurity Strategy & Operations

We continually review and update our cybersecurity strategy to help secure technology systems and support the safe flow of gas to our customers. In 2022 we launched a new Cybersecurity Implementation Plan which defines our cybersecurity strategy from 2022 through 2027. This plan is approved by the Transportation Security Administration for meeting revised federal security directives. It focuses on six key objectives: security governance, cybersecurity risk management, compliance, defensibility, zero-trust architecture, and cloud security. We've got a sharp focus on cybersecurity operations.

- 100% of our active employees participated in information security training that demonstrates how to protect confidential information at work, identify potential cybersecurity risks and take action in case of a suspected information security incident. We also provided focused phishing training, including extra training for groups that face elevated security risks.
- We continued adhering to process controls, performing security assessments, and working toward alignment of our program to the NIST Cybersecurity Framework and other key standards.
- We expanded our detection capabilities.

Key components of our cybersecurity risk management program include:

- Risk assessments designed to help identify cybersecurity risks to our critical systems, information, services, and our broader technology environment
- The use of external service providers with specific expertise, where appropriate, to assess, test or otherwise assist with aspects of our security processes
- Cybersecurity awareness training of our employees, incident response personnel and senior management, as well as periodic experiential learning through "phishing simulations"
- Segmentation of, and back-ups for, certain of our sensitive systems and data
- Third-party cyber risk management process for vendors including, among other things, a security assessment, contracting program, and ongoing monitoring for vendors based on their risk profile
- Physical security around our sensitive infrastructure and cybersystems

Our cybersecurity operations received an excellent rating of 750 in 2023 from BitSight, the world's foremost cybersecurity ratings platform. NW Natural's rating was higher than 65% of our industry peers.

Cybersecurity activities are supported and overseen at the highest levels of the company. Our executive team, with leadership from our vice president and chief information officer, is responsible for implementing the IT and services strategic plan and setting the tone at the top with respect to cybersecurity. Specialists in particular business areas such IT, security, and procurement, apply their specific expertise to the company's strategy. Our audit committee, comprised solely of independent board members, oversees management's strategies, investments and risks related to the company's IT systems, cybersecurity, and compliance. In 2023, the Audit Committee or board was briefed on cybersecurity matters at least four times in formal meetings.

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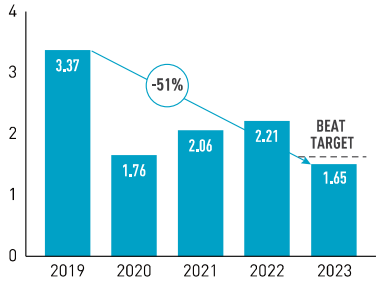
Employee Safety

NW Natural is engaged in a companywide initiative to systematically pursue our ultimate goal of eliminating safety incidents. Our Journey to Zero program, launched in 2020, focuses on preventing injuries and building a safety culture based on open communication, collaboration, and a strong service ethic. Each year, we set a target of reducing injuries by 10% over the previous three-year period. Our Journey to Zero on-the-job safety initiative continued to deliver results in its fourth year. The period from 2020 to 2023 marked one of the best safety performances in the last 20 years. Highlights include:

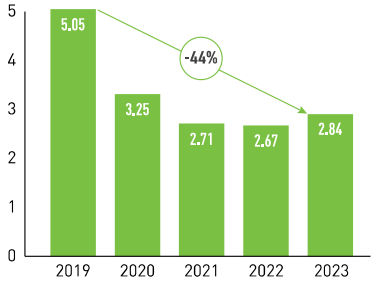
- Recorded a 4% decrease in workplace injuries and a 29% decrease in days away or restricted time rate (DART)
- Increased our near miss frequency/good-catch rate by 15%, which is an improvement of over 100% since we launched Journey to Zero in 2020. The near miss frequency rate is a leading indicator that reflects our expanded focus on proactively addressing safety concerns.
- No OSHA injuries for two months in 2023—one of the best monthly safety performances since we began documenting safety incidents

Days Away or Restricted Time Rate (DART)*



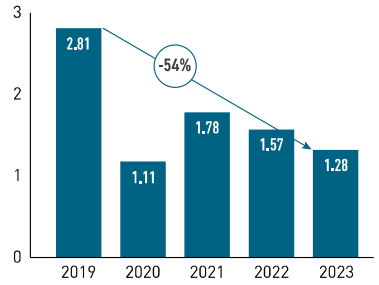
DART = # of incidents with lost time or restricted duty x 200,000 Number of hours worked

Total Recordable Incident Rate (TRIR)*



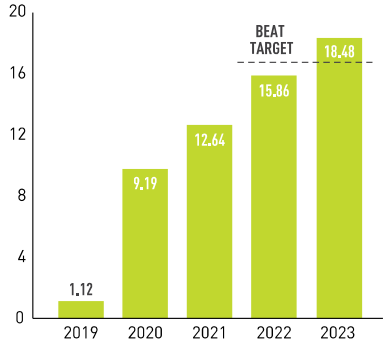
TRIR = # of incidents requiring medical attention x 200,000 Number of hours worked

Lost Time Incident Rate (LTIR)*



LTIR = # of lost time injuries x 200,000 Number of hours worked

Near Miss Frequency Rate/ Good-Catch Rate*



Safety data subject to change past publication date.

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Continuing the Journey Toward Safety Excellence

In addition to emphasizing critical on-the-job safety practices, we supported our employees' safety and health, with the following initiatives and programs:

- **Continued our Work Ready program** designed to help employees work and move in safer ways, using the same techniques that keep athletes at peak performance. Work Ready brings a scientific approach to preventing workplace injuries—including strains and sprains, the most common causes of lost work time. The voluntary app-based program is not just for employees out in the field lifting, reaching, climbing, and bending; it's also for employees who are sitting at desks looking at screens. Work Ready is available for employees and their immediate family members.
- **Used our powerful enterprise resource planning technology** that includes new tools to streamline health and safety reporting. The platform allows employees to log incidents, near misses and safety observations in real time from a mobile device, laptop, or desktop computer, and it provides a one-stop shop for analyzing safety submissions and extracting key insights.
- **Focused on preventing Serious Injury and Fatality (SIF) incidents.** NW Natural has maintained a zero SIF rate, with no fatalities for more than a decade. To take SIF prevention a step further, in 2022, we began reviewing all collisions, injuries and near miss/good catch reports to identify potential SIF incidents and evaluate the controls we have in place to prevent serious injuries.
- **Continued to design facilities to promote employee safety.** Beginning with our new Lincoln City Resource Center, our operations, facilities and safety teams use prevention through design principles to eliminate or mitigate safety and ergonomic risks in all newly constructed or remodeled NW Natural facilities.
- **Participating in a nationwide worker-safety study** supported by the National Institute for Occupational Safety and Health. The Total Worker Health research program focuses on reducing and preventing work-related risk factors that have an impact on employees' safety, health, and well-being. In addition to contributing to the research effort, we're getting ideas we can implement to contribute to the excellence of NW Natural's employee safety program.

Safety Management Program

NW Natural's health and safety policies and procedures are designed to comply with all applicable regulations—and we strive to go beyond compliance.

- Strict stop-work policy—when an employee is involved in an accident, they must stop work and a 24/7 nurse care line is available to all employees. We provide alternative working opportunities that allow employees to recover while continuing to contribute.
- Executive compensation on the line—a portion of our executives' compensation is tied to achieving our safety metrics, and our board of directors regularly reviews company safety metrics.
- Safety steering committee is overseen by our executives, as well as a dedicated safety team led by our VP, chief human resources and diversity officer, who reports directly to the CEO.
- Monitor safety performance to help us understand the origins of incidents and develop root-cause trend analysis.
- Work to incorporate industry best practices and benchmarking, including peer analysis and assessments done by the AGA. Our internal auditors periodically review our safety department and health and safety policies. We also conduct third-party assessments to audit aspects of our safety management system.
- Hold contractors accountable—we seek to work with contractors that meet or exceed safety standards and practices for their industries. We use ISNetworld's contractor management services to help us evaluate contractors' safety performance and policies, including criteria such as insurance and drug and alcohol testing standards.

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2023 TRAININGS

34,959
TOTAL PIPELINE SAFETY TRAINING HOURS

1,520
TRAINING HOURS
clocked by employees at our "Training Town" simulated neighborhood

357-member field staff
attended additional quarterly, annual, and scenario-based safety trainings, as well as monthly safety presentations

350 firefighters trained
in emergency procedures involving gas lines

Comprehensive Safety & Technical Training

We maintain an extensive, proactive training program that includes compliance, awareness, emergency preparedness, identifying hazards and handling high-risk situations. Every year operations employees complete classroom instruction and hands-on training at our state-of-the-art Training Town facility, which features a simulated neighborhood complete with functioning underground natural gas lines. We also offer self-paced virtual training through our learning management system (LMS) to keep training current and support our blended learning approach.

NW Natural employees logged nearly 35,000 pipeline safety training hours in 2023, and we also continued to provide training for third parties. We hosted more than 28 immersive safety trainings to prepare 350 firefighters to respond to emergencies that involve or affect the natural gas system.

The technical training department fully leverages NW Natural's LMS to obtain a robust set of data for analyzing the effectiveness of our safety training. The ability to track employee qualifications and automate training requirements helps us ensure regulatory compliance and verify that our field personnel have the knowledge and skills to maintain system safety, identify hazards and safeguard our crews, customers, and communities.

Quality Assurance Program

Quality Assurance (QA) programs for gas distribution utilities are not mandated by federal code, but NW Natural has had a QA program in place since 2006. The QA team follows up on training and inspects work in the field to verify that employees and contractors are working safely and effectively across field operations. In 2023, the team completed nearly 3,000 inspections of work performed by NW Natural employees or contractors. Our quality & qualifications manager reports quarterly results to a QA steering committee that includes leadership from field operations and operations technical services.

Since implementing our QA program, we have seen consistent improvements in work performance, and we have collected data to help us provide timely feedback for employees and improve training, policies, and procedures. Our leading practices in this area have allowed us to serve as a resource for companies looking to implement similar programs.

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NW Natural®

Environmental Stewardship

NW Natural is committed to environmental stewardship. We believe NW Natural has an important role to play in helping our region move to a lower-carbon, renewable energy future in a more resilient and affordable way.

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Our Legacy of Environmental Leadership

2000 REPLACED CAST IRON

Completed replacement of all known cast iron pipe in our system

2002 DECOUPLING

Adopted a rate structure that supports energy conservation

2007 VOLUNTARY CARBON OFFSET PROGRAM

Provided customers with a voluntary program that allows them to offset carbon emissions from their natural gas use

2013 SUSTAINABILITY TEAM CREATED

Employee interest group that promotes continuous improvement of sustainability efforts

2015 REPLACED BARE STEEL

Completed replacement of known bare steel pipe to create one of the nation's lowest-leak distribution systems

2016 ESTABLISHED CARBON SAVINGS GOAL

Established a voluntary carbon savings goal for our operations and customers' emissions from the use of natural gas

2019 OREGON SENATE BILL 98 ESTABLISHED

Oregon passed groundbreaking legislation that supports gas utilities investing in and procuring renewable natural gas and hydrogen for all its customers. Regulators completed rulemaking in 2020.

2021 RELEASED VISION 2050: DESTINATION ZERO REPORT

Analyzes scenarios for carbon neutrality for energy provided

2022 ENVIRONMENTAL CHAMPION

Named 2022 Escalent Environmental Champion[2]

2022 FIRST RNG FACILITY

Commenced operations at our first RNG facility. We believe we are one of the first local gas distribution utilities in the continental U.S. to invest in a renewable natural gas facility on behalf of its customers.

2023 HIGHLIGHTS

- Successfully completed a 20% hydrogen blend pilot[1]
- Unveiled innovative methane pyrolysis technology at NW Natural's Central Portland facility, which produces hydrogen and captures solid carbon[1]

[1] For more information, see "Hydrogen"

[2] Escalent's Environmental Dedication Index score comprises customer ratings of utility actions to build strong environmental stewardship

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NW Natural®

The Gas System is a Powerhouse for Delivering Natural Gas Today and Renewables in the Future

Since NW Natural started delivering energy in 1859, the fuel going through our pipes has changed from manufactured gas to natural gas. We're now working toward our next evolution, from natural gas to renewable natural gas (RNG) and hydrogen. We believe natural gas and its delivery system will continue to be needed for a long time.

The Gas System is a Powerhouse for Delivering Natural Gas Today and Renewables in the Future

NW Natural's pipeline system

- Delivers 50% more energy than any other utility in Oregon[3]
- Meets 90% of energy needs for our residential space and water heat customers on the coldest winter days in Portland, Oregon

2x the energy

During winter peak-demand periods, the natural gas system in Portland, Oregon, delivers about twice as much energy as the electric system to residential customers

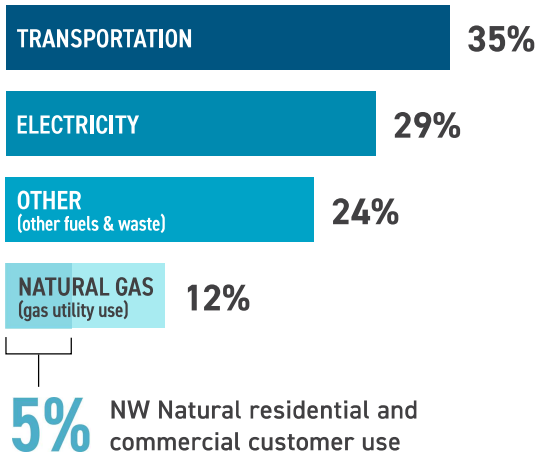
5% of Oregon's emissions

The natural gas our residential and commercial customers use accounts for only **about 5% of Oregon's greenhouse gas (GHG) emissions**[4]

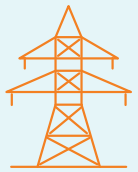
[3] Per data from the Oregon Public Utility Commission, 2022 Oregon Utility Statistics Book

[4] Representative of residential and commercial combustion emissions. State emissions data from the Oregon Department of Environmental Quality Greenhouse Gas Sector-Based Preliminary Inventory 2021

Oregon Greenhouse Gas Emissions by Sector



Source: Oregon DEQ In-Boundary GHG Inventory 2021 preliminary data.



THE ELECTRIC SYSTEM DEPENDS ON NATURAL GAS

Electrical power generation is the largest end-use sector of natural gas in the U.S.[5]

Electric power generators use more natural gas in Oregon than the amount delivered by natural gas utilities to their customers for direct use.[6]

[5] U.S. Energy Information Administration, U.S. Natural Gas Consumption by End Use

[6] 2022 Oregon Public Utility Commission Biannual Report

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While we know our system is a powerhouse, we also believe we need to transition to renewables. We believe what is needed is a thoughtful and strategic transition that benefits the environment and the communities we serve, but balances our customers' ability to pay for energy necessary to live their lives. To meet the needs of our communities and help our customers reduce their GHG emissions, we believe our region will need an integrated portfolio of diverse lower-carbon energy sources, delivered through pipelines as well as wires. We believe a diversified energy system can be stronger and more affordable—and diversification will be even more important as climate change and severe weather pose new risks to reliability and resiliency.

The natural gas system provides benefits today and can support the future:

- **Continued reliability**: During winter peak-demand periods, the natural gas system in Portland, Oregon delivers about twice as much energy as the electric system to residential customers. The gas system is critical for energy reliability in our region, where the electric grid already faces serious capacity limitations.[7] In the future, a gas system with renewable molecules can complement electric renewables, adding stability to the entire energy system.
- **Ample existing pipeline capacity and affordability**: NW Natural delivers 50% more energy than any other utility in Oregon.[8] To handle that load without the gas system, the electric system would need to increase substantially, requiring intense investment to build new transmission and distribution lines and deploy batteries for storing renewable energy. That would come with a high price tag. Meanwhile, the infrastructure for RNG distribution exists today.
- **Energy system resilience**: The natural gas system's underground infrastructure is less vulnerable than above-ground systems to hurricanes, fires, winter storms, and other extreme weather events.[9]
- **Resiliency for our customers**: Some natural gas appliances and generators can operate in a power outage, providing critical energy resiliency benefits during extreme temperatures.
- **Unmatched storage capacity**: As the world transitions toward decarbonizing its energy systems, long-duration storage of renewable energy will be critical. We envision that in the future, the storage facilities we currently have in place could be used to store RNG or hydrogen. Leveraging these unique assets could have significant benefits for decarbonization strategies across the energy sector. NW Natural's existing storage can hold more than 6 million MWh of energy that can be delivered whenever it's needed.

NW Natural currently has more than 20 billion cubic feet of underground storage—equivalent to the capacity of a battery that would cost more than $2 trillion in today's market.[10]

[7] Northwest Power and Conservation Council, 2019

[8] Oregon Public Utility Commission, 2022 Oregon Utility Statistics Book

[9] American Gas Foundation, Building a Resilient Energy Future: How the Gas System Contributes to US Energy System Resilience, 2021

[10] Prices based on NREL, Cost Projections for Utility-Scale Battery Storage, 2023. Equivalent to more than 6 million megawatt hours of storage. To convert natural gas volumes to MWh for comparison, this figure uses a national average heat content of 1036 btu/cf and a direct energy conversion of 0.29307 MWh/MMBtu.

Not to be used for investment purposes—see NW Natural and NW Natural Holdings most recent Form 10-Ks as updated by the most recent quarterly and periodic reports for information relevant to investment decisions.

Our Vision

We believe NW Natural has a pivotal role to play in helping our region move to a lower-carbon, renewable energy future in a more resilient, efficient, and affordable way.

Lower-Carbon Pathway

In 2016 we established NW Natural's Lower-Carbon Pathway as a cornerstone of the company's strategic plan, setting a voluntary initiative of 30% carbon savings by 2035.[11] This is a unique and aggressive target because it includes emissions from our customers' use of our product as well as emissions from our own operations. With the right policy support, we could see success far into the future. In 2023, we remained ahead of target pace for meeting this goal by taking the following steps: lowering energy use through increased efficiency and decreased consumption; providing customers with a voluntary carbon offset program; working to procure natural gas with lower carbon intensity; and evolving our supply to include renewables.

2023: Ahead of Target Savings Rate

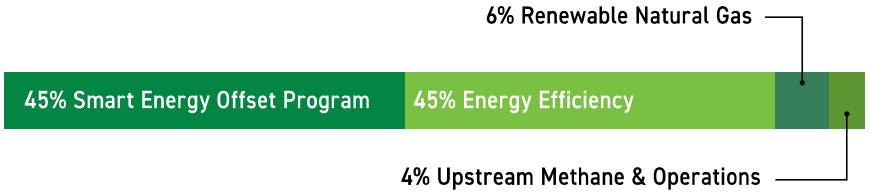
604,848 metric tons of carbon dioxide equivalent saved.

This marks 47% of savings toward goal, ahead of target pace.

2023 savings equal to removing nearly 144,000 cars from the road for one year (EPA GHG equivalencies calculator).

[11] Based on 2015 emission levels attributable to NW Natural operations and customer use of our product.

2023 Source of Savings Mix



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Energy Efficiency

From conservation to energy efficiency improvements, reduced energy use currently accounts for the second largest savings toward our Lower-Carbon Pathway, and we're working hard to increase that savings in the coming years.

Through Energy Trust of Oregon, we've supported energy-efficiency measures such as cost-effective equipment upgrades, insulation, and building improvements that last for many years. In 2023, NW Natural customers provided funding that covered over $41.1 million of energy-efficiency expenses and generated more than 5.8 million therms in energy savings. Since 2016, we have saved approximately 257,000 metric tons of CO_2e related to efficiency measures.

	Energy-Efficiency Expenses (in millions)	Therms of Energy Savings (in million of therms)	Equivalent Cars Removed from Roads
2022	$35.2	5.6	6,500
2021	$34.5	6.5	7,500
2020	$28.8	6.8	7,800

For two decades NW Natural's rate structure has been based on decoupling, which is intended to break the link between a utility's revenues and the quantity of gas used by its customers, removing financial incentives a utility might have to discourage customers from conserving energy. In 2023 more than 77% of our gas utility revenues were decoupled.

Reducing Supply Chain Emissions

NW Natural works to reduce emissions throughout the supply chain.

- NW Natural developed and implemented an emissions-screening tool that allows us to understand the carbon intensity of gas supplies and consider environmental impact when we evaluate supply purchases (alongside other key purchasing criteria such as price, creditworthiness, and geographic diversity). Through this analysis we can award contracts to lower-emitting producers. Our program helped us procure natural gas with 10% lower emissions associated with upstream production.
- By targeting gas purchases from more environmentally conscious producers, in 2023 we avoided more than 19,800 dekatherms of methane emissions for a year-over-year savings of more than 19,000 metric tons of CO_2e.
- We use alternative blowdown practices that reduce emissions from pipeline venting. In 2023, we avoided releasing over 3,800 metric tons of CO_2e from our 72 field gas operation procedures, reducing the amount these blowdowns would have vented into the atmosphere by 90%.
- We work with like-minded industry members and trade groups to encourage producers to adopt best practices (see Environmental Memberships & Associations in Appendix).

Smart Energy Program—Empowering Customers to Offset Emissions

We believe NW Natural was one of the first stand-alone gas utilities in the U.S. to offer customers a voluntary program that allows them to offset carbon emissions from their natural gas use. Launched in 2007, our Smart Energy program purchases third-party verified carbon offsets from projects that reduce or prevent the release of GHGs. These projects include biodigesters on family-owned dairy farms and RNG projects.

Smart Energy participation increased almost 10% in 2023, and now more than 12% of our residential customers are enrolled in the program. In 2023, the program addressed over 271,000 metric tons of CO_2 emissions, making it the largest contributor to the Lower-Carbon Pathway. Since its inception, the Smart Energy program has addressed more than 1.7 million metric tons CO_2.

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Vision 2050: Destination Zero

As we make progress on our Lower-Carbon Pathway, we are evolving our thinking on what's possible for our system and what's best for our customers. We are assessing new ways we can work toward evolving into a lower-carbon gas utility, including enhanced energy efficiency, new technologies, lower carbon fuels such as RNG and hydrogen, and more.

Our vision is focused on collective actions toward:

- Further reducing energy use through intensive energy-efficiency measures and new technologies
- Leveraging our tight pipeline system and long-duration storage to enable a faster, resilient, cost-effective energy transition
- Looking to emerging opportunities to help our company and customers reduce GHG emissions, including possible carbon capture, utilization, and sequestration that can align with our skills and services
- Facilitating adoption of policies that use joint gas and electric system planning and encourage the development of renewables for the pipeline

RNG for the Pipeline

Leveraging our existing natural gas system in new ways is our priority and displacing natural gas with increasing amounts of renewable energy is central to our vision. NW Natural is already procuring supplies of RNG[12], which is derived from biogas and produced from decomposing organic waste from landfills, agricultural waste and wastewater from treatment facilities, that has been captured and cleaned for the pipeline.

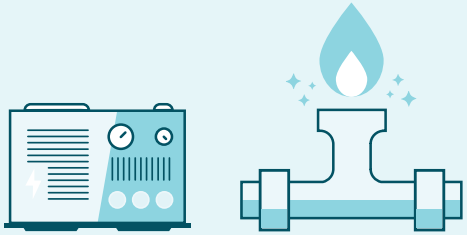
As a renewable fuel that can directly replace conventional natural gas, RNG provides a reliable solution that exists right now and works with the infrastructure we already have.

[12] In 2023, under OR-SB98, the total volume of RNG received by NW Natural in M-RETS was 680,698 Dths, which represents .91% of the Oregon sales load delivered to retail customers.

Our vision of carbon neutrality

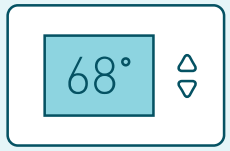
RENEWABLE ENERGY*

Renewable sources that do not contribute new carbon to the atmosphere



COORDINATED ENERGY SYSTEMS

Partnership with cleaner electric systems to create seasonal and peak energy storage



ENERGY EFFICIENCY

Encouraging end-use innovation for deep efficiency

*From a lifecycle emissions accounting perspective

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RNG is already in use at major facilities like WM[13] and the Port of Seattle, which cut net emissions by 46% in a single year by switching to RNG.[14] There are over 885 RNG facilities online or under construction in the U.S. today. Denmark, a leader in the production of biogas in Europe, increased the proportion of biogas injected into its system to almost 40% of total demand during 2023, and the country reports it is on track to meet 75% of its gas demand from RNG by 2030 and 100% by 2034.[15]

Public Policy Support – The effort to reduce emissions from the gas grid has depended on public policy that supports the development and delivery of renewable power sources. We actively advocate for thoughtful design of regulatory programs in Oregon and Washington state. We are excited about early steps such as Oregon Senate Bill 98 and Washington House Bill 1257, which create a pathway for RNG.

In Oregon, Senate Bill 98 allows gas utilities to procure RNG, and eventually renewable hydrogen, for customers. The law outlines voluntary goals for adding as much as 30% RNG into the pipeline system by 2050 and allows gas utilities to use up to 5% of their revenue requirement to cover the incremental cost. We have exclusive rights to purchase or develop RNG totaling 2% of our current annual sales volumes in Oregon.[16] Washington state passed House Bill 1257 in 2019, which also supports renewable energy procurement and investment by natural gas utilities.

Oregon Senate Bill 98 supports volumetric RNG targets

2025	2030	2035	2040	2045
10%	15%	20%	25%	30%

Our RNG Projects – We believe NW Natural was one of the first movers in the market for RNG. As a result, we've been positioning ourselves to play a key role in the market as it develops. Our team continues to establish relationships with RNG producers, developers, and feedstock owners. In 2022, our first biogas facility began flowing RNG to heat homes and businesses. We believe NW Natural was one of the first local gas distribution utilities in the continental U.S. to invest in and own an RNG facility on behalf of its customers.

- **Anew Climate:** NW Natural is purchasing the environmental attributes, or Renewable Thermal Certificates (RTC)s,[17] generated by landfills, foodwaste, and manure facilities throughout the country.
- **Archaea Energy:** Through a long-term agreement with Archaea Energy Marketing LLC, NW Natural is purchasing RTCs generated by landfills throughout the country.
- **BP Products North America:** NW Natural is purchasing RTCs generated by a facility in the Western U.S. that produces RNG from organic waste, which includes food scraps, liquid waste, and manufacturing food waste.
- **Tyson Foods:** Our first investment under SB 98 supported the development of a facility in Lexington, Nebraska that is converting methane from a Tyson Foods processing plant into RNG. In April 2023, a second RNG facility at a Tyson Foods processing plant in Dakota City, Nebraska was commissioned.
- **Metropolitan Wastewater Management Commission:** In 2021, the MWMC treatment plant in Eugene became the first public agency in Oregon to produce RNG. Nearly all the biogas from the facility's anaerobic digesters that stabilize and treat solids is "scrubbed" and then injected into NW Natural's system.

[13] WM's Renewable Energy Investments Expected to Power over 1 Million Homes by 2026, 2022

[14] Pacific Maritime Magazine, Carbon Emissions Down 46% at Seattle's Port-Owned Facilities, Operations, 2022

[15] Energinet Denmark

[16] In 2023, under OR-SB98, the total volume of RNG received by NW Natural in M-RETS was 680,698 Dths, which represents .91% of the Oregon sales load delivered to retail customers.

[17] Under Oregon law, NW Natural is able to develop RNG projects and either transport the RNG directly to our customers or sell it and detach the environmental attributes to be used for our customers' benefit.

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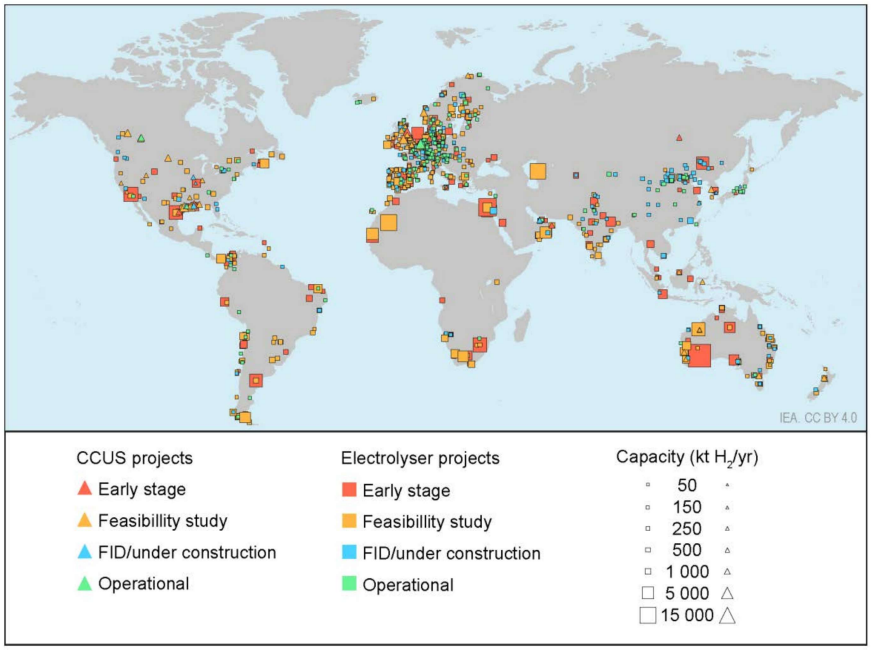
NW Natural advanced the company's RNG strategy on multiple fronts in 2023:

- Began operation of our second RNG facility with Tyson Foods under the landmark Oregon Senate Bill 98
- Issued a request for proposals (RFP) for RNG resources, which attracted a robust volume of bids
- Generated nearly 40,000 metric tons of CO_2 emissions savings. Since 2021, we have saved more than 53,000 metric tons of net CO_2 by using RNG.[18]

Hydrogen

Hydrogen is a key part of moving toward a lower-carbon future. It's a versatile fuel at the point of use and can be blended with natural gas in existing NW Natural pipelines to help decarbonize the gas system. Hydrogen equipment can also be paired with carbon capture and sequestration.

Map of announced low-emission hydrogen production projects



Note: Map includes also announced projects starting after 2030.
Source: IEA Hydrogen Projects database.

Our Hydrogen Pilot Projects – After several years of initial testing, in 2023, we stepped up our hydrogen blending efforts to 20% to heat NW Natural's resource center and training facility in Sherwood, Oregon. We also tested the 20% blend on end-use equipment like furnaces, fireplaces, and water heaters. Additionally, we use the facility as an educational opportunity and invite stakeholders, policymakers, and other parties to learn more about hydrogen innovation.

The Netherlands, United Kingdom, and Germany have been testing 20% hydrogen blending for some time. In the U.S., Hawai'i Gas has been using up to 15% hydrogen in its distribution system since the 1970s, and gas utilities have more than three dozen hydrogen projects planned or underway nationwide.[19]

NW Natural is working with technical partners to determine how to convert our large industrial customers from natural gas to pure hydrogen made on-site. In 2022 NW Natural formed a partnership with Seattle-based Modern Hydrogen to generate hydrogen on-site at our facilities. Modern Hydrogen's groundbreaking technology is designed to strip the carbon from natural gas and turns the decarbonized gas into hydrogen at the point of use, without the need for new infrastructure or storage. This process is designed to produce hydrogen and solid carbon as outputs, and the carbon can be sequestered or used to make products such as asphalt, construction materials, automobile tires, and soil amendments. Unlike other hydrogen production methods, Modern Hydrogen's technology requires no electricity or catalysts for the methane pyrolysis process. Generating the hydrogen on-site reduces supply-chain risk and eliminates costly hydrogen fuel transportation from origin to pipeline. In 2023, we successfully tested this hydrogen generation technology at our Central Resource Center and will continue to evaluate it.

[18] RNG emissions savings verified by a third-party in compliance with Oregon Department of Environmental Quality standards.
[19] S&P Global, Gas utilities increasingly focus on pipeline blending in hydrogen pilot projects, 2023

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Carbon Capture, Use and Storage (CCUS)

In 2023, we installed two CleanO_2 CarbinX carbon capture units at commercial customers to pilot the equipment. The units are designed to capture and reduce GHG emissions from existing boilers as well as reduce energy use by using captured waste heat to preheat water so less energy is needed to heat the water. The captured CO_2 is converted into a raw material used in soap. We see opportunities with this technology and are excited to see the results of the pilot.

What's Next

Our nation is at the beginning stages of developing renewables for the gas system. As the electric system works to increase wind and solar generation, we need to aggressively accelerate development of renewables for our pipeline networks. We're pleased with the progress we've made at NW Natural, and we're continuing to channel the advantages of our modern infrastructure, our expertise, and our innovative spirit in support of our environmental vision.

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Environmental Responsibility in Our Business & Operations

We strive to lessen our impact on the environment in a multitude of ways throughout the business.

Environmental Policy & Leadership

We encourage all employees to participate in our sustainability efforts. In 2023, our Sustainability Equity and Engagement Committee (SEEC), an employee-led interest group, celebrated its 10th anniversary. SEEC promotes continuous improvement and adoption of environmental practices through employee education and programming.

Our dedicated environmental management and sustainability department focuses daily on environmental policy and management issues, and reports to our VP, chief public affairs and sustainability officer, who reports directly to our president. Board meetings for both NW Natural Holdings and NW Natural incorporate environmental items into the topics reviewed, including climate-related risks and opportunities. The Public Affairs and Environmental Policy Committee of the boards of directors provides oversight of environmental matters. The committee is guided by the company's environmental policy, which is reviewed and approved annually. It sets forth our commitment to:

- Environmental stewardship, for example supporting conservation through our decoupling rate structure for customers
- Reducing emissions, releases, and waste, for example through our emissions screening tool for supply purchases
- Using our natural resources and energy more efficiently, for example supporting efforts in RNG
- Protecting and enhancing the quality of the natural environment, such as working hard to reduce leaks in our distribution system
- Operating our business in an increasingly sustainable manner, through exploring new technologies such as hydrogen

The Board receives updates and discusses the Company's approach to climate change-related risks and opportunities at each regular meeting. Climate considerations are also woven into the Board's oversight of the Company's strategic planning and risk management processes.

Environmental Management

With one of the most modern natural gas distribution systems in the country, in a well-established service territory, NW Natural performs a limited amount of new construction or other work that might disrupt local communities and the environment, including waterways. When work is required, our environmental management team strives to comply with all environmental regulations and leave the area the same as, or better than, it was when we began. Our environmental management program is supported by:

- Our rigorous procedure manual, which provides guidance on environmental matters. This includes EPA, Oregon Department of Environmental Quality (DEQ) and Washington Department of Ecology (DOE) regulations, and local jurisdictions' requirements. In certain instances, we take the strictest regulation within our jurisdictions and apply it to our entire service territory, which assists us in holding ourselves to a higher standard and facilitates consistent procedures across our operations.
- Our internal Environmental Management System (EMS), which addresses how our resource centers and field work sites are designed and operated. The EMS procedure manual:
  - » Outlines how to design sites to prevent runoff and soil erosion, mitigate spills, obtain necessary Clean Water Act permits, and follow federal, state, and local rules and regulations. These rules and regulations are primarily related to water quality, air quality, chemical handling, spill response, waste, cultural resources, and threatened and endangered species.
  - » Serves as a guide for rigorously vetting products, substances, activities, and services to help us try to minimize our impact on the environment and use the safest and most environmentally responsible materials appropriate in our operations. We keep environmental records and provide environmental training for each project, and we offer awareness programs and trainings for new employees and refresher trainings for established employees.
- Allows us to assign roles and responsibilities, as well as monitor activities for compliance with our permits. Our internal audit department performs periodic audits of our environmental programs and trainings, and external agencies such as EPA, DEQ, and DOE also periodically audit our permitted facilities.

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Suppliers

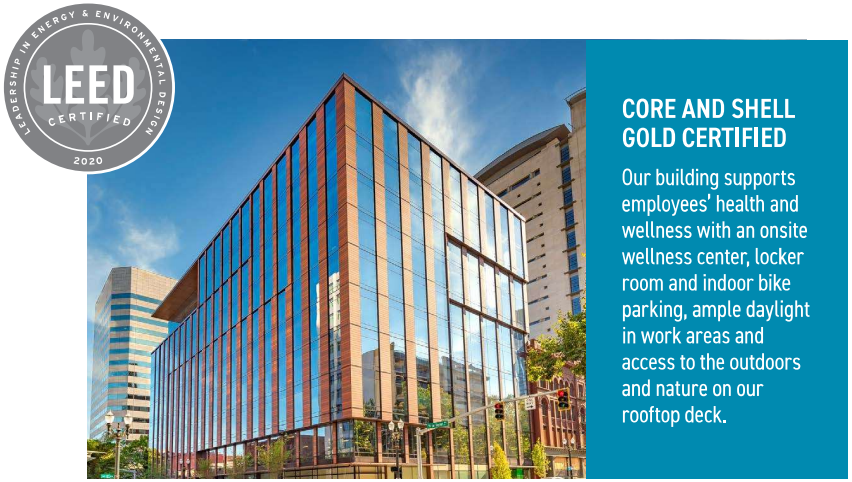
In addition to our efforts to procure RNG and target gas purchases from more environmentally conscious producers, we have similar criteria for vendors we work with:

- We have implemented a sustainable purchasing program covering various focus areas, including sustainability, community, and governance. We strive to procure goods and services in an increasingly sustainable manner, and we expect our suppliers to comply with our Supplier Code of Ethics.
- Our Supplier Code of Ethics contains expectations for our suppliers related to environmental protection and sustainability. We also include language setting expectations for environmental stewardship and sustainability in our master contracts and agreements, and we have launched a website specific to suppliers that allows them to better understand how we promote sustainable procurement efforts.
- We monitor key vendors' environmental records, and we have implemented a scorecard for certain vendors that addresses identified sustainability-related topics, including environmental performance.
- As part of our RFP process, we include in our bid evaluations the extent to which contractors demonstrate their willingness to work together on finding ways to reduce environmental impacts, and we ask prospective suppliers to describe their current or planned practices for utilizing recycled products and minimizing waste.

Energy-Efficient Facilities

Our headquarters and operations center in Portland is LEED Core and Shell Gold certified by the U.S. Green Building Council. A range of features allow us to use less energy, conserve natural resources, minimize waste and support our strategic goals.

- **Energy conservation measures**: Through our high-efficiency building envelope (wall, roof and window assemblies), efficient heating, ventilation and air-conditioning system and controls, 100% LED lighting and other measures, we estimate energy cost savings for the building's core and shell of approximately 28% annually, compared to a code-compliant building—more than 550,000 kilowatt hours and approximately 8,000 therms of natural gas saved.
- **Water savings**: Efficient plumbing fixtures that use approximately 40% less water than code-compliant fixtures reduce water demand, along with a drip irrigation system to efficiently water native plants on our rooftop deck. In 2023, we used approximately 880,000 gallons of water.
- **Use of green building materials**: Nearly 21% of the materials cost for the building core and shell construction came from recycled materials, reducing environmental impacts of extracting and processing virgin materials.
- **Convenient downtown location**: Our headquarters are conveniently located in our downtown core within walking distance of transit stops for public bus lines, light rail, and the streetcar. We provide secure and indoor bicycle parking to further encourage sustainable transportation alternatives and reduce pollution from automobile use.
- **Onsite recycling and composting**: To limit waste, each floor is equipped with central recycling and compost stations.



CORE AND SHELL GOLD CERTIFIED

Our building supports employees' health and wellness with an onsite wellness center, locker room and indoor bike parking, ample daylight in work areas and access to the outdoors and nature on our rooftop deck.

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As we're continuing to renovate and upgrade our facilities, we are inspired by LEED certification principles and focus on building resilient, energy-efficient structures that serve the needs of our customers, employees, and the environment.

- For NW Natural's use of natural gas in its operations, we pay for carbon offsets through the Smart Energy program. We became our first Smart Energy customer when the program launched in 2007, and since 2020, NW Natural has offset 100% of the CO_2 associated with the natural gas heating for its facilities.
- Our facility in Sherwood, Oregon once again received Washington County's Green Business Leaders certification in 2024, which recognizes a company's efforts in sustainable materials management, toxics reduction, and social responsibility.
- NW Natural Salem received Oregon's EcoBiz Certification, designating them as a location that met high standards to reduce toxins, prevent pollution, and protect the environment.
- We are part of the Energy Trust of Oregon's Strategic Energy Management program, which helps us continually improve our operations through equipment and building choices as well as employee behavior.

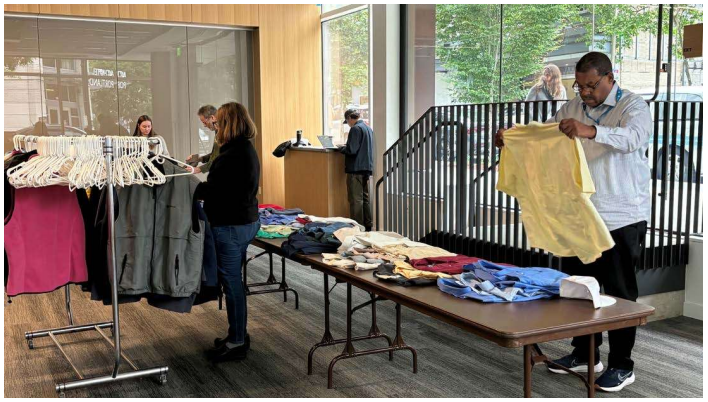
Waste Reduction

Our team of in-house environmental specialists oversee all waste assessments. The environmental specialists must have over ten years of experience managing waste stream assessments and complete OSHA's 40-hour "hazwoper" certification. Additionally, they:

- Participate on a chemical evaluation safety team that works to eliminate products that may produce potentially hazardous waste before it's generated, and they periodically perform waste audits at our resource centers
- Attend annual waste management training seminars hosted by the Oregon DEQ
- Implement several written environmental modules directed at managing commonly occurring waste streams
- Identify opportunities for continued improvement

We strive to reduce and recycle any byproducts of our process by:

- Performing waste audits at all our resource centers.
- Implementing and maintaining recycling programs in our operations. We currently recycle 100% of the following items: batteries, waste soil from our fleet transportation, oil filters, antifreeze, scrap metal, and some types of plastic. NW Natural's recycling activities in 2023 eliminated over 85% of the total volume of total ordinary operating waste potentially requiring disposal ,and diverted those materials into recycling opportunities instead. We recycled more than 2,000 pounds of plastic film in 2023.
- Diligently following EPA's rules and regulations for hazardous waste. We report to the state government the amount of hazardous waste that is incinerated or sent to the landfill annually. In addition to materials recycled in 2023, NW Natural disposed of materials from ordinary operations as well as remedial-site wastes. Of the ordinary operational waste that was disposed; 99% was non-hazardous waste (98% landfilled and 2% incinerated) and 1% was hazardous waste (33% landfilled and 67% incinerated).
- Signing up nearly 336,000 customers for paperless billing, enabling them to receive their bill electronically rather than through the mail. Enrollment increased by 3% in 2023, and today nearly 42% of our customers are enrolled for paperless billing. To further promote online transactions and paperless billing to conserve resources, during Earth Month in April we promoted paperless billing. We also promote paperless billing to customers throughout the year via their bills, print and electronic newsletters, and more.
- Holding an annual, free NW Natural logo wear swap where employees can exchange used NW Natural clothing and gear and refresh their wardrobe.



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Air

In addition to our Lower-Carbon Pathway, we are conscious of emissions from our transportation fleet. We have invested in the use of compressed natural gas (CNG), a fuel that emits 90% less nitrogen oxide (NOx) air pollutants and particulate matter from heavy-duty vehicles than diesel.

- We have invested in five CNG stations for our own fleet, which includes 198 vehicles.
- In 2023, NW Natural supplied 11 companies and municipalities with over 4.5 million therms of CNG to power their fleets.
- Our idling-reduction initiative is aimed at reducing particulate emissions. Emissions such as sulfur oxides (SOx), NOx, and non-methane volatile organic compounds (VOCs) are below applicable permitting thresholds for the majority of our facilities and, as such, we do not consider them to be significant to our operations.

Water

While our natural gas distribution operations are not water-intensive, we strive to adhere to all Clean Water Act requirements, and we use limited water, much of it recycled, for hydrostatic testing and pipeline construction. We also repurpose water, use leading stormwater-management techniques, and conduct regular audits at construction sites.

Biodiversity

We aim to lessen the impact to our ecosystem before, during, and after construction by working with the Oregon Department of Fish and Wildlife (ODFW). We work to restore and revegetate habitats that have had temporary impacts using approved native seed mixes that are beneficial to wildlife. For permanently impacted habitats, we work with ODFW to enhance the habitat quality as much as possible.

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Customers & Community

We've operated for more than 165 years with a focus on serving our customers and investing in our communities. It's not just what we do, but how we do it.

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Customers & Community Highlights

Continued our **two-decade streak** of **earning high marks** from our customers in the J.D. Power Gas Utility Residential Customer Satisfaction Study

DISBURSED
$9.9 MILLION
in energy assistance to help low-income customers pay bills and stay warm

DONATED OVER
$1 MILLION
to nonprofits

Distributed approximately **$4 million** to fund weatherization projects and energy efficiency upgrades for low-income customers in Oregon

DISTRIBUTED
$23.5 MILLION
in bill credits to Oregon customers

KEPT CUSTOMER BILLS LOWER
than they were 15 years ago by judiciously managing system capacity and skillfully navigating record volatility in the natural gas market

Today **6% of customers** are in the bill discount program for income-qualifying residential customers

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NW Natural®

Caring for Our Customers

Our customers have always been the focal point of NW Natural. We work to go above and beyond in providing our customers with superior service. We engage with community members and organizations to understand customers' priorities, challenges, and successes. NW Natural supports customers in a variety of ways including energy efficiency programs, bills savings plans, and low-income assistance. Additionally, we prioritize philanthropy to better the community we serve.

A core value of our service is making it easy for all our customers to get help and manage their accounts from every location. We are available to our customers through our 24/7 self-service and account management options online, our dedicated customer service center, and field service technicians. In 2023, our customer contact center and phone systems answered nearly 300,000 calls, and our service technicians and other field resources responded to over 200,000 requests. Our customer satisfaction survey continued to show high satisfaction ratings among contacted customers:

Percentage of Customers that Rated NW Natural Either 9 or 10

(On a 10-point scale, where 1 = Poor and 10 = Excellent)

	OVERALL	STAFF INTERACTION	PHONE	SERVICE TECH
2023	75%	90%	83%	97%
2022	80%	90%	84%	96%
2021	84%	91%	86%	96%
2020	77%	89%	86%	93%

Award Winning Customer Service Experience

In 2023, NW Natural continued its two-decade streak of earning high marks from our customers in the J.D. Power Gas Utility Residential Customer Satisfaction Study. For the fourth year in a row, the company scored second highest in customer satisfaction among large utilities in the West. This is the 20th time the company has scored in the top two in the West regional segment, which includes utilities serving 500,000 or more residential customers. NW Natural also scored in the top 10 in the nation among large gas utilities. The J.D. Power study measures residential customer satisfaction with natural gas utilities across six categories: safety and reliability; billing and payment; price; corporate citizenship; communications; and customer service.

Natural Gas Remained Affordable in 2023

The Portland metro area continues to be the most affordable major metropolitan area[1] on the West Coast. Even with economywide inflation and increases in the wholesale price natural gas, our residential and commercial customers paid less for gas in 2023 than they did 15 years ago. A typical monthly natural gas bill for a residential customer was $82 in 2023. In 2023, we saw residential bills decrease by 4% and commercial bills decrease by 39% compared to 2008. NW Natural has taken several steps to increase accessibility and affordability[2] including:

- Locking in gas purchases at lower rates
- Smart investments in energy storage
- Effective and efficient operations
- Energy efficiency measures

[1] As defined by the U.S. Office of Management and Budget for Metropolitan Statistical Area on the West Coast.

[2] Affordability also depends on the wider economic dynamics of our service territory as well as the cost of the natural gas commodity.

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Natural gas is one of the most affordable utility bills our customers have

Reductions in bills from 15 years ago[3]

↓4%

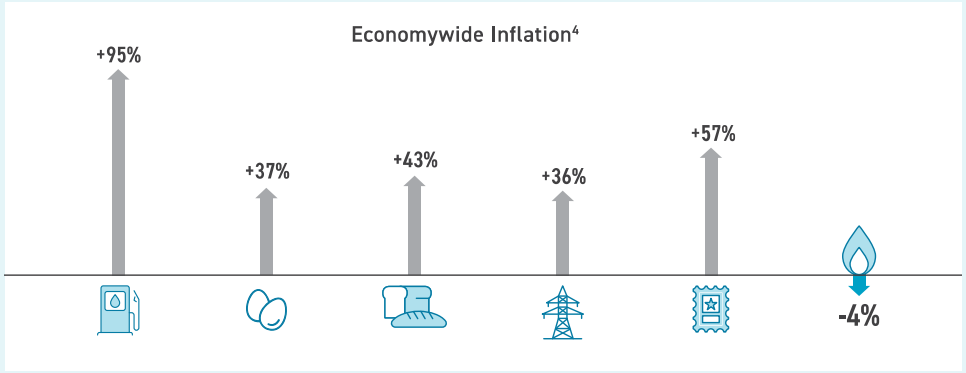
RESIDENTIAL BILLS

↓39%

COMMERCIAL BILLS

[3] Natural gas bill data for NW Natural residential and commercial customers from 11/1/2007 to 10/31/2008, compared to 11/1/2023 to 10/31/2024 using normal weather assumptions.

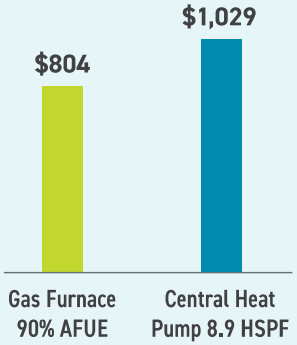
Gas Bills Remain Affordable



Residential Average Monthly Utility Bills

Natural Gas Gas Space & Water Heating[5]	Electricity Has Gas Space & Water Heating[6]	Water & Sewer[7]	Cell Phone[8]	Internet[9]
$82	$103	$121	$175	$82

Annual Cost of Gas vs. Electric Heating Methods[10]



[4] Bureau of Labor Statistics, 2008-2023; U.S. Postal Service, 2008-2023; Natural gas bill data for NW Natural residential customers from 11/1/2007 to 10/31/2008, compared to 11/1/2023 to 10/31/2024 using normal weather assumptions.

[5] Usage based on weighted average rate for Portland metro from National Renewable Energy Laboratory (NREL) in 2021. End-use load profiles for the U.S. Building Stock. Natural gas costs based on NW Natural rates, Oregon Rate Schedule 2 as of 11/1/23 to 10/31/24.

[6] Usage based on weighted average rate for Portland metro from NREL in 2021. End-use load profiles for the U.S. Building Stock. Local PGE Rates effective 7/1/23. Natural gas costs based on NW Natural rates, Oregon Rate Schedule 2 as of 11/1/23 to 10/31/24. Assumptions made for heating season and simplifying assumption to place all customers under same rate and tax schedule.

[7] Bluefield Research, U.S. Municipal Water & Wastewater: Annual Utility Rate Index, 2023. Oregon rates could differ from this.

[8] J.D. Power, Average Oregon cell phone bill in 2023.

[9] U.S. Federal Communications Commissions, 2023 Broadband Survey.

[10] Based on NW Natural Heating Cost Comparison Calculator. Retrieved 7/24/24. Assumes electricity provided by local electric providers. Assumes single-family home size is 2,138 square feet, built in 1970. Includes cost of space heating only.

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Customer Support Programs

We want all our customers who qualify for payment assistance to use the resources available to them. We actively seek out income-eligible customers across our service territory to help lower their gas bills. We offer multiple financial assistance programs targeted at reducing gas bills for low-income customers, especially energy burdened[11] households that spend a disproportionately high percentage of their income on energy costs. Meaningful community engagement is a critical piece of these programs' success, so we work directly with community members and local community action agencies and organizations. Our outreach strategy prioritizes clear communication and includes:

- Seeking community input to make sure we're reaching out to residents in a culturally competent way
- Reducing barriers that prevent underserved communities from finding information and receiving energy assistance
- Producing communication materials in our service territory's five most commonly spoken languages
- Maximizing the reach of our messaging through multiple communication channels, including our customer website, social media platforms, monthly newsletters, emails, and bill inserts

Energy equity is central to our core value of caring, and we believe it is essential to the strength and well-being of the communities where we live and do business. In 2022, we conducted our first low-income needs assessment to better understand the low-income customer base in our region. We engaged a third-party consultant to layer multiple data sources to identify areas of high energy burden. In 2023, we refined and improved our low-income needs assessment by engaging a Portland State University MBA graduate research team to help us further target our outreach. As a result of our efforts, we've increased the percentage of customers receiving assistance from approximately 3% of customers for the 2022 program year to 6% for 2023.

[11] Energy burden is defined by the U.S. Department of Energy as the percentage of gross household income spent on energy costs.

Community & Equity Advisory Group

In 2022, we voluntarily launched a community development program—the Community & Equity Advisory Group (CEAG). The group is committed to bringing community voices forward who have historically been left out of the energy planning space. The objective is to make NW Natural programs and practices more equitable and provide us with direct feedback, recommendations, and advice on planning and programs. Community-based organizations (CBOs) in our service territory who have not historically had a voice within the energy planning or utility industry are formally recruited to join CEAG as members and are compensated by NW Natural for participation. We monitor community development programs and identify local stakeholders or communities of interest through a formal system of applications and adhere to community consultation guidelines and ongoing consultation mechanisms throughout the process. Our objective is to bring in these voices in during the early stages of a project or process. Representatives from CBOs and NW Natural join with a 3rd party facilitator to meet to openly discuss community perspectives and lived experiences related to our energy system planning and policies, renewable resource development, income-based programs, philanthropic investments, workforce development, and more. We look to the facilitator for guidance on community engagement and advisory group practices, including creating collaborative, trusting spaces for members to share their experiences.

For example, we consulted CEAG at the early stages of our Bill Discount Program, and based on our conversations with CBOs, we redesigned our communication strategy for the program to improve accessibility, education, and digital and printable content. Best practices developed with the CEAG on specific programs are then applied throughout the company's operations. This systematic involvement of local stakeholders enhances our commitment to promote community development and provides an accessible mechanism to collect, record, and address complaints, and set community development targets and deadlines that work for both our community and NW Natural. Understanding the experience and perspectives from diverse and underrepresented groups is imperative to the success of the communities we serve.

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Through customer assistance programs, we provided **$13.5 million** of support in 2023, an **increase of 71%** compared to 2022.

2023 NW Natural Customer Assistance Programs

Program	Funds Distributed ($ in millions) 2023	2022	% Change
Bill discount program	$3.6	$0.4	+800%
Low-income energy assistance programs[12] (LIHEAP, OLGA, GREAT, Misc. programs)	$5.7	$5.1	+12%
Gas assistance program (Shareholder and customer funded)	$0.2	$0.1	+100%
Low-income energy efficiency Programs (OLIEE and WALIEE)	$4.0	$2.3	+74%
Total	$13.5	$7.9	+71%

2023 Low-Income Energy Program Savings

175 OREGON DWELLINGS
SAVED OVER 56,000 THERMS OR 5,600 MMBTU

12 WASHINGTON HOMES
SAVED OVER 3,800 THERMS (380 MMBTU)

[12] The program year date range is October 1, 2022 to September 30, 2023, coinciding with the release of federal Low-Income Energy Assistance Program funds.

Our programs include:

- **Bill Discount Program:** This program provides income-eligible customers with ongoing discounts ranging from 15% to 40%, in addition to other energy assistance customers may already be receiving. At the end of 2023, approximately 44,000 customers were enrolled.
- **Gas Assistance Program (GAP):** For over 40 years, GAP has helped low-income families and seniors in our communities pay their heating costs. Since its inception, the voluntary program has raised more than $6.7 million and assisted more than 60,000 people. In 2023, customers facing financial challenges received nearly $0.2 million from GAP to cover their heating costs.
- **Low-income energy assistance programs:** Our programs distributed over $5.7 million in energy assistance during the 2023 program year. These programs include Oregon Low-Income Gas Assistance (OLGA), Gas Residential Energy Assistance Tariff (GREAT), the federal Low Income Home Energy Assistance Program (LIHEAP), and more.
- **Low-income energy efficiency programs:** We work with state and community organizations to provide whole-home weatherization, efficiency upgrades, and energy education. We distributed approximately $4 million Oregon Low-Income Energy Efficiency Program (OLIEE) funds as well as funded two community development projects to provide energy efficiency to low-income, hard to reach populations. Additionally, we distributed over $79,000 Washington Low-Income Energy Efficiency Program (WALIEE) funds.

Other ways we help our customers stay warm and pay their bills include:

- **Suspension of disconnections** during severe weather events, prolonged periods of extreme cold, poor air quality, wildfires, and winter holidays
- **Time Payment Agreements (TPAs)** that allow customers with past-due accounts to pay in installments and avoid disconnections
- **Medical Certificate exemptions and TPAs** for customers with medical conditions

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Caring for and Investing in our Community

As an essential service provider and a key employer in the Northwest, we view caring for our communities as both a moral imperative and a sound business practice. We invest time and resources in community development programs to benefit all the communities we serve—especially those facing social and economic challenges. In order to understand our community and the energy challenges they face, we monitor community development programs, identify local stakeholders, and consult with organizations through initiatives like our Community & Equity Advisory Group. These meetings provide an accessible mechanism to collect, record, and address issues, and set community development targets that work for both our community and NW Natural.

Throughout 2023, we supported over 200 community and nonprofit groups in the fields of youth and family resiliency, environmental stewardship, health and human services, and arts and culture. In 2023, we exceeded $1 million in total giving. Our customers and neighbors are key stakeholders in our business. Community matters are overseen by the Public Affairs and Environmental Policy Committee of our board of directors. Our VP, chief public affairs and sustainability officer is the NW Natural executive tasked with primary responsibility for government affairs and community involvement programs.

Stakeholder Engagement

We value our community stakeholders, and we actively seek a broad range of perspectives in our decision-making processes. Our senior management and board of directors use feedback received through our various outreach activities to help inform business strategy and decisions.

Our community of stakeholders starts with our employees and extends to our customers, business partners, suppliers, labor unions, shareholders, lenders, financial analysts, regulators, government officials, community leaders, the media, nonprofits, and other organizations. Our Human Rights Policy sets forth our public commitment to work to engage with these groups where appropriate to better enable us to listen to, learn from, collaborate with, and incorporate the views of stakeholders into our business.

As a regulated utility, we remain transparent through regular public meetings, workshops, and proceedings before the public utility commissions in the states where we do business. Approximately every two years, we develop our integrated resource plan (IRP), which describes how we plan to meet our customers' energy needs now and in the future while fulfilling our commitment in helping the region reduce its impact on the climate. The IRP is developed through a process open to the public, informed by feedback, reviewed by a diverse set of interested parties, and ultimately filed with the public utility commissions that regulate our business.

Service ethic is one of our core values, and one way we foster this value is by engaging regularly with customers and community members through satisfaction and opinion surveys, along with our website, newsletter, and social media channels. Our government affairs team regularly solicits feedback from governments, legislators, nonprofit organizations and community members on important issues, trends and policies so we can be responsive to the communities we serve. We also engage with our communities through partnership, programs and philanthropic support of nonprofit organizations that provide essential services. In 2023, we continued our direct engagement with nonprofits that serve our low-income community and customer needs.

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We aim to be the employer of choice and regularly engage with employees through a wide variety of channels such as internal and external websites, meetings and events, communications, and surveys, including our annual engagement survey that is designed to enable company leaders to gather valuable feedback and guidance from employees. In 2023, we continued to engage in surveys and other means in order to attend to employee concerns. We have a hotline, maintained by a third party, available for our employees, our communities or anyone else to anonymously raise concerns.

Our notable engagements in 2023 included:

- We participated in ongoing policy, renewables project and climate action planning discussions at the federal, state, and local level, and worked with elected officials, community leaders and nongovernmental organizations to share our Low Carbon Pathway goals and pipeline decarbonization strategies.
- Dedicated staff allowed us to increase capacity and focus on growing community engagement. They worked with partners to continue to improve participation in low-income and community serving programs and to increase responsiveness to complex needs of front-line communities.
- We continued funding and enhanced community outreach on arrearage management resources, including partnering with community organizations to reach populations experiencing hardship.
- We developed partnerships with local community action agencies to increase awareness of low-income assistance and weatherization resources.
- We attended more than 35 events and directly engaged with individuals on topics ranging from natural gas safety to renewable energy education.
- We awarded three college students $5,000 each to enroll in essential training that will prepare them for careers in the trades.
- Through our supplier webpage, we have promoted sustainable procurement and engaged with diverse suppliers. In 2023, we increased the number of diverse supplier inquiries as a part of our sustainable purchasing program.

Charitable Donations & Volunteerism

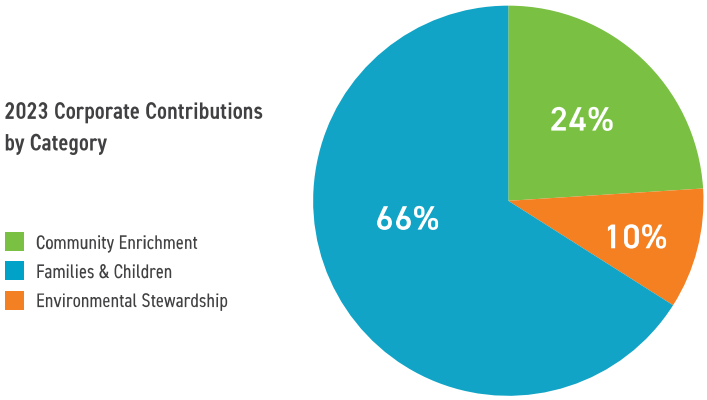
Charitable Donations

Corporate philanthropy is an integral part of NW Natural's company culture and an enduring example of our core value of caring. Through our shareholder-funded Corporate Philanthropy Fund we gave over $1 million to more than 380 local nonprofits in 2023, with an emphasis on supporting family and children, environmental stewardship, and community enrichment.

Through our annual Spirit of Giving campaign, employees and retirees donate to their favorite local nonprofits and a 100% match from the shareholder Corporate Philanthropy Fund doubles the impact of their generosity. In 2023, employees gave to 233 nonprofits and together with the company match, employees and retirees contributed $0.2 million to local charities. Additionally, in response to the wildfire disaster in Maui, Hawai'i, NW Natural partnered with our Asian American Network to hold a fundraiser and matched the first $5,000 in employee contributions.

For NW Natural's conservation champion, we selected the Oregon Bee Atlas, a program that focuses on supporting an organization working toward environmental sustainability. Oregon Bee Atlas is a cooperative of diverse stakeholders that work to maintain and enhance bee health in Oregon. From 2023-2025, they will receive $10,000 per year as well as in-kind support and employee engagement.

2023 Corporate Contributions by Category



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Inclusion & Belonging

Inclusion and belonging guide our charitable giving, and we're committed to working with the community to improve outcomes for people who face barriers based on racial, social, economic, and geographic inequalities. We continue to ensure in 2023 at least 10% of philanthropic dollars are directed to organizations whose primary mission is supporting racially or culturally diverse or marginalized groups. We ensure that all organizations receiving NW Natural philanthropic dollars demonstrate actions, programming and practices that align with our priority of inclusion and belonging principles.

NW Natural supports local organizations making a difference through our Programs of Focus. Grant recipients are chosen through a competitive review process that actively engages a diverse group of employees from across the company. The program is NW Natural's highest level of philanthropic support. In 2022, the company announced its Programs of Focus for 2023-2025. These organizations will receive $0.4 million in unrestricted funding over the next three years, along with in-kind resources and volunteer support from employees. Our 2023-2025 programs of focus are:

- Adelante Mujeres
- Store to Door
- Growing Gardens
- Asian Health & Service Center

Sponsorships & Events

Hospitality engagement is part of NW Natural's long history of community engagement, and every year we contribute resources and sponsorship dollars for events organized by nonprofit, community, and civic organizations. Our community events team served over 10,400 meals and provided 193 shade tents worth $0.1 million for events held by groups such as Pride Northwest, Portland Veterans Stand Down, and CASA. We also provide our headquarters conference space and food service to nonprofits. Events like these are core to how we show up for our communities.

For Volunteer of the Year, Safety is Key

For Steve Eversmeyer, safety is a thread that runs through both his professional and personal life. As a safety consultant, Steve helps maintain the company's commitment to keeping employees safe while they work. In his personal time, as a long-time volunteer with Mt. Hood Ski Patrol, Steve helps keep people safe on the mountain. For over 37 years, Steve has contributed to the patrol in various capacities, including as an instructor for medical and avalanche training programs, and as an active ski patroller. His volunteer work also extends beyond the mountain to supporting local running and bike race events in the Cascade Locks and Portland metro areas.

> "Steve's dedication to safety is unparalleled. During the workday he is committed to NW Natural employee safety and after hours he shares that passion with the community. It is a privilege to recognize his volunteer service."
>
> — Mary Moerlins, NW Natural director of environmental policy and corporate responsibility

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NW Natural®

Volunteerism

We are proud of our employees that volunteer to better our community. We offer a number of volunteer opportunities throughout the year, from downtown cleanups to grocery delivery for adults living with disabilities. In 2023, we chose four Volunteer Champions, who are individuals or employee groups, to train, recruit, and lead other interested employees in volunteerism, with a goal to reduce barriers to volunteering. Every year our employee volunteers and Volunteer Champions are recognized at a company-wide celebration, and an outstanding employee is awarded Volunteer of the Year.

Through our Dollars for Doers program, NW Natural makes financial contributions to the nonprofits that employees support with their volunteer time. The program, funded with shareholder dollars through our corporate philanthropy fund, is one of the ways NW Natural supports our culture of caring and the good work employees do in the community.

2023 Dollars for Doers Statistics

29	Number of 2023 Dollars for Doers grants
3,606	Estimated number of volunteer hours in 2023
9	Average number of years volunteers have been engaged with their organizations

Political Contributions

NW Natural makes campaign contributions to state and local candidates and political committees and caucuses, as allowed by law. In addition, NW Natural Holdings can make contributions from time to time. Our Code of Ethics sets forth our expectations regarding the use of company funds for political purposes. We also maintain memberships in various business and trade associations that advocate on public policy. In 2023 we made campaign contributions and had lobbying expenditures totaling approximately $3.3 million on a consolidated basis for NW Natural Holdings.[13]

[13] Calculated using U.S. Internal Revenue Service guidance.

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NW Natural®

People & Culture

Our employees are the heart of NW Natural. We are committed to supporting, engaging, and empowering them in a work environment where they can thrive and grow. We have a longstanding commitment to creating a culture of belonging that reflects and supports the communities we serve.

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People & Culture Highlights

84% of NW Natural employees describe themselves as having a sense of belonging at work

50/50 WOMEN ON BOARDS

NW Natural Holdings has the highest gender diversity rating ("GB" for gender balanced) from 50/50 Women on Boards

Women comprised **45%** of NW Natural Holdings' Board of Directors in 2023 and NW Natural Holdings is one of only **8%** of publicly traded companies in the U.S. with a woman board chair

89% of employees are proud to work for NW Natural

After a redesigned PTO policy focusing on work-life balance, **94%** of employee PTO hours were used, compared to **81%** in 2022

Launched Leadership Monthly, a leadership skill building series for supervisors, managers, directors, and officers

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Who We Are

Our more than 1,200 employees are the core of NW Natural, and we are committed to providing a dynamic and rewarding work culture so they can thrive in their career. We support our employees by offering competitive benefits, growth and development programs, and social opportunities. We strive to prioritize belonging and equity in all aspects of our work, from hiring and daily operations to the way we interact with our customers and communities, to the biggest decisions we make as a business.

2023 Employee Satisfaction Survey

We highly value employee feedback and listen to the voice of our workforce. Each year, all employees are invited to complete a survey to provide feedback on their job, supervisor, work group, training programs, and the company. This information gives company leaders valuable insight on ways to make NW Natural a more effective company and a better place to work.

Every officer reviews the summarized survey results, and frontline managers are encouraged to initiate meaningful dialogue with employees about the responses their teams provided. Additionally, our CEO, David Anderson, and officers regularly visit each work location to answer questions and get input from employees.

79%	Employees participated in 2023
89%	Proud to work for NW Natural
84%	Feel like they belong at NW Natural
87%	Engaged, committed, and enthusiastic about their work at NW Natural

Results of our 2023 survey indicated that employees are engaged in their work and appreciative of their managers. There was a wide appreciation for unified work groups and collaborative coworkers, and diversity, equity, and inclusion (DEI) was a topic of celebration. Surveyed employees also agreed or strongly agreed with the following:

96%	Agree they operate with integity and ethical conduct in their work area
96%	Demonstrate safe work practices in their work area

Our 2023 Workforce

10
Average years of employment

4%
Voluntary separation rate (not including retirements)

2%
Retirement rate

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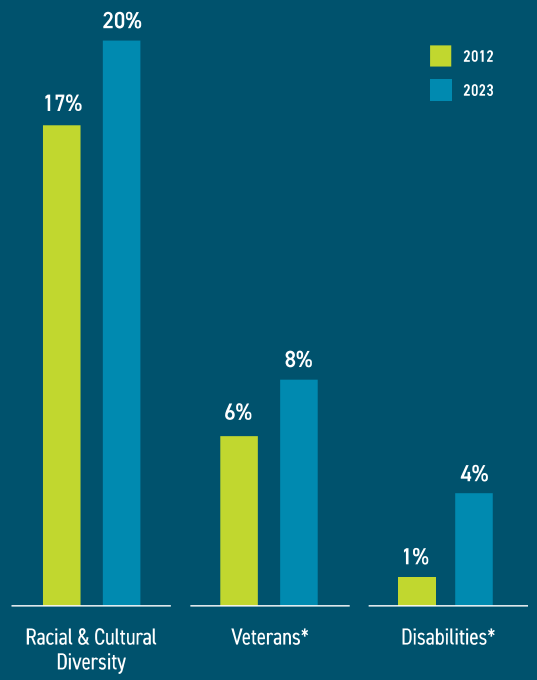
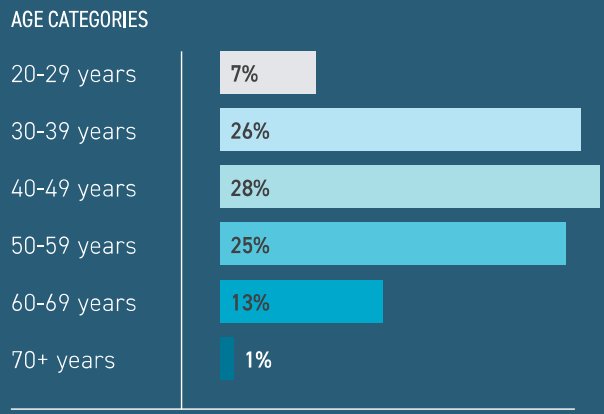
Our 2023 Workforce

Employee Demographics



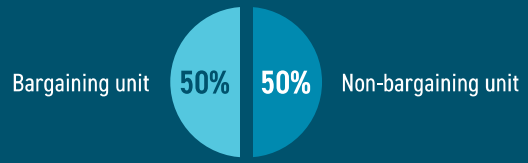
*Disabilities and Veterans' data is collected via voluntary employee disclosure beginning in 2015 and may be underreported.

A Multigenerational Workforce



Average age
46

Employee Type



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NW Natural®

Supporting Our Employees

NW Natural strives to offer competitive total compensation packages[1] designed to attract and retain employees and meet the needs of our workforce. We continuously look for ways to enhance employees' physical, psychological, and financial well-being. This is reflected in the programs we offer to meet the needs of employees and help them care for their families.

> "Every day our employees embody the pillars of NW Natural, and I am honored to work with them."
>
> — David Anderson, NW Natural CEO

Employee Benefits

Health coverage for all full-time staff: We provide multiple insurance carrier and health plan options for employees. All plans include outpatient and inpatient medical care, vision, and dental insurance, offer coverage for dependents, and are transgender inclusive. Non-union employees have the option to enroll in a Health Savings Account that the company contributes to.

Financial wellness: We provide a 401(k) with employer match, automatic employer contribution to 401(k) for non-pension employees, pension plan for employees hired before 2007 (non-union) or 2010 (union), and employee stock purchase plan.

Paid leave and sick time: We provide paid parental and bereavement leave, and we pay for short- and long-term disability insurance that provide some wage replacement when an employee is out for a qualifying health condition. Non-union employees get 80 hours of paid sick time annually, more than the national average reported by the U.S. Bureau of Labor Statistics.

Generous vacation and holidays: Non-union employees start with 20 days of paid time off (PTO) per year at beginning of employment and receive 31 days of PTO per year after 15 years of service. In 2023, NW Natural changed its PTO policy to incentivize employees to use their vacation days and increased the number of days new employees receive. So far, employees' use of PTO has increased 13% as a result of the new policy. Union employees annually accrue 16 days of PTO at the beginning of their service, and annually accrue 26 days of PTO after 13 years of service. This compares to approximately 10 days for new hires on average for other utilities in the Pacific Northwest.[2] Both non-union and union employees receive a total of 13 paid holidays including 3 floating holidays. Nationally, the average number of vacation leave reaches 20 days only after 20 years of employment.[3]

Hybrid work model for office workers: In 2023, we offered a hybrid work model based on meeting individual employees' needs and working styles. Based on employee feedback, our officer team implemented a flexible hybrid work model for 2023 that allowed managers and supervisors to decide what's best for the people they lead, as long as work arrangements meet the company's goals and continue to support our high level of customer service. We conducted a survey at the end of 2022 to track how people were doing with the hybrid work model, and results were overwhelmingly positive, with 97% of employees saying their manager trusts them to manage their time and 93% saying their team is connected and productive while working a hybrid schedule. In 2023, we announced our flexible schedule beginning in 2024, where individual contributors work in the office a minimum of two days a week and managers work in the office at least three days a week.

Career development and culture: We invest in employees' career growth through professional training programs, a robust mentorship program developed with an emphasis on cultural relevance for underrepresented groups, and tuition assistance. Employee resource groups (ERGs) and other employee-led organizations help our workforce form connections with their coworkers.

Onsite offerings. We offer free fitness centers at our Portland headquarters and most resource centers. The headquarters building features indoor bike parking, ergonomic workstations, lactation and quiet rooms, and access to nature on our rooftop deck. Employees working at our headquarters can get a company-paid public transit pass.

[1] Our package options vary depending on date of hire and whether the employee is full-time, part-time, or a union member. Employees who work more than 20 hours are also eligible for certain benefits.

[2] Milliman, 2023 Northwest Benefits Survey, 2023

[3] U.S. Bureau of Labor Statistics 2023

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2023 Employee Benefits

Healthcare & Insurance	Wellness	Financial	Work-Life Balance	Culture & Community	Employee Recognition & Discounts
Medical	Health screenings, flu, and COVID-19 vaccines	401(k) with employer match	Paid Time Off (PTO)	Seven Employee Resource Groups	Formal employee-recognition program
Dental	Free fitness centers (company headquarters & certain resource centers)	Automatic employer contribution to 401(k) for employees not in pension plan (regardless of employee contribution)		Volunteer opportunities, recognition and financial support for volunteer work	Recognition of years of service (every five years)
Vision			Paid holidays (10) plus three floating holidays		20% off natural gas service
Flexible Spending Accounts	Activity rewards program	Financial education workshops for all employees		Sustainability & Equity Engagement Committee	Free public transit pass (headquarters), bike room, and carpooling support programs
	Tobacco cessation	Employee stock purchase plan	Flexible and hybrid work arrangements based on employees' needs and working styles		
Health Savings Account	Digital Wellness Library with resources on mental health, nutrition, and seasonal health considerations	Pension for employees hired before January 1, 2007 for nonunion and January 1, 2010 for union employees		Diversity, Equity & Inclusion Council	Discounts on natural gas appliances and equipment at the NW Natural Appliance Center
				Company match for employee charitable giving	
Life Insurance	Work Ready digital wellness and injury-prevention program, available to employees and families	NW Natural Scholarship program for children of employees—awards four scholarships toward full-time study at an accredited institution	Employee assistance program		
			Education assistance	Casual attire dress code in the office	Vendor discounts on personal technology, sportswear, carsharing
Short-Term and Long-Term Disability		PTO buy-back program (union employees)	Paid parental leave	Learning opportunities, including lunch & learns	
	Wellness Advisory Committee	Tuition reimbursement program for employees seeking job-related degrees at an accredited institution	Paid bereavement leave		Discounts at cultural and entertainment establishments
Transgender-inclusive benefits	Lactation & quiet rooms (company headquarters)		Predictable scheduling for hourly employees	Team building events and activities	

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Pay Equity

We strive to compensate all our employees equitably, and we have established multiple initiatives to help us achieve pay equity across our workforce.

- We do a comprehensive pay analysis for each new hire.
- To help identify opportunities for improving equity, an external consultant annually reviews our regular employees' pay data.
- We periodically review pay to provide adjustments when needed during an employee's tenure. These reviews include internal and external equity reviews, and when an employee has a promotion, job reclassification, and/or department reorganizations.

We are proud of our focus on increasing pay equity, and we continue to work on evaluating equitable wages. We are working to increase the number of women and nonbinary people in the field.

Pay Transparency

We believe in the principles of pay transparency as a fundamental aspect of our commitment to fairness and equity. We work to provide employees with clear and accessible information about job profiles, salary ranges, total compensation statements, and performance related incentive information to increase employees' understanding of their pay and opportunities.

Growth & Development

To help employees reach their full potential, NW Natural provides education, training, mentorship, and other programs designed to build skills and relationships. Annually, we offer:

- **Gas Class**: Our internal series of informational videos educates employees on the history of NW Natural, the world of utilities, and how our business is run.
- **Training programs**: In addition to our comprehensive safety training for employees in the field (see the Safety & Reliability section), we require all employees to complete comprehensive training programs including cybersecurity, and ethics training. Certain employees complete further technical, managerial, contractor training, and more. We strive to provide training programs that are effective, relevant, and engaging, and we regularly evaluate our trainings through surveys and feedback, among other things.
- **Mentorship**: Our internal peer-to-peer mentorship program is focused on building relationships, diversity and belonging, and skill-building. The program was designed from the ground up in 2022 to offer robust opportunities for development for all employees, with a focus on racially and culturally diverse employees, and we strive to improve it through post-program surveys and evaluations.
- **Leadership and development**: We provide ongoing management and leadership training through a variety of programs. In 2023 we revamped our monthly leadership meetings to emphasize skill building with topics such as inclusivity and leading in a hybrid workplace.
- **Educational events**: We offer lunch-and-learns on various topics, utility finance classes, ERG leadership training, and more.
- **Tuition, scholarships, continuing education**: Qualified employees are eligible for tuition support of up to $5,250 per year for relevant undergraduate and graduate degree programs. Employees are also able to attend continuing education courses relevant to their areas of expertise through partner organizations and LinkedIn Learning.

Union Partnership

Approximately half of NW Natural employees are represented by the Office and Professional Employees International Union Local 11, AFL-CIO. The company has a history of maintaining good relations with the union through communication and collaboration. Working together, union and NW Natural leaders reached a mutually beneficial agreement in 2019 that is in effect through May 31, 2024. During calendar year 2023, NW Natural did not experience any work stoppages (strikes or lockouts) and had zero idle days for the year. The company and the union work together with a collective aim to achieve a transparent relationship where bargaining union employees feel valued and supported.

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Growing Through Mentorship

Caring is a core value at NW Natural, and that means we work every day to support, engage, and empower all employees. As part of this commitment, we have created a mentorship program that offers robust opportunities for growth and development and aligns with our focus on DEI. All employees are eligible, and mentors and mentees are paired for a six month program, on paid company time. Topics include career progression, developing skills to work more effectively, creating a culture of belonging, and building one-on-one and group relationships. 46 mentors and mentees graduated from our 2023 program. In our follow-up survey, respondents rated their experience a 4 out of 5, and they reported an increase of confidence in all skills taught in the program.

> "My mentor helps me align and set my goals. He helps me understand that goals can be adjusted. Through this mentorship I've learned to broaden my horizons."
>
> — Jonny Walker,
> 2023 Mentorship Program participant

Employee-Led Engagement Opportunities

Employee Resource Groups: Our ERGs create opportunities for employees to connect with each other around shared backgrounds, interests, and experiences. In addition to helping their co-workers understand and value diversity and belonging, ERGs engage in community outreach, partnerships, host educational and entertaining events for celebrations and holidays, and support recruiting, development, and advancement of diverse employees within the company.

OUR CURRENT ERGs

- AFRICAN AMERICAN EMPLOYEE RESOURCE GROUP
- ASIAN AMERICAN NETWORK
- NEURODIVERSITY NETWORK
- RAINBOW ALLIANCE
- SOMOS UNIDOS
- VETERANS EMPLOYEE RESOURCE GROUP
- WOMEN'S NETWORK

Diversity, Equity, & Inclusion Council: Founded more than 20 years ago, the DEI Council works to make NW Natural Holdings a more diverse, inclusive, and welcoming workplace for everyone. The council supports this vision through education, outreach, advocacy, and action.

Sustainability & Equity Engagement Committee (SEEC): Celebrating its 10th anniversary in 2023, SEEC works to build a broad coalition around energy, equity, and environment practices. The committee promotes sustainable practices within the company and serves as a conduit to management as well as community partners working to address climate change and environmental equity.

Wellness Advisory Committee: The Wellness Advisory Committee guides the company's wellness program, offering advice, new ideas and feedback from their peers to further the physical and mental health and well-being of all employees.

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Diversity & Belonging Strategy

At NW Natural, we know that all of us can benefit when we amplify underrepresented voices, celebrate our differences, and create an environment where everyone can contribute, thrive, and prosper. To accelerate our work in DEI, and belonging, we hired an outside consultant to review our progress on diversity. We convened focus groups and created an assessment and a set of recommendations for our executives. Incorporating this feedback, in 2019 we introduced a comprehensive DEI strategy overseen by the Public Affairs and Environmental Policy Committee of our board of directors.

Race/Ethnicity	NW Natural 2023	Oregon 2020 (Census Data)
American Indian or Alaska Native	3%	1%
Asian	6%	5%
Black or African American	4%	2%
Decline to Respond	2%	N/A
Hispanic or Latino	4%	13%
Native Hawaiian or Other Pacific Islander	1%	0%
Two or More Races	3%	4%
Undeclared/unknown	<1%	N/A
White	77%	75%

[4] U.S. Bureau of Labor Statistics 2023
[5] Deloitte, Women in the boardroom: A global perspective, 2023

Our People

We are actively working to build a diverse workforce that reflects the communities we serve. We have a diversity strategy for all levels in our organization, including senior management. Our VP, chief HR and diversity officer and DEI steering committee leads these efforts because we believe a diverse, equitable and inclusive workplace is vital to our long-term success.

Diversity starts at the top, and we are proud to have racially or culturally diverse individuals and women in leadership positions. In 2023 NW Natural Holdings' board received the highest gender diversity rating ("GB" for gender balanced) from 50/50 Women on Boards. In 2023, women held 45% of the seats on NW Natural Holdings' board of directors, and our board chair was a woman.

NW Natural Gender 2023	NW Natural Holdings' Board	Executive Management	Mid & Other Management	All Employees
Women	45%	42%	29%	29%
Men	55%	58%	71%	70%
Nonbinary	0%	0%	0%	<1%
Decline to Respond	0%	0%	0%	<1%

Women comprised 29% of NW Natural employees in 2023 compared to the national industry average of 21%[4] and NW Natural Holdings is one of only 8% of publicly traded companies to have a woman board chair.[5]

Board Demographics 2023	NW Natural Holdings	Russell 3000 Companies[6]
Percentage of board members that identify as racially or culturally diverse	27%	19%
Percentage of board members that identify as women	45%	29%
Percentage of women that hold C-suite positions[7]	46%	N/A

[6] 50/50 Women on Boards, Gender Diversity Index™ Fourth Quarter Key Findings, 2023
[7] Based on executive leadership team in January 2024

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Increasing the diversity of our workforce through recruitment is a top priority at NW Natural. A significant focus is to understand and increase awareness of systems and structures that could limit representation and equity for prospective employees. We have a comprehensive approach that includes recruitment and hiring strategies, increasing our pool of diverse candidates through our community partnerships, and anti-bias training for HR and hiring managers. In 2023 we:

- Increased the diversity of NW Natural's construction team by 14% from 2018 to 2023; now 31% of employees on the team are from historically underrepresented groups.
- Offered full-time positions at NW Natural to 80% of participants in our 2023-2024 construction internship programs, all of whom are from historically underrepresented groups.
- Maintained strong affirmative action plans which have been in compliance with every federal audit since 2017.

> "Our interns are valued members of NW Natural. We aim to provide them with hands-on training and work experience that will support their chosen career path."
>
> — David Anderson, NW Natural CEO

Diversity-Focused Career Development

To serve our communities and promote diversity within our field workforce, we work to create employment opportunities for underserved populations. We launched an innovative construction intern program in 2018 to seek out high-quality prospective employees who might not have the background to qualify for, or even find out about, a well-paying construction job. Every year the program provides up to 12 interns with nine months of paid on-the-job training and practical work experience that can lead to full-time employment at NW Natural. All our 2023 Construction interns were diverse employees. In 2021 we began developing our Construction Field Services internship program and the first intern class of five began in 2023.

We are committed to partnering with career development organizations in our community, especially those focusing on women, culturally or racially diverse candidates, veterans, and individuals with disabilities. In 2023, we partnered with:

- Urban League
- Portland Pre-Apprenticeship Training and Program Consortium
- Oregan Tradeswomen
- Portland Community College
- National Association of Women in Construction
- INCIGHT
- Emerging Leaders

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Our Partners & Suppliers

We actively work to expand the diversity of our supplier network and increase our purchasing from businesses owned by women, veterans, and other traditionally underserved and underrepresented groups. Our supplier diversity webpage highlights opportunities for diverse businesses to work with us and helps them navigate the process of becoming a certified culturally or racially diverse business. We also encourage our suppliers to use diverse subcontractors while performing work on NW Natural's behalf.

Our CFO and our VP controller and treasurer works with our chief diversity officer to oversee our supplier diversity activities in procurement. Highlights from 2023 include:

- Implemented a new vendor management process to expand our supplier diversity program
- 34% of supplier requests for proposals (RFPs) included a diverse supplier, an increase of 8% from 2022
- 9% of our addressable purchasing spend is from diverse suppliers

WE PURCHASED

$39.6

MILLION

in goods and services from 116 verified culturally or racially diverse-, woman-, or veteran-owned businesses, a 26% increase from 2022

WE PURCHASED

$147.9

MILLION

from small businesses in 2023

Through our Sustainable Purchasing Program, we form strategic partnerships that help us build a more diverse supplier base. These relationships support the communities we serve. Our current partners include the Oregon Association of Minority Entrepreneurs, Prosper Portland, and Portland Means Progress.

We expect our suppliers to adhere to the standards set forth in our Supplier Code of Ethics, Human Rights Policy, and Environmental Policy. Our Corporate Purchasing and Expenditures Policy sets forth certain business requirements, including diversity, that we consider when reviewing purchase orders. When evaluating RFPs, we consider the prospective supplier's ability to help NW Natural achieve our business requirements along with our goals for supplier diversity, and we request information that includes the prospective supplier's certification as a culturally or racially diverse-owned, women-owned, underrepresented, or emerging small business, as well as its own diverse-supplier program and opportunities to use diverse subcontractors.

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Human Rights, Equal Opportunity & Prohibition on Discrimination

We believe human rights are fundamental freedoms and standards of treatment to which all people are entitled. Our Human Rights Policy was reviewed and approved by our board of directors and articulates our commitment to identifying, preventing, and mitigating human rights risks, including: prevention of harassment and discrimination; commitment to diversity; freedom of association; safety and security; land rights and biodiversity; and prohibition of child or forced labor, among other things. We also maintain policies on equal employment opportunity and prohibition of discrimination and harassment, in keeping with our intention to foster a culture of inclusivity and support employees' right to work in an environment free of discrimination and harassment.

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NW Natural Water

NW Natural WATER™

Water is essential for life, security, and stability, and we take our responsibility seriously to provide and protect this critical resource. The core values and competencies that have made our natural gas utility successful for more than 165 years also guide our growing family of water and wastewater utilities and services.

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Water Highlights

Added over
10,400
new customers in 2023,
and now serve over
73,000
connections

Invested **$37 million** in
safety, reliability, and technology

Expanded our footprint
by adding four new utilities

87%
NW Natural Water employees responding to the 2023 survey are proud to work for NW Natural Water

Entered the
operations and maintenance services business
to support water and wastewater systems

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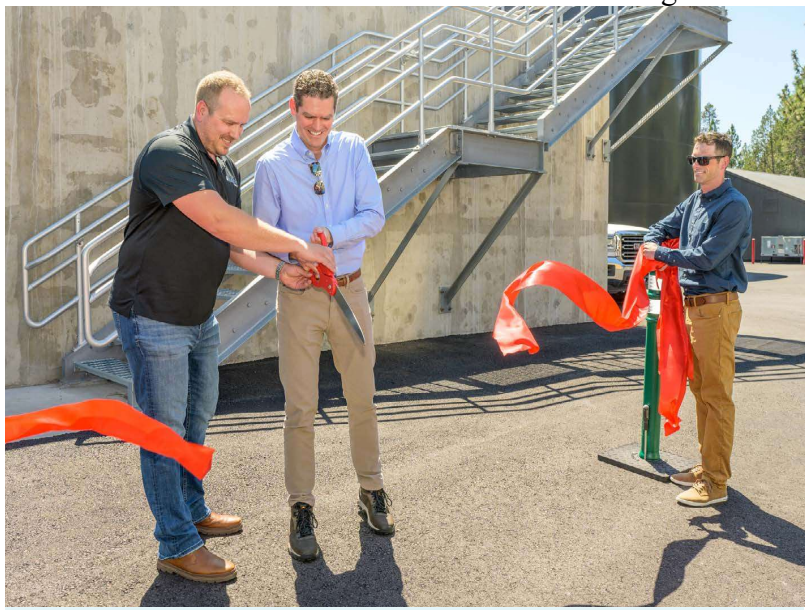
NW Natural WATER℠

Building on a Strong Foundation

NW Natural Water provides our service territories with financial, technical, and regulatory resources to help ensure safe, reliable, and affordable delivery of water and wastewater services to our customers every day. We are building on a strong foundation of superior customer service, environmental stewardship, and constructive regulatory engagement.

We've grown exponentially since NW Natural Holdings entered the water utility sector in December 2017. Through a deliberate and measured growth strategy, NW Natural Water has expanded its service territory to five states: Oregon, Washington, Idaho, Arizona, and Texas. In 2023, we acquired four more water and wastewater utilities. Since entering the sector, we have acquired more than 30 water and wastewater utilities and served over 73,000 connections at year end 2023. NW Natural Water is one of the 20 largest privately-owned water utilities in the U.S. based on customer count.

In 2023, we entered the operations and maintenance services businesses to support water and wastewater systems owners. We assist system owners by providing a range of services necessary to manage, operate, and maintain water and wastewater utilities. Our experienced personnel use an array of skills to assist in utility operations and to provide other business functions such as strategic planning, regulatory, customer service, and accounting assistance.



Upgrades at Sunriver Wastewater Treatment Plant Brings Water Quality to Class A Recycled Water

In 2023, NW Natural Water held a ribbon-cutting ceremony to celebrate the completion of a major upgrade to the Sunriver Water Wastewater Treatment Plant. This four-year, $18.5 million project enables the plant to treat an average of 1.5 million gallons of wastewater per day. This brings the water quality at the plant to a Class A reclaimed water profile, the Oregon Department of Environmental Quality's highest standard. Treated water from the plant also provides irrigation to nearby golf course, and byproducts create compost for the community.

> "Sunriver's Class A reclaimed water shows NW Natural Water's commitment to providing the highest standard of excellence to our customers and community."
>
> — Tim Smith, NW Natural Water
> Pacific Northwest regional manager

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NW Natural WATER™

Taking Rapid Action to Upgrade Critical Infrastructure

When NW Natural Water bought Foothills in October 2022, the company knew significant upgrades were needed to support the system and the growing Yuma, Arizona community it serves.

Right away in 2023, the team got to work and began major infrastructure upgrades on the wastewater plant. We're upgrading and adding membrane bioreactors, which improves our treatment process. Our Class A effluent discharge from the plant is used for irrigation at the adjacent golf course.

New remote-read smart meters are being installed, which provide more accurate usage data and allow for utility and customer access to leak detection capabilities. That's particularly important in dry regions like Yuma, Arizona. Upgrades also include structural projects and odor control system improvements.

> "The comprehensive upgrades at Foothills include important projects that allows us to provide clean water and reliable service to our customers. These upgrades wouldn't be possible without NW Natural Water."
>
> — Ed Fortner, NW Natural Water Southwest regional manager

Cleaner, Safer & More Reliable Service

Investing in new infrastructure and meeting customer needs safely and efficiently requires significant resources. We regularly invest in infrastructure improvements and safety measures that can be out of reach for smaller, stand-alone water utilities. In 2023, we continued to invest in safety, system reliability and information technology with spend totaling over $37 million with plans to invest $120 – $140 million in capital expenditures through 2028. In 2023 we:

- **Completed a major four-year, $18.5 million upgrade to the Sunriver Water wastewater treatment plant** to create a state-of-the-art facility that can now process 1.5 million gallons of Class A recycled water daily. This is the Oregon Department of Environmental Quality's highest standard for recycled water.
- **Launched a major infrastructure enhancement project at our Foothills wastewater plant.** Upgrades include the addition of membrane bioreactors, new advanced odor control systems, structural upgrades, and a system-wide installation of remote-read smart meters with leak detection.
- **Made broad investments in backup generation** to keep electric- driven equipment operating in the event of a power outage.
- **Contributed infrastructure capital to bring on new wells—** one of the most involved and expensive projects in the water business.
- **Invested in technology to prevent business disruptions.** We continued implementing supervisory control and data acquisition (SCADA) systems at all our water utilities, making it possible to proactively detect leaks and pressure drops.

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NW Natural WATER™

Investing in Safety

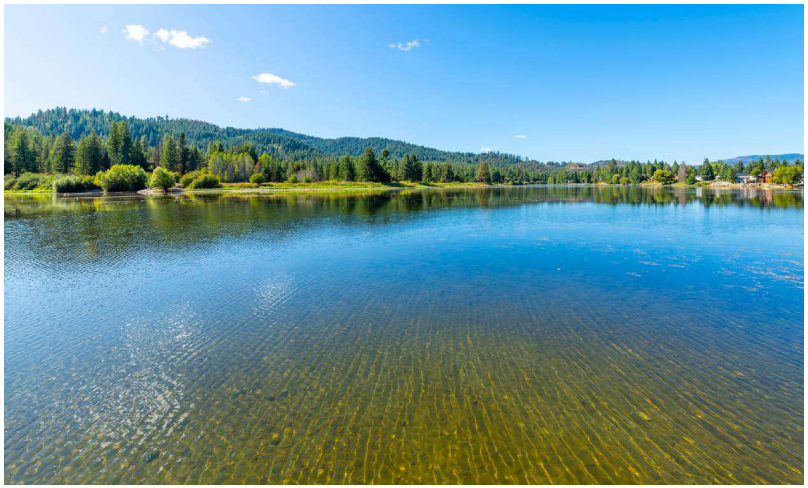
As our water business has grown, we have created a comprehensive safety program to help our NW Natural Water utilities all meet the same high health and safety standards to protect our employees and communities. To build that culture and standard of safety, we've implemented formalized safety practices and training that we are continually integrating throughout the workplace. Building a comprehensive safety program from the ground up is typically a long and challenging process, but we have been able to make swift, steady progress with the support from our experienced safety team. In 2023, the fourth year of our NW Natural Water safety program, we undertook the following measures:

- Hired a full-time Safety Environmental Program Manager to oversee our safety program
- Created a safety manual of standardized safety requirements and guidelines for all our utilities
- Increased our data collection to understand our safety needs

Environmental Stewardship

Water is a precious resource, and we're committed to using it wisely.

- **We strive to operate and maintain high-quality** water and wastewater systems so our facilities deliver safer and cleaner water to our customers.
- **We engage in comprehensive planning** to support investments in infrastructure and technology that are resource-efficient, cost-effective over their lifecycle, protective of the environment, and consistent with the goals of our communities.
- **We invest in critical infrastructure** that's essential for meeting water quality regulations. For example, across our water utilities we've invested in new wells, valves, pressure regulating valves, water mains, and technology like SCADA and geographic information systems (GIS) that help us maintain water quality by detecting and preventing low-pressure events that can lead to contamination.
- **At our wastewater treatment plants,** we strive to meet the highest standards for environmental sustainability. We continue to install SCADA systems at lift stations to help prevent wastewater overflow and protect lakes, rivers, and streams.
- **We look for opportunities to implement water reuse strategies** in areas of limited supply—a practice we believe is good business as well as our responsibility to the environment. For example, at our Sunriver and Foothills utilities, we reuse treated wastewater for secondary irrigation on golf courses within the community, and Sunriver's byproducts are used in compost for sale to the local community.
- **We are resolutely focused on reducing water loss, conserving water, and preventing waste.**
  - » We have installed technology to help minimize water leakage across our infrastructure. Our water utilities now have tools to perform water-loss analysis.
  - » We encourage customers to reduce water use. Our water utilities feature water conservation tips on their websites and encourage customers to use water-saving household fixtures. Sunriver Utilities provides low-flow faucet kits at no cost for homeowners who want to conserve water.
  - » Many of our water utilities have also adopted measures designed to reduce the amount of water used by residential customers who consume the highest percentage of water. In certain cases, we work directly with heavy water-users to help them reduce their consumption.



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Partnering with our Communities

Every year treated wastewater from our Sunriver Environmental plant irrigates a bountiful crop of orchard grass hay. In 2023 the utility donated the entire crop—52 tons of hay—to nearby organizations including two 4-H clubs. 4-H provides opportunities for youth, from kindergarten through high school, to acquire life skills through hands-on learning. 4-H members and volunteers can engage in more than 20 areas of interest including food and nutrition, animal science, art, gardening, and more.

Additionally in 2023, Sunriver partnered with the Ponderosa Project, which aims to repopulate Ponderosa Pine trees to their native ecosystem. Sunriver provides space at their compost site to plant and irrigate seedlings. Employees also support the Ponderosa Project by volunteering at youth workshops.

"At Sunriver, we have so much pride for our community and we aim to support a variety of causes."

— Tim Smith, NW Natural Water Pacific Northwest regional manager

Communities & Customers

Our customers are our community, and we are committed to serving and supporting them. We work with all our utilities to understand what makes their customers and communities unique.

CUSTOMER EXPERIENCE: We partner with community-oriented water utilities that are dedicated to serving customers, and we're committed to preserving and building on that legacy. We have enhanced the online experience people have when they do business with our utilities, with updated and standardized websites where customers can pay their bills and get instant access to features and information, including water quality (consumer confidence) reports, rate structure, a "call us" button, and water-emergency resources.

BILL PAYMENT ASSISTANCE: To support people experiencing financial hardship, we offer time payment agreements that allow customers in need to pay a portion of their bill in installments.

ENGAGEMENT: With deep roots in the communities they serve, our water and wastewater utilities work diligently to meet their customers' needs, understand their stakeholders' concerns, and operate as good neighbors. Our water and wastewater companies support a range of local nonprofits, and they solicit community input on important matters such as rate cases and infrastructure upgrades.

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People & Culture

Attracting and retaining a talented workforce is vital to the success of NW Natural Water, and we continuously look for ways to meet the needs of the dedicated employees who keep our water businesses running smoothly. In 2023, all active NW Natural Water employees completed our annual ethics and compliance training in support of a culture that seeks to promote integrity and ethical behavior. In 2023, NW Natural Water conducted its third employee engagement survey, and 87% reported that they take pride in their work at the company. In addition, 87% of NW Natural Water employees described themselves as engaged.

Additionally, NW Natural Water strives to offer competitive total compensation packages[1] designed to attract and retain employees and meet the needs of our workforce. We continuously look for ways to enhance employees' physical, psychological, and financial well-being. This is reflected in the programs we offer to meet the needs of employees and help them care for their families.

65% of Water employees participated in the 2023 survey

91% of employees feel their work area operates with integrity and ethical conduct

82% of employees feel like they are valued

91% feel that all employees are treated fairly and included regardless of race, gender, sexual orientation, age, disability, religion, ethnicity and/or interests

Employee Benefits

HEALTH COVERAGE FOR ALL FULL-TIME STAFF: We provide medical, dental, vision, and prescription insurance options for employees and eligible dependents. We also offer an optional Flexible Spending Account.

FINANCIAL WELLNESS: We provide a 401(k) with employer match.

INSURANCE: We provide life insurance, accidental death & disability, short- and long-term disability insurance to employees. We also offer voluntary accident insurance to employees.

GENEROUS VACATION AND HOLIDAYS: Full-time employees receive 15 days of paid time off (PTO) per year at the start of service and 30 days of PTO per year at 20 years of service. Additionally, full-time employees receive 9 paid holidays and 4 floating holidays per year.

EMPLOYEE ASSISTANCE PROGRAM: Our employee assistance program is a free and confidential consulting-and-advice benefit that provides resources and services to employees.

Employee-Led Engagement Opportunities

NW Natural Water employees have the option to connect with their peers through employee-led engagement opportunities, employee resource groups, special interest groups, and company events. We aim to create a culture of belonging for all employees of NW Natural Holdings.

> "I am proud to work alongside such passionate people that represent NW Natural Water to the fullest."
>
> — Justin Palfreyman, NW Natural Holdings president

[1] Our package options vary depending on date of hire and whether the employee is full-time or part-time. Terms of benefits may differ based on U.S. state.

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NW Natural Renewables

NW Natural Renewables is committed to leading in the energy transition by providing renewable fuels to support decarbonization efforts in the utility, commercial, industrial, and transportation sectors.

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NW Natural Renewables

Building on a long-standing vision of a lower-carbon future, we launched a renewable fuels business in 2021. As a subsidiary of NW Natural Holdings, NW Natural Renewables' mission is to support the energy transition through the supply of net lower-carbon fuels to the utility, commercial, industrial and transportation sectors. Our experienced team is focused on providing decarbonization solutions by using waste streams and more environmentally conscious energy sources to supply renewable natural gas (RNG) and provide these customers with additional emissions-reducing solutions. These efforts are separate from and in addition to NW Natural's gas utility efforts related to RNG and hydrogen.

Our country and region are in the early stages of a historic energy transition, and we project the demand for renewable fuels will only continue to grow. We are positioning our business to help NW Natural Renewables' partners achieve their decarbonization goals and drive down emissions.

In November 2021, we announced our first project with EDL, a leading global producer of sustainable distributed energy. NW Natural Renewables has contracted to provide approximately $50 million toward the development of two production facilities that are designed to convert landfill waste gases to RNG and connect that production to the existing regional pipeline networks. In 2023, construction was completed on the two facilities. We expect the facilities to be operational in 2024.

NW Natural Renewables and EDL executed agreements designed to obtain a 20-year supply of RNG produced by the facilities for NW Natural Renewables. Separately, we have contracted to sell an equivalent amount of fixed-volume RNG supply to investment grade counterparties under long-term, primarily fixed-price contracts.

We are excited about pursuing opportunities to move toward a lower-carbon energy future, and we remain focused on advancing other RNG investments that support this important transition.

> "I am excited about the future of NW Natural Renewables, and we look forward to providing a lower-carbon solution to meet both our partners' energy needs and the needs of our shared environment."
>
> — Anna Chittum, NW Natural Renewables president

Limestone RNG Facility, one of our first projects with EDL

Lorain RNG Facility, one of our first projects with EDL

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Governance

Strong corporate governance and integrity form the foundation for everything we do. Our board strives to adopt and maintain appropriate corporate governance practices. And we expect our employees to do what is right for our stakeholders, conduct business ethically, act with accountability, and work with business partners who share our high standards and principles. Our 2024 Proxy Statement provides a full discussion of our governance practices.

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Governance Highlights

Board of Directors

- Maintain a well-qualified, diverse and active board of directors
- Determine independence of directors (11 of 12 directors meet independence criteria)
- Engage in robust succession planning process supporting board refreshment (one-half of our directors are new within the last five years) as of September 1, 2024
- Separate roles of chair and CEO under current leadership structure
- Hold regular executive sessions of non-management directors
- Oversee company's risk management programs and policies
- Evaluate full board of directors, committees and individual directors on an annual basis
- Provide comprehensive director orientation and continuing education to enable directors to develop and maintain skills necessary or appropriate for the performance of their duties

Other Governance Practices

- Maintain stock-ownership guidelines
- Maintain insider trading policy applicable to directors, officers and employees, agents, advisors and independent contractors
- Maintain a hedging and pledging policy applicable to directors and officers
- Maintain a Clawback Policy and incorporate into annual and long-term cash and equity i ncentive awards

Business Integrity & Ethics

- Maintain and promote an active ethics and compliance program
- Foster a culture that mitigates risk and promotes ethical behavior and integrity
- Recognized by Ethisphere® as one of the 2024 World's Most Ethical Companies®, the third consecutive year earning this award[1]

[1] "World's Most Ethical Companies" and "Ethisphere" names and marks are registered trademarks of Ethisphere LLC

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Governance Practices

Board of Directors

The board of directors of NW Natural Holdings establishes policies designed to promote management of our business, to serve our stakeholders and maximize long-term shareholder value, that we conduct our business in compliance with all applicable laws and regulations, and that we do so with the highest standards of integrity. For complete information on our approach to corporate governance, please visit the governance portion of our website at nwnaturalholdings.com. The following sections highlight our approach to corporate governance.

Board Composition & Refreshment

The board is responsible for selecting candidates for board membership, and the Governance Committee has been assigned the responsibility of recommending nominees to the board of directors for election as directors.

The Governance Committee reviews director nominees in the context of the current composition and diversity of the board, the operating requirements and existing and prospective business environment faced by NW Natural Holdings, NW Natural Holdings' business strategy, and the long-term interests of shareholders. Director candidates must be able to make a significant contribution to the governance of NW Natural Holdings by virtue of their business and financial expertise, educational and professional background, and current or recent experience as a chief executive officer or other senior leader of a public company or other relevant organization.

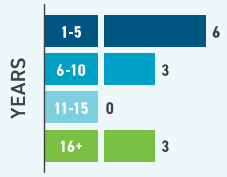
The business discipline that may be sought at any given time will vary depending on the needs and strategic direction of our company and the disciplines represented by our incumbent directors. In addition, the Governance Committee looks at the overall composition of the board and how a candidate would contribute to the overall synergy and collaborative process of the board. In conducting its assessment, the Governance Committee considers a variety of criteria, including, but not limited to, the candidate's integrity, reputation, judgment, knowledge, experience, commitment, skills, diversity, and independence.

In recent years, the board undertook a comprehensive succession planning and refreshment review in anticipation of the retirements of several long-tenured directors. In line with those plans, the board has undergone substantial refreshment in recent years, with 6 of the 11 current independent directors being added to the board in the last five years. Our Corporate Governance Standards provide for several mechanisms to encourage director refreshment, including: annual peer reviews of individual directors, a requirement to offer notice of resignation upon a change in principal position, and a mandatory retirement age of 75.

OUR BOARD COMPOSITION

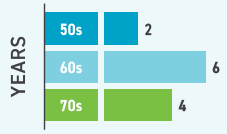
Tenure*

8.5
AVERAGE YEARS



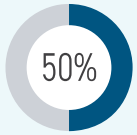
Age*

66
AVERAGE YEARS



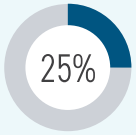
Board Refreshment*

6 out of 12 directors were first added to the Board in the last five years



Gender Diversity*

6 out of 12
directors identify as women



Cultural and Racial Diversity*

3 out of 12 directors identify as culturally or racially diverse

Independence

11 out of 12 directors are independent
(all directors except CEO)

Chairperson of the board is independent CEO

*Information provided for directors as of September 1, 2024

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NW Natural HOLDINGS™

COMMITMENT TO DIRECTOR INDEPENDENCE

The board of directors of NW Natural Holdings has adopted director independence standards that comply with New York Stock Exchange (NYSE) rules. The board of directors has affirmatively determined that 11 out of 12 directors are independent, according to NW Natural Holdings' director independence standards as well as additional qualifications prescribed under the listing standards of the NYSE and applicable state and federal statutes. All standing committees of the board are chaired by and currently comprised of independent directors. The current board leadership structure also separates the roles of chair and CEO and is designed to promote independence between board and management. Additionally, to support independence, the directors of the board meet regularly in executive sessions at which the independent board chair presides and only the non-management directors are present.

COMMITMENT TO BOARD DIVERSITY

NW Natural Holdings' Director Selection Criteria include a consideration of diversity as a factor in evaluating candidates for board membership. The board believes that diversity with respect to factors such as background, experience, skills, geographic location, race, gender, ethnicity, culture, veteran status, age, disability, and sexual orientation are important considerations in board composition. The Governance Committee discusses diversity considerations in connection with each director candidate, as well as on a periodic basis in connection with the composition of the board as a whole. In addition, the Governance Committee and the board conduct formal self-evaluations each year that include an assessment of whether the Governance Committee and the board have adequately considered diversity, among other factors, in identifying and discussing director candidates. Currently, of 12 members of our board, six directors identify as women, including our board chair, and three directors identify as racially or culturally diverse. Our composition of women on our board has earned a "Winning Company" award three times from 50/50 Women on boards, which described the board's gender diversity as a "shining example of enlightened business leadership." In 2023 our board received the highest distinction for Gender Balanced. In addition, two thirds of the leadership roles on our board are held by women, including the board chair and three out of five committee chairs.

BOARD EXPERIENCE

NW Holdings' board consists of 12 directors with extensive professional experience and a diverse array of skills. This diversity of experience provides our board with a collective skill set that is advantageous to the board's oversight of our business and operations. In addition to the qualifications required of all directors that are set forth in NW Holdings' Director Selection Criteria, our board members have experience in climate change and decarbonization, cyber and IT, risk management, and more. More information on board experience can be found in our 2024 Proxy Statement.

Board's Role in Risk Oversight

Management is responsible for managing the day-to-day risks faced by the company, while the board of directors, collectively and through its committees, has responsibility for the oversight of risk management.

The Corporate Governance Standards describe the board's primary responsibilities, which include oversight of NW Natural Holdings' mission, and key programs that enable the board to assess and manage material risks, including, but not limited to, risks related to business continuity and disaster response, gas supply, distribution and storage operations, product safety, strategic planning and business development, environmental and climate change matters, business improvement and information technology, cybersecurity, customer demand and market competition, economic environment, effective governance, legislative and regulatory risk and compliance, state and federal regulatory process and environment, financial performance, business integrity and compliance, financial reporting and internal controls, financing programs, pensions and retirement plans, reputational risk, human capital management, compensation and employee benefits, succession planning (including the CEO), human risks such as safety and diversity, equity and inclusion matters, environmental, social and governance matters and company culture. The board periodically reviews its committee oversight authority to ensure the board has adequate visibility and oversight of the company's key areas of risk to execute its responsibilities. Appropriate members of management serve as liaisons to board committees, attend board and committee meetings, and regularly discuss with the board and the committees various risks confronting the company.

An important aspect of the board's oversight role is the comprehensive enterprise risk management process, under which significant enterprise-wide risks have been identified and assessed with respect to likelihood of occurrence, potential impact on the business, and likely speed of onset, along with the mitigative measures to address and manage such risks. The enterprise risk management process allows the board to remain informed of risks, developing trends, or potential problems that might require their attention. Management conducts the enterprise risk management process annually with periodic interim updates and discusses those findings with the board and reports regularly to the board on significant risk categories. Additional review or reporting on enterprise risks is conducted as needed or requested by the board. The board and management consider enterprise risks and opportunities in their strategic and capital spending decision process and in their governance and oversight responsibilities.

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Board Structure & Function

COMMITTEES

There are five standing committees of the board: Audit, Finance, Governance, Organization and Executive Compensation Committee (OECC), and Public Affairs and Environmental Policy. Each of the standing committees operates according to a formal written charter, all of which are reviewed annually and are available at nwnaturalholdings.com. Each committee is comprised entirely of independent directors.

BOARD AND COMMITTEE OVERSIGHT

The full board considers key risks, issues and initiatives. Board committees additionally have primary responsibility and oversight with respect to the following areas:

Audit Committee

- Oversight and evaluation of policies with respect to significant risks and exposures and the procedures for assessing, monitoring and managing those risks.
- Oversight of accounting, financial reporting, internal controls, auditing, information technology systems and cybersecurity, enterprise risk management process, business continuity and disaster planning, capital projects and contingencies, and material litigation.
- Oversight of business compliance and integrity program, including Code of Ethics, and the company's system for review and treatment of integrity hotline complaints.

Public Affairs and Environmental Policy Committee

- Oversight of legislative and regulatory matters and policies and practices on public and political issues, including charitable and political contributions and budgets.
- Oversight of current and emerging political and societal trends.
- Oversight of programs and policies relating to civic affairs, human rights, charitable and community affairs, safety, diversity, equity and inclusion, equal employment opportunities, employee well-being, customer engagement and other corporate social responsibility matters.
- Review and recommendation of environmental matters and policies and sustainability efforts.
- Review of major environmental risks and plans for managing those risks.

Finance Committee

- Oversight of financing programs, budgets and forecasts, financial policy matters, including hedging policies and practices, economic environment, gas supply and pricing, including liquidity and cash flow impacts, and carbon credit pricing and procurement, and material regulatory issues, including regulatory policy related to financial strategy and policy, capital structure and dividend policy.
- Oversight of investor relations program, and credit agency and New York Stock Exchange relationships.
- Financial oversight of pension and retirement plans.
- Review and recommendation of finance aspects of corporate development strategies.

Organization and Executive Compensation Committee

- Oversight of company's human capital management.
- Review and recommendation of plans and preparations for talent succession and management of risks associated with transfer of knowledge and expertise.
- Recommendation of executive compensation programs and benefit plans to the board, as well as monitoring of risks and alignment of incentives related to such plans and programs.
- Review and approval of grants under equity incentive plans to eligible employees.
- Primary responsibility for ensuring executive compensation programs and plans are consistent with corporate objectives and OECC's compensation philosophy.

Governance Committee

- Recommendations to the board regarding nominees for election to the board, and committee composition and structure.
- Establishment of criteria for board and committee membership and policies that govern the board's activities.
- Review and recommendation of governance policies and structure, including the Corporate Governance Standards, to the board.
- Evaluation of board and individual director performance and oversight of director onboarding and continuing education.
- Oversight and consideration of plans and preparations for board succession.
- Oversight of director and executive stock ownership guidelines and ownership levels.
- Oversight of integrated environmental, social and governance matters.

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MANAGEMENT LEADERSHIP

Our executive leadership team is responsible for leading and managing our business and for developing and executing company strategy as approved by the board, and meets regularly to actively monitor operations, financial performance, and legal, regulatory, policy and other external developments; ensure compliance with policies, procedures and ethical business practices; identify, assess and manage company risks and opportunities; and develop and implement strategy to achieve sustainable, long-term performance. Each member of our executive leadership team has identified goals in support of sustainable, long-term business performance, with a portion of their compensation tied to the achievement of these goals. We have a diverse executive team and have expanded the number of women in leadership positions. Today, our 15-person executive leadership team includes six women.

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ESG Governance & Oversight

While our executives are responsible for day-to-day management and leadership of the company, the board of directors has responsibility for oversight of management and its development and implementation of company strategy, including ESG matters and risks and opportunities, including those related to climate and cybersecurity. The Governance Committee oversees the company's integrated ESG strategy and reviews its full board and committee oversight authority to ensure that the board has adequate visibility and oversight to execute its responsibilities. In order to assist the Governance Committee in its ESG oversight responsibilities, management provides formal ESG updates to the Governance Committee at each regularly scheduled meeting (approximately five times per year). In addition, appropriate members of management serve as liaisons to board committees, attend board and committee meetings, and regularly discuss with the board matters relevant to the company, including ESG matters and the company's risks and opportunities. Areas of ESG oversight include, but are not limited to:

Audit

- Business Integrity
- Whistleblower Hotline
- Enterprise Risk Management
- Business Continuity
- Significant Legal Matters
- Internal Controls Over Financial Reporting
- SEC Reporting Oversight
- Cybersecurity and IT

Board

- Decarbonization; Including Low Carbon Pathway and Vision 2050
- Customer Preference/Satisfaction
- Tone at the Top
- Operational and Business Development Initiatives (e.g., Water and RNG)
- Other Natural Gas Applications
- Strategic Matters
- Pipeline Safety

Public Affairs and Environmental Policy

- Employee Safety
- Diversity, Equity and Inclusion
- Employee Engagement and Well-Being
- Civic and Human Rights
- Environmental and Sustainability
- Community and Public Relations
- Charitable Giving and Political Contributions
- Legislative and Regulatory Matters
- Employee Satisfaction
- Procurement
- Customer Metrics, Engagement and Affordability Considerations

Organization and Executive Compensation

- Compensation and Benefit Programs, Including Alignment of Incentives with ESG
- Talent Strategy and Succession
- CEO Succession
- Labor Relations
- Employee Attrition Rates

Governance

- Board Structure, Policies, Governance and Expectations
- CEO and Board Succession Planning
- Board Composition, Diversity and Independence
- Board Evaluations
- Committee Oversight Roles/Responsibilities
- Continuing Board Education and Training
- ESG Strategy

Finance

- Financial Policies and Matters That May Have ESG Implications
- Investor Relations
- Goal Setting and Performance Metrics
- Rating Agency Relationships
- Capital Markets/Green Financings
- Carbon credit pricing and procurement
- Investment in Key ESG Improvements

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Management ESG Leadership

Each member of our executive leadership team is responsible for developing and implementing our business strategy and lead areas that are considered ESG. For example, our VP and chief public affairs and sustainability officer leads our environmental management and sustainability, legacy environmental programs, community and government affairs and community involvement teams. She also leads teams focused on procuring renewable natural gas and pursuing hydrogen gas initiatives. Our VP, chief human resources and diversity officer leads our safety, employee and labor relations, organizational effectiveness, diversity, equity and inclusion and human resources and benefits teams. Our VP, chief compliance officer and corporate secretary leads our governance and business integrity and compliance teams and co-leads our ESG Steering Committee, a cross functional group of executives and senior management that meets regularly to discuss the company's ESG strategy, implementation and disclosure. Each of these officers report directly to the CEO or president and serves as an executive liaison to a relevant committee of the board of directors. Also reporting directly to our president, our SVP and chief operating officer heads our efforts to pursue a lower-carbon pathway. Our VP, treasurer, chief accounting officer and controller oversees our sustainable financing and sustainable procurement efforts. And, our VP and chief information officer, leads our cybersecurity and compliance, and information technology (IT) teams. Each of our executive leaders has identified goals in support of sustainable, long-term business performance attentive to ESG matters, with a portion of their compensation tied to the achievement of these goals. Our 15-person executive leadership team meets regularly to discuss the development and implementation of company strategy, including sustainability matters.

Stock Ownership Requirements

To closely align director interests with shareholder interest, the board has adopted stock-ownership guidelines that require directors to own NW Natural Holdings shares of at least $450,000 in value within five years of joining the board. Similarly, executive officers are required to hold stock at a dollar value that is a multiple of base salary, with the CEO holding five times their annual salary, the president holding four times their annual salary, executive vice president or chief operating officer holding three times their annual salary, senior vice presidents or named executive officers holding two times their annual salary and vice presidents holding one times their annual salary.

Insider Trading

To foster integrity in trading in NW Natural Holdings stock, the company maintains an insider trading policy that specifies that if a director, officer, any employee of NW Natural Holdings or its subsidiaries, has material nonpublic information relating to the company, it is the company's policy that neither that person nor any related person may buy or sell securities of the company or engage in any other action to take advantage of, or pass on to others, that information.

Policy on Hedging & Pledging of NW Natural Holdings Securities

NW Natural Holdings has adopted a policy on hedging and pledging of securities that prohibits the directors and executive officers of the company and its subsidiaries from engaging in any short sales, zero-costcollars, or forward sale contracts with respect to the company's securities, or purchasing or selling puts, calls, options, or other derivatives securities based on the company's securities. In addition, the policy restricts the ability of directors and executive officers to pledge their ownership of company securities in a non-recourse loan, failing to meet a margin call with respect to a margin account resulting in the sale of company stock, or buying company securities on non-recourse margin.

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Business Integrity

Since 1859, NW Natural has been viewed as a respected leader in Oregon and SW Washington. We could not have maintained this reputation for over 165 years without one fundamental characteristic—integrity. Our customers trust us to provide them with essential energy and deal with them fairly, in a caring and equitable fashion. Our business integrity program aims to reinforce our core values in our everyday work.

We are honored to have been recognized as one of the 2024 World's Most Ethical Companies® by Ethisphere[1], a global leader in defining and advancing the standards of ethical business practices. It is the third year NW Natural Holdings has been recognized and the company is one of only eight honorees in the Energy & Utilities industry. In all, 136 honorees from 20 countries and 44 industries were recognized for their commitment to ethical business practices through programs that positively impact employees, communities, and broader stakeholders.

Oversight of Business Integrity Program

Our Business Integrity program is overseen by the Audit Committee of the board of directors and is managed on a day-to-day basis by our business integrity team, which is a cross-functional team led by our chief compliance officer and consisting of members of the internal audit, legal and human resources departments. Our chief compliance officer and director of internal audit each regularly provide updates on business integrity matters to the Audit Committee of the board of directors, including updates on business integrity reports, management actions, training, outreach and other integrity initiatives, business integrity trends and updates, and benchmarking analysis.

Code of Ethics

We maintain a Code of Ethics that applies to all of our employees, including supervisors, managers and officers, as well as to our board of directors and other agents, vendors and business partners working on our behalf. Our Code of Ethics is intended to set expectations for conduct that is consistent with our core values; help promote compliance with laws and NW Natural policies; establish our high standards of integrity; and provide information about how to resolve real-life questions or concerns. Employees are required to annually certify their commitment to the principles outlined in the Code of Ethics and disclose any business integrity concerns. Our Code of Ethics is approved annually by the board upon the review and recommendation of the Audit Committee.

Code of Ethics Training & Communications

To reinforce the company's core value of integrity, every employee and director completes an annual online Code of Ethics training to refresh their understanding of the company's Business Compliance and Integrity Program and Code of Ethics. NW Natural's program received the national award for Best Ethics and Compliance Program (Small and Mid-Cap) at the 2018 Corporate Governance Awards event, in recognition of its new Code of Ethics document and refreshed online training and certification program. The Code of Ethics training covers a number of topics including, but not limited to conflicts of interest, non-retaliation, anticorruption/ anti-bribery, fair business dealings, compliance with laws, government relations, confidentiality, politics in the workplace, and social media, among other things.

In 2023, 100% of our active employees participated in our annual ethics and compliance trainings. We also regularly provide specialized live training to help managers and supervisors navigate pertinent business integrity questions and emphasize their role as the front line of integrity at NW Natural and the resources available to them.

We reinforce our annual Code of Ethics and information security trainings with periodic communications spotlighting pertinent business integrity topics and messages from senior leadership. We also provide additional resources to employees via an internal intranet page dedicated to business integrity.

[1] "World's Most Ethical Companies" and "Ethisphere" names and marks are registered trademarks of Ethisphere LLC

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Reporting, Investigations & Actions

We maintain our Integrity Hotline to empower employees, shareholders, customers, the public and other third parties to raise issues or submit concerns anonymously at 1-866-546-3696 or NWNIntegrity.com, which is managed by a third party and is available through our external and internal websites. Our hotline offers employees and others the opportunity to anonymously ask questions about ethical decisions. We also provide several other avenues to raise issues or report concerns in addition to our hotline.

Our chief compliance officer and our director of internal audit handle matters reported on the hotline and through other reporting avenues. Both regularly report to the Audit Committee regarding hotline activity.

NW Natural is committed to investigating all potential violations of law, company policy or business integrity and handling each report fairly and reasonably. In 2023, we received 37 interactions with our hotline and other business integrity reporting channels (approximately 2.7 per 100 employees), of which 23 (approximately 1.7 per 100 employees) were determined to involve business integrity reports. Business integrity reports are reviewed by our Business Integrity team and investigated as necessary with assistance from the company's internal audit, human resources, legal, or other departments and/or other internal or external resources as appropriate under the circumstances, depending on the type and nature of the allegation. When violations are detected, appropriate actions are taken, which may include coaching or counseling, administering disciplinary action, up to and including termination and/or improvements to our policies, procedures or practices.

We maintain a Violation Reporting Policy, approved by the Audit Committee of the board of directors, that prohibits retaliation and offers protections for individuals that make good faith reports of possible violations of the Code of Ethics, company policy or law or who participates in an investigation in good faith. Employees who have engaged in retaliation may face disciplinary action, up to and including termination. We proactively communicate our prohibition on retaliation in multiple forums including our annual Code of Ethics Training, manager trainings, integrity website and periodic communications to employees.

Evaluation & Continuous Improvement

We strive to evaluate the effectiveness of our program on a regular basis. As part of this process, we monitor relevant business integrity risks, legal updates, hotline reports, investigation results and survey data, among other things. We also review compliance best practices and periodically benchmark our business integrity program against other companies. These activities help inform priority areas for training, communications and other program initiatives.

Supplier Code of Ethics & Fair Business Dealings

We seek to do business with organizations and service providers that embrace our core values, including integrity. We maintain a Supplier Code of Ethics, which is available on our supplier website and sets forth our expectations for our suppliers in areas of ethics and compliance, safety, human rights, and diversity, among other things. Under the Supplier Code, suppliers have a responsibility to report any suspected illegal or unethical conduct involving NW Natural or its business partners, and the company's business integrity hotline is available to suppliers and other third parties to anonymously report concerns. We monitor key suppliers on an ongoing basis and have implemented a scorecard for certain vendors that considers whether such vendor operated in accordance with our core values in doing business with us.

As set forth in our Code of Ethics, we strive to deal fairly and in good faith with NW Natural's customers, shareholders, employees, regulators, suppliers, competitors and others. We strive to avoid any attempt to take unfair advantage of any person through manipulation, misrepresentation, fraud, misuse of confidential information or any other unethical dealing, practice or act. Our Code of Ethics sets forth our policies and expectations regarding fair business dealings, including our expectations regarding expenses, purchasing and contracting, gathering competitive data, and engaging in transactions between utility and non-utility subsidiaries. Our Code of Ethics also sets forth our strict prohibition on bribes and kickbacks. In 2023, we received zero substantiated reports of bribery or corruption through our Integrity Hotline.

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Appendix

2023 Sustainability Accounting Standards Board (SASB)

2023 NW Natural Workforce Statistics

2023 American Gas Association (AGA) Voluntary Reporting Tool

2023 NW Natural Environmental Data

2023 Additional Statistics

2023 Environmental Memberships & Associations

Not to be used for investment purposes—see NW Natural and NW Natural Holdings most recent Form 10-Ks as updated by the most recent quarterly and periodic reports for information relevant to investment decisions.

2023 Sustainability Accounting Standards Board (SASB)

For the year ended Dec. 31, 2023

The following index sets forth Northwest Natural Holding Company's SASB reporting disclosures for our primary industry, Gas Utilities & Distributors. While we report information on nearly all of SASB's metrics, we may report a different unit of measure, different metric, or partial information for the topic area or accounting metric as noted. Unless otherwise noted, data in the below SASB disclosure is as of, or for the year ended December 31, 2023.

Gas Utilities & Distributors Accounting Standard

ENERGY AFFORDABILITY		
SASB CODE	**ACCOUNTING METRIC**	**2023 DISCLOSURE RESPONSE**
IF-GU-240a.1	Average retail gas rate for residential customers[1] per MMBtu	$13.76
	Average retail gas rate for commercial customers[1] per MMBtu	$11.64
	Average retail gas rate for industrial customers[1] per MMBtu	$9.35
	Average retail gas rate for transportation services[1] per MMBtu	$2.12
IF-GU-240a.2	Typical monthly gas bill for residential customers for 50 MMBtu of gas delivered per year[2] (USD)	$63.01
	Typical monthly gas bill for residential customers for 100 MMBtu of gas delivered per year[2] (USD)	$120.37
IF-GU-240a.3	Number of residential customer gas disconnections for nonpayment, percentage reconnected within 30 days	Approx. 8,535 within 20 days[3]
	Percentage of residential customer gas disconnections for nonpayment reconnected within 30 days	57% reconnected within 20 days[3]
IF-GU-240a.4	Discussion of impact of external factors on customer affordability of gas, including the economic conditions of the service territory	2023 Community & Sustainability Report, "Customers & Community"

[1] Weighted average rates from 11/1/22-10/31/23.
[2] Based on weighted average rates for the heating year beginning 11/1/2022 and ending 10/31/2023.
[3] NW Natural reports reconnections within 20 days rather than 30 days, consistent with our internal practice regarding measurement and reporting of reconnections.

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END-USE EFFICIENCY		
SASB CODE	**ACTIVITY METRIC**	**2023 DISCLOSURE**
IF-GU-420a.1	Percentage of gas utility revenues from rate structures that are decoupled	77%
	Percentage of gas utility revenues from rate structures that contain a lost revenue adjustment mechanism	0%
IF-GU-420a.2	Customer gas savings from efficiency measures by market (MMBtu)	Oregon: 549,258 Washington: 27,287

INTEGRITY OF GAS DELIVERY INFRASTRUCTURE		
SASB CODE	**ACTIVITY METRIC**	**2023 DISCLOSURE**
IF-GU-540a.1	Number of federally reportable pipeline incidents	0
	Number of federal corrective action orders	0
	Number of federal notices of probable violation	0
IF-GU-540a.2	Percentage of distribution pipeline that is cast and/or wrought iron	0%
	Percentage of distribution pipeline that is unprotected steel	0%
IF-GU-540a.3	Percentage of gas transmission pipelines inspected	75% as of December 31, 2023[4]
	Percentage of gas distribution pipelines inspected	20%[5]
IF-GU-540a.4	Description of efforts to manage the integrity of gas delivery infrastructure, including risks related to safety and emissions	2023 Community & Sustainability Report, "Safety & Reliability", "Environmental Stewardship"

[4] Pipeline inspected through December 31, 2023, but not limited to inspections during the calendar year 2023. As of December 31, 2023, we inspected 70% of our pipeline, 2.5 times the number required by 49 CFR 192.903 and reassess covered pipelines every seven years as set forth in 49 CFR §192.939(6) by the Pipeline and Hazardous Materials Safety Administration (PHMSA).

[5] We strive to perform a leak survey on 20% of our gas mains annually, with every gas main surveyed at least every five years. We also strive to perform leakage and atmospheric corrosion surveys every three years on residential service lines and annually in business districts and high-occupancy buildings.

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ACTIVITY METRICS		
SASB CODE	**ACTIVITY METRIC**	**2023 DISCLOSURE**
IF-GU-000.A	Number of residential customers served	728,915
	Number of commercial customers served	69,273
	Number of industrial customers served	1,062
IF-GU-000.B	Amount of natural gas delivered to residential customers (MMBtu)	45,570,284
	Amount of natural gas delivered to commercial customers (MMBtu)	28,005,196
	Amount of natural gas delivered to industrial customers (MMBtu)	17,931,727
	Amount of natural transferred to a third party (MMBtu)	29,160,138
IF-GU-000.C	Length of gas transmission pipelines	734 miles
	Length of gas distribution pipelines	14,419 miles

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2023 NW Natural Workforce Statistics

The following table sets forth NW Natural's consolidated EEO-1 data as submitted for the payroll period 12/15/23 through 12/31/2023.

JOB CATEGORIES	HISPANIC OR LATINO		NOT-HISPANIC OR LATINO												OVERALL TOTALS
			MALE						FEMALE						
	MALE	FEMALE	WHITE	BLACK OR AFRICAN AMERICAN	ASIAN	NATIVE HAWAIIAN OR PACIFIC ISLANDER	AMERICAN INDIAN OR ALASKAN NATIVE	TWO OR MORE RACES	WHITE	BLACK OR AFRICAN AMERICAN	ASIAN	NATIVE HAWAIIAN OR PACIFIC ISLANDER	AMERICAN INDIAN OR ALASKAN NATIVE	TWO OR MORE RACES	
EXECUTIVE/SR OFFICIALS & MGRS	2	0	62	1	5	1	1	1	33	1	1	0	2	0	110
FIRST/MID OFFICIALS & MGRS	6	1	49	1	6	0	1	0	15	1	0	0	0	1	81
PROFESSIONALS	16	14	172	9	18	2	3	8	120	5	19	0	3	4	393
TECHNICIANS	0	0	1	0	0	0	0	0	2	0	0	0	0	0	3
SALES WORKERS	0	0	2	0	0	0	0	0	2	0	0	0	0	0	4
ADMINISTRATIVE SUPPORT	3	17	35	4	3	0	1	1	73	14	6	1	1	8	167
CRAFT WORKERS	31	0	309	7	8	4	19	1	6	1	0	0	0	0	386
OPERATIVES	7	1	33	4	3	1	0	2	5	0	0	0	0	0	55
LABORERS & HELPERS	4	1	4	1	0	0	1	0	0	0	0	0	0	0	10
SERVICE WORKERS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023 TOTAL	69	34	667	26	43	7	26	13	256	22	26	1	6	13	1,209
PREVIOUS REPORT 2022 TOTAL	49	19	665	24	41	7	25	18	230	21	24	2	5	13	1,142

Not to be used for investment purposes—see NW Natural and NW Natural Holdings most recent Form 10-Ks as updated by the most recent quarterly and periodic reports for information relevant to investment decisions.

2023 American Gas Association (AGA) Voluntary Reporting Tool

Parent Company:	**NW Natural Holding Co.**
Operating Company(s):	**NW Natural**
Business Type(s):	*LDC*
State(s) of Operation:	**OR & WA**
Regulatory Environment:	*Regulated Utility*
Report Date:	*Sep-24*

Gas Company ESG/Sustainability Quantitative Information

Ref. No.	Refer to the "Definitions" column for more information on each metric.	Current Year 2023	Definitions
Natural Gas Distribution			
1	**METHANE EMISSIONS AND MITIGATION FROM DISTRIBUTION MAINS**		**All methane leak sources per 98.232 (i) (1-6) are included for Distribution. Combustion sources are excluded. CO2 is excluded.**
1.1	Number of Gas Distribution Customers	799,250	
1.2	Distribution Mains in Service		These metrics include all local distribution companies (LDCs) held by NW Natural that are above the LDC Facility reporting threshold for EPA's 40 C.F.R. 98, Subpart W reporting rule.
1.2.1	Plastic (miles)	7,885	
1.2.2	Cathodically Protected Steel – Bare & Coated (miles)	7,264	
1.2.3	Unprotected Steel – Bare & Coated (miles)	0	
1.2.4	Cast Iron / Wrought Iron – without upgrades (miles)	0	
1.3	Plan/Commitment to Replace / Upgrade Remaining Miles of Distribution Mains (# years to complete)		NW Natural has completed pipeline modernization system wide. As a result the values for these fields are all zero. Thorugh partnership with regulators The Company was able to accelerate replacement of cas iron and bare steel pipe. This has resulted in one of the lowest leaks per mile and provides opportunity for the company to pursue emisison reduction elsewehre in operations and along the supply chain.
1.3.1	Unprotected Steel (Bare & Coated) (# years to complete)	0	
1.3.2	Cast Iron / Wrought Iron (# years to complete)	0	
2	Distribution CO2e Fugitive Emissions		Fugitive methane emissions (not CO2 combustion emissions) stated as CO2e, as reported to EPA under 40 CFR 98, Subpart W, sections 98.236(q)(3)(ix)(D), 98.236(r)(1)(v), and 98.236(r)(2)(v)(B) – i.e., this is Subpart W methane emissions as input in row 2.2.1 below and converted to CO2e here. This metric should include fugitive methane emissions above the reporting threshold for all natural gas local distribution companies (LDCs) held by the Parent Company NW Natural that are above the LDC Facility reporting threshold for EPA's 40 C.F.R. 98, Subpart W reporting rule. Calculated value based on mt CH4 input in the 2.2.1 (below) and GWP of 25.
2.1	CO2e Fugitive Methane Emissions from Gas Distribution Operations (metric tons)	67,024	
2.2	CH4 Fugitive Methane Emissions from Gas Distribution Operations (metric tons)	2,678	INPUT VALUE (total mt CH4) as explained in definition above. Subpart W input is CH4 (mt).
2.2.1	CH4 Fugitive Methane Emissions from Gas Distribution Operations (MMSCF/year)	139	
2.3	Annual Natural Gas Throughput from Gas Distribution Operations in thousands of standard cubic feet (Mscf/year)	114,489,298	This metric provides gas throughput from distribution (quantity of natural gas delivered to end users) reported under Subpart W, 40 C.F.R. 98.236(aa)(9)(iv), as reported on the Subpart W e-GRRT integrated reporting form in the "Facility Overview" worksheet Excel form, Quantity of natural gas delivered to end users (column 4).
2.3.1	Annual Methane Gas Throughput from Gas Distribution Operations in millions of standard cubic feet (MMscf/year)	108,765	assumes 95% Methane content
2.4	Fugitive Methane Emissions Rate (MMscf of Methane Emissions per MMscf of Methane Throughput)	0.128%	$\frac{E_C}{TP_C} = \frac{tonnes\ CH_4}{MMscf\ gas} \times \frac{10^6\ g\ CH_4}{tonne\ CH_4} \times \frac{g\ mole\ CH_4}{16\ g\ CH_4} \times \frac{gmol\ Nat.Gas}{0.95\ gmol\ CH_4} \times \frac{scf\ gas}{1.198\ gmol\ gas} \times \frac{MMscf\ gas\ emissions}{10^6\ scf\ gas} = \frac{MMscf\ gas\ emissions}{MMscf\ gas\ throughput} = \%$

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2023 NW Natural Environmental Data

NW Natural's Emissions

	2023	2022	2021
Fugitive Methane Emissions Rate[6]	0.128%	0.126%	0.131%
Scope 1 Emissions[7]	101,298 $MTCO_2e$	102,496 $MTCO_2e$	97,113 $MTCO_2e$
Scope 2 Facility Emissions (electricity use)[8]	2,394 $MTCO_2e$	2,398 $MTCO_2e$	2,972 $MTCO_2e$
Scope 2 Total Emisssions (electricity use)[9]	2,662 $MTCO_2e$	2,646 $MTCO_2e$	N/A – information not available to perform calculation

[6] Fugitive emissions calculated in accordance with EPA's 40 CFR part 98 subpart W. Percentage is calculated by metric tons of fugitive emissions divided by volume of gas delivered through our system. MMscf of methane emissions per MMscf of methane throughput.

[7] Includes NW Natural's use of gas footprint, fleet fuel carbon footprint, and natural gas fugitive emissions from system operations. Company use of gas footprint includes emissions from direct use of gas by NW Natural, including space and water heat, line heaters, compressors and other natural gas equipment, and calculations use emission factors from 40 CFR Part 98 Subpart C Table C-1 and C-2. Fleet fuel carbon footprint includes all NW Natural fleet fuel combustion associated with operating fleet vehicles (including diesel, gasoline, and CNG vehicles), and fleet equipment, and calculations use emissions factors for CO2 from Appendix H of US EIA Instructions for Form EIA-1605. Natural gas fugitive emissions from system operation are calculated in accordance with EPA's 40 CFR part 98 subpart W and fugitive emission from our system in Oregon undergo third party verification under the Oregon Department of Environmental Quality's Greenhouse Gas Reporting Program framework.

[8] Includes data from electricity data from utility bills from facilities and legacy environmental accounts. Calculated by multiplying electricity usage at each facility by the emissions factor for the corresponding electric utilities (published in 2021 by the Oregon Department of Environmental Quality and 2020 by the Washington Department of Commerce). Scope 2 Facility Electricity Emissions represent 12 months of electricity usage at the 18 main facilities operated by NW Natural. Due to the meter reading dates on the utility bills this value is approximate.

[9] Includes data from utility bills from all NW Natural sites including legacy environmental accounts, rectifier, and telecom sites. Calculated by multiplying electricity usage at each facility by the emissions factor for the corresponding electric utilities (published in 2021 by the Oregon Department of Environmental Quality and 2020 by the Washington Department of Commerce).

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2023 Additional Statistics

2023 NW Natural Gas Utility Statistics

Sector	Customers (as of 12/31/23)	Gas Delivered During 2023		Natural Gas Rate (Weighted Average Rates from 11/1/22-10/31/23)	
		Therms	MMBtu	Variable Rate per Therm	Fixed Rate per Month
Residential	728,915	455,702,837	455,702,837	$1.22	$8
Commercial	69,273	280,051,963	28,005,196	$1.05	$24
Industrial	755	179,317,270	17,931,727	$0.75	$250
Transportation	307	291,601,384	29,160,138	$0.05	$880
Total	799,250	1,206,673,454	120,667,345		

In 2023, NW Natural used approximately 16,136 megawatt hours of electricity and approximately 5.7 million therms of natural gas in our own operations.

2023 Environmental Memberships & Associations

Founding Member:

- ERM Natural Gas Supply Collaborative
- Renewable Hydrogen Alliance
- U.S. Environmental Protection Agency Methane Challenge Program

Member:

- American Biogas Council
- American Gas Association
- Coalition for Renewable Natural Gas
- ERM Downstream Natural Gas Initiative
- GTI Energy
- Green Hydrogen Coalition
- HyReady
- Low-Carbon Resource Initiative
- NextGen Gas Coalition
- Northwest Energy Efficiency Alliance
- ONE Future

Not to be used for investment purposes—see NW Natural and NW Natural Holdings most recent Form 10-Ks as updated by the most recent quarterly and periodic reports for information relevant to investment decisions.

Forward-Looking Statements

This report and other materials prepared by NW Natural Holdings from time to time may contain forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. Forward-looking statements can be identified by words such as "anticipates," "assumes," "continues," "could," "intends," "plans," "seeks," "believes," "estimates," "expects", "will" and similar references to future periods. Examples of forward-looking statements include, but are not limited to, statements regarding the following: plans, objectives, assumptions, estimates, expectations, timing, goals, strategies, commitments, future events, continuation of past practices, investments, projections, expectations, outlooks, commitments, intentions, acquisitions and timing, completion and integration thereof, infrastructure investments, safety results and implementation of safety initiatives and expected benefits, system inspections and quality assurance measures, system modernization, improvements and reliability, infrastructure resiliency, gas storage capabilities, business continuity and emergency preparedness measures, damage prevention measures, risk management programs, commodity costs and sourcing, competitive advantage, marketing, service territory, customer service, customer and business growth, customer satisfaction ratings, weather and ability to serve customers during weather events, customer rates, customer support, affordability and bill payment assistance initiatives, customer preference, business risk, efficiency of business operations, operational performance and costs, business development, new business initiatives and the success of such initiatives, water, wastewater and water services industry, acquisitions, partnerships and investments, including timing, completion and integration of such investments and related operational initiatives, financial positions and performance, operating plans of third parties, global, local and national economies, economic and housing market conditions, trends and performance, capital expenditures, technological and equipment innovations and investments, cybersecurity initiatives and investments, strategic goals and visions and our communication of such goals and visions, environmental initiatives and expected outcomes, matters related to climate change, greenhouse gas reduction and the role of natural gas and the gas delivery system, including use of and demand for renewables, carbon emissions, targets and savings, renewable natural gas projects or investments and timing, and completion thereof, unregulated renewable natural gas strategy and initiatives, hydrogen projects, programs and investments and timing and completion thereof, emerging decarbonization technologies and equipment, gas supply initiatives, including supply chain emissions reduction and procurement of renewable natural gas or hydrogen, energy efficiency initiatives, investments and funding, carbon offset initiatives, energy usage and savings, operational sustainability measures, water use, waste reduction, charitable donations and volunteer programs, political contributions, workforce trends, labor relations, diversity, equity and inclusion initiatives, compensation and benefit programs, employee training, sustainable procurement initiatives, the regulatory environment, timing or effects of future regulatory proceedings or future regulatory approvals or rate case outcomes, effects of public policy, legislation and changes in laws and regulations, including but not limited to carbon, climate, renewable natural gas and hydrogen regulations, effects, extent, severity and duration of pandemics or epidemics and any resulting economic disruption therefrom, geopolitical uncertainty, and other statements that are other than statements of historical facts.

The forward-looking statements contained in this report are provided for the general information of our stakeholders and are not intended to induce any sales or purchases of securities or to be used in connection therewith for any investment purposes. Forward-looking statements are based on our current expectations and assumptions regarding our business, the economy, geopolitical factors and other future conditions. Because forward-looking statements relate to the future, they are subject to inherent uncertainties, risks and changes in circumstances that are difficult to predict. Our actual results may differ materially from those contemplated by the forward-looking statements. You are therefore cautioned against relying on any of these forward-looking statements. They are neither statements of historical fact nor guarantees or assurances of future performance. Important factors that could cause actual results to differ materially from those in the forward-looking statements are discussed by reference to the factors described in Part I, Item 1A "Risk Factors," and Part II, Item 7 and Item 7A "Management's Discussion and Analysis of Financial Condition and Results of Operations," and "Quantitative and Qualitative Disclosure about Market Risk" in the Company's most recent Annual Report on Form 10-K, and in Part I, Items 2 and 3 "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Quantitative and Qualitative Disclosures About Market Risk", and Part II, Item 1A, "Risk Factors", in the Company's quarterly reports filed thereafter, which, among others, outline legal, regulatory and legislative risks, public health risks, financial, macroeconomic and geopolitical risks, growth and strategic risks, operational risks, business continuity and technology risks, environmental risks and risks related to our water and renewables businesses.

All forward-looking statements made in this report and all subsequent forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by these cautionary statements. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to publicly update any forward-looking statement, whether as a result of new information, future developments or otherwise, except as may be required by law. New factors emerge from time to time and it is not possible to predict all such factors, nor can it assess the impact of each such factor or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements.

Not to be used for investment purposes—see NW Natural and NW Natural Holdings most recent Form 10-Ks as updated by the most recent quarterly and periodic reports for information relevant to investment decisions.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

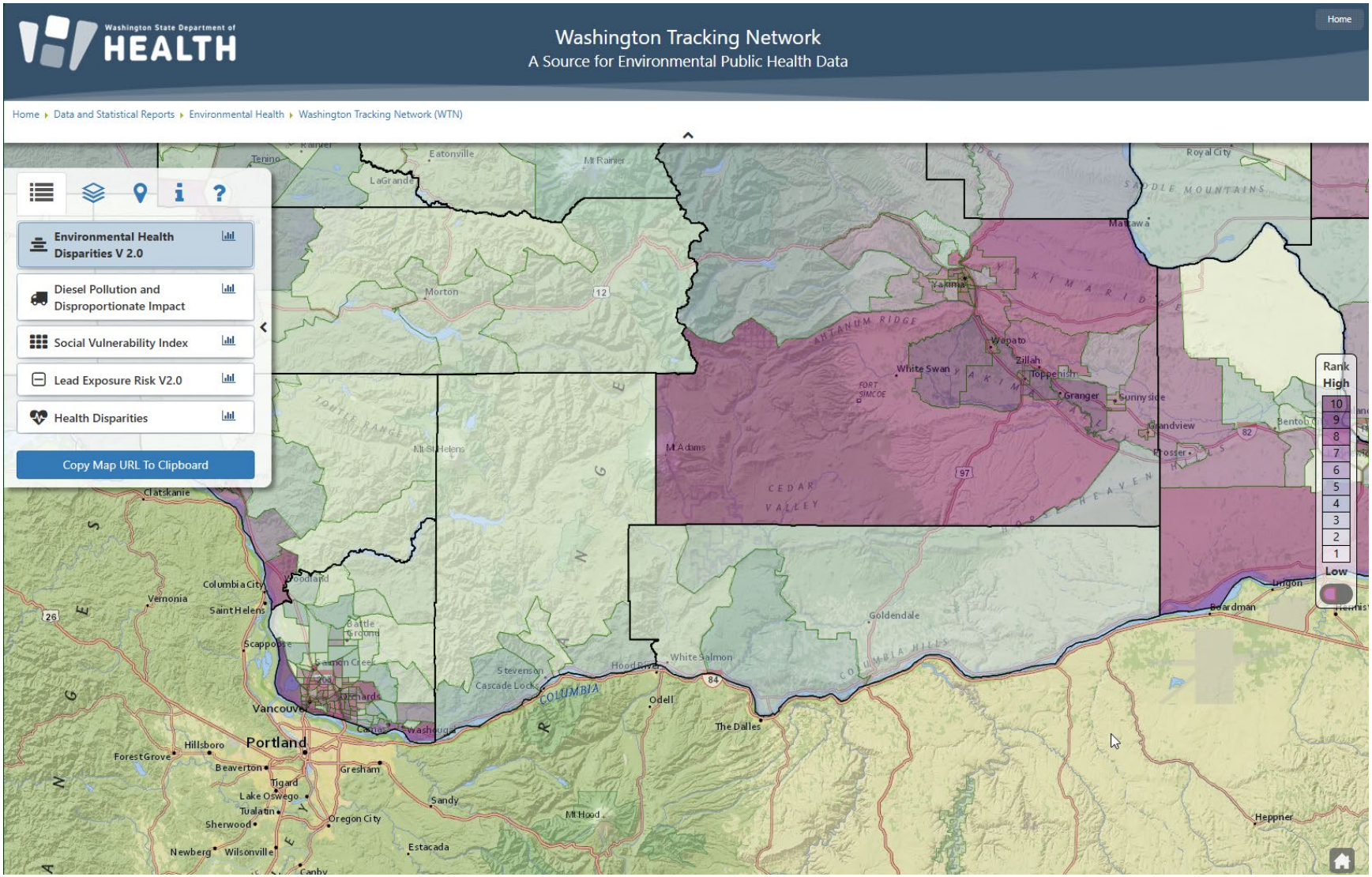
NORTHWEST NATURAL GAS COMPANY

Exhibit of Natasha C. Siores

PERFORMANCE-BASED RATEMAKING METRICS

Exh. NCS-3

August 29, 2025



Map and data available at: [Washington Environmental Health Disparities Map | Washington State Department of Health](). The map in the screenshot above was accessed July 31, 2025 and has been zoomed in to Clark, Klickitat, and Skamania counties.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Direct Testimony of Cory A. Beck

LANGUAGE ACCESS APPROACH

Exh. CAB-1T

August 29, 2025

DIRECT TESTIMONY OF CORY A. BECK

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position at Northwest Natural Gas Company ("NW Natural" or "the Company").

A. My name is Cory Beck. I am the Director of Customer Experience Services for NW Natural. My responsibilities include customer and public communications, advertising, website, digital portal and Interactive Voice Response (IVR) services, natural gas safety communications, and our Federal Public Safety Awareness program. I have worked for NW Natural since 2005.

Q. Please describe your education and employment background.

A. I received my undergraduate degree in Graphic Design from Oregon State University and a Master of Business Administration from Marylhurst University. From 1994 to 1998, I worked as an account executive at a design agency, Electro Art, in Portland, Oregon. From 1998 to 2000, I worked as an account executive at an advertising agency, Gerber Advertising, in Portland, Oregon. From 2000 to 2005, I worked as an account supervisor at a marketing and advertising agency, CMD (Creative Media Development), also in Portland, Oregon.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to describe NW Natural's commitment to making sure that all customers—regardless of English proficiency or income level—have equitable access to essential utility programs and information.

Q. Please summarize your testimony.

A. NW Natural's testimony outlines its proactive efforts to ensure language accessibility for all customers, especially those with limited English proficiency.[1] Currently, NW Natural collaborates with community-based organizations ("CBOs") and the Community Equity Advisory Group ("CEAG") to review and improve communications. Program information is shared through trusted CBOs, and materials are translated into multiple languages in partnership with Immigrant and Refugee Community Organization (IRCO). Spanish-language television and radio ads are aired on Spanish media channels, and plans are underway to expand the Company's website to support multiple languages. These efforts are guided by best practices in plain language, translation, reading level, and technology access, as recommended by our CBOs and CEAG members.

The testimony defines NW Natural's language access approach and explains why it matters—not just for compliance, but to promote equity and meaningful access to services. Priority is given to translating vital documents such as bills, disconnection notices, and low-income program materials, along with website content, self-service tools, outreach materials, and instructional content. These efforts help reduce confusion and service delays by addressing language barriers and improving program access for customers.

[1] As used here, Limited English Proficiency is defined in the same manner that the Commission defined the term in its Interim Procedural Equity Policy Statement in Docket A-230217, which is: "individuals for whom English is not their primary language and who have a limited ability to read, write, speak, or understand English." *See* Interim Procedural Equity Policy Statement at note 45.

Customers who benefit include speakers of Spanish, Chinese, Vietnamese, and Russian,[2] as well as those with lower literacy levels. To ensure continued success, NW Natural plans to monitor the use of language services—such as interpretation calls and QR code engagement in low-income program materials—while gathering feedback from CBOs and CEAG. The Company will also document challenges to refine future implementation.

Q. What is language access?

A. Language access is essential to advancing equity for all NW Natural customers. It ensures that customers with limited English proficiency can meaningfully access and engage with critical services and information. Beyond meeting compliance requirements, language access reflects NW Natural's commitment to inclusive customer experiences—both now and into the future—by supporting equitable access for the communities we serve.

Q. How did NW Natural determine what steps to take in developing its language access approach?

A. The Company relied on guidance from the State of Washington and the Commission itself in determining how to improve accessibility to vital services for customers with limited English proficiency. The Commission recently issued its Interim Policy Statement Regarding Procedural Justice in Docket A-230217, and the Company's language access approach reflects the values and guidance provided in that Policy Statement. Specifically, the Commission states:

[2] These languages, along with English, are the most commonly used by our customers according to the most recent census data.

> To better meet the needs of customers with limited English, energy utilities are encouraged to translate vital documents, including but not limited to: applications for service, informational correspondence once taking new service, and any brochure for Limited English Proficiency (LEP) customers within the utility's service territory outlining customers' rights and responsibilities. Once the utility has determined the top three languages spoken in its service territory using the most recent survey from the United States Census, the utility should post each of the translated documents in each of the three languages on the utility's website.[3]

Further, in Order 09 in Docket UG-210755, the Commission stated that utilities should internalize equity justice in their decision-making processes by viewing their decision-making process through an equity lens.[4] Four core tenets make up the framework of that equity lens: (1) recognition justice, (2) procedural justice (3) distributional justice, and (4) restorative justice, [5] as discussed in the Direct Testimony provided by Ms. Cecelia J. Tanaka (Exh. CJT-1T). Procedural justice means that a utility should seek to collaborate transparently with a broad range of constituents within its service territory when it makes a decision that will impact customers directly or indirectly. A genuine offer to collaborate must include consideration of anything that might hinder conversation, including the language spoken. Accordingly, the Commission has expressed a desire for utilities to incorporate a process for considering how to eliminate or reduce language barriers that may hinder customer conversation or

[3] *In the Matter of the Proceeding to Develop a Policy Statement to Address the Application of Equity and Justice in Commission and Regulated Company Processes and Decisions*, Docket A-230217, Interim Policy Statement Regarding Procedural Justice, at para. 50 (May 12, 2025).

[4] *In the Matter of Washington Utilities and Transportation Commission v. Cascade Natural Gas Corporation,* Docket UG-210755, Final Order 09, Approving and Adopting Settlement Agreement Subject to Conditions (Aug. 23, 2022).

[5] Docket UG-210755, Final Order 09, at para. 56 (Aug 23, 2022).

understanding. Additionally, "equity lens," as that term is used by the Commission, expressly includes considering language access in an equity evaluation.[6]

Q. Please describe the steps that NW Natural is taking to ensure that customer information—particularly regarding income-based energy assistance programs—is accessible and easy to understand.

A. The Company is committed to integrating accessibility features and offerings across its programming, customer communications, and public outreach. Whenever a new tool becomes known or available in one area, efforts are made to implement it throughout the Company as appropriate. For example, when Plain Language accessibility was recommended for bill discount program information materials, the Company's Communications team began incorporating these language screens across its material development process, in addition to bill discount material. This is in addition to NW Natural's practice of providing program information in the top five most used languages in the Company's territory (Chinese, Vietnamese, Russian, Spanish, and English).

Additional steps the Company makes to ensure inclusive, accessible communications, include:

[6] RCW 43.06D.010.

- Actively engaging CEAG[7] members, who represent diverse community-based organizations[8] throughout the Company's service territory, and providing feedback[9] across multiple topics. Outreach materials, strategies, and best practices have been reviewed and discussed in several meetings. This collaborative process ensures that the content is guided by the expertise of CBO partners that know their communities best. As a result, customers receive clearer, more accessible information about programs that lower bills and reduce energy usage---including bill discounts, arrearage management, free weatherization and energy efficiency resources, and other Company offerings.
- CEAG feedback played an integral role in the development of the Company's 2025 Integrated Resource Plan ("IRP"). With regard to enhanced language access, the Company made several CEAG-informed enhancements to the IRP, including:

[7] The Community & Equity Advisory Group (CEAG) is a collaboration between NW Natural and our community-based organization (CBO) partners. The CEAG meets quarterly to discuss and provide direct feedback, recommendations on utility operations and programming. It is intended to seek out and elevate historically underrepresented voices, perspectives and lived experiences to participate in NW Natural's energy and operational planning. NW Natural holds quarterly CEAG discussions with its members on specific topics related to equity, energy justice, or other topics of interest related to NW Natural's operations and energy services.

[8] CEAG recruitment focuses on CBOs that serve an identity, community, and underrepresented/underserved population present within the NW Natural service territory in Washington and Oregon —prioritizing organizations that had not participated in energy planning and Company program planning opportunities in the past.

[9] At each CEAG meeting, NW Natural provides a detailed report to the CEAG on topics such as the concrete actions, deliverables, and milestones achieved that were undertaken or achieved since the last meeting and under the recommendations from CEAG members in an effort to demonstrate and strengthen accountability to the CEAG. Providing a clear closed circle on how feedback is being utilized when it is collected from communities is core to this practice. This involves ensuring that community feedback is not only collected but also transparently integrated into decision-making processes, creating a loop where community members can see the impact of their input.

- Updating the Company's IRP webpage to offer more comprehensive information on the IRP development process, ways to get involved, and a section for Frequently Asked Questions (FAQs).
- Offering translation service upon request.
- Hosting community-based resource fairs, tabling events and partner workshops to engage non-technical audiences and provide a pathway to resource planning education and informed engagement.
- Developing an IRP informational toolkit to utilize at community events.
- Engaging external guidance to provide impartial facilitation and expertise in managing technically complex public processes and fostering meaningful dialogue and collaboration among technical experts, the general public, and the Company.
- Developing an IRP Feedback Form to establish a more standardized approach to its feedback process. The form is publicly accessible on the Company's Energy/Resource Planning webpage and highlighted during each IRP workshop, technical working group (TWG), and other public engagement events.

- Leveraging partnerships with CBOs to disseminate information about programs, especially those serving low-English-proficiency and low-income populations.
- Incorporating best practices related to plain language, reading grade level, translations, and technology access, recommended by our CBO and CEAG members.

- Creating materials in multiple languages, translated in partnership with locally based IRCO (Immigrant and Refugee Community Organization).
- Translating most television and radio advertising to Spanish and airing on Spanish media channels.
- NW Natural is also planning to add language preference and selection functionality to the customer-facing website that would translate the website into five of the most common languages spoken in NW Natural's service territory. This is part of the Customer Self-Service Enhancements Project, described in the confidential Direct Testimony provided by Mr. Brian E. Fellon (Exh. BEF-1CT).

Q. What type of information is prioritized in language access?

A. Language access focuses on ensuring clear, multilingual access to essential customer information, including:

- Vital documents such as billing statements, disconnection notices, and income-based program materials,
- Website content and self-service portals,
- Outreach materials shared at community events and through community-based organizations, and
- Calls to action and instructional content that guide customers through key processes.

Q. Do you have examples of how the Company is ensuring language access?

A. Yes. Exh. CAB-2 contains NW Natural's bill discount program application in Spanish, Chinese, Vietnamese, and Russian. Exh. CAB-3 is a brochure and a postcard for the bill discount program in each of these languages. Exh. CAB-4 is the bill insert and

letter for the meter update program in these languages. Finally, Exh. CAB-5 has examples of low-income outreach that also show the Company's commitment to language access.

Q. **How do NW Natural's language access enhancements benefit customers?**

A. By translating key materials—such as program eligibility, application steps, and contact information—into the commonly spoken languages in NW Natural's service area, customers with limited English proficiency can quickly understand their options. Language access also includes identifying and removing barriers, such as ensuring materials are linguistically and culturally appropriate, and closing communication gaps that may prevent customers from accessing low-income programs.

Language access is designed to support customers who speak the most common non-English languages in our service area: Spanish, Chinese, Vietnamese, and Russian. Additionally, customers with lower literacy levels—particularly those reading at a 6th- to 8th-grade level—will benefit from plain-language messaging that makes critical information easier to understand.

Q. How can NW Natural ensure successful language access?

A. NW Natural can ensure the success of language access through a commitment to continuous improvement. This could include:

- Tracking use of language services over time (e.g., monitoring volume of interpretation calls and number of times QR codes scanned—without requiring customers' personal information). Exhs. CAB-3, CAB-4, and CAB-5 all include QR codes. Exh. CAB-6 has an example of how the Company uses QR code data for the bill discount program.

- Engaging regularly with CBOs and the Community & Equity Advisory Group (CEAG) to gather feedback and identify areas for improvement. Engagement occurs quarterly—remotely and in person—and includes demonstration of applied feedback and recommendations.
- Documenting challenges and the actions taken to address them.
- Reviewing and updating language access based on data, community input, and changing customer needs.
- Developing language access plan anticipated to be completed by the end of 2026.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

II. LIST OF EXHIBITS

CAB-2	Multi-Lingual Bill Discount Application
CAB-3	Multi-Lingual Bill Discount Outreach Materials
CAB-4	Multi-Lingual Project Update Materials
CAB-5	Multi-Lingual Energy Efficiency Outreach Materials
CAB-6	QR Code Tracking Example

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Cory A. Beck

LANGUAGE ACCESS APPROACH

Exh. CAB-2

August 29, 2025

Washington

NW Natural®

Solicitud para el Programa de descuento de facturas residenciales de NW Natural

El registro está disponible para los clientes residenciales Washington calificables de NW Natural. La elegibilidad se basa en el tamaño de su unidad familiar y en el ingreso bruto anual promedio de todos los miembros de su unidad familiar de 18 años de edad o mayores, combinado. Ingreso bruto significa sus ingresos antes de impuestos. **Vea si califica y haga su solicitud hoy mismo.**

1 Paso 1: Marque las pautas de elegibilidad de ingresos.

Los ingresos totales del grupo familiar no pueden exceder las cantidades indicadas.

- Las cantidades están basadas en los ingresos brutos totales.
- Las familias que comparten una vivienda deben presentar la solicitud como una sola unidad de residencia.

Household Size	Annual Income	Monthly Income
1	$66,100	$5,508
2	$75,550	$6,296
3	$85,000	$7,083
4	$94,400	$7,867
5	$102,000	$8,500
6	$109,550	$9,129
7	$117,100	$9,758
8	$124,650	$10,388
9	$132,200	$11,017
10	$139,750	$11,646
11	$147,300	$12,275
12	$154,850	$12,904

Por cada miembro adicional de la familia, agregue $7,600 dólares anuales o $633 dólares mensuales. En vigor a partir del 1.o de octubre de 2024.

Si su grupo familiar cumple con las pautas de ingresos bajos a moderados del Servicio de Impuestos Internos (IRS, por sus siglas en inglés), podría reunir los requisitos para recibir créditos tributarios por ingresos del trabajo. Llame al IRS al **800-829-1040** o visite **www.irs.gov/es/credits-deductions/individuals/earned-income-tax-credit-eitc**

Cómo calcular los ingresos anuales de su grupo familiar

Para los trabajadores por hora, tome su salario por hora y multiplíquelo por el promedio de horas trabajadas semanalmente. A continuación, multiplique esa cifra por 52 (semanas al año) para obtener sus ingresos brutos anuales (antes de impuestos).

Por ejemplo:

- $13.50 (tarifa por hora) x 40 (promedio de horas trabajadas por semana) = $540
- $540 x 52 (semanas al año) = $28,080 (Este es su ingreso bruto anual)

Consejo: Si los ingresos de su grupo familiar cambian de un mes a otro, tome los ingresos combinados del último mes y multiplíquelos por 12 para calcular los ingresos brutos anuales promedio de su grupo familiar. Si tiene preguntas o necesita ayuda para presentar la solicitud, llámenos al 800-422-4012.

2 Paso 2: Complete la siguiente información obligatoria.

Nombre y apellido (nombre en la factura)

Número de cuenta de NW Natural (ejemplo: 1234567-8)

Dirección del servicio

Ciudad del servicio

Washington

Estado del servicio

Código postal del servicio

Número de teléfono

Dirección de correo electrónico (se usa para la confirmación)

Idioma preferido

Continuación →

Actualmente tengo ingresos fijos y recibo ingresos o beneficios de uno o más de los siguientes: Seguridad de Ingreso Suplementario (SSI, por sus siglas en inglés), Medicaid, Programas de Autosuficiencia (SSP, por sus siglas en inglés) y Seguro de Discapacidad del Seguro Social (SSDI, por sus siglas en inglés).

Por favor, agregue el ingreso bruto por tipo:

Ingresos provenientes del trabajo* (ejemplos: salarios, honorarios, propinas)	$
Desempleo y pensiones (ingrese la cantidad antes de impuestos)	$
Ingresos de autoempleo	$
Beneficios para veteranos	$
Seguro Social (SSA/SSI/SSD) (excluya Medicare deducido de sus beneficios)	$
Asistencia pública (ejemplos: Asistencia General (GA-U/GA-X), Asistencia en Efectivo por Edad, Ceguera, Discapacidad, TANF)	$
Manutención de hijos/conyugal, apoyo familiar que recibe	$
Otros ingresos (ejemplos: estipendios, ingresos militares, compensación para trabajadores, dividendos, en especie)	$

*Otorgue los ingresos brutos provenientes del trabajo y reste cualquier pago que haya hecho para manutención de hijos/conyugal.

Cantidad de personas en el grupo familiar

Continuación →

Declaración

1. Entiendo que la presente es una solicitud inicial y que NW Natural hará un seguimiento conmigo después de la inscripción formal con detalles sobre mi descuento.
2. Si cambian los ingresos anuales promedio de mi grupo familiar o la cantidad de personas que viven en mi grupo familiar, notificaré a NW Natural presentando una nueva solicitud en línea o llamando al 800-422-4012.
3. Entiendo que se me puede exigir una prueba de los ingresos del grupo familiar y de la cantidad de integrantes del grupo familiar, si se me pide. La información estará disponible para NW Natural y de las personas o entidades que trabajen en nombre de NW Natural para implementar este programa.
4. Entiendo que este descuento no se aplicará a los cargos que incurran antes de la inscripción, sino solamente a los nuevos cargos que surjan después de la inscripción (la inscripción puede tardar hasta 30 días).
5. Entiendo que este descuento solamente se aplica para mi residencia principal.
6. Es posible que tenga que volver a certificar cuando se transfiera el servicio o se abra una nueva cuenta.
7. NW Natural puede compartir mi información de cliente con otros servicios públicos o agencias para el registro en este y otros programas de asistencia.
8. Para optar por no participar en el programa, debo llamar a NW Natural al 800-422-4012.

Al presentar esta solicitud, certifico que la información que he proporcionado en esta solicitud es verdadera y correcta. Confirmo que he leído y entendido el contenido de la presente solicitud. También acepto los términos especificados en el Programa de descuento de facturas residenciales de NW Natural de NW Natural (Anexo L).

Firma del cliente de NW Natural
(Escriba su nombre a mano o en computadora, en el campo correspondiente)

Fecha

3 Paso 3: Envíe su solicitud en línea a través de nwnatural.com/billdiscount o envíe este formulario por correo electrónico o por correo postal. También puede llamarnos al número que aparece a continuación.

CSST@nwnatural.com

NW Natural Bill Discount
250 SW Taylor St.
Portland, OR 97204

503-226-4211 or 800-422-4012

Guarde este documento antes de cerrarlo.

华盛顿

NW Natural®

NW Natural 住宅账单折扣计划申请

华盛顿州符合资格的 NW Natural 住宅客户可以报名。资格取决于您的家庭人数以及 18 岁及以上的家庭所有成员的平均年总收入的总和。总收入指您的税前收入。立即申请，看看您是否符合资格。

1 第 1 步：查看收入资格指南。

家庭总收入不能超过所示金额。

- 金额基于合起来的总收入。
- 同屋共户的家庭必须作为一个住宅单元提出申请。

家庭人数	年收入	月收入
1	66,100 美元	5,508 美元
2	75,550 美元	6,296 美元
3	85,000 美元	7,083 美元
4	94,400 美元	7,867 美元
5	102,000 美元	8,500 美元
6	109,550 美元	9,129 美元
7	117,100 美元	9,758 美元
8	124,650 美元	10,388 美元
9	132,200 美元	11,017 美元
10	139,750 美元	11,646 美元
11	147,300 美元	12,275 美元
12	154,850 美元	12,904 美元

每增加一名家庭成员，年收入增加 7,600 美元或月收入增加 633 美元。 Effective October 1, 2024.

如果您的家庭符合国税局的中低收入指南，您就有资格获得收入所得税抵免。请致电 **800–829–1040** 联系国税局或浏览网站 **www.irs.gov/credits–deductions/individuals/earned–income–tax–credit–eitc**

如何计算您的家庭年收入

对于小时工，请将您的时薪乘以每周平均工作小时数。再将该数字乘以 52（每年的周数），得出您的年总收入（税前）。

示例：

- 13.50 美元（时薪）x 40（每周平均工作小时数）= 540 美元
- 540 美元 x 52（每年的周数）= 28,080 美元（这是您的年总收入）

提示： 如果您的家庭收入每个月都不同，请将您上个月的收入总和乘以 12，计算得出您的平均家庭年总收入。如果您有任何疑问或需要帮助提出申请，请致电 800–422–4012，联系我们。

2 第 2 步：填写以下必填信息。

名字和姓氏（账单上的姓名）

NW Natural 账号（示例：1234567–8）

服务街道地址

服务城市

华盛顿

服务州

服务邮政编码

电话号码

电子邮件地址（用于确认））

选语言

继续 →

我目前有固定收入，并从以下一项或多项获得收入或福利：补充保障收入 (SSI)、Medicaid、自给自足计划 (SSP) 和社会保障残疾保险 (SSDI)。

请输入按类型划分的总收入：

劳动收入* （示例：工资、薪金、小费）	$
失业金与养老金 （输入税前金额）	$
自主就业收入	$
退伍军人福利	$
社会保障 (SSA/SSI/SSD) （不包含从您的福利中扣除的 Medicare）	$
公共援助 （示例：一般援助 (GA–U/GA–X)、老年人、失明或 残障现金援助、TANF）	$
收到的子女 / 配偶赡养费、收到的家庭赡养费	$
其他收入 （示例：津贴、军人收入、工伤赔偿、股息、实物）	$

*提供总劳动收入，并减去支出的任何儿童 / 配偶赡养费。

家庭人数

继续 →

声明

1. 我明白，这是初步申请，NW Natural 将在我正式报名后跟进我的情况，并提供与我的折扣有关的详情。
2. 如果我的平均家庭年收入或居住在我家中的人数发生变化，我将提交新的在线申请或致电 800–422–4012，告知 NW Natural。
3. 我明白，如果有此要求，我可能需要提供家庭收入和家庭人数的证明。信息将提供给 NW Natural 和代表 NW Natural 工作的个人或实体，以用于实施该计划。
4. 我明白，此折扣不适用于报名前产生的费用，但仅适用于报名后产生的新费用（报名可能需要最多 30 天）。
5. 我明白，此折扣仅适用于我的主要住所。
6. 我在转移服务或开设新账户时可能需要重新认证。
7. NW Natural 可能与其他公用事业公司或机构分享我的客户信息，以便参加本项和其他 援助计划。
8. 如需退出计划，我必须致电 800–422–4012，联系 NW Natural。

通过提交此申请，我证明我在此申请中提供的信息正确属实。我承认，我已阅读和明白此申请的内容。我也同意 NW Natural 的住宅账单折扣计划（附表 L）中指明的条款。

NW Natural 客户签名
（在提供的字段中输入或写下您的姓名）

日期

3 第 3 步：请登录网站 nwnatural.com/billdiscount，提出在线申请，或通过电子邮件或邮件提交此表格。您也可以拨打以下电话号码联系我们。

CSST@nwnatural.com

NW Natural Bill Discount
250 SW Taylor St.
Portland, OR 97204

503-226-4211 or 800-422-4012

请在关闭此文档前保存。

Washington

NW Natural®

Đơn Đăng ký Chương trình Chiết khấu Hóa đơn Tiện ích cho Khách hàng Cư dân của NW Natural

Các khách hàng cư dân đủ tiêu chuẩn của NW Natural ở Washington hiện có thể ghi danh chương trình này. Khả năng hội đủ điều kiện sẽ được xác định dựa trên quy mô hộ gia đình và tổng thu nhập trung bình hàng năm của tất cả các thành viên từ 18 tuổi trở lên trong hộ gia đình của quý vị cộng lại. Tổng thu nhập có nghĩa là thu nhập trước thuế. **Hãy xem quý vị có đủ tiêu chuẩn hay không và đăng ký ngay hôm nay.**

1 Bước 1: Kiểm tra các hướng dẫn về tiêu chuẩn thu nhập.

Tổng thu nhập hộ gia đình không được vượt quá số tiền nêu ở đây.

- Các số tiền này dựa trên tổng thu nhập.
- Các gia đình ở chung nhà phải đăng ký như họ thuộc cùng một đơn vị.

Quy mô hộ gia đình	Hàng năm Thu nhập	Thu nhập hàng tháng
1	$66,100	$5,508
2	$75,550	$6,296
3	$85,000	$7,083
4	$94,400	$7,867
5	$102,000	$8,500
6	$109,550	$9,129
7	$117,100	$9,758
8	$124,650	$10,388
9	$132,200	$11,017
10	$139,750	$11,646
11	$147,300	$12,275
12	$154,850	$12,904

Đối với mỗi thành viên bổ sung trong gia đình, hãy cộng thêm $7,600 thu nhập hàng năm hoặc $633 hàng tháng. Có hiệu lực từ ngày 1 tháng 10 năm 2024.

Nếu hộ gia đình của quý vị đáp ứng các tiêu chí về thu nhập từ thấp đến trung bình của IRS, quý vị có thể đủ tiêu chuẩn để nhận Tín dụng Thuế Thu nhập Từ Việc làm (Earned Income Tax Credits). Gọi cho IRS theo số **800-829-1040** Hoặc truy cập trang web **www.irs.gov/credits-deductions/individuals/earned-income-tax-credit-eitc**

Cách tính thu nhập hộ gia đình hàng năm

Nếu quý vị làm việc theo giờ, hãy lấy tiền lương giờ của quý vị và nhân với số giờ làm việc trung bình hàng tuần. Sau đó nhân số đó với 52 (số tuần trong một năm) để có tổng thu nhập hàng năm (trước thuế).

Ví dụ:

- $13.50 (lương giờ) x 40 (số giờ làm việc trung bình mỗi tuần) = $540
- $540 x 52 (số tuần trong một năm) = $28,080 (Đây là tổng thu nhập hàng năm của quý vị)

Mẹo: Nếu thu nhập hộ gia đình của quý vị thay đổi từ tháng này sang tháng khác, hãy cộng lại tổng thu nhập của tất cả mọi người từ tháng trước, xong lấy số đó nhân với 12 để tính ra tổng thu nhập hộ gia đình trung bình hàng năm. Vui lòng gọi cho chúng tôi theo số 800-422-4012 nếu quý vị có thắc mắc hoặc cần trợ giúp đăng ký.

2 Bước 2: Điền các thông tin bắt buộc sau đây.

Họ và tên (tên trên hóa đơn)

Số trương mục NW Natural (ví dụ: 1234567-8)

Địa chỉ của nơi nhận dịch vụ tiện ích

Thành phố

Washington

Tiểu bang

Mã Zip

Số điện thoại

Địa chỉ Email (Cho mục đích xác nhận)

Ngôn ngữ quý vị muốn sử dụng

Tiếp →

Tôi hiện đang có thu nhập cố định và tôi có thu nhập hoặc trợ cấp từ (các) nguồn sau đây: Phụ cấp An sinh (Supplemental Security Income, hoặc SSI), Medicaid, Trợ cấp từ Chương trình Nâng cao Tính tự lực (Self Sufficiency Program, hoặc SSP), và Bảo hiểm An sinh Xã hội cho Người Bệnh tật (Social Security Disability Insurance hoặc SSDI).

Vui lòng nhập tổng thu nhập theo loại:

Thu nhập kiếm được*
(ví dụ: tiền lương, tiền lương, tiền boa)
$

Trợ cấp Thất nghiệp và lương hưu
(nhập số tiền trước thuế)
$

Thu nhập tự kinh doanh
$

Phúc lợi Cựu chiến binh
$

An Sinh Xã Hội (SSA/SSI/SSD)
(không bao gồm khoản khấu trừ Medicare khỏi phúc lợi của quý vị)
$

Hỗ trợ công cộng
(ví dụ: Hỗ trợ chung (GA-U/GA-X), Người cao tuổi, Người khiếm thị hoặc Hỗ Trợ Tiền Mặt Cho Người Khuyết Tật, TANF)
$

Khoản tiền hỗ trợ cho con cái/vợ chồng, hỗ trợ cho gia đình đã nhận được
$

Thu nhập khác
(ví dụ: tiền trợ cấp, thu nhập quân sự, bồi thường cho người lao động, cổ tức, hiện vật)
$

*Cung cấp tổng thu nhập kiếm được và trừ đi mọi khoản hỗ trợ cho con cái/vợ chồng đã chi trả.

Số người trong hộ gia đình

Tiếp →

Tờ khai

1. Tôi hiểu đây là đơn đăng ký đầu tiên và NW Natural sẽ liên hệ với tôi sau khi tôi được đăng ký chính thức để cung cấp thông tin chi tiết hơn liên quan đến chiết khấu của tôi.

2. Tôi sẽ thông báo cho NW Natural nếu thu nhập hộ gia đình trung bình hàng năm của tôi hoặc số người sống trong hộ gia đình của tôi thay đổi bằng cách nộp một đơn đăng ký mới trực tuyến hoặc gọi số 800-422-4012.

3. Tôi hiểu rằng có thể tôi sẽ phải cung cấp bằng chứng về thu nhập hộ gia đình và quy mô hộ gia đình nếu được yêu cầu. NW Natural và các cá nhân hoặc tổ chức đại diện cho NW Natural sẽ sử dụng các thông tin tôi cung cấp để thực hiện chương trình này.

4. Tôi hiểu rằng chiết khấu này sẽ không áp dụng cho các khoản phí phát sinh trước khi tôi đăng ký, mà chỉ áp dụng cho các khoản phí mới sau khi tôi đăng ký (việc đăng ký có thể mất đến 30 ngày).

5. Tôi hiểu rằng chiết khấu này chỉ áp dụng cho nơi ở chính của tôi.

6. Tôi có thể phải xin phép được chứng nhận lại nếu tôi chuyển đến nơi khác ở hoặc mở trương mục mới.

7. NW Natural có thể chia sẻ thông tin khách hàng với các cơ quan tiện ích hoặc cơ quan khác để ghi danh vào dịch vụ này và các chương trình hỗ trợ khác.

8. Nếu tôi chọn không tham gia chương trình này, tôi phải gọi cho NW Natural theo số 800-422-4012.

Bằng cách gửi đơn đăng ký này, tôi xác nhận rằng thông tin tôi kê khai trong đơn là đúng sự thật và chính xác. Tôi xác nhận rằng tôi đã đọc và hiểu nội dung của đơn này. Tôi cũng đồng ý với các điều khoản của Chương trình Chiết khấu Hóa đơn Tiện ích cho Khách hàng Dân cư của NW Natural (Phụ lục L).

Chữ ký của khách hàng NW Natural
(Nhập hoặc viết tên của quý vị vào ô trống)

Ngày

3 Bước 3: Nộp đơn trực tuyến tại nwnatural.com/billdiscount hoặc gửi đơn này qua email hoặc bưu điện. Quý vị cũng có thể gọi cho chúng tôi theo số điện thoại bên dưới.

CSST@nwnatural.com

NW Natural Bill Discount
250 SW Taylor St.
Portland, OR 97204

503-226-4211 or 800-422-4012

Lưu tài liệu này trước khi đóng.

Вашингтон

NW Natural®

Заявление на участие в программе скидок на коммунальные счета от компании NW Natural

Регистрация доступна для правомочных частных клиентов компании NW Natural в штате Вашингтон. Право на участие зависит от количественного состава вашей семьи и среднего годового валового дохода всех членов вашей семьи в возрасте 18 лет и старше. Валовой доход означает ваш доход до уплаты налогов. **Посмотрите, соответствуете ли вы требованиям, и подайте заявление сегодня.**

1 Шаг 1: Ознакомьтесь с требованиями, предъявляемыми к доходу.

Общий доход семьи не может превышать указанные суммы.

- Суммы представлены в виде общего валового дохода.
- Семьи, проживающие в одном доме, должны подать заявление в качестве одного домохозяйства.

Количественный состав семьи	Годовой доход	Месячный доход
1	66 100 долларов	5 508 долларов
2	75 550 долларов	6 296 долларов
3	85 000 долларов	7 083 долларов
4	94 400 долларов	7 867 долларов
5	102 000 долларов	8 500 долларов
6	109 550 долларов	9 129 долларов
7	117 100 долларов	9 758 долларов
8	124 650 долларов	10 388 долларов
9	132 200 долларов	11 017 долларов
10	139 750 долларов	11 646 долларов
11	147 300 долларов	12 275 долларов
12	154 850 долларов	12 904 долларов

Для каждого дополнительного члена семьи добавляйте 7 600 долларов в год или 633 долларов в месяц. Вступает в силу 1 октября 2024 года.

Если ваша семья соответствует требованиям управления IRS к доходам от низкого до среднего, вы, возможно, имеете право на получение налоговых баллов за заработанный доход. Позвоните в управление IRS по телефону **800-829-1040** или посетите веб-сайт **www.irs.gov/credits-deductions/individuals/earned-income-tax-credit-eitc**

Порядок расчета годового дохода семьи

Для работников, получающих почасовую оплату: начните с почасовой заработной платы и умножьте ее на среднее количество часов, отработанных в неделю. Затем умножьте это число на 52 (недель в году), чтобы получить годовой валовой доход (до вычета налогов).

Пример:

- 13,50 долларов (почасовая ставка) x 40 (среднее количество отработанных часов в неделю) = 540 долларов.
- 540 долларов x 52 (недель в году) = 28 080 долларов (это ваш годовой валовой доход)

Совет: Если доход вашей семьи меняется от месяца к месяцу, используйте совокупный доход за последний месяц и умножьте его на 12, чтобы рассчитать средний валовой годовой доход семьи. Если у вас возникли вопросы или вам необходима помощь в подаче заявления, позвоните нам по телефону 800-422-4012.

2 Шаг 2: Внесите запрашиваемую ниже обязательную информацию.

Имя и фамилия (имя, как указано на счете)

Номер учетной записи в компании NW Natural (например, 1234567-8)

Адрес (дом, улица) обслуживания

Город

Вашингтон

Штат

Почтовый индекс

Номер телефона

Адрес эл. почты (используется для подтверждения)

Предпочитаемый язык

Продолжение →

В настоящее время я получаю фиксированный доход и получаю доход или пособия от одного или нескольких из следующих источников: Дополнительный доход по программе социального обеспечения (SSI), пособие программы Medicaid, пособие программы развития самодостаточности (SSP) и пособие социального страхования на случай потери трудоспособности (SSDI).

Пожалуйста, укажите валовый доход по типу:

Заработанный доход* (например, заработная плата, оклад, чаевые)	$
Пособие по безработице и пенсионные выплаты (укажите сумму до вычета налогов)	$
Доход от индивидуальной предпринимательской деятельности	$
Пособия для бывших военнослужащих	$
Пособия социального обеспечения (SSA/SSI/SSD) (за исключением пособия программы Medicare, вычитаемых из ваших пособий)	$
Государственные пособия (например, общие пособия (GA-U/GA-X), денежные пособия для престарелых, незрячих или лиц с ограниченными возможностями здоровья, пособие TANF)	$
Выплаченные алименты на детей/супругов, выплаченные семейные алименты	$
Другой доход (например, стипендии, доходы военнослужащих, компенсационные выплаты работникам, дивиденды, выплаты в натуральной форме)	$

*Укажите валовый заработанный доход и вычтите выплаченные алименты на ребенка/супругу.

Количество человек в семье

Продолжение →

Декларация

1. Я понимаю, что этот документ является первоначальным заявлением, и представитель компании NW Natural свяжется со мной после официальной регистрации и предоставит подробную информацию о моей скидке.

2. Я уведомлю компанию NW Natural, если средний годовой доход моей семьи или количество людей, проживающих в моей семье, изменится, подав новое заявление через Интернет или позвонив по телефону 800-422-4012.

3. Я понимаю, что по запросу от меня могут потребовать предоставить подтверждение суммы дохода и количественного состава семьи. Информация будет предоставлена в компанию NW Natural и физическим или юридическим лицам, работающим от лица компании NW Natural для реализации этой программы.

4. Я понимаю, что эта скидка распространяется не на расходы, понесенные до регистрации, а исключительно на новые расходы после регистрации (регистрация может занять до 30 дней).

5. Я понимаю, что эта скидка распространяется исключительно на мое основное место жительства.

6. Возможно, мне придется пройти повторную сертификацию при регистрации услуги на новый адрес или открытии новой учетной записи.

7. Компания NW Natural может передавать информацию о клиентах другим коммунальным службам или агентствам для регистрации в этой и других программах помощи.

8. Для того, чтобы отказаться от участия в программе, мне необходимо позвонить в компанию NW Natural по телефону 800-422-4012.

Отправляя это заявление, я подтверждаю, что информация, предоставленная мной в этом заявлении, является достоверной и правильной. Я подтверждаю, что я прочитал(-а) и понял(-а) содержание этого заявления. Я также соглашаюсь с условиями, указанными в программе скидок на коммунальные счета от компании NW Natural (приложение L).

Подпись клиента компании NW Natural
(Введите или напишите свое имя в соответствующем поле)

Дата

3 Шаг 3: Подайте заявление онлайн на веб-сайте nwnatural.com/billdiscount или отправьте этот документ по электронной или обычной почте. Вы также можете позвонить нам по номеру, указанному ниже.

CSST@nwnatural.com

NW Natural Bill Discount
250 SW Taylor St.
Portland, OR 97204

503-226-4211 or 800-422-4012

Сохраните этот документ перед тем, как закрыть его.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Cory A. Beck

LANGUAGE ACCESS APPROACH

Exh. CAB-3

August 29, 2025

NW Natural can help lower your energy bills.

EN English ES Español CN 中国人

RU русский VI Tiếng Việt

SCAN ME

nwnatural.com/BillDiscount
503-226-4211 or 800-422-4012

NW Natural®

EN

We are here to help lower your energy bills.

You can learn more about these programs at **nwnatural.com/BillDiscount**, or contact us:

503-226-4211 or 800-422-4012, Monday to Friday, 7 a.m. to 6 p.m.
csst@nwnatural.com

Get Bill Discounts

NW Natural's bill discount program could save you 15% to 80% on your monthly NW Natural bills. Discounts are available if your household income is at or below 80% of area median income or federal poverty level. Effective 10/1/2024 to 9/30/2025.

Household income (family of four)	Bill discount
$18,720 or less	80%
$18,721 to $37,440	40%
$37,441 to $46,800	20%
$46,801 to $94,400	15%

Get Free Home Improvements

You may qualify for free home improvements through our partnerships with local Community Action Agencies. See these agencies at **nwnatural.com/BillDiscount**.

Free improvements can include:

- A new natural gas furnace
- A new natural gas water heater
- Home insulation

Get Help with Payments

NW Natural payment plans

We offer several payment plans. One plan, called Equal Pay, splits your yearly gas use into 11 predictable monthly payments.

Bill support from community agencies

We partner with nonprofit agencies to help you pay your energy bill. See a list of partner agencies at **nwnatural.com/BillDiscount**.

Use Less Energy

Even small steps like these can help lower your bills:

- **Keep furnace filters clean.** A dirty filter makes your furnace work harder and wastes energy.
- **Save up to 3% on energy use** with each degree you reduce the temperature on your thermostat.

See more tips at **nwnatural.com/BillDiscount**.

Get Help with Electric Bills

To lower your energy bills even more, you may qualify for support from your electric utility. Please contact your electric utility to learn more.

ES

Estamos aquí para ayudar a reducir sus facturas de energía.

Usted puede aprender más sobre estos programas en **nwnatural.com/BillDiscount**, o contáctenos:

503-226-4211 o 800-422-4012, de lunes a viernes, 7 a.m. to 6 p.m.
csst@nwnatural.com

Obtenga descuentos en las facturas

El programa de descuento en la factura de NW Natural puede ahorrarle de 15 % a 80 % en sus facturas mensuales de NW Natural. Los descuentos están disponibles si los ingresos de su unidad familiar son equivalentes al 80 %, o menos, del ingreso medio del área o del nivel federal de pobreza. En vigencia del 10/1/2024 al 9/30/2025.

Unidad familiar (familia de cuatro)	Descuento en la factura
Menos de $18,720 dólares	80%
de $18,721 a $37,440 dólares	40%
de $37,441 a $46,800 dólares	20%
de $46,801 a $94,400 dólares	15%

Obtenga mejoras para el hogar gratis

Usted podría calificar para mejoras para el hogar gratis a través de nuestras asociaciones con Agencias de Acción Comunitaria locales. Vea estas agencias en **nwnatural.com/BillDiscount**.

Las mejoras gratuitas pueden incluir:

- Una nueva unidad de calefacción de gas natural
- Un nuevo calentador de agua de gas natural
- Insolación para la casa

Obtenga ayuda con sus pagos

Planes de pago de NW Natural

Ofrecemos varios planes de pago. Un plan, llamado Equal Pay, divide su uso anual de gas en 11 pagos iguales.

Apoyo para facturas de las agencias comunitarias

Nos asociamos con agencias sin fines de lucro para ayudarle a pagar su factura de energía. Consulte la lista de agencias socias en **nwnatural.com/BillDiscount.**

Use menos energía

Incluso pequeño pasos como estos pueden ayudar a reducir sus facturas:

- **Mantener los filtros de la calefacción limpios.** Los filtros sucios hacen que su calefacción trabaje más duro y gaste energía.
- **Ahorre 3 % en el uso de energía** con cada grado que reduzca de temperatura en su termostato.

Consulte más consejos en **nwnatural.com/BillDiscount**.

Obtenga ayuda con las facturas de electricidad

Para reducir las facturas de energía aún más, usted podría calificar para obtener apoyo con su compañía de electricidad. Por favor, contacte a su compañía de electricidad para obtener más información.

CN

我们乐意帮助您减少能源账单。

您可以登录网站 **nwnatural.com/BillDiscount** 或联系我们，了解更多有关这些计划的信息：

503-226-4211 或 800-422-4012（周一到周五上午 7 点到下午 6 点）
csst@nwnatural.com

获取账单折扣

您可以通过 NW Natural 的账单折扣计划享受 NW Natural 月账单 15% 到 80% 的折扣。若您的家庭收入不超过地区中位收入或联邦贫困线的 80%，则符合折扣资格。折扣有效期：2023 年 10 月 1 日至 2025 年 9 月 30 日。

家庭收入（四口之家）	账单折扣
$18,720 美元以下	80%
$18,721 美元至 $37,440 美元	40%
$37,441 美元至 $46,800 美元	20%
$46,801 美元至 $94,400 美元	15%

获得免费家居改善

您有资格通过我们与当地社区行动机构的合作伙伴关系获得免费的家居改善。请登录网站 **nwnatural.com/BillDiscount**，查看这些机构。

免费改善包括：

- 一种新款天然气炉
- 一种新款天然气热水器
- 家居隔热层

获取付款方面的帮助

NW Natural 付款方案

我们提供多种付款方案。一种方案为等额付款方案，即是将您每年的天然气用量分成 11 个月的等额付款。

社区机构提供的账单援助

我们与非营利机构合作，帮助您支付能源账单。请登录网站 **nwnatural.com/BillDiscount**，查看合作伙伴机构列表。

使用更少的能源

即使是这样小小的举动，也可以帮助您减少账单：

- 保持火炉过滤器的清洁。肮脏的过滤器会使您的火炉效率变低，浪费能源。
- 每将恒温控制器的温度下调一度，就可以节能 3%。

请登录网站 **nwnatural.com/BillDiscount**，获得更多提示。

获取电费账单帮助

为了进一步减少您的能源账单，您可能有资格获得电力公司的援助。请联系您的电力公司，了解更多信息。

RU

Мы готовы помочь вам снизить счета за электроэнергию.

Вы можете получить дополнительную информацию об этих программах на веб-сайте **nwnatural.com/BillDiscount** или связаться с нами:

503-226-4211 или 800-422-4012 800-422-4012, с понедельника по пятницу, с 7 a.m. до 18:00 p.m.
csst@nwnatural.com

Получите скидки на оплату счетов

Программа скидок компании NW Natural может помочь вам сэкономить от 15 до 80% на ежемесячных счетах от NW Natural. Скидки предоставляются при условии, что доход вашей семьи составляет не более 80% от среднего дохода по району или от федерального уровня бедности. Действует в период с 1 октября 2024 года по 30 сентября 2025 года.

Семейный доход (семья из четырех человек)	Скидка на оплату счетов
До 18 720 долл.	80%
От 18 721 долл. до 37 440 долл.	40%
От 37 441 долл. до 46 800 долл.	20%
От 46 801 долл. до 94 400 долл.	15%

Получите бесплатные средства для благоустройства дома

Вы можете иметь право на бесплатные средства для благоустройства дома благодаря нашему партнерству с местными общественными службами. Перечень этих служб см. на веб-сайте **nwnatural.com/BillDiscount.**

К бесплатным средствам для благоустройства дома могут относиться:

- Новая газовая печь
- Новый водонагреватель, работающий на природном газе
- Теплоизоляция дома

Получите помощь с оплатой счетов

Схемы оплаты от компании NW Natural

Мы предлагаем несколько планов оплаты счетов. Один план, называемый «Equal Pay» (равные платежи), разделяет годовое потребление газа на 11 равных ежемесячных платежей.

Поддержка в оплате счетов от общественных организаций

Мы сотрудничаем с некоммерческими организациями, чтобы помочь вам в оплате счетов за электроэнергию. Перечень партнерских служб см. на веб-сайте **nwnatural.com/BillDiscount**.

Потребляйте меньше электроэнергии

Даже небольшие шаги, подобные тем, что перечислены ниже, могут помочь вам сократить ваши счета:

- **Поддерживайте печные фильтры в чистоте.** Грязный фильтр усложняет работу печи и приводит к трате энергии.
- **кономьте 3% энергии** с каждым градусом понижения температуры на термостате.

Дополнительные советы см. на веб-сайте **nwnatural.com/BillDiscount**.

Получите помощь в оплате счетов за электричество

Возможно, вы имеете право на поддержку со стороны вашей электроэнергетической компании, чтобы еще больше сократить расходы на электроэнергию. Пожалуйста, свяжитесь с вашей электроэнергетической компанией, чтобы получить дополнительную информацию.

Chúng tôi có thể giúp quý vị giảm chi phí năng lượng của mình.

VI

Quý vị có thể tìm hiểu thêm về các chương trình này tại **nwnatural.com/BillDiscount** hoặc liên lạc với chúng tôi.:

503-226-4211 hoặc 800-422-4012 800-422-4012, Thứ Hai đến Thứ Sáu, 7:00 sáng đến 6:00 chiều
csst@nwnatural.com

Chiết khấu hóa đơn

Chương Trình Giảm Giá Hóa Đơn của NW Natural có thể giúp quý vị tiết kiệm từ 15% đến 80% hóa đơn NW Natural hàng tháng. Chương trình giảm giá có thể áp dụng nếu thu nhập hộ gia đình của quý vị bằng hoặc dưới 80% thu nhập trung bình của khu vực hoặc mức nghèo liên bang. Có hiệu lực từ ngày 1/10/2023 đến ngày 30/9/2025.

Thu nhập hộ gia đình	Chiết khấu hóa đơn
Dưới $18,720	80%
$18,721 đến $37,440	40%
$37,441 đến $46,800	20%
$46,801 đến $94,400	15%

Nhận các thiết bị nâng cấp nhà cửa miễn phí

Quý vị có thể hội đủ tiêu chuẩn để được cải tiến các hệ thống tiện ích trong nhà miễn phí thông qua quan hệ đối tác của chúng tôi với các Cơ quan Vận động Cộng đồng (Community Action Agencies). Xem các cơ quan này tại **nwnatural.com/BillDiscount**.

Các cải tiến miễn phí này có thể bao gồm:

- Một lò khí đốt tự nhiên mới
- Một máy đun nước bằng khí đốt tự nhiên mới
- Hệ thống cách nhiệt trong nhà

Hỗ trợ trong việc thanh toán

Các kế hoạch thanh toán của NW Natural

Chúng tôi có một vài kế hoạch thanh toán. Kết hoạch Equal Pay sẽ chia hóa đơn tiền gas hàng năm của quý vị thành 11 khoản thanh toán hàng tháng bằng nhau.

Hỗ trợ thanh toán hóa đơn từ các cơ quan cộng đồng

Chúng tôi hợp tác với các cơ quan phi lợi nhuận để giúp quý vị thanh toán hóa đơn năng lượng. Xem danh sách các đối tác của chúng tôi tại **nwnatural.com/BillDiscount**.

Giảm tiêu dùng năng lượng

Ngay cả những việc làm nhỏ như thế này cũng có thể giúp quý vị tiết kiệm chi phí năng lượng:

- **Đảm bảo bộ lọc của lò sưởi luôn sạch.** Bộ lọc bẩn sẽ làm cho lò của quý vị làm việc nhiều hơn và lãng phí năng lượng.
- **Tiết kiệm 3% mức sử dụng năng lượng** với mỗi độ mà quý vị hạ xuống trên bộ điều nhiệt của mình.

Xem thêm mẹo tại **nwnatural.com/BillDiscount.**

Được trợ giúp về hóa đơn tiền điện

Để giảm hóa đơn năng lượng nhiều hơn nữa, quý vị có thể đủ tiêu chuẩn để được trợ giúp bởi công ty điện của mình. Vui lòng liên lạc với công ty điện của quý vị để tìm hiểu thêm.

NW Natural®

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nwnatural.com/BillDiscount
503-226-4211 or 800-422-4012

WASHINGTON

NW Natural®

NW Natural can help lower your energy bills.

You may be able to get 15% to 80% off your monthly gas bill with NW Natural's Bill Discount Program

Obtenga un 15% a 80% de descuento en su factura mensual de gas con el Programa de descuento en facturas naturales de NW.

通过 NW Natural Bill 折扣计划，每月燃气费可享受 15% 至 80% 的折扣。

Được giảm giá 15% đến 80% hóa đơn khí đốt hàng tháng của bạn với Chương trình Giảm giá Hóa đơn Tự nhiên Tây Bắc.

Получите скидку от 15% до 80% на ежемесячный счет за газ с помощью программы скидок NW Natural Bill.

We are here to help lower your energy bills with discounts. Scan the QR code to see qualifying incomes and apply. The application only takes minutes to complete online, by email, by traditional mail, or over the phone. You may be able to save more with free home energy improvements and flexible payment plans.

Estamos aquí para ayudarle a reducir sus facturas de energía con descuentos en la factura. Escanee el Código QR para ver los ingresos que califican y hacer la solicitud. Toma solo unos cuantos minutos completar la solicitud en línea, por correo electrónico o por correspondencia postal tradicional, o por teléfono. También podría ahorrar más con mejoras energéticas gratuitas en su hogar y con planes de pagos flexibles.

我们致力于帮助您降低能源费用，提供账单折扣。扫描二维码查看符合条件的收入并提出申请。申请只需几分钟即可在线、通过电子邮件、传统邮寄或电话完成。通过免费家庭节能改善和灵活的付款计划，您可能可以节省更多。

Chúng tôi ở đây để giúp quý vị giảm hóa đơn tiền điện bằng các khoản chiết khấu hóa đơn. Quét mã QR này để xem khả năng đủ điều kiện về thu nhập và nộp đơn. Chỉ mất vài phút để hoàn tất đơn trực tuyến, qua email hoặc thư truyền thống hoặc qua điện thoại. Quý vị có thể tiết kiệm nhiều hơn với các cải tiến năng lượng miễn phí tại nhà và các gói thanh toán linh hoạt.

Мы готовы помочь вам снизить стоимость счетов за электроэнергию с помощью скидок на оплату счетов. Отсканируйте QR-код, чтобы узнать о допустимых доходах и подать заявление. Заполнение заявления онлайн, по электронной или обычной почте или по телефону займет всего нескольких минут. Возможно, вы сможете сэкономить еще больше средств благодаря не требующему затрат повышению энергоэффективности дома и гибким планам оплаты.

nwnatural.com/BillDiscount
503-226-4211 or 800-422-4012

NW Natural®
NW Natural
250 SW Taylor Street
Portland OR 97204

11/24

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Cory A. Beck

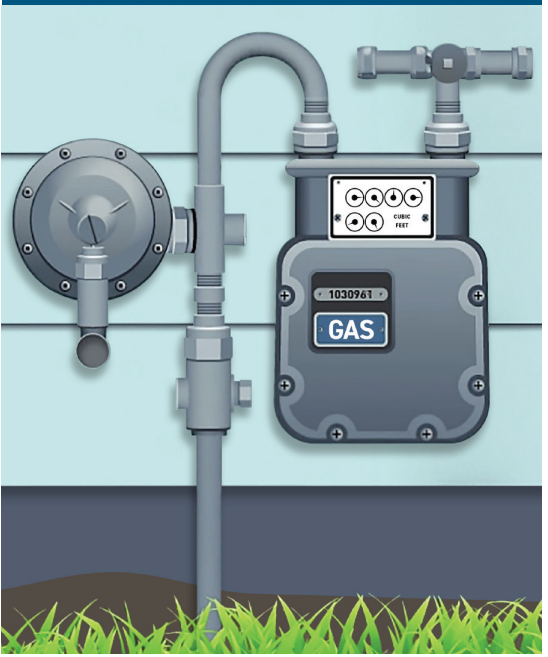
LANGUAGE ACCESS APPROACH

Exh. CAB-4

August 29, 2025

NW NATURAL

METER UPDATE PROJECT



Over the next few months, we will start updating some gas meters in your area. You may notice more NW Natural contractor vehicles and crews.

Not all meters will be updated. If your meter will be updated, you will receive a letter with additional details by mail or email before work begins. Your gas service should not be affected.

The schedule is subject to change.

NW Natural®

Visit **nwnatural.com/Meter** for more information.

Proyecto de Actualización del Medidor Natural del NW

En los próximos meses, comenzaremos a actualizar algunos medidores de gas en los hogares de su área. No se actualizarán todos los medidores. Los horarios están sujetos a cambios.

NW Natural 表具更换项目

在接下来的几个月里，我们将更新您所在地区的一些燃气表。并非所有灯具都需要更新。时间表可能会发生变化。

Dự Án Cập Nhật Đồng Hồ Đo NW Natural

Trong vài tháng tới, chúng tôi sẽ bắt đầu cập nhật một số đồng hồ đo gas cho các ngôi nhà trong khu vực của bạn. Không phải tất cả các đồng hồ đo sẽ được cập nhật. Lịch trình có thể thay đổi.

Проект обновления счетчиковкомпании NW Natural

В течение следующих нескольких месяцев мы начнем обновлять некоторые газовые счетчики в домах в вашем районе. Не все счетчики будут обновлены. Расписание может быть изменено.

nwnatural.com/Meter

NW Natural®

NW Natural®

250 SW Taylor Street
Portland, OR 97204

503-226-4211
nwnatural.com

Advance notice for gas meter access

Dear valued customer,

NW Natural contractor crews will be updating your gas meter as part of planned maintenance over the next few months.

You do not need to be home for your meter to be updated, and your gas service should not be affected. However, now is a great time to make sure there is clear access to your gas meter.

How to prepare for your meter update

- Please check the area around your meter to make sure we have a clear path to access it, and at least 3 feet of space in all directions. This could mean you need to prune, remove foliage, move objects away from your meter, and unlock gates.
- If we cannot reach the meter, we will leave a notice with a number for you to call and schedule time to access it.

Thank you in advance for working with us. Learn more about gas meter updates, schedules and what to expect at:

nwnatural.com/Meter

Sincerely,

NW Natural

NW Natural®

250 SW Taylor Street
Portland, OR 97204

503-226-4211
nwnatural.com

Notificación anticipada para el acceso al medidor de gas

Estimado/a y valorado/a cliente:

Las cuadrillas contratistas de NW Natural estarán actualizando su medidor de gas como parte de un mantenimiento planeado a partir de los siguientes meses. Usted no tiene que estar en casa para la actualización de su medidor, y su servicio de gas no se verá afectado. Sin embargo, este es un buen momento para garantizar que haya acceso sin obstrucciones a su medidor de gas. Escanee la código QR para obtener más información sobre el acceso al medidor, los calendarios, y qué esperar.

Предварительное уведомление о доступе к газовому счетчику

Уважаемый клиент!

В рамках планового технического обслуживания бригады подрядчиков компании NW Natural будут производить обновления газовых счетчиков в течение следующих нескольких месяцев. Во время работы по обновлению счетчика вам не обязательно находиться дома, и работа не должна повлиять на подачу природного газа. Тем не менее, сейчас самое время убедиться в том, что к вашему газовому счетчику имеется беспрепятственный доступ. Отсканируйте QR-код, чтобы получить дополнительную информацию об обеспечении доступа к счетчику, графике работ и о том, чего следует ожидать.

燃气表访问提前告知通知

尊敬的客户：

NW Natural 的承包商团队将在未来几个月内开始进行计划内维护，更新您的燃气表。您无需在家即可更新燃气表，您的燃气服务也不会受到影响。但是，现在是确保您的燃气表周围通道畅通的好时机。扫描二维码，了解更多关于燃气表访问、时间安排以及相关注意事项的信息。

Thông báo trước về việc tiếp cận đồng hồ đo gas

Kính gửi quý khách hàng,

Đội ngũ nhà thầu của NW Natural sẽ cập nhật đồng hồ đo gas của quý vị như một phần của hoạt động bảo trì theo kế hoạch bắt đầu trong vài tháng tới. Quý vị không cần phải ở nhà để cập nhật đồng hồ đo và dịch vụ gas của quý vị sẽ không bị ảnh hưởng. Tuy nhiên, bây giờ là thời điểm tuyệt vời để đảm bảo có thể tiếp cận đồng hồ đo gas của quý vị một cách dễ dàng. Vui lòng quét mã QR để tìm hiểu thêm về cách tiếp cận đồng hồ đo, lịch trình và những điều được mong đợi.

SCAN ME

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Cory A. Beck

LANGUAGE ACCESS APPROACH

Exh. CAB-5

August 29, 2025

Thank you for picking up the **NW Natural Home Energy Kit.**

This DIY kit is packed with powerful products that help lower energy bills and improve your home's comfort. **Please install and enjoy!**

- Door sweep
- Foam window insulators
- Light switch insulators
- Plastic window coverings
- Weather-stripping

See more ways NW Natural can help lower energy bills at **nwnatural.com/Savings.** Or scan the QR code.

See more ways NW Natural can help lower energy bills at **nwnatural.com/Savings.** Or scan the QR code.

Español 中国人 Русский Tiếng Việt

NW Natural®

02/2025

NW Natural®

Gracias por recoger el **Kit de Energía para la Casa de NW Natural.**

Este es un kit para hacerlo usted mismo, con poderosos productos que le ayudan a reducir sus facturas de electricidad y a mejorar la comodidad de su casa. **¡Por favor, instale y disfrute!**

- Guardapolvos para puertas
- Aislantes de espuma para ventana
- Aislantes para interruptores de luz
- Cubiertas de plástico para las ventanas
- Aislantes térmicos

Благодарим вас за получение набора для повышения энергоэффективности дома от компании **NW Natural.**

В этом наборе для самостоятельной установки собраны эффективные средства, которые помогут вам снизить расходы на электроэнергию и улучшить комфорт в вашем доме. **Установите и пользуйтесь!**

- Дверной уплотнитель
- Пенопластовые изолирующие материалы для окон
- Изолирующие материалы для выключателей
- Комплект из пластика для утепления окон
- Уплотнительная лента

感谢您购买 NW Natural 家庭能源套件。

这款 DIY 套件包含功能强大的产品，有助于降低能源费用并改善您家的舒适度。请安装并享用！

- 门底密封条
- 泡沫窗密封材料
- 灯开关绝缘体
- 塑料窗帘
- 挡风雨条

Cảm ơn quý vị đã chọn Bộ Dụng Cụ Năng Lượng **Natural Home NW.**

Bộ dụng cụ tự làm DIY này bao gồm các sản phẩm mạnh mẽ giúp giảm hóa đơn năng lượng và cải thiện sự thoải mái cho ngôi nhà của quý vị. **Hãy lắp đặt và tận hưởng!**

- Quét cửa
- Foam cách nhiệt cửa sổ
- Cách điện công tắc đèn
- Tấm che cửa sổ bằng nhựa
- Tước thời tiết

Climatización del hogar y mejoras de calefacción gratis

NW Natural puede ayudarle con sus facturas de energía

免费家庭气候改善和供暖改进

NW Natural 可以帮助降低家庭能源费用并提高舒适度

Miễn phí cải thiện khả năng chống chịu thời tiết và sưởi ấm tại nhà

NW Natural có thể giúp giảm hóa đơn năng lượng trong nhà và cải thiện sự thoải mái

Бесплатное утепление и модернизация системы отопления вашего дома

Компания NW Natural поможет вам снизить счет за электроэнергию и повысить уровень комфорта

Free home weatherization and heating improvements

NW Natural can help lower home energy bills and improve comfort

If you are on a limited income, you may qualify for a free home energy review and improvements through partnerships with local Community Action Agencies.

Free improvements may include:

- A new high-efficiency natural gas furnace
- A new high-efficiency natural gas water heater
- Home insulation
- Ventilation improvements

Flip over for next steps →

NW Natural®

¿Cómo obtengo más información y cómo hago la solicitud?

Usted puede recibir mejoras energéticas si su unidad familiar cumple con los requisitos de ingresos. Escanee el código QR para consultar los requisitos de ingresos, contactar a su Agencia de Acción Comunitaria, para obtener más información y para registrarse.

我如何了解更多信息并申请?

如果您的家庭符合收入要求，您可以获得免费的家庭能源改善。扫描二维码查看收入要求，联系您当地的社区行动机构获取更多信息并注册。

Làm cách nào để tôi tìm hiểu thêm thông tin và đăng ký?

Quý vị có thể nhận được cải tiến năng lượng miễn phí tại nhà nếu hộ gia đình của quý vị đáp ứng yêu cầu về thu nhập. Quét mã QR để xem yêu cầu về thu nhập, liên hệ với Cơ quan Hành động Cộng đồng (Community Action Agency, hoặc CAA) tại địa phương của quý vị để biết thêm thông tin và đăng ký.

Как я могу получить дополнительную информацию и подать заявление?

Вы можете получить бесплатные средства для повышения энергосбережения дома, если ваша семья соответствует требованиям по уровню дохода. Отсканируйте QR-код, чтобы узнать требования к доходу, свяжитесь с местной службой общественных действий (Community Action Agency), чтобы получить дополнительную информацию и записаться.

05/24

How do I learn more and apply?

You can receive free home energy improvements if your household meets income requirements. Scan the QR code to see income requirements, contact your local Community Action Agency for more information and sign up.

Get help with payments

- **Temporary payment plans.** Flexible monthly payment options can make your bill more manageable.
- **Payment extensions.** You may be able to extend your payment due date and pay in a timeframe that works for you.
- **Residential Bill Discount Program for income-qualifying customers.** You may be able to save 15% to 80% on monthly bills.

nwnatural.com/Savings

NW Natural®

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

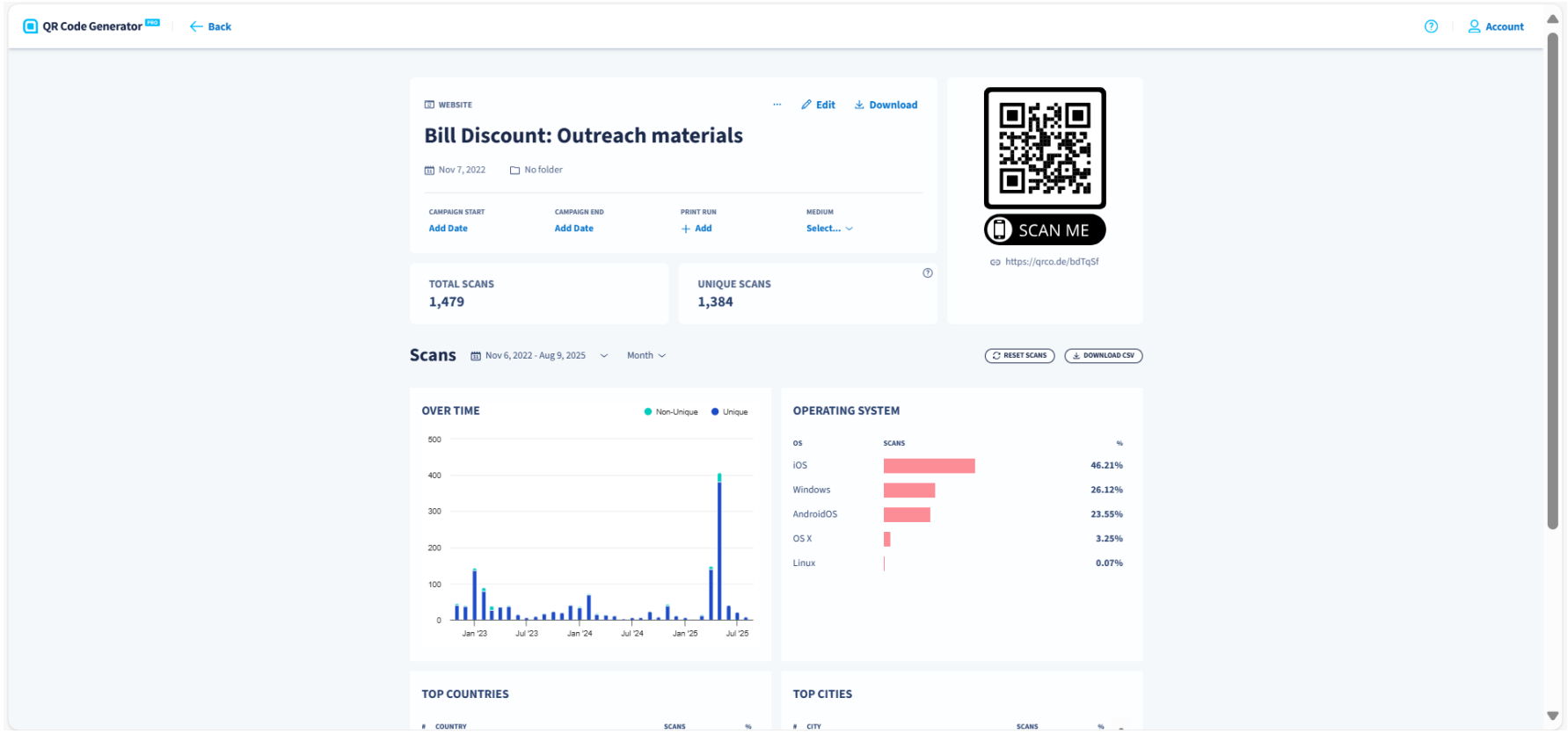
NORTHWEST NATURAL GAS COMPANY

Exhibit of Cory A. Beck

LANGUAGE ACCESS APPROACH

Exh. CAB-6

August 29, 2025


QR Code Generator PRO
Back
Account
WEBSITE
Edit
Download
Bill Discount: Outreach materials
Nov 7, 2022
No folder
CAMPAIGN START
Add Date
CAMPAIGN END
Add Date
PRINT RUN
Add
MEDIUM
Select...
SCAN ME
https://qrco.de/bdTqSf
TOTAL SCANS
1,479
UNIQUE SCANS
1,384
Scans
Nov 6, 2022 - Aug 9, 2025
Month
RESET SCANS
DOWNLOAD CSV
OVER TIME
Non-Unique
Unique
500
400
300
200
100
0
Jan '23
Jul '23
Jan '24
Jul '24
Jan '25
Jul '25
OPERATING SYSTEM
OS
SCANS
%
iOS
46.21%
Windows
26.12%
AndroidOS
23.55%
OS X
3.25%
Linux
0.07%
TOP COUNTRIES
COUNTRY
SCANS
%
TOP CITIES
CITY
SCANS
%

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Direct Testimony of Brody J. Wilson

COST OF CAPITAL

Exh. BJW-1CT

REDACTED VERSION

August 29, 2025

DIRECT TESTIMONY OF BRODY J. WILSON

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I. INTRODUCTION AND SUMMARY

Q. Please state your name, address and position at Northwest Natural Gas Company ("NW Natural" or "Company").

A. My name is Brody J. Wilson. My business address is 250 SW Taylor Street, Portland, Oregon 97204. My current position at NW Natural and Northwest Natural Holding Company ("NW Natural Holdings") is Vice President, Controller, Treasurer and Chief Accounting Officer.

Q. Please summarize your educational background and business experience.

A. I received a Bachelor of Arts in accounting from George Fox University in 2001. From 2001 through 2012, I worked at PricewaterhouseCoopers, LLP, in the Power and Utilities Assurance practice. I joined NW Natural in 2012 as Accounting Director. In 2013, I was appointed as Controller and Chief Accounting Officer of NW Natural and its subsidiaries. In 2016, I was appointed Treasurer.

Q. Please describe the purpose of your testimony.

A. The purpose of my testimony is to support the Company's requested capital structure and explain the Company's financing strategy and how that leads to a financially healthy utility that benefits its customers.

Q. Please summarize your testimony.

A. The Company's financing strategy is to maintain a balance of long-term debt and equity financing, by targeting a capital structure that supports its strong investment grade credit profile. The Company's strong investment grade credit ratings support its ability to efficiently access capital markets. NW Natural works to manage interest rate risk and secure low-cost capital to fund utility infrastructure and operations. To do this, the

Company prioritizes maintaining a strong balance sheet and focusing on financing the long-term assets of the Company through a balance of long-term debt and equity financing, with minimal reliance on short-term debt. To further explain the Company's financing strategy, my testimony:

- Describes NW Natural's request for a capital structure of 51 percent common equity, 1 percent short-term debt, and 48 percent long-term debt, with an overall rate of return ("ROR") on rate base for each rate year provided in Table 1 below.
- Describes NW Natural's plan to maintain its targeted ratios of equity, short-term debt, and long-term debt;
- Explains the method for calculating short and long-term cost of debt for the Test Year (Twelve Months ended 3/31/2025) and each subsequent rate year.

II. CAPITAL STRUCTURE AND RATE OF RETURN

Q. What is NW Natural's current Commission-authorized overall ROR?

A. In the Company's last general rate case (Order 05 in Docket UG-200994), the Commission adopted a settlement which included an ROR of 6.814 percent. The components of the ROR were not specified by the settling parties.

Q. What is NW Natural's requested capital structure for ratemaking purposes and overall ROR in this proceeding?

A. NW Natural is requesting an authorized capital structure of 51.0 percent equity, 1.0 percent short-term debt and 48.0 percent long-term debt, with an overall rate of return (ROR) on rate base provided by rate year in Table 1 below. The following table presents the proposed capital structure along with the calculation of the Company's ROR for each year of the Multi-Year Rate Plan:

Table 1. Requested Capital Structure and Rate of Return

Test Year (13-month Avg. Ending 3/31/25)			
Component	Ratio	Cost	Weighted Cost
Long-term Debt	50.06%	4.697%	***
Short-term Debt	2.06%	6.335%	***
Common Equity	47.87%	***	***
Total	**100%**		**6.982%**

*** Confidential due to black box settlement in UG 200994

Rate Year 1 (13-months Avg. Ending 7/31/27)			
Component	Ratio	Cost	Weighted Cost
Long-term Debt	48.0%	4.779%	2.294%
Short-term Debt	1.0%	6.04%	0.060%
Common Equity	51.0%	10.1%	5.151%
Total	**100%**		**7.505%**

Rate Year 2 (13-month Avg. Ending 7/31/2028)			
Component	Ratio	Cost	Weighted Cost
Long-term Debt	48.0%	4.924%	2.364%
Short-term Debt	1.0%	5.745%	0.057%
Common Equity	51.0%	10.2%	5.202%
Total	**100%**		**7.623%**

Rate Year 3 (13-month Avg. Ending 7/31/2029)			
Component	Ratio	Cost	Weighted Cost
Long-term Debt	48.0%	5.005%	2.402%
Short-term Debt	1.0%	5.674%	0.057%
Common Equity	51.0%	10.2%	5.202%
Total	**100%**		**7.661%**

Q. What was NW Natural's capital structure in the Test Year?

A. Based on a 13-month average of monthly averages ("AMA") for the year ended March 31, 2025, the Company's capital structure was 47.87 percent Equity, 50.06 percent Long-Term Debt, and 2.06 percent Short-Term Debt. However, recently NW Natural

has targeted a higher equity ratio in its capital structure. In Table 2 below, the capital structure has recently maintained Equity higher than 52 percent.

Table 2. Recent Capital Structure

Recent Cap Structures			
Component	Test Year (13-Month Avg Ending 3/31/25)	As of 3/31/25	As of 6/30/25
Long-term Debt	50.06%	47.4%	47.4%
Short-term Debt	2.06%	0.0%	0.0%
Common Equity	47.87%	52.6%	52.6%

Q. Why is NW Natural changing its targeted capital structure?

A. NW Natural's target capital structure has been 49 percent equity/1 percent short term debt/50 percent long term debt for a number of years. In order to strengthen its balance sheet, attract investment, better align with peer gas utilities, improve credit metrics, and maintain solid investment grade credit ratings—all of which benefit customer rates—NW Natural has taken steps to increase its capital structure to above 51 percent equity in 2025.

The Company is targeting a long-term debt percentage of 48 percent with a 1 percent short-term debt balance because generally, companies with higher debt ratios are considered riskier, as a higher debt layer in the capital structure inherently puts pressure on the credit metrics. By reducing its long-term debt ratio to 48 percent, the Company is improving its risk profile and moving to be in-line with its natural gas peer group. Reducing the Company's debt ratio to 48 percent is likely to be viewed positively by the rating agencies. Moody's Investor Service ("Moody's") methodology specifically looks at debt/capitalization ratios and generally, a lower amount of debt

improves the metrics. Moody's July 8, 2025 credit opinion states, "...we view a higher equity ratio as a credit positive because it supports higher required revenue and reduces reliance on debt, which helps to support stronger credit metrics...". The latest rating agency credit reports can be found in Exh. BJW-2.

This equity ratio demonstrates the Company's commitment to a strong and stable balance sheet, which helps maintain the Company's current credit ratings. Strong investment-grade credit ratings provide the Company with financing flexibility and liquidity, thereby ensuring timely, efficient, and cost-effective access to capital markets, which in turn helps to lower the cost of capital. The cost of capital and capital structure directly impact the return for debt service and common equity investors within the revenue requirement calculation.

Q. What is NW Natural's plan to maintain the target equity ratio of 51 percent over the next few years?

A. The Company plans to rely on retained earnings growth each year, as well as continuing to request equity infusions from its parent company. The Company has a strong track record of operating its business at or near its authorized capital structure. This includes a strong track record of support from NW Natural's parent company as evidenced through the equity contributions made over the years.

Q. Has the Company received equity from the parent company, NW Natural Holdings, since the holding company structure was approved by the Commission?

A. Yes. Table 3, below, displays the equity contributions from NW Natural Holdings to the Company since 2019. Equity infusions from the parent company help the Company manage its common equity and maintain a strong balance sheet.

Table 3. Equity Contributions from NW Natural Holdings to NW Natural

2019	2020	2021	2022	2023	2024	YTD June 2025
(In millions)						
$93	$ -	$116	$179.4	$30	$75	$135

Q. What are the credit concerns of the rating agencies for NW Natural?

A. The rating agencies' most significant factors in determining ratings are how constructive the regulatory framework is in the jurisdictions the Company does business (business risk), the ability of the Company to recover costs and earn a sufficient rate of return, and the financial strength of the organization as measured by its credit metrics. NW Natural's key credit metrics, which help investors evaluate the creditworthiness and risk profile of the Company, generally are quantitative measures of the Company's operating cash inflows, its capital requirements or outflows, and its debt profile. NW Natural's credit metrics have been inconsistent and below the rating agencies' downgrade thresholds over the last five years. By lowering the debt levels for the Company, NW Natural can improve its performance for these metrics.

Q. How does NW Natural's proposed utility capital structure compare with the natural gas peer group?

A. The Company's proposed capital structure is similar to the equity-to-capital ratio of its peer group identified by Ms. Nelson in the Company's Rate of Return on Equity Direct Testimony, Exh. JEN-1T. Specifically, the Company's gas proxy group has an average equity ratio of 53.58 percent over the last three years, and the Combined Proxy Group has a three-year average common equity ratio of 51.68 percent.

Q. What are NW Natural's current credit ratings?

A. Table 4, below, and Exh. BJW-3 show the Company's current ratings for each type of debt security from Moody's and Standard and Poor's Ratings ("S&P"), as well as the outlook issued by each agency.

Table 4. Current Ratings

	Moody's	S&P
Corporate credit rating	n/a	A+
Senior unsecured (long-term debt)	Baa1	n/a
Senior Secured (long-term debt)	A2	AA-
Commercial Paper	P-2	A-1
Outlook	Stable	Stable

Q. Please explain the implications of the credit ratings in terms of NW Natural's ability to access capital markets.

A. Generally speaking, companies with higher credit ratings will have greater access to investors at lower yields, given the lower risk profile of such companies. Lower-rated companies may find it difficult to access capital, or potentially pay significantly more (i.e., risk premium), especially in challenging capital market conditions. The capital market environment changes as macro business cycles move up and down, which creates tighter and looser access to capital. To ensure that the Company continues to have favorable pricing and access to capital markets during all market environments, it is imperative that the Company have strong investment grade credit ratings.

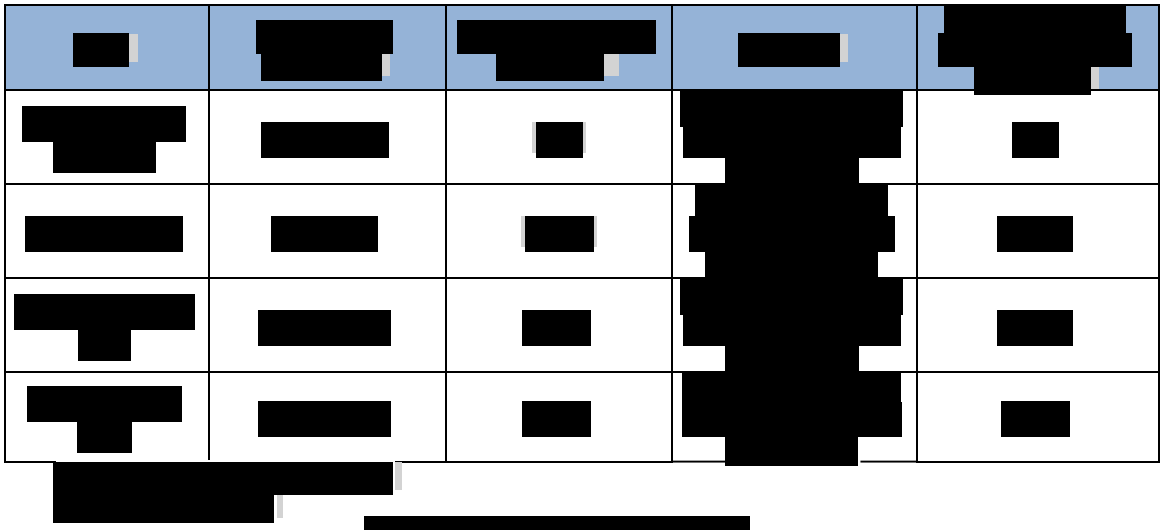
Q. Are there important factors that the rating agencies review in determining NW Natural's ratings?

A. Yes. Moody's and S&P rate the Company's debt based on their independent review of the Company's financial condition and credit metrics. Independent credit reviews

consist of qualitative and quantitative metrics—for example, the regulatory environment and cash flow metrics. Although each rating agency has a slightly different methodology for analyzing credit risk, many of the key financial ratios are similar and comparable.

Confidential Tables 5 and 6, below, display Moody's and S&P's benchmarks and consolidated NW Natural's financial forecast for the 2025 year-end ("YE") period.

[redacted]



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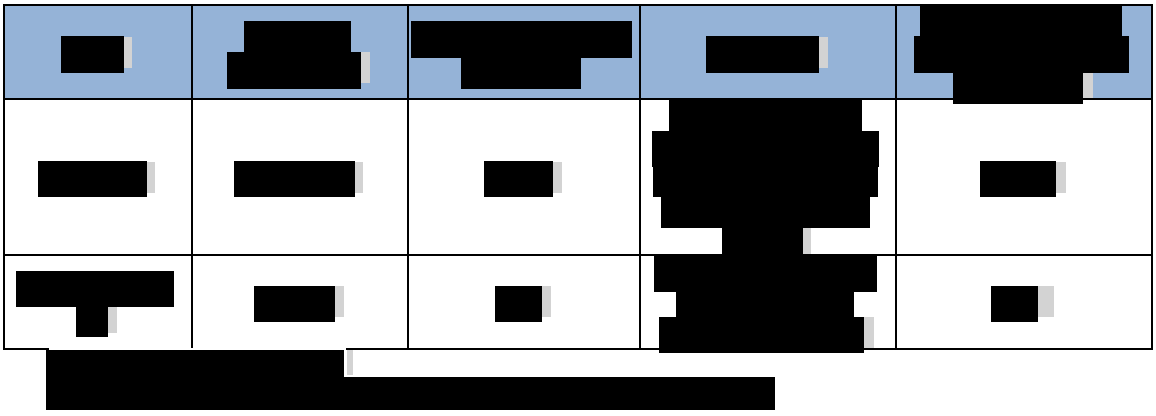


Q. How do NW Natural's credit ratings benefit customers?

A. Investment grade credit ratings provide NW Natural access to capital to support capital improvements in order to maintain a high standard of safe and reliable systems and operation. Credit ratings that are higher than investment grade, as is the case with NW Natural, generally provide access to capital at comparatively lower interest rates. This allows customers to benefit from lower interest expense. In particular, access to capital markets in highly volatile or constrained conditions reduces the impacts that could occur from market disruptions that may otherwise have required more expensive capital raising to fund ongoing operations. NW Natural has proven over time that as a result of its strong credit, it has been able to access capital markets and fund its operations without material disruption or cost to customers even during challenging capital market times.

Q. How has NW Natural performed under Moody's credit metrics?

A. Moody's credit metrics are focused on understanding a company's cash flows and debt profile. Specifically, Moody's uses cash flow from operations ("CFO") as a key metric, because CFO reflects the cash generated from a company's ongoing, regular business or operating activities. To get a clearer picture, Moody's looks at CFO before changes in working capital ("CFO pre-W/C"), which removes the effect of short-term fluctuations in items like receivables and payables. Another important metric is "retained cash flow," which is CFO pre-W/C minus dividends paid to shareholders, since stopping or changing dividends can have significant implications, even if they are not mandatory like interest payments on a bond. Moody's also examines a company's leverage through the "debt to total capitalization" ratio, which shows how much of the

company's capital structure is funded by debt. Please see Table 7 below, which shows Moody's historical credit metrics for NW Natural.

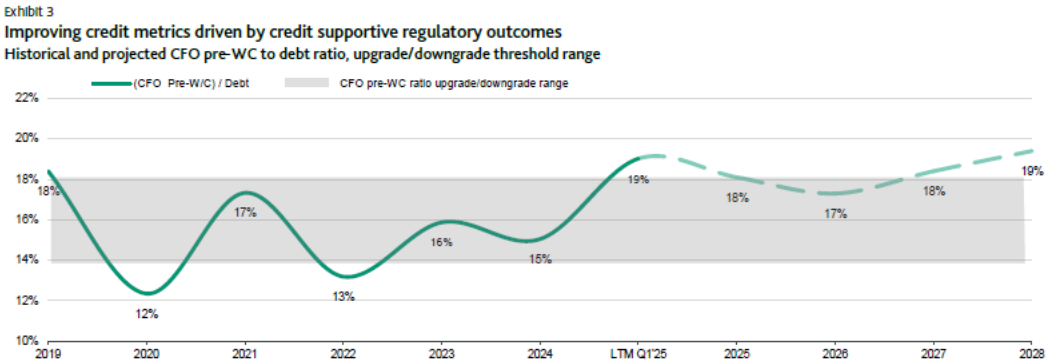
Table 7. Moody's Historical Credit Metrics for NW Natural

Moody's Metrics	2019	2020	2021	2022	2023	2024	LTM 3/31/2025	Downgrade Threshold	Upgrade Threshold
CFO Pre-W/C / Debt	18.4%	12.4%	17.3%	13.2%	15.9%	15.0 %	19.0%	14%	18%
Retained Cash Flow (CFO pre-WC – Dividends/Debt)	13.9%	8.5%	13.5%	9.0%	10.1%	10.8%	14.3%	7%	14%
Debt/Capitalization	51.2%	55.2%	52.5%	49.3%	50.0%	49.9%	44.8%	59% or more	50% or less

CFO = Cash Flow from Operations
W/C = working capital

Below is a table of historical and projected CFO pre-WC to Debt Ratio for NW Natural. NW Natural's ratio has fluctuated over the years, recently improving due to equity infusions from its parent company and improved cash flows. Prior periods were lower and fluctuated significantly based on the timing of debt issuances and or cash flows.

Table 8. Moody's Historical and Projected CFO pre-WC to Debt Ratio



For reference, the three peers Moody's has selected to compare with NW Natural average higher CFO pre-W/C to debt ratios (18.4 percent, with one peer averaging 24 percent) and lower debt to capitalization ratio (40.6 percent, with one peer averaging 35.4 percent).

According to Moody's methodology and specific scorecard for NW Natural, 40 percent of NW Natural's credit rating is based on these credit metrics. Because NW Natural's credit metrics have been weaker historically, it has been difficult for the Company to maintain its current senior unsecured long-term debt rating (Baa1) and the Company has not been able to achieve the higher rating (A3), despite qualifying in most other respects, except its credit metrics.

In addition to the financial metrics, Moody's report on July 30, 2024, cited credit challenges for NW Natural related to "[e]levated social risk due to higher scrutiny on natural gas as an energy source and long-term risks associated with environmental remediation costs and emission reduction requirements." Furthermore, Moody's stated that "[a] rating downgrade could occur if NW Natural's regulatory environment becomes less credit supportive, including material environmental challenges where costs cannot be recovered due to state emission reduction requirements." Moody's most recent report on July 8, 2025, cited, "A rating downgrade could also be considered if CFO pre-WC to debt is sustained below 14%." See Exh. BJW-2 for all referenced credit agency reports.

Q. How has NW Natural performed under S&P's credit metrics?

A. S&P evaluates NW Natural's creditworthiness primarily through two key financial metrics: Funds from Operations Divided by Debt ("FFO/Debt") and Debt/EBITDA (earnings before interest, taxes, depreciation and amortization). FFO/Debt is a ratio that measures a company's ability to cover its debt with cash generated by operations. Debt/EBITDA is a ratio that shows how many years it would take for a company to pay off its debt using earnings before interest, taxes, depreciation, and amortization.

NW Natural's credit metrics for S&P, like Moody's, have fluctuated and repeatedly been below the downgrade threshold over the past five years. Please see Table 9 below, which shows the key financial metrics used by S&P.

Table 9. S&P's Historical Credit Metrics for NW Natural

S&P's Metrics	2019	2020	2021	2022	2023	2024	Downgrade Threshold	Upgrade Threshold
FFO/Debt	18.9%	15.3%	15.3%	16.9%	14 .0%	14.6%	15%	21%
Debt/EBITDA	4.4	5.3	4.8	4.8	4.6	4.8	4x	3x

FFO = Funds From Operations

EBITDA = Earnings Before Interest, Taxes, Depreciation and Amortization

As shown in Table 9 above, NW Natural's FF/Debt ratio has fluctuated and has often been below S&P's downgrade threshold of 15 percent. In 2024, the ratio was 14.6 percent, which is lower than the peer average of 18.5 percent and below the level of two of the three peers, which were at 19 percent FFO/Debt or higher (based on peers disclosed in the S&P June 2025 report).

S&P's latest report on NW Natural on June 25, 2025, highlighted several risks that could lead to a downgrade. Per S&P: "We could lower our rating on NWNG [NW Natural Gas] over the next 24 months if the company's consolidated financial performance weakened such that FFO to debt remained consistently below 15%; or if the company's business risk increases. This could reflect higher risks due to decarbonization mandates and potential gas bans, a weakening of the company's effective management of regulatory risk, or an inability to consistently earn its authorized ROE." And in the previous report on June 24, 2024, S&P listed several key risks including "[c]ontinued negative discretionary cash flow over the next few years,

indicating external funding needs." See Exh. BJW-2 for all referenced credit agency reports.

As mentioned in the June 2025 report, S&P is focused on a company's ability to consistently earn its authorized ROE. But NW Natural has been earning below its authorized ROE for a number of years, and its underperformance has worsened in the recent past.

Q. How could NW Natural increase its credit metrics to continue to hold its current ratings and improve the liquidity of the organization to continue garnering capital?

A. There are two key ways to improve the Company's credit metrics. First is to improve the timely recovery of costs, which improves the cash flows of the business, and the other is to reduce the amount of debt of the Company. The recent improvements in the 2025 forecast are being largely driven by the higher equity layer of the business, resulting in lower reliance on debt.

Additionally, the Company also continuously monitors its funds from operations (FFO). The Company reviews and monitors items such as cash payments, accurate depreciation rates, timely collection of payments from customers, and swift recovery of deferrals.

Q. Have any of NW Natural's credit ratings changed since the Commission issued its order in the Company's last general rate case (UG-200994)?

A. No. There have not been any changes to NW Natural's credit ratings since the filing of the last general rate case, UG-200994. However, NW Natural has had outlook changes. Most recently, in the report issued for NW Natural on April 19, 2024, S&P

changed the outlook for NW Natural from negative to stable, and reaffirmed this stable outlook in June 2025. Historical ratings for each rating agency can be found in Exh. BJW-3.

Q. What reasons did S&P give for the stable outlook?

A. S&P originally moved NW Natural's outlook to negative in October 2023. S&P gave three primary reasons for the negative outlook. First, S&P noted that the Company's FFO (funds from operations) to debt ratio is near the low end of the range for its rating. This was attributed to challenges such as the COVID-19 pandemic, higher bad debt expenses, increased capital spending, and inflationary pressures, including higher operating costs. Second, S&P observed a gradual weakening of NW Natural's business risk profile, mainly due to the ongoing energy transition risks in Oregon and Washington associated with the implementation of decarbonization mandates. In particular, decarbonization mandates could negatively impact NW Natural's credit perspective to the extent decarbonization programs require NW Natural to finance costs ahead of recovery from customers rates. Lastly, S&P noted the Company's inability to consistently earn its authorized return on equity also weighed on the rating.

On April 19, 2024, S&P moved NW Natural's outlook back to stable, citing two main factors: (1) NW Natural's strong ring-fencing provisions, which help protect the utility's financial integrity; and (2) S&P's expectation that NW Natural Gas Company's financial measures, particularly the FFO to debt ratio, will remain above their downgrade threshold (15 percent) and within the 15 percent to 18 percent through 2026. S&P reaffirmed the stable outlook in its June 25, 2025 report. Despite the stable outlook, the cash flow metrics and the risks noted by S&P persist and must be closely

managed in order for the Company to continue garnering strong investment grade ratings.

III. LONG-TERM DEBT AND SHORT-TERM DEBT

Q. How was the cost of long-term debt calculated for the Test Year?

A. The cost of long-term debt for the Test Year was determined using the details provided in confidential Exh. BJW-4C, which lists all of the Company's outstanding long-term debt as of March 31, 2025, totaling ($1,375 million as of March 31, 2025). The corresponding weighted average cost of this debt was calculated to be 4.697 percent for the Test Year. The cost of long-term debt includes only existing debt at the end of the Test Year. The weighted average cost of long-term debt was calculated by multiplying the debt outstanding by the average cost for each debt issue.

The effective interest rate for each debt issue, shown in Column (o) of confidential Exh. BJW-4C, tabs "ECOD March 2025" through "COD – 2029," reflects the total annualized expense of each individual issue, which represents the total cost of issue, including coupon rate, premiums or discounts, underwriter's commissions, gains and losses on interest rate hedges, and other expenses related to the issue such as legal fees and unamortized debt discounts and early redemption premiums assigned to refunding issuances. Unamortized debt discounts and early redemption premiums from previously outstanding debt issuances are carried over to the new debt issuance because the Company was able to achieve a lower annualized cost of debt due to net present value savings from the early redemption.

Q. How was the cost of short-term debt calculated for the Test Year?

A. The cost of short-term debt was calculated in a similar manner to long-term debt, using details in confidential Exh. BJW-5C and the corresponding embedded cost (6.33 percent) for test year 13-month AMA ending March 31, 2025. The cost of short-term debt was calculated by multiplying the 13-month AMA short-term debt outstanding by its 13-month AMA average cost and fees for each debt issue.

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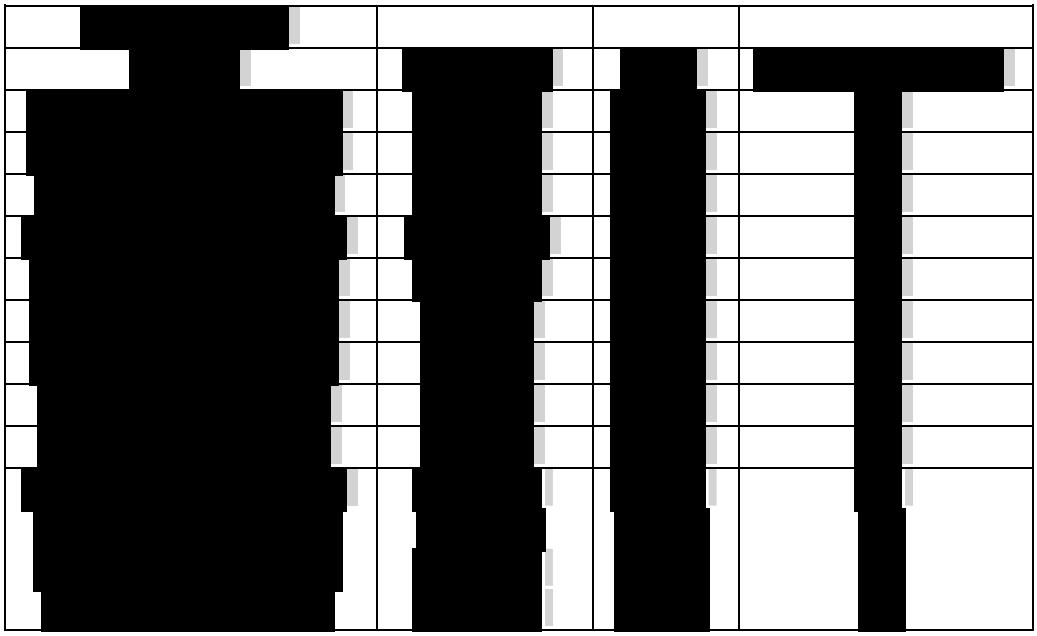

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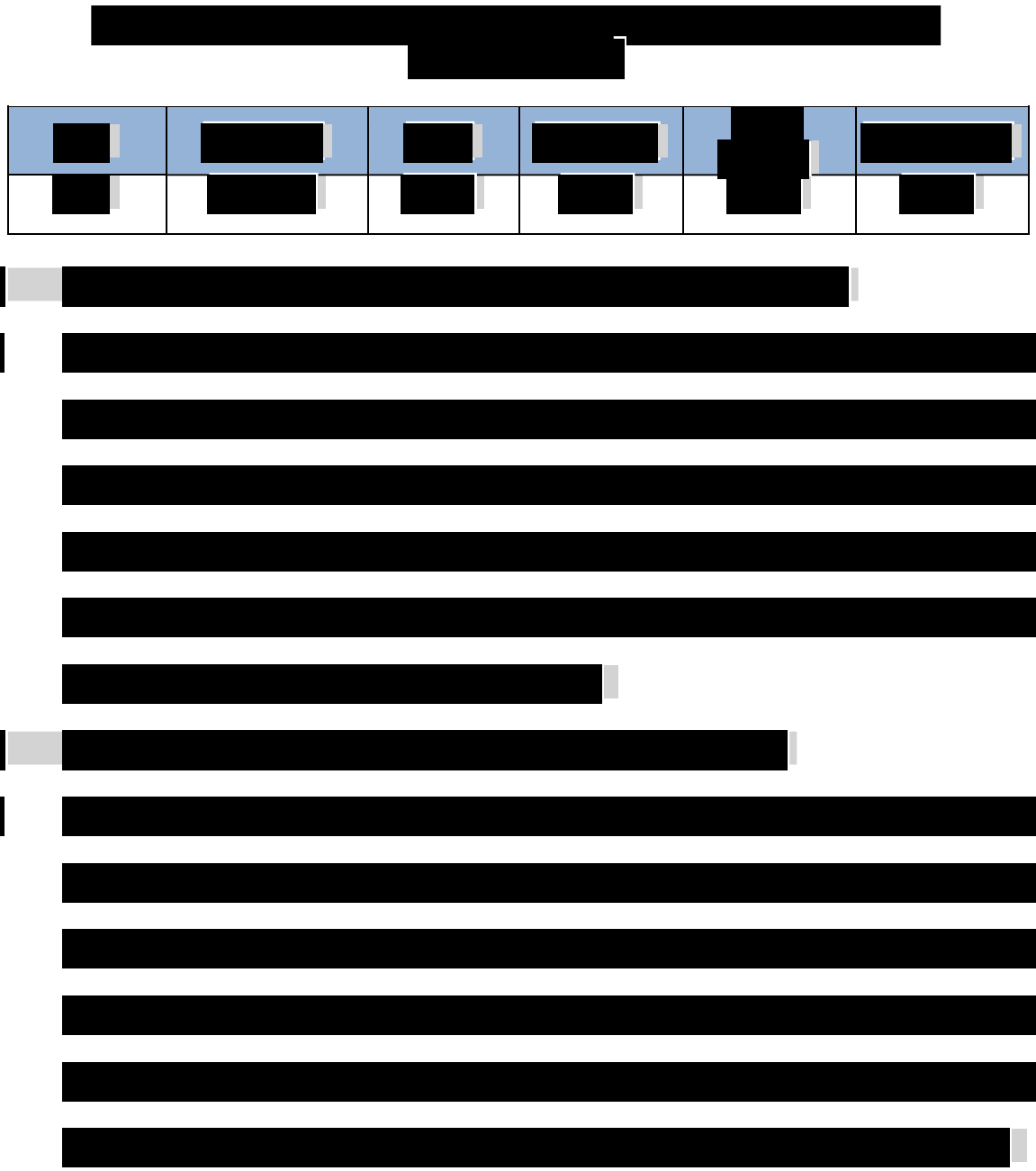

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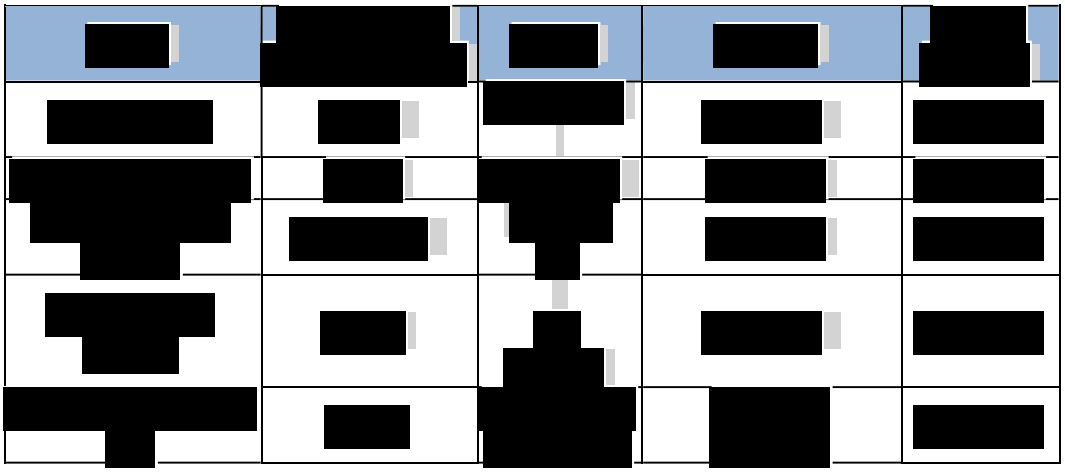

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Q. Does this conclude your Direct Testimony?

A. Yes.

IV. LIST OF EXHIBITS

Exh. BJW-2	Latest Credit Ratings of NW Natural
Exh. BJW-3	NW Natural Credit Ratings 2022 to 2025
Exh. BJW-4C	Embedded Cost of Long-Term Debt (Confidential and Redacted)
Exh. BJW-5C	Short-Term Cost of Debt (Confidential and Redacted)
Exh. BJW-6C	Market Implied Treasury Forwards (Confidential and Redacted)
Exh. BJW-7C	NW Natural Recent Peer Issuances (Confidential and Redacted)

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Brody J. Wilson

COST OF CAPITAL

Exh. BJW-2

August 29, 2025

MOODY'S RATINGS

CREDIT OPINION
8 July 2025

Update

Send Your Feedback

RATINGS

Northwest Natural Gas Company

Domicile	Portland, Oregon, United States
Long Term Rating	(P)Baa1
Type	Senior Unsec. Shelf - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Northwest Natural Gas Company

Update following rating affirmation

Summary

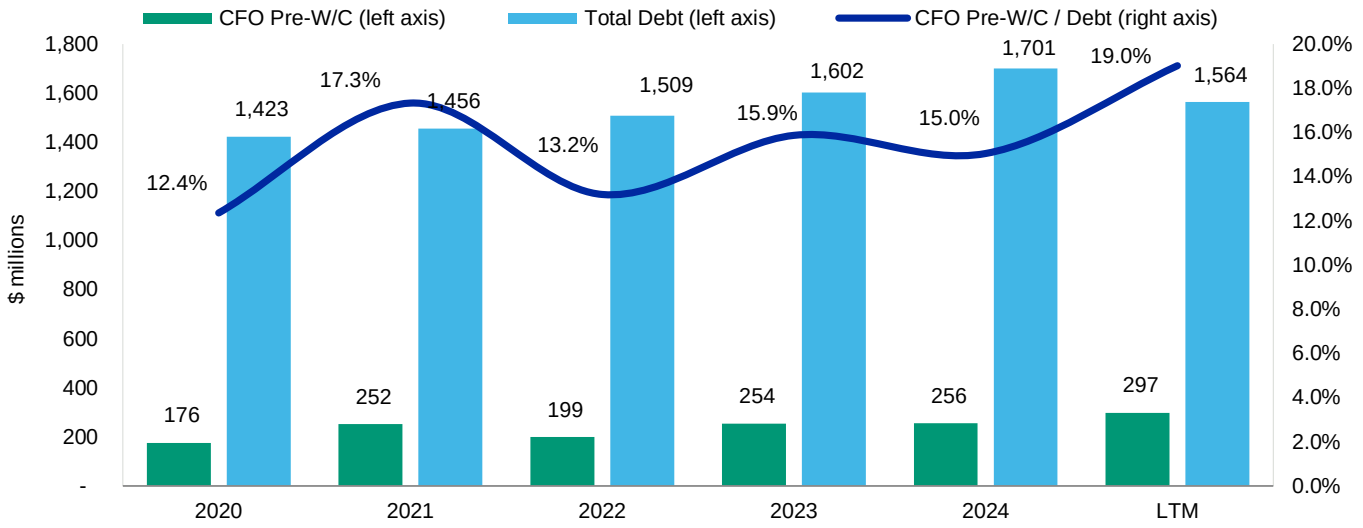
Northwest Natural Gas Company's (NW Natural, Baa1 stable) credit profile incorporates the company's low business risk as a local gas distribution company (LDC) operating in generally supportive regulatory environments. In particular, Oregon's suite of cost recovery mechanisms and constructive stakeholder relationships have supported NW Natural's solid, albeit volatile, cash flow generation over the last several years.

We expect NW Natural's financial performance to improve over the next several years driven by timely cash flow generation and credit supportive regulatory proceedings. The utility's cash flow from operations before changes in working capital (CFO pre-WC) to debt ratio has averaged about 15% over the last three years, ending at 15% in 2024. As of the last twelve months ending 31 March 2025, the ratio increased to 19%.

The recent improvement is attributed to stronger cash flow generation and temporarily reduced debt levels, aligning the utility's capital structure to a higher equity layer of 52%, as filed in their most recent general rate case. NW Natural entered into a stipulation, subject to commission approval, with parties in its 2025 rate case that includes a 50% equity layer as well as a 9.5% ROE (increase from 9.4%) and a $21 million revenue increase. Although we view a higher equity ratio as a credit positive because it supports higher required revenue and reduces reliance on debt, which helps to support stronger credit metrics, we view the 2025 rate case settlement as constructive.

Because of its supportive regulatory outcomes, we expect NW Natural's financial profile to improve over the next several years. We estimate that the CFO pre-WC to debt ratio will range between 16% and 18% over the next 12 to 18 months with a stronger longer-term run rate ranging between 17% and 19%. These estimates include an about $1.6 billion capital expenditure plan (2025-2029), which is consistent with the last five-year capex spend of $1.5 billion (2019-2024). We estimate funding at 50% equity and 50% debt as in prior years.

Exhibit 1
Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt ($ MM)



LTM= Last Twelve Months
Source: Moody's Financial Metrics™

Credit strengths

» Low business risk local gas distribution company

» Improving financial metrics

» Supportive regulatory jurisdictions, including cost tracking mechanisms and legislation that can help investment prospects

Credit challenges

» Historically volatile financial metrics

» CFO pre-W/C to debt has been below 14% downgrade threshold in some years

» Heightened social risk due to state led decarbonization goals

Rating outlook

The stable outlook reflects our expectation that NW Natural's track record of supportive regulatory outcomes will continue over the next several years. We expect credit metrics to improve to levels that are more commensurate with its current ratings, including a ratio of CFO pre-WC to debt ranging between 16% and 18% over the next 12 to 18 months with a stronger longer-term run rate in the 17% to 19% range.

Factors that could lead to an upgrade

A rating upgrade could occur if NW Natural's regulatory environment remains credit supportive and metrics improve such that its CFO pre-WC to debt ratio increases to 18% or above on a sustained basis.

Factors that could lead to a downgrade

A rating downgrade could occur if NW Natural's regulatory environment becomes less credit supportive. A rating downgrade could also be considered if CFO pre-WC to debt falls below 14%.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the issuer/deal page on https://ratings.moodys.com for the most updated credit rating action information and rating history.

Key indicators

Exhibit 2

Northwest Natural Gas Company [1]

	2020	2021	2022	2023	2024	LTM
CFO Pre-W/C + Interest / Interest	4.8x	5.8x	4.4x	4.5x	4.4x	5.0x
CFO Pre-W/C / Debt	12.4%	17.3%	13.2%	15.9%	15.0%	19.0%
CFO Pre-W/C – Dividends / Debt	8.5%	13.5%	9.0%	10.1%	10.8%	14.3%
Debt / Capitalization	55.2%	52.5%	49.3%	50.0%	49.9%	44.8%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics™

Profile

Northwest Natural Gas Company (NW Natural) is a natural gas local distribution company (LDC), serving 807,000 customers in Oregon (about 88% of utility margins) and Washington (about 12% of utility margins). NW Natural is regulated by the Oregon Public Utility Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC).

NW Natural's parent, Northwest Natural Holding Company (NW Holdings), is a holding company headquartered in Portland, Oregon and owns NW Natural (largest subsidiary), SiEnergy, NW Natural Water Company, LLC (NW Natural Water), NW Natural Renewables Holdings, LLC (NW Natural Renewables), and other businesses and activities.

Detailed credit considerations

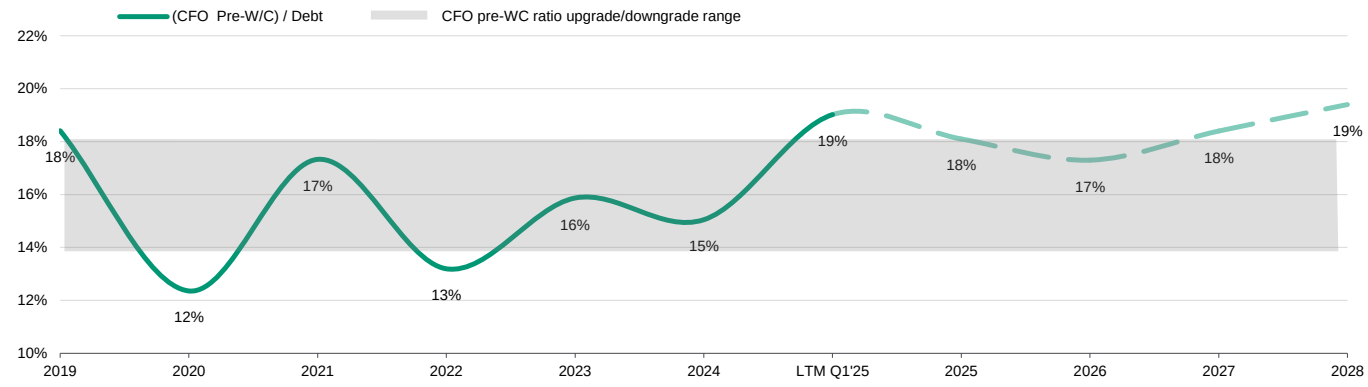
Improving financial performance driven by constructive regulatory proceedings

Over the past five years, NW Natural's credit metrics have experienced significant volatility, primarily driven by one-time events and the company's strategic investments in technology. These investments increased regulatory lag, with the utility's CFO pre-working capital (pre-WC) to debt ratio averaging approximately 15% from 2020 through 2024, falling below the 14% downgrade threshold in some years. However, in its 2024 general rate case, NW Natural received regulatory approval to recover these investments. Combined with a temporary reduction in debt, this led to a recent improvement in the CFO pre-WC to debt ratio, which rose to 19% on a last twelve months ending 31 March 2025.

We expect NW Natural's credit metrics to improve over the next several years driven by more timely recovery of cash flow as a result of supportive general rate case outcomes. As shown in Exhibit 3, we project the CFO pre-WC to debt ratio for the next 12 to 18 months to be between 16% and 18% with a longer-term run rate ranging between 17% and 19%, at or slightly above the 18% upgrade threshold. These estimates include capital expenditures for the next five years (2025-2029) of about $1.6 billion, an average of about $320 million annually. This compares to about $1.5 billion, or an average of about $300 million annually, from 2020 to 2024.

Exhibit 3

Improving credit metrics driven by credit supportive regulatory outcomes
Historical and projected CFO pre-WC to debt ratio, upgrade/downgrade threshold range



The range indicated is one of several factors that could lead to an upgrade or downgrade of the ratings if the CFO pre-WC to debt ratio is above or below the level for a sustained period
Source: Moody's Ratings

The utility had two years (2020 and 2022) where CFO pre-WC to debt dropped below 14%. In 2020, the utility's cash flow was affected by the coronavirus pandemic as well as debt levels that increased to ensure adequate liquidity that year amid pandemic uncertainties. The pandemic-related debt was subsequently repaid in 2021. In 2022, the weak metrics were due to cost inflation pressures, primarily within materials used in field work, higher natural gas prices and related short term debt to cover these gas costs. Notably, these were pressures that plagued the entire industry during most of 2022. Favorably, the utility was able to recover the deferred costs within a year as reflected in its stronger credit metrics for 2023.

Supportive legislative and regulatory framework in both Oregon and Washington

NW Natural's low business risk profile is supported by gas distribution operations that receive supportive regulatory treatment from the Oregon Public Utility Commission (OPUC) and Washington Utilities and Transportation Commission (WUTC), which allows for several cost recovery mechanisms that help provide stability and predictability of the utility's cash flow.

Oregon

Since 88% of the utility's margins are derived from Oregon customers, the legislative and regulatory support that NW Natural receives from the OPUC is a fundamental credit driver. In general, NW Natural has cooperative relationships with stakeholders in the state and has been able to negotiate supportive rate case outcomes and obtain tracking mechanisms for its most material costs.

The most important cost recovery mechanisms include: the use of forward test years for capital expenditures; a weather adjusted rate mechanism (WARM); a conservation tariff (i.e., revenue decoupling); purchased gas adjustment (PGA); utility gas reserve investments included in rate base; and a Site Remediation and Recovery Mechanism (SRRM), primarily for the recovery of manufactured gas plant environmental expenditures. These various cost recovery mechanisms help support recovery of the most significant costs that NW Natural faces.

The utility filed its most recent Oregon general rate case in December 2024 and entered into a stipulation, subject to commission approval, with parties that included a 50% equity layer as well as a 9.5% ROE (increase from 9.4%) and a $21 million revenue increase. NW Natural's original request included a $59.4 million revenue increase, a 10.4% ROE and 52% equity layer. Because the utility requested a higher equity layer, NW Natural reduced its debt to align with the requested capital structure. Although we view a higher equity ratio as more credit supportive, we view the stipulated filing as credit supportive despite the 50% equity ratio and lower revenue increase than requested.

NW Natural's last general rate case concluded in an all-party settlement agreement, that was approved by the OPUC in October 2024. The order authorized a $95 million revenue increase (10.2%) and a 9.4% ROE and 50% equity layer. The initial request included a $154.9 million revenue increase (16.6%), a 10.10% ROE, 50% equity layer and a $2.14 billion rate base. NW Natural's initial filing represented the largest base rate increase requested in recent years, underscoring the inflationary pressures that the utility was facing.

Washington

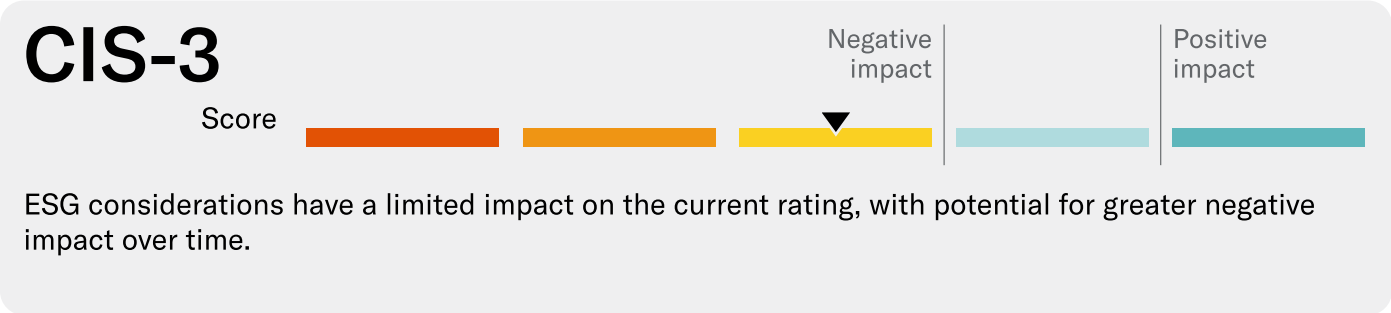
In October 2021, it most recent rate order, the WUTC authorized an annual revenue requirement increase over two years; a 6.4% or $5 million increase in the first year, effective 1 November 2021, and up to a 3.5% or $3 million increase in the second year beginning 1 November 2022. The order was based on an average rate base of $247.3 million.

The filing was based on system investments including costs associated with resiliency and reliability, consumer focused technology and building improvements and upgrades. The WUTC order did not specify the underlying inputs of the cost of capital such as capital structure and ROE. This multiyear rate case was filed for the recovery of investments and costs for system resiliency and reliability as well as for headquarter leasehold improvements and rent costs. It also provided for recovery of upgrades to the Vancouver, Washington service center.

ESG considerations

Northwest Natural Gas Company's ESG credit impact score is CIS-3

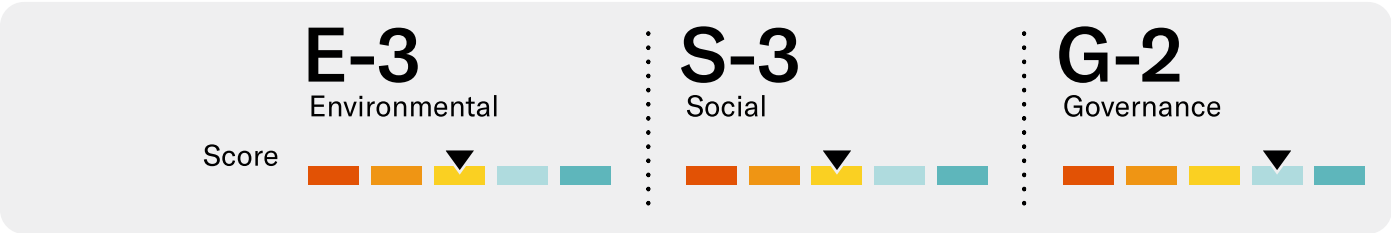
Exhibit 4
ESG credit impact score



Source: Moody's Ratings

NW Natural's **CIS-3** indicates its ESG considerations that have a limited impact on the current rating, with greater potential for future negative impact over time. The utility's scores reflect a combination of higher risk exposure to carbon transition, physical climate and demographic and societal trends.

Exhibit 5
ESG issuer profile scores



Source: Moody's Ratings

Environmental

NW Natural's **E-3** issuer profile score is driven by its higher risk exposure to carbon transition and physical climate risks. Favorably, the company has a strong track record of meeting established emissions targets set by legislative (Oregon Senate Bill 98) and regulatory policies. NW Natural established a Low Carbon Savings goal of 30% by 2035 that includes customers emissions and a goal of being a carbon neutral provider by 2050. This will be achieved through increasing the use of renewable natural gas as well as hydrogen blending. Although the utility is exposed to moderately high physical climate risks, the company worked to mitigate these risks by removing all bare steel pipe from its system by completing the multi-year investment in 2015. Additionally, the system is predominantly underground, which makes the infrastructure more resilient and less vulnerable to weather or other events that could disrupt power to the region.

Social

NW Natural's **S-3** issuer profile score reflects higher risk to responsible production and demographics and societal trends that increase public concern over environmental, social, or affordability issues that could lead to adverse regulatory political intervention. These risks are balanced by neutral to low exposure to health and safety, human capital, and customer relations. NW Natural has historically worked collaboratively with its regulator to make energy transition as affordable as possible for customers and we see this trend continuing as the company executes on its energy transmission goals over the next several years. Additionally, the company has a strong hedging program including storage and contracts that draw from a diverse supply to ensure reliability and reduce commodity risk

Governance

NW Natural's **G-2** issuer profile score is broadly in line with other utilities and does not pose a particular risk. This is supported by neutral to low exposure to financial strategy and risk management and management credibility and track record.

ESG Issuer Profile Scores and Credit Impact Scores for the rated entity/transaction are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for the entity/transaction on MDC and view the ESG Scores section.

Liquidity analysis

NW Natural maintains adequate liquidity through the use of external credit facilities and market issuances to fund negative free cash flow. As of the last twelve months ending 31 March 2025, NW Natural's internal liquidity included about $82 million of cash on hand and produced about $290 million in cash flow from operations; this compares to about $365 million in capital expenditures and $70 million in dividends for the same last twelve month period, resulting in approximately $150 million of negative free cash flow.

The utility has access to a $400 million revolving credit agreement. In December 2024, the agreement was amended with a new maturity date of 3 November 2027, with an option to extend one additional year, subject to lender approval. The credit agreement includes a feature that allows NW Natural to request an increase in the total amount up to $600 million. The credit agreement also permits the issuance of letters of credit in an aggregate amount of up to $60 million.

In January 2024, the utility entered into an uncommitted letter of credit and reimbursement agreement. Although there is no expressly stated maximum amount of letters of credit that can be issued or outstanding under the facility due to current regulatory authority from the OPUC, the sum of LCs outstanding cannot exceed $100 million at any one time. As of 31 March 2025, NW Natural did not have any outstanding balance drawn under its credit facility or letters of credit. The primary restrictive covenant for both agreements requires the company to maintain a debt to capitalization ratio of 70% or less, which NW Natural was in compliance with at 31 March 2025 (47.4%).

NW Natural's next debt maturities are in September 2025 and December 2025, when $20 million and $10 million of senior secured notes are due, respectively.

Rating methodology and scorecard factors

Exhibit 6
Methodology Scorecard Factors
Northwest Natural Gas Company

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 3/31/2025		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	4.7x	A	4.5x - 5.5x	A
b) CFO pre-WC / Debt (3 Year Avg)	16.8%	Baa	16% - 18%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	11.9%	Baa	11% - 15%	Baa
d) Debt / Capitalization (3 Year Avg)	47.5%	A	47% - 50%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching	0	0	0	0
a) Scorecard-Indicated Outcome		A3		A3
b) Actual Rating Assigned				(P)Baa1

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 3/31/2025(L)
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures
Source: Moody's Financial Metrics

Appendix

Exhibit 7

Cash Flow and Credit Metrics [1]

CF Metrics (in $ millions)	2020	2021	2022	2023	2024	LTM
FFO	**184**	**227**	**207**	**241**	**245**	**294**
+/- Other	(8)	25	(8)	13	11	4
CFO Pre-WC	**176**	**252**	**199**	**254**	**256**	**297**
+/- ΔWC	(3)	(105)	(53)	29	(4)	17
CFO	**173**	**148**	**146**	**283**	**252**	**315**
- Div	55	56	63	92	73	74
- Capex	267	280	320	293	356	368
FCF	(149)	(189)	(237)	(102)	(178)	(127)
(CFO Pre-W/C) / Debt	12.4%	17.3%	13.2%	15.9%	15.0%	19.0%
(CFO Pre-W/C - Dividends) / Debt	8.5%	13.5%	9.0%	10.1%	10.8%	14.3%
FFO / Debt	12.9%	15.6%	13.7%	15.1%	14.4%	18.8%
RCF / Debt	9.0%	11.8%	9.5%	9.3%	10.1%	14.0%
Revenue	759	843	1,014	1,159	1,100	1,127
Interest Expense	46	53	59	74	76	75
Net Income	78	85	86	95	85	110
Total Assets	3,599	3,898	4,453	4,511	4,756	4,768
Total Liabilities	2,764	2,921	3,262	3,279	3,432	3,251
Total Equity	835	978	1,191	1,233	1,324	1,516

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months.
Source: Moody's Financial Metrics™

Exhibit 8

Peer Comparison Table [1]

	Northwest Natural Gas Company (P)Baa1 Stable			Berkshire Gas Company A3 Negative			Wisconsin Gas LLC A3 Stable			Southwest Gas Corporation Baa1 Stable		
(in $ millions)	FY Dec-23	FY Dec-24	LTM Mar-25	FY Dec-23	FY Dec-24	LTM Mar-25	FY Dec-23	FY Dec-24	LTM Mar-25	FY Dec-23	FY Dec-24	LTM Mar-25
Revenue	1,159	1,100	1,127	97	93	102	770	680	746	2,500	2,475	2,169
CFO Pre-W/C	254	256	297	20	14	16	154	303	332	525	559	579
Total Debt	1,602	1,701	1,564	93	118	112	1,112	1,112	1,078	3,621	3,603	3,604
CFO Pre-W/C + Interest / Interest	4.5x	4.4x	5.0x	5.9x	3.8x	4.2x	4.9x	7.6x	8.2x	4.3x	4.3x	4.3x
CFO Pre-W/C / Debt	15.9%	15.0%	19.0%	21.6%	11.5%	14.6%	13.9%	27.2%	30.8%	14.5%	15.5%	16.1%
CFO Pre-W/C – Dividends / Debt	10.1%	10.8%	14.3%	21.6%	11.5%	14.6%	-1.5%	20.0%	17.8%	10.3%	10.6%	11.0%
Debt / Capitalization	50.0%	49.9%	44.8%	33.5%	36.8%	34.7%	41.2%	39.2%	38.2%	47.9%	46.8%	45.7%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade
Source: Moody's Financial Metrics™

Ratings

Exhibit 9

Category	Moody's Rating
NORTHWEST NATURAL GAS COMPANY	
Outlook	Stable
First Mortgage Bonds	A2
Senior Secured	A2
Senior Unsecured MTN	(P)Baa1
Pref. Shelf	(P)Baa3
Commercial Paper	P-2

Source: Moody's Ratings

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REPORT NUMBER 1453262

S&P Global
Ratings

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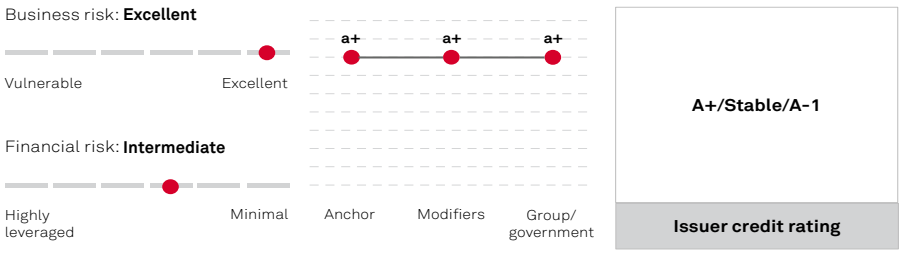
Northwest Natural Gas Co.

June 25, 2025

Ratings Score Snapshot



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Credit Highlights

Overview

Key strengths	Key risks
Low-risk natural gas distribution operations with limited unregulated storage operations.	Limited geographic and regulatory diversity.
Effective management of regulatory risks with operations under the credit-supportive regulatory frameworks in Washington and Oregon.	Decarbonization initiatives that pressure future growth.
Insulating measures that we assess as sufficient to rate the company above its parent's group credit profile.	Continued negative discretionary cash flow over the next few years, indicating external funding needs.

We continue to monitor the ongoing Oregon rate case proceedings. On June 23, 2025, Northwest Natural Gas Co. (NWNG), and certain parties filed a stipulation in the company's 2024 rate case filing for a revenue increase of $21.3 million (about 35% of the company's original request). The stipulation is based on a modestly improved return on equity (ROE) of 9.5% and maintaining the 50% equity structure. While the stipulated revenue increase appears modest, it is in line with our base-case expectations, and we believe it will continue to support credit quality. We expect the stipulation, subject to approval by the Public Utility Commission of Oregon (OPUC), will be in effect by year-end 2025. We also believe items not addressed in the

stipulation, will be subject to ongoing litigation process. This current filing follows a $95 million rate case order based on a settlement that was approved in late 2024. We assessed this previous rate case order as supportive of credit quality and expect that the company will continue to effectively manage regulatory risk.

We view the insulating measures in place as sufficient to rate NWNG two-notches above the 'a-' group credit profile on parent Northwest Natural Holding Co. (NWNH). Our analysis incorporates our 'a+' stand-alone credit profile (SACP) on NWNG and the cumulative value of the insulating and regulatory measures in place. NWNG has the following insulating measures:

- NWNG's financial performance and funding prospects are independent from those of NWNH.
- NWNG issues its own debt and has its own credit facility.
- NWNG is regulated by the Oregon and Washington regulatory commissions.
- NWNG has dividend restrictions. It must maintain 45% equity before distributing any dividends upstream if its secured issue-level ratings are below 'A-', maintain 46% equity if its secured issue-level ratings are below 'BBB'. No dividends are allowed if its equity falls below 44% or the secured issue-level ratings drop below 'BBB-'.
- NWNG's board of directors is highly independent with eight independent directors on a board of 10.
- Independent directors on NWNG's board have effective influence on decisions, and their votes are required for a voluntary bankruptcy filing.
- NWNG is unlikely to be drawn or forced into a NWNH bankruptcy due to absence of cross-default provisions.
- An independent third party holds the "golden share" vote required to file for a bankruptcy filing.

Outlook

The stable rating outlook on NWNG reflects our base-case assumption that the company will generate sufficient cash flow to maintain appropriate consolidated financial measures for the current rating, including funds from operations (FFO) to debt of 15%-17% through 2027. The stable outlook also reflects our expectation of continued strong operating performance and effective management of regulatory risk.

Downside scenario

We could lower our rating on NWNG over the next 24 months if:

- The company's consolidated financial performance consistently weakens such that FFO to debt falls below 15%; or
- The company's business risk increases. This could reflect higher risks due to decarbonization mandates and potential gas bans, a weakening of the company's effective management of regulatory risk, or an inability to consistently earn its authorized ROE.

Upside scenario

We could raise our rating on NWNG over the next 12-24 months if the company's financial performance improves such that FFO to debt is consistently above 21%, with no increase to business risk.

Our Base-Case Scenario

Assumptions

- Modest customer growth and continued use of regulatory mechanisms.
- Continued negative discretionary cash flow through 2027.
- Annual capital spending averaging about $350 million through 2027.
- Annual dividends averaging about $85 million.
- All debt maturities refinanced.

Northwest Natural Gas Co.--Forecast summary

Period ending	Dec-31-2021	Dec-31-2022	Dec-31-2023	Dec-31-2024	Dec-31-2025	Dec-31-2026	Dec-31-2027
(Mil. $)	2021a	2022a	2023a	2024a	2025e	2026f	2027f
Adjusted ratios							
Debt/EBITDA (x)	4.8	4.8	4.9	4.8	4.5-5.0	4.5-5.0	4.0-4.5
FFO/debt (%)	15.3	16.9	14.0	14.6	15-17	15-17	15-17
FFO cash interest coverage (x)	5.4	5.6	4.1	4.8	4.5-5.0	4.5-5.0	4.5-5.0

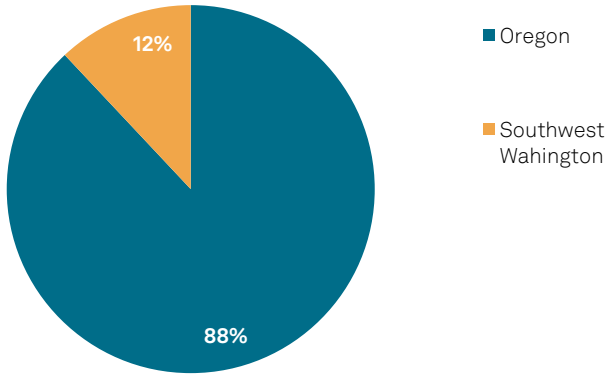
*All figures adjusted by S&P Global Ratings, unless stated as reported. a--Actual. e--Estimate. f--Forecast. FFO--Funds from operations to debt.

Company Description

NWNG operates as a regulated natural gas distribution company, providing natural gas service to approximately 805,000 residential, commercial, and industrial customers in Oregon and Southwest Washington through 14,400 miles of pipeline systems. Residential customers generate 65% of its margin, 24% from commercial customers, and 6% from industrial customers.

Northwest Natural Gas Co.'s customers by geographic area

As of Dec. 31, 2024.



Source: Company filings.

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Peer Comparison

Northwest Natural Gas Co.--Peer Comparisons

	Northwest Natural Gas Co.	ONE Gas Inc.	Atmos Energy Corp.	Piedmont Natural Gas Co. Inc.
Foreign currency issuer credit rating	A+/Stable/A-1	A-/Stable/A-2	A-/Stable/A-2	BBB+/Stable/A-2
Local currency issuer credit rating	A+/Stable/A-1	A-/Stable/A-2	A-/Stable/A-2	BBB+/Stable/A-2
Period	Annual	Annual	Annual	Annual
Period ending	2024-12-31	2024-12-31	2024-09-30	2024-12-31
Mil.	$	$	$	$
Revenue	1,100	2,040	4,151	1,729
EBITDA	341	673	2,070	902
Funds from operations (FFO)	239	550	1,714	670
Interest	69	140	213	194
Cash interest paid	63	144	341	184
Operating cash flow (OCF)	232	337	1,736	652
Capital expenditure	354	695	2,922	1,017
Free operating cash flow (FOCF)	(122)	(357)	(1,187)	(365)
Discretionary cash flow (DCF)	(196)	(508)	(1,680)	(475)
Cash and short-term investments	20	58	307	2
Gross available cash	20	58	307	2
Debt	1,635	2,844	7,743	4,704
Equity	1,324	3,105	12,158	4,354
EBITDA margin (%)	30.9	33.0	49.9	52.2
Return on capital (%)	6.9	6.9	7.6	7.9
EBITDA interest coverage (x)	4.9	4.8	9.7	4.6

Northwest Natural Gas Co.--Peer Comparisons				
FFO cash interest coverage (x)	4.8	4.8	6.0	4.6
Debt/EBITDA (x)	4.8	4.2	3.7	5.2
FFO/debt (%)	14.6	19.3	22.1	14.2
OCF/debt (%)	14.2	11.9	22.4	13.9
FOCF/debt (%)	(7.4)	(12.6)	(15.3)	(7.8)
DCF/debt (%)	(12.0)	(17.9)	(21.7)	(10.1)

Business Risk

We assess NWNG's business risk based on its low-risk regulated gas distribution operations accounting for about 95% of consolidated operating revenue, residential-focused customer base, and effective management of regulatory risks.

The company benefits from stable and supportive regulatory environments in both jurisdictions in which it operates, with purchased gas adjustments and environmental cost recovery, decoupling, and a forward-looking test year in Oregon and multiyear rate case fillings in Washington. We view these mechanisms as supportive of its financial measures, allowing the company to mitigate regulatory lag. In addition, 90% of the margin is generated from residential and commercial customers, providing a stable margin profile.

Northwest Natural Gas Co.'s natural gas distribution by segment

As of Dec. 31, 2024

Source: Company filings.

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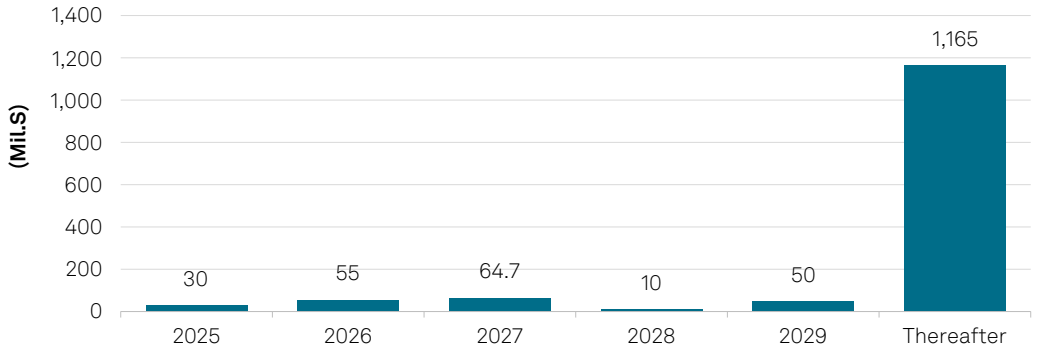
Financial Risk

Under our base case, we assess NWNG using our low-volatility table, reflecting the low-risk nature of its natural gas distribution operations and effective management of regulatory risk. NWNG's 2024 stand-alone FFO to debt was 14.6%, and we expect it to strengthen modestly over our forecast period but remain in the middle of the range for its financial risk profile category. Specifically, we project FFO-to-debt in the range of 15%-17% through 2027. Our assumptions include the 2024 and 2025 Oregon rate case increases, annual capital spending averaging about

$350 million, and annual dividends averaging about $85 million through 2027. We expect a majority of the capital spending to fund replacing and improving system reliability.

Debt maturities

Northwest Natural Gas Co.'s debt maturity schedule
As of Dec. 31, 2024



Source: Company filings.

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Northwest Natural Gas Co.--Financial Summary

Period ending	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022	Dec-31-2023	Dec-31-2024
Reporting period	2019a	2020a	2021a	2022a	2023a	2024a
Display currency (mil.)	$	$	$	$	$	$
Revenues	740	759	843	1,014	1,159	1,100
EBITDA	245	257	286	292	316	341
Funds from operations (FFO)	202	207	211	236	218	239
Interest expense	41	44	49	52	66	69
Cash interest paid	40	44	48	51	70	63
Operating cash flow (OCF)	191	148	143	146	283	232
Capital expenditure	221	274	280	319	291	354
Free operating cash flow (FOCF)	(31)	(126)	(137)	(173)	(8)	(122)
Discretionary cash flow (DCF)	(84)	(182)	(193)	(236)	(100)	(196)
Cash and short-term investments	6	10	12	13	20	20
Gross available cash	6	10	12	13	20	20
Debt	1,066	1,353	1,379	1,397	1,553	1,635
Common equity	822	835	978	1,191	1,233	1,324
Adjusted ratios						
EBITDA margin (%)	33.0	33.9	33.9	28.8	27.2	30.9
Return on capital (%)	8.3	7.4	7.5	7.2	7.6	6.9
EBITDA interest coverage (x)	5.9	5.9	5.9	5.6	4.8	4.9
FFO cash interest coverage (x)	6.0	5.7	5.4	5.6	4.1	4.8
Debt/EBITDA (x)	4.4	5.3	4.8	4.8	4.9	4.8

Northwest Natural Gas Co.--Financial Summary

FFO/debt (%)	18.9	15.3	15.3	16.9	14.0	14.6
OCF/debt (%)	17.9	10.9	10.3	10.5	18.2	14.2
FOCF/debt (%)	(2.9)	(9.3)	(9.9)	(12.4)	(0.5)	(7.4)
DCF/debt (%)	(7.9)	(13.4)	(14.0)	(16.9)	(6.4)	(12.0)

Reconciliation Of Northwest Natural Gas Co. Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Financial year	Dec-31-2024									
Company reported amounts	1,502	1,324	1,100	330	190	63	341	231	73	354
Cash taxes paid	-	-	-	-	-	-	(39)	-	-	-
Cash interest paid	-	-	-	-	-	-	(57)	-	-	-
Lease liabilities	77	-	-	-	-	-	-	-	-	-
Operating leases	-	-	-	8	6	6	(6)	2	-	-
Postretirement benefit obligations/ deferred compensation	113	-	-	-	-	-	-	-	-	-
Accessible cash and liquid investments	(20)	-	-	-	-	-	-	-	-	-
Share-based compensation expense	-	-	-	3	-	-	-	-	-	-
Nonoperating income (expense)	-	-	-	-	2	-	-	-	-	-
Debt: Debt serviced by third parties	(38)	-	-	-	-	-	-	-	-	-
Total adjustments	133	-	-	10	8	6	(102)	2	-	-
S&P Global Ratings adjusted	**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
	1,635	1,324	1,100	341	197	69	239	232	73	354

Liquidity

As of March 31, 2025, we assess NWNG's liquidity as adequate, with sources covering uses by more than 1.1x over the coming 12 months, even if forecast consolidated EBITDA declines 10%. We believe the predictable regulatory framework for NWNG provides a manageable level of cash flow stability even in times of economic stress, supporting our use of slightly lower thresholds to

assess liquidity. In addition, NWNG can absorb high-impact, low-probability events, reflecting that the company maintains about $400 million in committed credit facilities through 2027. It also reflects our belief that the company can lower its high capital spending (averaging about $350 million annually through 2027) during stressful periods, indicating a limited need for refinancing under such conditions. Furthermore, our assessment reflects the company's generally prudent risk management and sound relationships with its banking group (which includes over four well-established banks).

Overall, we believe that the company can withstand adverse market circumstances over the next 12 months, with sufficient liquidity to meet its obligations. The company has no big long-term debt maturity coming due, and we expect it to proactively address this maturity well in advance of its scheduled due date.

Principal liquidity sources

- Cash and cash equivalents of about $81.8 million as of March 31, 2025;
- Credit facility availability of about $400 million; and
- Cash FFO estimated of about $280 million.

Principal liquidity uses

- Debt maturities of about $30 million;
- Capital expenditure of about $360 million; and
- Dividend payments of about $80 million

Environmental, Social, And Governance

ESG factors have no material influence on our credit rating analysis of NWNG.

Group Influence

Under our group rating methodology, we consider NWNH as the parent of the group with a GCP of 'a-'. We assess NWNG as a core subsidiary of NWNH because we view the utility as integral to the group's identity, highly unlikely to be sold, and having a strong commitment from NWNH's senior management, given the company's emphasis on maintaining its strategic focus on regulated gas distribution operations.

That said, our issuer credit rating on NWNG is two notches above the parent's GCP. Because NWNG is operationally separate from NWNH and there are certain regulatory restrictions in place, which we view the utility as having sufficient insulating measures that allow NWNG to be rated up to two notches above the NWNH's GCP. These regulatory protections include dividend restrictions, a highly independent board, and an independent third party that is the holder of the "golden share" whose vote is required to file for bankruptcy.

Issue Ratings--Subordination Risk Analysis

Capital structure

The short-term rating on NWNG is 'A-1' based on our 'A+' issuer credit rating on the company.

Analytical conclusions

We rate the company's medium-term notes program 'A+', equal to its issuer credit rating, because we view any debt issued under this program as debt issued by a qualifying investment-grade utility.

Issue Ratings--Recovery Analysis

Key analytical factors

NWNG's first-mortgage bonds benefit from a first-priority lien on substantially all of the utility's real property, owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue rating one notch above the issuer credit rating.

Rating Component Scores	
Foreign currency issuer credit rating	**A+/Stable/A-1**
Local currency issuer credit rating	**A+/Stable/A-1**
Business risk	**Excellent**
Country risk	Very Low
Industry risk	Very Low
Competitive position	Strong
Financial risk	**Intermediate**
Cash flow/leverage	Intermediate
Anchor	**a+**
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)
Liquidity	Adequate (no impact)
Management and governance	Neutral (no impact)
Comparable rating analysis	Neutral (no impact)
Stand-alone credit profile	**a+**
Group credit profile	**a-**
Entity status within group	**Insulated (Same as SACP)**

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, April 4, 2024
- Criteria | Corporates | General: Corporate Methodology, Jan. 7, 2024
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019

- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings Detail (as of June 24, 2025)*

Northwest Natural Gas Co.	
Issuer Credit Rating	A+/Stable/A-1
Commercial Paper	
Local Currency	A-1
Senior Secured	AA-
Issuer Credit Ratings History	
19-Apr-2024	A+/Stable/A-1
09-Oct-2023	A+/Negative/A-1
25-Jan-2010	A+/Stable/A-1
Related Entities	
Northwest Natural Holding Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Junior Subordinated	BBB

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings' credit ratings on the global scale are comparable across countries. S&P Global Ratings' credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

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MOODY'S
RATINGS

Rating Action: Moody's Ratings affirms Northwest Natural Gas Company's ratings; outlook stable

02 Jul 2025

Approximately $1.4 billion of debt instruments affected

New York, July 02, 2025 -- Moody's Ratings (Moody's) has affirmed Northwest Natural Gas Company's (NW Natural) ratings, including its A2 senior secured rating, (P)Baa1 senior unsecured shelf rating and P-2 short-term rating for commercial paper. The outlook is stable. A full list of affected ratings is included at the end of this press release.

RATINGS RATIONALE

"We expect NW Natural's financial performance to improve over the next several years driven by timely cash flow generation and credit supportive regulatory proceedings," stated Edna Marinelarena, Moody's Ratings Assistant Vice President. The utility's cash flow from operations before changes in working capital (CFO pre-WC) to debt ratio has averaged about 15% over the last three years, ending at 15% in 2024. As of the last twelve months ending 31 March 2025, the ratio increased to 19%.

The recent improvement is attributed to stronger cash flow generation and temporarily reduced debt levels, aligning the utility's capital structure to a higher equity layer of 52%, as filed in their most recent general rate case. NW Natural entered into a stipulation, subject to commission approval, with parties in its 2025 rate case that included a 50% equity layer as well as a 9.5% ROE (increase from 9.4%) and a $21 million revenue increase. Although we view a higher equity ratio as a credit positive because it supports higher required revenue and reduces reliance on debt, which helps to support stronger credit metrics, we view the 2025 rate case settlement as constructive.

Because of its supportive regulatory outcomes, we expect NW Natural's financial profile to improve over the next several years. We estimate that the CFO pre-WC to debt ratio will range between 16% and 18% over the next 12 to 18 months with a stronger longer-term run rate ranging between 17% and 19%. These estimates include an about $1.6 billion capital expenditure plan (2025-2029), which is consistent with the last five-year capex spend of $1.5 billion (2019-2024). We estimate funding at 50% equity and 50% debt as in prior years.

The ratings incorporate NW Natural's low business risk as a local gas distribution company (LDC) operating in generally supportive regulatory environments. Oregon's suite of cost recovery mechanisms and constructive stakeholder relationships have supported NW Natural's solid, albeit volatile, cash flow generation over the years.

Outlook

The stable outlook reflects our expectation that NW Natural's track record of supportive regulatory outcomes will continue over the next several years. We expect credit metrics to improve to levels that are more commensurate with its current ratings, including a ratio of CFO pre-WC to debt ranging between 16% and 18% over the next 12 to 18 months with a stronger longer-term run rate in the 17% to 19% range.

FACTORS THAT COULD LEAD TO AN UPGRADE OR DOWNGRADE OF THE RATINGS

Factors that could lead to an upgrade

A rating upgrade could occur if NW Natural's regulatory environment remains credit supportive and metrics improve such that its CFO pre-WC to debt ratio increases to 18% or above on a sustained basis.

Factors that could lead to a downgrade

A rating downgrade could occur if NW Natural's regulatory environment becomes less credit supportive. A rating downgrade could also be considered if CFO pre-WC to debt falls below 14%.

Northwest Natural Gas Company (NW Natural) is a natural gas local distribution company (LDC), serving 807,000 customers in Oregon (about 88% of utility margins) and Washington (about 12% of utility margins). NW Natural is regulated by the Oregon Public Utility Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC).

NW Natural's parent, Northwest Natural Holding Company (NW Holdings), is a holding company headquartered in Portland, Oregon and owns NW Natural (largest subsidiary), SiEnergy, NW Natural Water Company, LLC (NW Natural Water), NW Natural Renewables Holdings, LLC (NW Natural Renewables), and other businesses and activities.

LIST OF AFFECTED RATINGS

Issuer: Northwest Natural Gas Company

..Affirmations:

.... Senior Unsecured Shelf, Affirmed (P)Baa1

.... Senior Unsecured Medium-Term Note Program, Affirmed (P)Baa1

.... Preferred Shelf, Affirmed (P)Baa3

.... Senior Secured First Mortgage Bonds, Affirmed A2

.... Senior Secured Regular Bond/Debenture, Affirmed A2

.... Senior Secured Medium-Term Note Program, Affirmed (P)A2

.... Senior Secured Shelf, Affirmed (P)A2

.... Commercial Paper, Affirmed P-2

..Outlook Actions:

....Outlook, Remains Stable

The principal methodology used in these ratings was Regulated Electric and Gas Utilities published in August 2024 and available at https://ratings.moodys.com/rmc-documents/426183. Alternatively, please see the Rating Methodologies page on https://ratings.moodys.com for a copy of this methodology.

The net effect of any adjustments applied to rating factor scores or scorecard outputs under the primary methodology(ies), if any, was not material to the ratings addressed in this announcement.

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MOODY'S RATINGS

CREDIT OPINION
30 July 2024

Update

Send Your Feedback

RATINGS

Northwest Natural Gas Company

Domicile	Portland, Oregon, United States
Long Term Rating	(P)Baa1
Type	Senior Unsec. Shelf - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Northwest Natural Gas Company

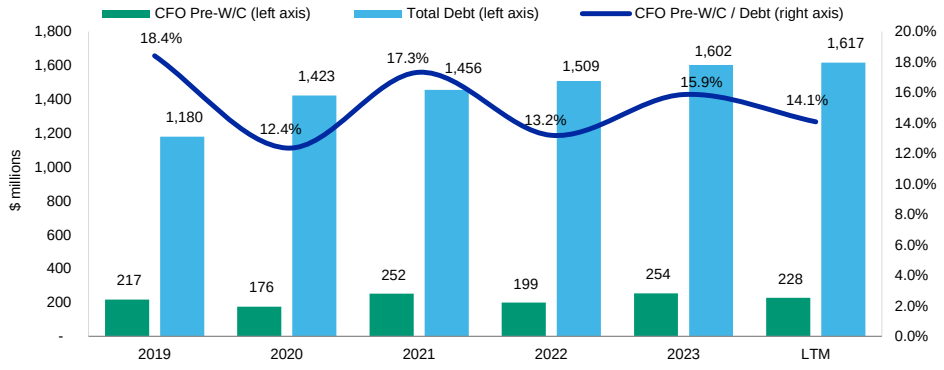
Update to credit analysis

Summary

Northwest Natural Gas Company's (NW Natural, Baa1 stable) credit profile reflects the low business risk nature of its business as a local gas distribution company (LDC) operating in generally constructive regulatory environments. In particular, Oregon's suite of cost recovery mechanisms and constructive stakeholder relationships have supported the utility's solid cash flow generation and financial metrics.

Because of its supportive regulatory outcomes, NW Natural has historically sustained credit metrics, including a cash flow from operations before changes in working capital (CFO pre-WC) to debt ratio, in the mid to high teens range over the last several years. The years of financial declines were due to one time events including the coronavirus pandemic (2020) and an increase in commodity prices that drove an increase in gas cost deferrals (2022). Favorably, the utility was authorized full recovery of these costs thereby driving the improvement in the utility's credit metrics in 2023. We expect NW Natural's financial profile to remain consistent over the next several years.

Exhibit 1
Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt ($ MM)



Source: Moody's Financial Metrics™

Credit strengths

» Low business risk local gas distribution company

» Supportive regulatory jurisdiction, including cost tracking mechanisms and legislation that can help investment prospects

» Good stakeholder relationships and ongoing dialogue to resolve most issues

Credit challenges

» Elevated social risk due to higher scrutiny on natural gas as an energy source

» Long-term risks associated with environmental remediation costs and emission reduction requirements

Rating outlook

The stable outlook reflects our expectation that NW Natural's track record of solid financial performance and credit supportive regulatory outcomes will continue over the next several years. We see credit metrics sustaining at levels sufficient for the current credit profile including a ratio of CFO pre-WC to debt in the mid-teens percent range over the longer-term.

Factors that could lead to an upgrade

A rating upgrade could occur if NW Natural's credit metrics improve such that CFO pre-WC to debt ratio increases to 18% and CFO pre-WC less dividends to debt is consistently above 14%.

Factors that could lead to a downgrade

A rating downgrade could occur if NW Natural's regulatory environment becomes less credit supportive, including material environmental challenges where costs cannot be recovered due to state emission reduction requirements. A rating downgrade could also be considered if CFO pre-WC to debt is sustained below 14%.

Key indicators

Exhibit 2

Northwest Natural Gas Company [1]

	2019	2020	2021	2022	2023	LTM
CFO Pre-W/C + Interest / Interest	5.5x	4.5x	5.8x	4.4x	4.5x	4.0x
CFO Pre-W/C / Debt	18.4%	12.4%	17.3%	13.2%	15.9%	14.1%
CFO Pre-W/C – Dividends / Debt	13.9%	8.5%	13.5%	9.0%	10.1%	8.3%
Debt / Capitalization	51.2%	55.2%	52.5%	49.3%	50.0%	49.3%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics™

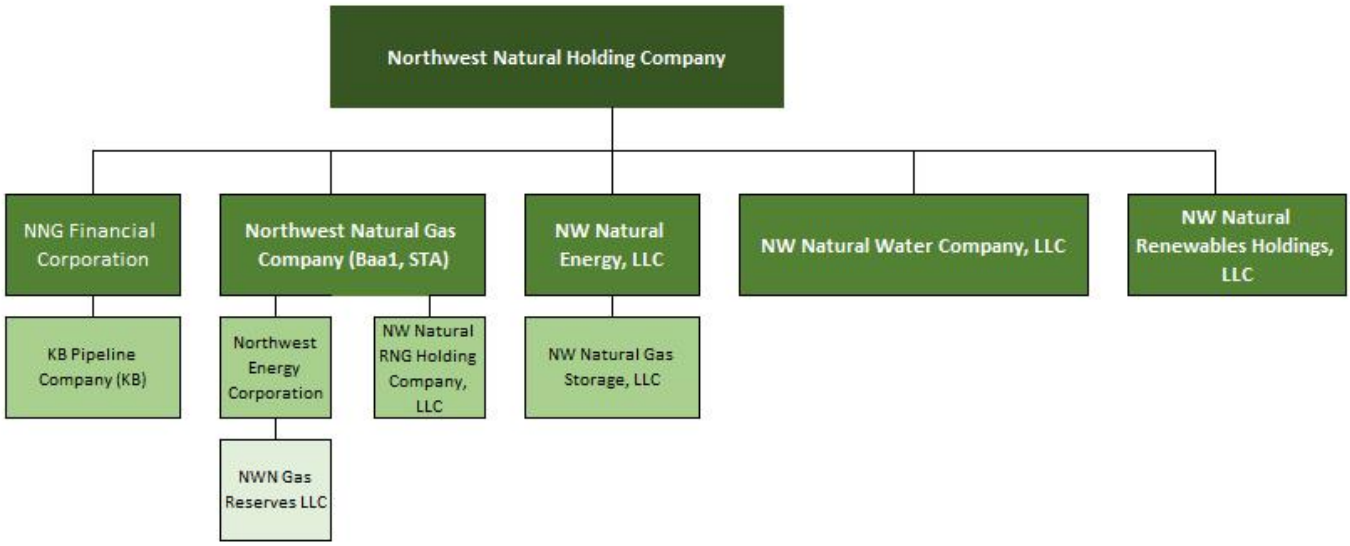
Profile

Northwest Natural Gas Company (NW Natural) is a natural gas local distribution company (LDC), serving 800,000 customers in Oregon (about 88% of utility margins) and Washington (about 12% of utility margins). NW Natural is regulated by the Oregon Public Utility Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC).

NW Natural's parent, Northwest Natural Holding Company (NW Holdings), is a holding company headquartered in Portland, Oregon and owns NW Natural, NW Natural Water Company, LLC (NWN Water), NW Natural Renewables Holdings, LLC, and other businesses and activities. NW Natural is NW Holdings' largest subsidiary and an illustrative organizational chart is shown in Exhibit 3.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the issuer/deal page on https://ratings.moodys.com for the most updated credit rating action information and rating history.

Exhibit 3
NW Natural simplified organizational chart



Source: NW Natural presentation

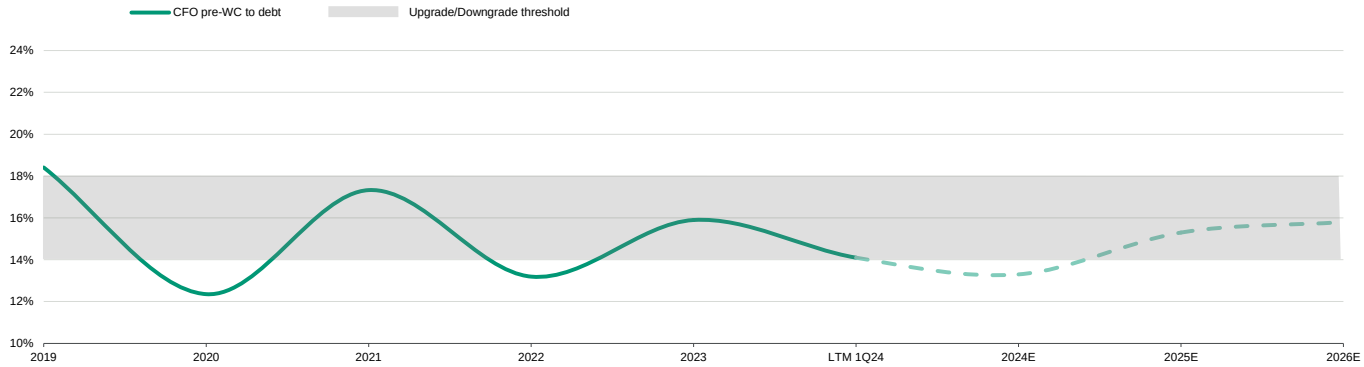
Detailed credit considerations

Consistent track record of solid financial performance expected to continue

NW Natural has a strong track record of producing solid financial performance as a result of its credit supportive regulatory framework and balanced fiscal policies. Over the last five years, the utility averaged about $220 million in cash flow from operations. This led to an average CFO pre-WC to debt ratio of about 15% from 2019 to 2023. As of the last twelve months ending 31 March 2024, the ratio was about 14%, as shown in Exhibit 4.

For 2024, credit metrics may fall to about 13% due to higher debt issued in 2023 and pressured cash flow due to higher O&M costs. NW Natural has a pending general rate case that is expected to conclude in a constructive manner with new rates effective November 2024; coupled with lower capital expenditures starting in 2025, we see credit metrics including its CFO pre-WC to debt ratio improving and sustaining in the 15% range over the next several years.

Exhibit 4
Consistent credit metrics expected over next several years
Historical and projected CFO pre-WC to debt ratio, upgrade/downgrade threshold range



The range indicated is one of several factors that could lead to an upgrade or downgrade of the ratings if the CFO pre-WC to debt ratio is above or below the level for a sustained period.
Source: Moody's Ratings

NW Natural's capital expenditures have averaged about $275 million from 2019 to 2023. In 2022 and 2023, capital spending increased to $319 million and $291 million, respectively. For 2024, NW Natural is projecting about $360 million. Capex has increased largely due to investments in technology of which much of it was related to the federal cybersecurity mandates. With the conclusion of these major projects, from 2025 to 2027, capital expenditures are projected to decrease totaling about $900 million or an average of about $225 million annually.

The utility had two years over this period where credit metrics dropped below 14% (its established downgrade threshold). In 2020, the utility's cash flow was affected by the impacts from the coronavirus pandemic as well as debt levels that increased to ensure adequate liquidity for the year amid the pandemic uncertainties. The pandemic-related debt was subsequently repaid in 2021. In 2022, the weaker metrics were due to cost inflation pressures, primarily within the materials used in field work, higher natural gas prices and related short term debt to cover the initial cost. Notably, these were pressures that plagued the industry during most of 2022. Favorably, the utility was able to recover the deferred costs within a year as reflected in its stronger credit metrics for 2023.

Supportive legislative and regulatory framework in Oregon and Washington

NW Natural's low business risk profile is supported by gas distribution operations that receive supportive regulatory treatment from the Oregon Public Utility Commission (OPUC) and Washington Utilities and Transportation Commission (WUTC), which allows for several cost recovery mechanisms that help provide stability and predictability of the utility's cash flow.

Oregon

Since 88% of the utility's margins are derived from Oregon customers, the legislative and regulatory support that NW Natural receives from the OPUC is a fundamental credit driver for the utility. In general, NW Natural has cooperative relationships with stakeholders in the state and has been able to negotiate constructive rate case outcomes and acquire tracking mechanisms for its most material costs.

The most important cost recovery mechanisms include: NW Natural's use of forward test years for capital expenditures; weather adjusted rate mechanism (WARM); conservation tariff (i.e., revenue decoupling); purchased gas adjustment (PGA); utility gas reserve investments included in rate base; and a Site Remediation and Recovery Mechanism (SRRM), primarily for the recovery of manufactured gas plant environmental expenditures. These various cost recovery mechanisms help support recovery of the most significant costs that NW Natural faces.

The utility filed its most recent Oregon general rate case on 29 December 2023 requesting $154.9 million revenue increase (16.6%), a 10.10% ROE, 50% equity layer and a $2.14 billion rate base. On 24 July 2024, NW Natural entered into an all-party settlement agreement that included a $95 million revenue increase (10.2%) and a 9.4% ROE and 50% equity layer, which remain unchanged. If approved by the OPUC, we view the settlement as credit supportive and consistent with prior rate case outcomes that have also been constructive. It also illustrates NW Natural's robust relationship with its regulatory authority. NW Natural's initial filing represented the largest base rate increase requested in recent years, underscoring the inflationary pressures the utility has been navigating. NW Natural expects new rates to take effect 1 November 2024.

From a legislative perspective, Oregon has frequently been on the forefront of progressive environmental measures, including the 2019 passage of Senate Bill 98 (SB 98), which allows utilities to acquire renewable natural gas (RNG) on behalf of customers. In July 2020, the parameters surrounding the rulemaking for RNG cost recovery were determined, which allowed for NW Natural to sign its first RNG investment in December 2020. We see this as an important step in supporting ongoing investment and growth for NW Natural in the face of the threat of electrification. The state support for RNG development can be a helpful tool for the company to maintain its place as a significant energy provider for customers, at the same time as state reduces carbon and methane emissions.

We also view the company as having low stranded asset risk given the state's policy goals of advancing renewable natural gas as a form of decarbonization and OPUC ongoing support of cost recovery for these projects. In the 2021 general rate case, the OPUC approved the recovery of costs associated with the Lexington RNG facility under Senate Bill 98 and authorized the adoption of an automatic adjustment clause that allows the utility to add costs associated with its renewable natural gas projects to rates annually on 1 November.

Washington

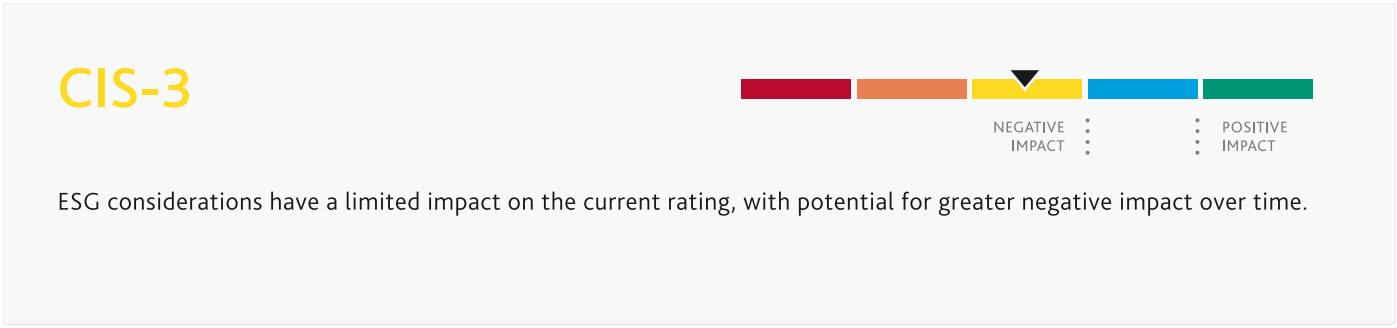
In October 2021, the WUTC issued an order authorizing an annual revenue requirement increase over two years; a 6.4% or $5 million increase in the first year, effective 1 November 2021, and up to a 3.5% or $3 million increase in the second year beginning 1 November

2022. The order was based on an average rate base of $247.3 million. The filing was based on system investments including costs associated with resiliency and reliability, consumer focused technology and building improvements and upgrades. The new WUTC order does not specify the underlying inputs of the cost of capital such as capital structure and ROE. This multiyear rate case is purposed to recover investments and costs for system resiliency and reliability as well as headquarter leasehold improvements and rent costs. It also provides for recovery of upgrades to the Vancouver, Washington service center.

ESG considerations

Northwest Natural Gas Company's ESG credit impact score is CIS-3

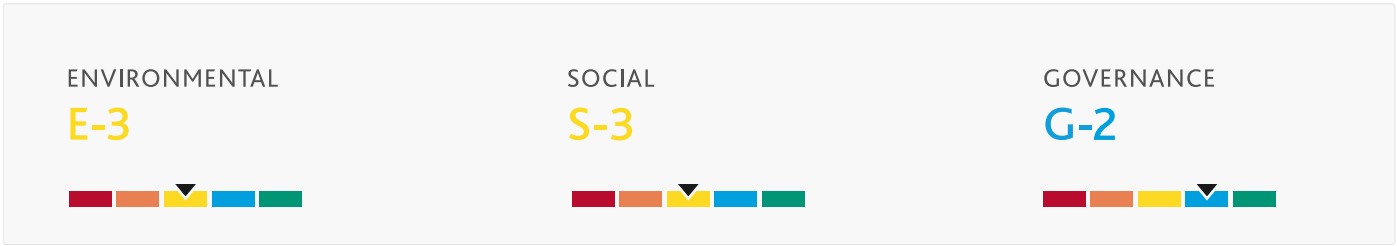
Exhibit 5
ESG credit impact score



Source: Moody's Ratings

NW Natural's **CIS-3** indicates that its ESG attributes are overall considered as having a limited impact on the current rating, with greater potential for future negative impact over time. The utility's scores reflect a combination of higher risk exposure to carbon transition, physical climate and demographic and societal trends.

Exhibit 6
ESG issuer profile scores



Source: Moody's Ratings

Environmental

NW Natural's **E-3** issuer profile score is driven by its moderately negative carbon transition and physical climate risks. Favorably, the company has a strong track record of meeting established emissions targets set by legislative (Oregon Senate Bill 98) and regulatory policies. NW Natural established a Low Carbon Savings goal of 30% by 2035 that includes customers emissions and a goal of being a carbon neutral provider by 2050. This will be achieved through increasing the use of renewable natural gas as well as hydrogen blending. Although the utility is exposed to moderately high physical climate risks, the company worked to mitigate these risks by removing all bare steel pipe from its system by completing the multi-year investment in 2015. Additionally, the system is predominantly underground, which makes the infrastructure more resilient and less vulnerable to weather or other events that could disrupt power to the region.

Social

NW Natural's **S-3** issuer profile score reflects higher risk to responsible production and demographics and societal trends that increase public concern over environmental, social, or affordability issues that could lead to adverse regulatory political intervention. These

risks are balanced by neutral to low exposure to health and safety, human capital, and customer relations. NW Natural has historically worked collaboratively with its regulator to make energy transition as affordable as possible for customers and we see this trend continuing as the company executes on its energy transmission goals over the next several years. Additionally, the company has a strong hedging program including storage and contracts that draw from a diverse supply to ensure reliability and reduce commodity risk

Governance

NW Natural's **G-2** issuer profile score is broadly in line with other utilities and does not pose a particular risk. This is supported by neutral to low exposure to financial strategy and risk management and management credibility and track record.

ESG Issuer Profile Scores and Credit Impact Scores for the rated entity/transaction are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for the entity/transaction on MDC and view the ESG Scores section.

Liquidity analysis

NW Natural maintains adequate liquidity through the use of external credit facilities and market issuances to fund negative free cash flow. As of the last twelve months ending 31 March 2024, NW Natural's internal liquidity included about $62 million of cash on hand and produced about $225 million in cash flow from operations; this compares to about $299 million in capital expenditures and $94 million in dividends for the same last twelve month period.

The utility has access to a $400 million revolving credit agreement that expires on 3 November 2026. The credit agreement includes a feature that allows NW Natural to request an increase to the total amount up to $600 million as well as request to extend the agreement for two additional one-year periods, subject to lender approval. Additionally, the credit agreement also permits the issuance of letters of credit in an aggregate amount of up to $60 million. As of 31 March 2024, NW Natural did not have any outstanding balance drawn under its credit facility or letters of credit. The primary restrictive covenant requires the company to maintain a debt to capitalization ratio of 70% or less, which NW Natural was in compliance with at 31 March 2024 (52.1%).

NW Natural's next debt maturities are due in September 2025 and December 2025, when $20 million and $10 million of senior secured notes are due, respectively.

Rating methodology and scorecard factors

Exhibit 7
Methodology Scorecard Factors
Northwest Natural Gas Company

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 3/31/2024		Moody's 12-18 Month Forward View As of 7/8/2024 [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	A	A
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	4.6x	A	4.5x - 5.5x	A
b) CFO pre-WC / Debt (3 Year Avg)	15.0%	Baa	15% - 19%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	10.3%	Baa	10% - 13%	Baa
d) Debt / Capitalization (3 Year Avg)	49.4%	A	48% - 50%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching	0	0	0	0
a) Scorecard-Indicated Outcome		A3		A3
b) Actual Rating Assigned				(P)Baa1

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 3/31/2024(L)
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures
Source: Moody's Financial Metrics

Appendix

Exhibit 8

Cash Flow and Credit Metrics [1]

CF Metrics (in $ millions)	2019	2020	2021	2022	2023	LTM
FFO	**219**	**184**	**227**	**207**	**238**	**223**
+/- Other	(2)	(8)	25	(8)	16	4
CFO Pre-WC	**217**	**176**	**252**	**199**	**254**	**228**
+/- ΔWC	(20)	(3)	(105)	(53)	29	(1)
CFO	**198**	**173**	**148**	**146**	**283**	**227**
- Div	53	55	56	63	92	94
- Capex	226	267	280	320	293	301
FCF	(82)	(149)	(189)	(237)	(102)	(168)
(CFO Pre-W/C) / Debt	18.4%	12.4%	17.3%	13.2%	15.9%	14.1%
(CFO Pre-W/C - Dividends) / Debt	13.9%	8.5%	13.5%	9.0%	10.1%	8.3%
FFO / Debt	18.6%	12.9%	15.6%	13.7%	14.9%	13.8%
RCF / Debt	14.1%	9.0%	11.8%	9.5%	9.1%	8.0%
Revenue	740	759	843	1,014	1,159	1,127
Interest Expense	48	51	53	59	74	75
Net Income	81	75	85	86	95	88
Total Assets	3,321	3,599	3,898	4,453	4,511	4,495
Total Liabilities	2,505	2,764	2,921	3,262	3,279	3,212
Total Equity	816	835	978	1,191	1,233	1,282

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months.
Source: Moody's Financial Metrics™

Exhibit 9

Peer Comparison Table [1]

	Northwest Natural Gas Company (P)Baa1 Stable			Berkshire Gas Company A3 Stable			Wisconsin Gas LLC A3 Stable			Southwest Gas Corporation Baa1 Stable		
(in $ millions)	FY Dec-22	FY Dec-23	LTM Mar-24	FY Dec-22	FY Dec-23	LTM Mar-24	FY Dec-22	FY Dec-23	LTM Mar-24	FY Dec-22	FY Dec-23	LTM Mar-24
Revenue	1,014	1,159	1,127	102	97	91	917	770	681	1,935	2,500	2,638
CFO Pre-W/C	199	254	228	18	20	20	170	154	154	449	525	510
Total Debt	1,509	1,602	1,617	80	93	96	1,081	1,112	1,080	3,648	3,621	3,622
CFO Pre-W/C + Interest / Interest	4.4x	4.5x	4.0x	6.3x	5.9x	5.4x	8.9x	4.9x	4.7x	4.6x	4.3x	4.3x
CFO Pre-W/C / Debt	13.2%	15.9%	14.1%	21.9%	21.6%	20.6%	15.7%	13.9%	14.3%	12.3%	14.5%	14.1%
CFO Pre-W/C – Dividends / Debt	9.0%	10.1%	8.3%	9.5%	21.6%	20.6%	10.2%	-1.5%	11.0%	9.0%	10.3%	9.7%
Debt / Capitalization	49.3%	50.0%	49.3%	31.5%	33.5%	33.4%	42.0%	41.2%	39.5%	52.9%	47.9%	47.1%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade
Source: Moody's Financial Metrics™

Ratings

Exhibit 10

Category	Moody's Rating
NORTHWEST NATURAL GAS COMPANY	
Outlook	Stable
First Mortgage Bonds	A2
Senior Secured	A2
Senior Unsecured MTN	(P)Baa1
Pref. Shelf	(P)Baa3
Commercial Paper	P-2

Source: Moody's Ratings

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REPORT NUMBER 1414632

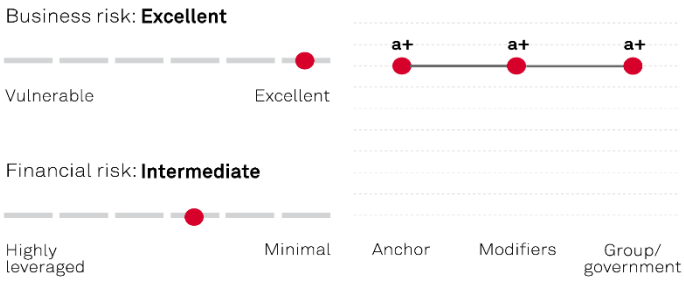
S&P Global
Ratings

RatingsDirect®

Northwest Natural Gas Co.

June 24, 2024

Ratings Score Snapshot



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Credit Highlights

Overview

Key strengths	Key risks
Primarily low-risk natural gas distribution operations with limited unregulated storage operations.	Limited geographic and regulatory diversity.
Effective management of regulatory risks with operations under the credit-supportive regulatory frameworks in Washington and Oregon.	Decarbonization initiatives add pressure to earnings and limit future growth.
Residential-focused customer base, which provides some cash flow stability.	Continued negative discretionary cash flow over the next few years, indicating external funding needs.

We continue to monitor the Oregon rate application. Northwest Natural Gas. Co. (NWNG) requested a revenue increase of about $154.9 million, along with a return on equity (ROE) of 10.1%, to which intervener proposed a rate change of about $74.2 million, along with an ROE of

9.2%, much lower than the initial request. The rate application, which includes the recovery of expenses such as operation and maintenance, taxes, and depreciation, could potentially result in an average customer bill increase of about 18%. Under our base case, we expect an outcome that is consistent with the historical rate applications in Oregon.

We consider NWNG to be insulated from its parent, Northwest Natural Holding Co. (NWNH). Based on the strength of the insulating measures, NWNG could potentially be rated up to two notches higher than NWNH's group credit profile (GCP). Currently, NWNG is rated only one notch higher than its GCP, limited by its 'a+' stand-alone credit profile.

Outlook

The stable rating outlook on NWNG reflects our base case assumption that the company will generate sufficient cash flows to maintain appropriate consolidated financial measures for the current rating, including funds from operations (FFO) to debt of 15%-18% through 2026. The stable outlook also reflects our expectation of strong operating performance and effective management of regulatory risk.

Downside scenario

We could lower our rating on NWNG over the next 24 months if the company's consolidated financial performance weakened such that FFO to debt remained consistently below 15%. We could also lower our rating if the company's business risk increased. This could reflect higher risks due to decarbonization mandates and potential gas bans, a weakening of the company's management of regulatory risk, or an inability to consistently earn its authorized ROE.

Upside scenario

We could raise our rating on NWNG over the next 12-24 months if the company's financial performance improved such that FFO to debt were consistently above 21%, with no weakening of business risk.

Our Base-Case Scenario

Assumptions

- Modest customer growth and continued use of regulatory mechanisms.
- Continued negative discretionary cash flow through 2026.
- Annual capital spending averaging about $330 million through 2026.
- Annual dividends averaging about $80 million.
- All debt maturities refinanced.

Key metrics

Northwest Natural Gas Co. --Key Metrics*

	2023a	2024e	2025f	2026f

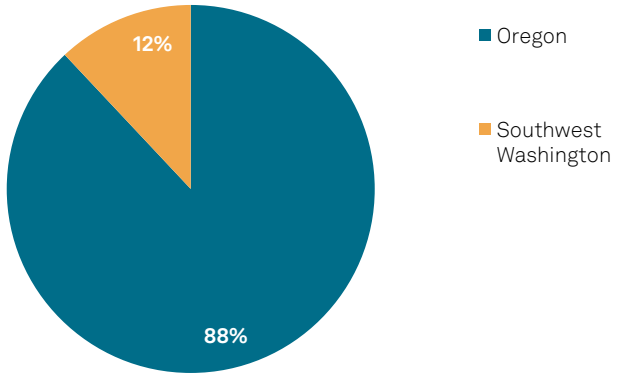
FFO to debt (%)	15	15-17	17-19	17-19
Debt to EBITDA (x)	4.6	4.5-5.0	4.0-4.5	4.0-4.5

*All figures adjusted by S&P Global Ratings. a--Actual. e--Estimate. f--Forecast. FFO--Funds from operations.

Company Description

NWNG operates as a regulated natural gas distribution company, providing natural gas service to approximately 799,000 residential, commercial, and industrial customers in Oregon and southwest Washington through 14,200 miles of pipeline systems. Approximately 88% of the company's customers are in Oregon and 12% are in southwest Washington.

Northwest Natural Gas Co.'s Customers by geographic area



Source: Company filings.

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Peer Comparison

Northwest Natural Gas Co.--Peer Comparisons

	Northwest Natural Gas Co.	ONE Gas Inc.	Atmos Energy Corp.	Piedmont Natural Gas Co. Inc.

Northwest Natural Gas Co.--Peer Comparisons

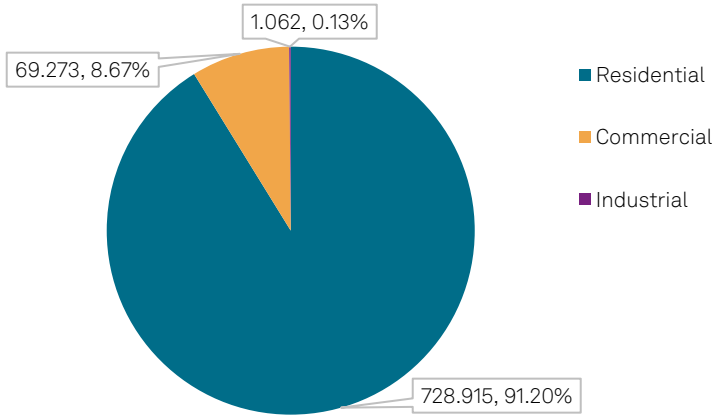
Foreign currency issuer credit rating	A+/Stable/A-1	A-/Stable/A-2	A-/Stable/A-2	BBB+/Stable/A-2
Local currency issuer credit rating	A+/Stable/A-1	A-/Stable/A-2	A-/Stable/A-2	BBB+/Stable/A-2
Period	Annual	Annual	Annual	Annual
Period ending	2023-12-31	2023-12-31	2023-09-30	2023-12-31
Mil.	$	$	$	$
Revenue	1,159	2,327	4,274	1,628
EBITDA	316	633	1,725	804
Funds from operations (FFO)	218	539	1,429	606
Interest	66	105	163	174
Cash interest paid	70	73	281	170
Operating cash flow (OCF)	283	911	3,471	756
Capital expenditure	291	661	2,790	1,028
Free operating cash flow (FOCF)	(8)	250	681	(272)
Discretionary cash flow (DCF)	(100)	103	250	(272)
Cash and short-term investments	20	19	15	0
Gross available cash	20	19	15	0
Debt	1,459	2,647	6,775	4,137
Equity	1,233	2,766	10,870	4,052
EBITDA margin (%)	27.2	27.2	40.3	49.4
Return on capital (%)	7.7	6.9	6.5	7.8
EBITDA interest coverage (x)	4.8	6.0	10.6	4.6
FFO cash interest coverage (x)	4.1	8.4	6.1	4.6
Debt/EBITDA (x)	4.6	4.2	3.9	5.1
FFO/debt (%)	15.0	20.4	21.1	14.6
OCF/debt (%)	19.4	34.4	51.2	18.3
FOCF/debt (%)	(0.5)	9.4	10.0	(6.6)
DCF/debt (%)	(6.8)	3.9	3.7	(6.6)

Business Risk

We assess NWNG’s business risk based on its low-risk regulated gas distribution operations accounting for about 98% of consolidated operating revenue, residential-focused customer base, and effective management of regulatory risks. NWNG provides natural gas service to approximately 799,000 customers, with 65% of its margin generated from residential customers, 24% from commercial customers, and 6% from industrial customers. Residential and commercial customers accounted for slightly more than 60% of natural gas distribution volumes delivered. Almost 60% of the gas supply was from Canada while most of the rest was from the U.S. Rocky Mountain region. The company benefits from stable and supportive regulatory environments in both jurisdictions in which it operates, with purchased gas adjustments and environmental cost recovery, decoupling, and a forward-looking test year in Oregon and multiyear rate case fillings in Washington. We view these mechanisms as supportive of its financial measures, allowing the company to mitigate regulatory lag. In addition, NWNG has continued its strategy to diversify its business operations by purchasing small, regulated water utilities. Given the low-risk nature of water utilities, we view NWNG's entry into the

regulated water utility space as a modest positive for its business risk profile. These factors support our view of the company's business risk profile at the stronger end of the excellent category.

Northwest Natural Gas Co.'s natural gas distribution segment customers
As of Dec. 31, 2023 (000s)



Source: Company filings.

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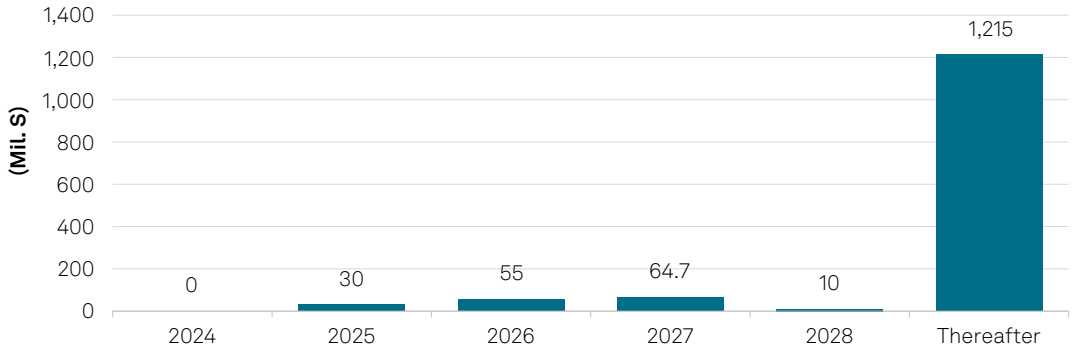
Financial Risk

Under our base case scenario, we assess NWNG using our low-volatility table, reflecting the low-risk nature of its natural gas distribution operations and effective management of regulatory risk. We incorporate our assumptions, including the continued use of regulatory mechanisms and rate riders to effectively manage regulatory risk, annual capital spending averaging about $320 million, and annual dividends averaging about $80 million through 2026. NWNG plans to invest about 65% of capital spending in replacing and enhancing systems and technologies. We expect FFO to debt in the middle of the intermediate financial risk profile range, with FFO to debt about 15%-18% throughout 2026.

Our base case forecast includes the continued use of regulatory mechanisms and rate riders to effectively manage regulatory risk, annual capital spending averaging about $330 million, and annual dividends averaging about $75 million. We expect NWNG's stand-alone financial measures to remain in the middle range of its financial risk profile category such that FFO to debt is 15%-18% through 2026.

Debt maturities

Northwest Natural Gas Co.'s Debt maturity schedule



Source: Company filings.

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Northwest Natural Gas Co.--Financial Summary

Period ending	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022	Dec-31-2023
Reporting period	2018a	2019a	2020a	2021a	2022a	2023a
Display currency (mil.)	$	$	$	$	$	$
Revenues	706	740	759	843	1,014	1,159
EBITDA	226	245	257	286	292	316
Funds from operations (FFO)	157	202	207	211	236	218
Interest expense	43	41	44	49	52	66
Cash interest paid	41	40	44	48	51	70
Operating cash flow (OCF)	173	191	148	143	146	283
Capital expenditure	214	221	274	280	319	291
Free operating cash flow (FOCF)	(41)	(31)	(126)	(137)	(173)	(8)
Discretionary cash flow (DCF)	(80)	(84)	(182)	(193)	(236)	(100)
Cash and short-term investments	8	6	10	12	13	20
Gross available cash	8	6	10	12	13	20
Debt	1,121	1,066	1,353	1,379	1,397	1,459
Common equity	716	822	835	978	1,191	1,233
Adjusted ratios						
EBITDA margin (%)	32.0	33.0	33.9	33.9	28.8	27.2
Return on capital (%)	8.0	8.3	7.4	7.5	7.2	7.7
EBITDA interest coverage (x)	5.3	5.9	5.9	5.9	5.6	4.8
FFO cash interest coverage (x)	4.8	6.0	5.7	5.4	5.6	4.1
Debt/EBITDA (x)	5.0	4.4	5.3	4.8	4.8	4.6

Northwest Natural Gas Co.--Financial Summary

FFO/debt (%)	14.0	18.9	15.3	15.3	16.9	15.0
OCF/debt (%)	15.4	17.9	10.9	10.3	10.5	19.4
FOCF/debt (%)	(3.7)	(2.9)	(9.3)	(9.9)	(12.4)	(0.5)
DCF/debt (%)	(7.1)	(7.9)	(13.4)	(14.0)	(16.9)	(6.8)

Reconciliation Of Northwest Natural Gas Co. Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Financial year	Dec-31-2023									
Company reported amounts	1,382	1,233	1,159	305	186	61	316	282	92	291
Cash taxes paid	-	-	-	-	-	-	(28)	-	-	-
Cash interest paid	-	-	-	-	-	-	(64)	-	-	-
Lease liabilities	79	-	-	-	-	-	-	-	-	-
Operating leases	-	-	-	7	6	6	(6)	1	-	-
Postretirement benefit obligations/ deferred compensation	129	-	-	-	-	-	-	-	-	-
Accessible cash and liquid investments	(20)	-	-	-	-	-	-	-	-	-
Share-based compensation expense	-	-	-	3	-	-	-	-	-	-
Nonoperating income (expense)	-	-	-	-	12	-	-	-	-	-
Debt: other	(111)	-	-	-	-	-	-	-	-	-
Total adjustments	77	-	-	11	18	6	(98)	1	-	-

S&P Global Ratings adjusted	Debt	Equity	Revenue	EBITDA	EBIT	Interest expense	Funds from Operations	Operating cash flow	Dividends	Capital expenditure
	1,459	1,233	1,159	316	204	66	218	283	92	291

Liquidity

As of March 31, 2024, we assess NWNG's liquidity as adequate, with sources covering uses by 1.1x over the coming 12 months and covering uses even if forecast consolidated EBITDA declines by 10%. We believe the predictable regulatory framework for NWNG provides a manageable level of cash flow stability for the company even in times of economic stress, supporting our use of slightly lower thresholds to assess liquidity. In addition, NWNG has the ability to absorb high-impact, low-probability events, reflecting that the company maintains about $400 million in committed credit facilities through 2026. It also reflects our belief that the company can lower its high capital spending (averaging about $320 million annually through 2026) during stressful periods, indicative of a limited need for refinancing under such conditions. Furthermore, our assessment reflects the company's generally prudent risk management and sound

relationships with its banking group (which includes over four well-established banks). Overall, we believe that the company should be able to withstand adverse market circumstances over the next 12 months, with sufficient liquidity to meet its obligations. The company has no big long-term debt maturity coming due, and we expect it to proactively address this maturity well in advance of its scheduled due date.

Principal liquidity sources

- Cash and cash equivalents of about $61.9 million as of March 31, 2024;
- Credit facility of about $400 million; and
- Cash FFO estimated of about $245 million.

Principal liquidity uses

- Debt maturities of about $31.7 million,
- Capital expenditure of about $335 million,
- Working capital outflow of about $40 million, and
- Dividend payments of about $75 million.

Environmental, Social, And Governance

ESG factors have no material influence on our credit rating analysis of NWNG.

Group Influence

Under our group rating methodology, we consider NWNH as the parent of the group with a GCP of 'a-'. We assess NWNG as a core subsidiary of NWNH because we view the utility as integral to the group's identity, highly unlikely to be sold, and having a strong commitment from NWNH's senior management, given the company's emphasis on maintaining its strategic focus on regulated gas distribution operations.

Because NWNG is operationally separate from NWNH and there are certain regulatory restrictions in place, we view the utility as having sufficient insulating measures that allow NWNG to be rated potentially up to two notches above the NWNH group. These regulatory protections include dividend restrictions, a highly independent board, and an independent third party that is the holder of the "golden share" whose vote is required to file for bankruptcy. That said, our issuer credit rating on NWNG is limited to just one notch above the parent since NWNG's stand-alone credit profile reflects one-notch above the parent's GCP.

Issue Ratings--Subordination Risk Analysis

Capital structure

The short-term rating on NWNG is 'A-1' based on our 'A+' issuer credit rating on the company.

Analytical conclusions

We rate the company's medium-term notes program 'A+', equal to the issuer credit rating, because we view any debt issued under this program as debt issued by a qualifying investment-grade utility.

Issue Ratings--Recovery Analysis

Key analytical factors

NWNG's first-mortgage bonds benefit from a first-priority lien on substantially all of the utility's real property, owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue rating one notch above the issuer credit rating.

Rating Component Scores

Foreign currency issuer credit rating	**A+/Stable/A-1**
Local currency issuer credit rating	**A+/Stable/A-1**
Business risk	**Excellent**
Country risk	Very Low
Industry risk	Very Low
Competitive position	Strong
Financial risk	**Intermediate**
Cash flow/leverage	Intermediate
Anchor	**a+**
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)
Liquidity	Adequate (no impact)
Management and governance	Neutral (no impact)
Comparable rating analysis	Neutral (no impact)
Stand-alone credit profile	**a+**

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, April 4, 2024
- Criteria | Corporates | General: Corporate Methodology, Jan. 7, 2024
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings Detail (as of June 24, 2024)*

Northwest Natural Gas Co.

Issuer Credit Rating	A+/Stable/A-1
Commercial Paper	
Local Currency	A-1
Senior Secured	AA-

Issuer Credit Ratings History

19-Apr-2024	A+/Stable/A-1
09-Oct-2023	A+/Negative/A-1
25-Jan-2010	A+/Stable/A-1

Related Entities

Northwest Natural Holding Company

Issuer Credit Rating	A/Negative/--

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BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Brody J. Wilson

COST OF CAPITAL

Exh. BJW-3

August 29, 2025

NW Natural
NW Natural Credit Ratings 2022 - 2025

Debt Rating History

Standard & Poors

Rating Type	6/15/2022	6/15/2023	6/24/2024	6/25/2025
Outlook	Stable	Stable	Stable	Stable
Senior Secured LT Debt	AA-	AA-	AA-	AA-
Corporate Credit Rating	A+	A+	A+	A+
Short-Term	A-1	A-1	A-1	A-1

Moody's Investor Service

Rating Type	6/27/2022	7/19/2023	7/30/2024	7/8/2025
Outlook	Stable	Stable	Stable	Stable
Senior Secured LT Debt	A2	A2	A2	A2
Corporate Credit Rating	Baa1	Baa1	Baa1	Baa1
Short-Term	P-2	P-2	P-2	P-2

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Brody J. Wilson

COST OF CAPITAL

Exh. BJW-4C

REDACTED VERSION

August 29, 2025

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BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Brody J. Wilson

COST OF CAPITAL

Exh. BJW-5C

REDACTED VERSION

August 29, 2025

*** Budget adjusted for 48%/1%/51%

Month	Forecast or Actuals	Days	PROXY 2 Avg CP Bal	CP Rate	Interest	Fees	Interest + Fees
Jan-24	Actual	31	6,961,290	5.48%	32,317	62,776	95,093
Feb-24	Actual	29	14,500,000	5.53%	63,516	57,791	121,306
Mar-24	Actual	31	32,000,000	5.53%	149,884	61,765	211,649
Apr-24	Actual	30	18,123,333	5.53%	82,149	60,446	142,596
May-24	Actual	31	-	0.00%	-	61,439	61,439
Jun-24	Actual	30	-	0.00%	-	59,457	59,457
Jul-24	Actual	31	6,438,710	5.49%	29,950	61,439	91,390
Aug-24	Actual	31	42,103,226	5.49%	195,610	61,439	257,049
Sep-24	Actual	30	79,603,333	5.33%	347,712	60,457	408,169
Oct-24	Actual	31	109,806,452	5.13%	477,421	62,117	539,538
Nov-24	Actual	30	159,660,000	4.86%	635,879	60,113	695,992
Dec-24	Actual	31	154,716,129	4.80%	628,946	61,106	690,052
Jan-25	Actual	31	91,358,065	4.77%	370,032	72,282	442,315
Feb-25	Actual	28	8,553,571	4.68%	30,710	64,374	95,084
Mar-25	Actual	31	-	0.00%	-	69,271	69,271
Apr-25	Actual	30	-	0.00%	-	66,448	66,448
May-25	Actual	31	-	0.00%	-	73,795	73,795
Jun-25	Actual	30	-	0.00%	-	67,972	67,972
[redacted]							
Monthly Avg		30	34,576,039	4.09%	117,918	63,583	181,501
Embedded Rate			34,576,039	6.30%			181,501
							Embedded Rate
Test Year AMA 13-Month 3/31/2025			57,196,902	5.02%	239,446	62,516	301,962	6.3%
Rate Year 1: AMA 13-month Ending July 2027	[redacted]						
Rate Year 2: AMA 13-month Ending July 2028							
Rate Year 3: AMA 13-month Ending July 2029							

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Brody J. Wilson

COST OF CAPITAL

Exh. BJW-6C

REDACTED VERSION

August 29, 2025

GENERAL MARKET RATES

	2025			2026				2027				2028				2029				2030				2031				2032				2033			
Indices	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Fed Funds Effective (Avg)	[redacted]																																		
3-Month SOFR																																			
5 Year UST Note																																			
10 Year UST Note																																			
30 Year UST Bond																																			
3-Year Interporlation																																			

Source Bloomberg: As of 03/28/2025

GAS UTILITY RATES

	Commercial Paper STD SPREAD	[redacted]																																	
March 28, 2025 FORECAST	**TOTAL STD RATE**																																		
December 17, 2024 FORECAST																																			
2025 BUDGET																																			
Change December 17 to Budget																																			
Change December 17 to March 28																																			
	5 YR SPREAD																																		
March 28, 2025 FORECAST	**TOTAL 5 YR RATE**																																		
December 17, 2024 FORECAST																																			
2025 Budget																																			
Change December 17 to Budget																																			
Change December 17 to March 28																																			
	10 YR SPREAD																																		
March 28, 2025 FORECAST	**TOTAL 10 YR RATE**																																		
December 17, 2024 FORECAST																																			
2025 Budget																																			
Change December 17 to Budget																																			
Change December 17 to March 28																																			
	30 YR SPREAD																																		
March 28, 2025 FORECAST	**TOTAL 30 YR RATE**																																		
December 17, 2024 FORECAST																																			
2025 Budget																																			
Change December 17 to Budget																																			
Change December 17 to March 28																																			
March 28, 2025 FORECAST	**BLENDED RATE - 20 YR**																																		
December 17, 2024 FORECAST																																			
2025 Budget																																			
Change December 17 to Budget																																			
Change December 17 to March 28																																			

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Brody J. Wilson

COST OF CAPITAL

Exh. BJW-7C

REDACTED VERSION

August 29, 2025

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BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Direct Testimony of Jennifer E. Nelson

RATE OF RETURN ON EQUITY

Exh. JEN-1T

August 29, 2025

DIRECT TESTIMONY OF JENNIFER E. NELSON

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I. INTRODUCTION AND SUMMARY

Q. Please state your name, affiliation, and business address.

A. My name is Jennifer E. Nelson. I am a Vice President at Concentric Energy Advisors ("Concentric"). Concentric is a management consulting and economic advisory firm that specializes in the North American energy and water industries. Based in Marlborough, Massachusetts, Washington, D.C., and Calgary, Alberta, Concentric specializes in regulatory and litigation support, financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. Please describe your professional background and education.

A. I have more than fifteen years of experience in the energy industry, having served as a consultant and energy/regulatory economist for state government agencies. Since 2013, I have provided consulting services to utility and regulated energy clients on a range of financial and regulatory issues including cost of capital, ratemaking policy, and regulatory strategy issues. Prior to consulting, I was a staff economist at the Massachusetts Department of Public Utilities, and a petroleum economist for the State of Alaska. I completed utility regulatory training offered by New Mexico State University's Center for Public Utilities and earned the Certified Rate of Return Analyst designation from the Society of Utility and Regulatory Financial Analysts based on my experience and successful completion of an examination. A summary of my professional and educational background, including a list of my testimony filed before regulatory commissions, is included as Exh.JEN-2.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of Northwest Natural Gas Company ("NW Natural" or "the Company").

Q. Have you previously testified before the Washington Utilities and Transportation Commission (the "Commission")?

A. This is my first time submitting testimony before the Commission, however, I have filed testimony before 22 state regulatory commissions as detailed in Exh. JEN-2. During my time as a consultant, I have supported the development of expert witness testimony and analyses regarding the cost of capital (i.e., Return on Equity ("ROE") and capital structure) in more than 100 proceedings filed before numerous U.S. state regulatory commissions and the Federal Energy Regulatory Commission.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my Direct Testimony is to present evidence and provide a recommendation regarding an appropriate return on equity (ROE)[1] for the Company's regulated natural gas utility operations and to assess the reasonableness of the Company's proposed capital structure for ratemaking purposes. My analyses and conclusions are supported by the data presented in JEN-3 to JEN-12, which have been prepared by me or under my direction.

[1] Throughout my testimony, I use the terms "ROE" and "cost of equity" interchangeably.

Q. Please summarize your conclusions regarding the appropriate cost of equity and capital structure in this proceeding.

A. To develop my ROE recommendation, I rely on the results of three widely used market-based financial models applied to two proxy groups of companies comparable in risk to NW Natural: (1) the constant growth and quarterly growth forms of the Discounted Cash Flow ("DCF") model, (2) the traditional and empirical forms of the Capital Asset Pricing Model ("CAPM"), and (3) the Bond Yield Plus Risk Premium analysis. As shown in Figure 1, these models indicate a cost of equity in the range of 10.00 percent to 11.00 percent. Within this range, I conclude that 10.20 percent is a reasonable and conservative estimate of NW Natural's cost of equity.

Figure 1: Summary of Results[2]

	Including SWX in DCF		*Excluding SWX from DCF*	
Model	**Gas Proxy Group**	**Combined Proxy Group**	**Gas Proxy Group**	**Combined Proxy Group**
Constant Growth DCF	10.69%	10.17%	10.34%	10.06%
Quarterly Growth DCF	10.95%	10.33%	10.59%	10.23%
Average DCF	*10.82%*	*10.25%*	*10.47%*	*10.15%*
Blended CAPM	11.17%	11.12%	11.17%	11.12%
Historical CAPM	10.20%	10.16%	10.20%	10.16%
Blended ECAPM	11.75%	11.71%	11.75%	11.71%
Historical ECAPM	10.69%	10.66%	10.69%	10.66%
Average CAPM	*10.96%*	*10.91%*	*10.96%*	*10.91%*
Average Risk Premium	*10.24%*	*10.28%*	*10.24%*	*10.28%*
3-Model Average	*10.67%*	*10.48%*	*10.56%*	*10.45%*
ROE Range	**10.00% - 11.00%**			
Recommendation	**10.20%**			

[2] Exhs. JEN-4 to JEN-8. DCF and CAPM model results are the average of the mean and median proxy group results. Data as of June 30, 2025.

As part of its Multi-year Rate Plan, NW Natural is proposing to phase in its rate request, including the requested return. In this proceeding, the Company is requesting an ROE of 10.10 percent in Rate Year 1, and 10.20 percent in Rate Years 2 and 3, which are at the low end of the range of analytical results shown in Figure 1 and below the average of the three models (approximately 10.50 percent).

As to the Company's capital structure, the requested capital structure consisting of 51.00 percent common equity, 48.00 percent long-term debt and 1.00 percent short-term debt reflects its projected capital structure over the rate years and is somewhat more leveraged (i.e., contains more debt) than its gas utility peers on average. Accordingly, the Company's requested capital structure is reasonable and should be approved.

Q. How do you determine your recommendation from the results summarized above?

A. The cost of equity is an opportunity cost that cannot be precisely quantified. Therefore, it must be estimated using various financial models. Each of the ROE estimation models is subject to limiting assumptions and each provides a different perspective on investors' return requirements under varying market conditions. The use of multiple financial models, therefore, enables a robust and comprehensive assessment of the cost of equity instead of relying on one specific estimation model.

In addition to the analytical results summarized above, my recommendation considers the Company's (1) regulatory risk and the need to access capital to fund its capital expenditure program; (2) the risks associated with decarbonization policies; and (3) NW Natural's significantly smaller size relative to a group of proxy companies

to assist with determining the appropriate ROE. In a recent credit report for NW Natural, S&P Global Ratings ("S&P") noted a potential increase in the Company's business risk associated with ongoing decarbonization policy risks in Oregon and Washington.[3] Similarly, Moody's noted "[e]levated social risk due to higher scrutiny on natural gas as an energy source"[4] as a credit challenge for NW Natural. Moody's reiterated that view in its most recent credit opinion for the Company issued in July 2025.[5]

Lastly, my recommendation reflects the current capital market and macroeconomic environment in which utilities such as NW Natural operate. Although these factors are relevant to investors, their effect on the Company's cost of equity cannot be directly quantified and I have not made an explicit adjustment to my ROE recommendation to reflect these factors. As shown in Figure 1 above, an ROE of 10.20 percent is at the low end of the range of analytical results, and below the 3-model averages for the two proxy groups.

Q. Does your recommendation consider changes in economic and financial market conditions since NW Natural's recent rate cases?

A. Yes, it does. The cost of equity is forward-looking; as such, the relevant point of emphasis in the cost of equity estimation process is on forward-looking data and expectations. As shown in Figure 2 and Figure 3 below, government and utility bond

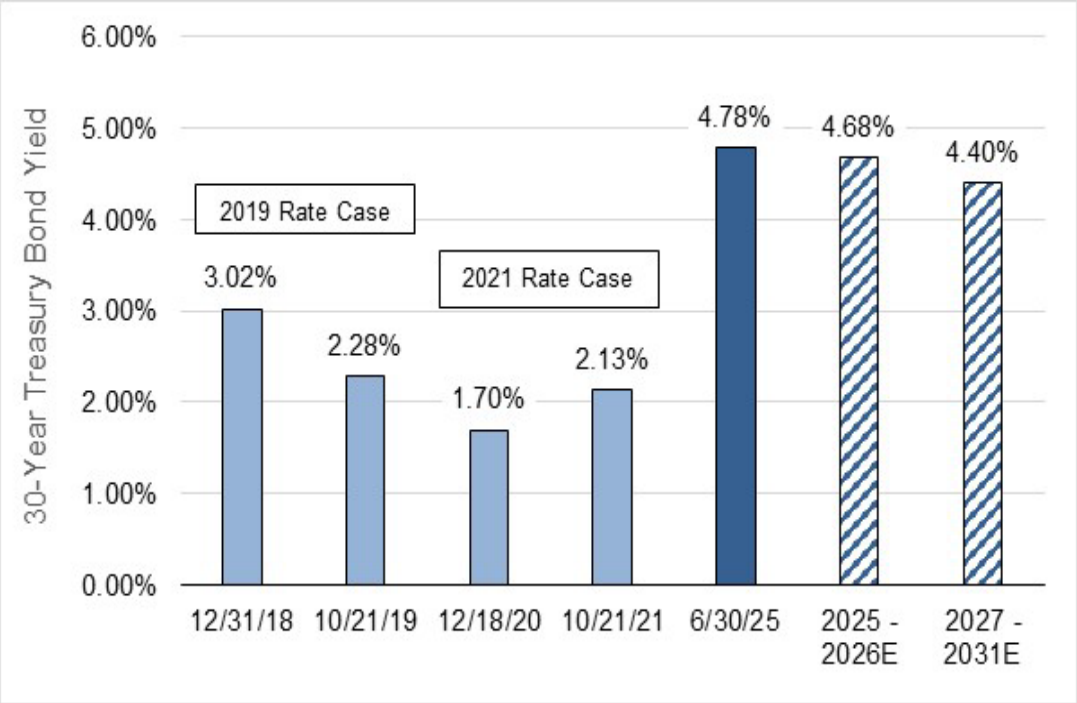
[3] S&P Global Ratings, "Northwest Natural Holding Co. Downgraded To 'A'; Outlook Negative; Subsidiary Ratings Affirmed, Outlook To Stable," at 2 (April 19, 2024).

[4] Moody's Investors Service, "Credit Opinion, Northwest Natural Gas Company, Update to credit analysis," at 1 (July 30, 2024).

[5] Moody's Investors Service, "Credit Opinion: Northwest Natural Gas Company," at 2 (July 8, 2025).

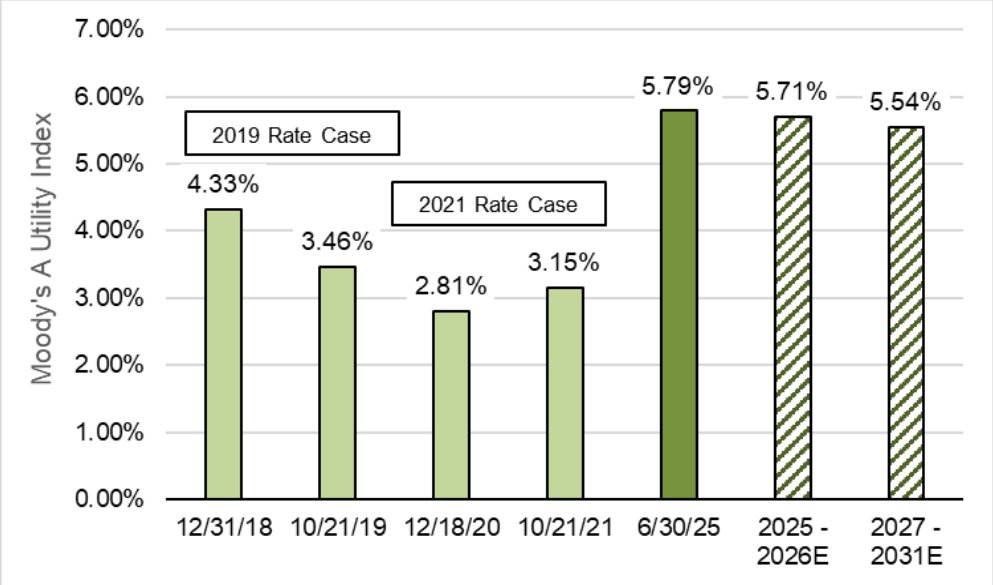
yields have increased significantly since the Company's last two rate cases and are expected to remain at elevated levels over the next five years. My CAPM and Risk Premium analyses incorporate both current and projected bond yields that reflect the existing view of the market.

Figure 2: 30-Year Treasury Yield (2019-2031)[6]



[6] Spot yields as of date referenced. Source: Federal Reserve Bank of St. Louis FRED Economic Data; Blue Chip Financial Forecasts Vol. 44, No. 7, at 2 (July 1, 2025), Blue Chip Financial Forecasts Vol. 44, No. 6, at 14 (June 2, 2025). I note that as of July 31, 2025, the spot yield on the 30-year Treasury bond was 4.89 percent.

Figure 3: Moody's 'A' Utility Index (2019-2031)[7]



Prevailing long-term bond yields have a significant effect on utilities' cost of capital, as well as investors' return requirements. Rising treasury yields signal to investors that they can earn a higher return investing in risk-free government bonds. Investors expect higher returns when investing in assets riskier than government-issued bonds (such as utility stocks); therefore, the cost of equity for utilities has increased along with the rise in interest rates, though not on a one-to-one basis.

As explained in Section III, a utility's capital costs are part of the cost of service and reflect the cost that the utility must pay its debt and equity investors to compensate them for the use of their financial capital. An ROE that does not sufficiently allow NW Natural to recover its higher capital costs ultimately reduces the Company's

[7] Spot yields as of date referenced. Source: Federal Reserve Bank of St. Louis FRED Economic Data; Bloomberg Professional, Blue Chip Financial Forecasts Vol. 44, No. 7, at 2 (July 1, 2025), Blue Chip Financial Forecasts Vol. 44, No. 6, at 14 (June 2, 2025). I note that as of July 31, 2025, the spot yield Moody's Utility A Index was 5.81 percent. Projected Utility Bond Yields assume long-term average spread between the Moody's 'A' Utility Bond Index and Moody's 'Aaa' Corporate Bond Index between 2015-2025.

attractiveness to investors and further increases the cost of debt and equity. Consequently, it is important that the Commission's decision in this case reflect the increase in capital costs that NW Natural faces.

Q. What is your conclusion regarding the Company's proposed capital structure?

A. I support NW Natural's requested capital structure of 51.00 percent common equity 48.00 percent long-term debt, and 1.00 percent short-term debt as reasonable relative to the range of capital structures for the operating companies held by the proxy group companies. My analyses regarding the Company's capital structure is further explained in Section VII.

Q. How is the remainder of your Direct Testimony organized?

A. The balance of my Direct Testimony is organized as follows:

- Section III – Summarizes the regulatory guidelines and principles relevant to the cost of capital estimation in regulatory proceedings;
- Section IV – Explains the development of the proxy groups used to develop my analytical results;

  Section V – Describes the analyses on which my ROE determination is based;

  Section VI – Discusses the Company's business risks relative to the proxy group that affect its cost of equity;
- Section VII – Provides an assessment of the Company's proposed capital structure;
- Section VIII – Reviews the current capital market conditions and the effect on the cost of equity;
- Section IX – Summarizes my conclusions and recommendations; and

- Section X – Provides a list of my Exhibits.

III. REGULATORY GUIDELINES AND PRINCIPLES

Q. Before addressing the specific aspects of this proceeding, please explain the connection between the cost of capital and a utility's cost of service.

A. Under the cost-of-service ratemaking paradigm, the development of utility rates begins with determining the utility's total cost to serve customers. This is known as the revenue requirement, since the utility's revenues must be sufficient to recover its costs to serve customers. The revenue requirement consists of four components: (1) operating and maintenance ("O&M") expenses, (2) taxes, (3) the return *of* capital through depreciation expense, and (4) the return *on* capital through the regulated return on rate base. The return on rate base is calculated as the weighted average cost of capital multiplied by the rate base. The return on capital must be sufficient to allow the utility to repay its debt obligations and compensate equity investors for the use of their financial capital. From that important perspective, the return on capital reflects a cost to the utility just like any other component of the revenue requirement.

Q. Please explain the cost of capital conceptually.

A. The cost of capital (i.e., the costs of both debt and equity) is the return that investors require to commit capital to a firm. Investors will provide funds to a firm only if the return they *expect* is equal to, or greater than, the return they *require* to accept the risk of investing capital in the firm. Simply, the cost of capital is the expected rate of return prevailing in the capital markets on alternative investments of similar risk.[8]

[8] Lawrence A. Kolbe, James A. Read, Jr., and George R. Hall, The Cost of Capital – Estimating the Rate of Return for Public Utilities, The MIT Press, Cambridge, MA (1985).

Conceptually, the cost of capital is: (1) forward looking and reflects an *expected* rate of return; (2) an opportunity cost; (3) determined in the capital markets, and (4) dependent on, and proportional to, the risk of the investment.[9]

Because the cost of equity is expectational and premised on the principle of opportunity costs, it is not directly observable. Instead, it must be estimated using market data applied to various financial models that reflect simplified representations of investor behavior and expectations. Further, equity investors have a claim on cash flows only *after* debt holders are paid; the uncertainty (or risk) associated with those residual cash flows determines the cost of equity. Because equity investors bear the residual risk, they take greater risks and require higher returns than debt holders. Ultimately, the estimated cost of equity should reflect the return that investors require considering the subject company's risk profile and the returns available on comparable investments.

Q. How is the cost of equity estimated in regulatory proceedings?

A. Regulated utilities primarily use long-term capital (i.e., common stock, preferred stock, and long-term debt) to finance their permanent rate base. The allowed rate of return for a regulated utility is calculated as its weighted average cost of capital, in which the costs of the individual sources of capital are weighted by their respective book values. The ROE reflects the cost of raising and retaining equity capital and is estimated by using one or more market-based analytical approaches. However, as noted earlier, although quantitative models are used to estimate the ROE, it cannot be precisely

[9] *Ibid*.

quantified through a strict mathematical exercise.[10] As such, a reasonable and appropriate ROE reflects the financial, economic, and regulatory environment in which the estimate is developed, as well as the subject company's relative risk profile.

Q. Please describe the guiding principles used in establishing the cost of capital for a regulated utility.

A. Public utility regulation is rooted in the principle that utilities receive a fair rate of return sufficient to attract the capital required to provide public utility service for customers at reasonable rates. The U.S. Supreme Court ("Supreme Court") established the guiding principles for establishing a fair rate of return for a public utility in two seminal cases: (1) *Bluefield Water Works and Improvement Co. v. Public Service Comm'n*. ("*Bluefield*");[11] and (2) *Federal Power Comm'n v. Hope Natural Gas Co.* ("*Hope*").[12] In *Bluefield*, the Supreme Court stated:

> A public utility is entitled to such rates as will permit it to earn a return upon the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties.[13]

[10] This is consistent with the *Hope* and *Bluefield* principle that the analytical result, as opposed to the method employed, controls the determination of just and reasonable rates.

[11] See, Bluefield Water Works and Improvement Co. v. Public Service Comm'n. 262 U.S. 679, 692 (1923).

[12] See, Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).

[13] Bluefield Water Works and Improvement Co. v. Public Service Comm'n. 262 U.S. 679, 692 (1923).

In *Hope*, the Supreme Court reiterated the three primary standards for a regulated rate of return:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock...By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[14]

In summary, the Supreme Court has recognized that the fair rate of return on equity should be: (1) comparable to returns investors expect to earn on other investments of similar risk (the "comparable return" standard); (2) sufficient to assure confidence in the company's financial integrity (the "financial integrity" standard); and (3) adequate to maintain and support the company's credit and to attract capital (the "capital attraction" standard). Importantly, a fair and reasonable return satisfies all three of these standards.

Q. Why is it important for a utility to be allowed the opportunity to earn a return that is adequate to attract capital at reasonable terms?

A. Regulated utilities have a legal obligation to serve regardless of prevailing economic and capital market conditions. Unlike non-regulated firms, a regulated utility cannot decide to whom it provides utility service in its footprint, how much service it delivers, nor when it provides service. Utility service requires substantial amounts of capital, and utilities must ensure they have access to external financial capital (debt and equity) on cost effective terms to finance its assets not only during times when markets are

[14] Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).

well-behaving, but also when markets are volatile or constrained (e.g., during periods of high inflation and interest rates, global pandemics, changes in government, and economic recessions). A return that is adequate to attract capital at reasonable terms enables the utility to provide safe and reliable service to customers while maintaining its financial integrity. As discussed above, and in keeping with the *Hope* and *Bluefield* standards, that return must be commensurate with the returns expected for investments of equivalent risk.

The ratemaking process is based on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility services, the utility must have the opportunity to recover the return of, and the market-required return on, invested capital. The allowed ROE should enable the subject utility to maintain its financial integrity in a variety of economic and capital market conditions. A return that is adequate to attract capital at reasonable terms enables the utility to provide safe, reliable service to customers while maintaining its financial soundness.

Further, the financial community carefully monitors utility companies' current and expected financial conditions, as well as the regulatory environment in which those companies operate. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' assessments of risk.[15] That consideration is especially important during uncertain economic and financial conditions in which the utility may require access to capital markets.

[15] *See*, *e.g.*, Moody's Ratings, *Rating Methodology: Regulated Electric and Gas Utilities*, August 6, 2024, at 2.

The outcome of the Commission's order in this case, therefore, must provide NW Natural with the opportunity to earn a ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks. Providing NW Natural with a reasonable opportunity to earn its market-based cost of equity ensures that customers receive safe and reliable service at a reasonable cost in all market environments.

Q. What are your conclusions regarding the regulatory principles pertaining to the cost of capital for a public utility?

A. Congruent with other costs in a utility's cost of service, the regulated return on rate base is a cost that NW Natural incurs as part of its normal operations, including the need to compensate equity investors for the use of their capital. Under the *Hope* and *Bluefield* standards, the cost of equity authorized for NW Natural in this proceeding should be (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks.

Because utilities are capital intensive and investors have many investment alternatives, the Company's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions. The Commission's decision regarding the authorized ROE and capital structure in this proceeding will directly affect the Company's ability to attract the capital needed to maintain and enhance service to customers.

IV. PROXY GROUP SELECTION

Q. Why is it necessary to select a proxy group to estimate the fair return on equity for NW Natural?

A. In this proceeding, we are focused on estimating the cost of equity for NW Natural's Washington-jurisdictional operations. Since the ROE is a market-based concept and NW Natural's Washington service territory is not a separate entity with its own stock price, it is necessary to select a group of companies that are both publicly traded and comparable to certain NW Natural business and financial characteristics to serve as a "proxy" for the ROE estimation process. Even if NW Natural's regulated gas utility operations in Washington made up the entirety of the publicly traded entity, it is possible that transitory events could bias the Company's market value in one way or another over a given period. A significant benefit of using a proxy group is the ability to mitigate the effects of company-specific events that may not be representative of the industry or long-term trends. As a result of the screening criteria used to select the proxy group, the companies included in the proxy groups and used in my ROE analyses have similar business and operating characteristics to NW Natural's regulated utility operations, and thus provide a reasonable basis for the derivation and assessment of ROE estimates.

Q. Please provide a brief overview of NW Natural's operations.

A. NW Natural distributes natural gas to approximately 806,000 residential commercial and industrial customers in Oregon and southwest Washington. The Company's Washington territory represents approximately 12 percent of its customer base, while

88 percent of its customer base is in Oregon.[16] NW Natural's long-term issuer rating is A+ from Standard & Poor's ("S&P"). The Company's senior unsecured shelf rating from Moody's Investor Services ("Moody's") is (P)Baa1.[17]

Q. What criteria do you use to select the proxy groups?

A. As explained below, I have developed two proxy groups: a Gas Proxy Group and a Combined Proxy Group. The Gas Proxy Group is utilized to develop my ROE recommendation. The Combined Proxy Group is utilized to inform, verify, and support my ROE recommendation. To develop the Gas Proxy Group, I first began with the nine companies that Value Line classifies as "Natural Gas Utilities" and then screened companies according to the following criteria to develop a proxy group reasonably comparable to NW Natural:

1. Pays quarterly cash dividends that have not been reduced or omitted in the last two years;
2. Maintains an investment grade long-term issuer rating (BBB- or higher from S&P or Baa3 or higher from Moody's) from both S&P and Moody's;
3. Is consistently covered by more than one equity analyst;
4. Has positive earnings growth rates published by at least two of the following sources: Value Line Investment Survey ("Value Line"), S&P, and Zacks Investment Research ("Zacks");

[16] Northwest Natural Holding Company, 2024 SEC Form 10-K, at 8. Accessible at NW Natural Holding's website: https://d18rn0p25nwr6d.cloudfront.net/CIK-0000073020/226d33d4-f658-4229-bd74-ca083bb85049.pdf.

[17] NW Natural's rating from Moody's is a provisional rating.

5. Natural gas distribution net operating income makes up a majority of the consolidated company's net operating income, on average, for the three years ended 2024;
6. Has not had a recent significant merger activity or transaction or have had a recent significant financial event that could affect its market data or financial condition.

Q. Do you include Northwest Natural Holding Company in your proxy groups?

A. No. It is my general practice to exclude the subject company, or its publicly traded parent company, from the proxy group due to the circular logic that would occur by including those results.

Q. What is the composition of your Gas Proxy Group?

A. Based on the screening criteria discussed above, and removing Northwest Natural Gas Holding Company, I arrived at a proxy group consisting of six publicly traded natural gas utilities shown in Figure 4.

Figure 4: Gas Proxy Group

Company	Ticker
Atmos Energy Corporation	ATO
New Jersey Resources Corporation	NJR
NiSource, Inc.	NI
ONE Gas, Inc.	OGS
Southwest Gas Holdings, Inc.	SWX
Spire Inc.	SR

Q. Does the Gas Proxy Group of six companies provide a reasonable basis to estimate NW Natural's ROE?

A. Yes. In selecting a proxy group, my objective is to balance the competing interests of selecting companies that are representative of the risks and prospects faced by NW Natural, while at the same time ensuring that there is a sufficient number of companies in the proxy group. The analyses performed in estimating the ROE are more likely to be representative of the subject utility's cost of equity to the extent that the selected proxy companies are fundamentally comparable to the subject utility. A larger proxy group does not necessarily improve the representative nature of the proxy group. Including companies whose fundamental comparability may be questionable simply for the purpose of expanding the number of observations does not improve the reliability of the results or the conclusions drawn from them. On balance, the Gas Proxy Group is reasonably comparable to NW Natural and is an appropriate set of companies to use in the ROE estimation process.

Q. Please describe your Combined Proxy Group alternative and the specific screening criteria you utilized to develop that group.

A. Due to consolidation in the natural gas industry over the last decade, the universe of publicly traded natural gas utilities covered by Value Line has been reduced to nine companies. The Gas Proxy Group screening criteria described above narrowed that group to six companies. Although it is my opinion that a proxy group of six natural gas companies is sufficient in size for the purpose of estimating NW Natural's cost of equity, I recognize that it may be appropriate to develop a larger proxy group to evaluate the reasonableness of Gas Proxy Group's ROE model results. A Combined

Proxy Group may be necessary in the future if there is further consolidation in the gas industry reducing the number of companies in the Natural Gas Utilities universe. Therefore, I developed a Combined Proxy Group consisting of the six natural gas utilities contained in the Gas Proxy Group, supplemented with electric utilities that have a meaningful amount of natural gas operations.

To screen the universe of 36 electric utilities covered by Value Line for inclusion in the Combined Proxy Group, I relied on the following criteria:

1. Pays quarterly cash dividends that have not been reduced or omitted in the last two years;
2. Maintains an investment grade long-term issuer rating (BBB- or higher from S&P or Baa3 or higher from Moody's) from both S&P and Moody's;
3. Is consistently covered by more than one equity analyst;
4. Has positive earnings growth rates published by at least two of the following sources: Value Line, S&P, and Zacks;
5. Regulated net operating income makes up a majority of the consolidated company's net operating income, on average, for the three years ended 2024;
6. Natural gas distribution net operating income makes up more than 15 percent of the consolidated company's net operating income, on average, for the three years ended 2024; and
7. Has not had a recent significant merger activity or transaction or have had a recent significant financial event that could affect its market data or financial condition.

Based on this screening criteria, 13 electric utilities were added to the six gas proxy companies to produce a Combined Proxy Group consisting of the following 19 companies:

Figure 5: Combined Proxy Group

Company	Ticker
Atmos Energy Corporation	ATO
New Jersey Resources Corporation	NJR
NiSource, Inc.	NI
ONE Gas, Inc.	OGS
Southwest Gas Holdings, Inc.	SWX
Spire Inc.	SR
Ameren Corporation	AEE
Avista Corporation	AVA
Black Hills Corporation	BKH
CenterPoint Energy, Inc.	CNP
CMS Energy Corporation	CMS
Consolidated Edison, Inc.	ED
DTE Energy Company	DTE
Eversource Energy	ES
Public Service Enterprise Group Inc.	PEG
Sempra Energy	SRE
Southern Company	SO
Wisconsin Energy Corporation	WEC
Xcel Energy Inc.	XEL

Q. Do your screening criteria result in groups of companies that investors would view as comparable to NW Natural?

A. Yes. The proxy groups have been selected to develop two groups of companies that are reasonably comparable (but not identical) to the financial and operational characteristics of NW Natural in aggregate. The screening criterion requiring an investment grade credit rating ensures that the proxy companies, like NW Natural, are generally in sound financial condition. Additionally, the criterion based on the percentage of net operating income from regulated natural gas distribution operations differentiates between utilities that derive a meaningful proportion of income from regulated natural gas distribution operations from those with substantial unregulated risks. These screens collectively reflect the risk factors that investors consider in making their investment decisions in natural gas utility companies.

V. COST OF EQUITY ESTIMATION

Q. What analytical approaches do you rely on to determine the Company's ROE?

A. As discussed earlier, I rely on the constant growth and quarterly growth forms of the DCF model, the traditional and empirical forms of the CAPM, and the Bond Yield Plus Risk Premium approach. The models I apply are commonly used in practice, as well as in regulatory proceedings.[18] Additionally, each model provides a different perspective of investors' views of risk and return. Therefore, using multiple methods provides a more comprehensive, and therefore more reliable, perspective on investors' return requirements.

[18] *See, for example,* Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed., 1994, at 341.

A. Constant Growth Discounted Cash Flow Model

Q. Please describe the Constant Growth DCF approach.

A. The Constant Growth DCF model is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its simplest form, the Constant Growth DCF model expresses the cost of equity shown in Equation [1] below sets the ROE equal to the expected dividend yield plus the expected long-term annual growth rate in perpetuity:

$$k = \frac{D_0\ (1+g)}{\mathrm{P}} + g \qquad [1]$$

where:

k = the required ROE,

D_0 = the current annualized dividend,

P = the current stock price, and

g = the expected long-term annual growth rate.

Q. What assumptions underlie the Constant Growth DCF model?

A. The Constant Growth DCF model assumes: (1) a constant average annual growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant Price/Earnings multiple; and (4) a discount rate greater than the expected growth rate. The model also assumes that the current cost of equity remains constant in perpetuity.

Q. What market data do you use as inputs of your Constant Growth DCF analysis?

A. I calculate the Constant Growth DCF result for each of the proxy companies using the following inputs:

- The average daily closing prices for the 30-, 90-, and 180-trading days ended June 30, 2025, for the term P_0;
- The current quarterly dividend as of June 30, 2025 multiplied by 4, for the term D_0; and
- Long-term earnings per share ("EPS") growth rate projections as of June 30, 2025 reported by Zacks, S&P Capital IQ Pro, and *Value Line*.

Q. Why do you use three averaging periods to calculate an average stock price?

A. I do so to ensure that the model's results are not skewed by anomalous events that may affect stock prices on any given trading day. At the same time, the averaging period should be reasonably reflective of expected capital market conditions over the long term. Using 30-, 90-, and 180-trading day averaging periods balances those concerns.

Q. How do you calculate the expected dividend yield over the coming year?

A. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is appropriate to calculate the expected dividend yield by applying one-half of the long-term growth rate to the current dividend yield. That adjustment ensures that the expected dividend yield is, on average, representative of the coming 12-month period.

Q. Why are analysts' projected earnings growth rates the appropriate measure of long-term growth in the Constant Growth DCF model?

A. In its Constant Growth form, the DCF model (i.e., as presented in Equation [1] above) assumes a single expected growth estimate in perpetuity, which assumes a fixed payout

ratio, and the same constant growth rate in EPS, dividends per share, and book value per share. In the long run, dividend growth can only be sustained by earnings growth.

Further, academic studies have clearly and consistently shown that measures of earnings and cash flow are strongly related to returns, and that analysts' forecasts of growth are superior to other measures of growth in predicting stock prices.[19] For example, the research of Vander Weide and Carleton demonstrates that earnings growth projections have a statistically significant relationship to stock valuation levels, while dividend growth rates do not.[20] Those findings suggest that investors form their investment decisions based on expectations of growth in earnings, not dividends. Lastly, the only forward-looking growth rates that are available on a consensus basis are analysts' EPS growth rates. The fact that earnings growth projections are the only widely available estimates of growth further supports the conclusion that earnings growth is the most meaningful measure of growth among the investment community. For these reasons, earnings growth is the appropriate measure of long-term growth in the DCF model.

[19] *See, e.g.*, Andreas C. Christofi, Petros C. Christofi, Marcus Lori and Donald M. Moliver, *Evaluating Common Stocks Using Value Line's Projected Cash Flows and Implied Growth Rate*, Journal of Investing (Spring 1999); Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management at 21 (Summer 1992); and Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988); Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management (Spring 1986).

[20] *See* Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988).

Q. What are the results of your Constant Growth DCF analysis?

A. To provide a spectrum of DCF-based ROE estimates, I calculate the low, mean, and high Constant Growth DCF result. The mean result combines the average of the three EPS growth rate estimates with each proxy company's expected dividend yield. The high DCF result adds the maximum EPS growth rate estimate with each proxy company's expected dividend yield. Similarly, the low DCF result adds the minimum EPS growth rate estimate for each proxy company to the expected dividend yield. I then calculate the mean and median low, mean, and high DCF results for the proxy group. In developing my ROE recommendation, I rely on the average of the mean and median proxy group Constant Growth DCF results (see Figure 6, below, and Exh. JEN-4). By relying on the average of the mean and median proxy group results, I consider the individual DCF results of each proxy company while mitigating the effect of the highest and lowest estimates.

I note that the Constant Growth DCF results for Southwest Gas Holdings ("Southwest Gas" or "SWX") currently exceed the Gas Proxy Group average and median results by approximately 300 basis points. Therefore, to be conservative, I give more weight to the results excluding Southwest Gas's DCF results. Figure 6 summarizes the results of the Constant Growth DCF analysis using the average of the three earnings growth rate projections.

Figure 6: Constant Growth DCF Results[21]

	Mean ROE (Including SWX)	Mean ROE (Excluding SWX)
Gas Proxy Group		
30-Day Average	10.73%	10.40%
90-Day Average	10.63%	10.28%
180-Day Average	10.72%	10.33%
Combined Proxy Group		
30-Day Average	10.15%	10.05%
90-Day Average	10.12%	10.02%
180-Day Average	10.24%	10.12%

B. Quarterly Growth DCF Model

Q. Please briefly describe the Quarterly Growth DCF model.

A. As noted earlier, the Constant Growth DCF model is based on several limiting assumptions, one of which is that dividends are paid annually. However, most dividend-paying companies, including utilities, pay dividends on a quarterly (as opposed to an annual) basis. Although the dividend yield adjustment discussed earlier is meant to address that assumption (by increasing the current dividend yield by one-half of the expected growth rate), it does not fully account for the quarterly receipt and reinvestment of dividends. As a consequence, the Constant Growth DCF model likely understates the cost of equity.

[21] Exh. JEN-4. Average of the mean and median proxy group results using mean growth rates.

The Quarterly Growth DCF model specifically incorporates investors' expectations of the quarterly payment of dividends, and the associated quarterly compounding of those dividends as they are reinvested at the required ROE. As noted by Dr. Roger Morin:

> Clearly, given that dividends are paid quarterly and that the observed stock price reflects the quarterly nature of dividend payments, the market-required return must recognize quarterly compounding, for the investor receives dividend checks and reinvests the proceeds on a quarterly schedule ... The annual DCF model inherently understates the investors' true return because it assumes all cash flows received by investors are paid annually.[22]

Q. How is the dividend yield component of the Quarterly Growth DCF model calculated?

A. To reflect the timing and compounding of quarterly dividends more accurately, the model replaces the "*D*" component of the Constant Growth DCF equation with the following equation:

$$D = d_1(1+k)^{0.75}+d_2(1+k)^{0.50}+d_3(1+k)^{0.25}+d_4(1+k)^{0} \quad [2]$$

where:

d_1, d_2, d_3, d_4 = expected quarterly dividends over the coming year; and

k = the required Return on Equity.

Because the required ROE (k) is a variable in the dividend yield calculation, the Quarterly Growth DCF model is solved iteratively.

To calculate the expected dividends over the coming year for the proxy companies (i.e., $d_1, d_2, d_3,$ and d_4), I obtained the last four paid quarterly dividends for

[22] Roger A. Morin, Ph.D., New Regulatory Finance, Public Utility Reports, Inc., 2006 at 344.

each company and multiplied them by one plus the growth rate (i.e., $1 + g$). For the P_0 component of the dividend yield, I used the same average stock prices applied in the Constant Growth DCF analysis for each proxy company.

Q. What are the results of your Quarterly Growth DCF analysis?

A. My Quarterly Growth DCF results are summarized in Figure 7, below (see also Exh. JEN-5). As with my Constant Growth DCF results, I rely on the average of the mean and median proxy group results and give more weight to the results excluding Southwest Gas.

Figure 7: Quarterly Growth DCF Results[23]

	Mean ROE (Including SWX)	**Mean ROE (Excluding SWX)**
Gas Proxy Group		
30-Day Average	10.99%	10.66%
90-Day Average	10.89%	10.53%
180-Day Average	10.99%	10.58%
Combined Proxy Group		
30-Day Average	10.32%	10.22%
90-Day Average	10.29%	10.19%
180-Day Average	10.39%	10.28%

[23] Exh. JEN-5. Average of the mean and median proxy group results using mean growth rates.

C. Capital Asset Pricing Model and Empirical Capital Asset Pricing Model

Q. Please describe the general form of the CAPM.

A. The CAPM is a risk premium method that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security. As shown in Equation [3], the CAPM is defined by four components, each of which theoretically is a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \qquad [3]$$

where:

K_e = the required market ROE for a security;

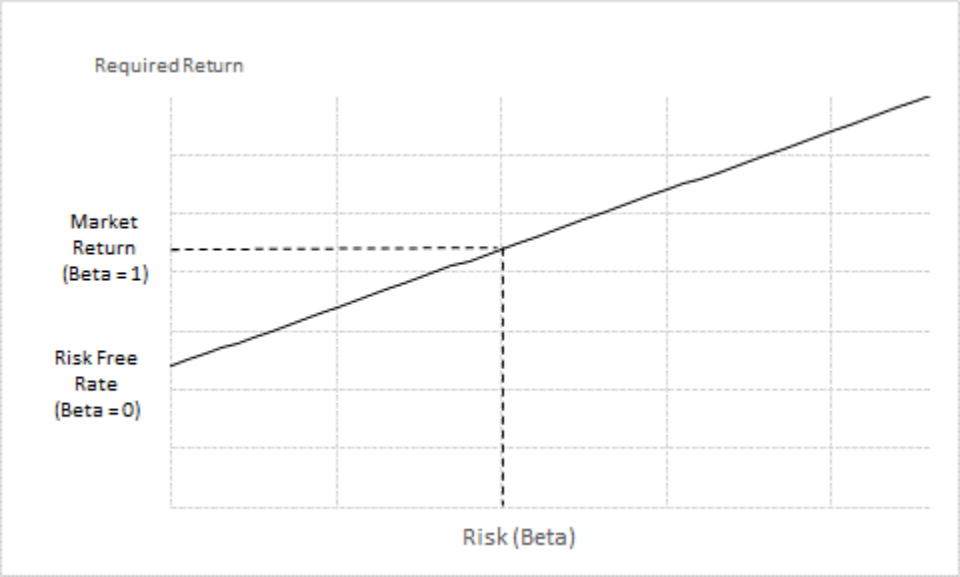
β = the Beta coefficient of that security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

Equation [3] describes the Security Market Line ("SML"), or the CAPM risk-return relationship, depicted in Figure 8 below. The intercept is the risk-free rate (r_f) that has a Beta coefficient of zero, and the slope is the expected market risk premium ($r_m - r_f$). As shown in Figure 8, the slope of the line is upward sloping, illustrating the principle that investments of higher risk require a higher return. By definition, r_m, the return on the market, has a Beta coefficient of 1.00.

Figure 8: Security Market Line



The CAPM assumes that all non-market or unsystematic risk, can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. Therefore, the CAPM assumes that investors require compensation only for systematic, or market, risk. Systematic (or non-diversifiable) risk is measured by the Beta coefficient, which is defined as:

$$\beta_j = \frac{\sigma_j}{\sigma_m} \text{ x } \rho_{j,m} \quad [4]$$

where σ_j is the standard deviation of returns for company "*j*," σ_m is the standard deviation of returns for the broad market (as measured, for example, by the S&P 500 Index), and $\rho_{j,m}$ is the correlation of returns in between company *j* and the broad market. The Beta coefficient, therefore, represents both relative volatility (i.e., the standard deviation) of returns, and the correlation in returns between the subject company and the overall market. Intuitively, higher Beta coefficients indicate that the subject

company's returns have been relatively volatile and have moved in tandem with the overall market.

Q. What risk-free rates do you assume in your CAPM analysis?

A. I apply two estimates of the risk-free rate: (1) the current 30-day average yield on 30-year Treasury bonds (i.e., 4.92 percent)[24] and (2) a projected 30-year Treasury yield (i.e., 4.52 percent).[25]

Q. Why do you rely on the 30-year Treasury yield as the risk-free rate in your CAPM analysis?

A. In determining the security most relevant to the application of the CAPM, the term (or maturity) should approximate the life of the underlying investment. Natural gas utilities are typically long-duration investments; therefore, the 30-year Treasury yield is more suitable for the risk-free rate applied in the CAPM.

Q. What Beta coefficients did you use in your CAPM model?

A. As shown in Exh. JEN-7, I rely on two estimates of the Beta coefficient. I first consider the average five year Beta coefficients from Value Line and Bloomberg for each proxy company as of June 30, 2025. Beta coefficients from both services are calculated using weekly returns over a five-year period, adjusted to reflect the tendency of Beta coefficients to regress toward the market mean of 1.00. I also consider Bloomberg Beta coefficients calculated using weekly return data over the ten years ended June 30, 2025,

[24] Source: Bloomberg Professional Service, as of June 30, 2025.

[25] The average of: (1) the average projected 30-year Treasury yield for the six quarters ended Q4 2026 and (2) the average long-term projected 30-year Treasury yield for the years 2027-2031 and 2032-2036, reported by *Blue Chip Financial Forecasts*. *See, Blue Chip Financial Forecasts* Vol. 44, No. 7, July 1, 2025, at 2 and *Blue Chip Financial Forecasts,* Vol. 44, No. 6, June 2, 2025, at 14.

rather than a five-year period. The 10-year Bloomberg Beta coefficients provide a longer term view of the proxy group's relative risk and attenuate any perceived distortion in the five year Beta coefficients associated with short-term market events.

Q. What estimates of the expected market return do you use to calculate the market risk premium?

A. I apply two estimates of the expected market return. The first calculates the market capitalization-weighted ROE of the S&P 500 Index by applying the Constant Growth DCF formula described earlier to the S&P 500 Index. The second estimate applies the long run historical arithmetic average market return of 12.17 percent between 1926 and 2024 reported by Kroll (formerly Duff & Phelps).[26]

Q. Please explain your forward-looking DCF approach to estimating the market return.

A. For the forward-looking market return estimate, I use the Constant Growth DCF formula to estimate the total market return for the S&P 500 Index. I consider projected earnings growth rates and dividend yields from three sources: (1) S&P's Earnings and Estimates report; (2) Bloomberg Professional; and (3) Value Line. As shown in Figure 9 these independent estimates of the expected market return range from 14.81 percent to 16.06 percent. (see also Exh. JEN-6). To be conservative, I rely on the lowest forward market return estimate from Value Line of 14.81 percent.

[26] Source: Kroll, Cost of Capital Navigator.

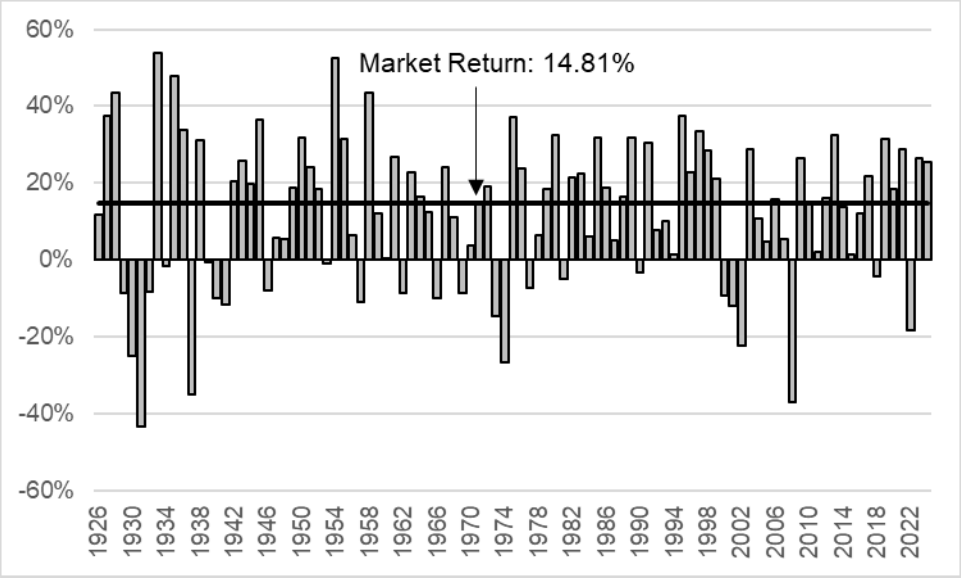
Figure 9: DCF-Based Expected Market Return

Source	Market Return
S&P Earnings & Estimates	15.56%
Bloomberg Professional	16.06%
Value Line	14.81%

Q. Is the Value-Line DCF-based market return estimate of 14.81 percent consistent with actual observed returns on the market?

A. Yes, it is. As shown in Figure 10 below, an expected market return of 14.81 percent or higher occurred in 50 of the last 99 years (i.e., more than 50 percent of the time). Since 2009, the annual market return has averaged 15.58 percent, and equaled or exceeded 14.81 percent in 10 of the last 16 years. In other words, an annual market return of 14.81 percent, or higher, has occurred frequently and is not an outlier.

Figure 10: Annual Market Return, 1926-2024[27]



[27] Source: Kroll, 2023 SBBI Yearbook, Appendix A-1, A-7 (years 1926-2022); Cost of Capital Navigator (years 2023-2024).

To moderate the effect of the forward-looking market return, however, I average the forward-looking return of 14.81 percent with the long-term average historical return between 1926 and 2024 of 12.17 percent as reported by Kroll (formerly Duff & Phelps). I then subtracted the current and projected risk-free rates to calculate a "blended" MRP of 8.57 percent and 8.97 percent, respectively.

Q. Do you also perform a CAPM analysis applying only the MRP calculated using the long-term historical average market return?

A. Yes. Although the estimation of the cost of equity is a forward-looking analysis, it may be reasonable to expect that, over the long term, the market return will revert to its long-run historical arithmetic average. Therefore, I also perform a CAPM analysis using only the current long-term historical average market return of 12.17 percent. Subtracting the current and projected risk-free rates from long-term historical average market return of 12.17 percent produces MRP estimates of 7.25 percent and 7.65 percent, respectively.

Q. What are the results of your CAPM analysis?

A. As shown in Figures 11 and 12 below, the CAPM results range from 10.05 percent to 11.34 percent for the Gas Proxy Group and 9.98 percent to 11.31 percent for the Combined Proxy Group (see Exh. JEN-7).

Figure 11: Summary of CAPM Results (Gas Proxy Group)[28]

	Current Risk-Free Rate (4.92%)	Projected Risk-Free Rate (4.52%)
Blended Market Return, 5-Yr Average Beta Coefficients	11.11%	11.00%
Blended Market Return, 10-Yr Bloomberg Beta Coefficients	11.34%	11.24%
Historical Market Return, 5-Yr Average Beta Coefficients	10.16%	10.05%
Historical Market Return, 10-Yr Bloomberg Beta Coefficients	10.35%	10.25%

Figure 12: Summary of CAPM Results (Combined Proxy Group)[29]

	Current Risk-Free Rate (4.92%)	Projected Risk-Free Rate (4.52%)
Blended Market Return, 5-Yr Average Beta Coefficients	11.04%	10.92%
Blended Market Return, 10-Yr Bloomberg Beta Coefficients	11.31%	11.21%
Historical Market Return, 5-Yr Average Beta Coefficients	10.09%	9.98%
Historical Market Return, 10-Yr Bloomberg Beta Coefficients	10.32%	10.22%

Q. Did you consider another form of the CAPM?

A. Yes, I also consider the Empirical CAPM ("ECAPM") approach, which calculates the product of the adjusted Beta coefficient and the Market Risk Premium and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight

[28] Exh. JEN-7. Average of the proxy group mean and median.

[29] Exh. JEN-7. Average of the proxy group mean and median.

to the Market Risk Premium, without any effect from the Beta coefficient.[30] The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [5] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \quad [5]$$

where:

k_e = the required market ROE;

β = the adjusted Beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

Q. What is the benefit of the ECAPM approach?

A. The ECAPM addresses the tendency of the CAPM to underestimate the cost of equity for companies, such as regulated utilities, with relatively low Beta coefficients. As discussed below, the ECAPM recognizes academic research that indicates the risk-return relationship is flatter than that estimated by the CAPM, and that the CAPM under-estimates the Alpha (α), or the constant return term.[31]

Numerous tests of the CAPM have measured the extent to which security returns and Beta coefficients are related as predicted by the CAPM. The ECAPM method reflects the finding that the actual SML described by the CAPM formula is not as steeply sloped as the predicted SML.[32] Fama and French state that "[t]he returns on

[30] *See, e.g.*, Roger A. Morin, Ph.D., New Regulatory Finance, at 189-190 (2006).

[31] Roger A. Morin, Ph.D., New Regulatory Finance, at 191 (2006).

[32] Roger A. Morin, Ph.D., New Regulatory Finance, at 175 (2006). The Security Market Line plots the CAPM estimate on the Y-axis, and Beta coefficients on the X-axis.

the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[33] Similarly, Morin states:

> With few exceptions, the empirical studies agree that . . . low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. . . .
>
> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:
>
> $$K = R_F + x\,(R_M - R_F) + (1-x)\beta(R_M - R_F)$$
>
> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:
>
> $$K = R_F + 0.25(R_M - R_F) + 0.75\,\beta(R_M - R_F)$$ [34]

Q. Does the use of adjusted Beta coefficients in the ECAPM address the empirical issues with the CAPM?

A. No, it does not. Beta coefficients are adjusted because of their general regression tendency to converge toward 1.00 over time, i.e., over successive calculations. As also noted earlier, numerous studies have determined that at any given point in time, the SML described by the CAPM formula is not as steeply sloped as the predicted SML. To that point, Morin explains:

> Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the

[33] Eugene F. Fama & Kenneth R. French, *The Capital Asset Pricing Model: Theory and Evidence*, Journal of Economic Perspectives, Vol. 18, No. 3, Summer 2004, at 33.

[34] Roger A. Morin, Ph.D., New Regulatory Finance at 175, 190 (2006).

> CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to Figure 6-1, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary.[35]

Therefore, it is appropriate to rely on adjusted Beta coefficients in both the CAPM and ECAPM.

Q. Are you aware of academic studies that support the use of the ECAPM for utilities?

A. Yes, I am. In a 2011 study by Stéphane Chrétien and Frank Coggins, the authors studied the CAPM's ability to estimate the risk premium for the utility industry in particular subgroups of utilities.[36] The study considered the traditional CAPM approach, the Fama-French three-factor model, and a model similar to the ECAPM. In the study, the ECAPM relied on adjusted Beta coefficients similar to *Value Line*'s approach. As Chrétien and Coggins found, the ECAPM significantly outperformed the traditional CAPM model at predicting the observed risk premium for the various utility subgroups.

[35] Roger A. Morin, Ph.D., New Regulatory Finance, at 191 (2006).

[36] Stéphane Chrétien and Frank Coggins, *Cost of Equity for Energy Utilities: Beyond The CAPM*, Energy Studies Review, Vol. 18, No. 2 (2011).

Q. What are the results of your ECAPM analyses?

A. I apply the same market return, Beta coefficient, and risk-free rates described earlier in my ECAPM analysis to Equation [5] above. The results of my ECAPM analyses are summarized in Figure 13 and Figure 14 below (see Exh. JEN-7).

Figure 13: Summary of ECAPM Results (Gas Proxy Group)[37]

	Current Risk-Free Rate (4.92%)	Projected Risk-Free Rate (4.52%)
Blended Market Return, 5-Yr Average Beta Coefficients	11.71%	11.62%
Blended Market Return, 10-Yr Bloomberg Beta Coefficients	11.88%	11.81%
Historical Market Return, 5-Yr Average Beta Coefficients	10.66%	10.58%
Historical Market Return, 10-Yr Bloomberg Beta Coefficients	10.81%	10.73%

Figure 14: Summary of ECAPM Results (Combined Proxy Group)[38]

	Current Risk-Free Rate (4.92%)	Projected Risk-Free Rate (4.52%)
Blended Market Return, 5-Yr Average Beta Coefficients	11.65%	11.56%
Blended Market Return, 10-Yr Bloomberg Beta Coefficients	11.85%	11.78%
Historical Market Return, 5-Yr Average Beta Coefficients	10.61%	10.53%
Historical Market Return, 10-Yr Bloomberg Beta Coefficients	10.79%	10.71%

[37] Exh. JEN-7. Average of the proxy group mean and median.

[38] Exh. JEN-7. Average of the proxy group mean and median.

D. Bond Yield Plus Risk Premium Approach

Q. Please describe the Bond Yield Plus Risk Premium approach.

A. The Bond Yield Plus Risk Premium approach is based on the basic financial principle of risk and return, which states that equity investors require a premium over the return required as a bondholder to account for the incremental residual risk associated the cost of equity as the sum of equity risk premium and the yield on a particular class of bonds.

Q. Please explain how you perform your Bond Yield Plus Risk Premium analysis.

A. I first define the equity risk premium as the difference between the authorized ROE and the then-prevailing 30-year Treasury bond yield, using the authorized ROE for 1,348 natural gas utility rate proceedings between January 1, 1980, and June 30, 2025. To reflect the prevailing level of bond yields during the pendency of the proceedings, I calculate the average 30-year Treasury yield over the average lag period between the filing of the rate case and the date of the final order (approximately 188 days). For the electric utilities in the Combined Proxy Group, I perform the same analysis using 1,834 electric utility rate cases between January 1, 1980 and June 30, 2025 (with a lag period of 199 days).

Because the data covers several economic cycles, the analysis is helpful in assessing the change in the equity risk premium over time. Prior research, for example, has shown that the equity risk premium is inversely related to the level of bond yields.[39]

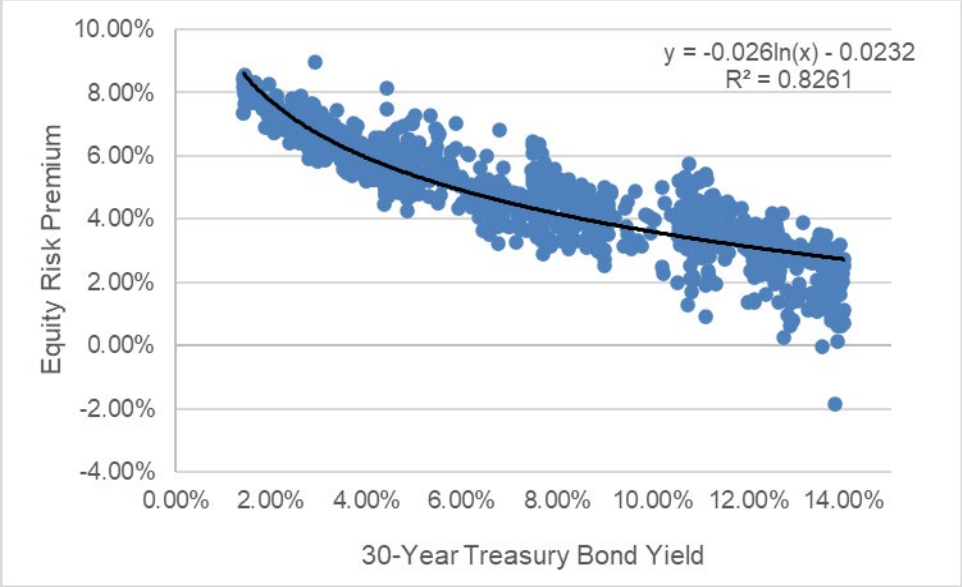
[39] *See*, *e.g.,* Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management at 63-70 (Summer 1992); Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management at 33-45 (Spring 1985); and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management at 89-95 (Autumn 1995).

Q. How do you analyze the relationship between bond yields and the equity risk premium?

A. I estimate the relationship between bond yields and the equity risk premium by applying a regression analysis, in which the equity risk premium described above is the dependent variable, and the 30-year Treasury yield is the independent variable. To account for the variability in bond yields and authorized ROEs over several decades, I use the semi-log regression, in which the equity risk premium ("*RP*") is expressed as a function of the natural log of the 30-year Treasury yield ("T_{30}"):

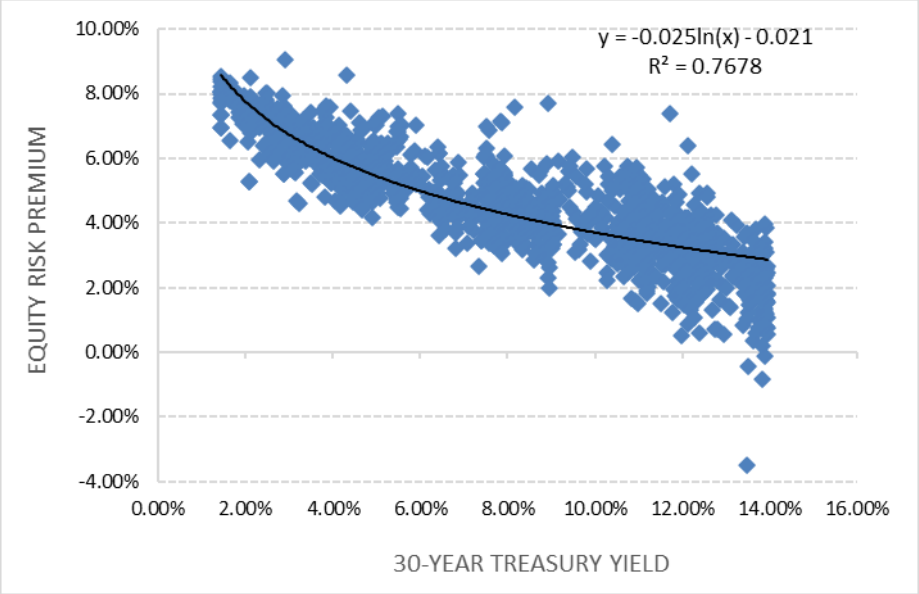
$$RP = \alpha + \beta \left(LN \left(T_{30}\right)\right) \quad [6]$$

Figure 15: Gas Equity Risk Premium[40]



[40] Exh. JEN-8.

Figure 16: Electric Equity Risk Premium[41]



As Figure 15 and Figure 16 illustrate, the equity risk premium increases as interest rates fall. The finding that the equity risk premium and interest rates are inversely related is supported by published research. For example, Dr. Roger Morin notes that: "… [p]ublished studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin (2005), McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when interest rates rose."[42] Based on the regression coefficients in Figure 15 and Figure 16, the implied ROE is between 10.15 percent and 10.41 percent (see Figure 17 and Exh. JEN-8).

[41] Exh. JEN-8.

[42] Roger A: Morin, Ph.D., New Regulatory Finance, Public Utilities Reports, Inc., 2006, at 128 [clarification added].

Figure 17: Summary of Bond Yield Plus Risk Premium Results[43]

Gas Risk Premium	**30-Year Treasury Bond**	**Risk Premium**	**Return on Equity**
Current 30-Year Treasury	4.92%	5.42%	10.33%
Projected 30-Year Treasury	4.52%	5.64%	10.15%
Electric Risk Premium	**30-Year Treasury Bond**	**Risk Premium**	**Return on Equity**
Current 30-Year Treasury	4.92%	5.49%	10.41%
Projected 30-Year Treasury	4.52%	5.70%	10.22%

Q. What are the advantages of the Bond Yield Plus Risk Premium approach?

A. There are several advantages. First, authorized ROEs in other jurisdictions are a significant part of the market information that investors consider when evaluating their investment alternatives. Therefore, they are a direct measure of returns available to other natural gas utilities, as required under the comparable return standard of the *Hope* and *Bluefield* decisions. The level of authorized ROE also provides a signal to investors about the level of regulatory support that a company can expect with regard to its ability to compete for capital and to ensure its financial integrity. An ROE below its peers for a given period may be an impediment to the Company's ability to attract capital and finance the infrastructure required to provide safe, reliable service to its customers. As discussed in Section VI, NW Natural expects to invest approximately $1.75 to $1.9

[43] Exh. JEN-8.

billion in infrastructure in the 2025-2030 period,[44] or approximately 70 percent of the Company's net utility plant at year end 2024.[45] As Company witness Brody J. Wilson explains, it is important that NW Natural maintain a strong balance sheet to attract both debt and equity capital on reasonable terms for the benefit of customers.[46]

Second, the use of the Bond Yield Plus Risk Premium model in conjunction with the DCF and CAPM approaches adds diversity to the model results, which enables a more robust and reliable ROE estimate. The fewer models that are relied upon, the more likely it is that model risk biases the ultimate ROE determination. For the same reasons that diversity is a wise and prudent investment strategy, diversity of the models used to estimate the ROE is similarly prudent, as it reduces the risk that the results of any single model may not reasonably reflect investors' return requirements.

A third advantage of the Bond Yield Plus Risk Premium approach is its simplicity and reliance on fewer contentious inputs. Lastly, the Bond Yield Plus Risk Premium approach adds a measure of stability because it is less vulnerable to changes in market data. As shown in the regression equation in Figures 15 and 16, the change in the risk premium (and therefore the ROE estimate) that corresponds with a change

[44] Northwest Natural Holdings June 2025 Investor Presentation, at 10; 70% of total holding company capital expenditures of $2.5 to $2.7 billion allocated to NW Natural. Accessible at: https://s23.q4cdn.com/611156738/files/doc_presentations/2025/Jun/04/June-2025-Investor-Presentation_Final.pdf

[45] Oregon Public Utilities Commission Docket RG 40, NW Natural's Earnings Review for the 12 Months Ended December 31, 2024 (filed April 29, 2025). Accessible at: https://edocs.puc.state.or.us/efdocs/HAQ/rg40haq336464026.pdf; Washington Utilities & Transportation Commission Docket UG-250296, NW Natural's Annual Commission Basis Report for the 12 Months Ended December 31, 2024 with Workpapers (filed April 29, 2025). Accessible at: https://www.utc.wa.gov/casedocket/2025/250296/docsets

[46] Confidential Direct Testimony of Brody J. Wilson, Exh. BJW-1CT.

in bond yields is less than one-to-one. For example, as shown in Figure 17 above, using the Gas Risk Premium analysis, a 40-basis point increase in the bond yield (from 4.52 percent to 4.92 percent) results in an 18-basis point change in the ROE from 10.15 percent to 10.33 percent.

Q. Which Risk Premium results do you rely on for your two proxy groups?

A. For the Gas Proxy Group, I rely on average of the Gas Risk Premium results using current and projected 30-year Treasury bond yields. For the Combined Proxy Group, I rely on the average of the gas and electric risk premium results using both the current and projected 30-year Treasury bond yields.

VI. BUSINESS RISKS

Q. Are there factors specific to NW Natural's operating environment that you considered in your ROE recommendation?

A. Yes, there are several additional factors that have a direct bearing on NW Natural's ability to earn a fair return and on the Company's riskiness relative to the Gas Proxy Group, including (1) its capital expenditure plan, the regulatory environment in which it operates, and the need to maintain access to capital, (2) the risk associated with decarbonization legislation and electrification, and (3) the Company's significantly smaller size. These factors increase NW Natural's risk relative to the Gas Proxy Group. While I do not make an explicit adjustment to my ROE recommendation to account for these risks, it is important that they are considered in determining the Company's ROE and capital structure in this proceeding.

A. Capital Expenditures, Regulatory Environment, and Capital Access

Q. Do you have any preliminary thoughts on the importance of access to capital for natural gas utilities such as NW Natural?

A. Yes, I do. As a capital-intensive enterprise, the authorized ROE should enable NW Natural to finance capital expenditures and working capital requirements at reasonable rates and to maintain its financial integrity in a variety of economic and capital market conditions. A return that is adequate to attract capital at reasonable terms enables the utility to provide safe, reliable service while maintaining its financial soundness to the benefit of customers.

Natural gas utilities are one of the most capital-intensive market sectors. On average, natural gas utilities generate less than 40 percent of the revenue per dollar of assets than the non-utility U.S. companies covered by Value Line.[47] To fund the significant capital expenditures needed to maintain, expand, and modernize existing infrastructure, natural gas utilities require sufficient internally generated cash flow and ongoing access to investor supplied capital. Because natural gas utilities tend to be cash flow negative (i.e., cash spent on plant investment is more than cash flow received from operations), it is critical that regulation provide predictable, adequate, and achievable allowed returns that support the financial integrity of the utility.

[47] Source: Value Line, accessed July 18, 2024.

Q. Please summarize the Company's capital expenditure plan.

A. The Company estimates that from 2025-2030 it will invest approximately $1.75 to $1.9 billion in capital.[48] The planned investments are primarily related to safety and reliability investments in the pipeline and storage systems, the Company's meter modernization program, public works projects, information technology and security, renewable natural gas projects, and customer growth.[49] In total, these capital expenditures are equal to approximately 70 percent of the Company's total net utility plant in service of $2.6 billion as of December 31, 2024.[50]

Q. Does the regulatory environment influence utilities' access to capital?

A. Yes, it does. The regulatory environment is a key driver of investors' assessment of a utility's risk. Investors and rating agencies understand that a constructive regulatory environment is critical to support utilities' credit ratings and financial integrity, especially during adverse market conditions. Ratings agencies also recognize the importance of the regulatory environment when assessing a utility's business risk profile.

[48] Northwest Natural Holdings June 2025 Investor Presentation, at 10; 70% of total holding company capital expenditures of $2.5 to $2.7 billion allocated to NW Natural. Accessible at: https://s23.q4cdn.com/611156738/files/doc_presentations/2025/Jun/04/June-2025-Investor-Presentation_Final.pdf.

[49] Northwest Natural Holdings June 2025 Investor Presentation, at 17. Accessible at: https://s23.q4cdn.com/611156738/files/doc_presentations/2025/Jun/04/June-2025-Investor-Presentation_Final.pdf.

[50] Oregon Public Utilities Commission, Docket RG 40, NW Natural's Earnings Review for the 12 Months Ended December 31, 2024 (filed April 29, 2025). Accessible at: https://edocs.puc.state.or.us/efdocs/HAQ/rg40haq336464026.pdf; Washington Utilities & Transportation Commission, Docket 250296, NW Natural's Annual Commission Basis Report for the 12 Months Ended December 31, 2024 with Workpapers (filed April 29, 2025). Accessible at: https://www.utc.wa.gov/casedocket/2025/250296/docsets.

Moody's considers the regulatory structure to be so important that 50 percent of the factors that weigh in a ratings determination are related to the nature of regulation.[51] The predictability and consistency of regulatory actions are among the key factors considered by Moody's in assessing the regulatory framework:

> As the revenues set by the regulator are a primary component of a utility's cash flow, the utility's ability to obtain predictable and supportive treatment within its regulatory framework is one of the most significant factors in assessing a utility's credit quality. The regulatory framework generally provides more certainty around a utility's cash flow and typically allows the company to operate with significantly less cushion in its cash flow metrics than comparably rated companies in other industrial sectors.
>
> ***
>
> In situations where the regulatory framework is less supportive, or is more contentious, a utility's credit quality can deteriorate rapidly.[52]

S&P states that regulatory advantage is "of critical importance" because "[i]t defines the environment in which a utility operates and has a significant bearing on a utility's financial performance."[53] S&P explains that it considers four subfactors when assessing a utility's ability to recover all its costs "on time and in full – and to earn a return on the capital it deploys."[54] Those four subfactors are (1) regulatory stability, (2) tariff-setting procedures and design, (3) financial stability, and (4) regulatory independence and insulation.[55] With respect to capital expenditures, S&P notes that a

[51] Moody's Ratings, Rating Methodology, *Regulated Electric and Gas Utilities,* at 2 (August 6, 2024).

[52] Moody's Investors Service, Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities at 2 (June 18, 2010).

[53] S&P Global Ratings, *Sector-Specific Corporate Methodology*, Section 29 Regulated Utilities, at 147 (April 4, 2024).

[54] S&P Global Ratings, *Sector-Specific Corporate Methodology*, Section 29 Regulated Utilities, at 147 (April 4, 2024).

[55] S&P Global Ratings, *Sector-Specific Corporate Methodology*, Section 29 Regulated Utilities, at 147 (April 4, 2024).

regulatory "framework's ability to attract long-term capital, and the availability of capital support during construction," support a utility's financial stability as they "alleviate funding and cash flow pressure when heavy investment is needed."[56] Thus, predictability and consistency of regulatory actions are among the primary concerns for the rating agencies, as is full and timely cost recovery, including recovery of capital costs.

Q. Do credit rating agencies recognize the risk associated with increased capital expenditures?

A. Yes. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for large capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[57]

[56] S&P Global Ratings, *Sector-Specific Corporate Methodology*, Section 29 Regulated Utilities, at 147 (April 4, 2024).

[57] S&P Ratings Direct, "Assessing U.S. Investor-Owned Utility Regulatory Environments," at 7 (August 10, 2016).

Moody's also notes that increasing capital expenditures are pressuring utility credit profiles by widening cash flow deficits and weakening their financial strength:

> Credit pressure is emerging most acutely for companies with large, complete or multiyear projects or for those that are experiencing a delay in the recovery of investment costs. Unlike exogenous events of recent year – such as severe storms, commodity price spikes and the COVID-19 pandemic, which we viewed as temporary events – capital spending and related financings are core long-term financial policy issues.[58]

To the extent that the regulatory environment does not enable timely and sufficient cost recovery of its full cost of doing business, including capital costs, the Company will face increased pressure on its credit metrics thus raising the cost of both debt and equity. Maintaining the ability to access to capital markets on favorable terms, in the form of financial integrity (i.e., capital structure and return on equity) is especially important for utilities and their customers during periods of significant capital investment.

Q. How does the regulatory environment in which a utility operates affect its cost of capital?

A. The regulatory environment can significantly affect both the access to and the cost of capital in several ways. First, the proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. Regulatory decisions regarding the authorized ROE and capital structure have direct consequences for the subject utility's internal cash flow generation (sometimes referred to as "Funds from Operations," or "FFO"; or "Cash from

[58] Moody's Ratings, Sector In-Depth, "High capital spending will weigh on credit quality without supportive company actions," at 2 (October 21, 2024).

Operations," or "CFO"). Because credit ratings are intended to reflect the ability to meet financial obligations as they come due, the ability to generate the cash flows required to meet those obligations (and to provide an additional amount for unexpected events) is of critical importance to debt investors. Two of the most important metrics used to assess that ability are the ratios of FFO to debt, and FFO to interest expense, both of which are directly affected by regulatory decisions regarding the appropriate rate of return and capital structure.

In short, supportive regulation supports credit profiles. Investors recognize that an authorized capital structure and ROE that are reasonable, but subject to earnings attrition due to unfavorable regulatory or economic factors, do not provide assurance that the utility will have a reasonable opportunity to recover its costs, or to earn a reasonable return. The authorized capital structure and ROE affect not only the cash flow-related metrics that measure financial strength, but also provide an indication of the degree of regulatory support, and risk, associated with a given utility and jurisdiction. Thus, the authorized ROE and capital structure are important signals of regulatory support and financial integrity. Consequently, a utility that operates in a less predictable and more challenging regulatory environment is likely to be viewed as a riskier investment; this may result in lower credit ratings, constrained access to capital (particularly in volatile and adverse market environments), and higher costs of both debt and equity, all else equal. To meet the obligation to serve, it is in customers' best interests to ensure that a utility has efficient access to capital on reasonable terms in all market environments.

Q. Please summarize the Company's proposed Multiyear Rate Plan.

A. As explained in the Direct Testimony of Company witness Kyle T. Walker (Exh. KTW-1T), pursuant to RCW 80.28.425, NW Natural is proposing a three-year rate plan based on a test year ending March 31, 2025. Rate year one ("RY1") covers August 1, 2026 through July 31, 2027. Rate year two ("RY2") covers August 1, 2027 through July 31, 2028. Rate year three ("RY3") covers August 1, 2028 through July 31, 2029. The proposed plan includes an asymmetrical true-up mechanism that credits surplus earnings back to customers if earnings are more than 0.5 percent (50 basis points) above the ROE authorized in this proceeding. However, the Company would bear the risk of any underearning. The Company also proposes performance metrics aligned with the Commission's objectives of developing resilient, reliable, and customer-focused distribution systems; enhancing customer affordability; advancing equity in utility operations; and supporting environmental improvements. Please refer to the Direct Testimony of Company witness Natasha C. Siores (Exh. NCS-1T) for details on the proposed performance metrics.

Q. Have you compared the Company's regulatory risk relative to the natural gas utilities within the proxy group?

A. Yes, I have. To assess the regulatory environment of the proxy companies and NW Natural, I reviewed the key cost recovery mechanisms and ratemaking frameworks for each of the natural gas operating companies within the proxy group in the jurisdictions in which they operate, including the cost recovery and volumetric risk mitigation mechanisms in place, test year, and rate base methodology.

As shown in Exh. JEN-9, like NW Natural, all the proxy companies with a retail supply obligation have a purchased gas cost recovery mechanism. Further, like NW Natural, 71 percent have a mechanism to recover energy efficiency program expenses. Additionally, like NW Natural, for 57 percent of the proxy companies, the regulator allows a partially- or fully-forecasted test year. However unlike NW Natural, all the proxy companies have a mechanism that fully or partially mitigates volumetric risk (e.g., weather normalization adjustment, decoupling, or lost revenue adjustment mechanism). Additionally, 96 percent of the proxy companies have a mechanism to recover capital investment or infrastructure replacement capital outside base rates, whereas NW Natural does not. The Company's proposed Multiyear Rate Plan, however, mitigates some of the risk associated with a lack of capital cost recovery mechanism by recovering capital investment that is used and useful after the rate-effective date. In other words, the Multiyear Rate Plan would render the Company more comparable to the vast majority of the Gas Proxy Group companies.

From an investor perspective, the Company's regulatory mechanisms do not offer any level of risk mitigation that is meaningfully different from the proxy companies. Furthermore, these regulatory mechanisms are only as effective as their implementation, including a compensatory return. It is in customers' best interest that the regulatory environment in Washington be viewed as predictable, balanced, and supportive of utility investment.

Q. Are Multiyear Rate Plans and other alternative regulatory mechanisms common in the industry?

A. Yes, they are. Alternative regulatory mechanisms, including Multiyear Rate Plans, are common in the industry and the financial community is fully aware of their prevalence. In fact, rate adjustment mechanisms and Multiyear Rate Plans have become more common in the industry, not less. The Gas Proxy Group companies use rate adjustment mechanisms similar to NW Natural's rate mechanisms. While the specific details of the mechanics of the rate adjustment mechanisms may differ from utility to utility and jurisdiction to jurisdiction, their objective is the same: To improve the timeliness of cost recovery and mitigate (but not necessarily eliminate) earnings erosion associated with regulatory lag. Because the proxy companies all have mechanisms that improve the timeliness of cost recovery, the Company's regulatory mechanisms, including its proposed Multiyear Rate Plan, simply render it more comparable to its peers.

Q. What are your conclusions regarding the Company's capital investment plan and its regulatory environment on its cost of equity?

A. NW Natural requires ongoing access to capital market access on favorable terms to provide safe and reliable service. The regulatory environment, including the return authorized in this proceeding, is a key determinant of the Company's ability to access external markets under a variety of capital market circumstances as it executes its capital investment plan. It is in the customers' best interests that the outcome of this proceeding is constructive and the regulatory environment for gas utilities in Washington is viewed as stable and predictable.

B. Policy Risk

Q. Please summarize recent legislation enacted by the Washington Legislature regarding decarbonization.

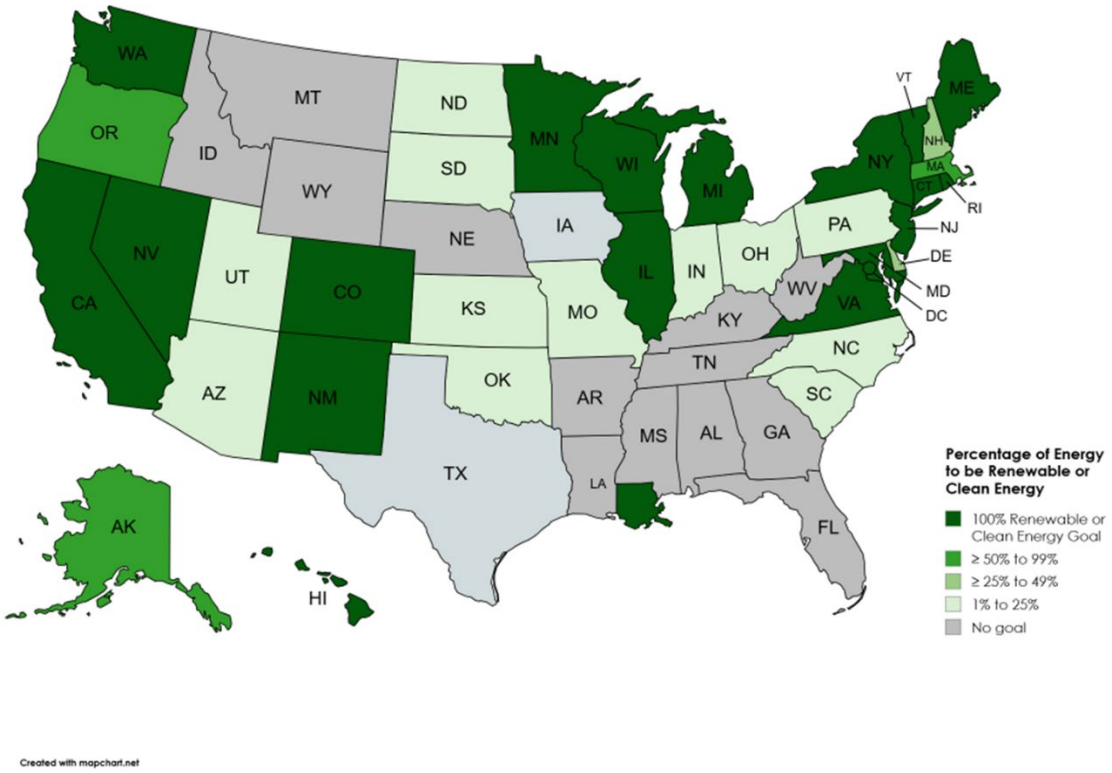
A. In 2019, Governor Inslee signed the Clean Energy Transformation Act, which commits the state to a 100 percent carbon neutral electricity supply by 2030 and 100 percent carbon free by 2045. Additionally, the Climate Commitment Act signed into state law in May 2021 requires utilities including NW Natural to reduce greenhouse gas emissions ("GHG") by 45 percent below 1990 levels by 2030, 70 percent below 1990 levels by 2040, and 95 percent below 1990 levels by 2050.[59] These targets can be achieved through purchased emissions allowances and offsets, purchases of low carbon fuels, and increased energy efficiency and conservation measures.

Addressing climate change is an increasing area of focus for federal, state, and local governments. As shown in Figure 18 below, 20 states have committed to net-zero or 100 percent renewable power targets by 2050 or earlier. As shown in Figure 18, Washington is among the 20 states with the most aggressive clean energy or renewable goals (i.e., "100 percent renewable").[60]

[59] Climate Commitment Act, Chapter 70A.65 RCW. See also, Chapter 173-446 Washington Administrative Code. Accessible at: https://app.leg.wa.gov/RCW/default.aspx?cite=70A.65&full=true&pdf=true.

[60] NW Natural also operates in Oregon, which is ranked in the "aggressive" category of decarbonization goals shown in Figure 18.

Figure 18: U.S. Renewable and Clean Energy Targets[61]



In its January 2025 outlook for the regulated utility sector, S&P Global Ratings noted the risk to LDCs' credit quality associated with policies that limit natural gas end uses, "We expect the longer-term credit quality for some natural gas local distribution companies (LDC) will become increasingly challenging, especially for utilities … whose cities or states have banned new gas connections, severely limiting the growth of natural gas LDCs."[62] The status of building codes that discourage or limit the use of natural gas in Washington is currently subject to litigation, including the King County

[61] Source: Regulatory Research Associates, "Renewable and Clean Energy Targets and Goals by State," as of December 15, 2024. Note that Texas and Iowa have a specific megawatt renewable goal that have been achieved (10,000 MW for Texas and 105 MW for Iowa).

[62] S&P Global Ratings "Industry Credit Outlook 2025: North America Regulated Utilities," at 14 (January 14, 2025).

Superior Court decision that invalidated ballot initiative I-2066.[63] If the building codes are ultimately upheld, this could pressure credit quality for LDCs like NW Natural.

Q. Have the credit rating agencies noted the risk associated with climate policies as a specific risk for NW Natural?

A. Yes. For example, in an April 2024 credit rating report for the Company, S&P explained:

> We also view the energy transition risks in Oregon and Washington as potentially increasing business risk. Washington has implemented decarbonization mandates and Oregon is contemplating various decarbonization initiatives. Furthermore, several cities are contemplating the implementation of a gas ban for new gas connections. We assess these evolving risks as potentially negative for credit quality and will continue to monitor future development.[64]

Similarly, Moody's noted "[e]levated social risk due to higher scrutiny on natural gas as an energy source" and "[l]ong-term risks associated with environmental remediation costs and emission reduction requirements" as credit challenges for NW Natural.[65] Moody's further stated that "[a] rating downgrade could occur if NW Natural's regulatory environment becomes less credit supportive, including material environmental challenges where costs cannot be recovered."[66] In its July 2025 report,

[63] See, e.g., https://washingtonstatestandard.com/2025/03/21/judge-overturns-washington-natural-gas-measure-approved-by-voters/; https://www.everettpost.com/state-news/biaw-asking-scow-for-direct-appeal-of-ruling-against-natural-gas-initiative/.

[64] S&P Global Ratings, "Northwest Natural Holding Co. Downgraded to 'A'; Outlook Negative; Subsidiary Ratings Affirmed; Outlook To Stable," at 2 (April 19, 2024).

[65] Moody's Investors Service, "Credit Opinion: Northwest Natural Gas Company," at 1-2 (July 30, 2024).

[66] Moody's Investors Service, "Credit Opinion: Northwest Natural Gas Company," at 2 (July 30, 2024).

Moody's reiterated its view that NW Natural's "heightened social risk due to state led decarbonization goals" is a credit challenge.[67]

Lastly, Moody's observed that "NW Natural has historically worked collaboratively with its regulator to make energy transition as affordable as possible for customers and we see this trend continuing as the company executes on its energy transmission goals over the next several years."[68] In other words, regulatory support is critical to the Company's ability to mitigate the policy risk it faces.

Q. Do the natural gas utilities in the Gas Proxy Group also face energy transition risk?

A. Yes, however, to a somewhat lesser extent. All but one of the Gas Proxy Group companies operate in multiple jurisdictions, which mitigates the effect of decarbonization policy risk through diversification. For example, Atmos Energy, NiSource, ONE Gas, and Spire operate in jurisdictions in the lowest tier or do not have a renewable energy target shown in Figure 18 above (e.g., Alabama, Mississippi, Louisiana, Kentucky, Kansas, Texas, Missouri, among others).

Q. Has the Commission found that higher ROEs may be needed to support energy transition policies and a utility's credit worthiness?

A. Yes, in Order 09 for Puget Sound Energy ("PSE") in Docket Nos. UE-240004 and UG-240005, the Commission recognized that an upward adjustment in the ROE was "needed to ensure the Company remains able to provide reliable and adequate service

[67] Moody's Investors Service, "Credit Opinion: Northwest Natural Gas Company," at 2 (July 8, 2025).

[68] Moody's Investors Service, "Credit Opinion: Northwest Natural Gas Company," at 6 (July 30, 2024).

to its customers, continues to meet its statutory obligation to transition to clean energy, per its CETA requirements, and remains credit worthy and able to acquire capital for continued operations. Balancing these competing interests goes to the heart of the Commission's responsibility."[69] In that decision, the Commission increased PSE's authorized ROE from 9.4 percent set in 2022 to 9.8 percent in Rate Year 1 and 9.9 percent in Rate Year 2.[70]

Q. What are your conclusions regarding the risk associated with decarbonization policies on NW Natural's cost of equity?

A. As a natural gas-only utility that operates in jurisdictions with more aggressive decarbonization policies, NW Natural is more exposed to the long-term threats to the natural gas utility business. It is critical that supportive regulation enables NW Natural to meet its decarbonization goals while maintaining access to capital.

C. Small Size

Q. To what extent does NW Natural's relatively small size affect its risk profile?

A. Academic literature recognizes that, over the long term, the total returns of smaller companies tend to be higher and more volatile than larger companies even after the relative illiquidity of smaller company stock is taken into account.[71] Figure 19 below

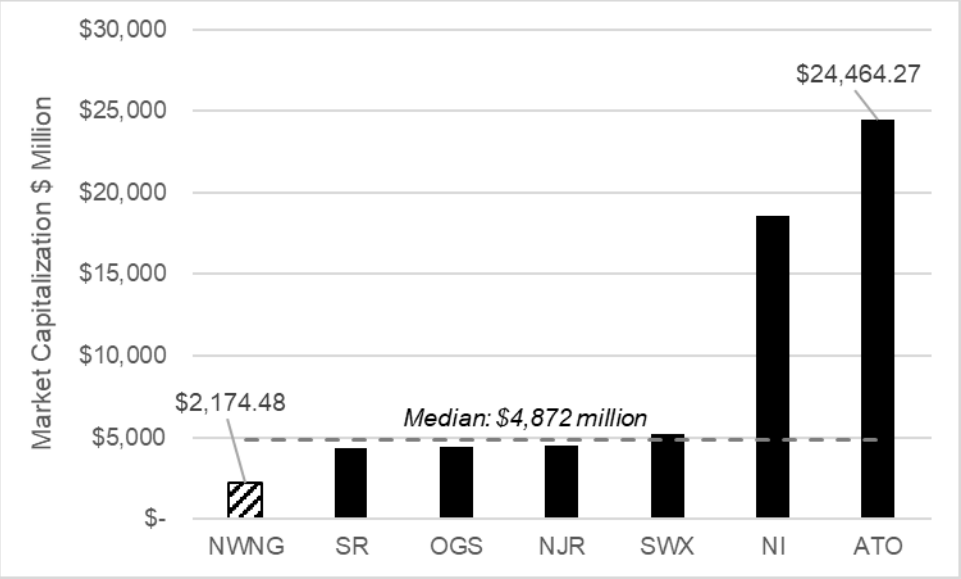
[69] Washington Utilities and Transportation Commission v. Puget Sound Energy, Dockets UE-240004 & UG-240005 (Consolidated), Order 09, at Para. 108 (January 15, 2025). Accessible at: https://www.utc.wa.gov/casedocket/2024/240004/orders.

[70] Washington Utilities and Transportation Commission v. Puget Sound Energy, Dockets UE-240004 & UG-240005 (Consolidated), Order 09, at Para. 109 (January 15, 2025). Accessible at: https://www.utc.wa.gov/casedocket/2024/240004/orders.

[71] *See*, *e.g.*, "Firm Size and Return," Ibbotson SBBI 2015 Classic Yearbook, at 99-100.

shows NW Natural's implied total company market capitalization relative to the Gas Proxy Group.

Figure 19: Comparison of Market Capitalization – Gas Proxy Group[72]



NW Natural's small size relative to its natural gas utility peers means that the Company's earnings may be disproportionately affected by adverse events such as weaker than expected demand for natural gas, plant outages, adverse regulatory rulings, or new legislation. The larger companies in the proxy groups can be expected to have an advantage in raising capital, suggesting that the ROE model results derived from this group could understate NW Natural's cost of equity. For example, Company witness Wilson explains that as a smaller utility, NW Natural's relatively smaller debt issuances are less liquid and therefore command a premium in the market.[73]

[72] Source: S&P Capital IQ, as of June 30, 2025; Exh. JEN-10.

[73] Confidential Direct Testimony of Brody J. Wilson, Exh. BJW-1CT.

Q. How did you estimate the size premium for NW Natural?

A. In its Cost of Capital Navigator, Kroll presents its calculation of the size premium for deciles of market capitalizations relative to the S&P 500 Index. The size premium associated with NW Natural can be estimated as the difference in Kroll's size risk premiums for the Gas Proxy Group median market capitalization and NW Natural's implied market capitalization.

As shown in Exh. JEN-10, the Gas Proxy Group median market capitalization of $4.87 billion corresponds to the fifth decile of Kroll's market capitalization data. Based on Kroll's analysis, the fifth decile has a size premium of 0.74 percent (or 74 basis points). The implied market capitalization for NW Natural is approximately $2.17 billion,[74] which falls within the seventh decile and corresponds to a size premium of 1.19 percent (or 119 basis points). The difference between those size premiums is 45 basis points (1.19 percent – 0.74 percent).

Q. Are there additional observations that support the consideration of a small size premium for NW Natural?

A. Yes, there are. Smaller companies typically have fewer shares outstanding and fewer shares traded than larger companies. Institutional investors[75] typically hold larger numbers of shares in each of their investments for management efficiency. Because

[74] Total company implied market capitalization of $2.17 billion = NW Natural's 2024 common equity of $1.32 billion x the proxy group median market-to-book ratio of 1.64. Because NW Natural's Washington-jurisdictional operations are roughly 12 percent of the Company's total business, the implied market capitalization for the Washington operations on a standalone basis is significantly smaller and would indicate an even larger size premium on a standalone basis.

[75] An institutional investor is a financial entity that invests money on behalf of clients or members, such as mutual funds, pension funds, insurance companies, and endowments.

institutional investors tend to have minimum dollar amounts for individual investments and smaller companies have fewer shares outstanding and lower trading volume, institutional investors' positions in smaller companies result in them owning a greater proportion of outstanding shares. If an institutional investor holds a relatively large portion of the shares of a company, its ability to sell its position without adversely affecting the market price of shares may be limited by the volume of shares traded each day. In other words, their investment is less liquid than it would be for a larger company with more shares outstanding and a higher trading volume. The uncertainty of institutional investors' ability to sell their shares quickly when needed is often referred to as "liquidity risk," and requires a higher expected return.

Amihud and Mendelson explained the following regarding liquidity and the effect on the expected return:

> Liquidity is an important factor in asset pricing. For both stocks, and bonds, the lower the liquidity of an asset (that is, the higher the cost of trading it), the higher the return it is expected to yield.
>
> ***
>
> Risk-averse investors require higher expected returns to compensate for greater risk. Similarly, investors prefer to commit capital to liquid investments, which can be traded quickly and at low cost whenever the need arises. Investments with less liquidity must offer higher expected returns to attract investors.[76]

[76] Yakov Amihud and Haim Mendelson, *Liquidity, Asset Prices and Financial Policy*, Financial Analysts Journal, Vol. 47, No. 6 (Nov-Dec 1991), at 56.

Q. Have you analyzed measures of liquidity for NW Natural relative to the Gas Proxy Group?

A. Yes, in addition to market capitalization as a measure of size, I analyzed three measures of liquidity for the publicly traded holding company (Northwest Natural Holding Company, "NWNH") to the companies in the Gas Proxy Group: (1) trading volume, (2) share turnover, and (3) the bid-ask spread as a percentage of the stock price.

Northwest Natural Holding Company's trading volume is significantly lower than the Gas Proxy Group companies on average. As Figure 20 below shows, Northwest Natural Holding Company's average daily trading volume has been 23.63 percent of the Gas Proxy Group's trading volume. Lower trading volume indicates lower liquidity, which can be an underlying factor of the size premium.

Figure 20: Market Capitalization and Trading Volume[77]

	Northwest Natural Holding Co.	Gas Proxy Group Average	NWNH % of Proxy Group
Market Capitalization ($ Million)	$1,628	$10,267	15.86%
Average Daily Volume	250,398	1,059,614	23.63%

I also calculated the average daily share turnover of Northwest Natural Holding Company's stock relative to the proxy companies. Share turnover is calculated as the percentage of outstanding shares traded on an average day (i.e., volume traded divided by shares outstanding). Between 2018 and 2025, Northwest Natural Holding Company's average daily share turnover was approximately 0.62 percent, compared to 0.67 percent for the Gas Proxy Group. Between January and June 2025, Northwest

[77] Source: S&P Capital IQ Pro. 30-trading day average ended June 30, 2025.

Natural Holding Company's and the Gas Proxy Group's share turnover was 0.69 percent and 0.76 percent, respectively. Further, over the last six years, Northwest Natural Holding Company had a lower share turnover than the Gas Proxy Group on average in nearly 70 percent of the 1,947 trading days.[78]

Next, I measured the relative difference in the average spread between the bid price and ask price in Northwest Natural Holding Company's stock price relative to the Gas Proxy Group. As Dr. Aswath Damodaran of New York University explains, less liquid assets have higher transaction costs, and the bid-ask spread is one measure of a stock's transaction costs.[79] Dr. Damodaran cites to studies demonstrating the bid-ask spread as a percentage of a stock's price increased as firm size decreased.[80] Similarly, Amihud and Mendelson found that "[a]sset illiquidity is inversely related to the bid-ask spread."[81] In a 1989 study, Amihud and Mendelson concluded that the annual expected return increased by 0.24 percent to 0.26 percent for every one percent increase in the bid-ask spread as a percent of the stock price.[82] Figure 21 below summarizes the average bid-ask spread as a percentage of the average stock price for Northwest Natural Holding Company's and the companies in the Gas Proxy Group.

[78] Source: Bloomberg Professional January 1, 2018 – June 30, 2025.

[79] Aswath Damodaran, "Marketability and Value: Measuring the Illiquidity Discount", Stern School of Business (July 2005), https://people.stern.nyu.edu/adamodar/pdfiles/papers/liquidity.pdf.

[80] Aswath Damodaran, "Marketability and Value: Measuring the Illiquidity Discount", Stern School of Business (July 2005), https://people.stern.nyu.edu/adamodar/pdfiles/papers/liquidity.pdf.

[81] Yakov Amihud and Haim Mendelson, *Liquidity*, *Asset Prices and Financial Policy*, Financial Analysts Journal, Vol. 47, No. 6 (Nov-Dec 1991), at 57.

[82] Amihud, Y. and Mendelson, 1989, *The Effects of Beta, Bid-Ask Spread, Residual Risk and Size on Stock Returns*, Journal of Finance, v. 44, 479-486.

Figure 21: Bid-Ask Spread as a Percent of Stock Price[83]

	30-day Average	90-day Average	180-day Average	YTD 2025 Average
Northwest Natural Holding	0.0463%	0.0620%	0.0689%	0.0673%
Proxy Group (Avg)	0.0267%	0.0288%	0.0293%	0.0293%
Difference	1.73x	2.15x	2.35x	2.29x

As Figure 21 shows, the bid-ask spread as a percentage of the stock price for Northwest Natural Holding Company is 1.73x to 2.35x higher than the Gas Proxy Group companies on average. Both the analyses shown in Figure 20 and Figure 21 indicate that Northwest Natural Holding Company is smaller in size and its stock is less liquid than the Gas Proxy Group, for which investors require a higher return as compensation.

Q. Do you propose an explicit risk adjustment to your ROE recommendation of 0.45 percent to reflect NW Natural's small size?

A. No. While I have quantified a 45-basis point premium associated with the Company's small size, I did not explicitly factor it into my ROE recommendation.

D. Business Risk Conclusion

Q. What is your conclusion regarding NW Natural's business risk factors and the implication on your ROE recommendation?

A. NW Natural is significantly smaller in size than the Gas Proxy Group and is more exposed to decarbonization policy risk than the Gas Proxy Group on average. As a smaller company, the potential for these risks to adversely affect the Company's

[83] Sources: S&P Capital IQ, Bloomberg Professional as of June 30, 2025.

financial profile is more acute because they may have a greater impact on revenues and expenses. While I have not made an explicit adjustment for the risk factors, they should be considered when determining the appropriate ROE and capital structure for NW Natural.

VII. CAPITAL STRUCTURE

Q. What common equity ratio is the Company proposing?

A. NW Natural is proposing a capital structure that includes 51.00 percent common equity, 48.00 percent long-term debt and 1.00 percent short-term debt, as discussed in the testimony of Company witness Wilson. The Company's proposed capital structure reflects its projected capital structure in the near term and is needed to strengthen its balance sheet and support its credit rating.

Q. How does the capital structure affect the cost of capital?

A. A company's total risk consists of business risk and financial risk. Business risk includes operating, market, regulatory, and competitive uncertainties, while financial risk is the incremental risk associated with greater debt. As the percentage of debt in the capital structure increases, so do the fixed obligations for the repayment of that debt and the risk of financial distress.[84] Therefore, the capital structure reflects the financial risk that a company may not have adequate cash flows to meet its financial obligations.

[84] *See*, Roger A. Morin, Ph.D., New Regulatory Finance, Public Utility Reports, Inc., at 45-46 (2006).

Q. How does NW Natural's proposed capital structure compare to those of the proxy group companies?

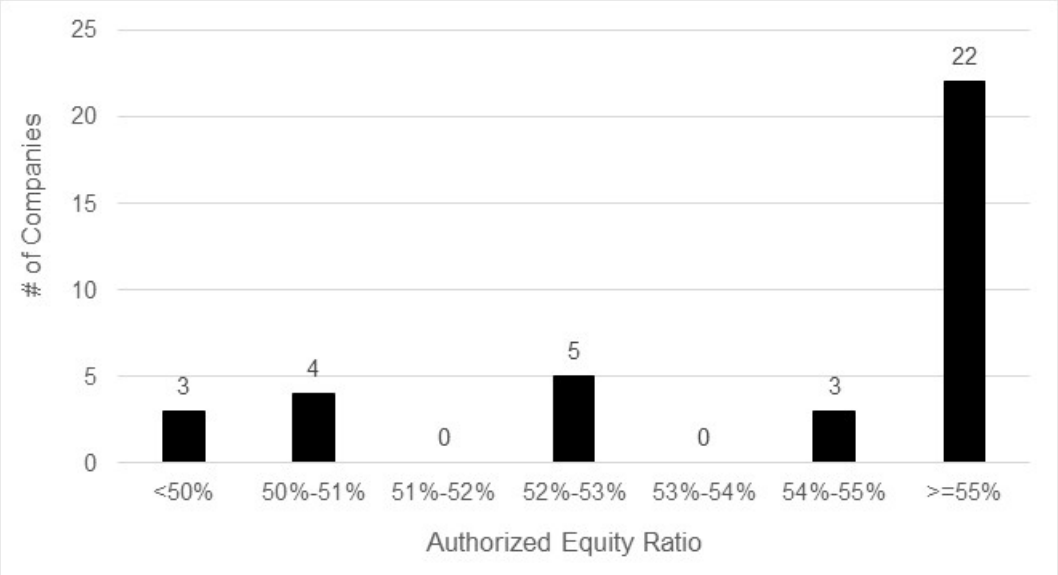
A. The reasonableness of NW Natural's requested capital structure is assessed within the context of industry practice and investor requirements. The capital structure should (1) be reasonably consistent with industry practice, (2) enable the subject company to sustain its operations and its financial integrity, and (3) allow it to maintain access to capital at competitive rates under a variety of market conditions.

As shown in Exh. JEN-11, NW Natural's proposed capital structure is within the range, but somewhat more leveraged (i.e., more debt in relation to equity) than the actual capital structures of the operating utilities contained in the Gas Proxy Group and Combined Proxy Group holding companies. For the three years ending 2024, I calculate the common equity, long-term debt, and short-term debt at the regulated utility operating company level for the Gas Proxy Group. I then "roll up" the individual operating company capital ratios to the holding company level by calculating the weighted average common equity, long-term debt, and short-term debt ratios of the utility operating companies within each proxy company. The Gas Proxy Group has an average and median equity ratio of 53.58 percent and 53.96 percent, respectively, over the last three years. For the Combined Proxy Group, the average and median equity ratio is 51.68 percent and 52.54 percent, respectively, over the last three years. NW Natural's proposed 51 percent common equity ratio is below the average and median for both proxy groups. Although this places equity holders at greater risk relative to the Gas Proxy Group, I have not made an adjustment to my recommended ROE on account of the proposed capital structure.

Q. Have you also reviewed the current authorized equity ratios for the Gas Proxy Group?

A. Yes. As shown in Exh. JEN-12, the current authorized equity ratios for the natural gas operating companies within the Gas Proxy Group range from 43.16 percent to 61.05 percent, with a mean and median of 55.71 percent and 58.00 percent, respectively. NW Natural's requested equity ratio of 51.00 percent is below the mean and median and on the low end of the range of the Gas Proxy Group authorized equity ratios. Notably, as shown in Figure 22 below, 25 of the 37 regulated natural gas operating utilities within the Gas Proxy Group (i.e., 68 percent) currently have an authorized equity ratio of 54.00 percent or higher. NW Natural's requested equity ratio is significantly below the majority of the equity ratios authorized for the Gas Proxy Group companies.

Figure 22: Gas Proxy Group Current Authorized Equity Ratio[85]



[85] Sources: Regulatory Research Associates and proxy company SEC Form 10-Ks (publicly available at https://www.sec.gov/search-filings). See Exh. JEN-12.

Q. Are there other factors that support NW Natural's request for a 51 percent equity ratio?

A. Yes. As Company witness Wilson shows in his Tables 5, 6, 7, and 9 in confidential Exh. BJW-1CT, NW Natural's credit metrics have been at the edge of, or weaker than, the rating agencies downgrade thresholds for its current credit rating. The rating agencies have stated that a rating downgrade could occur if its metrics are below the rating agencies' thresholds for a sustained period. By operating close to its downgrade thresholds, NW Natural risks an adverse event beyond its control jeopardizing its credit rating.

Q. Do customers benefit from a utility that maintains a strong financial profile?

A. Yes, in two important ways. First, both debt and equity investors require higher returns for a riskier utility with a lower credit rating. Because the cost of capital is a cost that customers ultimately bear, customers benefit from a utility that maintains a strong financial profile. Second, a utility with a stronger financial profile will have better access to capital at lower costs than a financially weaker utility. Better access to capital enables NW Natural to invest in its system and provide customers with safe and reliable service in all market environments.

VIII. ECONOMIC AND CAPITAL MARKET CONDITIONS

Q. Do economic conditions influence the required cost of capital, including the ROE?

A. Yes. The required cost of capital, including the ROE, is a function of prevailing and expected economic and capital market conditions. Each of the analytical models used to estimate the required ROE is influenced by current and expected capital market

conditions. Therefore, an evaluation of current and projected market conditions is integral to any ROE recommendation.

Q. What are the key factors affecting the cost of equity for regulated utilities in the current and prospective capital markets?

A. The cost of equity for regulated utilities is affected by several key factors, including: (1) the interest rate environment and central bank monetary policy; (2) inflationary pressure and the longer-term outlook for inflation; and (3) greater market volatility and economic uncertainty associated geopolitical events. As discussed below, although the Federal Reserve reduced the Federal Funds target rate in the Fall of 2024 as inflation stabilized and moved closer to the central bank's two percent target, stubborn inflation and greater market and economic uncertainty have prompted the Federal Reserve to alter its easing of monetary policy. Consequently, interest rates and inflation are expected to remain above the levels experienced prior to the COVID-19 pandemic and long-term yields on Treasury bonds are expected to remain above the prevailing levels at the time of the Company's last general rate case. Further, as discussed later in this section, inflation is expected to remain markedly above levels experienced prior to the COVID-19 pandemic and above the Federal Reserve's two percent target. Lastly, geopolitical events present significant uncertainties with respect to the near-term economic and capital market environment in which NW Natural will be raising external capital.

Q. Please summarize the changes in capital market conditions since early 2020.

A. The COVID-19 pandemic had wide ranging impacts on markets, affecting all market sectors, including utilities. At the start of the pandemic, both the S&P 500 Index and

the utility sector lost more than a third of its value. At the same time, the Chicago Board Options Exchange ("CBOE") Volatility Index ("VIX", a measure of expected market volatility) tripled, from 25.03 on February 24, 2020, to 82.69 on March 16, 2020.[86]

Treasury bond yields declined rapidly as the stock market became extremely volatile and investors sought the relative safety of government bonds, combined with the Federal Reserve's reduction in the Federal Funds rate to a target range of 0 percent to 0.25 percent. Because bond yields and bond prices are inversely related, as demand for safer bonds increases, investors bid up the price of bonds and bid down the yields. Since the decline in bond yields was caused by investors' increased aversion to equity market risk, the cost of equity did not decline commensurately with the decline in bond yields.

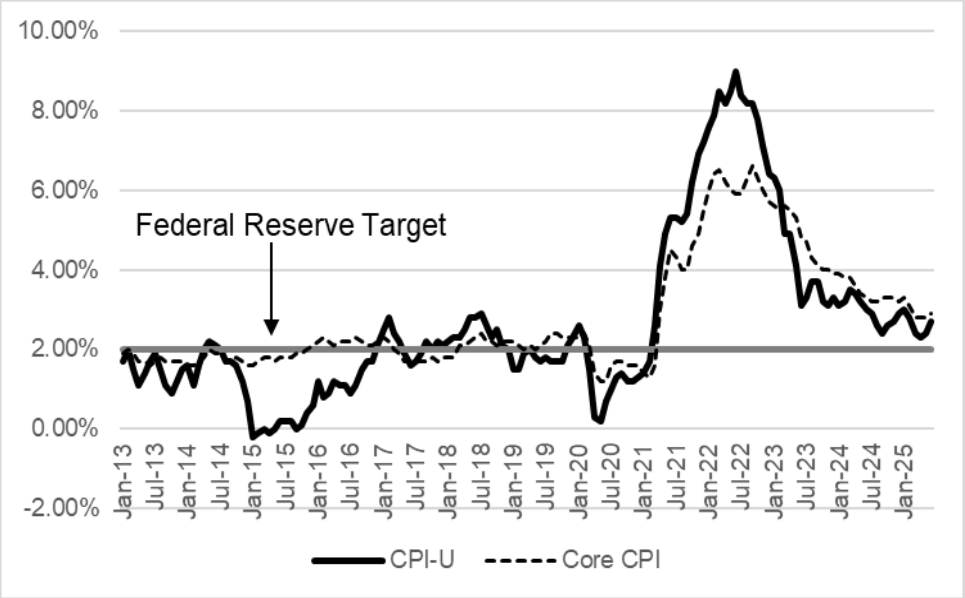
As the U.S. economy opened from the COVID-19 lockdowns, economic activity quickly rebounded, causing inflation to reach the highest levels seen in the last 40 years. In response, the Federal Reserve tightened monetary policy at the fastest pace since the 1980s by increasing the Federal Funds rate by 525 basis points over the course of 11 consecutive Federal Open Market Committee ("FOMC") meetings between March 2022 and July 2023.

As Figure 23 below illustrates, although the pace of inflation subsided from its peak reached in 2022, inflation remains above the Federal Reserve's 2.0 percent target,

[86] Source: Federal Reserve Bank of St. Louis FRED Database.

ticking up to 2.70 percent for all items and 2.90 percent excluding food and energy ("core CPI") as of June 2025.

Figure 23: Year-Over-Year U.S. Consumer Price Index (2013-2025)[87]



As shown in Figure 24, on a cumulative basis, seasonally adjusted inflation has increased 16.3 percent between October 2021 when the Commission's decision in the Company's last rate case was issued and June 2025.

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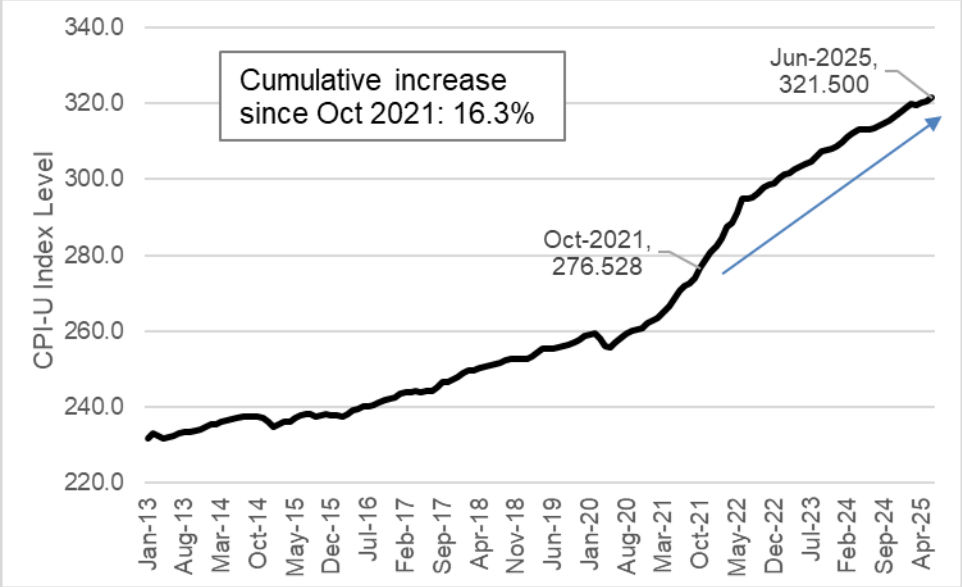
[87] Source: U.S. Bureau of Labor Statistics.

Figure 24: Consumer Price Index Level (2013-2025)[88]



Q. How did government and utility bond yields respond to the Federal Reserve's monetary policy tightening?

A. As the U.S. economy improved in 2021 and the Federal Reserve moved aggressively to tighten monetary policy to fight stubbornly higher inflation, prevailing interest rates rose to their highest levels since 2010.[89] As shown in Figure 25 below, the 30-year Treasury bond yield has increased 278 basis points since November 3, 2021, when the Federal Reserve signaled it would begin tapering its asset purchases, just 13 days after the Commission's October 2021 Order in the Company's last rate case. Utility bond yields have increased by approximately 270 basis points over the same period.

[88] Source: U.S. Bureau of Labor Statistics, CPI-U, seasonally adjusted.

[89] Source: Federal Reserve Bank of St. Louis, FRED Economic Database.

Figure 25: 30-Year Treasury Bond and Utility Bond Yields (2021-2025)[90]

	30-yr Treasury Bond	Moody's A Utility Bond	Moody's Baa Utility Bond
11/3/2021	2.00%	3.02%	3.27%
6/30/2025	4.78%	5.79%	5.97%
Change since 11/3/2021	+2.78%	+2.77%	+2.70%

Consensus forecasts from Blue Chip project long-term government and corporate bond yields to remain at elevated levels over the next six quarters, as shown previously in Figures 2 and 3 in Section II.[91]

Q. Please explain how higher bond yields affect the ROE estimates.

A. The 30-year Treasury bond yield is a direct input to both the CAPM and the Risk Premium models because, as explained earlier, the term of the security aligns with the long life of natural gas utility assets. As yields increase, the cost of capital generally increases, and the ROE estimates from those two models also increase, although not on a one-to-one basis. Further, while interest rates are not a direct input to the DCF model, dividend yields on utility stocks must compete with yields on Treasury bonds. As yields on government bonds increase, utilities must offer a higher dividend yield to attract and retain investors, signaling an increase in the cost of equity for utilities. All else equal, higher dividend yields produce higher ROE estimates in the DCF model.

[90] Source: Federal Reserve Bank of St. Louis, FRED Economic Database; Bloomberg Professional.

[91] Blue Chip Financial Forecasts, Vol. 44, No. 7, July 1, 2025, at 2.

Q. How have economic and financial market conditions changed in recent months?

A. At the end of 2024, financial markets were optimistic that the Federal Reserve was close to attaining a "soft landing" by taming inflation without a consequential rise in unemployment. Over the past few months, however, federal policy uncertainty has climbed sharply, and financial market volatility has increased. Since the announcement of the Administration's tariff policies in early April, data have shown a vulnerable and slowing economy with consumer and business sentiment declining and growing anticipation of higher inflation.[92]

Expectations for inflation are markedly higher than in the five years prior to the pandemic. The University of Michigan's Consumer Sentiment survey reported that U.S. consumer sentiment was 16 percent below December 2024 and well below its historical average, despite improvements in June and July 2025.[93] As noted in the June 2025 special report on inflation expectations:

> After four months of sharp increases to start 2025, long-run expectations fell in May and June. June's median now matches the peak reading from mid-2022, but the three-month-moving average remains above mid-2022. Expectations exhibit substantial uncertainty, particularly in light of ongoing developments and changes with economic policy.[94]

[92] *See*, *e.g.*, Blue Chip Financial Forecasts, Vol. 44, No. 5, May 1, 2025, at 1.

[93] University of Michigan Surveys of Consumers, accessed July 15, 2025, https://www.sca.isr.umich.edu/files/tbmpx1px5.pdf.

[94] University of Michigan, Surveys of Consumers, *June 2025 Update: Current versus Pre-Pandemic Long-Run Inflation Expectations* (June 27, 2025) https://data.sca.isr.umich.edu/fetchdoc.php?docid=79098.

Q. Please discuss recent changes in U.S. trade policy.

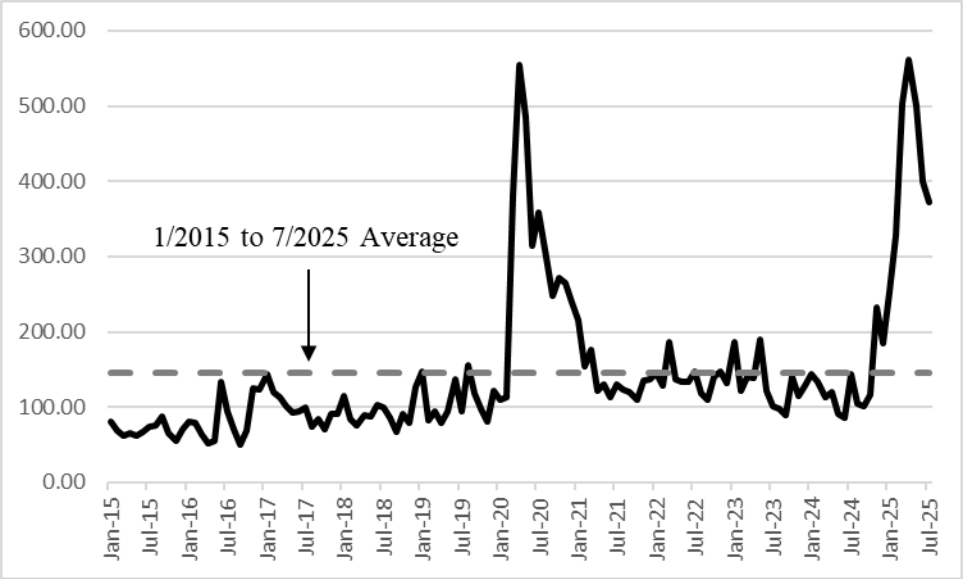
A. During the first half of 2025, the Trump administration had announced, implemented, or delayed implementation of tariffs on numerous U.S. trade partners. A highlight of this is when, on April 2, 2025, President Trump announced the administration would impose a 10 percent base tariff on all imports from nearly every country plus an additional "reciprocal" tariff customized for each of approximately 60 countries.[95] These reciprocal tariffs were subsequently paused, but significant uncertainty remains around the future course of U.S. trade policy and how it will affect the economy.

This created significant policy and market uncertainty; as can be seen in Figure 26 below, the Federal Reserve Bank of St. Louis' Economic Policy Uncertainty Index (the "Index") spiked to levels not seen since the COVID-19 pandemic. While the Index has partially subsided in recent months (to 372.15 as of July 2025), it is still significantly above the average level (145.23) and the level in October 2021 (109.65), when the Commission approved the settlement in NW Natural's last rate case. This indicates that there is still significant uncertainty related to international trade and the economy. Uncertainty increases risk, which increases the cost of equity, all else equal.[96]

[95] https://www.whitehouse.gov/presidential-actions/2025/04/regulating-imports-with-a-reciprocal-tariff-to-rectify-trade-practices-that-contribute-to-large-and-persistent-annual-united-states-goods-trade-deficits/.

[96] https://www.whitehouse.gov/presidential-actions/2025/07/extending-the-modification-of-the-reciprocal-tariff-rates/.

Figure 26: Economic Policy Uncertainty Index January 1, 2015 – July 31, 2025[97]



Q. How might these changes in U.S. trade policy affect inflation and interest rates?

A. Although the effect of these tariffs on the economy is uncertain, economists generally agree that higher tariffs increase inflation by increasing the cost of consumer goods. The tariffs could lead to higher inflation and reduced overall demand, as well as higher interest rates and a stronger dollar.[98] The Budget Lab at Yale University estimates that current tariff proposals would raise consumer prices by 1.8 percent before substitution, which would be the equivalent to $2,400 in in disposable income for the average household.[99] Moody's notes that Asian trading partners were "dealt the

[97] Federal Reserve Bank of St. Louis Economic Database (FRED), Economic Policy Uncertainty Index for United States (USEPUINDXD), https://fred.stlouisfed.org/series/USEPUINDXD.

[98] J.P. Morgan Asset Management, Market Insights "2025 Year-Ahead Investment Outlook," November 21, 2024.

[99] Yale Budget Lab, "State of U.S. Tariffs," August 7, 2025. Accessible at: https://budgetlab.yale.edu/research/state-us-tariffs-august-7-2025.

most consequential blow," including the Pacific Coast U.S. states that are more exposed to "severe increases in the cost of both final and intermediate goods."[100]

In a recent article published by S&P Global Market Intelligence, economists noted the "enormous uncertainty" associated with the effect of tariffs on inflation and the economy. The article projected that if President Trump's tariffs are imposed as proposed, they "would cause the core consumer price index[101] to run at a 6% annual pace on average over the next two years."[102]

Higher inflation is complicating the Federal Reserve's unwinding of restrictive monetary policies,[103] bolstering long-term bond yields like the 30-year Treasury yield. The FOMC paused its cuts in the Federal Funds rate at its January 2025 meeting, citing elevated inflation and a stable labor market, and held rates steady since. In an April 16, 2025 speech, Federal Reserve Chair Jerome Powell stated that the Fed faces a "challenging scenario" in balancing the goals of controlling inflation and supporting the labor market, driven primarily by the risk of prolonged inflation and slower economic growth as a result of the tariff policies.[104]

Longer-term bonds like the 30-year Treasury bond are more sensitive to inflation expectations than shorter-term bonds because their value is influenced more by inflation due to their longer maturity holding period and reinvestment rate

[100] Moody's Analytics, "U.S. Regional Economies Brace for Tariff Pain," at 1 (April 4, 2025).

[101] As measured by the Personal Consumption Expenditures ("PCE") price index.

[102] S&P Global Market Intelligence, "Tariffs projected to push US inflation near 2022 highs," April 9, 2025.

[103] *See*, *e.g.*, S&P Global Market Intelligence, "Tariffs projected to push US inflation near 2022 highs," April 9, 2025.

[104] Chair Powell's speech at the Economic Club of Chicago, Chicago, Illinois, April 16, 2025, https://www.federalreserve.gov/newsevents/speech/files/powell20250416a.pdf.

implications. Thus, as the value (price) of bonds declines due to higher inflation expectations, the yield increases. Because utilities are capital intensive enterprises, higher inflation and interest rates tend to have a negative effect on utility stocks. If realized, higher inflation and interest rates would suggest that the cost of capital for utilities may increase in the future.

Q. What conclusions do you draw from your review of the current capital market environment and its implications for NW Natural's cost of equity?

A. Over the last five years, the economic and financial market environment has operated under heightened uncertainty associated with the COVID-19 pandemic, the war in Ukraine, stubborn inflation, and more recently, economic policy uncertainty and geopolitical tensions. Although the Federal Reserve responded to easing inflation by cutting short-term rates in late 2024, it has since paused those cuts to assess how the effects of fluctuating trade policies affect the economy. These factors underscore the importance of using multiple models when determining NW Natural's cost of equity to gain a comprehensive perspective of the effect of fluid and evolving market conditions on the cost of equity.

IX. CONCLUSION

Q. Please summarize your ROE recommendation based on this range of results.

A. Based on my analyses of three widely used analytical approaches applied to a proxy group of six natural gas utilities, I estimate that the Company's cost of equity is within a range of 10.00 percent to 11.00 percent. Within that range, I conclude that an ROE of 10.20 percent is reasonable and conservative. Given the small size of the proxy group of natural gas utilities, I evaluated the reasonableness of my recommendation by

applying the same analytical approaches to an expanded proxy group that added 13 electric utilities with meaningful gas operations to the group of six natural gas utilities. The results of the expanded Combined Proxy Group produced a recommended ROE range of approximately 10.15 percent to 10.91 percent. Therefore, those results reinforce my conclusion that an ROE of 10.20 percent is reasonable and conservative.

Additionally, I consider the Company's business risk profile, including its capital expenditure plan, its exposure to decarbonization policies, and its significantly smaller size relative to the proxy companies. My 10.20 percent ROE recommendation does not include an explicit adjustment for these risks; therefore, my recommendation is conservative.

Q. What is your conclusion regarding the Company's proposed capital structure?

A. I support NW Natural's requested capital structure of 51.00 percent common equity, 48.00 percent long-term debt and 1.00 percent short-term debt as reasonable relative to the range of capital structures for the operating companies held by the two proxy groups.

Q. Does this conclude your Direct Testimony?

A. Yes.

X. LIST OF EXHIBITS

Exh. JEN-2	Résumé and Testimony Listing of Jennifer E. Nelson
Exh. JEN-3	Summary of ROE Model Results and ROE Recommendation
Exh. JEN-4	Constant Growth DCF Analysis
Exh. JEN-5	Quarterly Growth DCF Analysis
Exh. JEN-6	Forward Market Return Calculation
Exh. JEN-7	Capital Asset Pricing Model
Exh. JEN-8	Bond Yield Plus Risk Premium Analysis
Exh. JEN-9	Gas Proxy Group Regulatory Risk Comparative Assessment
Exh. JEN-10	Small Size Analysis
Exh. JEN-11	Gas Proxy Group Capital Structure Analysis
Exh. JEN-12	Gas Proxy Group Current Authorized Equity Ratio by Jurisdiction
Exh. JEN-13	Moody's and S&P Credit Rating Reports for NW Natural and Northwest Natural Holdings (2024 and 2025)
Exh. JEN-14	RRA Regulatory Focus: Alternative ratemaking plans in the U.S. (April 2020)

Exh. JEN-15	RRA Adjustment clauses: A state by state overview (July 2022)
Exh. JEN-16	RRA State Regulatory Evaluations Quarterly Update, December 2024, Excel Databook (Confidential and Redacted))
Exh. JEN-17	Standard & Poor's Corporate Methodology Sector Specific Criteria for the Regulated Utilities Sector
Exh. JEN-18	Moody's Rating Methodology: Regulated Electric and Gas Utilities
Exh. JEN-19	S&P Global Ratings Industry Credit Outlook 2025: North America Regulated Utilities (Confidential and Redacted)

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Jennifer E. Nelson

RATE OF RETURN ON EQUITY

Exh. JEN-2

August 29, 2025

JENNIFER E. NELSON
VICE PRESIDENT

Ms. Nelson is a Certified Rate of Return Analyst with more than fifteen years of experience in the energy industry. As an expert witness, she has testified to the cost of capital and alternative ratemaking proposals for electric, natural gas, and water utilities. In her time as a consultant, Ms. Nelson has provided consulting services on a variety of utility regulatory matters including ratemaking and regulatory policy, cost of service and revenue requirements, integrated resource planning, renewable power contracts, natural gas pipeline development, utility supply planning issues, and merger and acquisition transactions. Ms. Nelson has extensive experience performing statistical analyses, developing economic and financial models, and providing policy analyses and recommendations.

Prior to joining Concentric, Ms. Nelson was a Director at ScottMadden, Inc., and a managing consultant at Sussex Economic Advisors, LLC. Prior to consulting, she was a staff economist at the Massachusetts Department of Public Utilities and a petroleum economist for the State of Alaska. Ms. Nelson holds a Master of Science degree in Resource and Applied Economics from the University of Alaska and a Bachelor of Science degree in Business Economics from Bentley University.

AREAS OF EXPERTISE

Cost of Capital

- Submitted expert testimony on behalf of electric utilities before regulatory commissions in Arkansas, Michigan, New Hampshire, New Mexico, North Carolina, South Carolina, Texas and Virginia regarding the cost of capital.
- Submitted expert testimony on behalf of natural gas utilities before regulatory commissions in Alaska, Florida, North Carolina, Ohio, Oregon, South Carolina, Utah, West Virginia, and Wyoming regarding the cost of capital.
- Submitted expert testimony on behalf of a water utility before the Kentucky Public Service Commission regarding the appropriate capital structure and cost of debt.
- Supported expert testimony regarding the cost of capital before numerous state utility regulatory commissions and the FERC on behalf of electric and natural gas utilities through research, financial analysis and modeling, and testimony development.

Alternative Ratemaking Mechanisms

- Submitted expert testimony on behalf of electric utilities and a water utility before the Arkansas Public Service Commission regarding the utilities' proposed Formula Rate Plans.
- Submitted expert testimony on behalf of an electric utility before the Oklahoma Corporation Commission regarding the utility's proposed Formula Rate Plan.
- Submitted expert testimony on behalf of an electric and natural gas utility before the Delaware Public Service Commission regarding the utility's proposed performance-based rate plan.

- Submitted expert testimony on behalf of an electric and natural gas utility before the Montana Public Service Commission regarding the utility's proposed alternative rate mechanisms.
- Co-sponsored expert testimony on behalf of a natural gas utility before the Maine Public Utilities Commission regarding the utility's proposed capital investment cost recovery mechanism.
- Supported expert testimony and performed research and analysis on alternative ratemaking frameworks.

Resource and Supply Planning

- Supported expert testimony on the reasonableness of utility resource supply portfolio decisions.
- Assisted in a benchmarking analysis on behalf of a Northeast U.S. natural gas utility regarding its supply planning standards and design day demand forecast process.
- Supported rebuttal testimony filed on behalf of an Alaska natural gas utility regarding the utility's gas supply planning standards.
- Supported the development of a New Hampshire electric utility's Integrated Resource Plan filed with the New Hampshire Public Utility Commission.
- Performed research and financial analysis to evaluate the benefits, costs, and policy options associated with natural gas expansion by Massachusetts natural gas utilities as part of a prepared report for the Massachusetts Department of Energy Resources.
- Developed a dynamic natural gas demand forecast model for in-state use for the State of Alaska, which included forecasting demand from both existing and anticipated natural gas utilities, power consumption, and large commercial operations.
- Conducted research and prepared analyses for a natural gas pipeline Open Season.

Other Regulatory Financial Issues

- Filed expert testimony before the California PUC regarding the benefits of financial flexibility and diversity in sources of financial capital associated with an electric utility's request to lease entitlements as a means of raising capital.
- Supported expert testimony on the appropriate level of remuneration associated with the Massachusetts electric utilities' long-term contracts for wind power through research, financial analysis and modeling, and testimony development.
- Provided research and analytical support estimating financial damages incurred as a result of construction delays for an electric transmission company.
- Prepared a Feasibility Study for an electric cooperative utility supporting a utility-owned solar project.

Mergers & Acquisitions

- Performed buy-side benchmarking and regulatory analysis for utility acquisitions.

RELEVANT PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2021-present)
Vice President
Assistant Vice President

ScottMadden, Inc. (2016-2021)
Director
Manager

Sussex Economic Advisors, LLC (2013-2016)
Managing Consultant

Massachusetts Department of Public Utilities (2011-2013)
Economist, Electric Power Division

State of Alaska Department of Revenue, Tax Division (2007-2010)
Petroleum Economist

Federal Reserve Bank of Boston (2000-2002)
Research Assistant, Economic Research Department

EDUCATION AND RELEVANT COURSEWORK

University of Alaska
Master of Science, Resource and Applied Economics

Bentley University (formerly Bentley College)
Bachelor of Science, Business Economics
Graduated *magna cum laude*

New Mexico State University
Center for Public Utilities, Regulatory Basics

ISO New England
Wholesale Energy Markets (WEM-101)

Colorado School of Mines
Petroleum Engineering SuperSchool

EUCI
Course Instructor – Performance-Based Ratemaking

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts
Member, Society of Utility and Regulatory Financial Analysts

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Regulatory Commission of Alaska				
ENSTAR Natural Gas Company	04/25	ENSTAR Natural Gas Company	TA-352-4	Cost of Capital
Arkansas Public Service Commission				
Liberty Utilities (Pine Bluff Water)	10/18	Liberty Utilities (Pine Bluff Water)	18-027-U	Formula Rate Plan and tariff
Entergy Arkansas, LLC	11/20	Entergy Arkansas, LLC	16-036-FR	Sponsored testimony evaluating the Return on Equity included in Rider FRP
Oklahoma Gas & Electric	10/21	Oklahoma Gas & Electric	21-087-U	Formula Rate Plan
California Public Utilities Commission				
Pacific Gas & Electric Co.	01/25	Pacific Gas & Electric Co.	A-24-03-009	Financial flexibility and capital diversity
Delaware Public Service Commission				
Delmarva Power & Light Company	08/24	Delmarva Power & Light Company	24-0868	Alternative Ratemaking Proposal
Florida Public Service Commission				
Pivotal Utility Holdings, Inc. d/b/a Florida City Gas	05/22	Pivotal Utility Holdings, Inc. d/b/a Florida City Gas	20220069-GU	Cost of Capital
State Corporate Commission of Kansas				
Evergy Kansas Central and Evergy Kansas South, Inc.	07/25	Evergy Kansas Central and Evergy Kansas South, Inc.	25-EKCE-294-RTS	Capital Structure
Kentucky Public Service Commission				
Bluegrass Water Utility Operating Company, LLC	09/20	Bluegrass Water Utility Operating Company, LLC	2020-290	Capital Structure and Cost of Long-Term Debt
Maine Public Utilities Commission				
Unitil Corporation	06/19	Northern Utilities, Inc.	19-00092	Co-sponsored testimony supporting a proposed CIRA capital tracking mechanism
Michigan Public Service Commission				
DTE Electric Company	04/25	DTE Electric Company	U-21860	Cost of Capital
Montana Public Utilities Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
NorthWestern Corporation	08/22	NorthWestern Corporation	2022-7-78 (elect.) 2022-7-78 (gas)	Alternative Ratemaking Proposals
New Hampshire Public Utilities Commission				
Unitil Energy Systems, Inc.	04/21	Unitil Energy Systems, Inc.	DE 21-030	Cost of Capital
New Mexico Public Regulation Commission				
El Paso Electric Company	07/20	El Paso Electric Company	20-00104-UT	Cost of Capital
North Carolina Utilities Commission				
Public Service Company of North Carolina d/b/a Dominion Energy North Carolina	04/21	Public Service Company of North Carolina d/b/a Dominion Energy North Carolina	G-5, Sub 632	Cost of Capital
Virginia Electric & Power Co., d/b/a Dominion Energy North Carolina	03/24	Virginia Electric & Power Co., d/b/a Dominion Energy North Carolina	E-22, Sub 694	Cost of Capital
Public Service Company of North Carolina	04/25	Public Service Company of North Carolina	G-5, Sub 686	Cost of Capital
Public Utilities Commission of Ohio				
The East Ohio Gas Company d/b/a Dominion Energy Ohio	11/23	The East Ohio Gas Company d/b/a Dominion Energy Ohio	23-0894-GA-AIR	Cost of Capital
Oklahoma Corporation Commission				
Oklahoma Gas & Electric	12/21	Oklahoma Gas & Electric	PUD202100164	Formula Rate Plan
Public Utility Commission of Oregon				
Northwest Natural Gas Company dba NW Natural	12/23	Northwest Natural Gas Company dba NW Natural	UG 490	Cost of Capital
Northwest Natural Gas Company dba NW Natural	12/24	Northwest Natural Gas Company dba NW Natural	UG 520	Cost of Capital
Public Utilities Commission of South Carolina				
Dominion Energy South Carolina	04/23	Dominion Energy South Carolina	2023-70-G	Cost of Capital
Dominion Energy South Carolina	03/24	Dominion Energy South Carolina	2024-34-E	Cost of Capital

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Public Utilities Commission of Texas				
Sharyland Utilities L.L.C.	12/20	Sharyland Utilities L.L.C.	51611	Cost of Capital
El Paso Electric Company	06/21	El Paso Electric Company	52195	Cost of Capital
Wind Energy Transmission Texas, LLC dba WETT	12/24	Wind Energy Transmission Texas, LLC dba WETT	57299	Cost of Capital
El Paso Electric Company	01/25	El Paso Electric Company	57568	Cost of Capital
Utah Public Service Commission				
Enbridge Gas Utah	05/25	Enbridge Gas Utah	25-057-06	Cost of Capital
Dominion Energy Utah	05/22	Dominion Energy Utah	22-057-03	Cost of Capital
Virginia State Corporation Commission				
Virginia Electric & Power Company (Dominion Energy Virginia)	03/25	Virginia Electric & Power Company (Dominion Energy Virginia)	PUR-2025-00058	Cost of Capital
Public Service Commission of West Virginia				
Hope Gas, Inc.	04/25	Hope Gas, Inc.	25-0417-G-42T	Cost of Capital
Hope Gas, Inc. d/b/a Dominion Energy West Virginia	11/20	Hope Gas, Inc. d/b/a Dominion Energy West Virginia	20-0746-G-42T	Cost of Capital
Wyoming Public Service Commission				
Dominion Energy Wyoming	03/23	Dominion Energy Wyoming	30010-215-GR-23	Cost of Capital

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Jennifer E. Nelson

RATE OF RETURN ON EQUITY

Exh. JEN-3

August 29, 2025

Exhibit JEN-3
Page 1 of 1

SUMMARY OF ROE MODEL RESULTS AND ROE RECOMMENDATION

	Incluing SWX from DCF		*Excluding SWX from DCF*	
Model	**Gas Proxy Group**	**Combined Proxy Group**	**Gas Proxy Group**	**Combined Proxy Group**
Constant Growth DCF	10.69%	10.17%	10.34%	10.06%
Quarterly Growth DCF	10.95%	10.33%	10.59%	10.23%
Average DCF	*10.82%*	*10.25%*	*10.47%*	*10.15%*
Blended CAPM	11.17%	11.12%	11.17%	11.12%
Historical CAPM	10.20%	10.16%	10.20%	10.16%
Blended ECAPM	11.75%	11.71%	11.75%	11.71%
Historical ECAPM	10.69%	10.66%	10.69%	10.66%
Average CAPM	*10.96%*	*10.91%*	*10.96%*	*10.91%*
Risk Premium	*10.24%*	*10.28%*	*10.24%*	*10.28%*
3-Model Average	10.67%	10.48%	10.56%	10.45%
ROE Recommendation	**10.20%**			

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Jennifer E. Nelson

RATE OF RETURN ON EQUITY

Exh. JEN-4

August 29, 2025

Exhibit JEN-4
Page 1 of 3

Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment
30 Day Average Stock Price

	Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] CIQ Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
1	Atmos Energy Corporation	ATO	$3.48	$154.39	2.25%	2.33%	7.20%	7.28%	7.00%	7.16%	9.33%	9.50%	9.62%
2	New Jersey Resources Corporation	NJR	$1.80	$45.25	3.98%	4.11%	n/a	7.90%	5.00%	6.45%	9.08%	10.56%	12.04%
3	NiSource Inc.	NI	$1.12	$39.46	2.84%	2.96%	7.90%	7.95%	9.50%	8.45%	10.85%	11.41%	12.47%
4	ONE Gas, Inc.	OGS	$2.68	$73.63	3.64%	3.74%	5.60%	5.84%	4.50%	5.31%	8.22%	9.05%	9.58%
5	Southwest Gas Holdings, Inc.	SWX	$2.48	$72.26	3.43%	3.60%	9.90%	n/a	10.00%	9.95%	13.50%	13.55%	13.60%
6	Spire, Inc.	SR	$3.14	$73.77	4.26%	4.39%	6.50%	8.08%	4.50%	6.36%	8.85%	10.75%	12.51%
7	Ameren Corporation	AEE	$2.84	$96.16	2.95%	3.05%	7.00%	7.00%	6.50%	6.83%	9.55%	9.89%	10.06%
8	Avista Corporation	AVA	$1.96	$37.97	5.16%	5.31%	6.10%	5.50%	5.50%	5.70%	10.80%	11.01%	11.42%
9	Black Hills Corporation	BKH	$2.70	$57.35	4.71%	4.83%	5.30%	5.70%	3.50%	4.83%	8.30%	9.66%	10.55%
10	CenterPoint Energy, Inc.	CNP	$0.88	$36.75	2.39%	2.48%	7.80%	7.99%	6.50%	7.43%	8.97%	9.91%	10.48%
11	CMS Energy Corporation	CMS	$2.17	$69.90	3.10%	3.21%	7.80%	7.00%	5.50%	6.77%	8.69%	9.98%	11.03%
12	Consolidated Edison, Inc.	ED	$3.40	$102.33	3.32%	3.42%	5.60%	6.20%	6.00%	5.93%	9.02%	9.35%	9.63%
13	DTE Energy Company	DTE	$4.36	$134.55	3.24%	3.34%	7.60%	7.15%	4.50%	6.42%	7.81%	9.76%	10.96%
14	Eversource Energy	ES	$3.01	$64.19	4.69%	4.82%	5.70%	5.50%	5.50%	5.57%	10.32%	10.39%	10.52%
15	Public Service Enterprise Group Inc.	PEG	$2.52	$80.81	3.12%	3.22%	7.00%	6.10%	7.00%	6.70%	9.31%	9.92%	10.23%
16	Sempra Energy	SRE	$2.58	$76.33	3.38%	3.50%	7.90%	7.65%	5.50%	7.02%	8.97%	10.52%	11.41%
17	Southern Company	SO	$2.96	$89.56	3.30%	3.41%	6.50%	6.57%	6.50%	6.52%	9.91%	9.94%	9.98%
18	Wisconsin Energy Corporation	WEC	$3.57	$105.51	3.38%	3.50%	7.00%	7.10%	6.00%	6.70%	9.48%	10.20%	10.60%
19	Xcel Energy Inc.	XEL	$2.28	$68.78	3.31%	3.44%	7.50%	7.75%	7.00%	7.42%	10.43%	10.85%	11.19%
20	Gas Proxy Group Mean				3.40%	3.52%	7.42%	7.41%	6.75%	7.28%	9.97%	10.80%	11.64%
21	Gas Proxy Group Median				3.54%	3.67%	7.20%	7.90%	6.00%	6.81%	9.21%	10.65%	12.25%
22	**Gas Proxy Group Average of the Mean and Median**				**3.47%**	**3.60%**	**7.31%**	**7.66%**	**6.38%**	**7.04%**	**9.59%**	**10.73%**	**11.95%**
23	Combined Proxy Group Mean				3.50%	3.61%	6.99%	6.90%	6.11%	6.71%	9.55%	10.33%	10.94%
24	Combined Proxy Group Median				3.32%	3.44%	7.00%	7.05%	6.00%	6.70%	9.31%	9.98%	10.60%
25	**Combined Proxy Group Average of the Mean and Median**				**3.41%**	**3.53%**	**7.00%**	**6.98%**	**6.05%**	**6.71%**	**9.43%**	**10.15%**	**10.77%**
26	**Gas Proxy Group Average of the Mean and Median - Excluding SWX**				**3.52%**	**3.62%**	**6.83%**	**7.66%**	**5.55%**	**6.60%**	**9.17%**	**10.40%**	**11.64%**
27	**Combined Proxy Group Average of the Mean and Median - Excluding SWX**				**3.41%**	**3.52%**	**6.91%**	**6.98%**	**5.82%**	**6.57%**	**9.26%**	**10.05%**	**10.68%**

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of 06/30/2025
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: S&P Capital IQ
[7] Source: Value Line
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Exhibit JEN-4
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Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment
90 Day Average Stock Price

	Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] CIQ Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
1	Atmos Energy Corporation	ATO	$3.48	$153.65	2.26%	2.35%	7.20%	7.28%	7.00%	7.16%	9.34%	9.51%	9.63%
2	New Jersey Resources Corporation	NJR	$1.80	$47.31	3.80%	3.93%	n/a	7.90%	5.00%	6.45%	8.90%	10.38%	11.85%
3	NiSource Inc.	NI	$1.12	$39.33	2.85%	2.97%	7.90%	7.95%	9.50%	8.45%	10.86%	11.42%	12.48%
4	ONE Gas, Inc.	OGS	$2.68	$74.79	3.58%	3.68%	5.60%	5.84%	4.50%	5.31%	8.16%	8.99%	9.53%
5	Southwest Gas Holdings, Inc.	SWX	$2.48	$72.82	3.41%	3.58%	9.90%	n/a	10.00%	9.95%	13.47%	13.53%	13.58%
6	Spire, Inc.	SR	$3.14	$75.35	4.17%	4.30%	6.50%	8.08%	4.50%	6.36%	8.76%	10.66%	12.42%
7	Ameren Corporation	AEE	$2.84	$97.74	2.91%	3.01%	7.00%	7.00%	6.50%	6.83%	9.50%	9.84%	10.01%
8	Avista Corporation	AVA	$1.96	$39.48	4.96%	5.11%	6.10%	5.50%	5.50%	5.70%	10.60%	10.81%	11.22%
9	Black Hills Corporation	BKH	$2.70	$59.03	4.58%	4.69%	5.30%	5.70%	3.50%	4.83%	8.16%	9.52%	10.41%
10	CenterPoint Energy, Inc.	CNP	$0.88	$36.37	2.42%	2.51%	7.80%	7.99%	6.50%	7.43%	9.00%	9.94%	10.50%
11	CMS Energy Corporation	CMS	$2.17	$71.76	3.02%	3.13%	7.80%	7.00%	5.50%	6.77%	8.61%	9.89%	10.94%
12	Consolidated Edison, Inc.	ED	$3.40	$105.34	3.23%	3.32%	5.60%	6.20%	6.00%	5.93%	8.92%	9.26%	9.53%
13	DTE Energy Company	DTE	$4.36	$134.29	3.25%	3.35%	7.60%	7.15%	4.50%	6.42%	7.82%	9.77%	10.97%
14	Eversource Energy	ES	$3.01	$61.54	4.89%	5.03%	5.70%	5.50%	5.50%	5.57%	10.53%	10.59%	10.73%
15	Public Service Enterprise Group Inc.	PEG	$2.52	$80.96	3.11%	3.22%	7.00%	6.10%	7.00%	6.70%	9.31%	9.92%	10.22%
16	Sempra Energy	SRE	$2.58	$73.58	3.51%	3.63%	7.90%	7.65%	5.50%	7.02%	9.10%	10.65%	11.54%
17	Southern Company	SO	$2.96	$89.78	3.30%	3.40%	6.50%	6.57%	6.50%	6.52%	9.90%	9.93%	9.98%
18	Wisconsin Energy Corporation	WEC	$3.57	$106.33	3.36%	3.47%	7.00%	7.10%	6.00%	6.70%	9.46%	10.17%	10.58%
19	Xcel Energy Inc.	XEL	$2.28	$69.44	3.28%	3.41%	7.50%	7.75%	7.00%	7.42%	10.40%	10.82%	11.16%
20	Gas Proxy Group Mean				3.35%	3.47%	7.42%	7.41%	6.75%	7.28%	9.92%	10.75%	11.58%
21	Gas Proxy Group Median				3.49%	3.63%	7.20%	7.90%	6.00%	6.81%	9.12%	10.52%	12.14%
22	**Gas Proxy Group Average of the Mean and Median**				**3.42%**	**3.55%**	**7.31%**	**7.66%**	**6.38%**	**7.04%**	**9.52%**	**10.63%**	**11.86%**
23	Combined Proxy Group Mean				3.47%	3.58%	6.99%	6.90%	6.11%	6.71%	9.52%	10.29%	10.91%
24	Combined Proxy Group Median				3.30%	3.41%	7.00%	7.05%	6.00%	6.70%	9.31%	9.94%	10.73%
25	**Combined Proxy Group Average of the Mean and Median**				**3.38%**	**3.49%**	**7.00%**	**6.98%**	**6.05%**	**6.71%**	**9.41%**	**10.12%**	**10.82%**
	Gas Proxy Group Average of the Mean and Median - Excluding SWX				**3.46%**	**3.56%**	**6.83%**	**7.66%**	**5.55%**	**6.60%**	**9.05%**	**10.28%**	**11.52%**
	Combined Proxy Group Average of the Mean and Median - Excluding SWX				**3.38%**	**3.49%**	**6.91%**	**6.98%**	**5.82%**	**6.57%**	**9.25%**	**10.02%**	**10.71%**

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of 06/30/2025
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: S&P Capital IQ
[7] Source: Value Line
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Exhibit JEN-4
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Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment
180 Day Average Stock Price

			[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
	Company	Ticker	Annualized Dividend	Average Stock Price	Dividend Yield	Expected Dividend Yield	Zacks Earnings Growth	CIQ Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Low ROE	Mean ROE	High ROE
1	Atmos Energy Corporation	ATO	$3.48	$148.08	2.35%	2.43%	7.20%	7.28%	7.00%	7.16%	9.43%	9.60%	9.72%
2	New Jersey Resources Corporation	NJR	$1.80	$47.27	3.81%	3.93%	n/a	7.90%	5.00%	6.45%	8.90%	10.38%	11.86%
3	NiSource Inc.	NI	$1.12	$37.96	2.95%	3.07%	7.90%	7.95%	9.50%	8.45%	10.97%	11.52%	12.59%
4	ONE Gas, Inc.	OGS	$2.68	$73.42	3.65%	3.75%	5.60%	5.84%	4.50%	5.31%	8.23%	9.06%	9.60%
5	Southwest Gas Holdings, Inc.	SWX	$2.48	$73.48	3.38%	3.54%	9.90%	n/a	10.00%	9.95%	13.44%	13.49%	13.54%
6	Spire, Inc.	SR	$3.14	$71.82	4.37%	4.51%	6.50%	8.08%	4.50%	6.36%	8.97%	10.87%	12.63%
7	Ameren Corporation	AEE	$2.84	$94.46	3.01%	3.11%	7.00%	7.00%	6.50%	6.83%	9.60%	9.94%	10.11%
8	Avista Corporation	AVA	$1.96	$38.33	5.11%	5.26%	6.10%	5.50%	5.50%	5.70%	10.75%	10.96%	11.37%
9	Black Hills Corporation	BKH	$2.70	$59.53	4.54%	4.65%	5.30%	5.70%	3.50%	4.83%	8.12%	9.49%	10.37%
10	CenterPoint Energy, Inc.	CNP	$0.88	$33.89	2.60%	2.69%	7.80%	7.99%	6.50%	7.43%	9.18%	10.12%	10.69%
11	CMS Energy Corporation	CMS	$2.17	$69.92	3.10%	3.21%	7.80%	7.00%	5.50%	6.77%	8.69%	9.98%	11.02%
12	Consolidated Edison, Inc.	ED	$3.40	$100.73	3.38%	3.48%	5.60%	6.20%	6.00%	5.93%	9.07%	9.41%	9.68%
13	DTE Energy Company	DTE	$4.36	$128.47	3.39%	3.50%	7.60%	7.15%	4.50%	6.42%	7.97%	9.92%	11.12%
14	Eversource Energy	ES	$3.01	$61.09	4.93%	5.06%	5.70%	5.50%	5.50%	5.57%	10.56%	10.63%	10.77%
15	Public Service Enterprise Group Inc.	PEG	$2.52	$84.02	3.00%	3.10%	7.00%	6.10%	7.00%	6.70%	9.19%	9.80%	10.10%
16	Sempra Energy	SRE	$2.58	$79.91	3.23%	3.34%	7.90%	7.65%	5.50%	7.02%	8.82%	10.36%	11.26%
17	Southern Company	SO	$2.96	$87.98	3.36%	3.47%	6.50%	6.57%	6.50%	6.52%	9.97%	10.00%	10.05%
18	Wisconsin Energy Corporation	WEC	$3.57	$101.98	3.50%	3.62%	7.00%	7.10%	6.00%	6.70%	9.61%	10.32%	10.72%
19	Xcel Energy Inc.	XEL	$2.28	$68.29	3.34%	3.46%	7.50%	7.75%	7.00%	7.42%	10.46%	10.88%	11.22%
20	Gas Proxy Group Mean				3.42%	3.54%	7.42%	7.41%	6.75%	7.28%	9.99%	10.82%	11.66%
21	Gas Proxy Group Median				3.51%	3.65%	7.20%	7.90%	6.00%	6.81%	9.20%	10.63%	12.22%
22	**Gas Proxy Group Average of the Mean and Median**				**3.47%**	**3.59%**	**7.31%**	**7.66%**	**6.38%**	**7.04%**	**9.60%**	**10.72%**	**11.94%**
23	Combined Proxy Group Mean				3.53%	3.64%	6.99%	6.90%	6.11%	6.71%	9.58%	10.35%	10.97%
24	Combined Proxy Group Median				3.38%	3.48%	7.00%	7.05%	6.00%	6.70%	9.19%	10.12%	10.77%
25	**Combined Proxy Group Average of the Mean and Median**				**3.45%**	**3.56%**	**7.00%**	**6.98%**	**6.05%**	**6.71%**	**9.38%**	**10.24%**	**10.87%**
	Gas Proxy Group Average of the Mean and Median - Excluding SWX				**3.54%**	**3.64%**	**6.83%**	**7.66%**	**5.55%**	**6.60%**	**9.14%**	**10.33%**	**11.57%**
	Combined Proxy Group Average of the Mean and Median - Excluding SWX				**3.45%**	**3.56%**	**6.91%**	**6.98%**	**5.82%**	**6.57%**	**9.27%**	**10.12%**	**10.79%**

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, equals indicated number of trading day average as of 06/30/2025

[3] Equals [1] / [2]

[4] Equals [3] x (1 + 0.5 x [8])

[5] Source: Zacks

[6] Source: S&P Capital IQ

[7] Source: Value Line

[8] Equals Average ([5], [6], [7])

[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])

[10] Equals [4] + [8]

[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Jennifer E. Nelson

RATE OF RETURN ON EQUITY

Exh. JEN-5

August 29, 2025

Exhibit JEN-5
Page 1 of 3

Quarterly Growth Discounted Cash Flow Model
30 Day Average Stock Price

	Company	Ticker	[1] Dividend 1	[2] Dividend 2	[3] Dividend 3	[4] Dividend 4	[5] Expected Dividend 1	[6] Expected Dividend 2	[7] Expected Dividend 3	[8] Expected Dividend 4	[9] Average Stock Price	[10] Zacks Earnings Growth	[11] CIQ Earnings Growth	[12] Value Line Earnings Growth	[13] Average Earnings Growth	[14] Low ROE	[15] Mean ROE	[16] High ROE
1	Atmos Energy Corporation	ATO	$0.81	$0.87	$0.87	$0.87	$0.86	$0.93	$0.93	$0.93	$154.39	7.20%	7.28%	7.00%	7.16%	9.45%	9.61%	9.74%
2	New Jersey Resources Corporation	NJR	$0.45	$0.45	$0.45	$0.45	$0.48	$0.48	$0.48	$0.48	$45.25	n/a	7.90%	5.00%	6.45%	9.32%	10.85%	12.39%
3	NiSource Inc.	NI	$0.27	$0.28	$0.28	$0.28	$0.29	$0.30	$0.30	$0.30	$39.46	7.90%	7.95%	9.50%	8.45%	11.04%	11.61%	12.71%
4	ONE Gas, Inc.	OGS	$0.66	$0.66	$0.67	$0.67	$0.70	$0.70	$0.71	$0.71	$73.63	5.60%	5.84%	4.50%	5.31%	8.39%	9.25%	9.80%
5	Southwest Gas Holdings, Inc.	SWX	$0.62	$0.62	$0.62	$0.62	$0.68	$0.68	$0.68	$0.68	$72.26	9.90%	n/a	10.00%	9.95%	13.86%	13.92%	13.97%
6	Spire, Inc.	SR	$0.76	$0.79	$0.79	$0.79	$0.80	$0.83	$0.83	$0.83	$73.77	6.50%	8.08%	4.50%	6.36%	9.05%	11.02%	12.85%
7	Ameren Corporation	AEE	$0.67	$0.67	$0.71	$0.71	$0.72	$0.72	$0.76	$0.76	$96.16	7.00%	7.00%	6.50%	6.83%	9.66%	10.01%	10.18%
8	Avista Corporation	AVA	$0.48	$0.48	$0.49	$0.49	$0.50	$0.50	$0.52	$0.52	$37.97	6.10%	5.50%	5.50%	5.70%	11.08%	11.29%	11.72%
9	Black Hills Corporation	BKH	$0.65	$0.65	$0.68	$0.68	$0.68	$0.68	$0.71	$0.71	$57.35	5.30%	5.70%	3.50%	4.83%	8.43%	9.85%	10.78%
10	CenterPoint Energy, Inc.	CNP	$0.20	$0.21	$0.22	$0.22	$0.21	$0.23	$0.24	$0.24	$36.75	7.80%	7.99%	6.50%	7.43%	9.04%	10.00%	10.58%
11	CMS Energy Corporation	CMS	$0.52	$0.52	$0.54	$0.54	$0.55	$0.55	$0.58	$0.58	$69.90	7.80%	7.00%	5.50%	6.77%	8.79%	10.12%	11.19%
12	Consolidated Edison, Inc.	ED	$0.83	$0.83	$0.85	$0.85	$0.88	$0.88	$0.90	$0.90	$102.33	5.60%	6.20%	6.00%	5.93%	9.18%	9.53%	9.81%
13	DTE Energy Company	DTE	$1.09	$1.09	$1.09	$1.09	$1.16	$1.16	$1.16	$1.16	$134.55	7.60%	7.15%	4.50%	6.42%	7.99%	9.99%	11.23%
14	Eversource Energy	ES	$0.72	$0.72	$0.75	$0.75	$0.75	$0.75	$0.79	$0.79	$64.19	5.70%	5.50%	5.50%	5.57%	10.51%	10.58%	10.72%
15	Public Service Enterprise Group Inc.	PEG	$0.60	$0.60	$0.63	$0.63	$0.64	$0.64	$0.67	$0.67	$80.81	7.00%	6.10%	7.00%	6.70%	9.44%	10.07%	10.38%
16	Sempra Energy	SRE	$0.62	$0.62	$0.65	$0.65	$0.66	$0.66	$0.69	$0.69	$76.33	7.90%	7.65%	5.50%	7.02%	9.11%	10.70%	11.63%
17	Southern Company	SO	$0.72	$0.72	$0.72	$0.74	$0.77	$0.77	$0.77	$0.79	$89.56	6.50%	6.57%	6.50%	6.52%	10.08%	10.10%	10.15%
18	Wisconsin Energy Corporation	WEC	$0.84	$0.84	$0.89	$0.89	$0.89	$0.89	$0.95	$0.95	$105.51	7.00%	7.10%	6.00%	6.70%	9.59%	10.32%	10.74%
19	Xcel Energy Inc.	XEL	$0.55	$0.55	$0.57	$0.57	$0.59	$0.59	$0.61	$0.61	$68.78	7.50%	7.75%	7.00%	7.42%	10.61%	11.05%	11.40%
20	Gas Proxy Group Mean											7.42%	7.41%	6.75%	7.28%	10.19%	11.04%	11.91%
21	Gas Proxy Group Median											7.20%	7.90%	6.00%	6.81%	9.38%	10.94%	12.55%
22	**Gas Proxy Group Average of the Mean and Median**											**7.31%**	**7.66%**	**6.38%**	**7.04%**	**9.78%**	**10.99%**	**12.23%**
23	Combined Proxy Group Mean											6.99%	6.90%	6.11%	6.71%	9.72%	10.52%	11.16%
24	Combined Proxy Group Median											7.00%	7.05%	6.00%	6.70%	9.44%	10.12%	10.78%
25	**Combined Proxy Group Average of the Mean and Median**											**7.00%**	**6.98%**	**6.05%**	**6.71%**	**9.58%**	**10.32%**	**10.97%**
26	**Gas Proxy Group Average of the Mean and Median - Excluding SWX**											**6.83%**	**7.66%**	**5.55%**	**6.60%**	**9.39%**	**10.66%**	**11.94%**
27	**Combined Proxy Group Average of the Mean and Median - Excluding SWX**											**6.91%**	**6.98%**	**5.82%**	**6.57%**	**9.43%**	**10.22%**	**10.88%**

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service
[3] Source: Bloomberg Professional Service
[4] Source: Bloomberg Professional Service
[5] Equals Col. [1] x (1 + Col. [13])
[6] Equals Col. [2] x (1 + Col. [13])
[7] Equals Col. [3] x (1 + Col. [13])
[8] Equals Col. [4] x (1 + Col. [13])
[9] Source: Bloomberg Professional, equals indicated number of trading day average as of 06/30/2025
[10] Source: Zacks
[11] Source: S&P Capital IQ
[12] Source: Value Line
[13] Equals Average (Cols. [10], [11], [12])
[14] Implied Low DCF
[15] Implied Mean DCF
[16] Implied High DCF

Exhibit JEN-5
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Quarterly Growth Discounted Cash Flow Model
90 Day Average Stock Price

			[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
	Company	Ticker	Dividend 1	Dividend 2	Dividend 3	Dividend 4	Expected Dividend 1	Expected Dividend 2	Expected Dividend 3	Expected Dividend 4	Average Stock Price	Zacks Earnings Growth	CIQ Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Low ROE	Mean ROE	High ROE
1	Atmos Energy Corporation	ATO	$0.81	$0.87	$0.87	$0.87	$0.86	$0.93	$0.93	$0.93	$153.65	7.20%	7.28%	7.00%	7.16%	9.46%	9.63%	9.75%
2	New Jersey Resources Corporation	NJR	$0.45	$0.45	$0.45	$0.45	$0.48	$0.48	$0.48	$0.48	$47.31	n/a	7.90%	5.00%	6.45%	9.13%	10.66%	12.19%
3	NiSource Inc.	NI	$0.27	$0.28	$0.28	$0.28	$0.29	$0.30	$0.30	$0.30	$39.33	7.90%	7.95%	9.50%	8.45%	11.05%	11.62%	12.72%
4	ONE Gas, Inc.	OGS	$0.66	$0.66	$0.67	$0.67	$0.70	$0.70	$0.71	$0.71	$74.79	5.60%	5.84%	4.50%	5.31%	8.33%	9.18%	9.74%
5	Southwest Gas Holdings, Inc.	SWX	$0.62	$0.62	$0.62	$0.62	$0.68	$0.68	$0.68	$0.68	$72.82	9.90%	n/a	10.00%	9.95%	13.83%	13.88%	13.94%
6	Spire, Inc.	SR	$0.76	$0.79	$0.79	$0.79	$0.80	$0.83	$0.83	$0.83	$75.35	6.50%	8.08%	4.50%	6.36%	8.95%	10.92%	12.75%
7	Ameren Corporation	AEE	$0.67	$0.67	$0.71	$0.71	$0.72	$0.72	$0.76	$0.76	$97.74	7.00%	7.00%	6.50%	6.83%	9.61%	9.96%	10.13%
8	Avista Corporation	AVA	$0.48	$0.48	$0.49	$0.49	$0.50	$0.50	$0.52	$0.52	$39.48	6.10%	5.50%	5.50%	5.70%	10.86%	11.07%	11.50%
9	Black Hills Corporation	BKH	$0.65	$0.65	$0.68	$0.68	$0.68	$0.68	$0.71	$0.71	$59.03	5.30%	5.70%	3.50%	4.83%	8.29%	9.71%	10.63%
10	CenterPoint Energy, Inc.	CNP	$0.20	$0.21	$0.22	$0.22	$0.21	$0.23	$0.24	$0.24	$36.37	7.80%	7.99%	6.50%	7.43%	9.07%	10.03%	10.61%
11	CMS Energy Corporation	CMS	$0.52	$0.52	$0.54	$0.54	$0.55	$0.55	$0.58	$0.58	$71.76	7.80%	7.00%	5.50%	6.77%	8.71%	10.03%	11.10%
12	Consolidated Edison, Inc.	ED	$0.83	$0.83	$0.85	$0.85	$0.88	$0.88	$0.90	$0.90	$105.34	5.60%	6.20%	6.00%	5.93%	9.08%	9.43%	9.71%
13	DTE Energy Company	DTE	$1.09	$1.09	$1.09	$1.09	$1.16	$1.16	$1.16	$1.16	$134.29	7.60%	7.15%	4.50%	6.42%	7.99%	10.00%	11.24%
14	Eversource Energy	ES	$0.72	$0.72	$0.75	$0.75	$0.75	$0.75	$0.79	$0.79	$61.54	5.70%	5.50%	5.50%	5.57%	10.73%	10.80%	10.94%
15	Public Service Enterprise Group Inc.	PEG	$0.60	$0.60	$0.63	$0.63	$0.64	$0.64	$0.67	$0.67	$80.96	7.00%	6.10%	7.00%	6.70%	9.43%	10.06%	10.37%
16	Sempra Energy	SRE	$0.62	$0.62	$0.65	$0.65	$0.66	$0.66	$0.69	$0.69	$73.58	7.90%	7.65%	5.50%	7.02%	9.25%	10.84%	11.77%
17	Southern Company	SO	$0.72	$0.72	$0.72	$0.74	$0.77	$0.77	$0.77	$0.79	$89.78	6.50%	6.57%	6.50%	6.52%	10.07%	10.09%	10.14%
18	Wisconsin Energy Corporation	WEC	$0.84	$0.84	$0.89	$0.89	$0.89	$0.89	$0.95	$0.95	$106.33	7.00%	7.10%	6.00%	6.70%	9.56%	10.30%	10.71%
19	Xcel Energy Inc.	XEL	$0.55	$0.55	$0.57	$0.57	$0.59	$0.59	$0.61	$0.61	$69.44	7.50%	7.75%	7.00%	7.42%	10.58%	11.01%	11.36%
20	Gas Proxy Group Mean											7.42%	7.41%	6.75%	7.28%	10.13%	10.98%	11.85%
21	Gas Proxy Group Median											7.20%	7.90%	6.00%	6.81%	9.29%	10.79%	12.45%
22	**Gas Proxy Group Average of the Mean and Median**											**7.31%**	**7.66%**	**6.38%**	**7.04%**	**9.71%**	**10.89%**	**12.15%**
23	Combined Proxy Group Mean											6.99%	6.90%	6.11%	6.71%	9.68%	10.49%	11.12%
24	Combined Proxy Group Median											7.00%	7.05%	6.00%	6.70%	9.43%	10.09%	10.94%
25	**Combined Proxy Group Average of the Mean and Median**											**7.00%**	**6.98%**	**6.05%**	**6.71%**	**9.56%**	**10.29%**	**11.03%**
26	**Gas Proxy Group Average of the Mean and Median - Excluding SWX**											**6.83%**	**7.66%**	**5.55%**	**6.60%**	**9.26%**	**10.53%**	**11.81%**
27	**Combined Proxy Group Average of the Mean and Median - Excluding SWX**											**6.91%**	**6.98%**	**5.82%**	**6.57%**	**9.40%**	**10.19%**	**10.90%**

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service
[3] Source: Bloomberg Professional Service
[4] Source: Bloomberg Professional Service
[5] Equals Col. [1] x (1 + Col. [13])
[6] Equals Col. [2] x (1 + Col. [13])
[7] Equals Col. [3] x (1 + Col. [13])
[8] Equals Col. [4] x (1 + Col. [13])
[9] Source: Bloomberg Professional, equals indicated number of trading day average as of 06/30/2025
[10] Source: Zacks
[11] Source: S&P Capital IQ
[12] Source: Value Line
[13] Equals Average (Cols. [10], [11], [12])
[14] Implied Low DCF
[15] Implied Mean DCF
[16] Implied High DCF

Exhibit JEN-5
Page 3 of 3

Quarterly Growth Discounted Cash Flow Model
180 Day Average Stock Price

	Company	Ticker	[1] Dividend 1	[2] Dividend 2	[3] Dividend 3	[4] Dividend 4	[5] Expected Dividend 1	[6] Expected Dividend 2	[7] Expected Dividend 3	[8] Expected Dividend 4	[9] Average Stock Price	[10] Zacks Earnings Growth	[11] CIQ Earnings Growth	[12] Value Line Earnings Growth	[13] Average Earnings Growth	[14] Low ROE	[15] Mean ROE	[16] High ROE
1	Atmos Energy Corporation	ATO	$0.81	$0.87	$0.87	$0.87	$0.86	$0.93	$0.93	$0.93	$148.08	7.20%	7.28%	7.00%	7.16%	9.55%	9.72%	9.85%
2	New Jersey Resources Corporation	NJR	$0.45	$0.45	$0.45	$0.45	$0.48	$0.48	$0.48	$0.48	$47.27	n/a	7.90%	5.00%	6.45%	9.13%	10.66%	12.19%
3	NiSource Inc.	NI	$0.27	$0.28	$0.28	$0.28	$0.29	$0.30	$0.30	$0.30	$37.96	7.90%	7.95%	9.50%	8.45%	11.17%	11.74%	12.83%
4	ONE Gas, Inc.	OGS	$0.66	$0.66	$0.67	$0.67	$0.70	$0.70	$0.71	$0.71	$73.42	5.60%	5.84%	4.50%	5.31%	8.40%	9.26%	9.81%
5	Southwest Gas Holdings, Inc.	SWX	$0.62	$0.62	$0.62	$0.62	$0.68	$0.68	$0.68	$0.68	$73.48	9.90%	n/a	10.00%	9.95%	13.80%	13.85%	13.90%
6	Spire, Inc.	SR	$0.76	$0.79	$0.79	$0.79	$0.80	$0.83	$0.83	$0.83	$71.82	6.50%	8.08%	4.50%	6.36%	9.18%	11.15%	12.98%
7	Ameren Corporation	AEE	$0.67	$0.67	$0.71	$0.71	$0.72	$0.72	$0.76	$0.76	$94.46	7.00%	7.00%	6.50%	6.83%	9.72%	10.07%	10.24%
8	Avista Corporation	AVA	$0.48	$0.48	$0.49	$0.49	$0.50	$0.50	$0.52	$0.52	$38.33	6.10%	5.50%	5.50%	5.70%	11.02%	11.24%	11.67%
9	Black Hills Corporation	BKH	$0.65	$0.65	$0.68	$0.68	$0.68	$0.68	$0.71	$0.71	$59.53	5.30%	5.70%	3.50%	4.83%	8.25%	9.67%	10.59%
10	CenterPoint Energy, Inc.	CNP	$0.20	$0.21	$0.22	$0.22	$0.21	$0.23	$0.24	$0.24	$33.89	7.80%	7.99%	6.50%	7.43%	9.26%	10.22%	10.80%
11	CMS Energy Corporation	CMS	$0.52	$0.52	$0.54	$0.54	$0.55	$0.55	$0.58	$0.58	$69.92	7.80%	7.00%	5.50%	6.77%	8.79%	10.11%	11.19%
12	Consolidated Edison, Inc.	ED	$0.83	$0.83	$0.85	$0.85	$0.88	$0.88	$0.90	$0.90	$100.73	5.60%	6.20%	6.00%	5.93%	9.24%	9.59%	9.87%
13	DTE Energy Company	DTE	$1.09	$1.09	$1.09	$1.09	$1.16	$1.16	$1.16	$1.16	$128.47	7.60%	7.15%	4.50%	6.42%	8.15%	10.16%	11.40%
14	Eversource Energy	ES	$0.72	$0.72	$0.75	$0.75	$0.75	$0.75	$0.79	$0.79	$61.09	5.70%	5.50%	5.50%	5.57%	10.77%	10.84%	10.98%
15	Public Service Enterprise Group Inc.	PEG	$0.60	$0.60	$0.63	$0.63	$0.64	$0.64	$0.67	$0.67	$84.02	7.00%	6.10%	7.00%	6.70%	9.31%	9.94%	10.25%
16	Sempra Energy	SRE	$0.62	$0.62	$0.65	$0.65	$0.66	$0.66	$0.69	$0.69	$79.91	7.90%	7.65%	5.50%	7.02%	8.95%	10.53%	11.46%
17	Southern Company	SO	$0.72	$0.72	$0.72	$0.74	$0.77	$0.77	$0.77	$0.79	$87.98	6.50%	6.57%	6.50%	6.52%	10.14%	10.17%	10.21%
18	Wisconsin Energy Corporation	WEC	$0.84	$0.84	$0.89	$0.89	$0.89	$0.89	$0.95	$0.95	$101.98	7.00%	7.10%	6.00%	6.70%	9.72%	10.45%	10.87%
19	Xcel Energy Inc.	XEL	$0.55	$0.55	$0.57	$0.57	$0.59	$0.59	$0.61	$0.61	$68.29	7.50%	7.75%	7.00%	7.42%	10.64%	11.07%	11.42%
20	Gas Proxy Group Mean											7.42%	7.41%	6.75%	7.28%	10.20%	11.06%	11.93%
21	Gas Proxy Group Median											7.20%	7.90%	6.00%	6.81%	9.36%	10.91%	12.51%
22	**Gas Proxy Group Average of the Mean and Median**											**7.31%**	**7.66%**	**6.38%**	**7.04%**	**9.78%**	**10.99%**	**12.22%**
23	Combined Proxy Group Mean											6.99%	6.90%	6.11%	6.71%	9.75%	10.55%	11.19%
24	Combined Proxy Group Median											7.00%	7.05%	6.00%	6.70%	9.31%	10.22%	10.98%
25	**Combined Proxy Group Average of the Mean and Median**											**7.00%**	**6.98%**	**6.05%**	**6.71%**	**9.53%**	**10.39%**	**11.08%**
26	**Gas Proxy Group Average of the Mean and Median - Excluding SWX**											**6.83%**	**7.66%**	**5.55%**	**6.60%**	**9.33%**	**10.58%**	**11.86%**
27	**Combined Proxy Group Average of the Mean and Median - Excluding SWX**											**6.91%**	**6.98%**	**5.82%**	**6.57%**	**9.40%**	**10.28%**	**10.98%**

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service
[3] Source: Bloomberg Professional Service
[4] Source: Bloomberg Professional Service
[5] Equals Col. [1] x (1 + Col. [13])
[6] Equals Col. [2] x (1 + Col. [13])
[7] Equals Col. [3] x (1 + Col. [13])
[8] Equals Col. [4] x (1 + Col. [13])
[9] Source: Bloomberg Professional, equals indicated number of trading day average as of 06/30/2025
[10] Source: Zacks
[11] Source: S&P Capital IQ
[12] Source: Value Line
[13] Equals Average (Cols. [10], [11], [12])
[14] Implied Low DCF
[15] Implied Mean DCF
[16] Implied High DCF

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Jennifer E. Nelson

RATE OF RETURN ON EQUITY

Exh. JEN-6

August 29, 2025

Exhibit JEN-6
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Expected Market Return
Market DCF Based Method - Value Line EPS Growth

[1] Market Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.28%
[2] Market Cap. Weighted Estimate of the S&P 500 Growth Rate	13.44%
[3] Market Cap. Weighted Estimated Required Market Return	14.81%

Notes:
[1] Equals Sum of Col. [8]
[2] Equals Sum of Col. [9]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]

		[4]	[5]	[6]	[7]	[8]	[9]
Company	Ticker	Market Capitalization Excluding No Growth Rate ($ mill)	Weight in Index	Dividend Yield	Long-Term Growth Est.	Weighted Dividend Yield	Weighted Long-Term Growth Rate
Agilent Technologies Inc	A	$33,522	0.06%	0.84%	6.50%	0.0005%	0.0042%
Apple Inc	AAPL	$3,064,383	5.92%	0.51%	10.00%	0.0300%	0.5921%
AbbVie Inc	ABBV	$327,880	0.63%	3.53%	7.00%	0.0224%	0.0443%
Airbnb Inc	ABNB	$57,308	0.11%	N/A	23.00%	N/A	0.0255%
Abbott Laboratories	ABT	$236,635	0.46%	1.74%	6.00%	0.0079%	0.0274%
Arch Capital Group Ltd	ACGL	$34,121	0.07%	N/A	10.00%	N/A	0.0066%
Accenture PLC	ACN	$187,113	0.36%	1.98%	12.50%	0.0072%	0.0452%
Adobe Inc	ADBE	$164,114	0.32%	N/A	13.50%	N/A	0.0428%
Analog Devices Inc	ADI	$118,117	0.23%	1.66%	9.00%	0.0038%	0.0205%
Archer-Daniels-Midland Co	ADM	$25,358	0.05%	3.87%	2.50%	0.0019%	0.0012%
Automatic Data Processing Inc	ADP	$125,187	0.24%	2.00%	8.50%	0.0048%	0.0206%
Autodesk Inc	ADSK	$66,248	0.13%	N/A	10.50%	N/A	0.0134%
Ameren Corp	AEE	$26,547	0.05%	2.96%	6.50%	0.0015%	0.0033%
American Electric Power Co Inc	AEP	$55,428	0.11%	3.59%	6.50%	0.0038%	0.0070%
AES Corp/The	AES	$7,489	0.01%	6.69%	30.00%	0.0010%	0.0043%
Aflac Inc	AFL	$57,016	0.11%	2.20%	8.50%	0.0024%	0.0094%
American International Group Inc	AIG	$49,328	0.10%	2.10%	15.00%	0.0020%	0.0143%
Assurant Inc	AIZ	$10,013	0.02%	1.62%	10.50%	0.0003%	0.0020%
Arthur J Gallagher & Co	AJG	$81,983	0.16%	0.81%	17.50%	0.0013%	0.0277%
Akamai Technologies Inc	AKAM	$11,661	0.02%	N/A	8.00%	N/A	0.0018%
Albemarle Corp	ALB	$7,374	0.01%	2.58%	-3.50%	0.0004%	-0.0005%
Align Technology Inc	ALGN	$13,724	0.03%	N/A	17.00%	N/A	0.0045%
Allstate Corp/The	ALL	$53,310	0.10%	1.99%	27.50%	0.0020%	0.0283%
Allegion plc	ALLE	$12,401	0.02%	1.42%	7.00%	0.0003%	0.0017%
Applied Materials Inc	AMAT	$146,913	0.28%	1.01%	9.00%	0.0029%	0.0255%
Amcor PLC	AMCR	$20,998	0.04%	5.55%	11.50%	0.0023%	0.0047%
Advanced Micro Devices Inc	AMD	$230,077	0.44%	N/A	17.00%	N/A	0.0756%
AMETEK Inc	AME	$41,780	0.08%	0.69%	8.50%	0.0006%	0.0069%
Amgen Inc	AMGN	$150,133	0.29%	3.41%	5.50%	0.0099%	0.0160%
Ameriprise Financial Inc	AMP	$50,823	0.10%	1.20%	10.00%	0.0012%	0.0098%
American Tower Corp	AMT	$103,468	0.20%	3.08%	10.00%	0.0062%	0.0200%
Amazon.com Inc	AMZN	$2,329,122	4.50%	N/A	24.50%	N/A	1.1026%
Arista Networks Inc	ANET	$128,493	0.25%	N/A	16.00%	N/A	0.0397%
ANSYS Inc	ANSS	$30,878	0.06%	N/A	9.50%	N/A	0.0057%
Aon PLC	AON	$77,039	0.15%	0.84%	11.50%	0.0012%	0.0171%
A O Smith Corp	AOS	$7,622	0.01%	2.07%	7.50%	0.0003%	0.0011%
APA Corp	APA	$6,600	0.01%	5.47%	7.00%	0.0007%	0.0009%
Air Products and Chemicals Inc	APD	$62,771	0.12%	2.54%	10.50%	0.0031%	0.0127%
Amphenol Corp	APH	$119,448	0.23%	0.67%	17.00%	0.0015%	0.0392%
Apollo Global Management Inc	APO	$81,078	0.16%	1.44%	23.50%	0.0023%	0.0368%
Aptiv PLC	APTV	$14,854	0.03%	N/A	28.50%	N/A	0.0082%
Alexandria Real Estate Equities Inc	ARE	$12,564	0.02%	7.27%	8.50%	0.0018%	0.0021%
Atmos Energy Corp	ATO	$24,478	0.05%	2.26%	7.00%	0.0011%	0.0033%
AvalonBay Communities Inc	AVB	$28,972	0.06%	3.44%	6.00%	0.0019%	0.0034%
Broadcom Inc	AVGO	$1,296,512	2.51%	0.86%	24.50%	0.0214%	0.6138%
Avery Dennison Corp	AVY	$13,717	0.03%	2.14%	2.00%	0.0006%	0.0005%
American Water Works Co Inc	AWK	$27,128	0.05%	2.38%	4.50%	0.0012%	0.0024%
Axon Enterprise Inc	AXON	$64,456	0.12%	N/A	26.00%	N/A	0.0324%
American Express Co	AXP	$223,474	0.43%	1.03%	9.00%	0.0044%	0.0389%
AutoZone Inc	AZO	$62,101	0.12%	N/A	7.50%	N/A	0.0090%
Boeing Co/The	BA	N/A	N/A	N/A	N/A	N/A	N/A
Bank of America Corp	BAC	$356,408	0.69%	2.20%	8.50%	0.0151%	0.0585%
Ball Corp	BALL	$15,560	0.03%	1.43%	10.50%	0.0004%	0.0032%
Baxter International Inc	BAX	$15,539	0.03%	2.25%	0.50%	0.0007%	0.0002%
Best Buy Co Inc	BBY	$14,188	0.03%	5.66%	3.00%	0.0016%	0.0008%
Becton Dickinson & Co	BDX	$49,368	0.10%	2.42%	7.00%	0.0023%	0.0067%
Franklin Resources Inc	BEN	$12,534	0.02%	5.37%	4.00%	0.0013%	0.0010%
Brown-Forman Corp	BF/B	$8,170	0.02%	3.37%	9.50%	0.0005%	0.0015%
Bunge Global SA	BG	$10,790	0.02%	3.49%	1.50%	0.0007%	0.0003%
Biogen Inc	BIIB	$18,402	0.04%	N/A	1.00%	N/A	0.0004%
Bank of New York Mellon Corp/The	BK	$65,183	0.13%	2.06%	10.50%	0.0026%	0.0132%
Booking Holdings Inc	BKNG	$188,384	0.36%	0.66%	22.00%	0.0024%	0.0801%
Baker Hughes Co	BKR	$37,985	0.07%	2.40%	21.50%	0.0018%	0.0158%
Builders FirstSource Inc	BLDR	$12,896	0.02%	N/A	0.00%	N/A	0.0000%
Blackrock Inc	BLK	$162,556	0.31%	1.99%	9.50%	0.0062%	0.0298%
Bristol-Myers Squibb Co	BMY	$94,204	0.18%	5.36%	30.00%	0.0098%	0.0546%
Broadridge Financial Solutions Inc	BR	$28,547	0.06%	1.45%	9.50%	0.0008%	0.0052%
Berkshire Hathaway Inc	BRK/B	$650,886	1.26%	N/A	9.50%	N/A	0.1195%
Brown & Brown Inc	BRO	$36,132	0.07%	0.54%	11.00%	0.0004%	0.0077%
Boston Scientific Corp	BSX	$158,907	0.31%	N/A	12.50%	N/A	0.0384%
Blackstone Inc	BX	$109,141	0.21%	2.49%	16.00%	0.0052%	0.0337%
BXP Inc	BXP	$10,682	0.02%	5.81%	1.50%	0.0012%	0.0003%
Citigroup Inc	C	$158,981	0.31%	2.63%	3.00%	0.0081%	0.0092%
Conagra Brands Inc	CAG	$9,772	0.02%	6.84%	2.00%	0.0013%	0.0004%
Cardinal Health Inc	CAH	$40,098	0.08%	1.22%	6.50%	0.0009%	0.0050%

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Company	Ticker	[4] Market Capitalization Excluding No Growth Rate ($ mill)	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
Carrier Global Corp	CARR	$62,747	0.12%	1.23%	12.00%	0.0015%	0.0145%
Caterpillar Inc	CAT	$182,581	0.35%	1.56%	6.50%	0.0055%	0.0229%
Chubb Ltd	CB	$116,098	0.22%	1.34%	11.00%	0.0030%	0.0247%
Cboe Global Markets Inc	CBOE	$24,420	0.05%	1.08%	13.00%	0.0005%	0.0061%
CBRE Group Inc	CBRE	$41,770	0.08%	N/A	6.00%	N/A	0.0048%
Crown Castle Inc	CCI	N/A	N/A	4.14%	N/A	N/A	N/A
Carnival Corp	CCL	N/A	N/A	N/A	N/A	N/A	N/A
Cadence Design Systems Inc	CDNS	$84,138	0.16%	N/A	12.00%	N/A	0.0195%
CDW Corp/DE	CDW	$23,518	0.05%	1.40%	6.50%	0.0006%	0.0030%
Constellation Energy Corp	CEG	$101,708	0.20%	0.48%	18.00%	0.0009%	0.0354%
CF Industries Holdings Inc	CF	N/A	N/A	2.17%	N/A	N/A	N/A
Citizens Financial Group Inc	CFG	$19,406	0.04%	3.75%	5.50%	0.0014%	0.0021%
Church & Dwight Co Inc	CHD	$23,670	0.05%	1.23%	8.00%	0.0006%	0.0037%
CH Robinson Worldwide Inc	CHRW	$11,392	0.02%	2.58%	5.00%	0.0006%	0.0011%
Charter Communications Inc	CHTR	$56,111	0.11%	N/A	6.50%	N/A	0.0070%
Cigna Group/The	CI	$88,312	0.17%	1.83%	11.00%	0.0031%	0.0188%
Cincinnati Financial Corp	CINF	$23,277	0.04%	2.34%	15.50%	0.0011%	0.0070%
Colgate-Palmolive Co	CL	$73,667	0.14%	2.29%	10.00%	0.0033%	0.0142%
Clorox Co/The	CLX	$14,799	0.03%	4.06%	10.00%	0.0012%	0.0029%
Comcast Corp	CMCSA	$132,919	0.26%	3.70%	7.50%	0.0095%	0.0193%
CME Group Inc	CME	$99,321	0.19%	1.81%	5.50%	0.0035%	0.0106%
Chipotle Mexican Grill Inc	CMG	$75,654	0.15%	N/A	19.00%	N/A	0.0278%
Cummins Inc	CMI	$45,115	0.09%	2.22%	8.00%	0.0019%	0.0070%
CMS Energy Corp	CMS	$20,723	0.04%	3.13%	6.00%	0.0013%	0.0024%
Centene Corp	CNC	$27,010	0.05%	N/A	9.50%	N/A	0.0050%
CenterPoint Energy Inc	CNP	$23,981	0.05%	2.40%	6.50%	0.0011%	0.0030%
Capital One Financial Corp	COF	$136,086	0.26%	1.13%	9.50%	0.0030%	0.0250%
Coinbase Global Inc	COIN	N/A	N/A	N/A	N/A	N/A	N/A
Cooper Cos Inc/The	COO	$14,197	0.03%	N/A	8.50%	N/A	0.0023%
ConocoPhillips	COP	$113,289	0.22%	3.48%	4.00%	0.0076%	0.0088%
Cencora Inc	COR	$58,118	0.11%	0.73%	6.50%	0.0008%	0.0073%
Costco Wholesale Corp	COST	$439,016	0.85%	0.53%	10.00%	0.0045%	0.0848%
Corpay Inc	CPAY	$23,391	0.05%	N/A	12.00%	N/A	0.0054%
The Campbell's Company	CPB	$9,138	0.02%	5.09%	6.00%	0.0009%	0.0011%
Copart Inc	CPRT	$47,448	0.09%	N/A	8.00%	N/A	0.0073%
Camden Property Trust	CPT	$12,040	0.02%	3.73%	-6.50%	0.0009%	-0.0015%
Charles River Laboratories Internatio	CRL	$7,452	0.01%	N/A	4.50%	N/A	0.0006%
Salesforce Inc	CRM	$260,692	0.50%	0.61%	22.00%	0.0031%	0.1108%
Crowdstrike Holdings Inc	CRWD	N/A	N/A	N/A	N/A	N/A	N/A
Cisco Systems Inc	CSCO	$274,745	0.53%	2.36%	5.50%	0.0125%	0.0292%
CoStar Group Inc	CSGP	$33,920	0.07%	N/A	11.50%	N/A	0.0075%
CSX Corp	CSX	$61,297	0.12%	1.59%	6.00%	0.0019%	0.0071%
Cintas Corp	CTAS	$89,992	0.17%	0.70%	14.00%	0.0012%	0.0243%
Coterra Energy Inc	CTRA	$19,372	0.04%	3.47%	7.00%	0.0013%	0.0026%
Cognizant Technology Solutions Cor	CTSH	$38,464	0.07%	1.59%	9.00%	0.0012%	0.0067%
Corteva Inc	CTVA	$50,905	0.10%	0.91%	9.50%	0.0009%	0.0093%
CVS Health Corp	CVS	$87,261	0.17%	3.86%	0.50%	0.0065%	0.0008%
Chevron Corp	CVX	$250,066	0.48%	4.78%	4.00%	0.0231%	0.0193%
Caesars Entertainment Inc	CZR	N/A	N/A	N/A	N/A	N/A	N/A
Dominion Energy Inc	D	$48,200	0.09%	4.72%	6.00%	0.0044%	0.0056%
Delta Air Lines Inc	DAL	$32,112	0.06%	1.53%	6.50%	0.0009%	0.0040%
DoorDash Inc	DASH	N/A	N/A	N/A	N/A	N/A	N/A
Dayforce Inc	DAY	N/A	N/A	N/A	N/A	N/A	N/A
DuPont de Nemours Inc	DD	$28,705	0.06%	2.39%	10.50%	0.0013%	0.0058%
Deere & Co	DE	$137,713	0.27%	1.27%	3.00%	0.0034%	0.0080%
Deckers Outdoor Corp	DECK	$15,402	0.03%	N/A	16.00%	N/A	0.0048%
Dell Technologies Inc	DELL	$41,650	0.08%	1.71%	2.50%	0.0014%	0.0020%
Dollar General Corp	DG	$25,172	0.05%	2.06%	1.50%	0.0010%	0.0007%
Quest Diagnostics Inc	DGX	$20,053	0.04%	1.78%	3.50%	0.0007%	0.0014%
DR Horton Inc	DHI	$39,602	0.08%	1.24%	3.50%	0.0009%	0.0027%
Danaher Corp	DHR	$141,373	0.27%	0.65%	2.00%	0.0018%	0.0055%
Walt Disney Co/The	DIS	$222,939	0.43%	0.81%	25.00%	0.0035%	0.1077%
Digital Realty Trust Inc	DLR	$58,713	0.11%	2.80%	8.00%	0.0032%	0.0091%
Dollar Tree Inc	DLTR	$20,669	0.04%	N/A	22.00%	N/A	0.0088%
Healthpeak Properties Inc	DOC	$12,165	0.02%	6.97%	6.00%	0.0016%	0.0014%
Dover Corp	DOV	$25,122	0.05%	1.12%	5.00%	0.0005%	0.0024%
Dow Inc	DOW	$18,689	0.04%	10.57%	6.50%	0.0038%	0.0023%
Domino's Pizza Inc	DPZ	$15,429	0.03%	1.54%	13.50%	0.0005%	0.0040%
Darden Restaurants Inc	DRI	$25,508	0.05%	2.75%	10.50%	0.0014%	0.0052%
DTE Energy Co	DTE	$27,488	0.05%	3.29%	4.50%	0.0017%	0.0024%
Duke Energy Corp	DUK	$91,689	0.18%	3.54%	6.00%	0.0063%	0.0106%
DaVita Inc	DVA	$10,755	0.02%	N/A	10.50%	N/A	0.0022%
Devon Energy Corp	DVN	$20,425	0.04%	3.02%	1.50%	0.0012%	0.0006%
Dexcom Inc	DXCM	N/A	N/A	N/A	N/A	N/A	N/A
Electronic Arts Inc	EA	$40,128	0.08%	0.48%	12.50%	0.0004%	0.0097%
eBay Inc	EBAY	$34,326	0.07%	1.56%	12.00%	0.0010%	0.0080%
Ecolab Inc	ECL	$76,390	0.15%	0.96%	8.00%	0.0014%	0.0118%
Consolidated Edison Inc	ED	$36,156	0.07%	3.39%	6.00%	0.0024%	0.0042%
Equifax Inc	EFX	$32,214	0.06%	0.77%	6.00%	0.0005%	0.0037%
Everest Group Ltd	EG	$14,455	0.03%	2.35%	14.50%	0.0007%	0.0040%
Edison International	EIX	$19,854	0.04%	6.41%	6.50%	0.0025%	0.0025%
Estee Lauder Cos Inc/The	EL	$18,924	0.04%	1.73%	3.50%	0.0006%	0.0013%
Elevance Health Inc	ELV	$87,880	0.17%	1.76%	9.50%	0.0030%	0.0161%
Eastman Chemical Co	EMN	$8,620	0.02%	4.45%	3.50%	0.0007%	0.0006%
Emerson Electric Co	EMR	$74,998	0.14%	1.58%	11.00%	0.0023%	0.0159%
Enphase Energy Inc	ENPH	$5,202	0.01%	N/A	6.50%	N/A	0.0007%
EOG Resources Inc	EOG	$65,282	0.13%	3.41%	4.50%	0.0043%	0.0057%
EPAM Systems Inc	EPAM	$10,017	0.02%	N/A	20.50%	N/A	0.0040%
Equinix Inc	EQIX	$77,812	0.15%	2.36%	15.00%	0.0035%	0.0226%

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Company	Ticker	[4] Market Capitalization Excluding No Growth Rate ($ mill)	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
Equity Residential	EQR	$25,642	0.05%	4.10%	4.00%	0.0020%	0.0020%
EQT Corp	EQT	$34,912	0.07%	1.08%	7.50%	0.0007%	0.0051%
Erie Indemnity Co	ERIE	$16,018	0.03%	1.57%	14.00%	0.0005%	0.0043%
Eversource Energy	ES	$23,373	0.05%	4.73%	5.50%	0.0021%	0.0025%
Essex Property Trust Inc	ESS	$18,247	0.04%	3.63%	5.50%	0.0013%	0.0019%
Eaton Corp PLC	ETN	$139,690	0.27%	1.17%	11.00%	0.0031%	0.0297%
Entergy Corp	ETR	$35,806	0.07%	2.89%	3.00%	0.0020%	0.0021%
Evergy Inc	EVRG	$15,836	0.03%	3.87%	7.50%	0.0012%	0.0023%
Edwards Lifesciences Corp	EW	$45,878	0.09%	N/A	6.50%	N/A	0.0058%
Exelon Corp	EXC	N/A	N/A	3.68%	N/A	N/A	N/A
Expand Energy Corp	EXE	N/A	N/A	1.97%	N/A	N/A	N/A
Expeditors International of Washingt	EXPD	$15,646	0.03%	1.35%	-0.50%	0.0004%	-0.0002%
Expedia Group Inc	EXPE	$20,511	0.04%	0.95%	39.00%	0.0004%	0.0155%
Extra Space Storage Inc	EXR	$31,288	0.06%	4.40%	-1.00%	0.0027%	-0.0006%
Ford Motor Co	F	$42,377	0.08%	5.53%	20.50%	0.0045%	0.0168%
Diamondback Energy Inc	FANG	$40,144	0.08%	2.91%	1.50%	0.0023%	0.0012%
Fastenal Co	FAST	$48,184	0.09%	2.10%	8.00%	0.0020%	0.0074%
Freeport-McMoRan Inc	FCX	$62,259	0.12%	1.38%	17.50%	0.0017%	0.0211%
FactSet Research Systems Inc	FDS	$16,973	0.03%	0.98%	8.00%	0.0003%	0.0026%
FedEx Corp	FDX	$54,463	0.11%	2.55%	6.50%	0.0027%	0.0068%
FirstEnergy Corp	FE	$23,235	0.04%	4.42%	4.50%	0.0020%	0.0020%
F5 Inc	FFIV	$16,903	0.03%	N/A	9.50%	N/A	0.0031%
Fiserv Inc	FI	$95,590	0.18%	N/A	11.00%	N/A	0.0203%
Fair Isaac Corp	FICO	$44,496	0.09%	N/A	20.50%	N/A	0.0176%
Fidelity National Information Services	FIS	$42,772	0.08%	1.97%	7.00%	0.0016%	0.0058%
Fifth Third Bancorp	FITB	$27,454	0.05%	3.60%	5.00%	0.0019%	0.0027%
Fox Corp	FOX	N/A	N/A	1.05%	N/A	N/A	N/A
Fox Corp	FOXA	$11,995	0.02%	0.96%	8.50%	0.0002%	0.0020%
Federal Realty Investment Trust	FRT	$8,194	0.02%	4.63%	2.50%	0.0007%	0.0004%
First Solar Inc	FSLR	$17,753	0.03%	N/A	26.00%	N/A	0.0089%
Fortinet Inc	FTNT	$80,920	0.16%	N/A	13.00%	N/A	0.0203%
Fortive Corp	FTV	$17,718	0.03%	0.61%	11.00%	0.0002%	0.0038%
General Dynamics Corp	GD	$78,280	0.15%	2.06%	12.50%	0.0031%	0.0189%
GoDaddy Inc	GDDY	$25,656	0.05%	N/A	12.50%	N/A	0.0062%
General Electric Co	GE	$274,477	0.53%	0.56%	21.00%	0.0030%	0.1114%
GE HealthCare Technologies Inc	GEHC	N/A	N/A	0.19%	N/A	N/A	N/A
Gen Digital Inc	GEN	$18,235	0.04%	1.70%	10.50%	0.0006%	0.0037%
GE Vernova Inc	GEV	N/A	N/A	0.19%	N/A	N/A	N/A
Gilead Sciences Inc	GILD	$137,914	0.27%	2.85%	16.00%	0.0076%	0.0426%
General Mills Inc	GIS	$28,103	0.05%	4.71%	3.00%	0.0026%	0.0016%
Globe Life Inc	GL	$10,259	0.02%	0.87%	9.00%	0.0002%	0.0018%
Corning Inc	GLW	$45,042	0.09%	2.13%	23.00%	0.0019%	0.0200%
General Motors Co	GM	$47,312	0.09%	1.22%	8.50%	0.0011%	0.0078%
Generac Holdings Inc	GNRC	$8,461	0.02%	N/A	18.50%	N/A	0.0030%
Alphabet Inc	GOOG	$968,372	1.87%	0.47%	12.50%	0.0089%	0.2339%
Alphabet Inc	GOOGL	N/A	N/A	0.48%	N/A	N/A	N/A
Genuine Parts Co	GPC	$16,837	0.03%	3.40%	3.50%	0.0011%	0.0011%
Global Payments Inc	GPN	$19,520	0.04%	1.25%	11.00%	0.0005%	0.0041%
Garmin Ltd	GRMN	$40,187	0.08%	1.72%	7.00%	0.0013%	0.0054%
Goldman Sachs Group Inc/The	GS	$217,167	0.42%	1.70%	12.00%	0.0071%	0.0504%
WW Grainger Inc	GWW	$49,972	0.10%	0.87%	5.00%	0.0008%	0.0048%
Halliburton Co	HAL	$17,521	0.03%	3.34%	9.50%	0.0011%	0.0032%
Hasbro Inc	HAS	$10,344	0.02%	3.79%	8.50%	0.0008%	0.0017%
Huntington Bancshares Inc/OH	HBAN	$24,416	0.05%	3.70%	5.00%	0.0017%	0.0024%
HCA Healthcare Inc	HCA	$92,164	0.18%	0.75%	10.00%	0.0013%	0.0178%
Home Depot Inc/The	HD	$364,780	0.70%	2.51%	7.00%	0.0177%	0.0493%
Hess Corp	HES	$42,846	0.08%	1.44%	2.00%	0.0012%	0.0017%
Hartford Insurance Group Inc/The	HIG	$36,044	0.07%	1.64%	7.00%	0.0011%	0.0049%
Huntington Ingalls Industries Inc	HII	$9,475	0.02%	2.24%	10.00%	0.0004%	0.0018%
Hilton Worldwide Holdings Inc	HLT	N/A	N/A	0.23%	N/A	N/A	N/A
Hologic Inc	HOLX	$14,521	0.03%	N/A	2.00%	N/A	0.0006%
Honeywell International Inc	HON	$149,668	0.29%	1.94%	9.50%	0.0056%	0.0275%
Hewlett Packard Enterprise Co	HPE	$26,835	0.05%	2.54%	5.50%	0.0013%	0.0029%
HP Inc	HPQ	$22,975	0.04%	4.73%	5.00%	0.0021%	0.0022%
Hormel Foods Corp	HRL	$16,634	0.03%	3.83%	5.00%	0.0012%	0.0016%
Henry Schein Inc	HSIC	$8,892	0.02%	N/A	10.50%	N/A	0.0018%
Host Hotels & Resorts Inc	HST	$10,655	0.02%	5.21%	11.50%	0.0011%	0.0024%
Hershey Co/The	HSY	$24,559	0.05%	3.30%	5.00%	0.0016%	0.0024%
Hubbell Inc	HUBB	$21,798	0.04%	1.29%	6.00%	0.0005%	0.0025%
Humana Inc	HUM	$29,507	0.06%	1.45%	2.00%	0.0008%	0.0011%
Howmet Aerospace Inc	HWM	$75,136	0.15%	0.21%	12.00%	0.0003%	0.0174%
International Business Machines Cor	IBM	$273,968	0.53%	2.28%	3.00%	0.0121%	0.0159%
Intercontinental Exchange Inc	ICE	$105,243	0.20%	1.05%	7.00%	0.0021%	0.0142%
IDEXX Laboratories Inc	IDXX	$43,133	0.08%	N/A	11.00%	N/A	0.0092%
IDEX Corp	IEX	$13,263	0.03%	1.62%	5.00%	0.0004%	0.0013%
International Flavors & Fragrances In	IFF	$18,813	0.04%	2.18%	2.00%	0.0008%	0.0007%
Incyte Corp	INCY	$13,182	0.03%	N/A	33.00%	N/A	0.0084%
Intel Corp	INTC	$97,709	0.19%	N/A	18.00%	N/A	0.0340%
Intuit Inc	INTU	$219,707	0.42%	0.53%	13.50%	0.0022%	0.0573%
Invitation Homes Inc	INVH	$20,105	0.04%	3.54%	10.00%	0.0014%	0.0039%
International Paper Co	IP	$24,722	0.05%	3.95%	16.50%	0.0019%	0.0079%
Interpublic Group of Cos Inc/The	IPG	$9,051	0.02%	5.39%	8.00%	0.0009%	0.0014%
IQVIA Holdings Inc	IQV	$27,263	0.05%	N/A	9.00%	N/A	0.0047%
Ingersoll Rand Inc	IR	$33,560	0.06%	0.10%	10.50%	0.0001%	0.0068%
Iron Mountain Inc	IRM	$30,263	0.06%	3.06%	3.50%	0.0018%	0.0020%
Intuitive Surgical Inc	ISRG	$194,768	0.38%	N/A	14.50%	N/A	0.0546%
Gartner Inc	IT	$31,112	0.06%	N/A	7.50%	N/A	0.0045%
Illinois Tool Works Inc	ITW	$72,444	0.14%	2.43%	9.00%	0.0034%	0.0126%
Invesco Ltd	IVZ	$7,058	0.01%	5.33%	10.50%	0.0007%	0.0014%

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate ($ mill)	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
Jacobs Solutions Inc	J	$15,795	0.03%	0.97%	8.00%	0.0003%	0.0024%
JB Hunt Transport Services Inc	JBHT	$14,244	0.03%	1.23%	7.50%	0.0003%	0.0021%
Jabil Inc	JBL	$23,406	0.05%	0.15%	11.50%	0.0001%	0.0052%
Johnson Controls International plc	JCI	$69,503	0.13%	1.40%	11.50%	0.0019%	0.0154%
Jack Henry & Associates Inc	JKHY	$13,119	0.03%	1.29%	5.50%	0.0003%	0.0014%
Johnson & Johnson	JNJ	$367,528	0.71%	3.40%	4.50%	0.0242%	0.0320%
Juniper Networks Inc	JNPR	$13,352	0.03%	2.20%	7.00%	0.0006%	0.0018%
JPMorgan Chase & Co	JPM	$805,687	1.56%	1.93%	8.50%	0.0301%	0.1323%
Kellanova	K	$27,592	0.05%	2.87%	2.50%	0.0015%	0.0013%
Keurig Dr Pepper Inc	KDP	$44,901	0.09%	2.78%	12.00%	0.0024%	0.0104%
KeyCorp	KEY	N/A	N/A	4.71%	N/A	N/A	N/A
Keysight Technologies Inc	KEYS	$28,202	0.05%	N/A	5.50%	N/A	0.0030%
Kraft Heinz Co/The	KHC	$30,559	0.06%	6.20%	4.50%	0.0037%	0.0027%
Kimco Realty Corp	KIM	$14,283	0.03%	4.76%	27.50%	0.0013%	0.0076%
KKR & Co Inc	KKR	$118,482	0.23%	0.56%	5.00%	0.0013%	0.0114%
KLA Corp	KLAC	$118,454	0.23%	0.85%	12.50%	0.0019%	0.0286%
Kimberly-Clark Corp	KMB	$42,778	0.08%	3.91%	6.50%	0.0032%	0.0054%
Kinder Morgan Inc	KMI	$65,329	0.13%	3.98%	8.50%	0.0050%	0.0107%
CarMax Inc	KMX	$10,086	0.02%	N/A	2.50%	N/A	0.0005%
Coca-Cola Co/The	KO	$304,527	0.59%	2.88%	7.00%	0.0170%	0.0412%
Kroger Co/The	KR	$47,425	0.09%	1.95%	5.00%	0.0018%	0.0046%
Kenvue Inc	KVUE	N/A	N/A	3.92%	N/A	N/A	N/A
Loews Corp	L	$19,221	0.04%	0.27%	13.00%	0.0001%	0.0048%
Leidos Holdings Inc	LDOS	$20,307	0.04%	1.01%	10.00%	0.0004%	0.0039%
Lennar Corp	LEN	$25,682	0.05%	1.81%	4.00%	0.0009%	0.0020%
Labcorp Holdings Inc	LH	$21,972	0.04%	1.10%	1.50%	0.0005%	0.0006%
L3Harris Technologies Inc	LHX	$46,893	0.09%	1.91%	9.00%	0.0017%	0.0082%
Lennox International Inc	LII	$20,341	0.04%	0.91%	11.00%	0.0004%	0.0043%
Linde PLC	LIN	$220,855	0.43%	1.28%	6.00%	0.0055%	0.0256%
LKQ Corp	LKQ	$9,554	0.02%	3.24%	7.00%	0.0006%	0.0013%
Eli Lilly & Co	LLY	$738,788	1.43%	0.77%	26.50%	0.0110%	0.3783%
Lockheed Martin Corp	LMT	$108,512	0.21%	2.85%	12.50%	0.0060%	0.0262%
Alliant Energy Corp	LNT	$15,533	0.03%	3.36%	6.00%	0.0010%	0.0018%
Lowe's Cos Inc	LOW	$124,344	0.24%	2.16%	6.00%	0.0052%	0.0144%
Lam Research Corp	LRCX	$124,509	0.24%	0.95%	11.00%	0.0023%	0.0265%
Lululemon Athletica Inc	LULU	$27,257	0.05%	N/A	12.00%	N/A	0.0063%
Southwest Airlines Co	LUV	$18,486	0.04%	2.22%	14.50%	0.0008%	0.0052%
Las Vegas Sands Corp	LVS	N/A	N/A	2.30%	N/A	N/A	N/A
Lamb Weston Holdings Inc	LW	$7,317	0.01%	2.85%	4.50%	0.0004%	0.0006%
LyondellBasell Industries NV	LYB	$18,596	0.04%	9.47%	-6.00%	0.0034%	-0.0022%
Live Nation Entertainment Inc	LYV	N/A	N/A	N/A	N/A	N/A	N/A
Mastercard Inc	MA	$506,456	0.98%	0.54%	11.00%	0.0053%	0.1076%
Mid-America Apartment Communities	MAA	$17,326	0.03%	4.09%	-13.50%	0.0014%	-0.0045%
Marriott International Inc/MD	MAR	$74,831	0.14%	0.98%	9.00%	0.0014%	0.0130%
Masco Corp	MAS	$13,576	0.03%	1.93%	9.00%	0.0005%	0.0024%
McDonald's Corp	MCD	$208,911	0.40%	2.42%	8.50%	0.0098%	0.0343%
Microchip Technology Inc	MCHP	$37,958	0.07%	2.59%	3.00%	0.0019%	0.0022%
McKesson Corp	MCK	$91,674	0.18%	0.39%	10.00%	0.0007%	0.0177%
Moody's Corp	MCO	$90,236	0.17%	0.75%	8.00%	0.0013%	0.0139%
Mondelez International Inc	MDLZ	$87,322	0.17%	2.79%	7.50%	0.0047%	0.0127%
Medtronic PLC	MDT	$111,688	0.22%	3.26%	6.00%	0.0070%	0.0129%
MetLife Inc	MET	$53,986	0.10%	2.82%	7.50%	0.0029%	0.0078%
Meta Platforms Inc	META	$1,602,503	3.10%	0.28%	17.00%	0.0088%	0.5264%
MGM Resorts International	MGM	$9,359	0.02%	N/A	25.00%	N/A	0.0045%
Mohawk Industries Inc	MHK	$6,555	0.01%	N/A	3.50%	N/A	0.0004%
McCormick & Co Inc/MD	MKC	$19,186	0.04%	2.37%	6.00%	0.0009%	0.0022%
MarketAxess Holdings Inc	MKTX	$8,376	0.02%	1.36%	10.00%	0.0002%	0.0016%
Martin Marietta Materials Inc	MLM	$33,094	0.06%	0.58%	9.50%	0.0004%	0.0061%
Marsh & McLennan Cos Inc	MMC	$107,768	0.21%	1.49%	11.50%	0.0031%	0.0239%
3M Co	MMM	$81,933	0.16%	1.92%	40.00%	0.0030%	0.0633%
Monster Beverage Corp	MNST	$61,089	0.12%	N/A	12.00%	N/A	0.0142%
Altria Group Inc	MO	$98,759	0.19%	6.96%	6.00%	0.0133%	0.0114%
Molina Healthcare Inc	MOH	$16,146	0.03%	N/A	10.50%	N/A	0.0033%
Mosaic Co/The	MOS	$11,573	0.02%	2.41%	-8.00%	0.0005%	-0.0018%
Marathon Petroleum Corp	MPC	$51,031	0.10%	2.19%	-8.00%	0.0022%	-0.0079%
Monolithic Power Systems Inc	MPWR	$35,018	0.07%	0.85%	12.00%	0.0006%	0.0081%
Merck & Co Inc	MRK	$198,773	0.38%	4.09%	13.00%	0.0157%	0.0499%
Moderna Inc	MRNA	N/A	N/A	N/A	N/A	N/A	N/A
Morgan Stanley	MS	$225,984	0.44%	2.63%	12.50%	0.0115%	0.0546%
MSCI Inc	MSCI	$44,756	0.09%	1.25%	8.00%	0.0011%	0.0069%
Microsoft Corp	MSFT	$3,697,022	7.14%	0.67%	12.00%	0.0477%	0.8572%
Motorola Solutions Inc	MSI	$70,181	0.14%	1.04%	10.00%	0.0014%	0.0136%
M&T Bank Corp	MTB	$31,139	0.06%	2.78%	4.50%	0.0017%	0.0027%
Match Group Inc	MTCH	$7,575	0.01%	2.46%	11.00%	0.0004%	0.0016%
Mettler-Toledo International Inc	MTD	$24,414	0.05%	N/A	9.50%	N/A	0.0045%
Micron Technology Inc	MU	$137,932	0.27%	0.37%	39.00%	0.0010%	0.1039%
Norwegian Cruise Line Holdings Ltd	NCLH	N/A	N/A	N/A	N/A	N/A	N/A
Nasdaq Inc	NDAQ	$51,338	0.10%	1.21%	6.50%	0.0012%	0.0064%
Nordson Corp	NDSN	$12,114	0.02%	1.46%	8.50%	0.0003%	0.0020%
NextEra Energy Inc	NEE	$142,910	0.28%	3.26%	8.50%	0.0090%	0.0235%
Newmont Corp	NEM	$64,843	0.13%	1.72%	12.50%	0.0022%	0.0157%
Netflix Inc	NFLX	$569,895	1.10%	N/A	16.50%	N/A	0.1817%
NiSource Inc	NI	$18,988	0.04%	2.78%	9.50%	0.0010%	0.0035%
NIKE Inc	NKE	$83,692	0.16%	2.25%	2.00%	0.0036%	0.0032%
Northrop Grumman Corp	NOC	$71,961	0.14%	1.85%	7.50%	0.0026%	0.0104%
ServiceNow Inc	NOW	$212,813	0.41%	N/A	26.00%	N/A	0.1069%
NRG Energy Inc	NRG	$31,395	0.06%	1.10%	18.50%	0.0007%	0.0112%
Norfolk Southern Corp	NSC	$57,707	0.11%	2.11%	11.00%	0.0024%	0.0123%
NetApp Inc	NTAP	$21,349	0.04%	1.95%	9.50%	0.0008%	0.0039%

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Company	Ticker	[4] Market Capitalization Excluding No Growth Rate ($ mill)	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
Northern Trust Corp	NTRS	$24,666	0.05%	2.37%	5.00%	0.0011%	0.0024%
Nucor Corp	NUE	N/A	N/A	1.70%	N/A	N/A	N/A
NVIDIA Corp	NVDA	$3,854,956	7.45%	0.03%	31.50%	0.0019%	2.3463%
NVR Inc	NVR	$21,594	0.04%	N/A	1.50%	N/A	0.0006%
News Corp	NWS	N/A	N/A	0.58%	N/A	N/A	N/A
News Corp	NWSA	$11,210	0.02%	0.67%	17.00%	0.0001%	0.0037%
NXP Semiconductors NV	NXPI	$55,197	0.11%	1.86%	7.50%	0.0020%	0.0080%
Realty Income Corp	O	$52,026	0.10%	5.60%	5.00%	0.0056%	0.0050%
Old Dominion Freight Line Inc	ODFL	$34,298	0.07%	0.69%	7.00%	0.0005%	0.0046%
ONEOK Inc	OKE	$51,390	0.10%	5.05%	12.50%	0.0050%	0.0124%
Omnicom Group Inc	OMC	$14,036	0.03%	3.89%	7.00%	0.0011%	0.0019%
ON Semiconductor Corp	ON	$21,901	0.04%	N/A	4.00%	N/A	0.0017%
Oracle Corp	ORCL	$614,095	1.19%	0.91%	10.00%	0.0109%	0.1187%
O'Reilly Automotive Inc	ORLY	$77,047	0.15%	N/A	10.50%	N/A	0.0156%
Otis Worldwide Corp	OTIS	$39,081	0.08%	1.70%	10.00%	0.0013%	0.0076%
Occidental Petroleum Corp	OXY	$41,343	0.08%	2.29%	5.50%	0.0018%	0.0044%
Palo Alto Networks Inc	PANW	$136,454	0.26%	N/A	37.00%	N/A	0.0976%
Paramount Global	PARA	$8,172	0.02%	1.55%	5.50%	0.0002%	0.0009%
Paycom Software Inc	PAYC	$13,379	0.03%	0.65%	12.50%	0.0002%	0.0032%
Paychex Inc	PAYX	$52,393	0.10%	2.97%	8.00%	0.0030%	0.0081%
PACCAR Inc	PCAR	$49,903	0.10%	1.39%	14.50%	0.0013%	0.0140%
PG&E Corp	PCG	$30,636	0.06%	0.72%	9.50%	0.0004%	0.0056%
Public Service Enterprise Group Inc	PEG	$42,006	0.08%	2.99%	7.00%	0.0024%	0.0057%
PepsiCo Inc	PEP	$181,037	0.35%	4.31%	6.00%	0.0151%	0.0210%
Pfizer Inc	PFE	$137,813	0.27%	7.10%	6.00%	0.0189%	0.0160%
Principal Financial Group Inc	PFG	$17,807	0.03%	3.83%	4.00%	0.0013%	0.0014%
Procter & Gamble Co/The	PG	$373,532	0.72%	2.65%	5.00%	0.0191%	0.0361%
Progressive Corp/The	PGR	$156,440	0.30%	0.15%	16.50%	0.0005%	0.0499%
Parker-Hannifin Corp	PH	$89,249	0.17%	1.03%	10.00%	0.0018%	0.0172%
PulteGroup Inc	PHM	$21,137	0.04%	0.83%	5.00%	0.0003%	0.0020%
Packaging Corp of America	PKG	$16,957	0.03%	2.65%	9.00%	0.0009%	0.0029%
Prologis Inc	PLD	$97,360	0.19%	3.84%	2.50%	0.0072%	0.0047%
Palantir Technologies Inc	PLTR	N/A	N/A	N/A	N/A	N/A	N/A
Philip Morris International Inc	PM	$283,488	0.55%	2.96%	5.00%	0.0162%	0.0274%
PNC Financial Services Group Inc/Th	PNC	$73,742	0.14%	3.43%	7.50%	0.0049%	0.0107%
Pentair PLC	PNR	$16,890	0.03%	0.97%	12.00%	0.0003%	0.0039%
Pinnacle West Capital Corp	PNW	$10,683	0.02%	4.00%	5.00%	0.0008%	0.0010%
Insulet Corp	PODD	N/A	N/A	N/A	N/A	N/A	N/A
Pool Corp	POOL	$10,958	0.02%	1.72%	2.50%	0.0004%	0.0005%
PPG Industries Inc	PPG	$25,821	0.05%	2.39%	5.00%	0.0012%	0.0025%
PPL Corp	PPL	$25,054	0.05%	3.22%	7.50%	0.0016%	0.0036%
Prudential Financial Inc	PRU	$38,034	0.07%	5.03%	4.00%	0.0037%	0.0029%
Public Storage	PSA	$51,475	0.10%	4.09%	7.00%	0.0041%	0.0070%
Phillips 66	PSX	$48,607	0.09%	4.02%	0.00%	0.0038%	0.0000%
PTC Inc	PTC	$20,672	0.04%	N/A	29.00%	N/A	0.0116%
Quanta Services Inc	PWR	$56,031	0.11%	0.11%	17.50%	0.0001%	0.0189%
PayPal Holdings Inc	PYPL	$72,279	0.14%	N/A	13.50%	N/A	0.0189%
QUALCOMM Inc	QCOM	$174,867	0.34%	2.24%	5.50%	0.0076%	0.0186%
Ralliant Corp	RAL	N/A	N/A	N/A	N/A	N/A	N/A
Royal Caribbean Cruises Ltd	RCL	N/A	N/A	0.96%	N/A	N/A	N/A
Regency Centers Corp	REG	$12,930	0.02%	3.96%	10.00%	0.0010%	0.0025%
Regeneron Pharmaceuticals Inc	REGN	$55,728	0.11%	0.67%	3.50%	0.0007%	0.0038%
Regions Financial Corp	RF	$21,143	0.04%	4.25%	5.00%	0.0017%	0.0020%
Raymond James Financial Inc	RJF	$30,943	0.06%	1.30%	10.50%	0.0008%	0.0063%
Ralph Lauren Corp	RL	$10,612	0.02%	1.33%	12.00%	0.0003%	0.0025%
ResMed Inc	RMD	$37,830	0.07%	0.82%	11.00%	0.0006%	0.0080%
Rockwell Automation Inc	ROK	$37,441	0.07%	1.58%	8.00%	0.0011%	0.0058%
Rollins Inc	ROL	$27,344	0.05%	1.17%	9.50%	0.0006%	0.0050%
Roper Technologies Inc	ROP	$60,944	0.12%	0.58%	7.50%	0.0007%	0.0088%
Ross Stores Inc	ROST	$41,728	0.08%	1.27%	9.50%	0.0010%	0.0077%
Republic Services Inc	RSG	$77,065	0.15%	0.94%	11.00%	0.0014%	0.0164%
RTX Corp	RTX	$195,076	0.38%	1.86%	12.00%	0.0070%	0.0452%
Revvity Inc	RVTY	$11,400	0.02%	0.29%	-1.50%	0.0001%	-0.0003%
SBA Communications Corp	SBAC	$25,234	0.05%	1.89%	14.00%	0.0009%	0.0068%
Starbucks Corp	SBUX	$104,128	0.20%	2.66%	5.00%	0.0054%	0.0101%
Charles Schwab Corp/The	SCHW	$165,780	0.32%	1.18%	11.00%	0.0038%	0.0352%
Sherwin-Williams Co/The	SHW	$86,046	0.17%	0.92%	11.00%	0.0015%	0.0183%
J M Smucker Co/The	SJM	$10,476	0.02%	4.40%	6.50%	0.0009%	0.0013%
Schlumberger NV	SLB	$45,973	0.09%	3.37%	14.00%	0.0030%	0.0124%
Super Micro Computer Inc	SMCI	$29,250	0.06%	N/A	29.00%	N/A	0.0164%
Snap-on Inc	SNA	$16,272	0.03%	2.75%	4.50%	0.0009%	0.0014%
Synopsys Inc	SNPS	$79,548	0.15%	N/A	12.00%	N/A	0.0184%
Southern Co/The	SO	$101,031	0.20%	3.22%	6.50%	0.0063%	0.0127%
Solventum Corp	SOLV	N/A	N/A	N/A	N/A	N/A	N/A
Simon Property Group Inc	SPG	$52,475	0.10%	5.23%	3.50%	0.0053%	0.0035%
S&P Global Inc	SPGI	$165,516	0.32%	0.73%	8.50%	0.0023%	0.0272%
Sempra	SRE	$49,415	0.10%	3.41%	5.50%	0.0033%	0.0053%
STERIS PLC	STE	$23,631	0.05%	0.95%	8.00%	0.0004%	0.0037%
Steel Dynamics Inc	STLD	$19,004	0.04%	1.56%	0.50%	0.0006%	0.0002%
State Street Corp	STT	$30,326	0.06%	2.86%	7.00%	0.0017%	0.0041%
Seagate Technology Holdings PLC	STX	$30,629	0.06%	2.00%	23.50%	0.0012%	0.0139%
Constellation Brands Inc	STZ	$28,778	0.06%	2.51%	6.50%	0.0014%	0.0036%
Smurfit WestRock PLC	SW	N/A	N/A	3.99%	N/A	N/A	N/A
Stanley Black & Decker Inc	SWK	$10,482	0.02%	4.84%	9.50%	0.0010%	0.0019%
Skyworks Solutions Inc	SWKS	N/A	N/A	3.76%	N/A	N/A	N/A
Synchrony Financial	SYF	$25,405	0.05%	1.80%	47.00%	0.0009%	0.0231%
Stryker Corp	SYK	$151,196	0.29%	0.85%	9.50%	0.0025%	0.0278%
Sysco Corp	SYY	$36,715	0.07%	2.85%	9.50%	0.0020%	0.0067%
AT&T Inc	T	$208,241	0.40%	3.84%	6.50%	0.0154%	0.0262%

Exhibit JEN-6
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Company	Ticker	[4] Market Capitalization Excluding No Growth Rate ($ mill)	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
Molson Coors Beverage Co	TAP	$9,129	0.02%	3.91%	11.00%	0.0007%	0.0019%
TransDigm Group Inc	TDG	$85,410	0.17%	N/A	19.00%	N/A	0.0314%
Teledyne Technologies Inc	TDY	$24,007	0.05%	N/A	8.00%	N/A	0.0037%
Bio-Techne Corp	TECH	$8,066	0.02%	0.62%	10.00%	0.0001%	0.0016%
TE Connectivity PLC	TEL	$50,018	0.10%	1.68%	8.50%	0.0016%	0.0082%
Teradyne Inc	TER	$14,425	0.03%	0.53%	11.50%	0.0001%	0.0032%
Truist Financial Corp	TFC	$56,297	0.11%	4.84%	5.00%	0.0053%	0.0054%
Target Corp	TGT	$44,823	0.09%	4.62%	8.00%	0.0040%	0.0069%
TJX Cos Inc/The	TJX	$137,767	0.27%	1.38%	12.50%	0.0037%	0.0333%
TKO Group Holdings Inc	TKO	N/A	N/A	0.84%	N/A	N/A	N/A
Thermo Fisher Scientific Inc	TMO	$153,059	0.30%	0.42%	6.00%	0.0013%	0.0177%
T-Mobile US Inc	TMUS	$270,531	0.52%	1.48%	18.00%	0.0077%	0.0941%
Texas Pacific Land Corp	TPL	$24,284	0.05%	0.61%	10.00%	0.0003%	0.0047%
Tapestry Inc	TPR	$18,237	0.04%	1.59%	9.50%	0.0006%	0.0033%
Targa Resources Corp	TRGP	$37,763	0.07%	2.30%	22.00%	0.0017%	0.0161%
Trimble Inc	TRMB	$18,128	0.04%	N/A	6.00%	N/A	0.0021%
T Rowe Price Group Inc	TROW	$21,261	0.04%	5.26%	5.50%	0.0022%	0.0023%
Travelers Cos Inc/The	TRV	$60,616	0.12%	1.64%	10.50%	0.0019%	0.0123%
Tractor Supply Co	TSCO	$27,979	0.05%	1.74%	10.00%	0.0009%	0.0054%
Tesla Inc	TSLA	$1,023,169	1.98%	N/A	16.50%	N/A	0.3262%
Tyson Foods Inc	TSN	$16,011	0.03%	3.58%	4.00%	0.0011%	0.0012%
Trane Technologies PLC	TT	$97,550	0.19%	0.86%	12.50%	0.0016%	0.0236%
Take-Two Interactive Software Inc	TTWO	N/A	N/A	N/A	N/A	N/A	N/A
Texas Instruments Inc	TXN	$188,617	0.36%	2.62%	6.50%	0.0095%	0.0237%
Textron Inc	TXT	$14,495	0.03%	0.10%	12.00%	0.0000%	0.0034%
Tyler Technologies Inc	TYL	$25,565	0.05%	N/A	10.50%	N/A	0.0052%
United Airlines Holdings Inc	UAL	$26,095	0.05%	N/A	14.00%	N/A	0.0071%
Uber Technologies Inc	UBER	N/A	N/A	N/A	N/A	N/A	N/A
UDR Inc	UDR	$13,527	0.03%	4.21%	7.50%	0.0011%	0.0020%
Universal Health Services Inc	UHS	$10,360	0.02%	0.44%	13.00%	0.0001%	0.0026%
Ulta Beauty Inc	ULTA	$21,026	0.04%	N/A	4.50%	N/A	0.0018%
UnitedHealth Group Inc	UNH	$283,001	0.55%	2.83%	8.00%	0.0155%	0.0437%
Union Pacific Corp	UNP	$137,467	0.27%	2.33%	8.00%	0.0062%	0.0212%
United Parcel Service Inc	UPS	$74,062	0.14%	6.50%	0.50%	0.0093%	0.0007%
United Rentals Inc	URI	$48,970	0.09%	0.95%	9.50%	0.0009%	0.0090%
US Bancorp	USB	$70,501	0.14%	4.42%	4.00%	0.0060%	0.0054%
Visa Inc	V	$607,485	1.17%	0.66%	13.50%	0.0078%	0.1585%
VICI Properties Inc	VICI	$34,449	0.07%	5.31%	9.50%	0.0035%	0.0063%
Valero Energy Corp	VLO	$42,101	0.08%	3.36%	-8.00%	0.0027%	-0.0065%
Veralto Corp	VLTO	$25,022	0.05%	0.44%	6.00%	0.0002%	0.0029%
Vulcan Materials Co	VMC	$34,455	0.07%	0.75%	7.50%	0.0005%	0.0050%
Verisk Analytics Inc	VRSK	$43,574	0.08%	0.58%	11.00%	0.0005%	0.0093%
VeriSign Inc	VRSN	$27,118	0.05%	1.07%	10.00%	0.0006%	0.0052%
Vertex Pharmaceuticals Inc	VRTX	$114,326	0.22%	N/A	10.00%	N/A	0.0221%
Vistra Corp	VST	$65,766	0.13%	0.46%	30.50%	0.0006%	0.0388%
Ventas Inc	VTR	$28,499	0.06%	3.04%	23.00%	0.0017%	0.0127%
Viatris Inc	VTRS	$10,481	0.02%	5.38%	0.00%	0.0011%	0.0000%
Verizon Communications Inc	VZ	$182,437	0.35%	6.26%	0.50%	0.0221%	0.0018%
Westinghouse Air Brake Technologie	WAB	$35,825	0.07%	0.48%	16.00%	0.0003%	0.0111%
Waters Corp	WAT	$20,771	0.04%	N/A	6.50%	N/A	0.0026%
Walgreens Boots Alliance Inc	WBA	$9,937	0.02%	N/A	-11.00%	N/A	-0.0021%
Warner Bros Discovery Inc	WBD	N/A	N/A	N/A	N/A	N/A	N/A
Workday Inc	WDAY	$51,840	0.10%	N/A	12.00%	N/A	0.0120%
Western Digital Corp	WDC	$22,325	0.04%	0.63%	8.00%	0.0003%	0.0035%
WEC Energy Group Inc	WEC	$33,254	0.06%	3.43%	6.00%	0.0022%	0.0039%
Welltower Inc	WELL	$100,532	0.19%	1.74%	23.50%	0.0034%	0.0456%
Wells Fargo & Co	WFC	$260,725	0.50%	2.00%	9.50%	0.0101%	0.0479%
Waste Management Inc	WM	$92,079	0.18%	1.44%	8.50%	0.0026%	0.0151%
Williams Cos Inc/The	WMB	$76,691	0.15%	3.18%	9.50%	0.0047%	0.0141%
Walmart Inc	WMT	$780,325	1.51%	0.96%	10.00%	0.0145%	0.1508%
W R Berkley Corp	WRB	$27,871	0.05%	0.49%	13.50%	0.0003%	0.0073%
Williams-Sonoma Inc	WSM	$20,094	0.04%	1.62%	5.00%	0.0006%	0.0019%
West Pharmaceutical Services Inc	WST	$15,720	0.03%	0.38%	7.50%	0.0001%	0.0023%
Willis Towers Watson PLC	WTW	$30,389	0.06%	1.20%	6.50%	0.0007%	0.0038%
Weyerhaeuser Co	WY	$18,632	0.04%	3.27%	6.50%	0.0012%	0.0023%
Wynn Resorts Ltd	WYNN	$9,794	0.02%	1.07%	27.00%	0.0002%	0.0051%
Xcel Energy Inc	XEL	$39,277	0.08%	3.35%	7.00%	0.0025%	0.0053%
Exxon Mobil Corp	XOM	$464,579	0.90%	3.67%	-3.00%	0.0330%	-0.0269%
Xylem Inc/NY	XYL	$31,480	0.06%	1.24%	10.00%	0.0008%	0.0061%
Yum! Brands Inc	YUM	$41,189	0.08%	1.92%	8.50%	0.0015%	0.0068%
Zimmer Biomet Holdings Inc	ZBH	$18,046	0.03%	1.05%	6.50%	0.0004%	0.0023%
Zebra Technologies Corp	ZBRA	$15,681	0.03%	N/A	3.00%	N/A	0.0009%
Zoetis Inc	ZTS	$69,430	0.13%	1.28%	7.50%	0.0017%	0.0101%
		$51,754,768					

[4] Source: Bloomberg Professional as of June 30, 2025
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Bloomberg Professional as of June 30, 2025
[7] Source: Value Line as of June 30, 2025
[8] Equals [5] x [6]
[9] Equals [5] x [7]

Forward Market Return
Market DCF Based Method - Bloomberg

[1] Market Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.27%
[2] Market Cap. Weighted Estimate of the S&P 500 Growth Rate	14.70%
[3] Market Cap. Weighted Estimated Required Market Return	16.06%

Notes:
[1], [2] Source: Bloomberg Professional. Please see WP-6 (Confidential) for calculations
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]

Forward Market Return
Market DCF Based Method - S&P Earnings & Estimates Report

[4] S&P's estimate of the S&P 500 Dividend Yield	1.25%
[5] S&P's estimate of the S&P 500 Growth Rate	14.22%
[6] S&P 500 Estimated Required Market Return	15.56%

Notes:
[4], [5] Source: S&P 500 Earnings and Estimate Report June 30, 2025 provided as WP-25
[6] Equals ([4] x (1 + (0.5 x [5]))) + [5]

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Jennifer E. Nelson

RATE OF RETURN ON EQUITY

Exh. JEN-7

August 29, 2025

Exhibit JEN-7
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Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Using Blended Market Return and 5-year Beta Coefficients

	Company	Ticker	[1] Current 30-Year Treasury Yield	[2] 5-Year Bloomberg Beta Coefficient	[3] 5-Year Value Line Beta Coefficient	[4] Average Beta Coefficient	[5] DCF Expected Market Return	[6] Long-Term Average Historical Market Return (1926-	[7] Market Risk Premium	[8] Traditional CAPM	[9] Empirical CAPM
1	Atmos Energy Corporation	ATO	4.92%	0.65	0.75	0.70	14.81%	12.17%	8.57%	10.93%	11.57%
2	New Jersey Resources Corporation	NJR	4.92%	0.65	0.85	0.75	14.81%	12.17%	8.57%	11.33%	11.87%
3	NiSource Inc.	NI	4.92%	0.66	0.85	0.76	14.81%	12.17%	8.57%	11.40%	11.93%
4	ONE Gas, Inc.	OGS	4.92%	0.60	0.80	0.70	14.81%	12.17%	8.57%	10.94%	11.57%
5	Southwest Gas Holdings, Inc.	SWX	4.92%	0.64	0.80	0.72	14.81%	12.17%	8.57%	11.10%	11.69%
6	Spire, Inc.	SR	4.92%	0.64	0.80	0.72	14.81%	12.17%	8.57%	11.09%	11.69%
7	Ameren Corporation	AEE	4.92%	0.63	0.80	0.72	14.81%	12.17%	8.57%	11.05%	11.66%
8	Avista Corporation	AVA	4.92%	0.58	0.75	0.66	14.81%	12.17%	8.57%	10.60%	11.32%
9	Black Hills Corporation	BKH	4.92%	0.70	0.90	0.80	14.81%	12.17%	8.57%	11.77%	12.20%
10	CenterPoint Energy, Inc.	CNP	4.92%	0.72	0.85	0.78	14.81%	12.17%	8.57%	11.64%	12.11%
11	CMS Energy Corporation	CMS	4.92%	0.57	0.70	0.64	14.81%	12.17%	8.57%	10.38%	11.16%
12	Consolidated Edison, Inc.	ED	4.92%	0.48	0.65	0.57	14.81%	12.17%	8.57%	9.77%	10.70%
13	DTE Energy Company	DTE	4.92%	0.60	0.80	0.70	14.81%	12.17%	8.57%	10.91%	11.55%
14	Eversource Energy	ES	4.92%	0.63	0.85	0.74	14.81%	12.17%	8.57%	11.28%	11.83%
15	Public Service Enterprise Group Inc.	PEG	4.92%	0.71	0.90	0.80	14.81%	12.17%	8.57%	11.80%	12.22%
16	Sempra Energy	SRE	4.92%	0.73	0.90	0.82	14.81%	12.17%	8.57%	11.92%	12.31%
17	Southern Company	SO	4.92%	0.59	0.75	0.67	14.81%	12.17%	8.57%	10.65%	11.36%
18	Wisconsin Energy Corporation	WEC	4.92%	0.55	0.70	0.62	14.81%	12.17%	8.57%	10.26%	11.07%
19	Xcel Energy Inc.	XEL	4.92%	0.59	0.75	0.67	14.81%	12.17%	8.57%	10.67%	11.37%
20	GAS PROXY GROUP MEAN					0.72				11.13%	11.72%
21	GAS PROXY GROUP MEDIAN					0.72				11.09%	11.69%
22	AVERAGE OF THE MEAN AND MEDIAN					0.72				11.11%	11.71%
23	COMBINED PROXY GROUP MEAN					0.71				11.03%	11.64%
24	COMBINED PROXY GROUP MEDIAN					0.72				11.05%	11.66%
25	AVERAGE OF THE MEAN AND MEDIAN					0.71				11.04%	11.65%

	Company	Ticker	[10] Projected 30-Year Treasury Yield	[11] 5-Year Bloomberg Beta Coefficient	[12] 5-Year Value Line Beta Coefficient	[13] Average Beta Coefficient	[14] DCF Expected Market Return	[15] Average Historical Market Return (1926-2024)	[16] Market Risk Premium	[17] Traditional CAPM	[18] Empirical CAPM
1	Atmos Energy Corporation	ATO	4.52%	0.65	0.75	0.70	14.81%	12.17%	8.97%	10.81%	11.48%
2	New Jersey Resources Corporation	NJR	4.52%	0.65	0.85	0.75	14.81%	12.17%	8.97%	11.23%	11.79%
3	NiSource Inc.	NI	4.52%	0.66	0.85	0.76	14.81%	12.17%	8.97%	11.31%	11.85%
4	ONE Gas, Inc.	OGS	4.52%	0.60	0.80	0.70	14.81%	12.17%	8.97%	10.82%	11.49%
5	Southwest Gas Holdings, Inc.	SWX	4.52%	0.64	0.80	0.72	14.81%	12.17%	8.97%	10.98%	11.61%
6	Spire, Inc.	SR	4.52%	0.64	0.80	0.72	14.81%	12.17%	8.97%	10.98%	11.60%
7	Ameren Corporation	AEE	4.52%	0.63	0.80	0.72	14.81%	12.17%	8.97%	10.93%	11.57%
8	Avista Corporation	AVA	4.52%	0.58	0.75	0.66	14.81%	12.17%	8.97%	10.47%	11.22%
9	Black Hills Corporation	BKH	4.52%	0.70	0.90	0.80	14.81%	12.17%	8.97%	11.69%	12.14%
10	CenterPoint Energy, Inc.	CNP	4.52%	0.72	0.85	0.78	14.81%	12.17%	8.97%	11.56%	12.04%
11	CMS Energy Corporation	CMS	4.52%	0.57	0.70	0.64	14.81%	12.17%	8.97%	10.24%	11.05%
12	Consolidated Edison, Inc.	ED	4.52%	0.48	0.65	0.57	14.81%	12.17%	8.97%	9.59%	10.57%
13	DTE Energy Company	DTE	4.52%	0.60	0.80	0.70	14.81%	12.17%	8.97%	10.79%	11.46%
14	Eversource Energy	ES	4.52%	0.63	0.85	0.74	14.81%	12.17%	8.97%	11.18%	11.75%
15	Public Service Enterprise Group Inc.	PEG	4.52%	0.71	0.90	0.80	14.81%	12.17%	8.97%	11.72%	12.16%
16	Sempra Energy	SRE	4.52%	0.73	0.90	0.82	14.81%	12.17%	8.97%	11.84%	12.26%
17	Southern Company	SO	4.52%	0.59	0.75	0.67	14.81%	12.17%	8.97%	10.52%	11.26%
18	Wisconsin Energy Corporation	WEC	4.52%	0.55	0.70	0.62	14.81%	12.17%	8.97%	10.11%	10.96%
19	Xcel Energy Inc.	XEL	4.52%	0.59	0.75	0.67	14.81%	12.17%	8.97%	10.54%	11.27%
20	GAS PROXY GROUP MEAN					0.72				11.02%	11.64%
21	GAS PROXY GROUP MEDIAN					0.72				10.98%	11.61%
22	AVERAGE OF THE MEAN AND MEDIAN					0.72				11.00%	11.62%
23	COMBINED PROXY GROUP MEAN					0.71				10.91%	11.56%
24	COMBINED PROXY GROUP MEDIAN					0.72				10.93%	11.57%
25	AVERAGE OF THE MEAN AND MEDIAN					0.71				10.92%	11.56%

Notes:
[1] Source: Bloomberg Professional Service; 30-day average
[2] Source: Bloomberg Professional Service
[3] Source: Value Line
[4] Equals Average of Col. [2] and Col. [3]
[5] Source: JEN-6; Value Line DCF-based expected market return
[6] Source: Kroll Cost of Capital Navigator
[7] Average [6], [7] - Col. [1]
[8] Equals Col. [1] + (Col. [4] x Col. [7])
[9] Equals Col. [1] + (0.75 x Col. [4] x Col. [7]) + (0.25 x Col. [7])
[10] Source: Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025 at 14 and Vol. 44, No. 7, July 1, 2025 at 2
[11] See Note [2]
[12] See Note [3]
[13] Equals Average of Col. [11] and Col. [12]
[14] See Note [5]
[15] See Note [6]
[16] Equals Average Col. [14], [15] - Col. [10]
[17] Equals Col. [10] + (Col. [13] x Col. [16])
[18] Equals Col. [10] + (0.75 x Col. [13] x Col. [16]) + (0.25 x Col. [16])

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Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Using Blended Market Return and 10-year Beta Coefficients

	Company	Ticker	[1] Current 30-Year Treasury Yield	[2] 10-Year Bloomberg Beta Coefficient	[3] DCF Expected Market Return	[4] Long-Term Average Historical Market Return (1926-	[5] Market Risk Premium	[6] Traditional CAPM	[7] Empirical CAPM
1	Atmos Energy Corporation	ATO	4.92%	0.72	14.81%	12.17%	8.57%	11.11%	11.70%
2	New Jersey Resources Corporation	NJR	4.92%	0.76	14.81%	12.17%	8.57%	11.42%	11.94%
3	NiSource Inc.	NI	4.92%	0.77	14.81%	12.17%	8.57%	11.51%	12.00%
4	ONE Gas, Inc.	OGS	4.92%	0.74	14.81%	12.17%	8.57%	11.22%	11.79%
5	Southwest Gas Holdings, Inc.	SWX	4.92%	0.80	14.81%	12.17%	8.57%	11.75%	12.18%
6	Spire, Inc.	SR	4.92%	0.73	14.81%	12.17%	8.57%	11.21%	11.78%
7	Ameren Corporation	AEE	4.92%	0.72	14.81%	12.17%	8.57%	11.09%	11.69%
8	Avista Corporation	AVA	4.92%	0.71	14.81%	12.17%	8.57%	10.98%	11.60%
9	Black Hills Corporation	BKH	4.92%	0.85	14.81%	12.17%	8.57%	12.17%	12.50%
10	CenterPoint Energy, Inc.	CNP	4.92%	0.93	14.81%	12.17%	8.57%	12.89%	13.04%
11	CMS Energy Corporation	CMS	4.92%	0.70	14.81%	12.17%	8.57%	10.90%	11.54%
12	Consolidated Edison, Inc.	ED	4.92%	0.59	14.81%	12.17%	8.57%	9.95%	10.84%
13	DTE Energy Company	DTE	4.92%	0.78	14.81%	12.17%	8.57%	11.58%	12.06%
14	Eversource Energy	ES	4.92%	0.77	14.81%	12.17%	8.57%	11.48%	11.98%
15	Public Service Enterprise Group Inc.	PEG	4.92%	0.82	14.81%	12.17%	8.57%	11.97%	12.35%
16	Sempra Energy	SRE	4.92%	0.84	14.81%	12.17%	8.57%	12.15%	12.49%
17	Southern Company	SO	4.92%	0.74	14.81%	12.17%	8.57%	11.23%	11.79%
18	Wisconsin Energy Corporation	WEC	4.92%	0.69	14.81%	12.17%	8.57%	10.87%	11.53%
19	Xcel Energy Inc.	XEL	4.92%	0.70	14.81%	12.17%	8.57%	10.96%	11.59%
20	GAS PROXY GROUP MEAN			0.75				11.37%	11.90%
21	GAS PROXY GROUP MEDIAN			0.75				11.32%	11.86%
22	AVERAGE OF THE MEAN AND MEDIAN			0.75				11.34%	11.88%
23	COMBINED PROXY GROUP MEAN			0.76				11.39%	11.92%
24	COMBINED PROXY GROUP MEDIAN			0.74				11.23%	11.79%
25	AVERAGE OF THE MEAN AND MEDIAN			0.75				11.31%	11.85%

	Company	Ticker	[8] Projected 30-Year Treasury Yield	[9] 10-Year Bloomberg Beta Coefficient	[10] DCF Expected Market Return	[11] Average Historical Market Return (1926-2024)	[12] Market Risk Premium	[13] Traditional CAPM	[14] Empirical CAPM
1	Atmos Energy Corporation	ATO	4.52%	0.72	14.81%	12.17%	8.97%	11.00%	11.62%
2	New Jersey Resources Corporation	NJR	4.52%	0.76	14.81%	12.17%	8.97%	11.32%	11.86%
3	NiSource Inc.	NI	4.52%	0.77	14.81%	12.17%	8.97%	11.41%	11.93%
4	ONE Gas, Inc.	OGS	4.52%	0.74	14.81%	12.17%	8.97%	11.12%	11.71%
5	Southwest Gas Holdings, Inc.	SWX	4.52%	0.80	14.81%	12.17%	8.97%	11.67%	12.12%
6	Spire, Inc.	SR	4.52%	0.73	14.81%	12.17%	8.97%	11.11%	11.70%
7	Ameren Corporation	AEE	4.52%	0.72	14.81%	12.17%	8.97%	10.97%	11.60%
8	Avista Corporation	AVA	4.52%	0.71	14.81%	12.17%	8.97%	10.86%	11.52%
9	Black Hills Corporation	BKH	4.52%	0.85	14.81%	12.17%	8.97%	12.11%	12.45%
10	CenterPoint Energy, Inc.	CNP	4.52%	0.93	14.81%	12.17%	8.97%	12.86%	13.02%
11	CMS Energy Corporation	CMS	4.52%	0.70	14.81%	12.17%	8.97%	10.77%	11.45%
12	Consolidated Edison, Inc.	ED	4.52%	0.59	14.81%	12.17%	8.97%	9.79%	10.71%
13	DTE Energy Company	DTE	4.52%	0.78	14.81%	12.17%	8.97%	11.49%	11.99%
14	Eversource Energy	ES	4.52%	0.77	14.81%	12.17%	8.97%	11.39%	11.91%
15	Public Service Enterprise Group Inc.	PEG	4.52%	0.82	14.81%	12.17%	8.97%	11.90%	12.30%
16	Sempra Energy	SRE	4.52%	0.84	14.81%	12.17%	8.97%	12.09%	12.44%
17	Southern Company	SO	4.52%	0.74	14.81%	12.17%	8.97%	11.12%	11.71%
18	Wisconsin Energy Corporation	WEC	4.52%	0.69	14.81%	12.17%	8.97%	10.75%	11.44%
19	Xcel Energy Inc.	XEL	4.52%	0.70	14.81%	12.17%	8.97%	10.84%	11.50%
20	GAS PROXY GROUP MEAN			0.75				11.27%	11.83%
21	GAS PROXY GROUP MEDIAN			0.75				11.22%	11.79%
22	AVERAGE OF THE MEAN AND MEDIAN			0.75				11.24%	11.81%
23	COMBINED PROXY GROUP MEAN			0.76				11.29%	11.84%
24	COMBINED PROXY GROUP MEDIAN			0.74				11.12%	11.71%
25	AVERAGE OF THE MEAN AND MEDIAN			0.75				11.21%	11.78%

Notes:
[1] Source: Bloomberg Professional Service; 30-day average
[2] Source: Bloomberg Professional Service
[3] Source: JEN-6; Value Line DCF-based expected market return
[4] Source: Kroll Cost of Capital Navigator
[5] Average [3], [4] - Col. [1]
[6] Equals Col. [1] + (Col. [2] x Col. [5])
[7] Equals Col. [1] + (0.75 x Col. [2] x Col. [5]) + (0.25 x Col. [5])
[8] Source: Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025 at 14 and Vol. 44, No. 7, July 1, 2025 at 2
[9] See Note [2]
[10] See Note [3]
[11] See Note [4]
[12] Equals Average Col. [10], [11] - Col. [8]
[13] Equals Col. [8] + (Col. [9] x Col. [12])
[14] Equals Col. [8] + (0.75 x Col. [8] x Col. [9]) + (0.25 x Col. [12])

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Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Using Long-Term Historical Market Return and 5-year Beta Coefficients

			[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
	Company	Ticker	Current 30-Year Treasury Yield	5-Year Bloomberg Beta Coefficient	5-Year Value Line Beta Coefficient	Average Beta Coefficient	Long-Term Average Historical Market Return (1926-2024)	Market Risk Premium	Traditional CAPM	Empirical CAPM
1	Atmos Energy Corporation	ATO	4.92%	0.65	0.75	0.70	12.17%	7.25%	10.00%	10.54%
2	New Jersey Resources Corporation	NJR	4.92%	0.65	0.85	0.75	12.17%	7.25%	10.34%	10.80%
3	NiSource Inc.	NI	4.92%	0.66	0.85	0.76	12.17%	7.25%	10.40%	10.85%
4	ONE Gas, Inc.	OGS	4.92%	0.60	0.80	0.70	12.17%	7.25%	10.01%	10.55%
5	Southwest Gas Holdings, Inc.	SWX	4.92%	0.64	0.80	0.72	12.17%	7.25%	10.14%	10.65%
6	Spire, Inc.	SR	4.92%	0.64	0.80	0.72	12.17%	7.25%	10.14%	10.65%
7	Ameren Corporation	AEE	4.92%	0.63	0.80	0.72	12.17%	7.25%	10.10%	10.62%
8	Avista Corporation	AVA	4.92%	0.58	0.75	0.66	12.17%	7.25%	9.72%	10.34%
9	Black Hills Corporation	BKH	4.92%	0.70	0.90	0.80	12.17%	7.25%	10.72%	11.08%
10	CenterPoint Energy, Inc.	CNP	4.92%	0.72	0.85	0.78	12.17%	7.25%	10.61%	11.00%
11	CMS Energy Corporation	CMS	4.92%	0.57	0.70	0.64	12.17%	7.25%	9.54%	10.20%
12	Consolidated Edison, Inc.	ED	4.92%	0.48	0.65	0.57	12.17%	7.25%	9.02%	9.81%
13	DTE Energy Company	DTE	4.92%	0.60	0.80	0.70	12.17%	7.25%	9.98%	10.53%
14	Eversource Energy	ES	4.92%	0.63	0.85	0.74	12.17%	7.25%	10.30%	10.77%
15	Public Service Enterprise Group Inc.	PEG	4.92%	0.71	0.90	0.80	12.17%	7.25%	10.74%	11.10%
16	Sempra Energy	SRE	4.92%	0.73	0.90	0.82	12.17%	7.25%	10.84%	11.17%
17	Southern Company	SO	4.92%	0.59	0.75	0.67	12.17%	7.25%	9.77%	10.37%
18	Wisconsin Energy Corporation	WEC	4.92%	0.55	0.70	0.62	12.17%	7.25%	9.44%	10.12%
19	Xcel Energy Inc.	XEL	4.92%	0.59	0.75	0.67	12.17%	7.25%	9.78%	10.38%
20	GAS PROXY GROUP MEAN					0.72			10.17%	10.67%
21	GAS PROXY GROUP MEDIAN					0.72			10.14%	10.65%
22	AVERAGE OF THE MEAN AND MEDIAN					0.72			10.16%	10.66%
23	COMBINED PROXY GROUP MEAN					0.71			10.08%	10.61%
24	COMBINED PROXY GROUP MEDIAN					0.72			10.10%	10.62%
25	AVERAGE OF THE MEAN AND MEDIAN					0.71			10.09%	10.61%

			[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
	Company	Ticker	Projected 30-Year Treasury Yield	5-Year Bloomberg Beta Coefficient	5-Year Value Line Beta Coefficient	Average Beta Coefficient	Long-Term Average Historical Market Return (1926-2024)	Market Risk Premium	Traditional CAPM	Empirical CAPM
1	Atmos Energy Corporation	ATO	4.52%	0.65	0.75	0.70	12.17%	7.65%	9.88%	10.46%
2	New Jersey Resources Corporation	NJR	4.52%	0.65	0.85	0.75	12.17%	7.65%	10.24%	10.72%
3	NiSource Inc.	NI	4.52%	0.66	0.85	0.76	12.17%	7.65%	10.31%	10.77%
4	ONE Gas, Inc.	OGS	4.52%	0.60	0.80	0.70	12.17%	7.65%	9.89%	10.46%
5	Southwest Gas Holdings, Inc.	SWX	4.52%	0.64	0.80	0.72	12.17%	7.65%	10.03%	10.57%
6	Spire, Inc.	SR	4.52%	0.64	0.80	0.72	12.17%	7.65%	10.03%	10.56%
7	Ameren Corporation	AEE	4.52%	0.63	0.80	0.72	12.17%	7.65%	9.99%	10.53%
8	Avista Corporation	AVA	4.52%	0.58	0.75	0.66	12.17%	7.65%	9.59%	10.23%
9	Black Hills Corporation	BKH	4.52%	0.70	0.90	0.80	12.17%	7.65%	10.64%	11.02%
10	CenterPoint Energy, Inc.	CNP	4.52%	0.72	0.85	0.78	12.17%	7.65%	10.52%	10.93%
11	CMS Energy Corporation	CMS	4.52%	0.57	0.70	0.64	12.17%	7.65%	9.39%	10.09%
12	Consolidated Edison, Inc.	ED	4.52%	0.48	0.65	0.57	12.17%	7.65%	8.85%	9.68%
13	DTE Energy Company	DTE	4.52%	0.60	0.80	0.70	12.17%	7.65%	9.86%	10.44%
14	Eversource Energy	ES	4.52%	0.63	0.85	0.74	12.17%	7.65%	10.20%	10.69%
15	Public Service Enterprise Group Inc.	PEG	4.52%	0.71	0.90	0.80	12.17%	7.65%	10.66%	11.04%
16	Sempra Energy	SRE	4.52%	0.73	0.90	0.82	12.17%	7.65%	10.77%	11.12%
17	Southern Company	SO	4.52%	0.59	0.75	0.67	12.17%	7.65%	9.63%	10.27%
18	Wisconsin Energy Corporation	WEC	4.52%	0.55	0.70	0.62	12.17%	7.65%	9.29%	10.01%
19	Xcel Energy Inc.	XEL	4.52%	0.59	0.75	0.67	12.17%	7.65%	9.65%	10.28%
20	GAS PROXY GROUP MEAN					0.72			10.06%	10.59%
21	GAS PROXY GROUP MEDIAN					0.72			10.03%	10.56%
22	AVERAGE OF THE MEAN AND MEDIAN					0.72			10.05%	10.58%
23	COMBINED PROXY GROUP MEAN					0.71			9.97%	10.52%
24	COMBINED PROXY GROUP MEDIAN					0.72			9.99%	10.53%
25	AVERAGE OF THE MEAN AND MEDIAN					0.71			9.98%	10.53%

[1] Source: Bloomberg Professional Service; 30-day average
[2] Source: Bloomberg Professional Service
[3] Source: Value Line
[4] Equals Average of Col. [2] and Col. [3]
[5] Kroll, Cost of Capital Navigator
[6] Equals Col. [5] - Col. [1]
[7] Equals Col. [1] + (Col. [4] x Col. [6])
[8] Equals Col. [1] + (0.75 x Col. [4] x Col. [6]) + (0.25 x Col. [6])
[9] Source: Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025 at 14 and Vol. 44, No. 7, July 1, 2025 at 2
[10] See Note [2]
[11] See Note [3]
[12] Equals Average of Col. [10] and Col. [11]
[13] See Note [5]
[14] Equals Col. [13] - Col. [9]
[15] Equals Col. [9] + (Col. [12] x Col. [14])
[16] Equals Col. [9] + (0.75 x Col. [12] x Col. [14]) + (0.25 x Col. [14])

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Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Using Long-Term Historical Market Return and 10-year Beta Coefficients

			[1]	[2]	[3]	[4]	[5]	[6]
	Company	Ticker	Current 30-Year Treasury Yield	10-Year Bloomberg Beta Coefficient	Long-Term Average Historical Market Return (1926-2024)	Market Risk Premium	Traditional CAPM	Empirical CAPM
1	Atmos Energy Corporation	ATO	4.92%	0.72	12.17%	7.25%	10.15%	10.66%
2	New Jersey Resources Corporation	NJR	4.92%	0.76	12.17%	7.25%	10.42%	10.85%
3	NiSource Inc.	NI	4.92%	0.77	12.17%	7.25%	10.49%	10.91%
4	ONE Gas, Inc.	OGS	4.92%	0.74	12.17%	7.25%	10.25%	10.73%
5	Southwest Gas Holdings, Inc.	SWX	4.92%	0.80	12.17%	7.25%	10.70%	11.06%
6	Spire, Inc.	SR	4.92%	0.73	12.17%	7.25%	10.24%	10.72%
7	Ameren Corporation	AEE	4.92%	0.72	12.17%	7.25%	10.14%	10.64%
8	Avista Corporation	AVA	4.92%	0.71	12.17%	7.25%	10.04%	10.57%
9	Black Hills Corporation	BKH	4.92%	0.85	12.17%	7.25%	11.05%	11.33%
10	CenterPoint Energy, Inc.	CNP	4.92%	0.93	12.17%	7.25%	11.66%	11.79%
11	CMS Energy Corporation	CMS	4.92%	0.70	12.17%	7.25%	9.97%	10.52%
12	Consolidated Edison, Inc.	ED	4.92%	0.59	12.17%	7.25%	9.18%	9.93%
13	DTE Energy Company	DTE	4.92%	0.78	12.17%	7.25%	10.55%	10.96%
14	Eversource Energy	ES	4.92%	0.77	12.17%	7.25%	10.47%	10.90%
15	Public Service Enterprise Group Inc.	PEG	4.92%	0.82	12.17%	7.25%	10.89%	11.21%
16	Sempra Energy	SRE	4.92%	0.84	12.17%	7.25%	11.04%	11.32%
17	Southern Company	SO	4.92%	0.74	12.17%	7.25%	10.26%	10.73%
18	Wisconsin Energy Corporation	WEC	4.92%	0.69	12.17%	7.25%	9.95%	10.51%
19	Xcel Energy Inc.	XEL	4.92%	0.70	12.17%	7.25%	10.03%	10.56%
20	GAS PROXY GROUP MEAN			0.75			10.37%	10.82%
21	GAS PROXY GROUP MEDIAN			0.75			10.33%	10.79%
22	AVERAGE OF THE MEAN AND MEDIAN			0.75			10.35%	10.81%
23	COMBINED PROXY GROUP MEAN			0.76			10.39%	10.84%
24	COMBINED PROXY GROUP MEDIAN			0.74			10.26%	10.73%
25	AVERAGE OF THE MEAN AND MEDIAN			0.75			10.32%	10.79%

			[7]	[8]	[9]	[10]	[11]	[12]
	Company	Ticker	Projected 30-Year Treasury Yield	10-Year Bloomberg Beta Coefficient	Long-Term Average Historical Market Return (1926-2024)	Market Risk Premium	Traditional CAPM	Empirical CAPM
1	Atmos Energy Corporation	ATO	4.52%	0.72	12.17%	7.65%	10.04%	10.57%
2	New Jersey Resources Corporation	NJR	4.52%	0.76	12.17%	7.65%	10.32%	10.78%
3	NiSource Inc.	NI	4.52%	0.77	12.17%	7.65%	10.40%	10.84%
4	ONE Gas, Inc.	OGS	4.52%	0.74	12.17%	7.65%	10.14%	10.65%
5	Southwest Gas Holdings, Inc.	SWX	4.52%	0.80	12.17%	7.65%	10.61%	11.00%
6	Spire, Inc.	SR	4.52%	0.73	12.17%	7.65%	10.14%	10.64%
7	Ameren Corporation	AEE	4.52%	0.72	12.17%	7.65%	10.02%	10.56%
8	Avista Corporation	AVA	4.52%	0.71	12.17%	7.65%	9.92%	10.49%
9	Black Hills Corporation	BKH	4.52%	0.85	12.17%	7.65%	10.99%	11.28%
10	CenterPoint Energy, Inc.	CNP	4.52%	0.93	12.17%	7.65%	11.63%	11.77%
11	CMS Energy Corporation	CMS	4.52%	0.70	12.17%	7.65%	9.85%	10.43%
12	Consolidated Edison, Inc.	ED	4.52%	0.59	12.17%	7.65%	9.01%	9.80%
13	DTE Energy Company	DTE	4.52%	0.78	12.17%	7.65%	10.46%	10.89%
14	Eversource Energy	ES	4.52%	0.77	12.17%	7.65%	10.38%	10.83%
15	Public Service Enterprise Group Inc.	PEG	4.52%	0.82	12.17%	7.65%	10.82%	11.15%
16	Sempra Energy	SRE	4.52%	0.84	12.17%	7.65%	10.97%	11.27%
17	Southern Company	SO	4.52%	0.74	12.17%	7.65%	10.15%	10.66%
18	Wisconsin Energy Corporation	WEC	4.52%	0.69	12.17%	7.65%	9.83%	10.42%
19	Xcel Energy Inc.	XEL	4.52%	0.70	12.17%	7.65%	9.91%	10.48%
20	GAS PROXY GROUP MEAN			0.75			10.28%	10.75%
21	GAS PROXY GROUP MEDIAN			0.75			10.23%	10.72%
22	AVERAGE OF THE MEAN AND MEDIAN			0.75			10.25%	10.73%
23	COMBINED PROXY GROUP MEAN			0.76			10.30%	10.76%
24	COMBINED PROXY GROUP MEDIAN			0.74			10.15%	10.66%
25	AVERAGE OF THE MEAN AND MEDIAN			0.75			10.22%	10.71%

[1] Source: Bloomberg Professional Service; 30-day average
[2] Source: Bloomberg Professional Service
[3] Kroll, Cost of Capital Navigator
[4] Equals Col. [3] - Col. [1]
[5] Equals Col. [1] + (Col. [2] x Col. [4])
[6] Equals Col. [1] + (0.75 x Col. [2] x Col. [4]) + (0.25 x Col. [4])
[7] Source: Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025 at 14 and Vol. 44, No. 7, July 1, 2025 at 2
[8] See Note [2]
[9] See Note [3]
[10] Equals Col. [9] - Col. [7]
[11] Equals Col. [7] + (Col. [8] x Col. [10])
[12] Equals Col. [7] + (0.75 x Col. [8] x Col. [10]) + (0.25 x Col. [10])

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Jennifer E. Nelson

RATE OF RETURN ON EQUITY

Exh. JEN-8

August 29, 2025

Exhibit JEN-8
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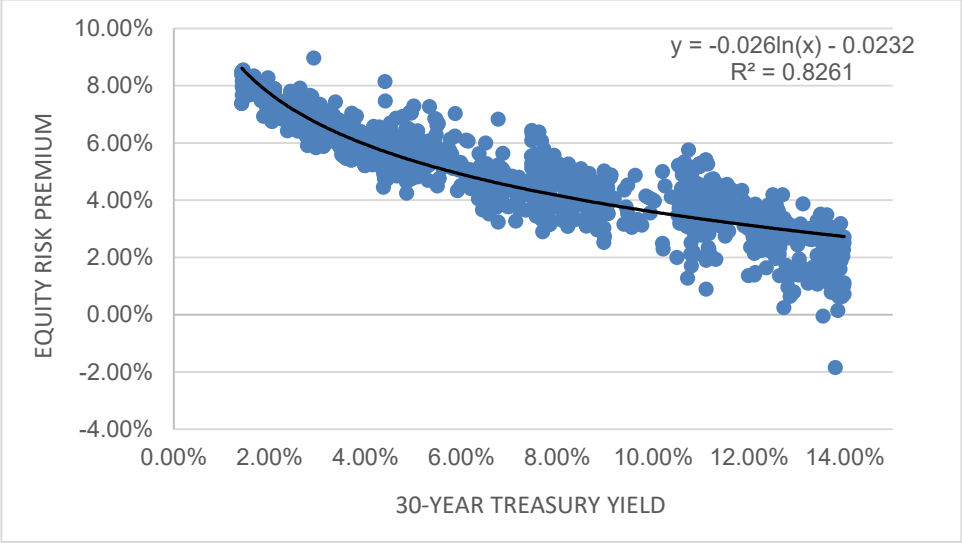
Bond Yield Plus Risk Premium

[1]	[2]	[3]	[4]	[5]
Constant	Slope	30-Year Treasury Yield	Risk Premium	Return on Equity
-2.32%	-2.57%			
Current 30-Year Treasury		4.92%	5.42%	10.33%
Projected 30-Year Treasury		4.52%	5.64%	10.15%



Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Sources: Current = Bloomberg Professional,
Projected = Average of near-term and long-term projected 30-year Treasury yield from
Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025 at 14 and
Blue Chip Financial Forecasts, Vol. 44, No. 7, July 1, 2025 at 2
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]
[6] Source: S&P Capital IQ
[7] Source: S&P Capital IQ
[8] Source: Bloomberg Professional, equals 188-trading day average (i.e. lag period)
[9] Equals [7] - [8]

Exhibit JEN-8
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Bond Yield Plus Risk Premium

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/3/1980	12.55%	9.39%	3.16%
1/4/1980	13.75%	9.40%	4.35%
1/14/1980	13.20%	9.44%	3.76%
1/18/1980	14.00%	9.47%	4.53%
1/31/1980	12.61%	9.56%	3.05%
2/8/1980	14.50%	9.63%	4.87%
2/14/1980	13.00%	9.67%	3.33%
2/15/1980	13.00%	9.69%	3.31%
2/29/1980	14.00%	9.85%	4.15%
3/5/1980	14.00%	9.90%	4.10%
3/7/1980	13.50%	9.94%	3.56%
3/14/1980	14.00%	10.03%	3.97%
3/27/1980	12.69%	10.19%	2.50%
4/1/1980	14.75%	10.25%	4.50%
4/29/1980	12.50%	10.50%	2.00%
5/7/1980	14.27%	10.55%	3.72%
5/8/1980	13.75%	10.55%	3.20%
5/19/1980	15.50%	10.61%	4.89%
5/27/1980	14.60%	10.64%	3.96%
5/29/1980	16.00%	10.66%	5.34%
6/10/1980	13.78%	10.70%	3.08%
6/25/1980	14.25%	10.73%	3.52%
7/9/1980	14.51%	10.77%	3.74%
7/17/1980	12.90%	10.78%	2.12%
7/18/1980	13.80%	10.79%	3.01%
7/22/1980	14.10%	10.79%	3.31%
7/23/1980	14.19%	10.79%	3.40%
8/1/1980	12.50%	10.80%	1.70%
8/11/1980	14.85%	10.81%	4.04%
8/21/1980	13.03%	10.84%	2.19%
8/28/1980	13.61%	10.87%	2.74%
8/28/1980	14.00%	10.87%	3.13%
9/4/1980	14.00%	10.89%	3.11%
9/24/1980	15.00%	10.98%	4.02%
10/9/1980	14.50%	11.05%	3.45%
10/9/1980	14.50%	11.05%	3.45%
10/24/1980	14.00%	11.09%	2.91%
10/27/1980	15.20%	11.10%	4.10%
10/27/1980	15.20%	11.10%	4.10%
10/28/1980	12.00%	11.10%	0.90%
10/28/1980	13.00%	11.10%	1.90%
10/31/1980	14.50%	11.12%	3.38%
11/4/1980	15.00%	11.13%	3.87%
11/6/1980	14.35%	11.13%	3.22%
11/10/1980	13.25%	11.14%	2.11%
11/17/1980	15.50%	11.15%	4.35%
11/19/1980	13.50%	11.15%	2.35%
12/5/1980	14.60%	11.14%	3.46%
12/8/1980	16.40%	11.14%	5.26%
12/12/1980	15.45%	11.15%	4.30%

Exhibit JEN-8
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[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/17/1980	14.20%	11.16%	3.04%
12/17/1980	14.40%	11.16%	3.24%
12/18/1980	14.00%	11.17%	2.83%
12/22/1980	13.45%	11.16%	2.29%
12/26/1980	14.00%	11.15%	2.85%
12/30/1980	14.50%	11.15%	3.35%
12/31/1980	14.56%	11.15%	3.41%
1/7/1981	14.30%	11.14%	3.16%
1/12/1981	14.95%	11.14%	3.81%
1/26/1981	15.25%	11.20%	4.05%
1/30/1981	13.25%	11.23%	2.02%
2/11/1981	14.50%	11.33%	3.17%
2/20/1981	14.50%	11.39%	3.11%
3/12/1981	15.65%	11.59%	4.06%
3/25/1981	15.30%	11.73%	3.57%
4/1/1981	15.30%	11.81%	3.49%
4/9/1981	15.00%	11.90%	3.10%
4/29/1981	13.50%	12.11%	1.39%
4/29/1981	14.25%	12.11%	2.14%
4/30/1981	13.60%	12.13%	1.47%
4/30/1981	15.00%	12.13%	2.87%
5/21/1981	14.00%	12.37%	1.63%
6/3/1981	14.67%	12.45%	2.22%
6/22/1981	16.00%	12.57%	3.43%
6/25/1981	14.75%	12.59%	2.16%
7/2/1981	14.00%	12.64%	1.36%
7/10/1981	16.00%	12.68%	3.32%
7/14/1981	16.90%	12.71%	4.19%
7/21/1981	15.78%	12.77%	3.01%
7/27/1981	13.77%	12.82%	0.95%
7/27/1981	15.50%	12.82%	2.68%
7/31/1981	13.50%	12.86%	0.64%
7/31/1981	14.20%	12.86%	1.34%
8/12/1981	13.72%	12.93%	0.79%
8/12/1981	13.72%	12.93%	0.79%
8/12/1981	14.41%	12.93%	1.48%
8/25/1981	15.45%	13.01%	2.44%
8/27/1981	14.43%	13.04%	1.39%
8/28/1981	15.00%	13.05%	1.95%
9/23/1981	14.34%	13.23%	1.11%
9/24/1981	16.25%	13.25%	3.00%
9/29/1981	14.50%	13.30%	1.20%
9/30/1981	15.94%	13.32%	2.62%
10/2/1981	14.80%	13.35%	1.45%
10/12/1981	16.25%	13.42%	2.83%
10/20/1981	15.25%	13.49%	1.76%
10/20/1981	16.50%	13.49%	3.01%
10/20/1981	17.00%	13.49%	3.51%
10/23/1981	15.50%	13.53%	1.97%
10/26/1981	13.50%	13.55%	-0.05%
10/29/1981	16.50%	13.59%	2.91%

Exhibit JEN-8
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[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
11/4/1981	15.33%	13.62%	1.71%
11/6/1981	15.17%	13.63%	1.54%
11/12/1981	15.00%	13.64%	1.36%
11/25/1981	15.25%	13.66%	1.59%
11/25/1981	16.10%	13.66%	2.44%
11/25/1981	16.10%	13.66%	2.44%
11/30/1981	16.75%	13.65%	3.10%
12/1/1981	15.70%	13.65%	2.05%
12/1/1981	16.00%	13.65%	2.35%
12/15/1981	15.81%	13.68%	2.13%
12/17/1981	14.75%	13.70%	1.05%
12/22/1981	15.70%	13.71%	1.99%
12/22/1981	16.00%	13.71%	2.29%
12/30/1981	16.00%	13.74%	2.26%
12/30/1981	16.25%	13.74%	2.51%
1/4/1982	15.50%	13.74%	1.76%
1/14/1982	11.95%	13.80%	-1.85%
1/25/1982	16.25%	13.84%	2.41%
1/27/1982	16.84%	13.85%	2.99%
1/31/1982	14.00%	13.85%	0.15%
2/2/1982	16.24%	13.86%	2.38%
2/8/1982	15.50%	13.87%	1.63%
2/9/1982	14.95%	13.88%	1.07%
2/9/1982	15.75%	13.88%	1.87%
2/11/1982	16.00%	13.89%	2.11%
3/1/1982	15.96%	13.91%	2.05%
3/3/1982	15.00%	13.91%	1.09%
3/8/1982	17.10%	13.91%	3.19%
3/26/1982	16.00%	13.96%	2.04%
3/31/1982	16.25%	13.97%	2.28%
4/1/1982	16.50%	13.98%	2.52%
4/6/1982	15.00%	13.98%	1.02%
4/9/1982	16.50%	13.99%	2.51%
4/12/1982	15.10%	13.98%	1.12%
4/12/1982	16.70%	13.98%	2.72%
4/18/1982	14.70%	13.98%	0.72%
4/27/1982	15.00%	13.97%	1.03%
5/10/1982	14.57%	13.94%	0.63%
5/14/1982	15.80%	13.92%	1.88%
5/20/1982	15.82%	13.91%	1.91%
5/21/1982	15.50%	13.90%	1.60%
5/25/1982	16.25%	13.90%	2.35%
6/2/1982	14.50%	13.87%	0.63%
6/7/1982	16.00%	13.86%	2.14%
6/23/1982	15.50%	13.81%	1.69%
6/25/1982	16.50%	13.81%	2.69%
7/1/1982	15.55%	13.80%	1.75%
7/1/1982	16.00%	13.80%	2.20%
7/2/1982	15.10%	13.79%	1.31%
7/13/1982	16.80%	13.76%	3.04%
7/22/1982	14.50%	13.72%	0.78%

Exhibit JEN-8
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[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
7/28/1982	16.10%	13.69%	2.41%
7/30/1982	14.82%	13.67%	1.15%
8/4/1982	15.58%	13.65%	1.93%
8/6/1982	16.50%	13.63%	2.87%
8/11/1982	17.11%	13.62%	3.49%
8/25/1982	16.00%	13.58%	2.42%
8/30/1982	16.25%	13.58%	2.67%
9/3/1982	15.50%	13.56%	1.94%
9/9/1982	16.04%	13.55%	2.49%
9/15/1982	16.04%	13.52%	2.52%
9/17/1982	15.25%	13.51%	1.74%
9/29/1982	14.50%	13.43%	1.07%
9/30/1982	14.74%	13.42%	1.32%
9/30/1982	15.50%	13.42%	2.08%
9/30/1982	16.50%	13.42%	3.08%
9/30/1982	16.70%	13.42%	3.28%
10/1/1982	16.50%	13.41%	3.09%
10/8/1982	15.00%	13.34%	1.66%
10/15/1982	15.90%	13.26%	2.64%
10/19/1982	15.90%	13.23%	2.67%
10/27/1982	17.00%	13.13%	3.87%
10/28/1982	14.75%	13.11%	1.64%
11/2/1982	16.25%	13.08%	3.17%
11/4/1982	15.75%	13.04%	2.71%
11/5/1982	14.73%	13.02%	1.71%
11/17/1982	16.00%	12.87%	3.13%
11/23/1982	15.50%	12.79%	2.71%
11/24/1982	14.50%	12.78%	1.72%
11/24/1982	16.02%	12.78%	3.24%
11/30/1982	12.98%	12.73%	0.25%
11/30/1982	15.50%	12.73%	2.77%
11/30/1982	15.50%	12.73%	2.77%
11/30/1982	15.65%	12.73%	2.92%
11/30/1982	16.00%	12.73%	3.27%
11/30/1982	16.10%	12.73%	3.37%
12/3/1982	15.33%	12.68%	2.65%
12/8/1982	15.75%	12.64%	3.11%
12/13/1982	16.00%	12.59%	3.41%
12/14/1982	16.40%	12.57%	3.83%
12/17/1982	16.25%	12.53%	3.72%
12/20/1982	15.00%	12.51%	2.49%
12/21/1982	15.70%	12.50%	3.20%
12/28/1982	15.25%	12.43%	2.82%
12/28/1982	15.25%	12.43%	2.82%
12/29/1982	16.25%	12.41%	3.84%
12/29/1982	16.25%	12.41%	3.84%
1/11/1983	15.90%	12.26%	3.64%
1/12/1983	15.50%	12.25%	3.25%
1/18/1983	15.00%	12.19%	2.81%
1/24/1983	15.50%	12.14%	3.36%
1/24/1983	16.00%	12.14%	3.86%

Exhibit JEN-8
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[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/28/1983	14.90%	12.09%	2.81%
1/31/1983	15.00%	12.07%	2.93%
2/10/1983	15.00%	11.98%	3.02%
2/25/1983	15.70%	11.85%	3.85%
3/2/1983	15.25%	11.80%	3.45%
3/16/1983	16.00%	11.64%	4.36%
3/21/1983	14.96%	11.58%	3.38%
3/23/1983	15.40%	11.54%	3.86%
3/23/1983	16.10%	11.54%	4.56%
3/24/1983	15.00%	11.53%	3.47%
4/12/1983	13.25%	11.31%	1.94%
4/29/1983	15.05%	11.11%	3.94%
5/3/1983	15.40%	11.08%	4.32%
5/9/1983	15.50%	11.01%	4.49%
5/19/1983	14.85%	10.90%	3.95%
5/31/1983	14.00%	10.85%	3.15%
6/2/1983	14.50%	10.83%	3.67%
6/7/1983	14.50%	10.81%	3.69%
6/9/1983	14.85%	10.80%	4.05%
6/20/1983	14.15%	10.74%	3.41%
6/20/1983	16.50%	10.74%	5.76%
6/27/1983	14.50%	10.72%	3.78%
6/30/1983	14.80%	10.71%	4.09%
6/30/1983	15.90%	10.71%	5.19%
7/1/1983	14.80%	10.70%	4.10%
7/5/1983	15.00%	10.70%	4.30%
7/8/1983	15.50%	10.69%	4.81%
7/19/1983	15.00%	10.71%	4.29%
7/19/1983	15.10%	10.71%	4.39%
8/18/1983	15.30%	10.81%	4.49%
8/19/1983	15.79%	10.82%	4.97%
8/29/1983	16.00%	10.85%	5.15%
8/31/1983	14.75%	10.86%	3.89%
8/31/1983	15.25%	10.86%	4.39%
9/8/1983	14.75%	10.89%	3.86%
9/16/1983	15.51%	10.93%	4.58%
9/26/1983	14.50%	10.96%	3.54%
9/28/1983	14.25%	10.97%	3.28%
9/30/1983	16.15%	10.98%	5.17%
9/30/1983	16.25%	10.98%	5.27%
10/1/1983	16.25%	10.98%	5.27%
10/13/1983	15.52%	11.02%	4.50%
10/19/1983	15.20%	11.04%	4.16%
10/26/1983	14.75%	11.06%	3.69%
10/27/1983	14.88%	11.07%	3.81%
10/27/1983	15.33%	11.07%	4.26%
11/9/1983	14.82%	11.10%	3.72%
11/9/1983	16.51%	11.10%	5.41%
11/9/1983	16.51%	11.10%	5.41%
12/1/1983	14.50%	11.17%	3.33%
12/8/1983	15.90%	11.20%	4.70%

Exhibit JEN-8
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[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/9/1983	15.30%	11.21%	4.09%
12/12/1983	14.50%	11.21%	3.29%
12/12/1983	15.50%	11.21%	4.29%
12/20/1983	15.40%	11.26%	4.14%
12/20/1983	16.00%	11.26%	4.74%
12/22/1983	15.75%	11.27%	4.48%
12/29/1983	15.00%	11.29%	3.71%
12/30/1983	15.00%	11.30%	3.70%
1/10/1984	15.90%	11.34%	4.56%
1/13/1984	15.50%	11.36%	4.14%
1/18/1984	15.53%	11.38%	4.15%
1/26/1984	15.90%	11.41%	4.49%
2/14/1984	14.25%	11.50%	2.75%
2/28/1984	14.50%	11.58%	2.92%
3/20/1984	16.00%	11.69%	4.31%
3/23/1984	15.50%	11.72%	3.78%
4/9/1984	15.20%	11.81%	3.39%
4/18/1984	16.20%	11.85%	4.35%
4/27/1984	15.85%	11.90%	3.95%
5/15/1984	13.35%	11.99%	1.36%
5/16/1984	15.00%	12.00%	3.00%
5/22/1984	14.40%	12.03%	2.37%
6/13/1984	15.50%	12.18%	3.32%
7/10/1984	16.00%	12.36%	3.64%
8/7/1984	16.69%	12.50%	4.19%
8/9/1984	15.33%	12.51%	2.82%
8/17/1984	14.82%	12.53%	2.29%
8/21/1984	14.64%	12.54%	2.10%
8/27/1984	14.52%	12.56%	1.96%
8/28/1984	14.75%	12.56%	2.19%
8/30/1984	15.60%	12.57%	3.03%
9/12/1984	15.60%	12.60%	3.00%
9/12/1984	15.90%	12.60%	3.30%
9/25/1984	16.25%	12.61%	3.64%
10/2/1984	14.80%	12.62%	2.18%
10/9/1984	14.75%	12.63%	2.12%
10/10/1984	15.50%	12.63%	2.87%
10/18/1984	15.00%	12.64%	2.36%
10/24/1984	15.50%	12.64%	2.86%
11/7/1984	15.00%	12.64%	2.36%
11/20/1984	15.92%	12.62%	3.30%
11/30/1984	15.50%	12.60%	2.90%
12/18/1984	15.00%	12.55%	2.45%
12/20/1984	15.00%	12.53%	2.47%
12/28/1984	15.75%	12.51%	3.24%
12/28/1984	16.25%	12.51%	3.74%
1/2/1985	16.00%	12.50%	3.50%
1/31/1985	14.75%	12.37%	2.38%
2/7/1985	14.85%	12.33%	2.52%
2/15/1985	15.00%	12.28%	2.72%
2/20/1985	14.50%	12.26%	2.24%

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[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
2/22/1985	14.86%	12.26%	2.60%
3/14/1985	15.50%	12.17%	3.33%
3/28/1985	14.80%	12.09%	2.71%
4/9/1985	15.50%	12.03%	3.47%
4/16/1985	15.70%	11.97%	3.73%
6/10/1985	15.75%	11.59%	4.16%
6/26/1985	14.82%	11.47%	3.35%
7/9/1985	15.00%	11.39%	3.61%
7/26/1985	14.50%	11.27%	3.23%
8/29/1985	14.50%	11.12%	3.38%
8/30/1985	14.38%	11.11%	3.27%
9/12/1985	15.25%	11.07%	4.18%
9/23/1985	15.30%	11.04%	4.26%
9/25/1985	14.50%	11.03%	3.47%
9/26/1985	13.80%	11.02%	2.78%
9/26/1985	14.50%	11.02%	3.48%
10/25/1985	15.25%	10.92%	4.33%
11/8/1985	12.94%	10.86%	2.08%
11/20/1985	14.90%	10.81%	4.09%
11/25/1985	13.30%	10.79%	2.51%
12/6/1985	12.00%	10.72%	1.28%
12/11/1985	14.90%	10.69%	4.21%
12/20/1985	14.88%	10.60%	4.28%
12/20/1985	15.00%	10.60%	4.40%
12/20/1985	15.00%	10.60%	4.40%
12/30/1985	15.75%	10.53%	5.22%
12/31/1985	14.00%	10.52%	3.48%
12/31/1985	14.50%	10.52%	3.98%
1/17/1986	14.50%	10.38%	4.12%
2/11/1986	12.50%	10.21%	2.29%
2/12/1986	15.20%	10.20%	5.00%
3/11/1986	14.00%	9.98%	4.02%
4/2/1986	12.90%	9.77%	3.13%
4/28/1986	13.01%	9.47%	3.54%
5/21/1986	13.25%	9.19%	4.06%
5/28/1986	14.00%	9.12%	4.88%
5/29/1986	13.90%	9.11%	4.79%
6/2/1986	13.00%	9.08%	3.92%
6/11/1986	14.00%	8.98%	5.02%
6/13/1986	13.55%	8.95%	4.60%
6/27/1986	11.88%	8.78%	3.10%
7/14/1986	12.60%	8.60%	4.00%
7/30/1986	13.30%	8.39%	4.91%
8/14/1986	13.50%	8.23%	5.27%
9/5/1986	13.30%	8.03%	5.27%
9/23/1986	12.75%	7.91%	4.84%
10/30/1986	13.00%	7.68%	5.32%
10/31/1986	13.75%	7.67%	6.08%
11/10/1986	14.00%	7.62%	6.38%
11/19/1986	13.75%	7.57%	6.18%
11/25/1986	13.15%	7.54%	5.61%

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[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/22/1986	13.80%	7.48%	6.32%
12/30/1986	13.90%	7.47%	6.43%
1/20/1987	12.75%	7.47%	5.28%
1/23/1987	13.55%	7.47%	6.08%
1/27/1987	12.16%	7.47%	4.69%
2/13/1987	12.60%	7.47%	5.13%
2/24/1987	12.00%	7.47%	4.53%
3/30/1987	12.20%	7.46%	4.74%
3/31/1987	13.00%	7.46%	5.54%
5/5/1987	12.85%	7.60%	5.25%
5/28/1987	13.50%	7.72%	5.78%
6/15/1987	13.20%	7.80%	5.40%
6/30/1987	12.60%	7.85%	4.75%
7/10/1987	12.90%	7.88%	5.02%
7/27/1987	13.50%	7.93%	5.57%
8/25/1987	11.40%	8.08%	3.32%
9/18/1987	13.00%	8.27%	4.73%
10/20/1987	12.60%	8.54%	4.06%
10/20/1987	12.98%	8.54%	4.44%
11/12/1987	12.75%	8.67%	4.08%
11/13/1987	12.75%	8.68%	4.07%
11/24/1987	12.50%	8.73%	3.77%
12/8/1987	12.50%	8.81%	3.69%
12/22/1987	12.00%	8.90%	3.10%
12/31/1987	12.85%	8.93%	3.92%
12/31/1987	13.25%	8.93%	4.32%
1/15/1988	13.15%	8.98%	4.17%
1/20/1988	12.75%	8.99%	3.76%
1/29/1988	13.20%	8.99%	4.21%
2/4/1988	12.60%	8.99%	3.61%
3/23/1988	13.00%	8.94%	4.06%
5/27/1988	13.18%	9.02%	4.16%
6/14/1988	13.50%	9.00%	4.50%
6/17/1988	11.72%	8.99%	2.73%
6/24/1988	11.50%	8.97%	2.53%
7/1/1988	12.75%	8.95%	3.80%
7/8/1988	12.00%	8.94%	3.06%
7/18/1988	12.00%	8.91%	3.09%
7/20/1988	13.40%	8.90%	4.50%
8/8/1988	12.74%	8.90%	3.84%
9/20/1988	12.90%	8.93%	3.97%
9/26/1988	12.40%	8.93%	3.47%
9/27/1988	13.65%	8.93%	4.72%
9/30/1988	13.25%	8.94%	4.31%
10/13/1988	13.10%	8.93%	4.17%
10/21/1988	12.80%	8.93%	3.87%
10/25/1988	13.25%	8.94%	4.31%
10/26/1988	13.50%	8.94%	4.56%
10/27/1988	12.95%	8.94%	4.01%
10/28/1988	13.00%	8.94%	4.06%
11/15/1988	12.00%	8.97%	3.03%

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[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
11/29/1988	12.75%	9.01%	3.74%
12/19/1988	13.00%	9.05%	3.95%
12/21/1988	12.90%	9.05%	3.85%
12/22/1988	13.50%	9.05%	4.45%
1/26/1989	12.60%	9.06%	3.54%
1/27/1989	13.00%	9.06%	3.94%
2/8/1989	13.37%	9.05%	4.32%
3/8/1989	13.00%	9.04%	3.96%
5/4/1989	13.00%	9.04%	3.96%
6/8/1989	13.50%	8.96%	4.54%
7/19/1989	11.80%	8.84%	2.96%
7/25/1989	12.80%	8.82%	3.98%
7/31/1989	13.00%	8.80%	4.20%
8/14/1989	12.50%	8.76%	3.74%
8/22/1989	12.80%	8.73%	4.07%
8/23/1989	12.90%	8.73%	4.17%
9/21/1989	12.10%	8.63%	3.47%
10/6/1989	13.00%	8.58%	4.42%
10/17/1989	12.41%	8.54%	3.87%
10/18/1989	13.25%	8.54%	4.71%
10/20/1989	12.90%	8.53%	4.37%
10/31/1989	13.60%	8.50%	5.10%
11/3/1989	12.93%	8.48%	4.45%
11/5/1989	13.20%	8.48%	4.72%
11/9/1989	12.60%	8.46%	4.14%
11/9/1989	13.00%	8.46%	4.54%
11/28/1989	12.75%	8.37%	4.38%
12/7/1989	13.25%	8.33%	4.92%
12/15/1989	13.00%	8.28%	4.72%
12/20/1989	12.90%	8.26%	4.64%
12/21/1989	12.80%	8.26%	4.54%
12/21/1989	12.90%	8.26%	4.64%
12/27/1989	12.50%	8.24%	4.26%
1/9/1990	13.00%	8.19%	4.81%
1/18/1990	12.50%	8.17%	4.33%
1/26/1990	12.10%	8.15%	3.95%
3/21/1990	12.80%	8.15%	4.65%
3/28/1990	13.00%	8.16%	4.84%
4/5/1990	12.20%	8.17%	4.03%
4/12/1990	13.25%	8.19%	5.06%
4/30/1990	12.45%	8.24%	4.21%
5/31/1990	12.40%	8.31%	4.09%
6/15/1990	13.20%	8.33%	4.87%
6/27/1990	12.90%	8.34%	4.56%
6/29/1990	13.25%	8.34%	4.91%
7/6/1990	12.10%	8.35%	3.75%
7/19/1990	11.70%	8.38%	3.32%
8/31/1990	12.50%	8.52%	3.98%
8/31/1990	12.50%	8.52%	3.98%
9/13/1990	12.50%	8.58%	3.92%
9/18/1990	12.75%	8.60%	4.15%

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[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
9/20/1990	12.50%	8.61%	3.89%
10/2/1990	13.00%	8.65%	4.35%
10/17/1990	11.90%	8.68%	3.22%
10/31/1990	12.95%	8.70%	4.25%
11/9/1990	13.25%	8.70%	4.55%
11/19/1990	13.00%	8.70%	4.30%
11/21/1990	12.10%	8.70%	3.40%
11/21/1990	12.50%	8.70%	3.80%
11/28/1990	12.75%	8.70%	4.05%
11/29/1990	12.75%	8.70%	4.05%
12/18/1990	13.10%	8.68%	4.42%
12/20/1990	12.50%	8.67%	3.83%
12/21/1990	12.50%	8.67%	3.83%
12/21/1990	13.00%	8.67%	4.33%
12/21/1990	13.60%	8.67%	4.93%
1/3/1991	13.02%	8.66%	4.36%
1/16/1991	13.25%	8.64%	4.61%
1/25/1991	11.70%	8.61%	3.09%
2/15/1991	12.70%	8.56%	4.14%
2/15/1991	12.80%	8.56%	4.24%
4/3/1991	13.00%	8.51%	4.49%
4/30/1991	12.45%	8.48%	3.97%
4/30/1991	13.00%	8.48%	4.52%
6/25/1991	11.70%	8.35%	3.35%
6/28/1991	12.50%	8.34%	4.16%
7/1/1991	11.70%	8.34%	3.36%
7/19/1991	12.10%	8.31%	3.79%
7/19/1991	12.30%	8.31%	3.99%
7/22/1991	12.90%	8.31%	4.59%
8/15/1991	12.25%	8.28%	3.97%
8/29/1991	13.30%	8.26%	5.04%
9/27/1991	12.50%	8.23%	4.27%
9/30/1991	12.40%	8.23%	4.17%
10/3/1991	11.30%	8.22%	3.08%
10/9/1991	11.70%	8.21%	3.49%
10/15/1991	13.40%	8.20%	5.20%
11/1/1991	12.90%	8.20%	4.70%
11/8/1991	12.75%	8.20%	4.55%
11/26/1991	11.60%	8.18%	3.42%
11/26/1991	12.00%	8.18%	3.82%
11/27/1991	12.70%	8.18%	4.52%
12/6/1991	12.70%	8.16%	4.54%
12/10/1991	11.75%	8.16%	3.59%
12/19/1991	12.60%	8.14%	4.46%
12/19/1991	12.80%	8.14%	4.66%
12/30/1991	12.10%	8.11%	3.99%
1/22/1992	12.84%	8.05%	4.79%
1/31/1992	12.00%	8.03%	3.97%
2/20/1992	13.00%	8.00%	5.00%
2/27/1992	11.75%	7.99%	3.76%
3/18/1992	12.50%	7.95%	4.55%

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[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
5/15/1992	12.75%	7.87%	4.88%
6/24/1992	12.20%	7.85%	4.35%
6/29/1992	11.00%	7.85%	3.15%
7/14/1992	12.00%	7.83%	4.17%
7/22/1992	11.20%	7.82%	3.38%
8/10/1992	12.10%	7.79%	4.31%
8/26/1992	12.43%	7.75%	4.68%
9/30/1992	11.60%	7.72%	3.88%
10/6/1992	12.25%	7.72%	4.53%
10/13/1992	12.75%	7.71%	5.04%
10/23/1992	11.65%	7.71%	3.94%
10/28/1992	12.25%	7.71%	4.54%
10/29/1992	12.75%	7.71%	5.04%
10/30/1992	11.40%	7.70%	3.70%
11/9/1992	10.60%	7.70%	2.90%
11/25/1992	11.00%	7.68%	3.32%
11/25/1992	12.00%	7.68%	4.32%
12/3/1992	11.85%	7.67%	4.18%
12/16/1992	11.90%	7.64%	4.26%
12/22/1992	12.30%	7.63%	4.67%
12/22/1992	12.40%	7.63%	4.77%
12/30/1992	12.00%	7.61%	4.39%
12/31/1992	12.00%	7.61%	4.39%
1/12/1993	12.00%	7.59%	4.41%
1/12/1993	12.00%	7.59%	4.41%
2/2/1993	11.40%	7.53%	3.87%
2/22/1993	11.60%	7.48%	4.12%
4/23/1993	11.75%	7.27%	4.48%
5/3/1993	11.50%	7.25%	4.25%
5/3/1993	11.75%	7.25%	4.50%
6/3/1993	12.00%	7.20%	4.80%
6/7/1993	11.50%	7.20%	4.30%
6/22/1993	11.75%	7.16%	4.59%
7/21/1993	11.78%	7.07%	4.71%
7/21/1993	11.90%	7.07%	4.83%
7/23/1993	11.50%	7.06%	4.44%
7/29/1993	11.50%	7.03%	4.47%
8/12/1993	10.75%	6.98%	3.77%
8/24/1993	11.50%	6.92%	4.58%
8/31/1993	11.90%	6.88%	5.02%
9/1/1993	11.25%	6.88%	4.37%
9/1/1993	11.47%	6.88%	4.59%
9/27/1993	10.50%	6.74%	3.76%
9/29/1993	11.00%	6.73%	4.27%
9/30/1993	11.60%	6.72%	4.88%
10/8/1993	11.50%	6.68%	4.82%
10/14/1993	11.20%	6.65%	4.55%
10/15/1993	11.75%	6.65%	5.10%
10/25/1993	11.55%	6.60%	4.95%
10/28/1993	11.50%	6.58%	4.92%
10/29/1993	10.10%	6.58%	3.52%

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[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/29/1993	10.20%	6.58%	3.62%
10/29/1993	11.25%	6.58%	4.67%
11/2/1993	10.80%	6.56%	4.24%
11/12/1993	11.80%	6.53%	5.27%
11/23/1993	12.50%	6.51%	5.99%
11/26/1993	11.00%	6.50%	4.50%
12/1/1993	11.45%	6.49%	4.96%
12/16/1993	10.60%	6.46%	4.14%
12/16/1993	11.20%	6.46%	4.74%
12/21/1993	11.30%	6.45%	4.85%
12/22/1993	11.00%	6.44%	4.56%
12/23/1993	10.10%	6.44%	3.66%
1/5/1994	11.50%	6.41%	5.09%
1/10/1994	11.00%	6.40%	4.60%
1/25/1994	12.00%	6.37%	5.63%
2/2/1994	10.40%	6.35%	4.05%
2/9/1994	10.70%	6.34%	4.36%
4/6/1994	11.24%	6.35%	4.89%
4/25/1994	11.00%	6.39%	4.61%
6/16/1994	10.50%	6.63%	3.87%
6/23/1994	10.60%	6.67%	3.93%
7/19/1994	10.70%	6.83%	3.87%
9/29/1994	10.90%	7.20%	3.70%
9/29/1994	11.00%	7.20%	3.80%
10/7/1994	11.87%	7.25%	4.62%
10/18/1994	11.50%	7.31%	4.19%
10/18/1994	11.50%	7.31%	4.19%
10/24/1994	11.00%	7.35%	3.65%
11/22/1994	12.12%	7.52%	4.60%
11/29/1994	11.30%	7.55%	3.75%
12/1/1994	11.00%	7.56%	3.44%
12/8/1994	11.50%	7.59%	3.91%
12/8/1994	11.70%	7.59%	4.11%
12/12/1994	11.82%	7.60%	4.22%
12/14/1994	11.50%	7.61%	3.89%
12/19/1994	11.50%	7.62%	3.88%
4/19/1995	11.00%	7.71%	3.29%
9/11/1995	11.30%	7.16%	4.14%
9/15/1995	10.40%	7.13%	3.27%
9/29/1995	11.50%	7.06%	4.44%
10/13/1995	10.76%	6.99%	3.77%
11/7/1995	12.50%	6.87%	5.63%
11/8/1995	11.10%	6.86%	4.24%
11/8/1995	11.30%	6.86%	4.44%
11/17/1995	10.90%	6.81%	4.09%
11/20/1995	11.40%	6.80%	4.60%
11/27/1995	13.60%	6.77%	6.83%
12/14/1995	11.30%	6.68%	4.62%
12/20/1995	11.60%	6.65%	4.95%
1/31/1996	11.30%	6.46%	4.84%
3/11/1996	11.60%	6.40%	5.20%

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[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
4/3/1996	11.13%	6.41%	4.72%
4/15/1996	10.50%	6.41%	4.09%
4/17/1996	10.77%	6.41%	4.36%
4/26/1996	10.60%	6.40%	4.20%
5/10/1996	11.00%	6.41%	4.59%
5/13/1996	11.25%	6.41%	4.84%
7/3/1996	11.25%	6.49%	4.76%
7/22/1996	11.25%	6.54%	4.71%
10/3/1996	10.00%	6.77%	3.23%
10/29/1996	11.30%	6.84%	4.46%
11/26/1996	11.30%	6.86%	4.44%
11/27/1996	11.30%	6.86%	4.44%
11/29/1996	11.00%	6.85%	4.15%
12/12/1996	11.96%	6.85%	5.11%
12/17/1996	11.50%	6.85%	4.65%
1/22/1997	11.30%	6.83%	4.47%
1/27/1997	11.25%	6.83%	4.42%
1/31/1997	11.25%	6.83%	4.42%
2/13/1997	11.00%	6.82%	4.18%
2/13/1997	11.80%	6.82%	4.98%
2/20/1997	11.80%	6.81%	4.99%
3/27/1997	10.75%	6.79%	3.96%
4/29/1997	11.70%	6.80%	4.90%
7/17/1997	12.00%	6.77%	5.23%
10/29/1997	10.75%	6.70%	4.05%
10/31/1997	11.25%	6.70%	4.55%
12/24/1997	10.75%	6.53%	4.22%
4/28/1998	10.90%	6.11%	4.79%
4/30/1998	12.20%	6.10%	6.10%
6/30/1998	11.00%	5.94%	5.06%
8/26/1998	10.93%	5.82%	5.11%
9/3/1998	11.40%	5.80%	5.60%
9/15/1998	11.90%	5.77%	6.13%
10/7/1998	11.06%	5.70%	5.36%
10/30/1998	11.40%	5.63%	5.77%
12/10/1998	12.20%	5.52%	6.68%
12/17/1998	12.10%	5.49%	6.61%
2/19/1999	11.15%	5.32%	5.83%
3/1/1999	10.65%	5.31%	5.34%
3/1/1999	10.65%	5.31%	5.34%
6/8/1999	11.25%	5.35%	5.90%
11/12/1999	10.25%	5.92%	4.33%
12/14/1999	10.50%	5.99%	4.51%
1/28/2000	10.71%	6.16%	4.55%
2/17/2000	10.60%	6.20%	4.40%
5/25/2000	10.80%	6.19%	4.61%
6/19/2000	11.05%	6.18%	4.87%
6/22/2000	11.25%	6.18%	5.07%
7/17/2000	11.06%	6.15%	4.91%
7/20/2000	12.20%	6.14%	6.06%
8/11/2000	11.00%	6.11%	4.89%

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[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
9/27/2000	11.25%	6.01%	5.24%
9/29/2000	11.16%	6.00%	5.16%
10/5/2000	11.30%	5.98%	5.32%
11/28/2000	12.90%	5.87%	7.03%
11/30/2000	12.10%	5.87%	6.23%
2/5/2001	11.50%	5.76%	5.74%
3/15/2001	11.25%	5.67%	5.58%
5/8/2001	10.75%	5.61%	5.14%
10/24/2001	10.30%	5.54%	4.76%
10/24/2001	11.00%	5.54%	5.46%
1/9/2002	10.00%	5.50%	4.50%
1/30/2002	11.00%	5.47%	5.53%
1/31/2002	11.00%	5.47%	5.53%
4/17/2002	11.50%	5.44%	6.06%
4/29/2002	11.00%	5.45%	5.55%
6/11/2002	11.77%	5.48%	6.29%
6/20/2002	12.30%	5.47%	6.83%
8/28/2002	11.00%	5.49%	5.51%
9/11/2002	11.20%	5.45%	5.75%
9/12/2002	12.30%	5.45%	6.85%
10/28/2002	11.30%	5.35%	5.95%
10/30/2002	10.60%	5.34%	5.26%
11/1/2002	12.60%	5.34%	7.26%
11/7/2002	11.40%	5.33%	6.07%
11/8/2002	10.75%	5.33%	5.42%
11/20/2002	10.00%	5.30%	4.70%
11/20/2002	10.50%	5.30%	5.20%
12/4/2002	10.75%	5.27%	5.48%
12/30/2002	11.20%	5.19%	6.01%
1/6/2003	11.25%	5.17%	6.08%
2/28/2003	12.30%	5.01%	7.29%
3/7/2003	9.96%	4.99%	4.97%
3/12/2003	11.40%	4.97%	6.43%
3/20/2003	12.00%	4.95%	7.05%
4/3/2003	12.00%	4.93%	7.07%
5/2/2003	11.40%	4.88%	6.52%
5/15/2003	11.05%	4.87%	6.18%
6/26/2003	11.00%	4.80%	6.20%
7/1/2003	11.00%	4.80%	6.20%
7/29/2003	11.71%	4.78%	6.93%
8/22/2003	10.20%	4.82%	5.38%
9/17/2003	9.90%	4.84%	5.06%
9/25/2003	10.25%	4.85%	5.40%
10/17/2003	10.54%	4.87%	5.67%
10/22/2003	10.46%	4.87%	5.59%
10/22/2003	10.71%	4.87%	5.84%
10/30/2003	11.00%	4.88%	6.12%
10/31/2003	10.20%	4.88%	5.32%
10/31/2003	10.75%	4.88%	5.87%
11/10/2003	10.60%	4.89%	5.71%
12/9/2003	10.50%	4.93%	5.57%

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[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/18/2003	10.50%	4.94%	5.56%
12/19/2003	12.00%	4.94%	7.06%
12/19/2003	12.00%	4.94%	7.06%
1/13/2004	10.25%	4.95%	5.30%
1/13/2004	12.00%	4.95%	7.05%
2/9/2004	11.25%	4.98%	6.27%
3/16/2004	10.90%	5.05%	5.85%
3/16/2004	10.90%	5.05%	5.85%
5/25/2004	10.00%	5.06%	4.94%
6/2/2004	11.22%	5.07%	6.15%
6/30/2004	10.50%	5.10%	5.40%
7/8/2004	10.00%	5.10%	4.90%
7/22/2004	10.25%	5.10%	5.15%
8/26/2004	10.50%	5.10%	5.40%
8/26/2004	10.50%	5.10%	5.40%
9/9/2004	10.40%	5.10%	5.30%
9/21/2004	10.50%	5.09%	5.41%
9/27/2004	10.30%	5.09%	5.21%
9/27/2004	10.50%	5.09%	5.41%
10/20/2004	10.20%	5.08%	5.12%
11/30/2004	10.60%	5.08%	5.52%
12/8/2004	9.90%	5.09%	4.81%
12/21/2004	11.50%	5.09%	6.41%
12/22/2004	11.50%	5.09%	6.41%
12/28/2004	10.25%	5.09%	5.16%
2/18/2005	10.30%	4.95%	5.35%
3/29/2005	11.00%	4.86%	6.14%
4/13/2005	10.60%	4.84%	5.76%
4/28/2005	11.00%	4.80%	6.20%
5/17/2005	10.00%	4.77%	5.23%
6/8/2005	10.18%	4.71%	5.47%
6/10/2005	10.90%	4.71%	6.19%
7/6/2005	10.50%	4.65%	5.85%
7/19/2005	11.50%	4.63%	6.87%
8/11/2005	10.40%	4.60%	5.80%
9/19/2005	9.45%	4.53%	4.92%
9/30/2005	10.51%	4.52%	5.99%
10/4/2005	9.90%	4.52%	5.38%
10/4/2005	10.75%	4.52%	6.23%
10/14/2005	10.40%	4.52%	5.88%
10/31/2005	10.25%	4.53%	5.72%
11/2/2005	9.70%	4.53%	5.17%
11/30/2005	10.00%	4.54%	5.46%
12/9/2005	9.70%	4.53%	5.17%
12/12/2005	11.00%	4.53%	6.47%
12/20/2005	10.13%	4.53%	5.60%
12/21/2005	10.40%	4.53%	5.87%
12/21/2005	11.00%	4.53%	6.47%
12/22/2005	10.20%	4.53%	5.67%
12/22/2005	11.00%	4.53%	6.47%
12/28/2005	10.00%	4.52%	5.48%

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[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/5/2006	11.00%	4.52%	6.48%
1/25/2006	11.20%	4.52%	6.68%
1/25/2006	11.20%	4.52%	6.68%
2/3/2006	10.50%	4.52%	5.98%
2/15/2006	9.50%	4.53%	4.97%
4/26/2006	10.60%	4.65%	5.95%
7/24/2006	9.60%	4.86%	4.74%
7/24/2006	10.00%	4.86%	5.14%
9/20/2006	11.00%	4.93%	6.07%
9/26/2006	10.75%	4.93%	5.82%
10/20/2006	9.80%	4.96%	4.84%
11/2/2006	9.71%	4.96%	4.75%
11/9/2006	10.00%	4.97%	5.03%
11/21/2006	11.00%	4.98%	6.02%
12/5/2006	10.20%	4.97%	5.23%
1/5/2007	10.40%	4.95%	5.45%
1/9/2007	11.00%	4.94%	6.06%
1/11/2007	10.90%	4.94%	5.96%
1/19/2007	10.80%	4.93%	5.87%
1/26/2007	10.00%	4.92%	5.08%
2/8/2007	10.40%	4.91%	5.49%
3/14/2007	10.10%	4.86%	5.24%
3/20/2007	10.25%	4.85%	5.40%
3/21/2007	11.35%	4.84%	6.51%
3/22/2007	10.50%	4.84%	5.66%
3/29/2007	10.00%	4.83%	5.17%
6/13/2007	10.75%	4.81%	5.94%
6/29/2007	9.53%	4.84%	4.69%
6/29/2007	10.10%	4.84%	5.26%
7/3/2007	10.25%	4.85%	5.40%
7/13/2007	9.50%	4.86%	4.64%
7/24/2007	10.40%	4.87%	5.53%
8/1/2007	10.15%	4.88%	5.27%
8/29/2007	10.50%	4.91%	5.59%
9/10/2007	9.71%	4.91%	4.80%
9/19/2007	10.00%	4.91%	5.09%
9/25/2007	9.70%	4.91%	4.79%
10/8/2007	10.48%	4.92%	5.56%
10/19/2007	10.50%	4.91%	5.59%
10/25/2007	9.65%	4.91%	4.74%
11/15/2007	10.00%	4.89%	5.11%
11/20/2007	9.90%	4.89%	5.01%
11/27/2007	10.00%	4.88%	5.12%
11/29/2007	10.90%	4.88%	6.02%
12/14/2007	10.80%	4.87%	5.93%
12/18/2007	10.40%	4.86%	5.54%
12/19/2007	9.80%	4.86%	4.94%
12/19/2007	9.80%	4.86%	4.94%
12/19/2007	10.20%	4.86%	5.34%
12/21/2007	9.10%	4.86%	4.24%
1/8/2008	10.75%	4.83%	5.92%

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[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/17/2008	10.75%	4.81%	5.94%
1/17/2008	10.75%	4.81%	5.94%
2/5/2008	9.99%	4.78%	5.21%
2/5/2008	10.19%	4.78%	5.41%
2/13/2008	10.20%	4.76%	5.44%
3/31/2008	10.00%	4.63%	5.37%
5/28/2008	10.50%	4.53%	5.97%
6/24/2008	10.00%	4.52%	5.48%
6/27/2008	10.00%	4.52%	5.48%
7/31/2008	10.70%	4.50%	6.20%
7/31/2008	10.82%	4.50%	6.32%
8/27/2008	10.25%	4.50%	5.75%
9/2/2008	10.25%	4.50%	5.75%
9/19/2008	10.70%	4.48%	6.22%
9/24/2008	10.68%	4.48%	6.20%
9/24/2008	10.68%	4.48%	6.20%
9/24/2008	10.68%	4.48%	6.20%
9/30/2008	10.20%	4.48%	5.72%
10/3/2008	10.30%	4.47%	5.83%
10/8/2008	10.15%	4.47%	5.68%
10/20/2008	10.06%	4.47%	5.59%
10/24/2008	10.60%	4.46%	6.14%
10/24/2008	10.60%	4.46%	6.14%
11/21/2008	10.50%	4.42%	6.08%
11/21/2008	10.50%	4.42%	6.08%
11/21/2008	10.50%	4.42%	6.08%
11/24/2008	10.50%	4.42%	6.08%
12/3/2008	10.39%	4.37%	6.02%
12/24/2008	10.00%	4.26%	5.74%
12/26/2008	10.10%	4.24%	5.86%
12/29/2008	10.20%	4.23%	5.97%
1/13/2009	10.45%	4.14%	6.31%
2/2/2009	10.05%	4.04%	6.01%
3/9/2009	10.30%	3.90%	6.40%
3/25/2009	10.17%	3.84%	6.33%
4/2/2009	10.75%	3.81%	6.94%
5/5/2009	10.75%	3.71%	7.04%
5/15/2009	10.20%	3.70%	6.50%
5/29/2009	9.54%	3.70%	5.84%
6/3/2009	10.10%	3.71%	6.39%
6/22/2009	10.00%	3.73%	6.27%
6/29/2009	10.21%	3.74%	6.47%
6/30/2009	9.31%	3.74%	5.57%
7/17/2009	9.26%	3.75%	5.51%
7/17/2009	10.50%	3.75%	6.75%
10/16/2009	10.40%	4.09%	6.31%
10/26/2009	10.10%	4.11%	5.99%
10/28/2009	10.15%	4.11%	6.04%
10/28/2009	10.15%	4.11%	6.04%
10/30/2009	9.95%	4.12%	5.83%
11/20/2009	9.45%	4.18%	5.27%

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[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/14/2009	10.50%	4.24%	6.26%
12/16/2009	10.75%	4.25%	6.50%
12/17/2009	10.30%	4.25%	6.05%
12/18/2009	10.40%	4.26%	6.14%
12/18/2009	10.40%	4.26%	6.14%
12/18/2009	10.50%	4.26%	6.24%
12/22/2009	10.20%	4.27%	5.93%
12/22/2009	10.40%	4.27%	6.13%
12/28/2009	10.85%	4.29%	6.56%
12/29/2009	10.38%	4.29%	6.09%
1/11/2010	10.24%	4.34%	5.90%
1/21/2010	10.23%	4.37%	5.86%
1/21/2010	10.33%	4.37%	5.96%
1/26/2010	10.40%	4.37%	6.03%
2/10/2010	10.00%	4.39%	5.61%
2/23/2010	10.50%	4.40%	6.10%
3/9/2010	9.60%	4.40%	5.20%
3/24/2010	10.13%	4.42%	5.71%
3/31/2010	10.70%	4.43%	6.27%
4/1/2010	9.50%	4.43%	5.07%
4/2/2010	10.10%	4.44%	5.66%
4/8/2010	10.35%	4.44%	5.91%
4/29/2010	9.19%	4.46%	4.73%
4/29/2010	9.40%	4.46%	4.94%
4/29/2010	9.40%	4.46%	4.94%
5/17/2010	10.55%	4.46%	6.09%
5/24/2010	10.05%	4.46%	5.59%
6/3/2010	11.00%	4.46%	6.54%
6/16/2010	10.00%	4.45%	5.55%
6/18/2010	10.30%	4.45%	5.85%
8/9/2010	12.55%	4.41%	8.14%
8/17/2010	10.10%	4.40%	5.70%
9/16/2010	9.60%	4.31%	5.29%
9/16/2010	10.00%	4.31%	5.69%
9/16/2010	10.00%	4.31%	5.69%
9/16/2010	10.30%	4.31%	5.99%
10/21/2010	10.40%	4.20%	6.20%
11/2/2010	9.75%	4.18%	5.57%
11/2/2010	9.75%	4.18%	5.57%
11/3/2010	10.75%	4.17%	6.58%
11/19/2010	10.20%	4.15%	6.05%
12/1/2010	10.00%	4.13%	5.87%
12/6/2010	9.56%	4.12%	5.44%
12/6/2010	10.09%	4.12%	5.97%
12/9/2010	10.25%	4.12%	6.13%
12/14/2010	10.33%	4.12%	6.21%
12/17/2010	10.10%	4.11%	5.99%
12/20/2010	10.10%	4.11%	5.99%
12/23/2010	9.92%	4.11%	5.81%
1/6/2011	10.35%	4.09%	6.26%
1/12/2011	10.30%	4.09%	6.21%

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[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/13/2011	10.30%	4.09%	6.21%
3/10/2011	10.10%	4.16%	5.94%
3/31/2011	9.45%	4.20%	5.25%
4/18/2011	10.05%	4.23%	5.82%
5/26/2011	10.50%	4.31%	6.19%
6/21/2011	10.00%	4.36%	5.64%
6/29/2011	8.83%	4.37%	4.46%
8/1/2011	9.20%	4.41%	4.79%
9/1/2011	10.10%	4.33%	5.77%
11/14/2011	9.60%	3.93%	5.67%
12/13/2011	9.50%	3.76%	5.74%
12/20/2011	10.00%	3.72%	6.28%
12/22/2011	10.40%	3.70%	6.70%
1/10/2012	9.06%	3.60%	5.46%
1/10/2012	9.45%	3.60%	5.85%
1/10/2012	9.45%	3.60%	5.85%
1/23/2012	10.20%	3.53%	6.67%
1/31/2012	10.00%	3.49%	6.51%
4/24/2012	9.50%	3.16%	6.34%
4/24/2012	9.75%	3.16%	6.59%
5/7/2012	9.80%	3.13%	6.67%
5/22/2012	9.60%	3.10%	6.50%
5/24/2012	9.70%	3.09%	6.61%
6/7/2012	10.30%	3.06%	7.24%
6/15/2012	10.40%	3.05%	7.35%
6/18/2012	9.60%	3.05%	6.55%
7/2/2012	9.75%	3.04%	6.71%
10/24/2012	10.30%	2.92%	7.38%
10/26/2012	9.50%	2.92%	6.58%
10/31/2012	9.30%	2.92%	6.38%
10/31/2012	9.90%	2.92%	6.98%
10/31/2012	10.00%	2.92%	7.08%
11/1/2012	9.45%	2.92%	6.53%
11/8/2012	10.10%	2.91%	7.19%
11/9/2012	10.30%	2.91%	7.39%
11/26/2012	10.00%	2.89%	7.11%
11/28/2012	10.40%	2.88%	7.52%
11/28/2012	10.50%	2.88%	7.62%
12/4/2012	10.00%	2.87%	7.13%
12/4/2012	10.50%	2.87%	7.63%
12/20/2012	9.50%	2.84%	6.66%
12/20/2012	10.10%	2.84%	7.26%
12/20/2012	10.25%	2.84%	7.41%
12/20/2012	10.30%	2.84%	7.46%
12/20/2012	10.40%	2.84%	7.56%
12/20/2012	10.50%	2.84%	7.66%
12/26/2012	9.80%	2.83%	6.97%
2/22/2013	9.60%	2.86%	6.74%
3/14/2013	9.30%	2.89%	6.41%
3/27/2013	9.80%	2.91%	6.89%
4/23/2013	9.80%	2.95%	6.85%

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[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
5/10/2013	9.25%	2.96%	6.29%
6/13/2013	9.40%	3.01%	6.39%
6/18/2013	9.28%	3.02%	6.26%
6/18/2013	9.28%	3.02%	6.26%
6/25/2013	9.80%	3.04%	6.76%
9/23/2013	9.60%	3.32%	6.28%
11/6/2013	10.20%	3.42%	6.78%
11/13/2013	9.84%	3.44%	6.40%
11/14/2013	10.25%	3.44%	6.81%
11/22/2013	9.50%	3.47%	6.03%
12/5/2013	10.20%	3.50%	6.70%
12/13/2013	9.60%	3.52%	6.08%
12/16/2013	9.73%	3.52%	6.21%
12/17/2013	10.00%	3.53%	6.47%
12/18/2013	9.08%	3.53%	5.55%
12/23/2013	9.72%	3.54%	6.18%
12/30/2013	10.00%	3.57%	6.43%
1/21/2014	9.65%	3.65%	6.00%
1/22/2014	9.18%	3.66%	5.52%
2/20/2014	9.30%	3.71%	5.59%
2/21/2014	9.85%	3.71%	6.14%
2/28/2014	9.55%	3.72%	5.83%
3/16/2014	9.72%	3.73%	5.99%
4/21/2014	9.50%	3.73%	5.77%
4/22/2014	9.80%	3.73%	6.07%
5/8/2014	9.10%	3.71%	5.39%
5/8/2014	9.59%	3.71%	5.88%
6/6/2014	10.40%	3.66%	6.74%
6/12/2014	10.10%	3.66%	6.44%
6/12/2014	10.10%	3.66%	6.44%
6/12/2014	10.10%	3.66%	6.44%
7/7/2014	9.30%	3.63%	5.67%
7/25/2014	9.30%	3.60%	5.70%
7/31/2014	9.90%	3.59%	6.31%
9/4/2014	9.10%	3.51%	5.59%
9/24/2014	9.35%	3.46%	5.89%
9/30/2014	9.75%	3.45%	6.30%
10/29/2014	10.80%	3.37%	7.43%
11/6/2014	10.20%	3.35%	6.85%
11/14/2014	10.20%	3.33%	6.87%
11/14/2014	10.30%	3.33%	6.97%
11/26/2014	10.20%	3.31%	6.89%
12/3/2014	10.00%	3.29%	6.71%
1/13/2015	10.30%	3.16%	7.14%
1/21/2015	9.05%	3.13%	5.92%
1/21/2015	9.05%	3.13%	5.92%
4/9/2015	9.50%	2.88%	6.62%
5/11/2015	9.80%	2.82%	6.98%
6/17/2015	9.00%	2.79%	6.21%
8/21/2015	9.75%	2.78%	6.97%
10/7/2015	9.55%	2.82%	6.73%

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[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/13/2015	9.75%	2.83%	6.92%
10/15/2015	9.00%	2.83%	6.17%
10/30/2015	9.80%	2.86%	6.94%
11/19/2015	10.00%	2.89%	7.11%
12/3/2015	10.00%	2.91%	7.09%
12/9/2015	9.60%	2.92%	6.68%
12/11/2015	9.90%	2.92%	6.98%
12/18/2015	9.50%	2.93%	6.57%
1/6/2016	9.50%	2.96%	6.54%
1/6/2016	9.50%	2.96%	6.54%
1/28/2016	9.40%	2.97%	6.43%
2/10/2016	9.60%	2.95%	6.65%
2/16/2016	9.50%	2.94%	6.56%
2/29/2016	9.40%	2.92%	6.48%
4/29/2016	9.80%	2.83%	6.97%
5/5/2016	9.49%	2.82%	6.67%
6/1/2016	9.55%	2.80%	6.75%
6/3/2016	9.65%	2.79%	6.86%
6/15/2016	9.00%	2.77%	6.23%
6/15/2016	9.00%	2.77%	6.23%
9/2/2016	9.50%	2.57%	6.93%
9/23/2016	9.75%	2.52%	7.23%
9/27/2016	9.50%	2.51%	6.99%
9/29/2016	9.11%	2.50%	6.61%
10/13/2016	10.20%	2.48%	7.72%
10/28/2016	9.70%	2.47%	7.23%
11/9/2016	9.80%	2.47%	7.33%
11/18/2016	10.00%	2.49%	7.51%
12/9/2016	10.10%	2.52%	7.58%
12/15/2016	9.00%	2.53%	6.47%
12/15/2016	9.00%	2.53%	6.47%
12/20/2016	9.75%	2.53%	7.22%
12/22/2016	9.50%	2.54%	6.96%
1/24/2017	9.00%	2.59%	6.41%
2/21/2017	10.55%	2.63%	7.92%
3/1/2017	9.25%	2.65%	6.60%
4/11/2017	9.50%	2.77%	6.73%
4/20/2017	8.70%	2.79%	5.91%
4/28/2017	9.50%	2.81%	6.69%
5/23/2017	9.60%	2.88%	6.72%
6/6/2017	9.70%	2.90%	6.80%
6/22/2017	9.70%	2.93%	6.77%
6/30/2017	9.60%	2.94%	6.66%
7/20/2017	9.55%	2.97%	6.58%
7/31/2017	10.10%	2.98%	7.12%
9/13/2017	9.40%	2.93%	6.47%
9/19/2017	9.70%	2.92%	6.78%
9/22/2017	11.88%	2.92%	8.96%
9/27/2017	10.20%	2.92%	7.28%
10/20/2017	9.60%	2.90%	6.70%
10/26/2017	10.20%	2.90%	7.30%

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[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/30/2017	10.05%	2.90%	7.15%
12/5/2017	9.50%	2.86%	6.64%
12/7/2017	9.80%	2.86%	6.94%
12/13/2017	9.25%	2.85%	6.40%
12/28/2017	9.50%	2.84%	6.66%
1/31/2018	9.80%	2.83%	6.97%
2/21/2018	9.80%	2.84%	6.96%
2/21/2018	9.80%	2.84%	6.96%
2/28/2018	9.50%	2.85%	6.65%
3/15/2018	9.00%	2.87%	6.13%
3/26/2018	10.19%	2.88%	7.31%
4/26/2018	9.50%	2.90%	6.60%
4/27/2018	9.30%	2.91%	6.39%
5/2/2018	9.50%	2.91%	6.59%
5/3/2018	9.70%	2.91%	6.79%
5/29/2018	9.40%	2.95%	6.45%
6/6/2018	9.80%	2.96%	6.84%
6/14/2018	8.80%	2.97%	5.83%
7/16/2018	9.60%	2.98%	6.62%
7/20/2018	9.40%	2.99%	6.41%
8/24/2018	9.28%	3.02%	6.26%
8/28/2018	10.00%	3.02%	6.98%
9/13/2018	10.00%	3.04%	6.96%
9/14/2018	10.00%	3.04%	6.96%
9/19/2018	9.85%	3.05%	6.80%
9/20/2018	9.80%	3.05%	6.75%
9/26/2018	9.40%	3.06%	6.34%
9/26/2018	10.20%	3.06%	7.14%
9/28/2018	9.50%	3.07%	6.43%
9/28/2018	9.50%	3.07%	6.43%
10/5/2018	9.61%	3.08%	6.53%
10/15/2018	9.80%	3.09%	6.71%
10/26/2018	9.40%	3.11%	6.29%
10/29/2018	9.60%	3.11%	6.49%
11/1/2018	9.87%	3.11%	6.76%
11/8/2018	9.70%	3.12%	6.58%
11/8/2018	9.70%	3.12%	6.58%
12/11/2018	9.70%	3.14%	6.56%
12/12/2018	9.30%	3.14%	6.16%
12/13/2018	9.60%	3.14%	6.46%
12/19/2018	9.30%	3.14%	6.16%
12/21/2018	9.35%	3.14%	6.21%
12/24/2018	9.25%	3.14%	6.11%
12/24/2018	9.25%	3.14%	6.11%
1/4/2019	9.80%	3.14%	6.66%
1/18/2019	9.70%	3.14%	6.56%
3/14/2019	9.00%	3.12%	5.88%
3/27/2019	9.70%	3.12%	6.58%
4/30/2019	9.73%	3.11%	6.62%
5/7/2019	9.65%	3.10%	6.55%
5/21/2019	9.80%	3.10%	6.70%

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[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
9/4/2019	10.00%	2.76%	7.24%
9/26/2019	9.90%	2.69%	7.21%
10/2/2019	9.73%	2.67%	7.06%
10/2/2019	9.90%	2.67%	7.23%
10/8/2019	9.40%	2.65%	6.75%
10/15/2019	9.70%	2.62%	7.08%
10/21/2019	9.40%	2.61%	6.79%
10/31/2019	9.70%	2.57%	7.13%
10/31/2019	10.00%	2.57%	7.43%
10/31/2019	10.00%	2.57%	7.43%
10/31/2019	10.20%	2.57%	7.63%
11/7/2019	9.35%	2.55%	6.80%
11/13/2019	9.60%	2.54%	7.06%
11/13/2019	9.60%	2.54%	7.06%
12/6/2019	9.87%	2.47%	7.40%
12/11/2019	9.40%	2.46%	6.94%
12/17/2019	9.75%	2.45%	7.30%
12/18/2019	9.60%	2.44%	7.16%
12/18/2019	9.60%	2.44%	7.16%
12/19/2019	10.05%	2.44%	7.61%
12/19/2019	10.20%	2.44%	7.76%
12/19/2019	10.25%	2.44%	7.81%
12/20/2019	9.20%	2.44%	6.76%
12/26/2019	9.75%	2.43%	7.32%
1/15/2020	9.35%	2.38%	6.97%
1/16/2020	8.80%	2.37%	6.43%
1/24/2020	9.44%	2.35%	7.09%
2/3/2020	9.40%	2.33%	7.07%
2/24/2020	9.10%	2.27%	6.83%
2/25/2020	9.50%	2.27%	7.23%
2/28/2020	9.70%	2.25%	7.45%
3/25/2020	9.40%	2.15%	7.25%
3/26/2020	9.48%	2.15%	7.33%
4/21/2020	9.80%	2.02%	7.78%
5/19/2020	9.20%	1.94%	7.26%
6/16/2020	9.65%	1.87%	7.78%
7/8/2020	9.40%	1.81%	7.59%
8/4/2020	9.50%	1.70%	7.80%
8/20/2020	9.90%	1.64%	8.26%
8/21/2020	9.35%	1.64%	7.71%
9/10/2020	9.90%	1.58%	8.32%
9/23/2020	9.60%	1.53%	8.07%
9/25/2020	9.25%	1.52%	7.73%
9/25/2020	9.25%	1.52%	7.73%
10/4/2020	9.80%	1.50%	8.30%
10/7/2020	9.70%	1.49%	8.21%
10/12/2020	9.20%	1.48%	7.72%
10/16/2020	9.40%	1.47%	7.93%
10/30/2020	9.90%	1.44%	8.46%
11/7/2020	9.60%	1.43%	8.17%
11/19/2020	8.80%	1.42%	7.38%

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[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
11/19/2020	8.80%	1.42%	7.38%
11/19/2020	9.90%	1.42%	8.48%
11/24/2020	9.80%	1.42%	8.38%
12/9/2020	9.10%	1.43%	7.67%
12/10/2020	9.40%	1.43%	7.97%
12/16/2020	9.38%	1.44%	7.94%
12/16/2020	9.65%	1.44%	8.21%
12/23/2020	10.00%	1.45%	8.55%
1/6/2021	9.40%	1.47%	7.93%
1/6/2021	9.60%	1.47%	8.13%
1/13/2021	9.67%	1.49%	8.18%
1/26/2021	9.50%	1.51%	7.99%
2/16/2021	9.80%	1.56%	8.24%
2/19/2021	9.86%	1.57%	8.29%
2/24/2021	9.25%	1.58%	7.67%
3/25/2021	10.00%	1.67%	8.33%
3/25/2021	10.00%	1.67%	8.33%
3/25/2021	10.00%	1.67%	8.33%
4/9/2021	9.70%	1.73%	7.97%
5/5/2021	9.30%	1.83%	7.47%
5/18/2021	9.40%	1.87%	7.53%
5/19/2021	8.80%	1.88%	6.92%
6/17/2021	10.24%	1.97%	8.27%
6/30/2021	9.43%	1.99%	7.44%
7/27/2021	9.54%	2.03%	7.51%
7/30/2021	9.30%	2.03%	7.27%
8/12/2021	8.80%	2.05%	6.75%
8/12/2021	8.80%	2.05%	6.75%
9/1/2021	9.40%	2.07%	7.33%
9/8/2021	9.67%	2.08%	7.59%
9/9/2021	9.85%	2.08%	7.77%
9/14/2021	9.50%	2.08%	7.42%
9/27/2021	9.40%	2.09%	7.31%
9/29/2021	9.80%	2.09%	7.71%
9/30/2021	9.70%	2.10%	7.60%
10/6/2021	9.70%	2.10%	7.60%
10/27/2021	9.37%	2.12%	7.25%
11/17/2021	9.60%	2.11%	7.49%
11/17/2021	9.80%	2.11%	7.69%
11/18/2021	9.00%	2.11%	6.89%
11/18/2021	9.75%	2.11%	7.64%
11/18/2021	10.00%	2.11%	7.89%
11/18/2021	10.00%	2.11%	7.89%
11/23/2021	9.80%	2.10%	7.70%
11/30/2021	9.40%	2.09%	7.31%
12/3/2021	9.65%	2.08%	7.57%
12/9/2021	9.90%	2.07%	7.83%
12/13/2021	9.20%	2.06%	7.14%
12/28/2021	9.35%	2.03%	7.32%
12/28/2021	9.38%	2.03%	7.35%
12/28/2021	9.60%	2.03%	7.57%

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[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/3/2022	9.25%	2.03%	7.22%
1/6/2022	9.60%	2.02%	7.58%
1/20/2022	9.00%	2.02%	6.98%
1/21/2022	9.60%	2.01%	7.59%
3/22/2022	9.40%	2.02%	7.38%
3/22/2022	9.40%	2.02%	7.38%
4/14/2022	9.20%	2.08%	7.12%
5/19/2022	9.23%	2.23%	7.00%
6/16/2022	9.25%	2.36%	6.89%
7/7/2022	9.90%	2.45%	7.45%
7/20/2022	9.30%	2.50%	6.80%
7/27/2022	9.85%	2.53%	7.32%
8/2/2022	9.40%	2.55%	6.85%
8/17/2022	9.60%	2.62%	6.98%
8/18/2022	9.39%	2.62%	6.77%
8/23/2022	9.40%	2.65%	6.75%
9/15/2022	9.30%	2.79%	6.51%
10/10/2022	9.60%	2.93%	6.67%
10/12/2022	9.60%	2.95%	6.65%
10/24/2022	9.40%	3.04%	6.36%
10/25/2022	9.20%	3.05%	6.15%
10/27/2022	9.70%	3.07%	6.63%
10/27/2022	9.80%	3.07%	6.73%
11/3/2022	10.20%	3.12%	7.08%
11/17/2022	9.65%	3.22%	6.43%
11/30/2022	9.38%	3.29%	6.09%
12/15/2022	9.80%	3.35%	6.45%
12/21/2022	9.60%	3.38%	6.22%
12/22/2022	9.40%	3.38%	6.02%
12/22/2022	9.80%	3.38%	6.42%
12/23/2022	9.60%	3.39%	6.21%
12/29/2022	9.80%	3.41%	6.39%
12/29/2022	9.80%	3.41%	6.39%
1/19/2023	9.60%	3.48%	6.12%
1/23/2023	9.30%	3.48%	5.82%
1/24/2023	10.25%	3.49%	6.76%
1/26/2023	9.60%	3.49%	6.11%
3/23/2023	9.57%	3.63%	5.94%
3/28/2023	9.50%	3.64%	5.86%
5/4/2023	9.30%	3.73%	5.57%
6/30/2023	9.50%	3.81%	5.69%
7/20/2023	9.25%	3.80%	5.45%
8/30/2023	9.80%	3.85%	5.95%
8/30/2023	9.90%	3.85%	6.05%
8/31/2023	9.40%	3.85%	5.55%
9/20/2023	9.35%	3.90%	5.45%
9/20/2023	9.49%	3.90%	5.59%
10/5/2023	9.30%	3.96%	5.34%
10/6/2023	9.80%	3.96%	5.84%
10/12/2023	9.20%	3.99%	5.21%
10/12/2023	9.20%	3.99%	5.21%

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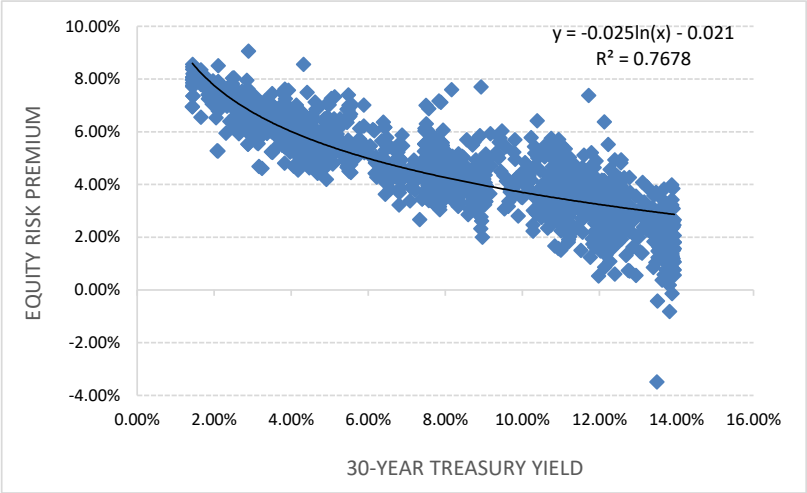
[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/25/2023	9.55%	4.05%	5.50%
10/26/2023	9.50%	4.06%	5.44%
10/26/2023	9.65%	4.06%	5.59%
11/1/2023	9.60%	4.09%	5.51%
11/3/2023	9.70%	4.10%	5.60%
11/7/2023	9.65%	4.11%	5.54%
11/9/2023	9.80%	4.12%	5.68%
11/9/2023	9.80%	4.12%	5.68%
11/9/2023	10.15%	4.12%	6.03%
11/16/2023	9.38%	4.14%	5.24%
11/16/2023	9.38%	4.14%	5.24%
11/16/2023	9.44%	4.14%	5.30%
11/16/2023	9.51%	4.14%	5.37%
12/4/2023	9.80%	4.18%	5.62%
12/14/2023	9.45%	4.20%	5.25%
12/14/2023	9.50%	4.20%	5.30%
12/15/2023	9.65%	4.21%	5.44%
12/21/2023	9.75%	4.21%	5.54%
12/22/2023	10.50%	4.21%	6.29%
1/17/2024	9.85%	4.26%	5.59%
1/31/2024	9.70%	4.29%	5.41%
3/24/2024	9.30%	4.38%	4.92%
4/8/2024	9.50%	4.41%	5.09%
4/8/2024	9.50%	4.41%	5.09%
4/8/2024	11.88%	4.41%	7.47%
4/17/2024	9.75%	4.44%	5.31%
6/26/2024	9.80%	4.48%	5.32%
6/28/2024	9.40%	4.48%	4.92%
7/18/2024	9.50%	4.45%	5.05%
7/23/2024	9.90%	4.44%	5.46%
7/25/2024	9.38%	4.43%	4.95%
7/31/2024	9.75%	4.43%	5.32%
8/15/2024	9.35%	4.40%	4.95%
8/15/2024	9.35%	4.40%	4.95%
9/17/2024	9.65%	4.38%	5.27%
9/18/2024	9.45%	4.38%	5.07%
9/26/2024	9.86%	4.38%	5.48%
10/1/2024	9.85%	4.38%	5.47%
10/9/2024	9.60%	4.38%	5.22%
10/17/2024	10.08%	4.38%	5.70%
10/25/2024	9.35%	4.39%	4.96%
10/25/2024	9.40%	4.39%	5.01%
10/31/2024	9.90%	4.39%	5.51%
11/6/2024	10.00%	4.40%	5.60%
11/7/2024	9.80%	4.40%	5.40%
11/7/2024	9.90%	4.40%	5.50%
11/7/2024	9.90%	4.40%	5.50%
11/18/2024	9.15%	4.40%	4.75%
11/18/2024	9.15%	4.40%	4.75%
11/20/2024	9.70%	4.40%	5.30%
11/21/2024	9.60%	4.40%	5.20%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
11/21/2024	9.60%	4.40%	5.20%
11/21/2024	9.85%	4.40%	5.45%
12/19/2024	9.70%	4.42%	5.28%
12/19/2024	9.80%	4.42%	5.38%
12/19/2024	9.80%	4.42%	5.38%
12/19/2024	9.80%	4.42%	5.38%
12/20/2024	9.80%	4.42%	5.38%
12/30/2024	9.75%	4.43%	5.32%
1/7/2025	9.80%	4.43%	5.37%
1/15/2025	9.90%	4.44%	5.46%
2/13/2025	9.60%	4.45%	5.15%
2/24/2025	9.50%	4.46%	5.04%
3/20/2025	9.75%	4.47%	5.28%
3/27/2025	9.84%	4.47%	5.37%
4/10/2025	9.90%	4.48%	5.42%
4/22/2025	9.80%	4.50%	5.30%
5/13/2025	9.80%	4.55%	5.25%
5/15/2025	9.75%	4.56%	5.19%
5/23/2025	9.50%	4.59%	4.91%
6/12/2025	9.50%	4.65%	4.85%
6/17/2025	9.80%	4.66%	5.14%
6/18/2025	9.60%	4.67%	4.93%
6/26/2025	9.79%	4.69%	5.10%
		# of Cases:	1,348

Bond Yield Plus Risk Premium

[1]	[2]	[3]	[4]	[5]
Constant	Slope	30-Year Treasury Yield	Risk Premium	Return on Equity
-2.095%	-2.518%			
Current 30-Year Treasury		4.92%	5.49%	10.41%
Projected 30-Year Treasury		4.52%	5.70%	10.22%



Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Sources: Current = Bloomberg Professional,
Projected = Average of near-term and long-term projected 30-year Treasury yield from
Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025 at 14 and
Blue Chip Financial Forecasts, Vol. 44, No. 7, July 1, 2025 at 2
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]
[6] Source: S&P Capital IQ
[7] Source: S&P Capital IQ
[8] Source: Bloomberg Professional, equals 199-trading day average (i.e. lag period)
[9] Equals [7] - [8]

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Bond Yield Plus Risk Premium

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
1/1/1980	14.50%	9.36%	5.14%
1/7/1980	14.39%	9.39%	5.00%
1/9/1980	15.00%	9.40%	5.60%
1/14/1980	15.17%	9.42%	5.75%
1/17/1980	13.93%	9.44%	4.49%
1/23/1980	15.50%	9.47%	6.03%
1/30/1980	13.86%	9.52%	4.34%
1/31/1980	12.61%	9.53%	3.08%
2/6/1980	13.71%	9.58%	4.13%
2/13/1980	12.80%	9.64%	3.16%
2/14/1980	13.00%	9.65%	3.35%
2/19/1980	13.50%	9.68%	3.82%
2/27/1980	13.75%	9.78%	3.97%
2/29/1980	13.75%	9.81%	3.94%
2/29/1980	14.00%	9.81%	4.19%
2/29/1980	14.77%	9.81%	4.96%
3/7/1980	12.70%	9.90%	2.80%
3/14/1980	13.50%	9.97%	3.53%
3/26/1980	14.16%	10.11%	4.05%
3/27/1980	14.24%	10.12%	4.12%
3/28/1980	14.50%	10.14%	4.36%
4/11/1980	12.75%	10.28%	2.47%
4/14/1980	13.85%	10.29%	3.56%
4/16/1980	15.50%	10.32%	5.18%
4/22/1980	13.25%	10.36%	2.89%
4/22/1980	13.90%	10.36%	3.54%
4/24/1980	16.80%	10.38%	6.42%
4/29/1980	15.50%	10.41%	5.09%
5/6/1980	13.70%	10.45%	3.25%
5/7/1980	15.00%	10.46%	4.54%
5/8/1980	13.75%	10.47%	3.28%
5/9/1980	14.35%	10.47%	3.88%
5/13/1980	13.60%	10.49%	3.11%
5/15/1980	13.25%	10.50%	2.75%
5/19/1980	13.75%	10.52%	3.23%
5/27/1980	13.62%	10.55%	3.07%
5/27/1980	14.60%	10.55%	4.05%
5/29/1980	16.00%	10.56%	5.44%
5/30/1980	13.80%	10.57%	3.23%
6/2/1980	15.63%	10.58%	5.05%
6/9/1980	15.90%	10.61%	5.29%
6/10/1980	13.78%	10.61%	3.17%
6/12/1980	14.25%	10.62%	3.63%
6/19/1980	13.40%	10.63%	2.77%
6/30/1980	13.00%	10.65%	2.35%
6/30/1980	13.40%	10.65%	2.75%
7/9/1980	14.75%	10.68%	4.07%
7/10/1980	15.00%	10.69%	4.31%
7/15/1980	15.80%	10.70%	5.10%
7/18/1980	13.80%	10.72%	3.08%
7/22/1980	14.10%	10.73%	3.37%
7/24/1980	15.00%	10.73%	4.27%
7/25/1980	13.48%	10.74%	2.74%
7/31/1980	14.58%	10.76%	3.82%
8/8/1980	13.50%	10.78%	2.72%
8/8/1980	14.00%	10.78%	3.22%
8/8/1980	15.45%	10.78%	4.67%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
8/11/1980	14.85%	10.78%	4.07%
8/14/1980	14.00%	10.79%	3.21%
8/14/1980	16.25%	10.79%	5.46%
8/25/1980	13.75%	10.82%	2.93%
8/27/1980	13.80%	10.83%	2.97%
8/29/1980	12.50%	10.84%	1.66%
9/15/1980	13.50%	10.88%	2.62%
9/15/1980	15.80%	10.88%	4.92%
9/15/1980	13.93%	10.88%	3.05%
9/24/1980	12.50%	10.93%	1.57%
9/24/1980	15.00%	10.93%	4.07%
9/26/1980	13.75%	10.95%	2.80%
9/30/1980	14.10%	10.96%	3.14%
9/30/1980	14.20%	10.96%	3.24%
10/1/1980	13.90%	10.97%	2.93%
10/3/1980	15.50%	10.99%	4.51%
10/7/1980	12.50%	11.00%	1.50%
10/9/1980	13.25%	11.01%	2.24%
10/9/1980	14.50%	11.01%	3.49%
10/9/1980	14.50%	11.01%	3.49%
10/16/1980	16.10%	11.03%	5.07%
10/17/1980	14.50%	11.03%	3.47%
10/31/1980	13.75%	11.11%	2.64%
10/31/1980	14.25%	11.11%	3.14%
11/4/1980	15.00%	11.12%	3.88%
11/5/1980	14.00%	11.13%	2.87%
11/5/1980	13.75%	11.13%	2.62%
11/8/1980	13.75%	11.15%	2.60%
11/10/1980	14.85%	11.15%	3.70%
11/17/1980	14.00%	11.18%	2.82%
11/18/1980	14.00%	11.19%	2.81%
11/19/1980	13.00%	11.19%	1.81%
11/24/1980	14.00%	11.20%	2.80%
11/26/1980	14.00%	11.21%	2.79%
12/8/1980	14.15%	11.22%	2.93%
12/8/1980	15.10%	11.22%	3.88%
12/9/1980	15.35%	11.22%	4.13%
12/12/1980	15.45%	11.22%	4.23%
12/17/1980	13.25%	11.23%	2.02%
12/18/1980	15.80%	11.23%	4.57%
12/19/1980	14.50%	11.23%	3.27%
12/19/1980	14.64%	11.23%	3.41%
12/22/1980	13.45%	11.22%	2.23%
12/22/1980	15.00%	11.22%	3.78%
12/30/1980	14.95%	11.21%	3.74%
12/30/1980	14.50%	11.21%	3.29%
12/31/1980	13.39%	11.21%	2.18%
1/2/1981	15.25%	11.21%	4.04%
1/7/1981	14.30%	11.21%	3.09%
1/19/1981	15.25%	11.19%	4.06%
1/23/1981	14.40%	11.20%	3.20%
1/23/1981	13.10%	11.20%	1.90%
1/26/1981	15.25%	11.20%	4.05%
1/27/1981	15.00%	11.20%	3.80%
1/31/1981	13.47%	11.21%	2.26%
2/3/1981	15.25%	11.23%	4.02%
2/5/1981	15.75%	11.25%	4.50%
2/11/1981	15.60%	11.28%	4.32%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
2/20/1981	15.25%	11.34%	3.91%
3/11/1981	15.40%	11.50%	3.90%
3/12/1981	14.51%	11.51%	3.00%
3/12/1981	16.00%	11.51%	4.49%
3/13/1981	13.02%	11.52%	1.50%
3/18/1981	16.19%	11.55%	4.64%
3/19/1981	13.75%	11.56%	2.19%
3/23/1981	14.30%	11.58%	2.72%
3/25/1981	15.30%	11.61%	3.69%
4/1/1981	14.53%	11.69%	2.84%
4/3/1981	19.10%	11.72%	7.38%
4/9/1981	15.00%	11.79%	3.21%
4/9/1981	15.30%	11.79%	3.51%
4/9/1981	17.00%	11.79%	5.21%
4/9/1981	16.50%	11.79%	4.71%
4/10/1981	13.75%	11.81%	1.94%
4/13/1981	13.57%	11.83%	1.74%
4/15/1981	15.30%	11.86%	3.44%
4/16/1981	13.50%	11.88%	1.62%
4/17/1981	14.10%	11.88%	2.22%
4/21/1981	14.00%	11.91%	2.09%
4/21/1981	16.80%	11.91%	4.89%
4/24/1981	16.00%	11.96%	4.04%
4/27/1981	12.50%	11.98%	0.52%
4/27/1981	13.61%	11.98%	1.63%
4/29/1981	13.65%	12.01%	1.64%
4/30/1981	13.50%	12.02%	1.48%
5/4/1981	16.22%	12.06%	4.16%
5/5/1981	14.40%	12.08%	2.32%
5/7/1981	16.25%	12.12%	4.13%
5/7/1981	16.27%	12.12%	4.15%
5/8/1981	13.00%	12.14%	0.86%
5/8/1981	16.00%	12.14%	3.86%
5/12/1981	13.50%	12.17%	1.33%
5/15/1981	15.75%	12.23%	3.52%
5/18/1981	14.88%	12.24%	2.64%
5/20/1981	16.00%	12.27%	3.73%
5/21/1981	14.00%	12.28%	1.72%
5/26/1981	14.90%	12.31%	2.59%
5/27/1981	15.00%	12.32%	2.68%
5/29/1981	15.50%	12.34%	3.16%
6/1/1981	16.50%	12.35%	4.15%
6/3/1981	14.67%	12.38%	2.29%
6/5/1981	13.00%	12.40%	0.60%
6/10/1981	16.75%	12.42%	4.33%
6/17/1981	14.40%	12.46%	1.94%
6/18/1981	16.33%	12.47%	3.86%
6/25/1981	14.75%	12.52%	2.23%
6/26/1981	16.00%	12.53%	3.47%
6/30/1981	15.25%	12.55%	2.70%
7/1/1981	15.50%	12.56%	2.94%
7/1/1981	17.50%	12.56%	4.94%
7/10/1981	16.00%	12.62%	3.38%
7/14/1981	16.90%	12.64%	4.26%
7/15/1981	16.00%	12.65%	3.35%
7/17/1981	15.00%	12.67%	2.33%
7/20/1981	15.00%	12.68%	2.32%
7/21/1981	14.00%	12.69%	1.31%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
7/28/1981	13.48%	12.75%	0.73%
7/31/1981	13.50%	12.79%	0.71%
7/31/1981	15.00%	12.79%	2.21%
7/31/1981	16.00%	12.79%	3.21%
8/5/1981	15.71%	12.83%	2.88%
8/10/1981	14.50%	12.87%	1.63%
8/11/1981	15.00%	12.88%	2.12%
8/20/1981	13.50%	12.95%	0.55%
8/20/1981	16.50%	12.95%	3.55%
8/24/1981	15.00%	12.97%	2.03%
8/28/1981	15.00%	13.01%	1.99%
9/3/1981	14.50%	13.06%	1.44%
9/10/1981	14.50%	13.11%	1.39%
9/11/1981	16.00%	13.12%	2.88%
9/16/1981	16.00%	13.15%	2.85%
9/17/1981	16.50%	13.16%	3.34%
9/23/1981	15.85%	13.20%	2.65%
9/28/1981	15.50%	13.23%	2.27%
10/9/1981	15.75%	13.34%	2.41%
10/15/1981	16.25%	13.37%	2.88%
10/16/1981	15.50%	13.39%	2.11%
10/16/1981	16.50%	13.39%	3.11%
10/19/1981	14.25%	13.40%	0.85%
10/20/1981	17.00%	13.41%	3.59%
10/20/1981	15.25%	13.41%	1.84%
10/23/1981	16.00%	13.46%	2.54%
10/27/1981	10.00%	13.49%	-3.49%
10/29/1981	16.50%	13.52%	2.98%
10/29/1981	14.75%	13.52%	1.23%
11/3/1981	15.17%	13.54%	1.63%
11/5/1981	16.60%	13.56%	3.04%
11/6/1981	15.17%	13.57%	1.60%
11/24/1981	15.50%	13.61%	1.89%
11/25/1981	15.35%	13.61%	1.74%
11/25/1981	15.25%	13.61%	1.64%
11/25/1981	16.10%	13.61%	2.49%
11/25/1981	16.10%	13.61%	2.49%
12/1/1981	16.00%	13.61%	2.39%
12/1/1981	16.50%	13.61%	2.89%
12/1/1981	16.49%	13.61%	2.88%
12/1/1981	15.70%	13.61%	2.09%
12/4/1981	16.00%	13.61%	2.39%
12/11/1981	16.25%	13.63%	2.62%
12/14/1981	14.00%	13.63%	0.37%
12/15/1981	15.81%	13.63%	2.18%
12/15/1981	16.00%	13.63%	2.37%
12/16/1981	15.25%	13.63%	1.62%
12/17/1981	16.50%	13.64%	2.86%
12/18/1981	15.45%	13.64%	1.81%
12/30/1981	14.25%	13.67%	0.58%
12/30/1981	16.25%	13.67%	2.58%
12/30/1981	16.00%	13.67%	2.33%
12/31/1981	16.15%	13.68%	2.47%
1/4/1982	15.50%	13.68%	1.82%
1/11/1982	17.00%	13.73%	3.27%
1/11/1982	14.50%	13.73%	0.77%
1/13/1982	14.75%	13.74%	1.01%
1/14/1982	15.75%	13.75%	2.00%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
1/15/1982	16.50%	13.76%	2.74%
1/15/1982	15.00%	13.76%	1.24%
1/22/1982	16.25%	13.80%	2.45%
1/27/1982	16.84%	13.81%	3.03%
1/28/1982	13.00%	13.82%	-0.82%
1/29/1982	15.50%	13.82%	1.68%
2/1/1982	15.85%	13.83%	2.02%
2/3/1982	16.44%	13.84%	2.60%
2/8/1982	15.50%	13.86%	1.64%
2/11/1982	16.00%	13.88%	2.12%
2/11/1982	16.20%	13.88%	2.32%
2/17/1982	15.00%	13.89%	1.11%
2/19/1982	15.17%	13.89%	1.28%
2/26/1982	15.25%	13.89%	1.36%
3/1/1982	15.03%	13.89%	1.14%
3/1/1982	16.00%	13.89%	2.11%
3/3/1982	15.00%	13.88%	1.12%
3/8/1982	17.10%	13.88%	3.22%
3/12/1982	16.25%	13.88%	2.37%
3/17/1982	17.30%	13.88%	3.42%
3/22/1982	15.10%	13.89%	1.21%
3/27/1982	15.40%	13.90%	1.50%
3/30/1982	15.50%	13.91%	1.59%
3/31/1982	17.00%	13.91%	3.09%
4/1/1982	14.70%	13.92%	0.78%
4/1/1982	16.50%	13.92%	2.58%
4/2/1982	15.50%	13.92%	1.58%
4/5/1982	15.50%	13.93%	1.57%
4/8/1982	16.40%	13.94%	2.46%
4/13/1982	14.50%	13.94%	0.56%
4/23/1982	15.75%	13.94%	1.81%
4/27/1982	15.00%	13.94%	1.06%
4/28/1982	15.75%	13.94%	1.81%
4/30/1982	14.70%	13.94%	0.76%
4/30/1982	15.50%	13.94%	1.56%
5/3/1982	16.60%	13.94%	2.66%
5/4/1982	16.00%	13.94%	2.06%
5/14/1982	15.50%	13.92%	1.58%
5/18/1982	15.42%	13.92%	1.50%
5/19/1982	14.69%	13.92%	0.77%
5/20/1982	15.10%	13.91%	1.19%
5/20/1982	15.50%	13.91%	1.59%
5/20/1982	15.00%	13.91%	1.09%
5/20/1982	16.30%	13.91%	2.39%
5/21/1982	17.75%	13.91%	3.84%
5/27/1982	15.00%	13.89%	1.11%
5/28/1982	17.00%	13.89%	3.11%
5/28/1982	15.50%	13.89%	1.61%
6/1/1982	13.75%	13.89%	-0.14%
6/1/1982	16.60%	13.89%	2.71%
6/9/1982	17.86%	13.88%	3.98%
6/14/1982	15.75%	13.88%	1.87%
6/15/1982	14.85%	13.87%	0.98%
6/18/1982	15.50%	13.86%	1.64%
6/21/1982	14.90%	13.86%	1.04%
6/23/1982	16.00%	13.86%	2.14%
6/23/1982	16.17%	13.86%	2.31%
6/24/1982	14.85%	13.86%	0.99%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
6/25/1982	14.70%	13.85%	0.85%
7/1/1982	16.00%	13.84%	2.16%
7/2/1982	15.62%	13.83%	1.79%
7/2/1982	17.00%	13.83%	3.17%
7/13/1982	16.80%	13.82%	2.98%
7/13/1982	14.00%	13.82%	0.18%
7/14/1982	15.76%	13.81%	1.95%
7/14/1982	16.02%	13.81%	2.21%
7/19/1982	16.50%	13.79%	2.71%
7/22/1982	17.00%	13.76%	3.24%
7/22/1982	14.50%	13.76%	0.74%
7/27/1982	16.75%	13.74%	3.01%
7/29/1982	16.50%	13.73%	2.77%
8/11/1982	17.50%	13.68%	3.82%
8/18/1982	17.07%	13.62%	3.45%
8/20/1982	15.73%	13.60%	2.13%
8/25/1982	16.00%	13.57%	2.43%
8/26/1982	15.50%	13.56%	1.94%
8/30/1982	15.00%	13.55%	1.45%
9/3/1982	16.20%	13.53%	2.67%
9/8/1982	15.00%	13.52%	1.48%
9/15/1982	16.25%	13.51%	2.74%
9/15/1982	13.08%	13.51%	-0.43%
9/16/1982	16.00%	13.50%	2.50%
9/17/1982	15.25%	13.50%	1.75%
9/23/1982	17.17%	13.47%	3.70%
9/24/1982	14.50%	13.47%	1.03%
9/27/1982	15.25%	13.46%	1.79%
10/1/1982	15.50%	13.42%	2.08%
10/15/1982	15.90%	13.32%	2.58%
10/22/1982	15.75%	13.24%	2.51%
10/22/1982	17.15%	13.24%	3.91%
10/29/1982	15.54%	13.16%	2.38%
11/1/1982	15.50%	13.14%	2.36%
11/3/1982	17.20%	13.12%	4.08%
11/4/1982	16.25%	13.10%	3.15%
11/5/1982	16.20%	13.09%	3.11%
11/9/1982	16.00%	13.05%	2.95%
11/23/1982	15.50%	12.88%	2.62%
11/23/1982	15.85%	12.88%	2.97%
11/30/1982	16.50%	12.80%	3.70%
12/1/1982	17.04%	12.78%	4.26%
12/6/1982	15.00%	12.72%	2.28%
12/6/1982	16.35%	12.72%	3.63%
12/10/1982	15.50%	12.66%	2.84%
12/13/1982	16.00%	12.64%	3.36%
12/14/1982	15.30%	12.62%	2.68%
12/14/1982	16.40%	12.62%	3.78%
12/20/1982	16.00%	12.57%	3.43%
12/21/1982	14.75%	12.55%	2.20%
12/21/1982	15.85%	12.55%	3.30%
12/22/1982	16.58%	12.54%	4.04%
12/22/1982	16.75%	12.54%	4.21%
12/22/1982	16.25%	12.54%	3.71%
12/29/1982	14.90%	12.48%	2.42%
12/29/1982	16.25%	12.48%	3.77%
12/30/1982	16.35%	12.46%	3.89%
12/30/1982	16.00%	12.46%	3.54%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/30/1982	16.77%	12.46%	4.31%
1/5/1983	17.33%	12.40%	4.93%
1/11/1983	15.90%	12.34%	3.56%
1/12/1983	15.50%	12.32%	3.18%
1/12/1983	14.63%	12.32%	2.31%
1/20/1983	17.75%	12.23%	5.52%
1/21/1983	15.00%	12.21%	2.79%
1/24/1983	15.50%	12.20%	3.30%
1/24/1983	14.50%	12.20%	2.30%
1/25/1983	15.85%	12.19%	3.66%
1/27/1983	16.14%	12.16%	3.98%
2/1/1983	18.50%	12.13%	6.37%
2/4/1983	14.00%	12.09%	1.91%
2/10/1983	15.00%	12.05%	2.95%
2/21/1983	15.50%	11.98%	3.52%
2/22/1983	15.50%	11.96%	3.54%
2/23/1983	16.00%	11.95%	4.05%
2/23/1983	15.10%	11.95%	3.15%
3/2/1983	15.25%	11.89%	3.36%
3/9/1983	15.20%	11.82%	3.38%
3/15/1983	13.00%	11.76%	1.24%
3/18/1983	15.25%	11.72%	3.53%
3/23/1983	15.40%	11.68%	3.72%
3/24/1983	15.00%	11.66%	3.34%
3/29/1983	15.50%	11.62%	3.88%
3/30/1983	16.71%	11.60%	5.11%
3/31/1983	15.00%	11.58%	3.42%
4/4/1983	15.20%	11.57%	3.63%
4/8/1983	15.50%	11.49%	4.01%
4/11/1983	14.81%	11.48%	3.33%
4/19/1983	14.50%	11.36%	3.14%
4/20/1983	16.00%	11.35%	4.65%
4/29/1983	16.00%	11.23%	4.77%
5/1/1983	14.50%	11.23%	3.27%
5/9/1983	15.50%	11.14%	4.36%
5/11/1983	16.46%	11.11%	5.35%
5/12/1983	14.14%	11.10%	3.04%
5/18/1983	15.00%	11.04%	3.96%
5/23/1983	14.90%	11.00%	3.90%
5/23/1983	15.50%	11.00%	4.50%
5/25/1983	15.50%	10.97%	4.53%
5/27/1983	15.00%	10.95%	4.05%
5/31/1983	14.00%	10.94%	3.06%
5/31/1983	15.50%	10.94%	4.56%
6/2/1983	14.50%	10.92%	3.58%
6/17/1983	15.03%	10.83%	4.20%
7/1/1983	14.90%	10.77%	4.13%
7/1/1983	14.80%	10.77%	4.03%
7/8/1983	16.25%	10.75%	5.50%
7/13/1983	13.20%	10.75%	2.45%
7/19/1983	15.00%	10.74%	4.26%
7/19/1983	15.10%	10.74%	4.36%
7/25/1983	16.25%	10.73%	5.52%
7/28/1983	15.90%	10.74%	5.16%
8/3/1983	16.34%	10.75%	5.59%
8/3/1983	16.50%	10.75%	5.75%
8/19/1983	15.00%	10.80%	4.20%
8/22/1983	15.50%	10.80%	4.70%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
8/22/1983	16.40%	10.80%	5.60%
8/31/1983	14.75%	10.85%	3.90%
9/7/1983	15.00%	10.87%	4.13%
9/14/1983	15.78%	10.89%	4.89%
9/16/1983	15.00%	10.90%	4.10%
9/19/1983	14.50%	10.91%	3.59%
9/20/1983	16.50%	10.91%	5.59%
9/28/1983	14.50%	10.94%	3.56%
9/29/1983	15.50%	10.95%	4.55%
9/30/1983	16.15%	10.95%	5.20%
9/30/1983	15.25%	10.95%	4.30%
10/4/1983	14.80%	10.96%	3.84%
10/7/1983	16.00%	10.97%	5.03%
10/13/1983	15.52%	10.99%	4.53%
10/17/1983	15.50%	11.00%	4.50%
10/18/1983	14.50%	11.00%	3.50%
10/19/1983	16.50%	11.01%	5.49%
10/19/1983	16.25%	11.01%	5.24%
10/26/1983	15.00%	11.04%	3.96%
10/27/1983	15.20%	11.04%	4.16%
11/1/1983	16.00%	11.06%	4.94%
11/9/1983	14.90%	11.09%	3.81%
11/10/1983	14.35%	11.10%	3.25%
11/23/1983	16.15%	11.13%	5.02%
11/23/1983	16.00%	11.13%	4.87%
11/30/1983	15.00%	11.14%	3.86%
12/5/1983	15.25%	11.15%	4.10%
12/6/1983	15.07%	11.16%	3.91%
12/8/1983	15.90%	11.16%	4.74%
12/9/1983	14.75%	11.17%	3.58%
12/12/1983	14.50%	11.18%	3.32%
12/15/1983	15.56%	11.20%	4.36%
12/19/1983	14.80%	11.21%	3.59%
12/20/1983	16.00%	11.22%	4.78%
12/20/1983	14.69%	11.22%	3.47%
12/20/1983	16.25%	11.22%	5.03%
12/22/1983	15.75%	11.23%	4.52%
12/22/1983	14.75%	11.23%	3.52%
1/3/1984	14.75%	11.27%	3.48%
1/10/1984	15.90%	11.30%	4.60%
1/12/1984	15.60%	11.31%	4.29%
1/18/1984	13.75%	11.33%	2.42%
1/19/1984	15.90%	11.33%	4.57%
1/30/1984	16.10%	11.37%	4.73%
1/31/1984	15.25%	11.38%	3.87%
2/1/1984	14.80%	11.39%	3.41%
2/6/1984	14.75%	11.41%	3.34%
2/6/1984	13.75%	11.41%	2.34%
2/9/1984	15.25%	11.43%	3.82%
2/15/1984	15.70%	11.45%	4.25%
2/20/1984	15.00%	11.46%	3.54%
2/20/1984	15.00%	11.46%	3.54%
2/22/1984	14.75%	11.48%	3.27%
2/28/1984	14.50%	11.52%	2.98%
3/2/1984	14.25%	11.54%	2.71%
3/20/1984	16.00%	11.65%	4.35%
3/23/1984	15.50%	11.67%	3.83%
3/26/1984	14.71%	11.68%	3.03%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
4/2/1984	15.50%	11.72%	3.78%
4/6/1984	14.74%	11.76%	2.98%
4/11/1984	15.72%	11.78%	3.94%
4/17/1984	15.00%	11.81%	3.19%
4/18/1984	16.20%	11.82%	4.38%
4/25/1984	14.64%	11.85%	2.79%
4/30/1984	14.40%	11.88%	2.52%
5/16/1984	14.69%	11.99%	2.70%
5/16/1984	15.00%	11.99%	3.01%
5/22/1984	14.40%	12.02%	2.38%
5/29/1984	15.10%	12.06%	3.04%
6/13/1984	15.25%	12.16%	3.09%
6/15/1984	15.60%	12.17%	3.43%
6/22/1984	16.25%	12.21%	4.04%
6/29/1984	15.25%	12.26%	2.99%
7/2/1984	13.35%	12.27%	1.08%
7/10/1984	16.00%	12.31%	3.69%
7/12/1984	16.50%	12.33%	4.17%
7/13/1984	16.25%	12.34%	3.91%
7/17/1984	14.14%	12.35%	1.79%
7/18/1984	15.50%	12.36%	3.14%
7/18/1984	15.30%	12.36%	2.94%
7/19/1984	14.30%	12.37%	1.93%
7/24/1984	16.79%	12.40%	4.39%
7/31/1984	16.00%	12.43%	3.57%
8/3/1984	14.25%	12.45%	1.80%
8/17/1984	14.30%	12.49%	1.81%
8/20/1984	15.00%	12.49%	2.51%
8/27/1984	16.30%	12.51%	3.79%
8/31/1984	15.55%	12.53%	3.02%
9/6/1984	16.00%	12.54%	3.46%
9/10/1984	14.75%	12.55%	2.20%
9/13/1984	15.00%	12.55%	2.45%
9/17/1984	17.38%	12.56%	4.82%
9/26/1984	14.50%	12.57%	1.93%
9/28/1984	15.00%	12.57%	2.43%
9/28/1984	16.25%	12.57%	3.68%
10/9/1984	14.75%	12.58%	2.17%
10/12/1984	15.60%	12.59%	3.01%
10/22/1984	15.00%	12.59%	2.41%
10/26/1984	16.40%	12.59%	3.81%
10/31/1984	16.25%	12.59%	3.66%
11/7/1984	15.60%	12.58%	3.02%
11/9/1984	16.00%	12.58%	3.42%
11/14/1984	15.75%	12.59%	3.16%
11/20/1984	15.25%	12.58%	2.67%
11/20/1984	15.92%	12.58%	3.34%
11/23/1984	15.00%	12.58%	2.42%
11/28/1984	16.15%	12.57%	3.58%
12/3/1984	15.80%	12.57%	3.23%
12/4/1984	16.50%	12.56%	3.94%
12/18/1984	16.40%	12.54%	3.86%
12/19/1984	15.00%	12.53%	2.47%
12/19/1984	14.75%	12.53%	2.22%
12/20/1984	16.00%	12.53%	3.47%
12/28/1984	16.00%	12.50%	3.50%
1/3/1985	14.75%	12.49%	2.26%
1/10/1985	15.75%	12.47%	3.28%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
1/11/1985	16.30%	12.46%	3.84%
1/23/1985	15.80%	12.43%	3.37%
1/24/1985	15.82%	12.43%	3.39%
1/25/1985	16.75%	12.42%	4.33%
1/30/1985	14.90%	12.40%	2.50%
1/31/1985	14.75%	12.39%	2.36%
2/8/1985	14.47%	12.35%	2.12%
3/1/1985	13.84%	12.30%	1.54%
3/8/1985	16.85%	12.28%	4.57%
3/14/1985	15.50%	12.25%	3.25%
3/15/1985	15.62%	12.25%	3.37%
3/29/1985	15.62%	12.16%	3.46%
4/3/1985	14.60%	12.13%	2.47%
4/9/1985	15.50%	12.10%	3.40%
4/16/1985	15.70%	12.05%	3.65%
4/22/1985	14.00%	12.01%	1.99%
4/26/1985	15.50%	11.97%	3.53%
4/29/1985	15.00%	11.96%	3.04%
5/2/1985	14.68%	11.93%	2.75%
5/8/1985	15.62%	11.88%	3.74%
5/10/1985	16.50%	11.86%	4.64%
5/29/1985	14.61%	11.73%	2.88%
5/31/1985	16.00%	11.71%	4.29%
6/14/1985	15.50%	11.60%	3.90%
7/9/1985	15.00%	11.44%	3.56%
7/16/1985	14.50%	11.39%	3.11%
7/26/1985	14.50%	11.32%	3.18%
8/2/1985	14.80%	11.29%	3.51%
8/7/1985	15.00%	11.26%	3.74%
8/28/1985	14.25%	11.15%	3.10%
8/28/1985	15.50%	11.15%	4.35%
8/29/1985	14.50%	11.14%	3.36%
9/9/1985	14.90%	11.11%	3.79%
9/9/1985	14.60%	11.11%	3.49%
9/17/1985	14.90%	11.08%	3.82%
9/23/1985	15.00%	11.06%	3.94%
9/27/1985	15.50%	11.04%	4.46%
9/27/1985	15.80%	11.04%	4.76%
10/2/1985	14.00%	11.03%	2.97%
10/2/1985	14.75%	11.03%	3.72%
10/3/1985	15.25%	11.03%	4.22%
10/24/1985	15.40%	10.96%	4.44%
10/24/1985	15.85%	10.96%	4.89%
10/24/1985	15.82%	10.96%	4.86%
10/28/1985	16.00%	10.95%	5.05%
10/29/1985	16.65%	10.94%	5.71%
10/31/1985	15.06%	10.93%	4.13%
11/4/1985	14.50%	10.91%	3.59%
11/7/1985	15.50%	10.89%	4.61%
11/8/1985	14.30%	10.89%	3.41%
12/12/1985	14.75%	10.73%	4.02%
12/18/1985	15.00%	10.69%	4.31%
12/20/1985	15.00%	10.66%	4.34%
12/20/1985	14.50%	10.66%	3.84%
12/20/1985	14.50%	10.66%	3.84%
1/24/1986	15.40%	10.40%	5.00%
1/31/1986	15.00%	10.35%	4.65%
2/5/1986	15.00%	10.32%	4.68%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
2/5/1986	15.75%	10.32%	5.43%
2/10/1986	13.30%	10.29%	3.01%
2/11/1986	12.50%	10.27%	2.23%
2/14/1986	14.40%	10.24%	4.16%
2/18/1986	16.00%	10.22%	5.78%
2/24/1986	14.50%	10.17%	4.33%
2/26/1986	14.00%	10.15%	3.85%
3/5/1986	14.90%	10.07%	4.83%
3/11/1986	14.50%	10.01%	4.49%
3/12/1986	13.50%	10.00%	3.50%
3/27/1986	14.10%	9.85%	4.25%
3/31/1986	13.50%	9.84%	3.66%
4/1/1986	14.00%	9.82%	4.18%
4/2/1986	15.50%	9.81%	5.69%
4/4/1986	15.00%	9.78%	5.22%
4/14/1986	13.40%	9.68%	3.72%
4/23/1986	15.00%	9.57%	5.43%
5/16/1986	14.50%	9.31%	5.19%
5/16/1986	14.50%	9.31%	5.19%
5/29/1986	13.90%	9.19%	4.71%
5/30/1986	15.10%	9.17%	5.93%
6/2/1986	12.81%	9.16%	3.65%
6/11/1986	14.00%	9.06%	4.94%
6/24/1986	16.63%	8.93%	7.70%
6/26/1986	14.75%	8.90%	5.85%
6/26/1986	12.00%	8.90%	3.10%
6/30/1986	13.00%	8.86%	4.14%
7/10/1986	14.34%	8.74%	5.60%
7/11/1986	12.75%	8.72%	4.03%
7/14/1986	12.60%	8.71%	3.89%
7/17/1986	12.40%	8.65%	3.75%
7/25/1986	14.25%	8.56%	5.69%
8/6/1986	13.50%	8.43%	5.07%
8/14/1986	13.50%	8.34%	5.16%
9/16/1986	12.75%	8.06%	4.69%
9/19/1986	13.25%	8.02%	5.23%
10/1/1986	14.00%	7.94%	6.06%
10/3/1986	13.40%	7.92%	5.48%
10/31/1986	13.50%	7.77%	5.73%
11/5/1986	13.00%	7.74%	5.26%
12/3/1986	12.90%	7.58%	5.32%
12/4/1986	14.44%	7.57%	6.87%
12/16/1986	13.60%	7.52%	6.08%
12/22/1986	13.80%	7.50%	6.30%
12/30/1986	13.00%	7.49%	5.51%
1/2/1987	13.00%	7.48%	5.52%
1/12/1987	12.40%	7.46%	4.94%
1/27/1987	12.71%	7.46%	5.25%
3/2/1987	12.47%	7.47%	5.00%
3/3/1987	13.60%	7.47%	6.13%
3/4/1987	12.38%	7.47%	4.91%
3/10/1987	13.50%	7.47%	6.03%
3/13/1987	13.00%	7.47%	5.53%
3/31/1987	13.00%	7.46%	5.54%
4/6/1987	13.00%	7.47%	5.53%
4/14/1987	12.50%	7.49%	5.01%
4/16/1987	14.50%	7.50%	7.00%
4/27/1987	12.00%	7.54%	4.46%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
5/5/1987	12.85%	7.58%	5.27%
5/12/1987	12.65%	7.62%	5.03%
5/28/1987	13.50%	7.70%	5.80%
6/15/1987	13.20%	7.78%	5.42%
6/29/1987	15.00%	7.84%	7.16%
6/30/1987	12.50%	7.84%	4.66%
7/8/1987	12.00%	7.86%	4.14%
7/10/1987	12.90%	7.87%	5.03%
7/15/1987	13.50%	7.88%	5.62%
7/16/1987	15.00%	7.88%	7.12%
7/16/1987	13.50%	7.88%	5.62%
7/27/1987	13.40%	7.92%	5.48%
7/27/1987	13.50%	7.92%	5.58%
7/27/1987	13.00%	7.92%	5.08%
7/31/1987	12.98%	7.95%	5.03%
8/26/1987	12.63%	8.06%	4.57%
8/26/1987	12.75%	8.06%	4.69%
8/27/1987	13.25%	8.07%	5.18%
9/9/1987	13.00%	8.14%	4.86%
9/30/1987	12.75%	8.31%	4.44%
9/30/1987	13.00%	8.31%	4.69%
10/2/1987	11.50%	8.33%	3.17%
10/15/1987	13.00%	8.44%	4.56%
11/2/1987	13.00%	8.55%	4.45%
11/19/1987	13.00%	8.64%	4.36%
11/30/1987	12.00%	8.69%	3.31%
12/3/1987	14.20%	8.71%	5.49%
12/15/1987	13.25%	8.78%	4.47%
12/16/1987	13.72%	8.79%	4.93%
12/16/1987	13.50%	8.79%	4.71%
12/17/1987	11.75%	8.80%	2.95%
12/18/1987	13.50%	8.80%	4.70%
12/21/1987	12.01%	8.81%	3.20%
12/22/1987	12.00%	8.82%	3.18%
12/22/1987	12.75%	8.82%	3.93%
12/22/1987	13.00%	8.82%	4.18%
12/22/1987	12.00%	8.82%	3.18%
1/20/1988	13.80%	8.94%	4.86%
1/26/1988	13.90%	8.96%	4.94%
1/29/1988	13.20%	8.96%	4.24%
2/4/1988	12.60%	8.96%	3.64%
3/1/1988	11.56%	8.94%	2.62%
3/23/1988	12.87%	8.92%	3.95%
3/24/1988	11.24%	8.92%	2.32%
3/30/1988	12.72%	8.92%	3.80%
4/1/1988	12.50%	8.92%	3.58%
4/7/1988	13.25%	8.93%	4.32%
4/25/1988	10.96%	8.96%	2.00%
5/3/1988	12.91%	8.98%	3.93%
5/11/1988	13.50%	8.99%	4.51%
5/16/1988	13.00%	8.99%	4.01%
6/30/1988	12.75%	8.99%	3.76%
7/1/1988	12.75%	8.99%	3.76%
7/20/1988	13.40%	8.96%	4.44%
8/5/1988	12.75%	8.91%	3.84%
8/23/1988	11.70%	8.93%	2.77%
8/29/1988	12.75%	8.94%	3.81%
8/30/1988	13.50%	8.94%	4.56%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
9/8/1988	12.60%	8.95%	3.65%
10/13/1988	13.10%	8.93%	4.17%
12/19/1988	13.00%	9.02%	3.98%
12/20/1988	13.00%	9.02%	3.98%
12/20/1988	12.25%	9.02%	3.23%
12/21/1988	12.90%	9.02%	3.88%
12/27/1988	13.00%	9.03%	3.97%
12/28/1988	13.10%	9.03%	4.07%
12/30/1988	13.40%	9.04%	4.36%
1/27/1989	13.00%	9.06%	3.94%
1/31/1989	13.00%	9.06%	3.94%
2/17/1989	13.00%	9.05%	3.95%
2/20/1989	12.40%	9.05%	3.35%
3/1/1989	12.76%	9.05%	3.71%
3/8/1989	13.00%	9.05%	3.95%
3/30/1989	14.00%	9.05%	4.95%
4/5/1989	14.20%	9.05%	5.15%
4/18/1989	13.00%	9.05%	3.95%
5/5/1989	12.40%	9.05%	3.35%
6/2/1989	13.20%	9.00%	4.20%
6/8/1989	13.50%	8.98%	4.52%
6/27/1989	13.25%	8.91%	4.34%
6/30/1989	13.00%	8.90%	4.10%
8/14/1989	12.50%	8.77%	3.73%
9/28/1989	12.25%	8.63%	3.62%
10/24/1989	12.50%	8.54%	3.96%
11/9/1989	13.00%	8.48%	4.52%
12/15/1989	13.00%	8.33%	4.67%
12/20/1989	12.90%	8.31%	4.59%
12/21/1989	12.90%	8.31%	4.59%
12/27/1989	13.00%	8.29%	4.71%
12/27/1989	12.50%	8.29%	4.21%
1/10/1990	12.80%	8.24%	4.56%
1/11/1990	12.90%	8.23%	4.67%
1/17/1990	12.80%	8.22%	4.58%
1/26/1990	12.00%	8.19%	3.81%
2/9/1990	12.10%	8.17%	3.93%
2/24/1990	12.86%	8.15%	4.71%
3/30/1990	12.90%	8.16%	4.74%
4/4/1990	15.76%	8.17%	7.59%
4/12/1990	12.52%	8.18%	4.34%
4/19/1990	12.75%	8.20%	4.55%
5/21/1990	12.10%	8.28%	3.82%
5/29/1990	12.40%	8.30%	4.10%
5/31/1990	12.00%	8.30%	3.70%
6/4/1990	12.90%	8.30%	4.60%
6/6/1990	12.25%	8.31%	3.94%
6/15/1990	13.20%	8.32%	4.88%
6/20/1990	12.92%	8.32%	4.60%
6/27/1990	12.90%	8.33%	4.57%
6/29/1990	12.50%	8.34%	4.16%
7/6/1990	12.10%	8.34%	3.76%
7/6/1990	12.35%	8.34%	4.01%
8/10/1990	12.55%	8.41%	4.14%
8/16/1990	13.21%	8.43%	4.78%
8/22/1990	13.10%	8.45%	4.65%
8/24/1990	13.00%	8.46%	4.54%
9/26/1990	11.45%	8.59%	2.86%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
10/2/1990	13.00%	8.61%	4.39%
10/5/1990	12.84%	8.63%	4.21%
10/19/1990	13.00%	8.67%	4.33%
10/25/1990	12.30%	8.68%	3.62%
11/21/1990	12.70%	8.69%	4.01%
12/13/1990	12.30%	8.67%	3.63%
12/17/1990	12.87%	8.67%	4.20%
12/18/1990	13.10%	8.67%	4.43%
12/19/1990	12.00%	8.66%	3.34%
12/20/1990	12.75%	8.66%	4.09%
12/21/1990	12.50%	8.66%	3.84%
12/27/1990	12.79%	8.66%	4.13%
1/2/1991	13.10%	8.66%	4.44%
1/4/1991	12.50%	8.65%	3.85%
1/15/1991	12.75%	8.65%	4.10%
1/25/1991	11.70%	8.63%	3.07%
2/4/1991	12.50%	8.60%	3.90%
2/7/1991	12.50%	8.59%	3.91%
2/12/1991	13.00%	8.57%	4.43%
2/14/1991	12.72%	8.56%	4.16%
2/22/1991	12.80%	8.55%	4.25%
3/6/1991	13.10%	8.53%	4.57%
3/8/1991	13.00%	8.52%	4.48%
3/8/1991	12.30%	8.52%	3.78%
4/22/1991	13.00%	8.49%	4.51%
5/7/1991	13.50%	8.47%	5.03%
5/13/1991	13.25%	8.47%	4.78%
5/30/1991	12.75%	8.43%	4.32%
6/12/1991	12.00%	8.41%	3.59%
6/25/1991	11.70%	8.38%	3.32%
6/28/1991	12.50%	8.38%	4.12%
7/1/1991	12.00%	8.37%	3.63%
7/3/1991	12.50%	8.36%	4.14%
7/19/1991	12.10%	8.34%	3.76%
8/1/1991	12.90%	8.32%	4.58%
8/16/1991	13.20%	8.29%	4.91%
9/27/1991	12.50%	8.23%	4.27%
9/30/1991	12.25%	8.23%	4.02%
10/17/1991	13.00%	8.20%	4.80%
10/23/1991	12.55%	8.20%	4.35%
10/23/1991	12.50%	8.20%	4.30%
10/31/1991	11.80%	8.19%	3.61%
11/1/1991	12.00%	8.19%	3.81%
11/5/1991	12.25%	8.19%	4.06%
11/12/1991	13.25%	8.18%	5.07%
11/12/1991	12.50%	8.18%	4.32%
11/25/1991	12.40%	8.18%	4.22%
11/26/1991	11.60%	8.18%	3.42%
11/26/1991	12.50%	8.18%	4.32%
11/27/1991	12.10%	8.18%	3.92%
12/18/1991	12.25%	8.15%	4.10%
12/19/1991	12.80%	8.15%	4.65%
12/19/1991	12.60%	8.15%	4.45%
12/20/1991	12.65%	8.14%	4.51%
1/9/1992	12.80%	8.09%	4.71%
1/16/1992	12.75%	8.07%	4.68%
1/21/1992	12.00%	8.06%	3.94%
1/22/1992	13.00%	8.06%	4.94%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
1/27/1992	12.65%	8.05%	4.60%
1/31/1992	12.00%	8.04%	3.96%
2/11/1992	12.40%	8.03%	4.37%
2/25/1992	12.50%	8.01%	4.49%
3/16/1992	11.43%	7.98%	3.45%
3/18/1992	12.28%	7.98%	4.30%
4/2/1992	12.10%	7.95%	4.15%
4/9/1992	11.45%	7.93%	3.52%
4/10/1992	11.50%	7.93%	3.57%
4/14/1992	11.50%	7.92%	3.58%
5/5/1992	11.50%	7.89%	3.61%
5/12/1992	12.46%	7.88%	4.58%
5/12/1992	11.87%	7.88%	3.99%
6/1/1992	12.30%	7.86%	4.44%
6/12/1992	10.90%	7.85%	3.05%
6/26/1992	12.35%	7.85%	4.50%
6/29/1992	11.00%	7.85%	3.15%
6/30/1992	13.00%	7.85%	5.15%
7/13/1992	11.90%	7.84%	4.06%
7/13/1992	13.50%	7.84%	5.66%
7/22/1992	11.20%	7.83%	3.37%
8/3/1992	12.00%	7.81%	4.19%
8/6/1992	12.50%	7.80%	4.70%
9/22/1992	12.00%	7.71%	4.29%
9/28/1992	11.40%	7.71%	3.69%
9/30/1992	11.75%	7.71%	4.04%
10/2/1992	13.00%	7.70%	5.30%
10/12/1992	12.20%	7.70%	4.50%
10/16/1992	13.16%	7.71%	5.45%
10/30/1992	11.75%	7.71%	4.04%
11/3/1992	12.00%	7.71%	4.29%
12/3/1992	11.85%	7.68%	4.17%
12/15/1992	11.00%	7.66%	3.34%
12/16/1992	11.90%	7.66%	4.24%
12/16/1992	12.40%	7.66%	4.74%
12/17/1992	12.00%	7.66%	4.34%
12/22/1992	12.40%	7.65%	4.75%
12/22/1992	12.30%	7.65%	4.65%
12/29/1992	12.25%	7.63%	4.62%
12/30/1992	12.00%	7.63%	4.37%
12/31/1992	11.90%	7.62%	4.28%
1/12/1993	12.00%	7.61%	4.39%
1/21/1993	11.25%	7.59%	3.66%
2/2/1993	11.40%	7.56%	3.84%
2/15/1993	12.30%	7.52%	4.78%
2/24/1993	11.90%	7.49%	4.41%
2/26/1993	12.20%	7.48%	4.72%
2/26/1993	11.80%	7.48%	4.32%
4/23/1993	11.75%	7.29%	4.46%
5/11/1993	11.75%	7.24%	4.51%
5/14/1993	11.50%	7.24%	4.26%
5/25/1993	11.50%	7.22%	4.28%
5/28/1993	11.00%	7.22%	3.78%
6/3/1993	12.00%	7.21%	4.79%
6/16/1993	11.50%	7.19%	4.31%
6/18/1993	12.10%	7.18%	4.92%
6/25/1993	11.67%	7.17%	4.50%
7/21/1993	11.38%	7.10%	4.28%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
7/23/1993	10.46%	7.09%	3.37%
8/24/1993	11.50%	6.95%	4.55%
9/21/1993	10.50%	6.80%	3.70%
9/29/1993	11.47%	6.76%	4.71%
9/30/1993	11.60%	6.76%	4.84%
11/2/1993	10.80%	6.60%	4.20%
11/12/1993	12.00%	6.56%	5.44%
11/26/1993	11.00%	6.52%	4.48%
12/14/1993	10.55%	6.48%	4.07%
12/16/1993	10.60%	6.48%	4.12%
12/21/1993	11.30%	6.47%	4.83%
1/4/1994	10.07%	6.44%	3.63%
1/13/1994	11.00%	6.42%	4.58%
1/21/1994	11.00%	6.40%	4.60%
1/28/1994	11.35%	6.39%	4.96%
2/3/1994	11.40%	6.38%	5.02%
2/17/1994	10.60%	6.36%	4.24%
2/25/1994	12.00%	6.35%	5.65%
2/25/1994	11.25%	6.35%	4.90%
3/1/1994	11.00%	6.35%	4.65%
3/4/1994	11.00%	6.34%	4.66%
4/25/1994	11.00%	6.40%	4.60%
5/10/1994	11.75%	6.44%	5.31%
5/13/1994	10.50%	6.46%	4.04%
6/3/1994	11.00%	6.54%	4.46%
6/27/1994	11.40%	6.65%	4.75%
8/5/1994	12.75%	6.88%	5.87%
10/31/1994	10.00%	7.33%	2.67%
11/9/1994	10.85%	7.40%	3.45%
11/9/1994	10.85%	7.40%	3.45%
11/18/1994	11.20%	7.46%	3.74%
11/22/1994	11.60%	7.47%	4.13%
11/28/1994	11.06%	7.50%	3.56%
12/8/1994	11.50%	7.55%	3.95%
12/8/1994	11.70%	7.55%	4.15%
12/14/1994	10.95%	7.57%	3.38%
12/15/1994	11.50%	7.57%	3.93%
12/19/1994	11.50%	7.58%	3.92%
12/28/1994	12.15%	7.61%	4.54%
1/9/1995	12.28%	7.64%	4.64%
1/31/1995	11.00%	7.69%	3.31%
2/10/1995	12.60%	7.70%	4.90%
2/17/1995	11.90%	7.70%	4.20%
3/9/1995	11.50%	7.72%	3.78%
3/20/1995	12.00%	7.72%	4.28%
3/23/1995	12.81%	7.72%	5.09%
3/29/1995	11.60%	7.72%	3.88%
4/6/1995	11.10%	7.72%	3.38%
4/7/1995	11.00%	7.71%	3.29%
4/19/1995	11.00%	7.70%	3.30%
5/12/1995	11.63%	7.68%	3.95%
5/25/1995	11.20%	7.65%	3.55%
6/9/1995	11.25%	7.60%	3.65%
6/21/1995	12.25%	7.56%	4.69%
6/30/1995	11.10%	7.51%	3.59%
9/11/1995	11.30%	7.20%	4.10%
9/27/1995	11.75%	7.12%	4.63%
9/27/1995	11.50%	7.12%	4.38%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
9/27/1995	11.30%	7.12%	4.18%
9/29/1995	11.00%	7.11%	3.89%
11/9/1995	12.36%	6.89%	5.47%
11/9/1995	11.38%	6.89%	4.49%
11/17/1995	11.00%	6.85%	4.15%
12/4/1995	11.35%	6.78%	4.57%
12/11/1995	11.40%	6.74%	4.66%
12/20/1995	11.60%	6.69%	4.91%
12/27/1995	12.00%	6.66%	5.34%
2/5/1996	12.25%	6.48%	5.77%
3/29/1996	10.67%	6.42%	4.25%
4/8/1996	11.00%	6.42%	4.58%
4/11/1996	12.59%	6.43%	6.16%
4/11/1996	12.59%	6.43%	6.16%
4/24/1996	11.25%	6.43%	4.82%
4/30/1996	11.00%	6.43%	4.57%
5/13/1996	11.00%	6.44%	4.56%
5/23/1996	11.25%	6.43%	4.82%
6/25/1996	11.25%	6.48%	4.77%
6/27/1996	11.20%	6.48%	4.72%
8/12/1996	10.40%	6.57%	3.83%
9/27/1996	11.00%	6.71%	4.29%
10/16/1996	12.25%	6.76%	5.49%
11/5/1996	11.00%	6.81%	4.19%
11/26/1996	11.30%	6.83%	4.47%
12/18/1996	11.75%	6.84%	4.91%
12/31/1996	11.50%	6.83%	4.67%
1/3/1997	10.70%	6.83%	3.87%
2/13/1997	11.80%	6.82%	4.98%
2/20/1997	11.80%	6.82%	4.98%
3/31/1997	10.02%	6.80%	3.22%
4/2/1997	11.65%	6.80%	4.85%
4/28/1997	11.50%	6.81%	4.69%
4/29/1997	11.70%	6.81%	4.89%
7/17/1997	12.00%	6.77%	5.23%
12/12/1997	11.00%	6.60%	4.40%
12/23/1997	11.12%	6.57%	4.55%
2/2/1998	12.75%	6.39%	6.36%
3/2/1998	11.25%	6.28%	4.97%
3/6/1998	10.75%	6.27%	4.48%
3/20/1998	10.50%	6.22%	4.28%
4/30/1998	12.20%	6.12%	6.08%
7/10/1998	11.40%	5.94%	5.46%
9/15/1998	11.90%	5.78%	6.12%
11/30/1998	12.60%	5.58%	7.02%
12/10/1998	12.20%	5.54%	6.66%
12/17/1998	12.10%	5.52%	6.58%
2/5/1999	10.30%	5.38%	4.92%
3/4/1999	10.50%	5.34%	5.16%
4/6/1999	10.94%	5.32%	5.62%
7/29/1999	10.75%	5.52%	5.23%
9/23/1999	10.75%	5.70%	5.05%
11/17/1999	11.10%	5.90%	5.20%
1/7/2000	11.50%	6.05%	5.45%
1/7/2000	11.50%	6.05%	5.45%
2/17/2000	10.60%	6.17%	4.43%
3/28/2000	11.25%	6.20%	5.05%
5/24/2000	11.00%	6.18%	4.82%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
7/18/2000	12.20%	6.16%	6.04%
9/29/2000	11.16%	6.03%	5.13%
11/28/2000	12.90%	5.89%	7.01%
11/30/2000	12.10%	5.88%	6.22%
1/23/2001	11.25%	5.79%	5.46%
2/8/2001	11.50%	5.77%	5.73%
5/8/2001	10.75%	5.62%	5.13%
6/26/2001	11.00%	5.62%	5.38%
7/25/2001	11.02%	5.60%	5.42%
7/25/2001	11.02%	5.60%	5.42%
7/31/2001	11.00%	5.59%	5.41%
8/31/2001	10.50%	5.56%	4.94%
9/7/2001	10.75%	5.55%	5.20%
9/10/2001	11.00%	5.55%	5.45%
9/20/2001	10.00%	5.55%	4.45%
10/24/2001	10.30%	5.54%	4.76%
11/28/2001	10.60%	5.49%	5.11%
12/3/2001	12.88%	5.49%	7.39%
12/20/2001	12.50%	5.50%	7.00%
1/22/2002	10.00%	5.50%	4.50%
3/27/2002	10.10%	5.45%	4.65%
4/22/2002	11.80%	5.45%	6.35%
5/28/2002	10.17%	5.46%	4.71%
6/10/2002	12.00%	5.47%	6.53%
6/18/2002	11.16%	5.48%	5.68%
6/20/2002	12.30%	5.48%	6.82%
6/20/2002	11.00%	5.48%	5.52%
7/15/2002	11.00%	5.48%	5.52%
9/12/2002	12.30%	5.45%	6.85%
9/26/2002	10.45%	5.41%	5.04%
12/4/2002	11.55%	5.29%	6.26%
12/13/2002	11.75%	5.27%	6.48%
12/20/2002	11.40%	5.25%	6.15%
1/8/2003	11.10%	5.19%	5.91%
1/31/2003	12.45%	5.13%	7.32%
2/28/2003	12.30%	5.04%	7.26%
3/6/2003	10.75%	5.02%	5.73%
3/7/2003	9.96%	5.02%	4.94%
3/20/2003	12.00%	4.98%	7.02%
4/3/2003	12.00%	4.95%	7.05%
4/15/2003	11.15%	4.93%	6.22%
6/25/2003	10.75%	4.79%	5.96%
6/26/2003	10.75%	4.79%	5.96%
7/9/2003	9.75%	4.79%	4.96%
7/16/2003	9.75%	4.79%	4.96%
7/25/2003	9.50%	4.79%	4.71%
8/26/2003	10.50%	4.83%	5.67%
12/17/2003	10.70%	4.94%	5.76%
12/17/2003	9.85%	4.94%	4.91%
12/18/2003	11.50%	4.94%	6.56%
12/19/2003	12.00%	4.94%	7.06%
12/19/2003	12.00%	4.94%	7.06%
12/23/2003	10.50%	4.94%	5.56%
1/13/2004	12.00%	4.95%	7.05%
3/2/2004	10.75%	4.99%	5.76%
3/26/2004	10.25%	5.02%	5.23%
4/5/2004	11.25%	5.03%	6.22%
5/18/2004	10.50%	5.07%	5.43%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
5/25/2004	10.25%	5.07%	5.18%
5/27/2004	10.25%	5.08%	5.17%
6/2/2004	11.22%	5.08%	6.14%
6/30/2004	10.50%	5.10%	5.40%
6/30/2004	10.50%	5.10%	5.40%
7/16/2004	11.60%	5.11%	6.49%
8/25/2004	10.25%	5.10%	5.15%
9/9/2004	10.40%	5.10%	5.30%
11/9/2004	10.50%	5.07%	5.43%
11/23/2004	11.00%	5.06%	5.94%
12/14/2004	10.97%	5.07%	5.90%
12/21/2004	11.50%	5.07%	6.43%
12/21/2004	11.25%	5.07%	6.18%
12/22/2004	10.70%	5.07%	5.63%
12/22/2004	11.50%	5.07%	6.43%
12/29/2004	9.85%	5.08%	4.77%
1/6/2005	10.70%	5.08%	5.62%
2/18/2005	10.30%	4.98%	5.32%
2/25/2005	10.50%	4.96%	5.54%
3/10/2005	11.00%	4.93%	6.07%
3/24/2005	10.30%	4.89%	5.41%
4/4/2005	10.00%	4.87%	5.13%
4/7/2005	10.25%	4.87%	5.38%
5/18/2005	10.25%	4.78%	5.47%
5/25/2005	10.75%	4.76%	5.99%
5/26/2005	9.75%	4.76%	4.99%
6/1/2005	9.75%	4.75%	5.00%
7/19/2005	11.50%	4.64%	6.86%
8/5/2005	11.75%	4.62%	7.13%
8/15/2005	10.13%	4.61%	5.52%
9/28/2005	10.00%	4.54%	5.46%
10/4/2005	10.75%	4.53%	6.22%
12/12/2005	11.00%	4.55%	6.45%
12/13/2005	10.75%	4.55%	6.20%
12/21/2005	10.29%	4.54%	5.75%
12/21/2005	10.40%	4.54%	5.86%
12/22/2005	11.15%	4.54%	6.61%
12/22/2005	11.00%	4.54%	6.46%
12/28/2005	10.00%	4.54%	5.46%
12/28/2005	10.00%	4.54%	5.46%
1/5/2006	11.00%	4.53%	6.47%
1/27/2006	9.75%	4.52%	5.23%
3/3/2006	10.39%	4.53%	5.86%
4/17/2006	10.20%	4.62%	5.58%
4/26/2006	10.60%	4.64%	5.96%
5/17/2006	11.60%	4.69%	6.91%
6/6/2006	10.00%	4.75%	5.25%
6/27/2006	10.75%	4.80%	5.95%
7/6/2006	10.20%	4.83%	5.37%
7/24/2006	9.60%	4.86%	4.74%
7/26/2006	10.50%	4.86%	5.64%
7/28/2006	10.05%	4.87%	5.18%
8/23/2006	9.55%	4.89%	4.66%
9/1/2006	10.54%	4.90%	5.64%
9/14/2006	10.00%	4.91%	5.09%
10/6/2006	9.67%	4.92%	4.75%
11/21/2006	10.08%	4.95%	5.13%
11/21/2006	10.08%	4.95%	5.13%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
11/21/2006	10.12%	4.95%	5.17%
12/1/2006	10.25%	4.96%	5.29%
12/1/2006	10.50%	4.96%	5.54%
12/7/2006	10.75%	4.96%	5.79%
12/21/2006	11.25%	4.95%	6.30%
12/21/2006	10.90%	4.95%	5.95%
12/22/2006	10.25%	4.95%	5.30%
1/5/2007	10.00%	4.95%	5.05%
1/11/2007	10.90%	4.95%	5.95%
1/11/2007	10.10%	4.95%	5.15%
1/11/2007	10.10%	4.95%	5.15%
1/12/2007	10.10%	4.95%	5.15%
1/13/2007	10.40%	4.95%	5.45%
1/19/2007	10.80%	4.94%	5.86%
3/21/2007	11.35%	4.86%	6.49%
3/22/2007	9.75%	4.86%	4.89%
5/15/2007	10.00%	4.81%	5.19%
5/17/2007	10.25%	4.80%	5.45%
5/17/2007	10.25%	4.80%	5.45%
5/22/2007	10.20%	4.80%	5.40%
5/22/2007	10.50%	4.80%	5.70%
5/23/2007	10.70%	4.80%	5.90%
5/25/2007	9.67%	4.80%	4.87%
6/15/2007	9.90%	4.82%	5.08%
6/21/2007	10.20%	4.83%	5.37%
6/22/2007	10.50%	4.83%	5.67%
6/28/2007	10.75%	4.84%	5.91%
7/12/2007	9.67%	4.86%	4.81%
7/19/2007	10.00%	4.87%	5.13%
7/19/2007	10.00%	4.87%	5.13%
8/15/2007	10.40%	4.88%	5.52%
10/9/2007	10.00%	4.91%	5.09%
10/17/2007	9.10%	4.91%	4.19%
10/31/2007	9.96%	4.90%	5.06%
11/29/2007	10.90%	4.87%	6.03%
12/6/2007	10.75%	4.86%	5.89%
12/13/2007	9.96%	4.86%	5.10%
12/14/2007	10.80%	4.86%	5.94%
12/14/2007	10.70%	4.86%	5.84%
12/19/2007	10.20%	4.86%	5.34%
12/20/2007	10.20%	4.86%	5.34%
12/20/2007	11.00%	4.86%	6.14%
12/28/2007	10.25%	4.85%	5.40%
12/31/2007	11.25%	4.85%	6.40%
1/8/2008	10.75%	4.83%	5.92%
1/17/2008	10.75%	4.81%	5.94%
1/28/2008	9.40%	4.80%	4.60%
1/30/2008	10.00%	4.79%	5.21%
1/31/2008	10.71%	4.79%	5.92%
2/29/2008	10.25%	4.75%	5.50%
3/12/2008	10.25%	4.73%	5.52%
3/25/2008	9.10%	4.68%	4.42%
4/22/2008	10.25%	4.60%	5.65%
4/24/2008	10.10%	4.60%	5.50%
5/1/2008	10.70%	4.58%	6.12%
5/19/2008	11.00%	4.56%	6.44%
5/27/2008	10.00%	4.55%	5.45%
6/10/2008	10.70%	4.54%	6.16%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
6/27/2008	11.04%	4.54%	6.50%
6/27/2008	10.50%	4.54%	5.96%
7/10/2008	10.43%	4.52%	5.91%
7/16/2008	9.40%	4.51%	4.89%
7/30/2008	10.80%	4.51%	6.29%
7/31/2008	10.70%	4.51%	6.19%
8/11/2008	10.25%	4.50%	5.75%
8/26/2008	10.18%	4.50%	5.68%
9/10/2008	10.30%	4.50%	5.80%
9/24/2008	10.65%	4.48%	6.17%
9/24/2008	10.65%	4.48%	6.17%
9/24/2008	10.65%	4.48%	6.17%
9/30/2008	10.20%	4.47%	5.73%
10/8/2008	10.15%	4.46%	5.69%
11/13/2008	10.55%	4.45%	6.10%
11/17/2008	10.20%	4.44%	5.76%
12/1/2008	10.25%	4.39%	5.86%
12/23/2008	11.00%	4.27%	6.73%
12/29/2008	10.00%	4.24%	5.76%
12/29/2008	10.20%	4.24%	5.96%
12/31/2008	10.75%	4.22%	6.53%
1/14/2009	10.50%	4.15%	6.35%
1/21/2009	10.50%	4.11%	6.39%
1/21/2009	10.50%	4.11%	6.39%
1/21/2009	10.50%	4.11%	6.39%
1/27/2009	10.76%	4.09%	6.67%
1/30/2009	10.50%	4.07%	6.43%
2/4/2009	8.75%	4.06%	4.69%
3/4/2009	10.50%	3.96%	6.54%
3/12/2009	11.50%	3.93%	7.57%
4/2/2009	11.10%	3.85%	7.25%
4/21/2009	10.61%	3.80%	6.81%
4/24/2009	10.00%	3.78%	6.22%
4/30/2009	11.25%	3.77%	7.48%
5/4/2009	10.74%	3.77%	6.97%
5/20/2009	10.25%	3.74%	6.51%
5/28/2009	10.50%	3.74%	6.76%
6/22/2009	10.00%	3.76%	6.24%
6/24/2009	10.80%	3.76%	7.04%
7/8/2009	10.63%	3.76%	6.87%
7/17/2009	10.50%	3.77%	6.73%
8/21/2009	10.25%	3.80%	6.45%
8/31/2009	10.25%	3.82%	6.43%
10/14/2009	10.70%	4.02%	6.68%
10/23/2009	10.88%	4.06%	6.82%
11/2/2009	10.70%	4.10%	6.60%
11/3/2009	10.70%	4.10%	6.60%
11/24/2009	10.25%	4.16%	6.09%
11/25/2009	10.75%	4.16%	6.59%
11/30/2009	10.35%	4.17%	6.18%
12/3/2009	10.50%	4.18%	6.32%
12/7/2009	10.70%	4.19%	6.51%
12/16/2009	11.00%	4.22%	6.78%
12/16/2009	10.90%	4.22%	6.68%
12/18/2009	10.40%	4.22%	6.18%
12/18/2009	10.40%	4.22%	6.18%
12/22/2009	10.20%	4.23%	5.97%
12/22/2009	10.40%	4.23%	6.17%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/22/2009	10.40%	4.23%	6.17%
12/30/2009	10.00%	4.26%	5.74%
1/4/2010	10.80%	4.28%	6.52%
1/11/2010	11.00%	4.31%	6.69%
1/26/2010	10.13%	4.35%	5.78%
1/27/2010	10.40%	4.36%	6.04%
1/27/2010	10.40%	4.36%	6.04%
1/27/2010	10.70%	4.36%	6.34%
2/9/2010	9.80%	4.38%	5.42%
2/18/2010	10.60%	4.40%	6.20%
2/24/2010	10.18%	4.41%	5.77%
3/2/2010	9.63%	4.41%	5.22%
3/4/2010	10.50%	4.41%	6.09%
3/5/2010	10.50%	4.41%	6.09%
3/11/2010	11.90%	4.42%	7.48%
3/17/2010	10.00%	4.41%	5.59%
3/25/2010	10.15%	4.42%	5.73%
4/2/2010	10.10%	4.43%	5.67%
4/27/2010	10.00%	4.46%	5.54%
4/29/2010	9.90%	4.46%	5.44%
4/29/2010	10.06%	4.46%	5.60%
4/29/2010	10.26%	4.46%	5.80%
5/12/2010	10.30%	4.45%	5.85%
5/12/2010	10.30%	4.45%	5.85%
5/28/2010	10.10%	4.44%	5.66%
5/28/2010	10.20%	4.44%	5.76%
6/7/2010	10.30%	4.44%	5.86%
6/16/2010	10.00%	4.44%	5.56%
6/28/2010	9.67%	4.43%	5.24%
6/28/2010	10.50%	4.43%	6.07%
6/30/2010	9.40%	4.43%	4.97%
7/1/2010	10.25%	4.43%	5.82%
7/15/2010	10.53%	4.43%	6.10%
7/15/2010	10.70%	4.43%	6.27%
7/30/2010	10.70%	4.41%	6.29%
8/4/2010	10.50%	4.41%	6.09%
8/6/2010	9.83%	4.41%	5.42%
8/25/2010	9.90%	4.37%	5.53%
9/3/2010	10.60%	4.35%	6.25%
9/14/2010	10.70%	4.33%	6.37%
9/16/2010	10.00%	4.32%	5.68%
9/16/2010	10.00%	4.32%	5.68%
9/30/2010	9.75%	4.28%	5.47%
10/14/2010	10.35%	4.24%	6.11%
10/28/2010	10.70%	4.21%	6.49%
11/2/2010	10.38%	4.20%	6.18%
11/4/2010	10.70%	4.19%	6.51%
11/19/2010	10.20%	4.17%	6.03%
11/22/2010	10.00%	4.17%	5.83%
12/1/2010	10.13%	4.16%	5.97%
12/6/2010	9.86%	4.15%	5.71%
12/9/2010	10.25%	4.15%	6.10%
12/13/2010	10.70%	4.15%	6.55%
12/14/2010	10.13%	4.15%	5.98%
12/15/2010	10.44%	4.15%	6.29%
12/17/2010	10.00%	4.14%	5.86%
12/20/2010	10.60%	4.14%	6.46%
12/21/2010	10.30%	4.14%	6.16%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/27/2010	9.90%	4.14%	5.76%
12/29/2010	11.15%	4.14%	7.01%
1/5/2011	10.15%	4.13%	6.02%
1/12/2011	10.30%	4.12%	6.18%
1/13/2011	10.30%	4.12%	6.18%
1/18/2011	10.00%	4.12%	5.88%
1/20/2011	9.30%	4.12%	5.18%
1/20/2011	10.13%	4.12%	6.01%
1/31/2011	9.60%	4.11%	5.49%
2/3/2011	10.00%	4.11%	5.89%
2/25/2011	10.00%	4.14%	5.86%
3/25/2011	9.80%	4.18%	5.62%
3/30/2011	10.00%	4.18%	5.82%
4/12/2011	10.00%	4.21%	5.79%
4/25/2011	10.74%	4.23%	6.51%
4/26/2011	9.67%	4.24%	5.43%
4/27/2011	10.40%	4.24%	6.16%
5/4/2011	10.00%	4.25%	5.75%
5/4/2011	10.00%	4.25%	5.75%
5/24/2011	10.50%	4.27%	6.23%
6/8/2011	10.75%	4.30%	6.45%
6/16/2011	9.20%	4.32%	4.88%
6/17/2011	9.95%	4.32%	5.63%
7/13/2011	10.20%	4.37%	5.83%
8/1/2011	9.20%	4.39%	4.81%
8/8/2011	10.00%	4.38%	5.62%
8/11/2011	10.00%	4.38%	5.62%
8/12/2011	10.35%	4.38%	5.97%
8/19/2011	10.25%	4.36%	5.89%
9/2/2011	12.88%	4.32%	8.56%
9/22/2011	10.00%	4.24%	5.76%
10/12/2011	10.30%	4.14%	6.16%
10/20/2011	10.50%	4.10%	6.40%
11/30/2011	10.90%	3.87%	7.03%
11/30/2011	10.90%	3.87%	7.03%
12/14/2011	10.00%	3.79%	6.21%
12/14/2011	10.30%	3.79%	6.51%
12/20/2011	10.20%	3.76%	6.44%
12/21/2011	10.20%	3.75%	6.45%
12/22/2011	9.90%	3.75%	6.15%
12/22/2011	10.40%	3.75%	6.65%
12/23/2011	10.19%	3.74%	6.45%
1/25/2012	10.50%	3.57%	6.93%
1/27/2012	10.50%	3.55%	6.95%
2/15/2012	10.20%	3.47%	6.73%
2/23/2012	9.90%	3.43%	6.47%
2/27/2012	10.25%	3.42%	6.83%
2/29/2012	10.40%	3.41%	6.99%
3/29/2012	10.37%	3.31%	7.06%
4/4/2012	10.00%	3.29%	6.71%
4/26/2012	10.00%	3.20%	6.80%
5/2/2012	10.00%	3.18%	6.82%
5/7/2012	9.80%	3.16%	6.64%
5/15/2012	10.00%	3.14%	6.86%
5/29/2012	10.05%	3.11%	6.94%
6/7/2012	10.30%	3.07%	7.23%
6/14/2012	9.40%	3.06%	6.34%
6/15/2012	10.40%	3.06%	7.34%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
6/18/2012	9.60%	3.05%	6.55%
6/19/2012	9.25%	3.05%	6.20%
6/26/2012	10.10%	3.04%	7.06%
6/29/2012	10.00%	3.04%	6.96%
7/9/2012	10.20%	3.03%	7.17%
7/16/2012	9.80%	3.02%	6.78%
7/20/2012	9.81%	3.01%	6.80%
7/20/2012	9.31%	3.01%	6.30%
9/13/2012	9.80%	2.94%	6.86%
9/19/2012	10.05%	2.94%	7.11%
9/19/2012	9.80%	2.94%	6.86%
9/26/2012	9.50%	2.94%	6.56%
10/12/2012	9.60%	2.93%	6.67%
10/23/2012	9.75%	2.93%	6.82%
10/24/2012	10.30%	2.93%	7.37%
11/9/2012	10.30%	2.92%	7.38%
11/28/2012	10.40%	2.90%	7.50%
11/29/2012	9.75%	2.89%	6.86%
11/29/2012	9.88%	2.89%	6.99%
12/5/2012	10.40%	2.89%	7.51%
12/5/2012	9.71%	2.89%	6.82%
12/12/2012	9.80%	2.88%	6.92%
12/13/2012	10.50%	2.88%	7.62%
12/13/2012	9.50%	2.88%	6.62%
12/14/2012	10.40%	2.88%	7.52%
12/19/2012	9.71%	2.87%	6.84%
12/19/2012	10.25%	2.87%	7.38%
12/20/2012	9.80%	2.87%	6.93%
12/20/2012	10.40%	2.87%	7.53%
12/20/2012	10.30%	2.87%	7.43%
12/20/2012	10.45%	2.87%	7.58%
12/20/2012	9.50%	2.87%	6.63%
12/20/2012	10.25%	2.87%	7.38%
12/20/2012	10.25%	2.87%	7.38%
12/21/2012	10.20%	2.87%	7.33%
12/26/2012	9.80%	2.86%	6.94%
1/9/2013	9.70%	2.84%	6.86%
1/9/2013	9.70%	2.84%	6.86%
1/9/2013	9.70%	2.84%	6.86%
1/16/2013	9.60%	2.84%	6.76%
1/16/2013	9.60%	2.84%	6.76%
2/13/2013	10.20%	2.84%	7.36%
2/22/2013	9.75%	2.85%	6.90%
2/27/2013	10.00%	2.86%	7.14%
3/14/2013	9.30%	2.88%	6.42%
3/27/2013	9.80%	2.90%	6.90%
5/1/2013	9.84%	2.94%	6.90%
5/15/2013	10.30%	2.96%	7.34%
5/30/2013	10.20%	2.98%	7.22%
5/31/2013	9.00%	2.98%	6.02%
6/11/2013	10.00%	3.00%	7.00%
6/21/2013	9.75%	3.02%	6.73%
6/25/2013	9.80%	3.03%	6.77%
7/12/2013	9.36%	3.08%	6.28%
8/8/2013	9.83%	3.14%	6.69%
8/14/2013	9.15%	3.16%	5.99%
9/11/2013	10.20%	3.27%	6.93%
9/11/2013	10.25%	3.27%	6.98%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
9/24/2013	10.20%	3.31%	6.89%
10/3/2013	9.65%	3.33%	6.32%
11/6/2013	10.20%	3.41%	6.79%
11/21/2013	10.00%	3.44%	6.56%
11/26/2013	10.00%	3.45%	6.55%
12/3/2013	10.25%	3.47%	6.78%
12/4/2013	9.50%	3.47%	6.03%
12/5/2013	10.20%	3.48%	6.72%
12/9/2013	9.75%	3.49%	6.26%
12/9/2013	8.72%	3.49%	5.23%
12/13/2013	9.75%	3.50%	6.25%
12/16/2013	9.95%	3.50%	6.45%
12/16/2013	9.95%	3.50%	6.45%
12/16/2013	10.12%	3.50%	6.62%
12/17/2013	9.50%	3.51%	5.99%
12/17/2013	10.95%	3.51%	7.44%
12/18/2013	9.80%	3.51%	6.29%
12/18/2013	8.72%	3.51%	5.21%
12/19/2013	10.15%	3.51%	6.64%
12/30/2013	9.50%	3.54%	5.96%
2/20/2014	9.20%	3.69%	5.51%
2/26/2014	9.75%	3.70%	6.05%
3/17/2014	9.55%	3.72%	5.83%
3/26/2014	9.96%	3.73%	6.23%
3/26/2014	9.40%	3.73%	5.67%
4/2/2014	9.70%	3.73%	5.97%
5/16/2014	9.80%	3.70%	6.10%
5/30/2014	9.70%	3.68%	6.02%
6/6/2014	10.40%	3.67%	6.73%
6/30/2014	9.55%	3.64%	5.91%
7/2/2014	9.62%	3.64%	5.98%
7/10/2014	9.95%	3.63%	6.32%
7/23/2014	9.75%	3.61%	6.14%
7/29/2014	9.45%	3.60%	5.85%
7/31/2014	9.90%	3.60%	6.30%
8/20/2014	9.75%	3.56%	6.19%
8/25/2014	9.60%	3.56%	6.04%
8/29/2014	9.80%	3.54%	6.26%
9/11/2014	9.60%	3.51%	6.09%
9/15/2014	10.25%	3.51%	6.74%
10/9/2014	9.80%	3.44%	6.36%
11/6/2014	9.56%	3.37%	6.19%
11/6/2014	10.20%	3.37%	6.83%
11/14/2014	10.20%	3.35%	6.85%
11/26/2014	9.70%	3.32%	6.38%
11/26/2014	10.20%	3.32%	6.88%
12/4/2014	9.68%	3.30%	6.38%
12/10/2014	9.25%	3.29%	5.96%
12/10/2014	9.25%	3.29%	5.96%
12/11/2014	10.07%	3.28%	6.79%
12/12/2014	10.20%	3.28%	6.92%
12/17/2014	9.17%	3.27%	5.90%
12/18/2014	9.83%	3.26%	6.57%
1/23/2015	9.50%	3.14%	6.36%
2/24/2015	9.83%	3.04%	6.79%
3/18/2015	9.75%	2.98%	6.77%
3/25/2015	9.50%	2.95%	6.55%
3/26/2015	9.72%	2.95%	6.77%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
4/23/2015	10.20%	2.87%	7.33%
4/29/2015	9.53%	2.86%	6.67%
5/1/2015	9.60%	2.85%	6.75%
5/26/2015	9.75%	2.83%	6.92%
6/17/2015	9.00%	2.82%	6.18%
6/17/2015	9.00%	2.82%	6.18%
9/2/2015	9.50%	2.79%	6.71%
9/10/2015	9.30%	2.79%	6.51%
9/25/2015	9.60%	2.80%	6.80%
10/15/2015	9.00%	2.81%	6.19%
11/19/2015	10.30%	2.88%	7.42%
11/19/2015	10.00%	2.88%	7.12%
12/3/2015	10.00%	2.90%	7.10%
12/9/2015	9.14%	2.90%	6.24%
12/9/2015	9.14%	2.90%	6.24%
12/11/2015	10.30%	2.90%	7.40%
12/15/2015	9.60%	2.91%	6.69%
12/17/2015	9.70%	2.91%	6.79%
12/18/2015	9.50%	2.91%	6.59%
12/30/2015	9.50%	2.93%	6.57%
1/6/2016	9.50%	2.94%	6.56%
2/23/2016	9.75%	2.94%	6.81%
3/16/2016	9.85%	2.91%	6.94%
4/29/2016	9.80%	2.83%	6.97%
6/3/2016	9.75%	2.80%	6.95%
6/8/2016	9.48%	2.80%	6.68%
6/15/2016	9.00%	2.78%	6.22%
6/15/2016	9.00%	2.78%	6.22%
7/18/2016	9.98%	2.71%	7.27%
8/9/2016	9.85%	2.66%	7.19%
8/18/2016	9.50%	2.63%	6.87%
8/24/2016	9.75%	2.61%	7.14%
9/1/2016	9.50%	2.59%	6.91%
9/8/2016	10.00%	2.57%	7.43%
9/28/2016	9.58%	2.53%	7.05%
9/30/2016	9.90%	2.53%	7.37%
11/9/2016	9.80%	2.48%	7.32%
11/10/2016	9.50%	2.48%	7.02%
11/15/2016	9.55%	2.49%	7.06%
11/18/2016	10.00%	2.50%	7.50%
11/29/2016	10.55%	2.51%	8.04%
12/1/2016	10.00%	2.51%	7.49%
12/6/2016	8.64%	2.52%	6.12%
12/6/2016	8.64%	2.52%	6.12%
12/7/2016	10.10%	2.52%	7.58%
12/12/2016	9.60%	2.53%	7.07%
12/14/2016	9.10%	2.53%	6.57%
12/19/2016	9.00%	2.54%	6.46%
12/19/2016	9.37%	2.54%	6.83%
12/22/2016	9.90%	2.55%	7.35%
12/22/2016	9.60%	2.55%	7.05%
12/28/2016	9.50%	2.55%	6.95%
1/18/2017	9.45%	2.58%	6.87%
1/24/2017	9.00%	2.59%	6.41%
1/31/2017	10.10%	2.60%	7.50%
2/15/2017	9.60%	2.62%	6.98%
2/22/2017	9.60%	2.64%	6.96%
2/24/2017	9.75%	2.64%	7.11%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
2/24/2017	9.60%	2.64%	6.96%
2/28/2017	10.10%	2.64%	7.46%
3/2/2017	9.41%	2.65%	6.76%
3/20/2017	9.50%	2.68%	6.82%
4/4/2017	10.25%	2.72%	7.53%
4/12/2017	9.40%	2.74%	6.66%
4/20/2017	9.50%	2.76%	6.74%
5/3/2017	9.50%	2.79%	6.71%
5/11/2017	9.20%	2.81%	6.39%
5/18/2017	9.50%	2.83%	6.67%
5/23/2017	9.70%	2.84%	6.86%
6/16/2017	9.65%	2.89%	6.76%
6/22/2017	9.70%	2.90%	6.80%
6/22/2017	9.70%	2.90%	6.80%
7/24/2017	9.50%	2.95%	6.55%
8/15/2017	10.00%	2.97%	7.03%
9/22/2017	9.60%	2.93%	6.67%
9/28/2017	9.80%	2.92%	6.88%
10/20/2017	9.50%	2.91%	6.59%
10/26/2017	10.25%	2.91%	7.34%
10/26/2017	10.20%	2.91%	7.29%
10/26/2017	10.30%	2.91%	7.39%
11/6/2017	10.25%	2.90%	7.35%
11/15/2017	11.95%	2.89%	9.06%
11/30/2017	10.00%	2.88%	7.12%
11/30/2017	10.00%	2.88%	7.12%
12/5/2017	9.50%	2.88%	6.62%
12/6/2017	8.40%	2.87%	5.53%
12/6/2017	8.40%	2.87%	5.53%
12/7/2017	9.80%	2.87%	6.93%
12/14/2017	9.60%	2.86%	6.74%
12/14/2017	9.65%	2.86%	6.79%
12/18/2017	9.50%	2.86%	6.64%
12/20/2017	9.58%	2.85%	6.73%
12/21/2017	9.10%	2.85%	6.25%
12/28/2017	9.50%	2.85%	6.65%
12/29/2017	9.51%	2.85%	6.66%
1/18/2018	9.70%	2.84%	6.86%
1/31/2018	9.30%	2.84%	6.46%
2/2/2018	9.98%	2.84%	7.14%
2/23/2018	9.90%	2.85%	7.05%
3/12/2018	9.25%	2.86%	6.39%
3/15/2018	9.00%	2.87%	6.13%
3/29/2018	10.00%	2.88%	7.12%
4/12/2018	9.90%	2.89%	7.01%
4/13/2018	9.73%	2.89%	6.84%
4/18/2018	10.00%	2.89%	7.11%
4/18/2018	9.25%	2.89%	6.36%
4/26/2018	9.50%	2.90%	6.60%
5/30/2018	9.95%	2.94%	7.01%
5/31/2018	9.50%	2.94%	6.56%
6/14/2018	8.80%	2.96%	5.84%
6/22/2018	9.50%	2.97%	6.53%
6/22/2018	9.90%	2.97%	6.93%
6/28/2018	9.35%	2.97%	6.38%
6/29/2018	9.50%	2.97%	6.53%
8/8/2018	9.53%	2.99%	6.54%
8/21/2018	9.70%	3.00%	6.70%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
8/24/2018	9.28%	3.01%	6.27%
9/5/2018	9.56%	3.02%	6.54%
9/14/2018	10.00%	3.03%	6.97%
9/20/2018	9.80%	3.04%	6.76%
9/26/2018	10.00%	3.05%	6.95%
9/26/2018	9.77%	3.05%	6.72%
9/27/2018	9.30%	3.05%	6.25%
10/4/2018	9.85%	3.06%	6.79%
10/29/2018	9.60%	3.10%	6.50%
10/31/2018	9.99%	3.11%	6.88%
11/1/2018	8.69%	3.11%	5.58%
12/4/2018	8.69%	3.14%	5.55%
12/13/2018	9.30%	3.14%	6.16%
12/14/2018	9.50%	3.14%	6.36%
12/19/2018	9.84%	3.14%	6.70%
12/20/2018	9.65%	3.14%	6.51%
12/21/2018	9.30%	3.14%	6.16%
1/9/2019	10.00%	3.14%	6.86%
2/27/2019	9.75%	3.12%	6.63%
3/13/2019	9.60%	3.12%	6.48%
3/14/2019	9.00%	3.12%	5.88%
3/14/2019	9.40%	3.12%	6.28%
3/22/2019	9.65%	3.12%	6.53%
4/30/2019	9.73%	3.11%	6.62%
4/30/2019	9.73%	3.11%	6.62%
5/1/2019	9.50%	3.11%	6.39%
5/2/2019	10.00%	3.11%	6.89%
5/8/2019	9.50%	3.10%	6.40%
5/14/2019	8.75%	3.10%	5.65%
5/16/2019	9.50%	3.09%	6.41%
5/23/2019	9.90%	3.09%	6.81%
8/12/2019	9.60%	2.89%	6.71%
8/29/2019	9.06%	2.81%	6.25%
9/4/2019	10.00%	2.78%	7.22%
9/30/2019	9.60%	2.70%	6.90%
10/31/2019	10.00%	2.60%	7.40%
10/31/2019	10.00%	2.60%	7.40%
11/7/2019	9.35%	2.58%	6.77%
11/29/2019	9.50%	2.52%	6.98%
12/4/2019	9.75%	2.51%	7.24%
12/4/2019	8.91%	2.51%	6.40%
12/16/2019	8.91%	2.48%	6.43%
12/17/2019	9.70%	2.47%	7.23%
12/17/2019	10.50%	2.47%	8.03%
12/19/2019	10.25%	2.47%	7.78%
12/19/2019	10.20%	2.47%	7.73%
12/19/2019	10.30%	2.47%	7.83%
12/20/2019	9.65%	2.46%	7.19%
12/20/2019	9.45%	2.46%	6.99%
12/24/2019	9.70%	2.46%	7.24%
1/8/2020	10.02%	2.43%	7.59%
1/16/2020	8.80%	2.41%	6.39%
1/22/2020	9.50%	2.39%	7.11%
1/23/2020	9.86%	2.39%	7.47%
2/6/2020	10.00%	2.34%	7.66%
2/11/2020	9.30%	2.33%	6.97%
2/14/2020	9.40%	2.32%	7.08%
2/19/2020	8.25%	2.31%	5.94%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
2/24/2020	9.75%	2.29%	7.46%
2/27/2020	9.40%	2.28%	7.12%
3/11/2020	9.70%	2.23%	7.47%
3/25/2020	9.40%	2.17%	7.23%
4/17/2020	9.70%	2.07%	7.63%
4/27/2020	9.25%	2.02%	7.23%
5/8/2020	9.90%	1.97%	7.93%
5/20/2020	9.45%	1.94%	7.51%
6/29/2020	9.70%	1.85%	7.85%
6/30/2020	9.10%	1.85%	7.25%
7/1/2020	9.25%	1.84%	7.41%
7/8/2020	9.40%	1.82%	7.58%
7/14/2020	9.60%	1.81%	7.79%
7/28/2020	9.50%	1.76%	7.74%
8/27/2020	10.00%	1.66%	8.34%
8/27/2020	9.45%	1.66%	7.79%
8/27/2020	8.20%	1.66%	6.54%
10/22/2020	9.50%	1.49%	8.01%
10/28/2020	9.60%	1.48%	8.12%
11/19/2020	8.80%	1.45%	7.35%
11/19/2020	8.80%	1.45%	7.35%
11/24/2020	9.20%	1.44%	7.76%
11/24/2020	9.80%	1.44%	8.36%
12/9/2020	8.38%	1.43%	6.95%
12/9/2020	8.38%	1.43%	6.95%
12/10/2020	9.40%	1.43%	7.97%
12/14/2020	9.50%	1.44%	8.06%
12/15/2020	9.30%	1.44%	7.86%
12/16/2020	9.50%	1.44%	8.06%
12/17/2020	9.90%	1.44%	8.46%
12/18/2020	9.50%	1.44%	8.06%
12/22/2020	9.15%	1.44%	7.71%
12/23/2020	10.00%	1.44%	8.56%
12/30/2020	9.65%	1.45%	8.20%
1/13/2021	9.30%	1.47%	7.83%
3/31/2021	9.60%	1.68%	7.92%
4/16/2021	9.60%	1.73%	7.87%
5/4/2021	9.85%	1.79%	8.06%
5/18/2021	9.50%	1.85%	7.65%
6/4/2021	9.28%	1.90%	7.38%
6/23/2021	9.00%	1.95%	7.05%
6/28/2021	9.55%	1.96%	7.59%
6/30/2021	9.43%	1.97%	7.46%
6/30/2021	9.43%	1.97%	7.46%
7/14/2021	9.60%	1.99%	7.61%
7/15/2021	9.38%	1.99%	7.39%
7/21/2021	9.50%	2.00%	7.50%
8/5/2021	9.60%	2.02%	7.58%
8/18/2021	9.50%	2.03%	7.47%
8/31/2021	8.57%	2.04%	6.53%
9/1/2021	9.40%	2.05%	7.35%
9/27/2021	9.40%	2.07%	7.33%
10/21/2021	9.95%	2.10%	7.85%
10/26/2021	10.60%	2.10%	8.50%
10/28/2021	9.35%	2.10%	7.25%
11/2/2021	8.90%	2.11%	6.79%
11/4/2021	9.48%	2.11%	7.37%
11/17/2021	9.70%	2.11%	7.59%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
11/18/2021	9.00%	2.11%	6.89%
11/18/2021	9.25%	2.11%	7.14%
11/18/2021	9.35%	2.11%	7.24%
11/18/2021	10.00%	2.11%	7.89%
11/18/2021	10.00%	2.11%	7.89%
11/23/2021	9.80%	2.11%	7.69%
12/1/2021	7.36%	2.10%	5.26%
12/7/2021	9.65%	2.09%	7.56%
12/13/2021	7.36%	2.08%	5.28%
12/15/2021	9.60%	2.08%	7.52%
12/22/2021	9.90%	2.06%	7.84%
12/28/2021	9.40%	2.05%	7.35%
1/20/2022	9.00%	2.03%	6.97%
2/16/2022	9.35%	2.02%	7.33%
2/23/2022	9.70%	2.02%	7.68%
3/16/2022	9.30%	2.02%	7.28%
4/14/2022	9.20%	2.07%	7.13%
4/25/2022	9.50%	2.11%	7.39%
5/12/2022	9.20%	2.18%	7.02%
5/23/2022	9.50%	2.22%	7.28%
8/31/2022	8.57%	2.64%	5.93%
9/8/2022	9.50%	2.69%	6.81%
9/15/2022	9.35%	2.73%	6.62%
10/4/2022	10.10%	2.85%	7.25%
10/4/2022	10.80%	2.85%	7.95%
10/25/2022	9.50%	3.00%	6.50%
11/3/2022	10.25%	3.07%	7.18%
11/3/2022	10.20%	3.07%	7.13%
11/3/2022	10.30%	3.07%	7.23%
11/17/2022	7.85%	3.16%	4.69%
11/18/2022	9.90%	3.17%	6.73%
11/30/2022	9.80%	3.23%	6.57%
12/1/2022	7.85%	3.24%	4.61%
12/14/2022	10.00%	3.30%	6.70%
12/14/2022	9.50%	3.30%	6.20%
12/14/2022	9.60%	3.30%	6.30%
12/15/2022	10.00%	3.30%	6.70%
12/15/2022	9.95%	3.30%	6.65%
12/15/2022	10.05%	3.30%	6.75%
12/16/2022	9.50%	3.31%	6.19%
12/20/2022	10.50%	3.32%	7.18%
12/22/2022	9.40%	3.33%	6.07%
12/22/2022	9.80%	3.33%	6.47%
12/27/2022	9.56%	3.35%	6.21%
12/29/2022	9.30%	3.37%	5.93%
12/29/2022	9.80%	3.37%	6.43%
1/19/2023	9.90%	3.45%	6.45%
1/23/2023	9.65%	3.45%	6.20%
1/26/2023	9.75%	3.47%	6.28%
2/9/2023	9.60%	3.50%	6.10%
2/17/2023	9.50%	3.52%	5.98%
3/9/2023	9.70%	3.58%	6.12%
3/24/2023	9.90%	3.61%	6.29%
4/27/2023	10.00%	3.67%	6.33%
5/31/2023	9.35%	3.76%	5.59%
6/1/2023	9.25%	3.76%	5.49%
6/6/2023	9.75%	3.77%	5.98%
6/6/2023	9.35%	3.77%	5.58%

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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
7/20/2023	9.25%	3.82%	5.43%
8/2/2023	9.80%	3.81%	5.99%
8/3/2023	9.57%	3.81%	5.76%
8/18/2023	9.80%	3.82%	5.98%
8/23/2023	9.58%	3.82%	5.76%
8/25/2023	9.55%	3.83%	5.72%
8/25/2023	8.63%	3.83%	4.80%
8/31/2023	11.45%	3.84%	7.61%
8/31/2023	9.40%	3.84%	5.56%
9/6/2023	9.30%	3.85%	5.45%
9/21/2023	9.65%	3.90%	5.75%
10/12/2023	9.20%	3.97%	5.23%
10/12/2023	9.20%	3.97%	5.23%
10/12/2023	9.75%	3.97%	5.78%
10/18/2023	9.50%	3.99%	5.51%
10/19/2023	9.50%	4.00%	5.50%
10/25/2023	9.65%	4.03%	5.62%
11/3/2023	9.30%	4.08%	5.22%
11/3/2023	9.70%	4.08%	5.62%
11/9/2023	9.80%	4.10%	5.70%
11/9/2023	9.80%	4.10%	5.70%
11/17/2023	9.60%	4.13%	5.47%
11/28/2023	9.35%	4.15%	5.20%
12/1/2023	9.90%	4.16%	5.74%
12/7/2023	9.70%	4.17%	5.53%
12/14/2023	8.91%	4.18%	4.73%
12/14/2023	8.72%	4.18%	4.54%
12/14/2023	10.00%	4.18%	5.82%
12/14/2023	9.50%	4.18%	5.32%
12/15/2023	10.10%	4.18%	5.92%
12/18/2023	9.50%	4.18%	5.32%
12/22/2023	10.70%	4.19%	6.51%
12/22/2023	10.65%	4.19%	6.46%
12/22/2023	10.75%	4.19%	6.56%
12/26/2023	9.52%	4.19%	5.33%
12/28/2023	9.60%	4.19%	5.41%
1/3/2024	9.26%	4.20%	5.06%
1/19/2024	9.75%	4.23%	5.52%
1/30/2024	9.75%	4.26%	5.49%
2/14/2024	9.60%	4.29%	5.31%
2/28/2024	9.70%	4.31%	5.39%
3/1/2024	9.90%	4.32%	5.58%
3/5/2024	9.55%	4.32%	5.23%
3/26/2024	9.80%	4.36%	5.44%
4/17/2024	9.90%	4.41%	5.49%
4/18/2024	9.60%	4.41%	5.19%
5/8/2024	9.85%	4.46%	5.39%
6/10/2024	9.50%	4.50%	5.00%
6/20/2024	9.94%	4.50%	5.44%
6/28/2024	9.40%	4.50%	4.90%
7/2/2024	9.86%	4.50%	5.36%
7/18/2024	9.50%	4.47%	5.03%
8/8/2024	9.94%	4.43%	5.51%
8/21/2024	10.30%	4.40%	5.90%
8/26/2024	9.97%	4.39%	5.58%
9/17/2024	9.87%	4.36%	5.51%
9/18/2024	9.74%	4.36%	5.38%
9/23/2024	9.50%	4.36%	5.14%

Exhibit JEN-8
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[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
9/26/2024	9.86%	4.37%	5.49%
9/30/2024	9.35%	4.37%	4.98%
10/3/2024	9.76%	4.37%	5.39%
10/9/2024	9.60%	4.37%	5.23%
10/10/2024	9.86%	4.37%	5.49%
10/17/2024	10.28%	4.38%	5.90%
10/17/2024	10.23%	4.38%	5.85%
10/17/2024	10.33%	4.38%	5.95%
10/24/2024	9.78%	4.38%	5.40%
11/20/2024	9.75%	4.40%	5.35%
11/25/2024	9.50%	4.41%	5.09%
11/26/2024	9.50%	4.41%	5.09%
12/3/2024	10.50%	4.41%	6.09%
12/19/2024	9.50%	4.42%	5.08%
12/19/2024	9.80%	4.42%	5.38%
12/19/2024	9.80%	4.42%	5.38%
12/20/2024	9.34%	4.42%	4.92%
12/20/2024	9.80%	4.42%	5.38%
12/30/2024	10.10%	4.43%	5.67%
1/14/2025	9.95%	4.45%	5.50%
1/15/2025	9.50%	4.45%	5.05%
1/15/2025	9.90%	4.45%	5.45%
1/16/2025	10.00%	4.45%	5.55%
1/23/2025	9.90%	4.46%	5.44%
1/29/2025	9.75%	4.46%	5.29%
2/3/2025	9.80%	4.46%	5.34%
3/4/2025	10.15%	4.46%	5.69%
3/12/2025	9.40%	4.46%	4.94%
3/13/2025	9.35%	4.46%	4.89%
3/13/2025	9.65%	4.46%	5.19%
3/20/2025	9.75%	4.47%	5.28%
3/21/2025	9.90%	4.47%	5.43%
3/25/2025	9.10%	4.47%	4.63%
4/25/2025	9.38%	4.50%	4.88%
5/15/2025	9.45%	4.53%	4.92%
6/20/2025	9.60%	4.64%	4.96%
6/26/2025	9.75%	4.66%	5.09%
		# of Cases	1,834

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Jennifer E. Nelson

RATE OF RETURN ON EQUITY

Exh. JEN-9

August 29, 2025

Exhibit JEN-9
Page 1 of 1

Proxy Group Regulatory Risk Comparative Assessment

Company	Parent	Jurisdiction	Natural Gas Commodity	Volumetric Risk Mechanism (F/P) [1]	New Capital Investment [2]	Energy Efficiency [3]	Other [4]	Test Year	Rate Base Methodology	Formula-Based Rates / Annual Rate Review Mechanism
Atmos Energy	ATO	Colorado	✓	P	✓	✓	✓	Historical	Average	
Atmos Energy	ATO	Kansas	✓	P	✓		✓	Historical	Year End	
Atmos Energy	ATO	Kentucky	✓	P	✓	✓	✓	Historical	Year End	
Atmos Energy	ATO	Louisiana — PSC	✓	P	✓	✓	✓	Historical	Average	✓
Atmos Energy	ATO	Mississippi	✓	P	✓	✓	✓	Forecast Permitted	Average	✓
Atmos Energy	ATO	Tennessee	✓	P	✓		✓	Forecast	Average	✓
Atmos Energy	ATO	Texas — RRC	✓	P	✓	✓	✓	Historical	Year End	✓
Atmos Energy	ATO	Virginia	✓	P	✓			Forecast Permitted	Average	
New Jersey Natural Gas	NJR	New Jersey	✓	F	✓	✓	✓	Partially Forecast	Year End	
Northern Indiana Public Service Co.	NI	Indiana	✓	P	✓	✓	✓	Forecast	Year End	
Columbia Gas of Kentucky Inc	NI	Kentucky	✓	P	✓	✓	✓	Historical	Year End	
Columbia Gas of Maryland Inc.	NI	Maryland	✓	P	✓	✓	✓	Forecast Permitted	Average	
Columbia Gas of Ohio Inc.	NI	Ohio	NA	F	✓	✓	✓	Partially Forecast	Year End	
Columbia Gas of Pennsylvania Inc.	NI	Pennsylvania	✓	P	✓	✓	✓	Forecast	Year End	
Columbia Gas of Virginia Inc.	NI	Virginia	✓	F	✓	✓	✓	Forecast Permitted	Average	
Kansas Gas Service	OGS	Kansas	✓	P	✓		✓	Historical	Year End	
Oklahoma Natural Gas	OGS	Oklahoma	✓	P	✓	✓	✓	Historical	Year End	✓
Texas Gas Service	OGS	Texas — RRC	✓	P	✓	✓	✓	Historical	Year End	
Southwest Gas Corp	SWX	Arizona	✓	F		✓	✓	Historical	Year End	
Southwest Gas Corp	SWX	California	✓	F	✓	✓	✓	Forecast	Average	
Southwest Gas Corp	SWX	Nevada	✓	F	✓	✓	✓	Forecast Permitted	Year End	
Spire Alabama	SR	Alabama	✓	P	✓		✓	Historical	Year End	✓
Spire Gulf, Inc.	SR	Alabama	✓	P	✓		✓	Historical	Year End	✓
Spire Mississippi	SR	Mississippi	✓	P	✓	✓		Forecast Permitted	Average	✓
Spire Missouri - East	SR	Missouri	✓	P	✓		✓	Partially Forecast	Year End	
Spire Missouri - West	SR	Missouri	✓	P	✓		✓	Partially Forecast	Year End	
	% of Proxy Group (Op Co)		100%	100%	96%	71%	93%	57%	32%	29%
NW Natural Gas Company		Washington	✓			✓	✓	Forecast Permitted	Average	

Notes:

A mechanism may cover one or more cost categories; therefore, designations may not indicate separate mechanisms for each category. Columbia Gas of Ohio does not have retail supply obligation.

[1] Full or partial decoupling (such as Straight-Fixed Variable rate design, weather normalization clauses, and recovery of lost revenues as a result of Energy Efficiency programs).

[2] Includes recovery of capital costs including infrastructure replacement programs and capital/plant additions.

[3] Utility-sponsored conservation, energy efficiency, or other demand side management programs.

[4] Pension expenses, bad debt costs, storm costs, environmental costs, regulatory fee, government & franchise fees and taxes, economic development, and low income assistance programs.

Sources: Company SEC Form 10-Ks; Operating company tariffs; Regulatory Research Associates, *State Regulatory Evaluations Quarterly Update* , December 2024; Regulatory Research Associates, *Adjustment Clauses: A State-by-State Overview,* July 18, 2022; Regulatory Research Associates, Alternative Ratemaking Frameworks in the U.S., April 16, 2020.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Jennifer E. Nelson

RATE OF RETURN ON EQUITY

Exh. JEN-10

August 29, 2025

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Small Size Premium

	[1] ($Mil)
NW Natural Gas Equity	$1,324.59
Median Market to Book for Proxy Group	1.64
NW Natural's Implied Market Capitalization	$2,174.48

Company Name	Ticker	[2] Market Cap ($Mil)	[3] Market to Book Ratio
Atmos Energy Corporation	ATO	$ 24,464.27	1.86
New Jersey Resources Corporation	NJR	$ 4,527.36	1.83
NiSource Inc.	NI	$ 18,593.86	2.09
ONE Gas, Inc.	OGS	$ 4,397.69	1.38
Southwest Gas Holdings, Inc.	SWX	$ 5,216.09	1.46
Spire, Inc.	SR	$ 4,349.84	1.33
MEDIAN		$4,871.72	1.64
MEAN		$10,258	1.66

	Market Capitalization ($Mil) [4]			
Decile	Low		High	Size Premium
2	$ 20,191	$	46,949	0.33%
3	$ 9,938	$	20,178	0.49%
4	$ 6,197	$	9,937	0.50%
5	$ 3,948	$	6,181	0.74%
6	$ 2,482	$	3,946	1.00%
7	$ 1,423	$	2,465	1.19%
8	$ 731	$	1,417	0.88%
9	$ 305	$	730	1.73%
10	$ 1	$	304	4.47%
Proxy Group Median		$	4,871.724	0.74%
7th Decile Size Premium		$	2,174.480	1.19%
Difference from Proxy Group Median				0.45%

Notes:

[1] Source: NW Natural's total company equity as of 12/31/2024 as reported on NW Natural's 2024 Annual Commission Basis Report pursuant to WAC 480-90-257, Docket No. UG-250296

[2] Source: S&P Capital IQ, 30-day average as of 06/30/2025

[3] Source: S&P Capital IQ, 30-day average as of 06/30/2025

[4] Source: Duff & Phelps Cost of Capital Navigator as of December 31, 2024

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Jennifer E. Nelson

RATE OF RETURN ON EQUITY

Exh. JEN-11

August 29, 2025

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CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO [1]

Company Name	Ticker	2024	2023	2022	Average
Atmos Energy Corporation	ATO	60.23%	60.20%	60.01%	60.15%
New Jersey Resources Corporation	NJR	53.84%	53.51%	52.09%	53.15%
NiSource Inc.	NI	54.78%	55.39%	54.17%	54.78%
ONE Gas, Inc.	OGS	59.93%	60.41%	58.24%	59.53%
Southwest Gas Holdings, Inc.	SWX	48.13%	47.45%	42.33%	45.97%
Spire, Inc.	SR	48.05%	46.27%	49.43%	47.92%
Ameren Corporation	AEE	53.28%	51.93%	52.32%	52.51%
Avista Corporation	AVA	47.34%	47.07%	46.57%	47.00%
Black Hills Corporation	BKH	49.46%	49.38%	46.79%	48.54%
CenterPoint Energy, Inc.	CNP	46.87%	47.35%	46.47%	46.90%
CMS Energy Corporation	CMS	48.34%	48.70%	49.48%	48.84%
Consolidated Edison, Inc.	ED	43.73%	45.39%	43.99%	44.37%
DTE Energy Company	DTE	48.84%	49.20%	48.74%	48.93%
Eversource Energy	ES	55.09%	55.05%	55.78%	55.31%
Public Service Enterprise Group Inc.	PEG	54.31%	54.64%	55.16%	54.71%
Sempra Energy	SRE	51.98%	52.05%	53.60%	52.54%
Southern Company	SO	55.29%	53.62%	53.35%	54.09%
Wisconsin Energy Corporation	WEC	54.72%	53.70%	51.53%	53.31%
Xcel Energy Inc.	XEL	53.47%	53.25%	53.58%	53.43%
Gas Proxy Group					
MEAN		54.16%	53.87%	52.71%	53.58%
MEDIAN		54.31%	54.45%	53.13%	53.96%
LOW		48.05%	46.27%	42.33%	45.97%
HIGH		60.23%	60.41%	60.01%	60.15%
Combined Proxy Group					
MEAN		51.98%	51.82%	51.24%	51.68%
MEDIAN		53.28%	52.05%	52.09%	52.54%
LOW		43.73%	45.39%	42.33%	44.37%
HIGH		60.23%	60.41%	60.01%	60.15%

Exhibit JEN-11
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COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2024	2023	2022	Average
Atmos Energy Corporation	ATO	60.23%	60.20%	60.01%	60.15%
New Jersey Natural Gas Company	NJR	53.84%	53.51%	52.09%	53.15%
Columbia Gas of Kentucky, Incorporated	NI	51.44%	53.66%	54.91%	53.34%
Columbia Gas of Maryland, Incorporated	NI	52.00%	52.00%	51.96%	51.99%
Columbia Gas of Ohio, Inc.	NI	50.27%	50.50%	50.67%	50.48%
Columbia Gas of Pennsylvania, Inc.	NI	56.07%	55.88%	56.64%	56.20%
Columbia Gas of Virginia, Incorporated	NI	44.58%	45.25%	44.25%	44.69%
Northern Indiana Public Service Company, LLC	NI	58.01%	59.14%	56.92%	58.02%
Northwest Natural Gas Company	NWN	46.96%	46.96%	47.72%	47.21%
Kansas Gas Service Company, Inc.	OGS	59.53%	60.44%	58.37%	59.45%
Oklahoma Natural Gas Company	OGS	59.23%	60.46%	58.26%	59.32%
Texas Gas Service Company, Inc.	OGS	61.07%	60.35%	58.13%	59.85%
Spire Alabama Inc.	SR	53.22%	51.50%	52.01%	52.25%
Spire Gulf Inc.	SR	47.39%	44.44%	41.35%	44.39%
Spire Mississippi Inc.	SR	NA	NA	NA	NA
Spire Missouri Inc.	SR	45.93%	44.11%	48.66%	46.23%
Southwest Gas Corporation	SWX	48.13%	47.45%	42.33%	45.97%
Ameren Illinois Company	AEE	54.84%	53.97%	54.33%	54.38%
Union Electric Company	AEE	51.92%	50.08%	50.52%	50.84%
Alaska Electric Light and Power Company	AVA	59.47%	62.52%	60.89%	60.96%
Avista Corporation	AVA	46.87%	46.50%	46.03%	46.47%
Black Hills Colorado Electric, Inc.	BKH	49.97%	49.15%	47.92%	49.01%
Black Hills Energy Arkansas, Inc.	BKH	46.81%	48.05%	43.30%	46.05%
Black Hills Power, Inc.	BKH	52.76%	52.58%	50.13%	51.82%
Black Hills Wyoming Gas, LLC	BKH	50.65%	49.89%	48.27%	49.60%
Cheyenne Light, Fuel and Power Company	BKH	46.22%	45.41%	42.85%	44.83%
CenterPoint Energy Houston Electric, LLC	CNP	44.52%	44.46%	42.09%	43.69%
Indiana Gas Company, Inc.	CNP	NA	51.65%	56.01%	53.83%
Southern Indiana Gas and Electric Company	CNP	55.93%	54.57%	55.65%	55.39%
Vectren Energy Delivery of Ohio, Inc.	CNP	53.91%	55.49%	54.80%	54.73%
Consumers Energy Company	CMS	48.34%	48.70%	49.48%	48.84%
Consolidated Edison Company of New York, Inc.	ED	43.66%	45.30%	43.95%	44.30%
Orange and Rockland Utilities, Inc.	ED	44.96%	47.14%	44.67%	45.59%
Rockland Electric Company	ED	NA	NA	NA	NA
Citizens Gas Fuel Company	DTE	NA	NA	NA	NA
DTE Electric Company	DTE	48.33%	48.77%	48.88%	48.66%
DTE Gas Company	DTE	50.86%	50.89%	48.17%	49.97%
Eversource Gas Company of Massachusetts	ES	55.11%	57.06%	53.20%	55.12%
NSTAR Electric Company	ES	55.12%	55.70%	56.13%	55.65%
NSTAR Gas Company	ES	57.13%	56.89%	50.96%	54.99%
Public Service Company of New Hampshire	ES	54.87%	53.20%	51.22%	53.10%
The Connecticut Light and Power Company	ES	54.75%	54.45%	57.70%	55.63%
Yankee Gas Services Company	ES	NA	55.24%	58.44%	56.84%
Public Service Electric and Gas Company	PEG	54.31%	54.64%	55.16%	54.71%
Oncor Electric Delivery Company LLC	SRE	51.26%	52.97%	56.50%	53.58%
San Diego Gas & Electric Company	SRE	53.09%	53.17%	53.17%	53.14%
Southern California Gas Company	SRE	NA	48.99%	49.00%	49.00%
Alabama Power Company	SO	53.88%	52.27%	52.22%	52.79%
Atlanta Gas Light Company	SO	58.86%	58.95%	59.05%	58.96%
Chattanooga Gas Company	SO	52.54%	52.54%	52.54%	52.54%
Georgia Power Company	SO	56.26%	54.41%	53.50%	54.73%
Mississippi Power Company	SO	55.11%	55.01%	55.67%	55.26%
Northern Illinois Gas Company	SO	51.16%	49.19%	50.95%	50.43%
Virginia Natural Gas, Inc.	SO	57.10%	52.16%	55.37%	54.88%
North Shore Gas Company	WEC	52.77%	51.03%	48.90%	50.90%
The Peoples Gas Light and Coke Company	WEC	52.19%	46.57%	48.49%	49.08%
Upper Michigan Energy Resources Corporation	WEC	47.93%	51.66%	50.60%	50.06%
Wisconsin Electric Power Company	WEC	57.23%	58.21%	52.61%	56.02%
Wisconsin Gas LLC	WEC	53.12%	53.18%	52.50%	52.93%
Wisconsin Public Service Corporation	WEC	53.76%	52.84%	52.43%	53.01%
Northern States Power Company	XEL	52.77%	52.03%	52.06%	52.29%
Northern States Power Company	XEL	52.77%	52.03%	52.06%	52.29%
Public Service Company of Colorado	XEL	54.86%	55.28%	56.15%	55.43%
Southwestern Public Service Company	XEL	53.13%	53.66%	54.04%	53.61%
MEAN		53.00%	52.87%	52.14%	52.67%
MEDIAN		52.61%	52.75%	52.05%	52.70%
LOW		44.58%	44.11%	41.35%	44.39%
HIGH		61.07%	60.46%	60.01%	60.15%

Notes:

Sources: Operating Company Annual LDC Reports; S&P Capital IQ. Excludes companies for which no data is reported

[1] Ratios are weighted by actual common equity and total long-term debt of operating subsidiaries.

[2] Spire Mississppi was excluded because it does not report long-term debt

[3] Rockland Electric and Citizens Gas were excluded because they are funded with 100% equity

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO [1]

Company Name	Ticker	2024	2023	2022	Average
Atmos Energy Corporation	ATO	39.72%	39.80%	39.99%	39.84%
New Jersey Resources Corporation	NJR	42.45%	43.52%	44.41%	43.46%
NiSource Inc.	NI	45.03%	44.51%	45.83%	45.12%
ONE Gas, Inc.	OGS	40.07%	39.59%	41.76%	40.47%
Southwest Gas Holdings, Inc.	SWX	51.87%	52.55%	53.97%	52.80%
Spire, Inc.	SR	42.63%	42.86%	37.06%	40.85%
Ameren Corporation	AEE	46.28%	44.36%	45.19%	45.27%
Avista Corporation	AVA	46.49%	46.63%	44.63%	45.92%
Black Hills Corporation	BKH	26.90%	22.44%	14.94%	21.43%
CenterPoint Energy, Inc.	CNP	53.13%	51.08%	48.92%	51.05%
CMS Energy Corporation	CMS	50.90%	50.49%	49.92%	50.43%
Consolidated Edison, Inc.	ED	51.42%	50.18%	50.14%	50.58%
DTE Energy Company	DTE	48.73%	48.98%	47.79%	48.50%
Eversource Energy	ES	41.88%	40.61%	42.69%	41.73%
Public Service Enterprise Group Inc.	PEG	44.38%	44.00%	44.84%	44.41%
Sempra Energy	SRE	46.03%	45.94%	44.02%	45.33%
Southern Company	SO	44.15%	44.04%	43.68%	43.96%
Wisconsin Energy Corporation	WEC	41.61%	39.86%	41.85%	41.11%
Xcel Energy Inc.	XEL	45.46%	45.33%	45.04%	45.28%
Gas Proxy Group					
MEAN		43.63%	43.80%	43.83%	43.76%
MEDIAN		42.54%	43.19%	43.08%	42.16%
LOW		39.72%	39.59%	37.06%	39.84%
HIGH		51.87%	52.55%	53.97%	52.80%
Combined Proxy Group					
MEAN		44.69%	44.04%	43.51%	44.08%
MEDIAN		45.03%	44.36%	44.63%	45.12%
LOW		26.90%	22.44%	14.94%	21.43%
HIGH		53.13%	52.55%	53.97%	52.80%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2024	2023	2022	Average
Atmos Energy Corporation	ATO	39.72%	39.80%	39.99%	39.84%
New Jersey Natural Gas Company	NJR	42.45%	43.52%	44.41%	43.46%
Columbia Gas of Kentucky, Incorporated	NI	48.56%	46.34%	45.09%	46.66%
Columbia Gas of Maryland, Incorporated	NI	48.00%	48.00%	48.04%	48.01%
Columbia Gas of Ohio, Inc.	NI	49.73%	49.50%	49.33%	49.52%
Columbia Gas of Pennsylvania, Inc.	NI	43.93%	44.12%	43.36%	43.80%
Columbia Gas of Virginia, Incorporated	NI	55.42%	54.75%	55.75%	55.31%
Northern Indiana Public Service Company, LLC	NI	41.60%	40.65%	43.08%	41.78%
Northwest Natural Gas Company	NWN	52.40%	52.40%	41.86%	48.88%
Kansas Gas Service Company, Inc.	OGS	40.47%	39.56%	41.63%	40.55%
Oklahoma Natural Gas Company	OGS	40.77%	39.54%	41.74%	40.68%
Texas Gas Service Company, Inc.	OGS	38.93%	39.65%	41.87%	40.15%
Spire Alabama Inc.	SR	42.09%	41.62%	33.01%	38.91%
Spire Gulf Inc.	SR	49.54%	51.30%	38.77%	46.54%
Spire Mississippi Inc.	SR	NA	NA	NA	NA
Spire Missouri Inc.	SR	42.49%	42.96%	38.93%	41.46%
Southwest Gas Corporation	SWX	51.87%	52.55%	53.97%	52.80%
Ameren Illinois Company	AEE	44.22%	42.05%	43.33%	43.20%
Union Electric Company	AEE	48.08%	46.47%	46.85%	47.13%
Alaska Electric Light and Power Company	AVA	34.90%	37.48%	39.11%	37.16%
Avista Corporation	AVA	46.94%	46.97%	44.84%	46.25%
Black Hills Colorado Electric, Inc.	BKH	0.00%	0.00%	0.00%	0.00%
Black Hills Energy Arkansas, Inc.	BKH	0.00%	0.00%	0.00%	0.00%
Black Hills Power, Inc.	BKH	46.83%	30.38%	30.95%	36.05%
Black Hills Wyoming Gas, LLC	BKH	49.15%	48.36%	10.94%	36.15%
Cheyenne Light, Fuel and Power Company	BKH	48.94%	54.51%	33.70%	45.72%
CenterPoint Energy Houston Electric, LLC	CNP	55.48%	55.54%	52.39%	54.47%
Indiana Gas Company, Inc.	CNP		38.16%	41.34%	39.75%
Southern Indiana Gas and Electric Company	CNP	44.07%	43.48%	42.89%	43.48%
Vectren Energy Delivery of Ohio, Inc.	CNP	46.09%	40.77%	40.19%	42.35%
Consumers Energy Company	CMS	50.90%	50.49%	49.92%	50.43%
Consolidated Edison Company of New York, Inc.	ED	51.55%	50.20%	50.06%	50.60%
Orange and Rockland Utilities, Inc.	ED	49.20%	49.91%	51.52%	50.21%
Rockland Electric Company	ED	NA	NA	NA	NA
Citizens Gas Fuel Company	DTE	NA	NA	NA	NA
DTE Electric Company	DTE	48.73%	49.33%	48.08%	48.71%
DTE Gas Company	DTE	48.71%	47.61%	46.61%	47.64%
Eversource Gas Company of Massachusetts	ES	44.89%	42.94%	46.80%	44.88%
NSTAR Electric Company	ES	40.86%	40.99%	43.87%	41.90%
NSTAR Gas Company	ES	38.45%	34.64%	40.11%	37.73%
Public Service Company of New Hampshire	ES	42.47%	41.53%	44.04%	42.68%
The Connecticut Light and Power Company	ES	42.92%	41.46%	42.30%	42.23%
Yankee Gas Services Company	ES		36.74%	36.40%	36.57%
Public Service Electric and Gas Company	PEG	44.38%	44.00%	44.84%	44.41%
Oncor Electric Delivery Company LLC	SRE	46.81%	45.99%	42.68%	45.16%
San Diego Gas & Electric Company	SRE	44.82%	46.83%	45.63%	45.76%
Southern California Gas Company	SRE		44.74%	44.39%	44.56%
Alabama Power Company	SO	46.12%	47.56%	47.78%	47.15%
Atlanta Gas Light Company	SO	41.14%	41.05%	40.95%	41.04%
Chattanooga Gas Company	SO	47.46%	47.46%	47.46%	47.46%
Georgia Power Company	SO	43.27%	42.20%	41.96%	42.47%
Mississippi Power Company	SO	44.52%	44.99%	44.33%	44.61%
Northern Illinois Gas Company	SO	44.82%	42.85%	39.47%	42.38%
Virginia Natural Gas, Inc.	SO	42.90%	47.84%	44.63%	45.12%
North Shore Gas Company	WEC	39.93%	42.30%	39.44%	40.56%
The Peoples Gas Light and Coke Company	WEC	43.06%	46.07%	44.69%	44.61%
Upper Michigan Energy Resources Corporation	WEC	37.32%	44.15%	42.25%	41.24%
Wisconsin Electric Power Company	WEC	40.89%	37.63%	41.54%	40.02%
Wisconsin Gas LLC	WEC	35.48%	33.37%	34.81%	34.55%
Wisconsin Public Service Corporation	WEC	45.01%	40.75%	43.30%	43.02%
Northern States Power Company	XEL	46.12%	46.93%	46.56%	46.54%
Northern States Power Company	XEL	46.12%	46.93%	46.56%	46.54%
Public Service Company of Colorado	XEL	44.50%	42.61%	42.06%	43.06%
Southwestern Public Service Company	XEL	44.96%	44.96%	45.48%	45.14%
MEAN		45.50%	45.39%	43.80%	44.90%
MEDIAN		43.21%	43.82%	42.47%	43.63%
LOW		38.93%	39.54%	33.01%	38.91%
HIGH		55.42%	54.75%	55.75%	55.31%

Notes:

Sources: Operating Company Annual LDC Reports; S&P Capital IQ. Excludes companies for which no data is reported

[1] Ratios are weighted by actual common equity and total long-term debt of operating subsidiaries.

[2] Spire Mississppi was excluded because it does not report long-term debt

CAPITAL STRUCTURE ANALYSIS

SHORT-TERM DEBT RATIO [1]

Company Name	Ticker	2024	2023	2022	Average
Atmos Energy Corporation	ATO	0.05%	0.00%	0.00%	0.02%
New Jersey Resources Corporation	NJR	3.71%	2.97%	3.50%	3.39%
NiSource Inc.	NI	0.20%	0.10%	0.00%	0.10%
ONE Gas, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Southwest Gas Holdings, Inc.	SWX	0.00%	0.00%	3.71%	1.24%
Spire, Inc.	SR	9.32%	10.87%	13.50%	11.23%
Ameren Corporation	AEE	0.44%	3.71%	2.50%	2.21%
Avista Corporation	AVA	6.17%	6.29%	8.80%	7.09%
Black Hills Corporation	BKH	23.64%	28.18%	38.27%	30.03%
CenterPoint Energy, Inc.	CNP	0.00%	1.57%	4.61%	2.06%
CMS Energy Corporation	CMS	0.76%	0.82%	0.61%	0.73%
Consolidated Edison, Inc.	ED	4.85%	4.42%	5.88%	5.05%
DTE Energy Company	DTE	2.43%	1.82%	3.48%	2.57%
Eversource Energy	ES	3.02%	4.34%	1.53%	2.96%
Public Service Enterprise Group Inc.	PEG	1.31%	1.36%	0.00%	0.89%
Sempra Energy	SRE	1.99%	2.02%	2.38%	2.13%
Southern Company	SO	0.56%	2.34%	2.96%	1.95%
Wisconsin Energy Corporation	WEC	3.68%	6.44%	6.63%	5.58%
Xcel Energy Inc.	XEL	1.07%	1.42%	1.38%	1.29%
Gas Proxy Group					
MEAN		2.21%	2.32%	3.45%	2.66%
MEDIAN		0.12%	0.05%	1.75%	0.67%
LOW		0.00%	0.00%	0.00%	0.00%
HIGH		9.32%	10.87%	13.50%	11.23%
Combined Proxy Group					
MEAN		3.33%	4.14%	5.25%	4.24%
MEDIAN		1.31%	2.02%	2.96%	2.13%
LOW		0.00%	0.00%	0.00%	0.00%
HIGH		23.64%	28.18%	38.27%	30.03%

SHORT-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2024	2023	2022	Average
Atmos Energy Corporation	ATO	0.05%	0.00%	0.00%	0.02%
New Jersey Natural Gas Company	NJR	3.71%	2.97%	3.50%	3.39%
Columbia Gas of Kentucky, Incorporated	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Maryland, Incorporated	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Ohio, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Pennsylvania, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Virginia, Incorporated	NI	0.00%	0.00%	0.00%	0.00%
Northern Indiana Public Service Company, LLC	NI	0.39%	0.21%	0.00%	0.20%
Northwest Natural Gas Company	NWN	0.64%	0.64%	10.43%	3.90%
Kansas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Oklahoma Natural Gas Company	OGS	0.00%	0.00%	0.00%	0.00%
Texas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Spire Alabama Inc.	SR	4.68%	6.88%	14.98%	8.85%
Spire Gulf Inc.	SR	3.06%	4.25%	19.88%	9.07%
Spire Mississippi Inc.	SR	NA	NA	NA	NA
Spire Missouri Inc.	SR	11.58%	12.93%	12.41%	12.31%
Southwest Gas Corporation	SWX	0.00%	0.00%	3.71%	1.24%
Ameren Illinois Company	AEE	0.94%	3.99%	2.35%	2.42%
Union Electric Company	AEE	0.00%	3.46%	2.63%	2.03%
Alaska Electric Light and Power Company	AVA	5.63%	0.00%	0.00%	1.88%
Avista Corporation	AVA	6.19%	6.53%	9.13%	7.28%
Black Hills Colorado Electric, Inc.	BKH	50.03%	50.85%	52.08%	50.99%
Black Hills Energy Arkansas, Inc.	BKH	53.19%	51.95%	56.70%	53.95%
Black Hills Power, Inc.	BKH	0.41%	17.04%	18.91%	12.12%
Black Hills Wyoming Gas, LLC	BKH	0.20%	1.75%	40.79%	14.25%
Cheyenne Light, Fuel and Power Company	BKH	4.83%	0.08%	23.46%	9.46%
CenterPoint Energy Houston Electric, LLC	CNP	0.00%	0.00%	5.53%	1.84%
Indiana Gas Company, Inc.	CNP		10.19%	2.64%	6.42%
Southern Indiana Gas and Electric Company	CNP	0.00%	1.96%	1.46%	1.14%
Vectren Energy Delivery of Ohio, Inc.	CNP	0.00%	3.74%	5.01%	2.92%
Consumers Energy Company	CMS	0.76%	0.82%	0.61%	0.73%
Consolidated Edison Company of New York, Inc.	ED	4.80%	4.50%	5.99%	5.10%
Orange and Rockland Utilities, Inc.	ED	5.84%	2.95%	3.81%	4.20%
Rockland Electric Company	ED	NA	NA	NA	NA
Citizens Gas Fuel Company	DTE	NA	NA	NA	NA
DTE Electric Company	DTE	2.94%	1.90%	3.04%	2.62%
DTE Gas Company	DTE	0.43%	1.50%	5.22%	2.38%
Eversource Gas Company of Massachusetts	ES	0.00%	0.00%	0.00%	0.00%
NSTAR Electric Company	ES	4.02%	3.31%	0.00%	2.45%
NSTAR Gas Company	ES	4.42%	8.48%	8.93%	7.28%
Public Service Company of New Hampshire	ES	2.65%	5.26%	4.74%	4.22%
The Connecticut Light and Power Company	ES	2.34%	4.09%	0.00%	2.14%
Yankee Gas Services Company	ES		8.03%	5.16%	6.60%
Public Service Electric and Gas Company	PEG	1.31%	1.36%	0.00%	0.89%
Oncor Electric Delivery Company LLC	SRE	1.93%	1.04%	0.82%	1.26%
San Diego Gas & Electric Company	SRE	2.09%	0.00%	1.20%	1.10%
Southern California Gas Company	SRE		6.27%	6.61%	6.44%
Alabama Power Company	SO	0.00%	0.17%	0.00%	0.06%
Atlanta Gas Light Company	SO	0.00%	0.00%	0.00%	0.00%
Chattanooga Gas Company	SO	0.00%	0.00%	0.00%	0.00%
Georgia Power Company	SO	0.48%	3.39%	4.54%	2.80%
Mississippi Power Company	SO	0.37%	0.00%	0.00%	0.12%
Northern Illinois Gas Company	SO	4.02%	7.97%	9.58%	7.19%
Virginia Natural Gas, Inc.	SO	0.00%	0.00%	0.00%	0.00%
North Shore Gas Company	WEC	7.30%	6.67%	11.66%	8.54%
The Peoples Gas Light and Coke Company	WEC	4.75%	7.37%	6.82%	6.31%
Upper Michigan Energy Resources Corporation	WEC	14.74%	4.19%	7.16%	8.70%
Wisconsin Electric Power Company	WEC	1.88%	4.15%	5.85%	3.96%
Wisconsin Gas LLC	WEC	11.40%	13.45%	12.69%	12.51%
Wisconsin Public Service Corporation	WEC	1.23%	6.41%	4.28%	3.97%
Northern States Power Company	XEL	1.11%	1.05%	1.38%	1.18%
Northern States Power Company	XEL	1.11%	1.05%	1.38%	1.18%
Public Service Company of Colorado	XEL	0.64%	2.11%	1.79%	1.51%
Southwestern Public Service Company	XEL	1.91%	1.37%	0.48%	1.25%
MEAN		1.51%	1.74%	4.06%	2.44%
MEDIAN		0.00%	0.00%	0.00%	0.01%
LOW		0.00%	0.00%	0.00%	0.00%
HIGH		11.58%	12.93%	19.88%	12.31%

Notes:

Sources: Operating Company Annual LDC Reports; S&P Capital IQ. Excludes companies for which no data is reported

[1] Ratios are weighted by actual common equity and total long-term debt of operating subsidiaries.

[2] Spire Mississppi was excluded because it does not report long-term debt

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Jennifer E. Nelson

RATE OF RETURN ON EQUITY

Exh. JEN-12

August 29, 2025

Exhibit JEN-12
Page 1 of 2

Proxy Group Current Authorized Equity Ratio by Jurisdiction

Ticker	Company Name	Docket Number	Jurisdiction	Date Authorized	Current Authorized Equity Ratio	
ATO	Atmos Energy Corporation					
	Colorado Division	D-22AL-0348G	CO	5/4/2023	58.00%	
	Kansas Division	D-23-ATMG-359-RTS	KS	5/9/2023	NA	
	Kansas Division	D-19-ATMG-525-RTS	KS	2/24/2020	56.32%	
	Kentucky Division	C-2021-00214	KY	5/19/2022	54.50%	
	Louisiana Division	D-U-36658	LA	5/13/2024	58.00%	
	Mississippi Division	C-2005-UN-503	MS	10/4/2022	60.74%	
	Tennessee Division	D-25-00007	TN	7/15/2025	61.05%	
	West Texas (Environs)	OS-24-00018879	TX RRC	5/13/2025	60.97%	
	Mid-Tex Division	OS-24-00019196	TX RRC	6/17/2025	60.97%	
	West Texas (Cities)	[1]	TX RRC	10/1/2022	58.00%	
	Mid-Tex (Cities)	[1]	TX RRC	10/1/2022	58.00%	
	West Texas Triangle	D-GUD-10900	TX RRC	6/1/2023	60.00%	
	West Texas (ALDC)	[1]	TX RRC	6/9/2023	59.00%	
	Mid-Tex (Environs)	[1]	TX RRC	6/1/2023	60.00%	
	Mid-Tex (Dallas)	[1]	TX RRC	6/1/2023	60.00%	
	Mid-Tex (ATM Cities)	[1]	TX RRC	6/9/2023	60.00%	
	Virginia Division	PUR-2018-00014	VA	3/11/2019	58.21%	
NI	NiSource Inc.					
	Columbia Gas of Kentucky, Incorporated	C-2024-00092	KY	12/30/2024	52.64%	
	Columbia Gas of Maryland, Incorporated	C-9754	MD	4/22/2025	52.17%	
	Columbia Gas of Ohio, Inc.	C-21-0637-GA-AIR	OH	1/26/2023	50.60%	
	Columbia Gas of Pennsylvania, Inc.	D-R-2024-3046519	PA	11/21/2024	NA	
	Columbia Gas of Pennsylvania, Inc.	D-R-2022-3031211	PA	12/8/2022	NA	
	Columbia Gas of Pennsylvania, Inc.	D-R-2021-3024296	PA	12/16/2021	NA	
	Columbia Gas of Pennsylvania, Inc.	D-R-2020-3018835	PA	2/19/2021	54.19%	
	Columbia Gas of Virginia, Incorporated	C-PUR-2024-00030	VA	5/15/2025	43.16%	[2]
	Northern Indiana Public Service Company	Ca-45967	IN	7/31/2024	58.51%	[3]
NJR	New Jersey Resources Corporation					
	New Jersey Natural Gas Company	D-GR24010071	NJ	11/21/2024	54.00%	
OGS	ONE Gas, Inc.					
	Kansas Gas Service Company, Inc.	D-24-KGSG-610-RTS	KS	10/3/2024	NA	
	Oklahoma Natural Gas Company	Ca-PUD2024-000010	OK	8/27/2024	NA	
	Oklahoma Natural Gas Company	Ca-PUD202200023	OK	11/29/2022	NA	
	Oklahoma Natural Gas Company	Ca-PUD202100063	OK	11/30/2021	58.55%	
	Texas Gas Service Company, Inc. (Central-Gul	D-OS-24-00017471	TX RRC	11/20/2024	59.58%	
	Texas Gas Service Company, Inc. (Rio Grande	D-OSS-23-00014399	TX RRC	1/31/2024	59.07%	
	Texas Gas Service Company, Inc. (WTX North)	D-OSS-22-00009896	TX RRC	1/19/2023	59.74%	
SR	Spire Inc.					
	Spire Alabama Inc.	D-18328	AL	9/30/2022	55.50%	[4]
	Spire Missouri Inc.	C-GR-2022-0179	MO	11/30/2022	NA	
	Spire Missouri Inc.	C-GR-2021-0108	MO	10/27/2021	49.86%	
	Spire Mississippi	D-2015-UN-109	MS	12/2/2022	50.00%	
	Spire Gulf Inc.	D-28101	AL	9/30/2021	55.50%	
SWX	Southwest Gas Corp.					
	Arizonia Division	D-G-G-01551A-23-0341	AZ	3/27/2025	48.50%	
	California Division (SoCal)	A-19-08-015 (SoCal)	CA	3/25/2021	52.00%	
	California Division (NoCal)	A-19-08-015 (NoCal)	CA	3/25/2021	52.00%	
	California Division (LkTah)	A-19-08-015 (LkTah)	CA	3/25/2021	52.00%	
	Nevada Division (Northern)	D-23-09012 (Northern)	NV	9/11/2023	50.00%	
	Nevada Division (Southern)	D-23-09012 (Southern)	NV	9/11/2023	50.00%	
	Average				55.71%	
	Median				58.00%	
	High				61.05%	
	Low				43.16%	
	Count ≥54%; % of Total				25	68%
	Total Count				37	

Source: Regulatory Research Associates; SEC Form 10-K for ATO and SR
If the capital structure was not determined in the most recent rate proceeding, the authorized equity ratio determined in the next most recent proceeding with a determination was used.

Notes:

[1] Gas utilities regulated by the Texas Rail Road Commission (RRC) have a general rate case only if they are unable to reach a settlement with the cities and unincorporated areas ("environs") within their service territories. Current authorized equity ratio for Atmos Texas' territories is published in ATO's 2024 10-K.

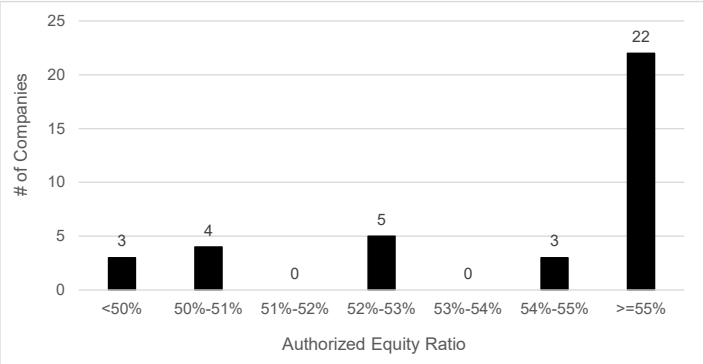
[2] Calculated using investor-supplied capital sources only. Columbia Gas of Virginia's authorized capital structure includes 7.316% short-term debt, 47.348% long-term debt, 2.166% preferred stock, 43.147% common equity and 0.023% Job Development Credits.

[3] Calculated using investor-supplied capital sources only. Indiana includes non-investor supplied capital in the ratemaking capital structure reported by RRA. Including non-investor supplied capital, NIPSCO's authorized equity ratio is 52.39%

[4] Source: Spire, Inc. 2024 10-K; authorized in Spire's RSE proceedings, not a general rate case

Exhibit JEN-12
Page 2 of 2

Equity Ratio	Count
<50%	3
50%-51%	4
51%-52%	0
52%-53%	5
53%-54%	0
54%-55%	3
>=55%	22



BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Jennifer E. Nelson

RATE OF RETURN ON EQUITY

Exh. JEN-13

August 29, 2025

MOODY'S RATINGS

CREDIT OPINION
30 July 2024

Update

Send Your Feedback

RATINGS

Northwest Natural Gas Company

Domicile	Portland, Oregon, United States
Long Term Rating	(P)Baa1
Type	Senior Unsec. Shelf - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Northwest Natural Gas Company

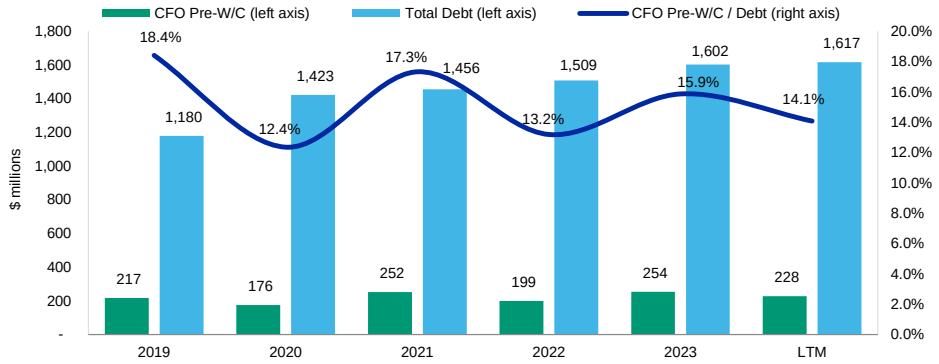
Update to credit analysis

Summary

Northwest Natural Gas Company's (NW Natural, Baa1 stable) credit profile reflects the low business risk nature of its business as a local gas distribution company (LDC) operating in generally constructive regulatory environments. In particular, Oregon's suite of cost recovery mechanisms and constructive stakeholder relationships have supported the utility's solid cash flow generation and financial metrics.

Because of its supportive regulatory outcomes, NW Natural has historically sustained credit metrics, including a cash flow from operations before changes in working capital (CFO pre-WC) to debt ratio, in the mid to high teens range over the last several years. The years of financial declines were due to one time events including the coronavirus pandemic (2020) and an increase in commodity prices that drove an increase in gas cost deferrals (2022). Favorably, the utility was authorized full recovery of these costs thereby driving the improvement in the utility's credit metrics in 2023. We expect NW Natural's financial profile to remain consistent over the next several years.

Exhibit 1
Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt ($ MM)



Source: Moody's Financial Metrics™

Credit strengths

» Low business risk local gas distribution company

» Supportive regulatory jurisdiction, including cost tracking mechanisms and legislation that can help investment prospects

» Good stakeholder relationships and ongoing dialogue to resolve most issues

Credit challenges

» Elevated social risk due to higher scrutiny on natural gas as an energy source

» Long-term risks associated with environmental remediation costs and emission reduction requirements

Rating outlook

The stable outlook reflects our expectation that NW Natural's track record of solid financial performance and credit supportive regulatory outcomes will continue over the next several years. We see credit metrics sustaining at levels sufficient for the current credit profile including a ratio of CFO pre-WC to debt in the mid-teens percent range over the longer-term.

Factors that could lead to an upgrade

A rating upgrade could occur if NW Natural's credit metrics improve such that CFO pre-WC to debt ratio increases to 18% and CFO pre-WC less dividends to debt is consistently above 14%.

Factors that could lead to a downgrade

A rating downgrade could occur if NW Natural's regulatory environment becomes less credit supportive, including material environmental challenges where costs cannot be recovered due to state emission reduction requirements. A rating downgrade could also be considered if CFO pre-WC to debt is sustained below 14%.

Key indicators

Exhibit 2

Northwest Natural Gas Company [1]

	2019	2020	2021	2022	2023	LTM
CFO Pre-W/C + Interest / Interest	5.5x	4.5x	5.8x	4.4x	4.5x	4.0x
CFO Pre-W/C / Debt	18.4%	12.4%	17.3%	13.2%	15.9%	14.1%
CFO Pre-W/C – Dividends / Debt	13.9%	8.5%	13.5%	9.0%	10.1%	8.3%
Debt / Capitalization	51.2%	55.2%	52.5%	49.3%	50.0%	49.3%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics™

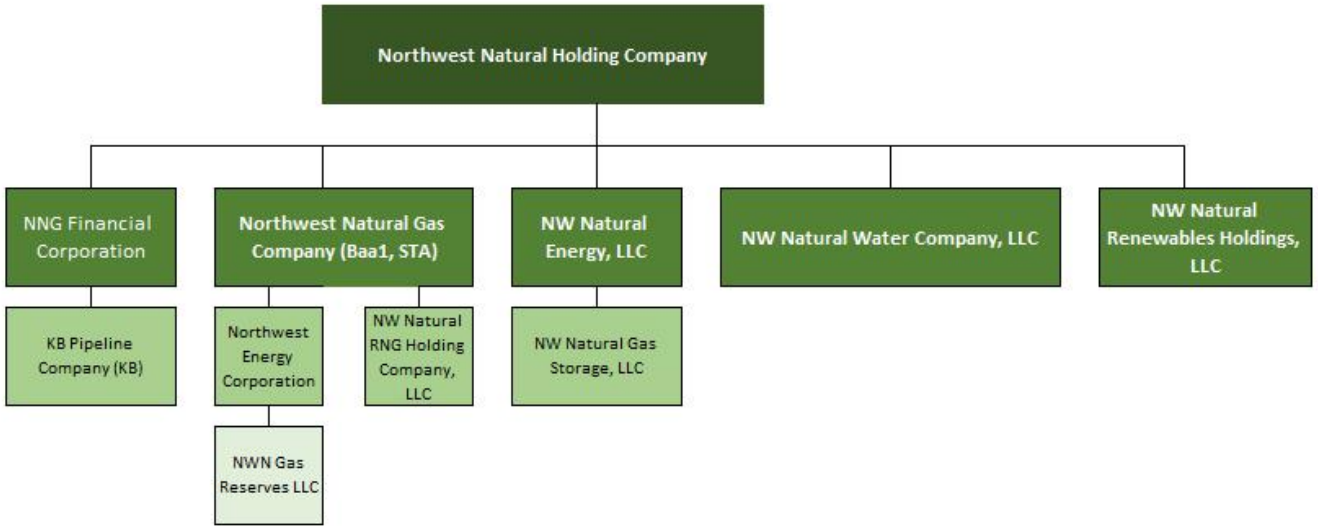
Profile

Northwest Natural Gas Company (NW Natural) is a natural gas local distribution company (LDC), serving 800,000 customers in Oregon (about 88% of utility margins) and Washington (about 12% of utility margins). NW Natural is regulated by the Oregon Public Utility Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC).

NW Natural's parent, Northwest Natural Holding Company (NW Holdings), is a holding company headquartered in Portland, Oregon and owns NW Natural, NW Natural Water Company, LLC (NWN Water), NW Natural Renewables Holdings, LLC, and other businesses and activities. NW Natural is NW Holdings' largest subsidiary and an illustrative organizational chart is shown in Exhibit 3.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the issuer/deal page on https://ratings.moodys.com for the most updated credit rating action information and rating history.

Exhibit 3
NW Natural simplified organizational chart



Source: NW Natural presentation

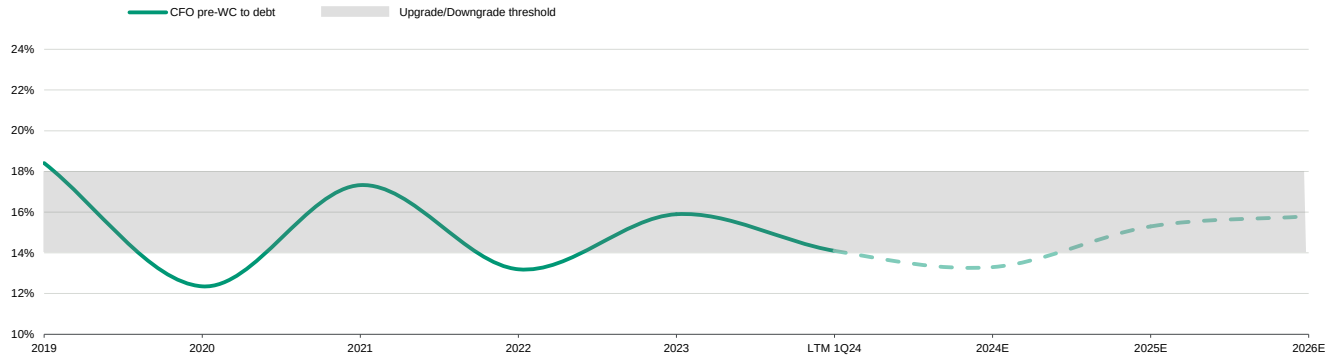
Detailed credit considerations

Consistent track record of solid financial performance expected to continue

NW Natural has a strong track record of producing solid financial performance as a result of its credit supportive regulatory framework and balanced fiscal policies. Over the last five years, the utility averaged about $220 million in cash flow from operations. This led to an average CFO pre-WC to debt ratio of about 15% from 2019 to 2023. As of the last twelve months ending 31 March 2024, the ratio was about 14%, as shown in Exhibit 4.

For 2024, credit metrics may fall to about 13% due to higher debt issued in 2023 and pressured cash flow due to higher O&M costs. NW Natural has a pending general rate case that is expected to conclude in a constructive manner with new rates effective November 2024; coupled with lower capital expenditures starting in 2025, we see credit metrics including its CFO pre-WC to debt ratio improving and sustaining in the 15% range over the next several years.

Exhibit 4
Consistent credit metrics expected over next several years
Historical and projected CFO pre-WC to debt ratio, upgrade/downgrade threshold range



The range indicated is one of several factors that could lead to an upgrade or downgrade of the ratings if the CFO pre-WC to debt ratio is above or below the level for a sustained period.
Source: Moody's Ratings

NW Natural's capital expenditures have averaged about $275 million from 2019 to 2023. In 2022 and 2023, capital spending increased to $319 million and $291 million, respectively. For 2024, NW Natural is projecting about $360 million. Capex has increased largely due to investments in technology of which much of it was related to the federal cybersecurity mandates. With the conclusion of these major projects, from 2025 to 2027, capital expenditures are projected to decrease totaling about $900 million or an average of about $225 million annually.

The utility had two years over this period where credit metrics dropped below 14% (its established downgrade threshold). In 2020, the utility's cash flow was affected by the impacts from the coronavirus pandemic as well as debt levels that increased to ensure adequate liquidity for the year amid the pandemic uncertainties. The pandemic-related debt was subsequently repaid in 2021. In 2022, the weaker metrics were due to cost inflation pressures, primarily within the materials used in field work, higher natural gas prices and related short term debt to cover the initial cost. Notably, these were pressures that plagued the industry during most of 2022. Favorably, the utility was able to recover the deferred costs within a year as reflected in its stronger credit metrics for 2023.

Supportive legislative and regulatory framework in Oregon and Washington

NW Natural's low business risk profile is supported by gas distribution operations that receive supportive regulatory treatment from the Oregon Public Utility Commission (OPUC) and Washington Utilities and Transportation Commission (WUTC), which allows for several cost recovery mechanisms that help provide stability and predictability of the utility's cash flow.

Oregon

Since 88% of the utility's margins are derived from Oregon customers, the legislative and regulatory support that NW Natural receives from the OPUC is a fundamental credit driver for the utility. In general, NW Natural has cooperative relationships with stakeholders in the state and has been able to negotiate constructive rate case outcomes and acquire tracking mechanisms for its most material costs.

The most important cost recovery mechanisms include: NW Natural's use of forward test years for capital expenditures; weather adjusted rate mechanism (WARM); conservation tariff (i.e., revenue decoupling); purchased gas adjustment (PGA); utility gas reserve investments included in rate base; and a Site Remediation and Recovery Mechanism (SRRM), primarily for the recovery of manufactured gas plant environmental expenditures. These various cost recovery mechanisms help support recovery of the most significant costs that NW Natural faces.

The utility filed its most recent Oregon general rate case on 29 December 2023 requesting $154.9 million revenue increase (16.6%), a 10.10% ROE, 50% equity layer and a $2.14 billion rate base. On 24 July 2024, NW Natural entered into an all-party settlement agreement that included a $95 million revenue increase (10.2%) and a 9.4% ROE and 50% equity layer, which remain unchanged. If approved by the OPUC, we view the settlement as credit supportive and consistent with prior rate case outcomes that have also been constructive. It also illustrates NW Natural's robust relationship with its regulatory authority. NW Natural's initial filing represented the largest base rate increase requested in recent years, underscoring the inflationary pressures the utility has been navigating. NW Natural expects new rates to take effect 1 November 2024.

From a legislative perspective, Oregon has frequently been on the forefront of progressive environmental measures, including the 2019 passage of Senate Bill 98 (SB 98), which allows utilities to acquire renewable natural gas (RNG) on behalf of customers. In July 2020, the parameters surrounding the rulemaking for RNG cost recovery were determined, which allowed for NW Natural to sign its first RNG investment in December 2020. We see this as an important step in supporting ongoing investment and growth for NW Natural in the face of the threat of electrification. The state support for RNG development can be a helpful tool for the company to maintain its place as a significant energy provider for customers, at the same time as state reduces carbon and methane emissions.

We also view the company as having low stranded asset risk given the state's policy goals of advancing renewable natural gas as a form of decarbonization and OPUC ongoing support of cost recovery for these projects. In the 2021 general rate case, the OPUC approved the recovery of costs associated with the Lexington RNG facility under Senate Bill 98 and authorized the adoption of an automatic adjustment clause that allows the utility to add costs associated with its renewable natural gas projects to rates annually on 1 November.

Washington

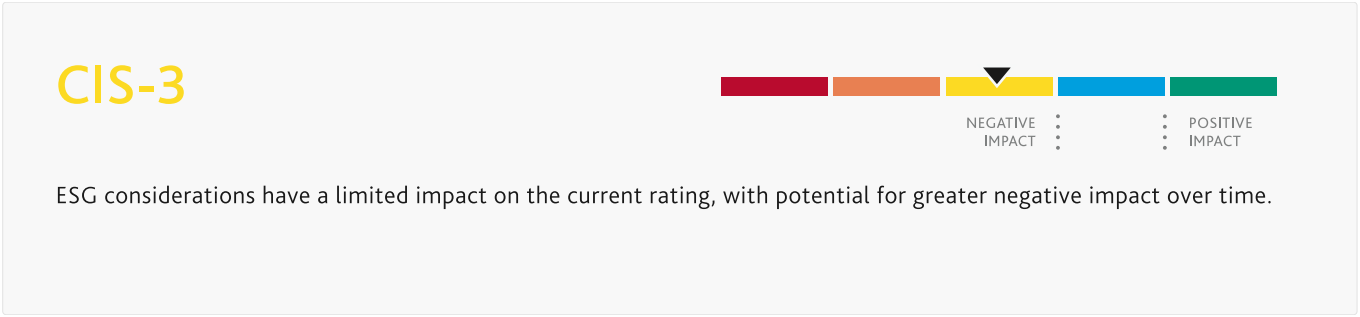
In October 2021, the WUTC issued an order authorizing an annual revenue requirement increase over two years; a 6.4% or $5 million increase in the first year, effective 1 November 2021, and up to a 3.5% or $3 million increase in the second year beginning 1 November

2022. The order was based on an average rate base of $247.3 million. The filing was based on system investments including costs associated with resiliency and reliability, consumer focused technology and building improvements and upgrades. The new WUTC order does not specify the underlying inputs of the cost of capital such as capital structure and ROE. This multiyear rate case is purposed to recover investments and costs for system resiliency and reliability as well as headquarter leasehold improvements and rent costs. It also provides for recovery of upgrades to the Vancouver, Washington service center.

ESG considerations

Northwest Natural Gas Company's ESG credit impact score is CIS-3

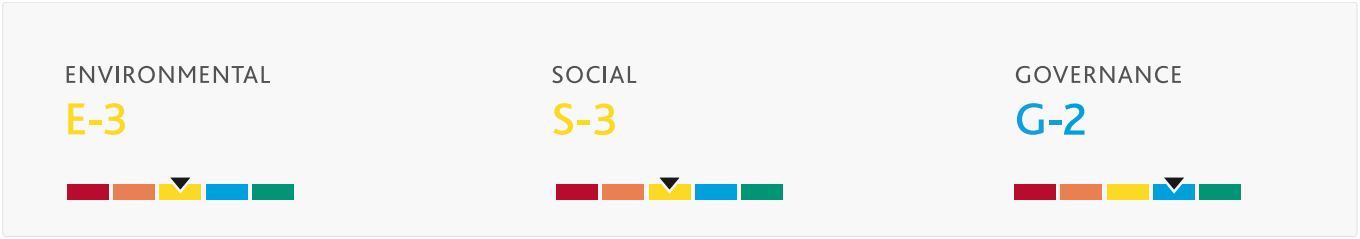
Exhibit 5
ESG credit impact score



Source: Moody's Ratings

NW Natural's **CIS-3** indicates that its ESG attributes are overall considered as having a limited impact on the current rating, with greater potential for future negative impact over time. The utility's scores reflect a combination of higher risk exposure to carbon transition, physical climate and demographic and societal trends.

Exhibit 6
ESG issuer profile scores



Source: Moody's Ratings

Environmental

NW Natural's **E-3** issuer profile score is driven by its moderately negative carbon transition and physical climate risks. Favorably, the company has a strong track record of meeting established emissions targets set by legislative (Oregon Senate Bill 98) and regulatory policies. NW Natural established a Low Carbon Savings goal of 30% by 2035 that includes customers emissions and a goal of being a carbon neutral provider by 2050. This will be achieved through increasing the use of renewable natural gas as well as hydrogen blending. Although the utility is exposed to moderately high physical climate risks, the company worked to mitigate these risks by removing all bare steel pipe from its system by completing the multi-year investment in 2015. Additionally, the system is predominantly underground, which makes the infrastructure more resilient and less vulnerable to weather or other events that could disrupt power to the region.

Social

NW Natural's **S-3** issuer profile score reflects higher risk to responsible production and demographics and societal trends that increase public concern over environmental, social, or affordability issues that could lead to adverse regulatory political intervention. These

risks are balanced by neutral to low exposure to health and safety, human capital, and customer relations. NW Natural has historically worked collaboratively with its regulator to make energy transition as affordable as possible for customers and we see this trend continuing as the company executes on its energy transmission goals over the next several years. Additionally, the company has a strong hedging program including storage and contracts that draw from a diverse supply to ensure reliability and reduce commodity risk

Governance

NW Natural's **G-2** issuer profile score is broadly in line with other utilities and does not pose a particular risk. This is supported by neutral to low exposure to financial strategy and risk management and management credibility and track record.

ESG Issuer Profile Scores and Credit Impact Scores for the rated entity/transaction are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for the entity/transaction on MDC and view the ESG Scores section.

Liquidity analysis

NW Natural maintains adequate liquidity through the use of external credit facilities and market issuances to fund negative free cash flow. As of the last twelve months ending 31 March 2024, NW Natural's internal liquidity included about $62 million of cash on hand and produced about $225 million in cash flow from operations; this compares to about $299 million in capital expenditures and $94 million in dividends for the same last twelve month period.

The utility has access to a $400 million revolving credit agreement that expires on 3 November 2026. The credit agreement includes a feature that allows NW Natural to request an increase to the total amount up to $600 million as well as request to extend the agreement for two additional one-year periods, subject to lender approval. Additionally, the credit agreement also permits the issuance of letters of credit in an aggregate amount of up to $60 million. As of 31 March 2024, NW Natural did not have any outstanding balance drawn under its credit facility or letters of credit. The primary restrictive covenant requires the company to maintain a debt to capitalization ratio of 70% or less, which NW Natural was in compliance with at 31 March 2024 (52.1%).

NW Natural's next debt maturities are due in September 2025 and December 2025, when $20 million and $10 million of senior secured notes are due, respectively.

Rating methodology and scorecard factors

Exhibit 7

Methodology Scorecard Factors
Northwest Natural Gas Company

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 3/31/2024		Moody's 12-18 Month Forward View As of 7/8/2024 [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	A	A
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	4.6x	A	4.5x - 5.5x	A
b) CFO pre-WC / Debt (3 Year Avg)	15.0%	Baa	15% - 19%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	10.3%	Baa	10% - 13%	Baa
d) Debt / Capitalization (3 Year Avg)	49.4%	A	48% - 50%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching	0	0	0	0
a) Scorecard-Indicated Outcome		A3		A3
b) Actual Rating Assigned				(P)Baa1

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 3/31/2024(L)
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures
Source: Moody's Financial Metrics

Appendix

Exhibit 8

Cash Flow and Credit Metrics [1]

CF Metrics (in $ millions)	2019	2020	2021	2022	2023	LTM
FFO	**219**	**184**	**227**	**207**	**238**	**223**
+/- Other	(2)	(8)	25	(8)	16	4
CFO Pre-WC	**217**	**176**	**252**	**199**	**254**	**228**
+/- ΔWC	(20)	(3)	(105)	(53)	29	(1)
CFO	**198**	**173**	**148**	**146**	**283**	**227**
- Div	53	55	56	63	92	94
- Capex	226	267	280	320	293	301
FCF	(82)	(149)	(189)	(237)	(102)	(168)
(CFO Pre-W/C) / Debt	18.4%	12.4%	17.3%	13.2%	15.9%	14.1%
(CFO Pre-W/C - Dividends) / Debt	13.9%	8.5%	13.5%	9.0%	10.1%	8.3%
FFO / Debt	18.6%	12.9%	15.6%	13.7%	14.9%	13.8%
RCF / Debt	14.1%	9.0%	11.8%	9.5%	9.1%	8.0%
Revenue	740	759	843	1,014	1,159	1,127
Interest Expense	48	51	53	59	74	75
Net Income	81	75	85	86	95	88
Total Assets	3,321	3,599	3,898	4,453	4,511	4,495
Total Liabilities	2,505	2,764	2,921	3,262	3,279	3,212
Total Equity	816	835	978	1,191	1,233	1,282

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months.
Source: Moody's Financial Metrics™

Exhibit 9

Peer Comparison Table [1]

	Northwest Natural Gas Company (P)Baa1 Stable			Berkshire Gas Company A3 Stable			Wisconsin Gas LLC A3 Stable			Southwest Gas Corporation Baa1 Stable		
(in $ millions)	FY Dec-22	FY Dec-23	LTM Mar-24	FY Dec-22	FY Dec-23	LTM Mar-24	FY Dec-22	FY Dec-23	LTM Mar-24	FY Dec-22	FY Dec-23	LTM Mar-24
Revenue	1,014	1,159	1,127	102	97	91	917	770	681	1,935	2,500	2,638
CFO Pre-W/C	199	254	228	18	20	20	170	154	154	449	525	510
Total Debt	1,509	1,602	1,617	80	93	96	1,081	1,112	1,080	3,648	3,621	3,622
CFO Pre-W/C + Interest / Interest	4.4x	4.5x	4.0x	6.3x	5.9x	5.4x	8.9x	4.9x	4.7x	4.6x	4.3x	4.3x
CFO Pre-W/C / Debt	13.2%	15.9%	14.1%	21.9%	21.6%	20.6%	15.7%	13.9%	14.3%	12.3%	14.5%	14.1%
CFO Pre-W/C – Dividends / Debt	9.0%	10.1%	8.3%	9.5%	21.6%	20.6%	10.2%	-1.5%	11.0%	9.0%	10.3%	9.7%
Debt / Capitalization	49.3%	50.0%	49.3%	31.5%	33.5%	33.4%	42.0%	41.2%	39.5%	52.9%	47.9%	47.1%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade
Source: Moody's Financial Metrics™

Ratings

Exhibit 10

Category	Moody's Rating
NORTHWEST NATURAL GAS COMPANY	
Outlook	Stable
First Mortgage Bonds	A2
Senior Secured	A2
Senior Unsecured MTN	(P)Baa1
Pref. Shelf	(P)Baa3
Commercial Paper	P-2

Source: Moody's Ratings

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REPORT NUMBER 1414632

MOODY'S RATINGS

CREDIT OPINION
8 July 2025

Update

Send Your Feedback

RATINGS

Northwest Natural Gas Company

Domicile	Portland, Oregon, United States
Long Term Rating	(P)Baa1
Type	Senior Unsec. Shelf - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Northwest Natural Gas Company

Update following rating affirmation

Summary

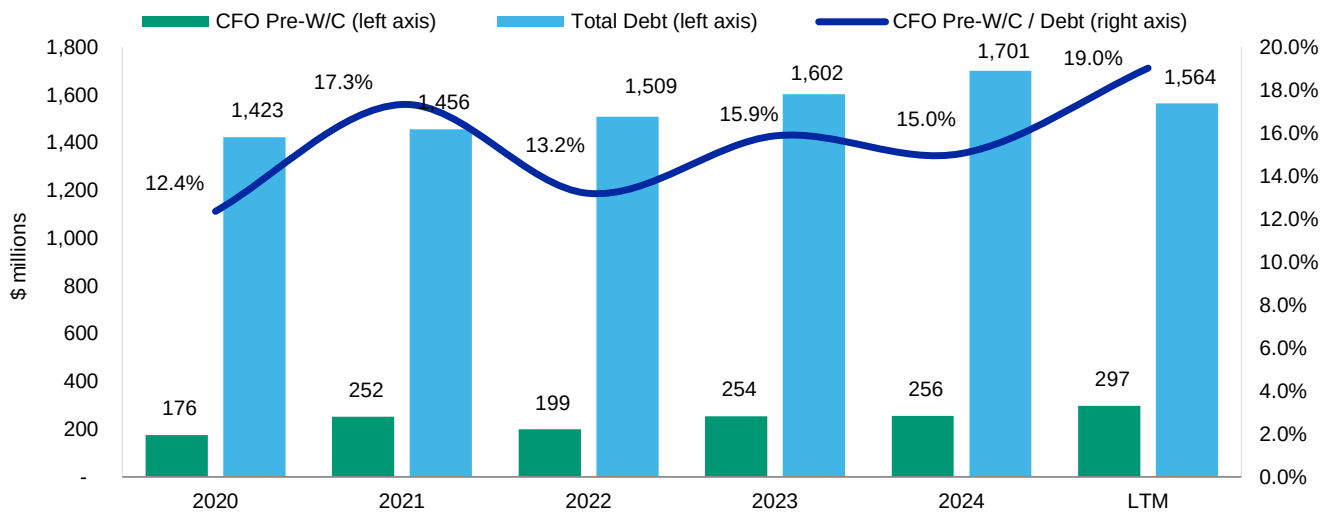
Northwest Natural Gas Company's (NW Natural, Baa1 stable) credit profile incorporates the company's low business risk as a local gas distribution company (LDC) operating in generally supportive regulatory environments. In particular, Oregon's suite of cost recovery mechanisms and constructive stakeholder relationships have supported NW Natural's solid, albeit volatile, cash flow generation over the last several years.

We expect NW Natural's financial performance to improve over the next several years driven by timely cash flow generation and credit supportive regulatory proceedings. The utility's cash flow from operations before changes in working capital (CFO pre-WC) to debt ratio has averaged about 15% over the last three years, ending at 15% in 2024. As of the last twelve months ending 31 March 2025, the ratio increased to 19%.

The recent improvement is attributed to stronger cash flow generation and temporarily reduced debt levels, aligning the utility's capital structure to a higher equity layer of 52%, as filed in their most recent general rate case. NW Natural entered into a stipulation, subject to commission approval, with parties in its 2025 rate case that includes a 50% equity layer as well as a 9.5% ROE (increase from 9.4%) and a $21 million revenue increase. Although we view a higher equity ratio as a credit positive because it supports higher required revenue and reduces reliance on debt, which helps to support stronger credit metrics, we view the 2025 rate case settlement as constructive.

Because of its supportive regulatory outcomes, we expect NW Natural's financial profile to improve over the next several years. We estimate that the CFO pre-WC to debt ratio will range between 16% and 18% over the next 12 to 18 months with a stronger longer-term run rate ranging between 17% and 19%. These estimates include an about $1.6 billion capital expenditure plan (2025-2029), which is consistent with the last five-year capex spend of $1.5 billion (2019-2024). We estimate funding at 50% equity and 50% debt as in prior years.

Exhibit 1
Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt ($ MM)



LTM= Last Twelve Months
Source: Moody's Financial Metrics™

Credit strengths

» Low business risk local gas distribution company

» Improving financial metrics

» Supportive regulatory jurisdictions, including cost tracking mechanisms and legislation that can help investment prospects

Credit challenges

» Historically volatile financial metrics

» CFO pre-W/C to debt has been below 14% downgrade threshold in some years

» Heightened social risk due to state led decarbonization goals

Rating outlook

The stable outlook reflects our expectation that NW Natural's track record of supportive regulatory outcomes will continue over the next several years. We expect credit metrics to improve to levels that are more commensurate with its current ratings, including a ratio of CFO pre-WC to debt ranging between 16% and 18% over the next 12 to 18 months with a stronger longer-term run rate in the 17% to 19% range.

Factors that could lead to an upgrade

A rating upgrade could occur if NW Natural's regulatory environment remains credit supportive and metrics improve such that its CFO pre-WC to debt ratio increases to 18% or above on a sustained basis.

Factors that could lead to a downgrade

A rating downgrade could occur if NW Natural's regulatory environment becomes less credit supportive. A rating downgrade could also be considered if CFO pre-WC to debt falls below 14%.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the issuer/deal page on https://ratings.moodys.com for the most updated credit rating action information and rating history.

Key indicators

Exhibit 2

Northwest Natural Gas Company [1]

	2020	2021	2022	2023	2024	LTM
CFO Pre-W/C + Interest / Interest	4.8x	5.8x	4.4x	4.5x	4.4x	5.0x
CFO Pre-W/C / Debt	12.4%	17.3%	13.2%	15.9%	15.0%	19.0%
CFO Pre-W/C – Dividends / Debt	8.5%	13.5%	9.0%	10.1%	10.8%	14.3%
Debt / Capitalization	55.2%	52.5%	49.3%	50.0%	49.9%	44.8%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics™

Profile

Northwest Natural Gas Company (NW Natural) is a natural gas local distribution company (LDC), serving 807,000 customers in Oregon (about 88% of utility margins) and Washington (about 12% of utility margins). NW Natural is regulated by the Oregon Public Utility Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC).

NW Natural's parent, Northwest Natural Holding Company (NW Holdings), is a holding company headquartered in Portland, Oregon and owns NW Natural (largest subsidiary), SiEnergy, NW Natural Water Company, LLC (NW Natural Water), NW Natural Renewables Holdings, LLC (NW Natural Renewables), and other businesses and activities.

Detailed credit considerations

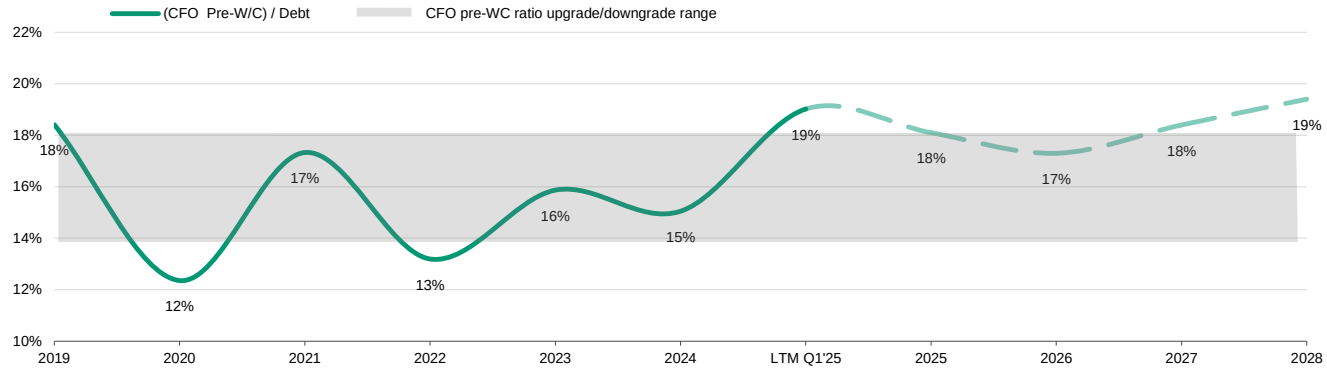
Improving financial performance driven by constructive regulatory proceedings

Over the past five years, NW Natural's credit metrics have experienced significant volatility, primarily driven by one-time events and the company's strategic investments in technology. These investments increased regulatory lag, with the utility's CFO pre-working capital (pre-WC) to debt ratio averaging approximately 15% from 2020 through 2024, falling below the 14% downgrade threshold in some years. However, in its 2024 general rate case, NW Natural received regulatory approval to recover these investments. Combined with a temporary reduction in debt, this led to a recent improvement in the CFO pre-WC to debt ratio, which rose to 19% on a last twelve months ending 31 March 2025.

We expect NW Natural's credit metrics to improve over the next several years driven by more timely recovery of cash flow as a result of supportive general rate case outcomes. As shown in Exhibit 3, we project the CFO pre-WC to debt ratio for the next 12 to 18 months to be between 16% and 18% with a longer-term run rate ranging between 17% and 19%, at or slightly above the 18% upgrade threshold. These estimates include capital expenditures for the next five years (2025-2029) of about $1.6 billion, an average of about $320 million annually. This compares to about $1.5 billion, or an average of about $300 million annually, from 2020 to 2024.

Exhibit 3

Improving credit metrics driven by credit supportive regulatory outcomes
Historical and projected CFO pre-WC to debt ratio, upgrade/downgrade threshold range



The range indicated is one of several factors that could lead to an upgrade or downgrade of the ratings if the CFO pre-WC to debt ratio is above or below the level for a sustained period
Source: Moody's Ratings

The utility had two years (2020 and 2022) where CFO pre-WC to debt dropped below 14%. In 2020, the utility's cash flow was affected by the coronavirus pandemic as well as debt levels that increased to ensure adequate liquidity that year amid pandemic uncertainties. The pandemic-related debt was subsequently repaid in 2021. In 2022, the weak metrics were due to cost inflation pressures, primarily within materials used in field work, higher natural gas prices and related short term debt to cover these gas costs. Notably, these were pressures that plagued the entire industry during most of 2022. Favorably, the utility was able to recover the deferred costs within a year as reflected in its stronger credit metrics for 2023.

Supportive legislative and regulatory framework in both Oregon and Washington

NW Natural's low business risk profile is supported by gas distribution operations that receive supportive regulatory treatment from the Oregon Public Utility Commission (OPUC) and Washington Utilities and Transportation Commission (WUTC), which allows for several cost recovery mechanisms that help provide stability and predictability of the utility's cash flow.

Oregon

Since 88% of the utility's margins are derived from Oregon customers, the legislative and regulatory support that NW Natural receives from the OPUC is a fundamental credit driver. In general, NW Natural has cooperative relationships with stakeholders in the state and has been able to negotiate supportive rate case outcomes and obtain tracking mechanisms for its most material costs.

The most important cost recovery mechanisms include: the use of forward test years for capital expenditures; a weather adjusted rate mechanism (WARM); a conservation tariff (i.e., revenue decoupling); purchased gas adjustment (PGA); utility gas reserve investments included in rate base; and a Site Remediation and Recovery Mechanism (SRRM), primarily for the recovery of manufactured gas plant environmental expenditures. These various cost recovery mechanisms help support recovery of the most significant costs that NW Natural faces.

The utility filed its most recent Oregon general rate case in December 2024 and entered into a stipulation, subject to commission approval, with parties that included a 50% equity layer as well as a 9.5% ROE (increase from 9.4%) and a $21 million revenue increase. NW Natural's original request included a $59.4 million revenue increase, a 10.4% ROE and 52% equity layer. Because the utility requested a higher equity layer, NW Natural reduced its debt to align with the requested capital structure. Although we view a higher equity ratio as more credit supportive, we view the stipulated filing as credit supportive despite the 50% equity ratio and lower revenue increase than requested.

NW Natural's last general rate case concluded in an all-party settlement agreement, that was approved by the OPUC in October 2024. The order authorized a $95 million revenue increase (10.2%) and a 9.4% ROE and 50% equity layer. The initial request included a $154.9 million revenue increase (16.6%), a 10.10% ROE, 50% equity layer and a $2.14 billion rate base. NW Natural's initial filing represented the largest base rate increase requested in recent years, underscoring the inflationary pressures that the utility was facing.

Washington

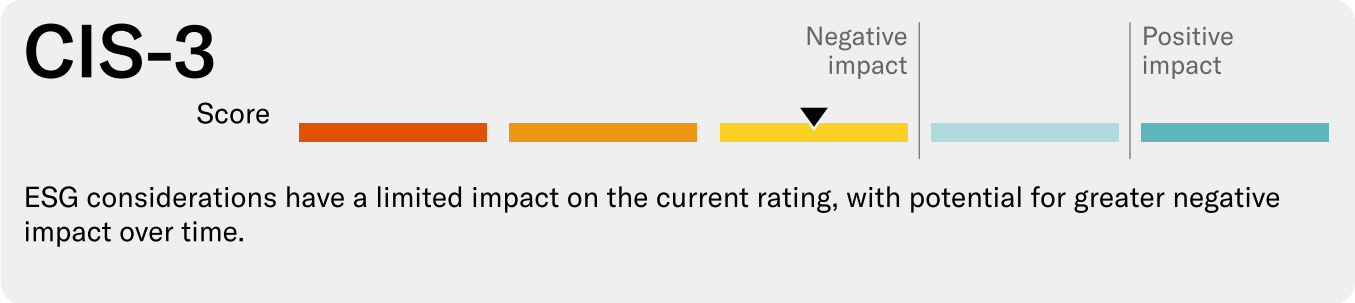
In October 2021, it most recent rate order, the WUTC authorized an annual revenue requirement increase over two years; a 6.4% or $5 million increase in the first year, effective 1 November 2021, and up to a 3.5% or $3 million increase in the second year beginning 1 November 2022. The order was based on an average rate base of $247.3 million.

The filing was based on system investments including costs associated with resiliency and reliability, consumer focused technology and building improvements and upgrades. The WUTC order did not specify the underlying inputs of the cost of capital such as capital structure and ROE. This multiyear rate case was filed for the recovery of investments and costs for system resiliency and reliability as well as for headquarter leasehold improvements and rent costs. It also provided for recovery of upgrades to the Vancouver, Washington service center.

ESG considerations

Northwest Natural Gas Company's ESG credit impact score is CIS-3

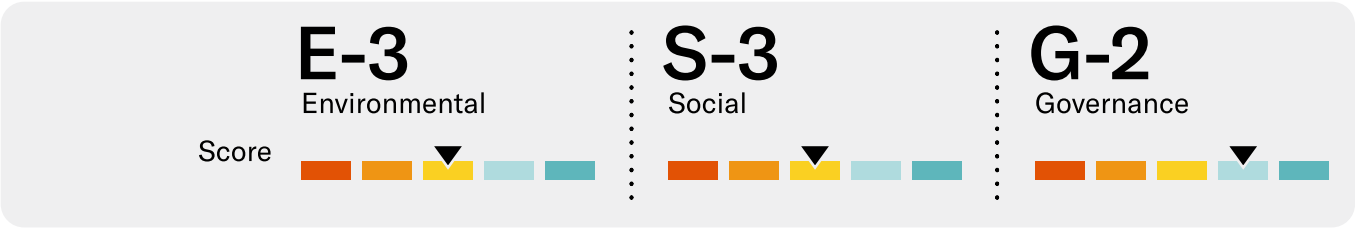
Exhibit 4
ESG credit impact score



Source: Moody's Ratings

NW Natural's **CIS-3** indicates its ESG considerations that have a limited impact on the current rating, with greater potential for future negative impact over time. The utility's scores reflect a combination of higher risk exposure to carbon transition, physical climate and demographic and societal trends.

Exhibit 5
ESG issuer profile scores



Source: Moody's Ratings

Environmental

NW Natural's **E-3** issuer profile score is driven by its higher risk exposure to carbon transition and physical climate risks. Favorably, the company has a strong track record of meeting established emissions targets set by legislative (Oregon Senate Bill 98) and regulatory policies. NW Natural established a Low Carbon Savings goal of 30% by 2035 that includes customers emissions and a goal of being a carbon neutral provider by 2050. This will be achieved through increasing the use of renewable natural gas as well as hydrogen blending. Although the utility is exposed to moderately high physical climate risks, the company worked to mitigate these risks by removing all bare steel pipe from its system by completing the multi-year investment in 2015. Additionally, the system is predominantly underground, which makes the infrastructure more resilient and less vulnerable to weather or other events that could disrupt power to the region.

Social

NW Natural's **S-3** issuer profile score reflects higher risk to responsible production and demographics and societal trends that increase public concern over environmental, social, or affordability issues that could lead to adverse regulatory political intervention. These risks are balanced by neutral to low exposure to health and safety, human capital, and customer relations. NW Natural has historically worked collaboratively with its regulator to make energy transition as affordable as possible for customers and we see this trend continuing as the company executes on its energy transmission goals over the next several years. Additionally, the company has a strong hedging program including storage and contracts that draw from a diverse supply to ensure reliability and reduce commodity risk

Governance

NW Natural's **G-2** issuer profile score is broadly in line with other utilities and does not pose a particular risk. This is supported by neutral to low exposure to financial strategy and risk management and management credibility and track record.

ESG Issuer Profile Scores and Credit Impact Scores for the rated entity/transaction are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for the entity/transaction on MDC and view the ESG Scores section.

Liquidity analysis

NW Natural maintains adequate liquidity through the use of external credit facilities and market issuances to fund negative free cash flow. As of the last twelve months ending 31 March 2025, NW Natural's internal liquidity included about $82 million of cash on hand and produced about $290 million in cash flow from operations; this compares to about $365 million in capital expenditures and $70 million in dividends for the same last twelve month period, resulting in approximately $150 million of negative free cash flow.

The utility has access to a $400 million revolving credit agreement. In December 2024, the agreement was amended with a new maturity date of 3 November 2027, with an option to extend one additional year, subject to lender approval. The credit agreement includes a feature that allows NW Natural to request an increase in the total amount up to $600 million. The credit agreement also permits the issuance of letters of credit in an aggregate amount of up to $60 million.

In January 2024, the utility entered into an uncommitted letter of credit and reimbursement agreement. Although there is no expressly stated maximum amount of letters of credit that can be issued or outstanding under the facility due to current regulatory authority from the OPUC, the sum of LCs outstanding cannot exceed $100 million at any one time. As of 31 March 2025, NW Natural did not have any outstanding balance drawn under its credit facility or letters of credit. The primary restrictive covenant for both agreements requires the company to maintain a debt to capitalization ratio of 70% or less, which NW Natural was in compliance with at 31 March 2025 (47.4%).

NW Natural's next debt maturities are in September 2025 and December 2025, when $20 million and $10 million of senior secured notes are due, respectively.

Rating methodology and scorecard factors

Exhibit 6
Methodology Scorecard Factors
Northwest Natural Gas Company

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 3/31/2025		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	4.7x	A	4.5x - 5.5x	A
b) CFO pre-WC / Debt (3 Year Avg)	16.8%	Baa	16% - 18%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	11.9%	Baa	11% - 15%	Baa
d) Debt / Capitalization (3 Year Avg)	47.5%	A	47% - 50%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching	0	0	0	0
a) Scorecard-Indicated Outcome		A3		A3
b) Actual Rating Assigned				(P)Baa1

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 3/31/2025(L)
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures
Source: Moody's Financial Metrics

Appendix

Exhibit 7

Cash Flow and Credit Metrics [1]

CF Metrics (in $ millions)	2020	2021	2022	2023	2024	LTM
FFO	**184**	**227**	**207**	**241**	**245**	**294**
+/- Other	(8)	25	(8)	13	11	4
CFO Pre-WC	**176**	**252**	**199**	**254**	**256**	**297**
+/- ΔWC	(3)	(105)	(53)	29	(4)	17
CFO	**173**	**148**	**146**	**283**	**252**	**315**
- Div	55	56	63	92	73	74
- Capex	267	280	320	293	356	368
FCF	(149)	(189)	(237)	(102)	(178)	(127)
(CFO Pre-W/C) / Debt	12.4%	17.3%	13.2%	15.9%	15.0%	19.0%
(CFO Pre-W/C - Dividends) / Debt	8.5%	13.5%	9.0%	10.1%	10.8%	14.3%
FFO / Debt	12.9%	15.6%	13.7%	15.1%	14.4%	18.8%
RCF / Debt	9.0%	11.8%	9.5%	9.3%	10.1%	14.0%
Revenue	759	843	1,014	1,159	1,100	1,127
Interest Expense	46	53	59	74	76	75
Net Income	78	85	86	95	85	110
Total Assets	3,599	3,898	4,453	4,511	4,756	4,768
Total Liabilities	2,764	2,921	3,262	3,279	3,432	3,251
Total Equity	835	978	1,191	1,233	1,324	1,516

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months.
Source: Moody's Financial Metrics™

Exhibit 8

Peer Comparison Table [1]

	Northwest Natural Gas Company (P)Baa1 Stable			Berkshire Gas Company A3 Negative			Wisconsin Gas LLC A3 Stable			Southwest Gas Corporation Baa1 Stable		
(in $ millions)	FY Dec-23	FY Dec-24	LTM Mar-25	FY Dec-23	FY Dec-24	LTM Mar-25	FY Dec-23	FY Dec-24	LTM Mar-25	FY Dec-23	FY Dec-24	LTM Mar-25
Revenue	1,159	1,100	1,127	97	93	102	770	680	746	2,500	2,475	2,169
CFO Pre-W/C	254	256	297	20	14	16	154	303	332	525	559	579
Total Debt	1,602	1,701	1,564	93	118	112	1,112	1,112	1,078	3,621	3,603	3,604
CFO Pre-W/C + Interest / Interest	4.5x	4.4x	5.0x	5.9x	3.8x	4.2x	4.9x	7.6x	8.2x	4.3x	4.3x	4.3x
CFO Pre-W/C / Debt	15.9%	15.0%	19.0%	21.6%	11.5%	14.6%	13.9%	27.2%	30.8%	14.5%	15.5%	16.1%
CFO Pre-W/C – Dividends / Debt	10.1%	10.8%	14.3%	21.6%	11.5%	14.6%	-1.5%	20.0%	17.8%	10.3%	10.6%	11.0%
Debt / Capitalization	50.0%	49.9%	44.8%	33.5%	36.8%	34.7%	41.2%	39.2%	38.2%	47.9%	46.8%	45.7%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade
Source: Moody's Financial Metrics™

Ratings

Exhibit 9

Category	Moody's Rating
NORTHWEST NATURAL GAS COMPANY	
Outlook	Stable
First Mortgage Bonds	A2
Senior Secured	A2
Senior Unsecured MTN	(P)Baa1
Pref. Shelf	(P)Baa3
Commercial Paper	P-2

Source: Moody's Ratings

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Ratings

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Research Update:

Northwest Natural Holding Co. Downgraded To 'A'; Outlook Negative; Subsidiary Ratings Affirmed, Outlook To Stable

April 19, 2024

Rating Action Overview

- We concluded our review of the insulating measures in place and determined that they are sufficient to potentially rate Northwest Natural Holding Co. (NWNH) subsidiary Northwest Natural Gas Co. (NWNG) up to two notches higher than its parent's group credit profile (GCP). We also assess the cumulative value of these insulating measures as increasing risk for parent NWNH because they limit or even materially restrict NWNH's access to NWNG's cash flows.
- Consequently, we lowered our rating on parent NWNH to 'A' from 'A+'. The outlook is negative.
- At the same time, we revised our outlook on subsidiary NWNG to stable from negative and affirmed our ratings on NWNG, including the 'A+' long-term issuer credit rating (ICR), the 'A+' unsecured debt rating, the 'AA-' senior secured debt rating, and the 'A-1' short-term rating. The recovery rating on the senior secured debt remains '1+'.
- The stable outlook on NWNG reflects our assessment that the insulating measures in place are sufficient to potentially rate NWNG up to two notches above NWNH's GCP and as such a downgrade to NWNH would not directly lead to a downgrade at NWNG. The stable outlook also reflects our expectations that NWNG's stand-alone financial measures will consistently remain above our downgrade threshold. Specifically, we expect stand-alone funds from operations (FFO) to debt of 15%-18% through 2026.
- The negative outlook on NWNH reflects its weak consolidated financial measures for the current rating. FFO to debt in 2023 was around 12%, significantly below our 15% downgrade threshold. We expect financial performance in 2024 will remain weak but improve in 2025, primarily reflecting our expectations for a fair Oregon rate case order.

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Rating Action Rationale

Our downgrade of NWNH to 'A' from 'A+' reflects higher risks because of material restrictions of cash flows within the company's corporate group. NWNG accounts for about 95% of NWNH's consolidated cash flows. We assess the cumulative value of the insulation measures in place as sufficient to rate NWNG up to two notches above NWNH's GCP. However, these insulating measures limit and could materially restrict NWNH's full access to NWNG cash flows. These insulating measures include dividend restrictions, a non-consolidation opinion, and independent directors on NWNG's board of directors that have effective influence on decision-making and whose vote is required for a voluntary bankruptcy filing.

The negative outlook on NWNH reflects its historical weak financial measures and our expectation that financial performance will remain weak for 2024. Since 2020, NWNH's FFO to debt has been consistently below our 15% downgrade threshold. The company's historical financial underperformance reflects its rising capital investments, including multiple acquisitions of water utilities, which increased its leverage and weakened its financial measures. More recently, NWNH's financial measures have been negatively affected by higher interest rates, higher cash taxes, and inflationary pressures, including higher operating costs.

We expect the company's financial measures will remain challenged in 2024 due to its elevated capital spending plan, including water utility acquisitions, investments in renewable natural gas (RNG) projects, and ongoing infrastructure investments. We expect financial improvement beginning in 2025, primarily reflecting a fair Oregon rate case order. However, financial measures could remain weak for the current rating if elevated capital investments and cash flow deficits are primarily debt funded or the company's rate case order is significantly below expectations.

We affirmed our 'A+' rating on subsidiary NWNG. Our rating largely reflects NWNG's low-risk regulated gas distribution operations in Oregon and Washington. NWNG provides natural gas service to approximately 800,000 customers with 65% of its margin generated from residential customers, 25% from commercial customers, and 7% from industrial customers. The company benefits from stable and supportive regulatory environments in both jurisdictions where it operates, with purchased gas adjustments and environmental cost recovery, decoupling and a forward-looking test year in Oregon, and multiyear rate case fillings in Washington. We view these mechanisms as supportive to its financial measures, allowing the company to largely mitigate regulatory lag. However, over the past few years, the company's earned return on equity (ROE) has been modestly weaker than its authorized ROEs, reflecting a potential weakening of management's ability to manage regulatory risk.

We also view the energy transition risks in Oregon and Washington as potentially increasing business risk. Washington has implemented decarbonization mandates and Oregon is contemplating various decarbonization initiatives. Furthermore, several cities are contemplating the implementation of a gas ban for new gas connections. We assess these evolving risks as potentially negative for credit quality and will continue to monitor future developments.

We assess NWNG's financial risk profile using our low-volatility benchmarks, reflecting the low-risk nature of its natural gas distribution operations and its track record of effective management of regulatory risk. We assume continued use of regulatory mechanisms and rate riders to effectively manage regulatory risk, annual capital spending averaging of about $330 million, and annual dividends averaging of about $75 million. We expect NWNG's stand-alone financial measures to remain in the middle range of its financial risk profile category such that FFO to debt is 15%-18% through 2026.

We consider NWNG to be insulated from its parent NWNH. Based on the strength of the insulating measures, NWNG could potentially be rated up to two notches higher than NWNH's GCP. Currently, NWNG is rated only one notch higher than its GCP, limited by its 'a+' standalone credit profile.

The key insulating measures include:

- NWNG's financial performance and funding prospects are independent from those of the group.
- NWNG issues its own debt and has its own credit facility.
- NWNG is regulated by Oregon and Washington regulatory commissions.
- NWNG has dividend restrictions.
- NWNG's board is highly independent with 11 out of 12 board of directors being independent.
- Independent directors on NWNG's board have effective influence on decision making, and their votes are required for a voluntary bankruptcy filing.
- NWNG is unlikely to be drawn or forced into a NWNH bankruptcy.
- There is an independent third party which is the holder of the "golden share" whose vote is required to file for bankruptcy.

We revised our outlook on NWNG to stable reflecting the insulation measures and the strength of its stand-alone credit profile. The stable outlook reflects our view that NWNG, because of the cumulative value of the insulating measures, could potentially be rated up to two notches above its parent's NWNH GCP. Because of the insulating measures, a downgrade to parent NWNH would not directly lead to a downgrade at NWNG. In addition, the stable outlook reflects our expectation that the company will continue to effectively manage regulatory risk and maintain financial measures consistent with the middle range for its financial risk profile category. Specifically, we expect stand-alone FFO to debt of 15%-18% through 2026.

Outlook

Northwest Natural Holding Co. (NWNH)

The negative outlook on NWNH reflects its current weak financial measures and the possibility that financial measures could remain weak. Our base case assumes continued weak financial performance in 2024 and then for financial performance improvement in 2025. This improvement primarily reflects a fair Oregon rate case order, such that FFO to debt is consistently greater than 15%.

Downside scenario

We could lower our ratings on NWNH over the next 12 to 24 months if FFO to debt remains below 15%. We could also lower our ratings on NWNH if business risk increases. This could reflect an unfavorable rate case outcome, higher risks due to decarbonization mandates and potential gas bans, a weakening of the company's management of regulatory risk, or an inability to consistently earn its authorized ROE.

Upside scenario

We could affirm ratings and revise our outlook on NWNH back to stable over the next 12 to 24 months if FFO to debt improves to consistently greater than 15%, with no increase of business risk.

Outlook

Northwest Natural Gas Co. (NWNG)

The stable outlook on NWNG reflects our base-case assumption that NWNG will generate sufficient cash flows to maintain appropriate consolidated financial measures for the current rating, including FFO to debt of 15%-18% through 2026. The stable outlook also reflects our expectation of strong operating performance and effective management of regulatory risk.

Downside scenario

We could lower our rating on NWNG over the next 24 months if the company's consolidated financial performance weakens such that FFO to debt remains consistently below 15%.We could also lower our rating on NWNG if the company's business risk increases. This could reflect a higher risks due to decarbonization mandates and potential gas bans, a weakening of the company's management of regulatory risk, or an inability to consistently earn its authorized ROE.

Upside scenario

We could raise our rating on NWNG over the next 12 to 24 months if the company's financial performance improves such that FFO to Debt is consistently above 21%, with no weakening of business risk.

Company Description

NWNH is the holding company of NWNG, NWNR and NW Natural Water Co. LLC (NWWC). NWNG operates as a regulated natural gas distribution company, providing natural gas service to approximately 800,000 residential, commercial, and industrial natural gas customers in Oregon and Southwest Washington through 14,200 miles of pipeline systems. Approximately 90% of customers are in Oregon and 10% are in southwest Washington. NWNR is engaged in investing competitive RNG operations while NWWC owns and operates several regulated water utilities. Together, NWNR and NWWC contribute about 5% of NWNH's revenues while NWNG contributes the remaining 95% revenues.

Our Base-Case Scenario

- Modest customer growth and continued use of regulatory mechanisms.
- Continued negative discretionary cash flow.
- Annual capital spending averaging about $370 million over our forecast period.

- Small tuck-in regulated water utilities acquisitions funded in a credit supportive manner.
- Annual dividends averaging about $77 million.
- All debt maturities refinanced.

Liquidity

We assess NWNH's liquidity as adequate, with sources covering uses by 1.1x over the coming 12 months, and that its sources cover uses even if forecasted consolidated EBITDA declines by 10%. We believe the predictable regulatory framework for NWNH provides a manageable level of cash flow stability for the company even in times of economic stress, supporting our use of slightly lower thresholds to assess liquidity. In addition, NWNH has the ability to absorb high-impact, low-probability events, reflecting that the company maintains about $600 million in committed credit facilities through 2026, and our belief that the company can lower its high capital spending (averaging about $370 million annually) during stressful periods, indicative of a limited need for refinancing under such conditions.

Furthermore, our assessment reflects the company's generally prudent risk management, sound relationships with its banking group (which includes over four well-established banks). Overall, we believe the company can withstand adverse market circumstances over the next 12 months with sufficient liquidity to meet its obligations. The company has no large long-term debt maturity coming due, and we expect the company to proactively address any maturities well in advance of its scheduled due dates.

Principal liquidity sources

- Cash and cash equivalents of about $33 million;
- Credit facilities of about $600 million; and
- Cash FFO estimated of about $275 million.

Principal liquidity uses

- Debt maturities, including commercial paper outstanding of about $241 million;
- Capital expenditure (capex) of about $400 million; and
- Dividend payments of about $75 million.

Environmental, Social, And Governance

ESG factors have no material influence on our credit rating analysis of NWNH.

Issue Ratings - Subordination Risk Analysis

Capital structure

The short-term rating on NWNG is 'A-1', based on our 'A+' issuer credit rating on the company. As on Dec 31, 2023, NWNG's capital structure consists of approximately $1.4 billion first mortgage bonds. The company also maintains a medium-term note program which is currently not utilized.

Analytical conclusions

We rate NWNG's medium-term notes program 'A+', equal to its issuer credit rating, because we view any debt issued under this program as debt issued by a qualifying investment-grade utility.

Issue Ratings - Recovery Analysis

Key analytical factors

NWNG's first-mortgage bonds benefit from a first-priority lien on substantially all of the utility's real property, owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+ and an issue-level rating one notch above the issuer credit rating.

Ratings Score Snapshot

Northwest Natural Holding Co.

Issuer credit rating: A/Negative/--

Business risk: Excellent

- Country risk: Very Low
- Industry risk: Very Low
- Competitive position: Strong

Financial risk: Intermediate

- Cash flow/leverage: Intermediate

Anchor: a+

Modifiers

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Neutral (no impact)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: a+

Group credit profile: a

Northwest Natural Gas Co.

Issuer credit rating: A+/Stable/A-1

Business risk: Excellent

- Country risk: Very Low
- Industry risk: Very Low
- Competitive position: Strong

Financial risk: Intermediate

- Cash flow/leverage: Intermediate

Anchor: a+

Modifiers

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Neutral (no impact)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: a+

Group credit profile: a

Entity status within group: Insulated (no impact)

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, April 4, 2024
- Criteria | Corporates | General: Corporate Methodology, Jan. 7, 2024
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014

- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings List

Downgraded

	To	From
Northwest Natural Holding Company		
Issuer Credit Rating	A/Negative/--	A+/Negative/--
Ratings Affirmed; Outlook Action		
	To	**From**
Northwest Natural Gas Co.		
Issuer Credit Rating	A+/Stable/A-1	A+/Negative/A-1
Ratings Affirmed; Recovery Ratings Unchanged		
Northwest Natural Gas Co.		
Senior Secured	AA-	AA-
Recovery Rating	1+	1+
Ratings Affirmed		
Commercial Paper	A-1	A-1

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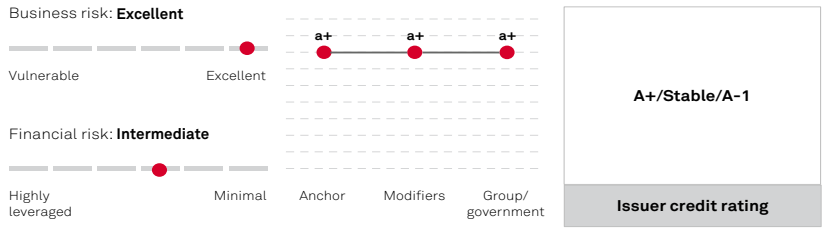
Northwest Natural Gas Co.

June 25, 2025

Ratings Score Snapshot



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Credit Highlights

Overview

Key strengths	Key risks
Low-risk natural gas distribution operations with limited unregulated storage operations.	Limited geographic and regulatory diversity.
Effective management of regulatory risks with operations under the credit-supportive regulatory frameworks in Washington and Oregon.	Decarbonization initiatives that pressure future growth.
Insulating measures that we assess as sufficient to rate the company above its parent's group credit profile.	Continued negative discretionary cash flow over the next few years, indicating external funding needs.

We continue to monitor the ongoing Oregon rate case proceedings. On June 23, 2025, Northwest Natural Gas Co. (NWNG), and certain parties filed a stipulation in the company's 2024 rate case filing for a revenue increase of $21.3 million (about 35% of the company's original request). The stipulation is based on a modestly improved return on equity (ROE) of 9.5% and maintaining the 50% equity structure. While the stipulated revenue increase appears modest, it is in line with our base-case expectations, and we believe it will continue to support credit quality. We expect the stipulation, subject to approval by the Public Utility Commission of Oregon (OPUC), will be in effect by year-end 2025. We also believe items not addressed in the

stipulation, will be subject to ongoing litigation process. This current filing follows a $95 million rate case order based on a settlement that was approved in late 2024. We assessed this previous rate case order as supportive of credit quality and expect that the company will continue to effectively manage regulatory risk.

We view the insulating measures in place as sufficient to rate NWNG two-notches above the 'a-' group credit profile on parent Northwest Natural Holding Co. (NWNH). Our analysis incorporates our 'a+' stand-alone credit profile (SACP) on NWNG and the cumulative value of the insulating and regulatory measures in place. NWNG has the following insulating measures:

- NWNG's financial performance and funding prospects are independent from those of NWNH.
- NWNG issues its own debt and has its own credit facility.
- NWNG is regulated by the Oregon and Washington regulatory commissions.
- NWNG has dividend restrictions. It must maintain 45% equity before distributing any dividends upstream if its secured issue-level ratings are below 'A-', maintain 46% equity if its secured issue-level ratings are below 'BBB'. No dividends are allowed if its equity falls below 44% or the secured issue-level ratings drop below 'BBB-'.
- NWNG's board of directors is highly independent with eight independent directors on a board of 10.
- Independent directors on NWNG's board have effective influence on decisions, and their votes are required for a voluntary bankruptcy filing.
- NWNG is unlikely to be drawn or forced into a NWNH bankruptcy due to absence of cross-default provisions.
- An independent third party holds the "golden share" vote required to file for a bankruptcy filing.

Outlook

The stable rating outlook on NWNG reflects our base-case assumption that the company will generate sufficient cash flow to maintain appropriate consolidated financial measures for the current rating, including funds from operations (FFO) to debt of 15%-17% through 2027. The stable outlook also reflects our expectation of continued strong operating performance and effective management of regulatory risk.

Downside scenario

We could lower our rating on NWNG over the next 24 months if:

- The company's consolidated financial performance consistently weakens such that FFO to debt falls below 15%; or
- The company's business risk increases. This could reflect higher risks due to decarbonization mandates and potential gas bans, a weakening of the company's effective management of regulatory risk, or an inability to consistently earn its authorized ROE.

Upside scenario

We could raise our rating on NWNG over the next 12-24 months if the company's financial performance improves such that FFO to debt is consistently above 21%, with no increase to business risk.

Our Base-Case Scenario

Assumptions

- Modest customer growth and continued use of regulatory mechanisms.
- Continued negative discretionary cash flow through 2027.
- Annual capital spending averaging about $350 million through 2027.
- Annual dividends averaging about $85 million.
- All debt maturities refinanced.

Northwest Natural Gas Co.--Forecast summary

Period ending	Dec-31-2021	Dec-31-2022	Dec-31-2023	Dec-31-2024	Dec-31-2025	Dec-31-2026	Dec-31-2027
(Mil. $)	2021a	2022a	2023a	2024a	2025e	2026f	2027f
Adjusted ratios							
Debt/EBITDA (x)	4.8	4.8	4.9	4.8	4.5-5.0	4.5-5.0	4.0-4.5
FFO/debt (%)	15.3	16.9	14.0	14.6	15-17	15-17	15-17
FFO cash interest coverage (x)	5.4	5.6	4.1	4.8	4.5-5.0	4.5-5.0	4.5-5.0

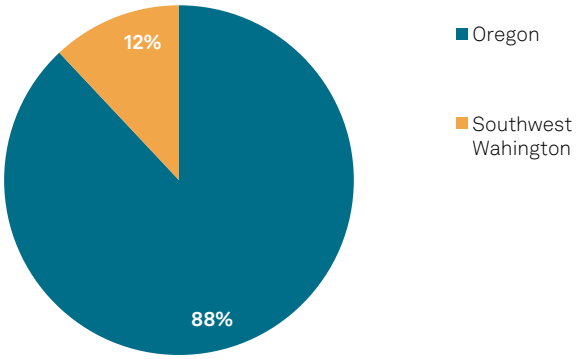
*All figures adjusted by S&P Global Ratings, unless stated as reported. a--Actual. e--Estimate. f--Forecast. FFO--Funds from operations to debt.

Company Description

NWNG operates as a regulated natural gas distribution company, providing natural gas service to approximately 805,000 residential, commercial, and industrial customers in Oregon and Southwest Washington through 14,400 miles of pipeline systems. Residential customers generate 65% of its margin, 24% from commercial customers, and 6% from industrial customers.

Northwest Natural Gas Co.'s customers by geographic area

As of Dec. 31, 2024.



Source: Company filings.

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Peer Comparison

Northwest Natural Gas Co.--Peer Comparisons

	Northwest Natural Gas Co.	ONE Gas Inc.	Atmos Energy Corp.	Piedmont Natural Gas Co. Inc.
Foreign currency issuer credit rating	A+/Stable/A-1	A-/Stable/A-2	A-/Stable/A-2	BBB+/Stable/A-2
Local currency issuer credit rating	A+/Stable/A-1	A-/Stable/A-2	A-/Stable/A-2	BBB+/Stable/A-2
Period	Annual	Annual	Annual	Annual
Period ending	2024-12-31	2024-12-31	2024-09-30	2024-12-31
Mil.	$	$	$	$
Revenue	1,100	2,040	4,151	1,729
EBITDA	341	673	2,070	902
Funds from operations (FFO)	239	550	1,714	670
Interest	69	140	213	194
Cash interest paid	63	144	341	184
Operating cash flow (OCF)	232	337	1,736	652
Capital expenditure	354	695	2,922	1,017
Free operating cash flow (FOCF)	(122)	(357)	(1,187)	(365)
Discretionary cash flow (DCF)	(196)	(508)	(1,680)	(475)
Cash and short-term investments	20	58	307	2
Gross available cash	20	58	307	2
Debt	1,635	2,844	7,743	4,704
Equity	1,324	3,105	12,158	4,354
EBITDA margin (%)	30.9	33.0	49.9	52.2
Return on capital (%)	6.9	6.9	7.6	7.9
EBITDA interest coverage (x)	4.9	4.8	9.7	4.6

Northwest Natural Gas Co.--Peer Comparisons				
FFO cash interest coverage (x)	4.8	4.8	6.0	4.6
Debt/EBITDA (x)	4.8	4.2	3.7	5.2
FFO/debt (%)	14.6	19.3	22.1	14.2
OCF/debt (%)	14.2	11.9	22.4	13.9
FOCF/debt (%)	(7.4)	(12.6)	(15.3)	(7.8)
DCF/debt (%)	(12.0)	(17.9)	(21.7)	(10.1)

Business Risk

We assess NWNG's business risk based on its low-risk regulated gas distribution operations accounting for about 95% of consolidated operating revenue, residential-focused customer base, and effective management of regulatory risks.

The company benefits from stable and supportive regulatory environments in both jurisdictions in which it operates, with purchased gas adjustments and environmental cost recovery, decoupling, and a forward-looking test year in Oregon and multiyear rate case fillings in Washington. We view these mechanisms as supportive of its financial measures, allowing the company to mitigate regulatory lag. In addition, 90% of the margin is generated from residential and commercial customers, providing a stable margin profile.

Northwest Natural Gas Co.'s natural gas distribution by segment

As of Dec. 31, 2024

Source: Company filings.

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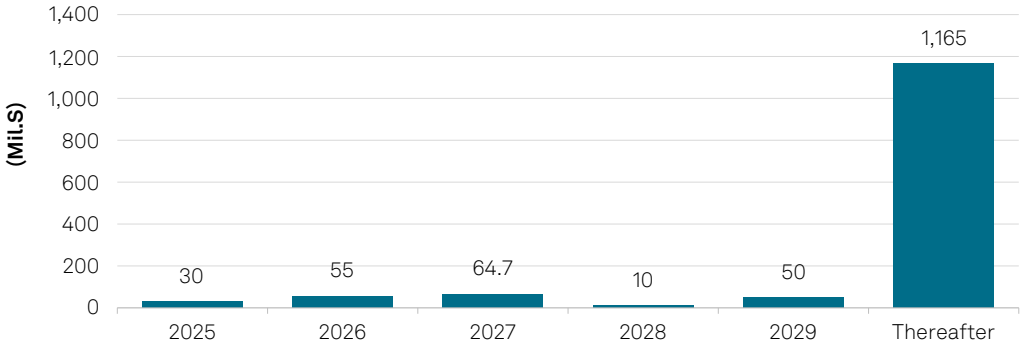
Financial Risk

Under our base case, we assess NWNG using our low-volatility table, reflecting the low-risk nature of its natural gas distribution operations and effective management of regulatory risk. NWNG's 2024 stand-alone FFO to debt was 14.6%, and we expect it to strengthen modestly over our forecast period but remain in the middle of the range for its financial risk profile category. Specifically, we project FFO-to-debt in the range of 15%-17% through 2027. Our assumptions include the 2024 and 2025 Oregon rate case increases, annual capital spending averaging about

$350 million, and annual dividends averaging about $85 million through 2027. We expect a majority of the capital spending to fund replacing and improving system reliability.

Debt maturities

Northwest Natural Gas Co.'s debt maturity schedule
As of Dec. 31, 2024



Source: Company filings.

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Northwest Natural Gas Co.--Financial Summary

Period ending	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022	Dec-31-2023	Dec-31-2024
Reporting period	2019a	2020a	2021a	2022a	2023a	2024a
Display currency (mil.)	$	$	$	$	$	$
Revenues	740	759	843	1,014	1,159	1,100
EBITDA	245	257	286	292	316	341
Funds from operations (FFO)	202	207	211	236	218	239
Interest expense	41	44	49	52	66	69
Cash interest paid	40	44	48	51	70	63
Operating cash flow (OCF)	191	148	143	146	283	232
Capital expenditure	221	274	280	319	291	354
Free operating cash flow (FOCF)	(31)	(126)	(137)	(173)	(8)	(122)
Discretionary cash flow (DCF)	(84)	(182)	(193)	(236)	(100)	(196)
Cash and short-term investments	6	10	12	13	20	20
Gross available cash	6	10	12	13	20	20
Debt	1,066	1,353	1,379	1,397	1,553	1,635
Common equity	822	835	978	1,191	1,233	1,324
Adjusted ratios						
EBITDA margin (%)	33.0	33.9	33.9	28.8	27.2	30.9
Return on capital (%)	8.3	7.4	7.5	7.2	7.6	6.9
EBITDA interest coverage (x)	5.9	5.9	5.9	5.6	4.8	4.9
FFO cash interest coverage (x)	6.0	5.7	5.4	5.6	4.1	4.8
Debt/EBITDA (x)	4.4	5.3	4.8	4.8	4.9	4.8

Northwest Natural Gas Co.--Financial Summary

FFO/debt (%)	18.9	15.3	15.3	16.9	14.0	14.6
OCF/debt (%)	17.9	10.9	10.3	10.5	18.2	14.2
FOCF/debt (%)	(2.9)	(9.3)	(9.9)	(12.4)	(0.5)	(7.4)
DCF/debt (%)	(7.9)	(13.4)	(14.0)	(16.9)	(6.4)	(12.0)

Reconciliation Of Northwest Natural Gas Co. Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Financial year	Dec-31-2024									
Company reported amounts	1,502	1,324	1,100	330	190	63	341	231	73	354
Cash taxes paid	-	-	-	-	-	-	(39)	-	-	-
Cash interest paid	-	-	-	-	-	-	(57)	-	-	-
Lease liabilities	77	-	-	-	-	-	-	-	-	-
Operating leases	-	-	-	8	6	6	(6)	2	-	-
Postretirement benefit obligations/ deferred compensation	113	-	-	-	-	-	-	-	-	-
Accessible cash and liquid investments	(20)	-	-	-	-	-	-	-	-	-
Share-based compensation expense	-	-	-	3	-	-	-	-	-	-
Nonoperating income (expense)	-	-	-	-	2	-	-	-	-	-
Debt: Debt serviced by third parties	(38)	-	-	-	-	-	-	-	-	-
Total adjustments	133	-	-	10	8	6	(102)	2	-	-
S&P Global Ratings adjusted	**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
	1,635	1,324	1,100	341	197	69	239	232	73	354

Liquidity

As of March 31, 2025, we assess NWNG's liquidity as adequate, with sources covering uses by more than 1.1x over the coming 12 months, even if forecast consolidated EBITDA declines 10%. We believe the predictable regulatory framework for NWNG provides a manageable level of cash flow stability even in times of economic stress, supporting our use of slightly lower thresholds to

assess liquidity. In addition, NWNG can absorb high-impact, low-probability events, reflecting that the company maintains about $400 million in committed credit facilities through 2027. It also reflects our belief that the company can lower its high capital spending (averaging about $350 million annually through 2027) during stressful periods, indicating a limited need for refinancing under such conditions. Furthermore, our assessment reflects the company's generally prudent risk management and sound relationships with its banking group (which includes over four well-established banks).

Overall, we believe that the company can withstand adverse market circumstances over the next 12 months, with sufficient liquidity to meet its obligations. The company has no big long-term debt maturity coming due, and we expect it to proactively address this maturity well in advance of its scheduled due date.

Principal liquidity sources

- Cash and cash equivalents of about $81.8 million as of March 31, 2025;
- Credit facility availability of about $400 million; and
- Cash FFO estimated of about $280 million.

Principal liquidity uses

- Debt maturities of about $30 million;
- Capital expenditure of about $360 million; and
- Dividend payments of about $80 million

Environmental, Social, And Governance

ESG factors have no material influence on our credit rating analysis of NWNG.

Group Influence

Under our group rating methodology, we consider NWNH as the parent of the group with a GCP of 'a-'. We assess NWNG as a core subsidiary of NWNH because we view the utility as integral to the group's identity, highly unlikely to be sold, and having a strong commitment from NWNH's senior management, given the company's emphasis on maintaining its strategic focus on regulated gas distribution operations.

That said, our issuer credit rating on NWNG is two notches above the parent's GCP. Because NWNG is operationally separate from NWNH and there are certain regulatory restrictions in place, which we view the utility as having sufficient insulating measures that allow NWNG to be rated up to two notches above the NWNH's GCP. These regulatory protections include dividend restrictions, a highly independent board, and an independent third party that is the holder of the "golden share" whose vote is required to file for bankruptcy.

Issue Ratings--Subordination Risk Analysis

Capital structure

The short-term rating on NWNG is 'A-1' based on our 'A+' issuer credit rating on the company.

Analytical conclusions

We rate the company's medium-term notes program 'A+', equal to its issuer credit rating, because we view any debt issued under this program as debt issued by a qualifying investment-grade utility.

Issue Ratings--Recovery Analysis

Key analytical factors

NWNG's first-mortgage bonds benefit from a first-priority lien on substantially all of the utility's real property, owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue rating one notch above the issuer credit rating.

Rating Component Scores	
Foreign currency issuer credit rating	**A+/Stable/A-1**
Local currency issuer credit rating	**A+/Stable/A-1**
Business risk	**Excellent**
Country risk	Very Low
Industry risk	Very Low
Competitive position	Strong
Financial risk	**Intermediate**
Cash flow/leverage	Intermediate
Anchor	**a+**
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)
Liquidity	Adequate (no impact)
Management and governance	Neutral (no impact)
Comparable rating analysis	Neutral (no impact)
Stand-alone credit profile	**a+**
Group credit profile	**a-**
Entity status within group	**Insulated (Same as SACP)**

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, April 4, 2024
- Criteria | Corporates | General: Corporate Methodology, Jan. 7, 2024
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019

- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings Detail (as of June 24, 2025)*

Northwest Natural Gas Co.	
Issuer Credit Rating	A+/Stable/A-1
Commercial Paper	
Local Currency	A-1
Senior Secured	AA-
Issuer Credit Ratings History	
19-Apr-2024	A+/Stable/A-1
09-Oct-2023	A+/Negative/A-1
25-Jan-2010	A+/Stable/A-1
Related Entities	
Northwest Natural Holding Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Junior Subordinated	BBB

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings' credit ratings on the global scale are comparable across countries. S&P Global Ratings' credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

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BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Jennifer E. Nelson

RATE OF RETURN ON EQUITY

Exh. JEN-14

August 29, 2025

S&P Global
Market Intelligence

April 16, 2020
spglobal.com/marketintelligence

RRA Regulatory Focus
Alternative ratemaking plans in the U.S.

A key to reducing regulatory lag and providing certainty for investors

In these increasingly volatile times, when investors are struggling to understand what the ongoing COVID-19 pandemic and the related recessionary pressures will mean for utility cash flow and profitability, alternative ratemaking plans can provide some degree of protection.

For Detailed Data

Click here to see supporting data tables.

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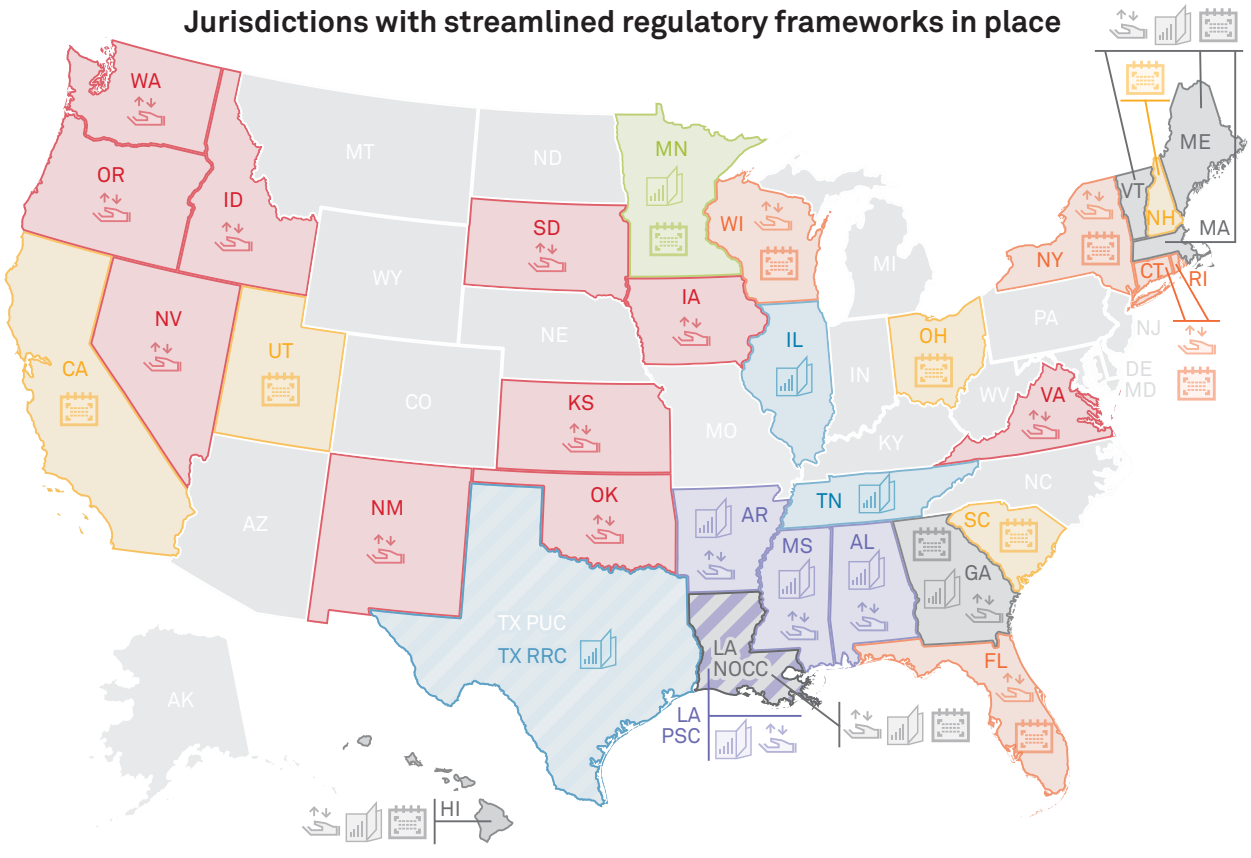
Jurisdictions with streamlined regulatory frameworks in place



S&P Global
Market Intelligence

As of March 31, 2020.
Map credit: Ciaralou Agpalo Palicpic
Source: S&P Global Market Intelligence

Regulatory Research Associates, a group within S&P Global Market Intelligence
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Even before the current global crisis, Regulatory Research Associates, a group within S&P Global Market Intelligence, had taken note of an uptick in state regulators' and policymakers' interest in pursuing innovative forms of regulation to address challenges associated with expanding utility capital spending plans, modest to flat sales growth in most parts of the country, regulatory lag and changes in the way the utilities are expected to do business.

Alternative ratemaking plans is a term applied to a wide-ranging complement of mechanisms that are generally outside of the traditional base rate case model.

These plans can be broadly or narrowly focused. Broad-based plans like formula based ratemaking, multi-year rate plans and earnings sharing mechanisms streamline the regulatory process, lessen the burden on regulatory commissions, their staff and stakeholders and reduce regulatory lag for utilities. These type of mechanisms may be implemented on a stand-alone basis or in combination. Many of these arrangements also include an opportunity for earnings enhancement.

As of this writing, 13 of the 53 jurisdictions followed by RRA had formula based ratemaking plans in place for at least one company in the jurisdiction, including jurisdictions where such plans were combined with other mechanisms. There are 17 jurisdictions in which a multi-year rate plan is in place for at least one utility, including instances where it is combined with other types of plans. Earnings sharing mechanisms are in place for at least one utility in 25 jurisdictions, on a stand-alone basis or as part of either a multi-year plan or a formula-based ratemaking mechanism.

Alternative regulation plans in the US[1]

Formula-based ratemaking	Multi-year rate plans	Earnings sharing	Incentive ROEs	Electric fuel/ Gas costs	Capacity release/ Off-system sales
Alabama	California	Alabama	Colorado	Indiana	Colorado
Arkansas	Connecticut	Arkansas	Iowa	Idaho	Delaware
Georgia	Dist. of Columbia[2]	Connecticut	Kansas[2]	Iowa	Florida
Hawaii	Florida	Florida	Mississippi	Illinois	Indiana
Illinois	Georgia	Georgia	Montana[2]	Kansas	Iowa
Louisiana—NOCC	Hawaii	Hawaii	Nevada	Kentucky	Kentucky
Louisiana—PSC	Louisiana—NOCC	Idaho	Ohio	Maryland	Louisiana
Maine	Maine	Iowa	Virginia	Missouri	Massachusetts
Massachusetts	Maryland[2]	Kansas	Washington[2]	Montana	Missouri
Minnesota	Massachusetts	Louisiana—NOCC	Wisconsin	New Jersey	New Jersey
Mississippi	Minnesota	Louisiana—PSC		Oregon	New York
Pennsylvania[2]	New Hampshire	Maine		Tennessee	North Dakota
Tennessee	New York	Massachusetts		Rhode Island	New Jersey
Texas—RRC	Ohio	Mississippi		Utah	Oklahoma
Vermont	Pennsylvania[2]	Nevada		Vermont	Pennsylvania
	Rhode Island	New Mexico		Virginia	Rhode Island
	South Carolina	New York		Wyoming	South Dakota
	Utah	Oklahoma			Tennessee
	Vermont	Oregon			Texas—PUC
	Washington[2]	Rhode Island			Texas—RRC
	Wisconsin	South Dakota			Utah
		Vermont			
		Virginia			
		Washington			
		Wisconsin			

As of March 31, 2020.
NOCC=New Orleans City Council; PSC=Public Service Commission; PUC=Public Utility (ies) Commission; RRC=Railroad Commission.
[1]Mechanism in place for at least on utility in the state, unless otherwise noted.
[2]Specifically permitted by rule, law or commission order; no mechanism currently in place.
Source: Regulatory Research Associates, a group withinn S&P Global Market Intelligence

In certain jurisdictions, legislation or commission rules permit these types of plans, but the commission has yet to approve a specific plan for one of the utilities.

Narrowly focused plans generally target a specific type of behavior or investment on the part of a utility. For example, some may allow a company to retain a portion of cost savings relative to a base level of some expense type, such as fuel, purchased power or pension costs.

Others might permit a company to retain for shareholders a portion of off-system sales or capacity release revenues.

Still others provide a company an enhanced equity return, or ROE, for achieving operational performance targets, customer service metrics, reliability standards, demand reduction targets under energy conservation programs or for meeting or exceeding renewable portfolio standards.

In some instances, commissions have approved ROE premiums for specific types of plant investment when there was a preference for in-state generation versus wholesale power purchases, or in order to incent the deployment of renewable resource facilities.

While narrowly focused plans do not necessarily stream line the regulatory process the way that more broadly focused plans do, they do provide the utilities with the opportunity for earnings enhancement that could offset the impact of regulatory lag.

RRA generally views the presence of alternative ratemaking plans as constructive from an investor viewpoint.

A more detailed discussion of the various types of plans in place is provided in the sections that follow, and a listing of the plans that are currently in place across the U.S. is provided in the related data file.

For additional information, refer to the Alternative regulation section of the Commission Profile for each jurisdiction.

Setting the stage

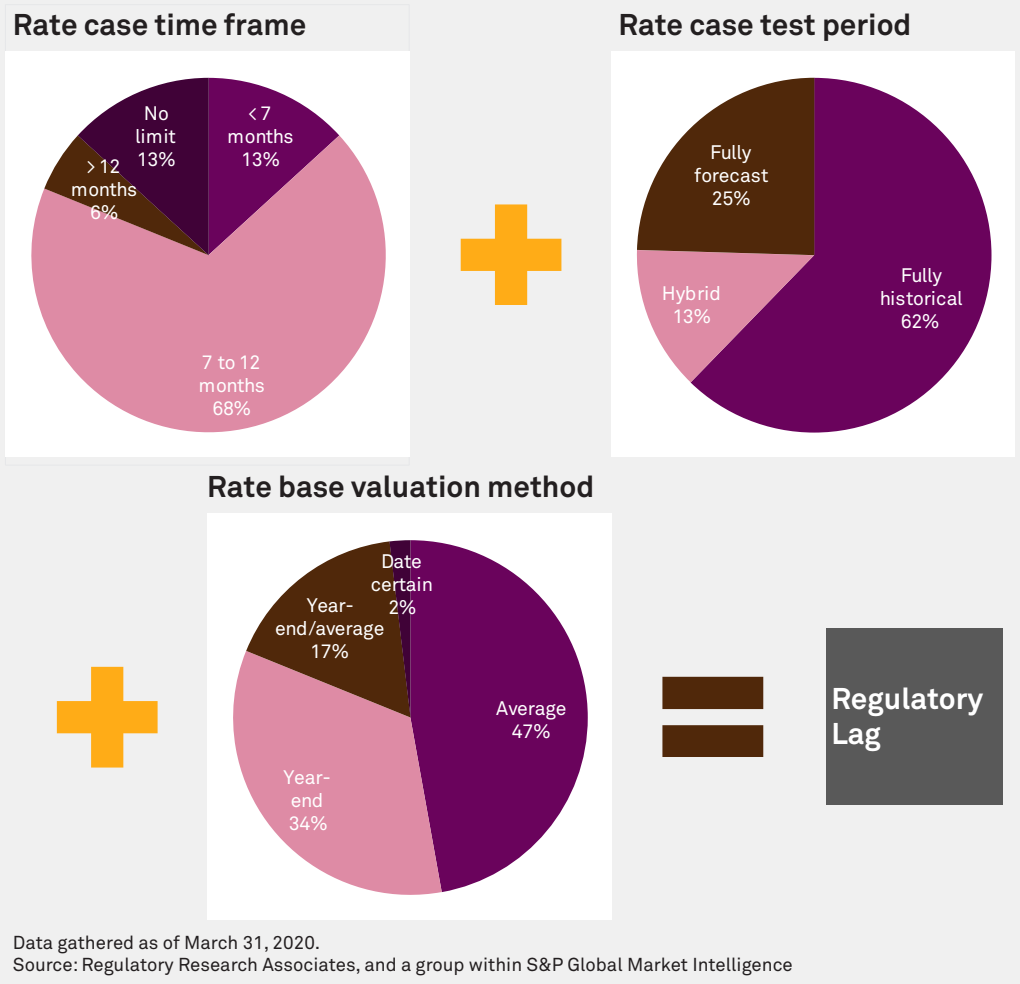
A quick word on regulatory lag

Regulatory lag refers to the time it takes for an investment or cost change to be reflected in rates after that change has occurred. This lag is an inherent part of the rate case process and comes in different forms.

First, is the sheer amount of time it takes for a rate case to be completed. Most states have rules in place that require rate cases to be completed within seven to 12 months of filing, but in some the time frame is substantially longer than 12 months and in others there is no statutory time frame at all.

Aside from processing time, there are the issues of whether the test year is historical, whether the commission employs an average or test-year-end rate base and/or to what extent adjustments to test year data are permitted. For information concerning how these policies are addressed in each state, refer to the Rate Case Timing/Interim Procedures and Rate Base and Test Period sections of RRA's Commission Profiles.

Changes to the basic components of the traditional process are often difficult to achieve, requiring legislative authority. Even in situations where the legislature is on board, stakeholders and commissioners may be slow to embrace the new concepts and there may be unintended consequences, such as a reduction in authorized ROE — whether implicit or explicit — to reflect the perceived reduced risk associated with these mechanisms.



Data gathered as of March 31, 2020.
Source: Regulatory Research Associates, and a group within S&P Global Market Intelligence

Capital spending trends reviewed

Robust capital spending in recent years has been a driver of regulators' interest in and acceptance of alternative forms of regulation.

Based on a study conducted by RRA in October 2019, it was estimated that capital spending for the 52 power and gas utility holding companies in RRA's Financial Focus coverage universe would exceed $134 billion in 2019.

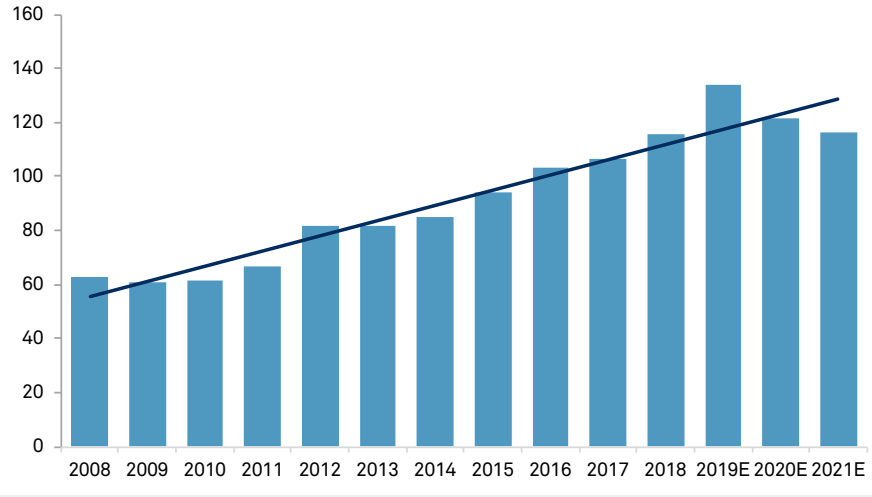
That figure is more than double 2008 capital spending for the group of $63 billion.

These expenditures are largely dedicated to projects such as grid modernization, deployment of advanced technologies, physical safety, reliability, environmental remediation and cyber security.

Such programs are aimed at improving service to existing customers, rather than expanding business into unserved territories or increasing per customer usage.

Up until this point, utilities have been able to achieve rate recognition of the increased investment, despite relatively flat load growth, without much complaint from regulators, because low interest rates and low gas and power market prices kept customer bills from rising precipitously.

Energy utility actual and estimated capital expenditures ($B)

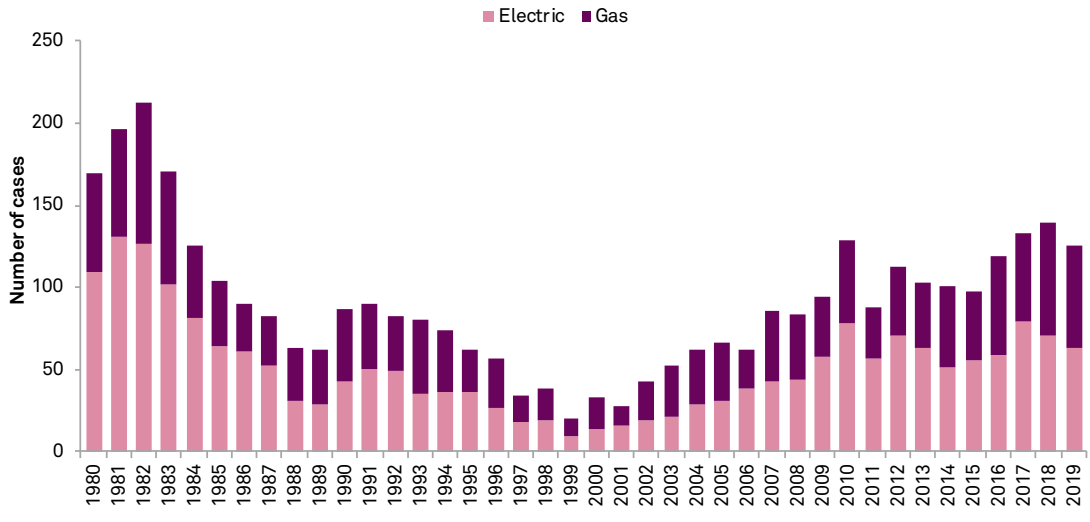


Data compiled Oct. 16, 2019.
E=Estimated
Source: S&P Global Market Intelligence

But that headroom has been eroding, there has already begun to be some pushback from regulators and stakeholders. The costs associated with maintaining service during the pandemic and the burgeoning recession will further erode that headroom. These added pressures may well result in changes to capital spending plans, at least in the near term.

Be that as it may, these increases in capital spending have been a major driver of the heightened level of rate case activity RRA has observed since 2010, as well as a driver of the increasing proliferation in alternative ratemaking frameworks.

Major rate case decisions, 1980-2019



Data gathered as of Jan. 2, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Ingelligence

There were almost 400 state-level electric and gas rate cases followed by RRA that were completed during the three years 2017 through 2019 — the busiest stretch since the generation construction boom of the 1980s.

Refer to RRA's report Major Rate Case Decisions — January - December 2019 for a discussion of rate case trends.

As of March 31, 2020, there were 31 electric and gas rate cases that had been decided nationwide and another 80 cases were pending. Thus, prior to the pandemic becoming so widespread, RRA had expected that 2020 could be another year where more than 100 rate cases were adjudicated.

In response to the financial strain on customers posed by the pandemic, schedules for several pending proceedings are already being delayed, others may be withdrawn and expected filings may be postponed for the time being, pushing the rate case cycle out to next year or perhaps longer.

Alternative ratemaking frameworks a closer look

As noted earlier, alternative ratemaking plans can be either broad-based or narrowly focused. In years passed these plans may have been referred to as incentive regulation because many were designed to accord the utility the ability to achieve incremental earnings relative to its authorized ROE for doing something regulators wanted them to do.

The term performance-based ratemaking was also used interchangeably with incentive regulation. The concept of mitigating regulatory lag is a newer phenomenon. As time has gone on, states have used a patchwork of these mechanisms. The discussion below is designed to provide a broad overview of what the plans currently in place entail, with some key examples for illustrative purposes. For detail concerning the specifics of the plans in place in a given jurisdiction, refer to the Alternative regulation section of the Commission Profile for that jurisdiction.

Formula based ratemaking plans

Formula based ratemaking plans generally refer to frameworks where the commission established a revenue requirement, including a target ROE, capital structure and rate of return for an initial rate base as part of a traditional cost or service base rate proceeding.

Once the initial parameters are set, rates may adjust periodically to reflect changes in expenses, revenue and capital investment. These changes generally occur on an annual basis, and there may be limitations on the percentage change that can be implemented in a given year or period of years.

The plans may remain in place until changed or rescinded by the commission, or there may be a set term. In some instances there are earnings sharing provisions and/or performance metrics the companies are required to meet with penalties/rewards embedded in the periodic rate adjustment to reflect the failure to meet or the ability to exceed the benchmark.

Alabama was the first state to embrace formula-based ratemaking and is perhaps the quintessential example of this construct. All three of the major utilities in the state have a formula ratemaking plan in place and they are all slightly different.

Taking Southern Company subsidiary Alabama Power Co.'s Rate RSE as an example—the framework was first implemented in 1982 and with the exception of a review several years ago to address allegations that the ROE incorporated in the plan was excessive, has operated uninterrupted since.

Under the plan, Alabama Power is permitted to adjust rates annually using a forward-looking test year. Rate changes are capped at 5% for any single year, and the two-year rolling average increase cannot exceed 4%.

The adjustment are designed to keep Alabama Power's earnings within a pre-established weighted cost of equity range — the ROE multiplied by the equity component of the capitals structure — of 5.75% to 6.15%. The Alabama Public Service Commission order approving the framework did not specify the ROE and capital structure; so, using this metric allows the utility added degree of financial flexibility.

Just to provide some perspective on the range, the average ROE authorized for vertically electric utilities in rate cases decided during 2019 was 9.73%, as calculated by RRA. According to RRA, the average authorized equity ratio for electric utilities that year was of 49.94%, which would equate to a 4.86% weighted average cost of equity.

Refunds are required of earnings in excess of the upper end of the range, but the utilities cannot recoup under-earnings below the lower end of the band. The company may earn a seven-basis-point return adder for achieving an "A" credit rating.

In addition to the Rate RSE mechanism, adjustment mechanisms are in place for energy costs and new generation facilities that are separate from the RSE framework.

This framework is viewed as constructive from an investor viewpoint. The automatic annual adjustments take into account changes in costs and sales volumes, up or down, and can also accommodate sea changes such as the federal tax overhaul that occupied so many of the states' time and energy during 2018 and 2019.

The rate change caps provide incentive for the companies to operate efficiently and the use of a target earnings range provides some upside potential.

The use of the weighted average cost of equity, rather than a straight ROE percentage takes into account the impact of changes in capital structure on the required ROE, while discouraging the utility from bulking up the capital structure to increase earnings. Conversely, the premium for maintaining a certain credit rating discourages the company from over-levering the utility.

Another example of formula based ratemaking is Southern Company subsidiary Mississippi Power Co.'s Performance Enhancement Plan, or PEP.

The PEP was implemented in 1986, and has remained in place with modest changes since. The plan allows for automatic annual increases based on a forward-looking test year, with the adjustments capped at 4% annually.

However, under the PEP, the ROE changes each year. First, a benchmark ROE is established using a combination of the Discounted Cash Flow, Capital Asset Pricing Model and Risk Premium methods and includes flotation costs. That ROE is then adjusted based on a formula that takes into account the company's performance against pre-established benchmarks for price, reliability and customer satisfaction.

No rate change is implemented if the company's actual ROE is within 50 basis points of the target. Outside of the range, there is a graduated sharing of the costs/benefits based on the company's performance on those same metrics.

There are separate mechanisms in place for fuel/purchased power and environmental compliance, with adjustments for the latter capped at 2% per year.

Similar mechanisms are in place for the other major utilities in the state.

While a bit more prescriptive than the Alabama plan the Mississippi plan is similarly viewed as constructive by investors even though the ROEs under the plan have been somewhat below prevailing industry averages when established. Like the Alabama plan, it can accommodate a variety of changes that affect the cost of service that may or may not be within the company's control. The price change cap and sliding scale ROE hold the utility accountable for operational efficiency, but provide opportunity for upside potential.

Mississippi Power PEP
Target ROE formula

Base ROE	
Discounted cash flow	33%
Capital asset pricing model	33%
Risk premium	30%
+Flotation costs	
+/- Company performance rating	
Price indicator	40%
Reliability	40%
Customer satisfaction	20%

Data gathered March 31, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Multi-year rate plans

As the name suggests, under multi-year rate plans, the commission approves a succession of rate changes that are designed to take into account anticipated changes in revenues, expenses and rate base. The PSC may approve a static authorized ROE or the plan may provide for adjustments to the ROE during the plan's term.

These plans often include true-up mechanisms to ensure that the company makes the investments it has committed to make at the inception of the plan. The plans often include earnings sharing mechanisms and may also include performance-based ratemaking provisions.

Generally, the company cannot come in for a new rate case during the term of a multi-year plan unless extraordinary circumstances occur, but there may be certain volatile costs that are addressed via adjustment clauses or deferral mechanisms.

New York has been one of the most prolific states when it comes to multi-year rate plans, as this framework has been used for virtually all of the state's major investor-owned utilities for decades.

Notably, there is no stated policy or statute that calls for the use of these types of plans. The plans have been approved following settlement negotiations among the parties to the affected company's rate case. One could make the argument that because they are the result of settlements, they represent a balance of stakeholder interests by definition.

New York uses fully forecasted test years, so the entire plan is forward looking. The rate changes, rate of return and updated rate bases for each year of the plan are identified up front, and are subject to true-up. The ROEs incorporated in the plans have generally been significantly below prevailing industry averages when established.

While the plans do vary from company to company, the most recent electric and gas rate plans, adopted for Consolidated Edison Co. subsidiary Consolidated Edison Co. of New York, or CECONY, in January 2020, provide a fair representation of how the plans generally work. The plans cover the calendar years 2020 through 2022.

CECONY is authorized an aggregate $810 million three-step electric base rate increase that includes a $113.3 million increase effective Jan. 1, 2020, a $370.3 million increase effective Jan. 1, 2021, and a $326.4 million increase effective Jan. 1, 2022.

For CECONY's gas operations, the company is authorized a $373 million aggregate three-step rate increase, consisting of an $83.9 million rate increase effective Jan. 1, 2020, a $122 million increase effective Jan. 1, 2021, and a $167.1 million increase effective Jan. 1, 2022.

The plan incorporates an 8.8% return on equity (48% of capital) and overall returns of 6.61% in rate years one, two and three for both electric and gas operations.

The 8.8% stipulated ROE is significantly below the electric and gas industry average authorizations nationwide for rate cases decided in recent years for similar utilities. Refer to RRA's report Major Rate Case Decisions — January - December 2019 for a discussion of trend in authorized ROEs.

Consolidated Edison ROE sharing provisions

Earned ROE	Sharing of incremental earnings
Up to 9.3%	None
Between 9.3% and 9.8%	50% ratepayers/50% shareholders
Between 9.8% and 10.3%	75% ratepayers/25% shareholders
Above 10.3%	90% to ratepayers/10% shareholders

As of Jan. 16, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

The plan includes earnings sharing provisions under which actual earnings above a threshold ROE are to be allocated between shareholders and customers.

CECONY is to continue to defer and reconcile through future rate proceedings the following expenses: pension and other post-employment benefits expense, variable-rate tax-exempt debt, major storms, property taxes, municipal infrastructure support costs and the impact of new laws, and environmental site investigation and remediation.

In addition, CECONY will be permitted to earn incentives for electric and gas energy efficiency. The company will be subject to penalties if certain performance targets related to reliability, safety and other matters are not met.

The joint proposal reflects a productivity adjustment ranging from 1% to 2% over the three-year rate plan as well as an imputation for "business cost optimization" savings. The PSC has a long-standing policy of imputing a productivity adjustment, which typically has been calculated as 1% of total labor expense, all employee benefits and payroll taxes.

CECONY is also subject to incentive mechanisms related to the utility's achievement of the state's clean energy targets and advancement of distributed resources, as well as reliability initiatives, including the deployment of non-wires and non-pipes alternatives to meet demand growth.

The company's existing revenue decoupling mechanisms as well as adjustment clauses for renewables expense and other items will continue to operate during the term of the multi-year plan.

In effect, the plan contains many of the constructive attributes of the formula rate plans discussed previously. The ROE sharing mechanism provides the potential to accelerate recovery of certain assets and for earnings enhancement tied to improving efficiency. Additional earnings enhancement is offered for attaining certain performance objectives. The plan recognizes planned new future new investment without the need for additional rate cases.

California has used multi-year rate plans for many years as well, although the framework is more of an established policy and so the process is more defined.

Until recently, the energy utilities filed general rate cases every three years. In the context of these cases, the PUC generally approved a rate change for the current rate year, reflecting a future test year and two subsequent test years, referred to as attrition years. In January 2020, the PUC voted to change the three-year cycle to a four-year cycle in the hopes of making rate cases more efficient and predictable. The change is intended to allow utilities more time to implement risk-mitigation and accountability structures and devote less time to litigating issues with stakeholders in Investor-owned utilities in California had pushed for the change, citing challenges that have prevented the commission from resolving general rate case proceedings in a timely fashion.

In the past, the amounts of the out-year rate changes and rate bases were specified, but in recent cases, the commission has approved overall percentage rate changes without specifying the amount or the rate base. Cost of capital is not an issue in these cases, as the cost of capital for each utility is reset annually through a separate formulaic process. This process is discussed more fully in the relevant section below.

In Connecticut, the Connecticut Public Utility Regulatory Authority has in recent years adopted earnings sharing mechanisms as part of multi-year rate plans approved for the utilities as part of settlements in rate cases.

In a plan approved in 2018 for Eversource Energy Inc. subsidiary Connecticut Light and Power Co., the company was authorized a series of three rate increases aggregating to $124.7 million during the years 2018 through 2020.

The plan reflects expected changes in rate base, senior capital cost rates and includes a static 9.25% authorized ROE. This ROE was below the averages authorized in cases decided during 2018 and 2019.

The company is subject to an earnings sharing mechanism under which any earnings above the stipulated 9.25% ROE are allocated evenly between ratepayers and shareholders.

Connecticut Light & Power Co. rate plan

Year	Rate change ($M)	ROE (%)	ROR (%)	Rate base ($B)
2018	64.3	9.25	7.15	3.701
2019	31.1	9.25	7.04	3.780
2020	29.2	9.25	7.09	3.861

As of April 18, 2018.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Any amounts due customers under the terms of the earnings sharing mechanism are first applied to reduce various regulatory assets associated with certain unamortized environmental remediation costs. Remaining amounts due customers would then be used to offset the cost of catastrophic storms.

The plan also included a capital tracking mechanism for the recovery of core capital, system resiliency and grid modernization costs.

Rate freeze/stayout

Rate freezes, otherwise known as "stayouts," may be required as part of multi-year rate plans explicitly or implicitly, since the plan sets out the revenue requirements or a methodology for calculating the revenue requirements for the years covered by the plan. However, various other riders and adjustment mechanisms may be permitted to operate even if base rates are frozen.

By that definition, utilities in California, Connecticut, Massachusetts, New Hampshire, New York, Rhode Island, South Carolina and Wisconsin that are operating under multi-year rate plans that include specified latter year rate adjustments can be said to be subject to a stayout because they cannot file for rates that differ from those specified in the plan, unless some extraordinary event occurs. For purposes of this report, those instances have been excluded from the discussion.

Rate freezes currently in place for US utilities

State/company	Ultimate parent ticker	Freeze is the result of	Ending date	State/company	Ultimate parent ticker	Freeze is the result of	Ending date
DISTRICT OF COLUMBIA				**OHIO**			
Potomac Electric Power*	EXC	Merger	May 2020	Cleve. Elec. Illum./Ohio Ed./ Toledo Ed.	FE	Electric industry restructuring transition	6/1/2024
Washington Gas Light Co.*	ALA	Merger	Jan. 2021	Dayton Power & Light Co.	AES	Electric industry restructuring transition	5/31/2023
FLORIDA				Duke Energy Ohio Inc.	DUK	Electric industry restructuring transition	5/31/2024
Florida Power & Light Co.	NEE	Rate case settlement	1/2/2021	Ohio Power	AEP	Electric industry restructuring transition	6/1/2024
Duke Energy Florida LLC	DUK	Rate case settlement	1/1/2022	**SOUTH DAKOTA**			
Peoples Gas System	EMA	Rate case settlement	1/2/2021	Black Hills Power Corp.	BKH	Approval of adjustment clause	1/1/2023
Pivotal Utility Holdings	NEE	Rate case settlement	6/22/2020	NorthWestern Corp.	XEL	Federal tax reform	1/1/2021
Tampa Electric Co.	EMA	Rate case settlement	1/1/2022	**TEXAS**			
KANSAS				Oncor Electric Delivery	SRE	Merger	Aug. 2020
Evergy Kansas Central Inc.	EVRG	Merger	Dec. 2023	Sharyland Utilities, LP	--	Merger	Dec. 2020
Evergy Kansas South Inc.	EVRG	Merger	Dec. 2023	**VIRGINIA**			
Evergy Metro Inc.	EVRG	Merger	Dec. 2023	Appalachian Power Co.*	AEP	Mandated by law	Nov. 2020
MAINE				Virginia Electric & Power Co.	D	Mandated by law	Nov. 2021
Emera Maine	EMA	Merger	10/1/2021	**WISCONSIN**			
				Northern States Power Co. -Minnesota	XEL	Rate case settlement	12/31/2021
				Wisconsin Power & Light Co.	LNT	Rate case settlement	2021

Data gathered as of March 31, 2020.
* Rate case pending.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Stayouts may also be a part of a settlement adopted in a traditional base rate case where no specific multi-year rate plan is implemented. In South Dakota, Black Hills Power, a subsidiary of Black Hills Corp., is subject to a rate freeze that runs through July 2023 that was approved as part of a 2017 settlement addressing recovery of certain transmission facility and environmental investments.

Also in South Dakota, Xcel Energy subsidiary Northern States Power Co. and Northwestern Corp. are operating under rate freezes that extend to Jan. 1, 2021; the stayouts were included in the terms of settlements adopted in 2018 that addressed the revenue requirement impacts of the 2017 federal tax reform.

Rate freezes have also commonly been part of the conditions placed on mergers. With less merger activity going on, many of the merger-related rate freezes and stayouts have expired. However, in Texas, Oncor Electric Delivery Co. LLC is subject to a stayout that expires later this year related to its 2018 acquisition by Sempra Energy Inc.

Rate freezes and stayouts are a subtle form of performance-based regulation and can be a double-edged sword. Generally, in addition to the company agreeing to refrain from filing a rate case, the intervenors will agree to refrain from filing complaints against the company's existing rates.

There is an incentive for the company to control its costs because to the extent costs are lower than the levels reflected in rates, the company would be able to retain the benefits. If costs are higher, then the utility would not have the ability to seek a rate increase.

In RRA's view the benefits for utilities of such programs are limited in times like these when capital spending is increasing at a steady pace, interest rates are at or near all-time lows, employee-related costs are on the rise and demand growth is limited at best.

Earnings sharing mechanisms

As the name implies, earnings sharing mechanism provide for the allocation between ratepayers and shareholders of earnings that differ from a target or target range established by the commission. As noted in the preceding sections, these mechanisms can be approved as part of formula based ratemaking plans.

They can also be implemented as part of multi-year rate plans, in conjunction with a rate freeze, as part of a merger-related filing, or on a stand-alone basis as part of a rate case.

For example, in Kansas, in 2018, the Kansas Corporation Commission, or KCC, approved a settlement related to the merger of Great Plains Energy Inc. and Westar Energy Inc.; the combined entity is now known as Evergy Inc.

The settlement incorporates a rate plan under which, following the conclusion of a then-pending rate case for Kansas City Power and Light, now Evergy Metro Inc., the utility's rates and those of then-Westar, subsidiary Kansas Gas and Electric, now Evergy Kansas Central Inc. are to be subject to a five-year base rate moratorium. However, the companies are permitted to seek rate changes under existing rate riders and to reflect the impact of new KCC rules or policies.

The companies are also subject to an earnings review and sharing plan. The companies were each awarded a 9.3% ROE in subsequently completed rate cases. For each of the years 2019 through 2022, the utilities are to file a report with the KCC. If in any year, the difference between the authorized 9.3% ROE and Evergy Metro's earned Kansas jurisdictional ROE, subject to certain adjustments, multiplied by the equity portion of rate base and grossed up for taxes, exceeds a $2.8 million rate credit, the company's ratepayers would receive one half of the difference. For Evergy Kansas Central, a similar calculation would apply, relative to an $8.6 million bill credit for the company.

In a 2019, rate case decision for Sierra Pacific Power Co., or SPP, the Public Utilities Commission of Nevada approved a settlement authorizing the company a 9.5% ROE and instituting an earnings sharing mechanism under which the company may retain earnings up to a 9.7% ROE, 20 basis points above the authorized return. Incremental earnings in excess of a 9.7% ROE are to be allocated evenly between ratepayers and shareholders.

Similarly in a 2017 decision for SPP affiliate Nevada Power Company, or NVP, the commission approved an earnings sharing mechanism as part of a rate case decision. The agreement and order specified a 9.51% ROE that included certain incentives for reliability performance. NVP may retain 100% of earnings up to a 9.7% ROE. Any earnings that exceed a 9.7% ROE would be shared evenly by ratepayers and shareholders.

These plans are to remain in place until the companies' next base rate proceeding is completed, at which time the commission may decide to terminate the plan, modify it, or replace it with some other mechanism.

SPP and NVP are subsidiaries of NV Energy Inc., which is a subsidiary of Berkshire Hathaway Energy and do business in Nevada as NV Energy. Berkshire Hathaway Energy is owned by a consortium of investors, including Berkshire Hathaway Inc.

While earnings sharing mechanisms are generally considered to be constructive from an investor viewpoint, there are some factors to consider. One consideration is how the benchmark ROE compares to the industry average. In the Kansas and Nevada plans discussed in this section and the Connecticut and New York plans discussed in the multi-year rate plan section, the benchmark ROEs were somewhat below the industry average when established.

Another consideration is whether there are provisions to allow the companies to recoup a portion of earnings below the authorized ROE. In the plans described so far, no such provisions exist, and for that reason RRA refers to these mechanisms as asymmetrical. So, they would be considered less constructive than the earnings sharing provisions in place as part of the formula rate plans for the Alabama and Mississippi utilities that contain symmetrical sharing mechanisms that allow the companies to adjust rates upward if earnings are below the benchmark.

Formulaic ROEs

Typically, the authorized ROE is one of the most, if not the most, highly contested issue in a rate case. While the commissions rely on generally accepted formulas, such as the discounted cash flow, risk premium and capital asset pricing models, the parties can vary widely as to the proxy group to which the analyses should apply, the weighting to granted each methodology employed and the inputs that go into many of the models.

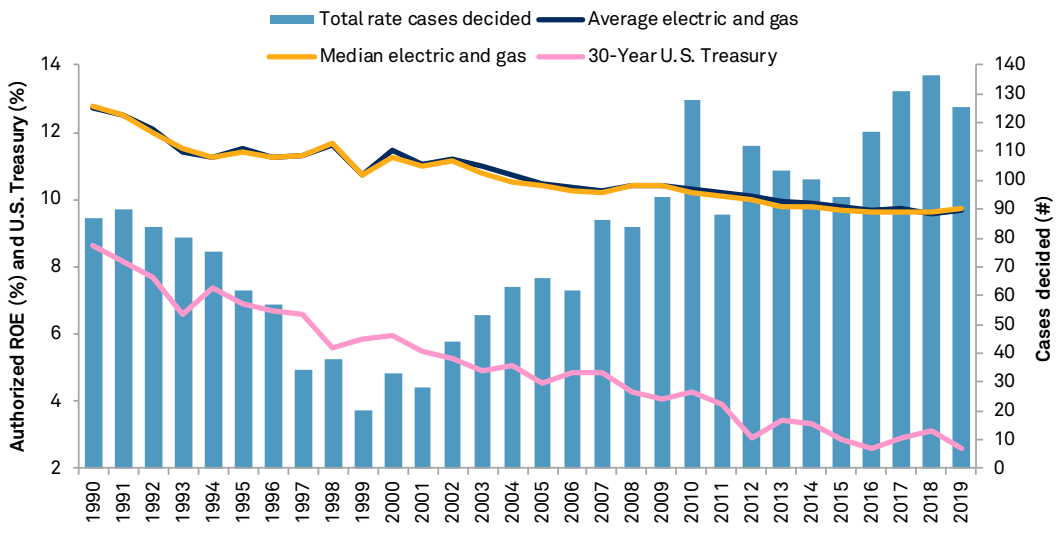
As a result, the recommendations from the different parties can differ by as much as 100 basis points versus the ROE sought by the company. This disparity increases the uncertainty when a utility does its internal analysis to decide whether it is worthwhile for the company to file a rate case at a particular time.

In order to reduce this uncertainty and lessen the amount of time it takes to complete rate cases, some states are taking a formulaic approach to selecting an authorized ROE. The idea being that establishing certain guidelines that must be adhered to will reduce or eliminate the variations among the parties and lessen the resource devoted to litigating these issues.

RRA generally views these mechanisms to be constructive for ratepayers; however, these formulaic plans may produce ROEs that are lower than prevailing industry averages at the time established.

As noted in the formula base ratemaking proceeding section, the Mississippi Power PEP plan employs a formulaic ROE in the sense that the plan specifies how much weight each of the calculation methodologies, but this only addresses a portion of the issues cited above.

Composite electric and gas authorized ROEs and number of rate cases, 1990-2019



Data compiled Jan.29, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Plans in place in Alabama, Illinois, California and Virginia take a more proscriptive approach. In Alabama, the formula rate plans in place of Spire Inc. subsidiaries Spire Alabama Inc. and Spire Gulf Inc. include a static ROE range, but the company may request a review of the authorized ROE should the interest rate for 30-year U.S. Treasury Bonds increase by more than 300 basis points. Conversely, the PSC may reexamine the authorized ROE should the interest rate for 30-year Treasury Bonds decrease by more than 200 basis points.

In California, automatic cost of capital, or COC, adjustment mechanisms are in place for Pacific Gas and Electric Co., or PG&E, Southern California Edison Co., or SCE, San Diego Gas & Electric Co., or SDG&E, and Southern California Gas Co., or SCG.

Under the mechanism, authorized ROEs are reviewed annually and reset if changes in the 12-month average of a Moody's long-term utility bond index yield, relative to a benchmark based on the same Moody's index yield, are greater than plus or minus 100 basis points.

If the ROE reset provision is triggered, the equity return would be adjusted, effective the following Jan. 1, by one-half of the difference in the 12-month average bond yield and the benchmark yield; in addition, long-term debt and preferred stock costs would be updated, but the authorized capital structure would not be adjusted. In any year in which the ROE is reset, the new 12-month average bond index yield would become the new benchmark.

A similar mechanism is in place for Southwest Gas Corp., or SWG, under which the authorized ROE is adjusted annually if utility bond yields change by more than 100 basis points.

SWG is a subsidiary of Southwest Gas Holdings Inc., PG&E is a subsidiary of PG&E Corp., SCE is a subsidiary of Edison International and SDG&E and SCG are subsidiaries of Sempra Energy.

In Illinois, the formula-based ratemaking plans in place for Exelon Corp. subsidiary Commonwealth Edison Co. and the electric operations of Ameren Corp. subsidiary Ameren Illinois incorporate ROEs that are updated annually and are equal to the 12-month average 30-year Treasury Bond yield for the prior calendar year, plus 580 basis points.

Hence, there is no controversy surrounding the ROE to be used for any give rate adjustment; however, the ROEs approved have been below industry averages when established. In the most recent adjustment, which was approved in December 2019, the formula produced an 8.91% ROE. The average ROE approved in electric delivery rate cases nationwide that were decided during 2019 was 9.37%.

In Virginia, in setting the base ROE for APCO's and VEPCO's rider mechanisms and for purposes of period earnings reviews for these companies, the SCC may "use any methodology to determine such return it finds consistent with the public interest." However, the ROE "shall not be set lower than the average of the returns on common equity reported to the Securities and Exchange Commission for the three most recent annual periods for which such data are available by not less than a majority, selected by the Commission ... of other investor-owned electric utilities in the peer group of the utility subject to such ... review." The selected ROE cannot be more than 300 basis points higher than the aforementioned average.

Incentive ROEs

Several states have approved "adders" to a company's overall ROE for achieving certain performance targets. As noted in the section on formula-based rate plans, the frameworks in place for the Mississippi utilities take certain performance metrics into account when setting the ROE benchmark for a given year. In Iowa, a utility may be awarded an ROE premium for achieving certain management efficiency goals.

In Indiana and Kansas the ROE may be adjusted to the extend the company meets certain renewable energy targets.

In Kansas and Wisconsin, ROE incentives may be awarded based on performance of some or all of company's generation units.

In Ohio one of the utilities has the opportunity to earn an enhanced ROE to the extent it meets certain grid modernization targets and in Washington, ROE premiums are available for meeting or exceeding certain distributed generation deployment targets.

In other instances, the utilities are permitted to earn an enhanced ROE on specific assets or asset classes.

For example, in Iowa, state law requires that the Iowa Utilities Board, or IUB, specify ratemaking principles — in advance of utility construction — to be applied to new baseload generation facilities of 300 MW or more for combined-cycle plants, alternative energy production facilities and certain investments to significantly alter an existing generation facility.

The IUB is not limited to traditional ratemaking with conventional cost recovery mechanisms and may authorize a rate of return on a new facility that is different than the return the utility is permitted to earn on existing generation assets. The enhanced ROEs remain in place for the life of the projects

Most recently, in 2016, the IUB approved an 11% ROE for Interstate Power & Light's, or IP&L's, New Wind Project, which will consist of up to a total of 500 MW. In 2013, for IP&L's 600-MW gas-fired Marshalltown plant, which went into commercial operation in April 2017, the IUB approved an 11% ROE. In 2008, the IUB adopted an 11.7% ROE for IP&L's 200-MW Whispering Willow-East Wind Farm, which was ultimately completed in 2009. IP&L is a subsidiary of Alliant Energy Corp.

Between 2002 and 2016, the IUB approved enhanced ROEs for a series of wind facilities constructed by MidAmerican Energy Co., or MEC, and these facilities were accorded ROEs ranging from 11.35% to 12.2%. MEC's 540-MW combined-cycle gas plant, the Greater Des Moines Energy Center, which was ultimately completed in 2004, was awarded a 12.23% ROE. MidAmerican's investment in a coal-fired generation facility, Council Bluffs Energy Center Unit 4, which was placed into service in 2007, was authorized a 12.29% ROE. MEC's ultimate parent is Berkshire Hathaway Energy.

The incentive ROEs are reflected in rates as part of base rate cases, where the IUB approves a blended ROE that represents the weighted average of the ROEs applied to the various categories of rate base.

In Virginia, state law allows the Virginia State Corporation Commission to authorize Appalachian Power Co. or APCO and Virginia Electric and Power Co., or VEPCO to recover certain types of investment through limited-issue rider mechanisms.

The riders include incentives for certain types of new generation, including a cash return on construction work in progress and an ROE premium that applies during construction and through up to the first 20 years of the plant's life.

The statute initially allowed premiums of up to: 200 basis-points on new nuclear generation facilities through the first 12 to 25 years of the plant's operation; 200 basis points on new carbon-capture compatible, clean-coal-powered facilities through the first 10 to 20 years of commercial operation; 200 basis points on new renewable resources through the first five to 15 years of commercial operation; and 100 basis points on new conventional coal or combined-cycle combustion turbine plants through the first 10 to 20 years of commercial operation.

The SCC approved ROE incentives for several VEPCO facilities prior to 2013, when legislation was enacted limiting the prospective availability of incentive ROE premiums to new nuclear and offshore wind facilities.

Such facilities could be eligible for premiums of 100 basis points that would apply during construction and continue through the first 12 to 25 years of a nuclear facility's useful life or the first five to 15 years of an offshore wind facility's useful life.

The SCC has yet to address any requests for ROE incentives for new nuclear or offshore wind. VEPCO has several other riders in place for generation and other types of investment that do not include ROE incentives.

Virginia Electric & Power Co. power plants with incentives

Plant Name(s)	Fuel source	ROE premium (basis points)	First year of operation	Duration of premium (years)
Altavista	Biomass	200	2013	5
Bear Garden	Gas	100	2011	10
Brunswick County Power Station	Gas	100	2016	10
Hopewell	Biomass	200	2013	5
Southampton Power Station	Biomass	200	2013	5
Virginia City Hybrid Energy Center	Coal/gas	100	2012	12
Warren County Power Station	Gas	100	2014	10

As of March 31, 2020
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

A limited issue rider is in place for APCO related to its investment in the natural gas-fired Dresden Energy Facility, but no ROE incentive is included.

VEPCO does business as Dominion Energy Virginia and is a subsidiary of Dominion Energy Inc., while APCO is a subsidiary of American Electric Power.

It goes without saying that ROE premiums in and of themselves are viewed as constructive from an investor standpoint, but the Virginia program that allows for expedited recovery through a limited issue rider, and recognition of construction work in progress goes a step even beyond the premium itself.

Cost savings sharing/performance based ratemaking

Many of the broader-based, holistic alternative regulation plans discussed so far contain performance-based components for achieving cost savings, management efficiency, meeting or exceeding public policy goals and the like. However, in many instances these type of mechanisms are separate from those plans, or where those plans do not exist, were adopted on a stand-alone basis.

RRA generally views these mechanisms as constructive from an investor viewpoint.

While the attached data tables provide a listing of what type of incentives are in place for each utility in each state, they are too numerous to go into detail here; the sections that follow are designed to provide some color about these mechanisms. Further details about the specific provisions in place in a given state can be found in the Commission Profiles.

Fuel/Purchased Power/Gas costs — Mechanisms that segregated commodity costs, i.e., fuel and purchased power for electric utilities and the gas commodity for gas utilities, are employed for all the utilities covered by RRA in each of the 53 state-level regulatory jurisdictions.

These mechanisms, which are separate from base rates, were implemented in the 1970s to address dramatic increases in commodity costs that were outside of the utility's control. The mechanisms were designed to allow the company's to adjust rates outside of a base rate case, hence on an accelerated basis, to reflect these rising costs that would otherwise threaten the utilities' solvency.

The costs were recovered on a dollar for dollar basis. Once commodity prices became less volatile, there was little incentive for the utilities to actively seek out lower cost alternatives, because any benefit would be passed on to ratepayers. In response, many states modified the recovery mechanisms to include a performance component, whereby the company could share in the benefit associated with lowering its commodity costs, and in many instances would be at risk of non-recovery if the costs rose beyond a certain point.

Commodity cost recovery mechanisms that include incentives are currently in place in close to 20 jurisdictions and RRA generally views these mechanisms as constructive, provided that there is a symmetrical sharing of risk i.e., the opportunity to achieve benefits is equal to the potential for non-recovery.

Capacity release/off-system sales sharing — These types of mechanisms arose largely due to the difficulty in timing capacity additions — be it gas pipeline or electric generation — with demand growth and also the need retain at least some reserve capacity on the system.

While there was a great deal of controversy in the 1990s surrounding major new generation additions that were seen as excess capacity when they were initially brought on line, the facilities were eventually recognized in base rates. Once they are there, customers within the utility service territories continue to pay the portion of fixed costs included in rates regardless of whether where demand goes from there on.

Under traditional ratemaking, were an electric utility to sell power to another utility that was in a load crunch or if a gas utility were to lease pipeline capacity on its system to another utility, the related revenues would be used to offset the cost to provide service to native load customers, thus flowing 100% of the benefit to customers.

Hence, there would be no incentive for the utility to actively pursue this type of activity. By allowing the utility to retain a portion of the benefit, regulators reasoned that the companies would increase their level of such activity to the benefit of both customers and shareholders.

Demand-side management program costs — The rationale here is similar to that for off-system sales. All else being equal utilities would not be amenable to instituting programs to encourage customers to use less power or gas. In the short-term revenues are lower. Presumably the lower volume would be reflected in the revenue requirement in a rate case and costs per unit sold would rise to make sure fixed costs were recovered, but there would be a lag. In addition, in the longer term there would be no need to add incremental facilities to the system and grow rate base, thus eroding future earnings potential.

Fixed vs. variable costs

Fixed	Variable
Depreciation	Gas commodity
Delivery O&M	Electric commodity
Property taxes	Generation O&M
Return on investment	
Customer service	

As of March 31, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence.

In order to encourage utilities to pursue these types of programs, many commissions implemented mechanisms that allow the utility to recover the direct program costs and recoup the lost revenues on an expedited basis. These mechanisms remove the disincentive to pursue such programs, and are discussed further in later sections of this report. However, they do not provide an affirmative incentive to pursue these initiatives.

In RRA's view, an incentive would entail the ability to earn a higher ROE for achieving certain demand reduction goals, the ability to earn a return on program costs, which are usually considered expenses rather than "rate base," and/or the ability to retain a portion of the avoided marginal costs. About 20 jurisdictions currently have these types of mechanisms in place for at least one utility in the jurisdiction.

Reliability/customer satisfaction — The regulatory compact that forms the basis for utility regulation in the U.S. requires the utility to provide safe, reliable service at just and reasonable rates. In exchange the utility is provided the sole right to operate within its franchised service territory and regulators are to provide the company the opportunity to earn a just and reasonable return commensurate with the level of risk for shareholders.

This begs the question of why the company would need an incentive to provide reliable service, and many consumer advocates have asked this same question. The answers are both simple and complex.

When faced with a choice between upgrading an existing asset that will provide better service to existing customers but will not, at least until the next rate case, generate any new revenue and investing in projects that will increase penetration into unserved areas or accommodate new customers in existing areas thus generating new revenue sources and ultimately growing rate base in the next rate case, utilities will choose the latter every time.

Also, in the context of a base rate proceeding it is easier for the utility to provide objective proof of why an investment is/was needed to serve new customers which can be documented than it is to show that an investment is needed to forestall some catastrophe that may or may not occur in the future.

However, as weather volatility has increased with severe storms and wildfires becoming both more frequent and more widespread, failures of aging infrastructure leading to well publicized catastrophes and advanced technologies of the digital age requiring higher quality more consistent power flows, reliability has become a front burner issue.

As will be discussed in the next section of this report, these realities have given rise to the spread of expedited cost recovery mechanisms that remove some of the disincentives to investments in these non-growth related projects.

Some jurisdictions are going a bit further and providing companies incentives for meeting exceeding deployment targets, or for hitting certain benchmarks for service interruptions and customer satisfaction. There are four states with explicit incentives in place for at least one utility associated with reliability and two with customer satisfaction.

RRA finds these mechanisms to be constructive from an investor viewpoint, provided that there is as much of an opportunity for the utility to achieve benefit a benefit for shareholders as there is to incur a penalty.

Productivity — Productivity is a broad term that can include: achieving overall operations maintenance cost or a specific expense, such a pension costs; lowering commodity costs; demonstrating superior generation plant operational performance; meeting or exceeding energy conservation program participation or demand reduction targets; attaining or exceeding goals with respect to clean energy or advanced technology deployment; or, beating benchmarks associated with reliability and customer service.

Incentives are generally in the form or ROE enhancement, sharing of incremental revenues or retention of cost savings. Several examples were included in the preceding discussions of the other types of alternative forms of regulation that are in place.

Adjustment clauses — Alternative ratemaking by another name?

While the above-discussed mechanisms are generally what comes to mind when the phrase "alternative ratemaking" is used, adjustment clauses, also known as limited issue riders, are another approach to reducing regulatory lag, and using a broad definition could be considered "alternative ratemaking."

Adjustment clauses were first introduced in the 1970s to mitigate volatile fuel costs that were threatening company earnings and cash flows. In the ensuing years, the use of these mechanisms expanded to include other expenses that were outside of a company's control or were mandated by government regulation.

More recently, they have become increasingly prevalent to address capital investment, be it gas main replacement, electric grid modernization or in some cases new generation — particularly when a state wanted to foster construction of a particular type of generation or the deployment of new technologies. It is because of this "incentive" aspect and the use of these mechanisms to address regulatory lag that they are included in this discussion.

Select adjustment clauses in the US[1]

Generation		Infrastructure			
Traditional	Renewable	Electric		Gas	
Alabama	Colorado	Colorado	New Hampshire	Colorado	Mississippi
Coloradao	Florida	Connecticut	New Jersey	Connecticut	Missouri
Florida	Louisiana—PSC	Delaware	New Mexico	Delaware	Montana
Georgia	Massachusetts	Dist. of Columbia	New York	Dist. of Columbia	Nebraska
Hawaii	Minnsesota	Hawaii	North Dakota	Florida	Nevada
Indiana	North Carolina	Illinois	Ohio	Georgia	New Jersey
Kansas	North Dakota	Indiana	Oklahoma	Illinois	North Carolina
Kentucky	Oregon	Kentucky	Pennsylvania	Indiana	Ohio
Louisiana—NOCC	Virginia	Louisiana—PSC	Rhode Island	Iowas	Pennsylvania
Louisiana—PSC		Maryland	South Dakota	Kansas	Rhode Island
Minnsesota		Massachusetts	Texas—PUC	Kentucky	Tennessee
Mississippi		Minnsesota	Virgnia	Louisiana—PSC	Texas—RRC
North Dakota		Missouri	West Virginia	Maine	Utah
Oregon				Maryland	Virginia
South Dakota				Massachusetts	Washington
Virginia				Michigan	West Virginia
West Virginia				Minnsesota	Wyoming

As of March 31, 2020.
NOCC=New Orleans City Council; PSC=Public Service Commission; RRC=Railroad Commission.
[1]Mechanism in place for at least on utility in the state, unless otherwise noted.
Source: Regulatory Research Associates, a group withinn S&P Global Market Intelligence

Like the broader-based alternative regulation plans discussed earlier, these mechanisms tend to reduce regulatory lag, but only as it pertains to the assets, asset classes, or expenses that are permitted to be recovered through these mechanisms. It is also noteworthy that the presence of a broad based alternative ratemaking does not preclude the use of stand-alone adjustment mechanisms for certain items.

However, in some instances, where these mechanisms are used heavily, RRA has observed some degree of pushback from customers, consumer advocates and commissions.

Virginia, Texas and Pennsylvania are states that rely heavily on limited issue with or without "alternative ratemaking" per se.

Virginia's electric utilities have remained vertically integrated. Retail choice is only available for large volume industrial customers and commercial customers that can aggregate load to reach a 5MW threshold.

For the two largest electric utilities, "base rates" have largely been frozen for several years pursuant to a statutory periodic earnings review process. In this instance, "base rates" refers to legacy generation and distribution assets.

The periodic earnings review process incorporates an ROE-based earnings-sharing mechanism. The ROEs are set based on a formula laid out in state law.

Back in 2007 when other mid-Atlantic states were grappling with congestion issues, Virginia embarked on a course to incent "inside the fence" generation in order to avoid incurring PJM Interconnection congestion charges, and specifically targeted gas-fired baseload generation.

State policy allowed these investments to be recovered through plant-specific generation riders that included a cash return on construction work in progress while the facilities were being constructed and an incentive ROE premium of as much as 200 basis points on the investment for a fixed term.

Adjustments under the riders are based on forward-looking "rate years," that are the first year the new rates are in effect. As noted above certain types of plants are eligible for and have received ROE premiums within the riders.

This paradigm was ultimately expanded to include other types of capital investment including utility-owned renewables, certain types of electric infrastructure and environmental compliance costs.

Riders are also permitted for demand-side management program costs, and the utilities are awarded a return on these expenses as an incentive to pursue the programs.

At the same time, Virginia allows certain expenses to be passed through to ratepayers using an adjustment clause – examples include fuel, renewable energy credit costs and FERC transmission charges.

For the most part these riders are updated annually and the capital investment related riders are essentially mini rate cases that take eight to nine months to adjudicate. Each adjustment includes a true-up for prior period over- and under-recoveries.

Over the last couple of years, there has been some backlash with regard to this approach, including legislative changes to the framework, some successful, others not. There has also been a push by large commercial customers to aggregate load in order to qualify to obtain their supply competitively. See the Virginia Commission Profile for additional detail.

In Texas, electric utilities and gas utilities are regulated by different agencies and the policies are very different. On the electric side, part of the state is restructured and part is not.

There are adjustment clauses to pass-through costs such as fuel and purchased power, wholesale transmission costs assigned to the utility by regional transmission organizations, demand-side management and storm costs.

Annual and semi-annual adjustments are permitted for distribution investment and transmission investment for both vertically integrated and delivery only companies.

State law allows for adjustment mechanisms for incremental generation facilities in the areas of the state that have not implemented retail competition.

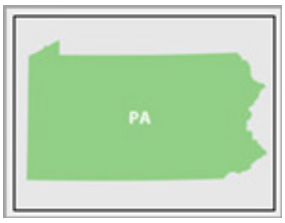
The adjustments rely on the ROE approved in the company's most recent rate case and a historical test year, consistent with the policy for base rate cases in the state. A prudence determination does not occur until the next base rate case, when related investments and revenue requirement roll into base rates and the adjustment clause is reset to zero.

Notably, there have been instances where the Public Utility Commission of Texas has in the context of a base rate case, disallowed recovery of assets that were reflected in the adjustment mechanism.

In addition, state law requires the PUC to maintain a schedule so that there is no more than four years between utility base rate cases. Also, the PUC staff conducts an earnings analysis for each utility at the end of each calendar year and then makes recommendations to the PUC regarding whether a full earnings investigation is warranted.

For additional information, see the Texas PUC Commission Profile.

Pennsylvania is one of the states that allows retail competition for all generation service customers. In 2012, Pennsylvania transitioned from using a historical test period to a fully forecasted test period. At the same time, the state adopted the distribution system improvement charge, or DSIC, framework for incremental infrastructure spending between rate cases.



Adjustments under the mechanism occur quarterly and are forward looking. The ROEs used are either those established in the companies' most recent base rate case, or if the last fully litigated ROE is more than three years old, a "generic" ROE set by the PUC for each industry based on a quarterly review the utilities' earnings is used.

A utility may only adjust rates under the DSIC if it is earning below the established ROE, a provision that offers some assurances for stakeholders that the utilities are not "gaming the system."

The costs reflected in each adjustment are subject to prudence review in the company's next base rate case. So, despite the frequency of the adjustments, it does not appear that the framework places an undue burden on the participants.

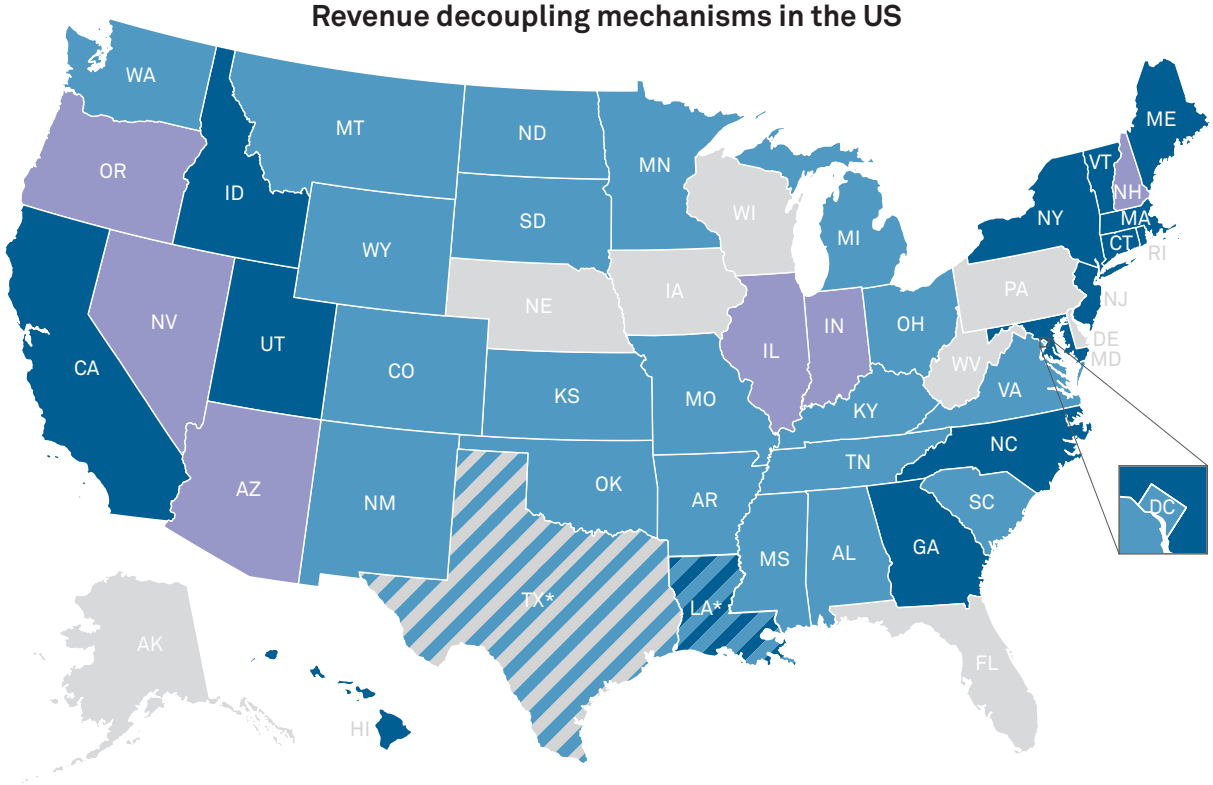
Until recently, Pennsylvania had eschewed "alternative ratemaking." However, legislation permitting various forms of alternative regulation was enacted recently and the commission has adopted rules for implementing these mechanisms on a company-specific basis. No alternative ratemaking plans have been requested or approved to date.

Revenue decoupling mechanisms

Decoupling mechanisms allow utilities to adjust rates between rate cases to reflect fluctuations in revenues versus the level approved in the most recent base rate case that are caused by a variety of factors.

Some of these factors, such as weather are beyond a utility's control and the mechanism can work both ways — in other words it can allow the company to raise rates to recoup revenue losses associated with weather trends that reduce customer usage and can also require the company to reduce rates when weather trends cause usage to be higher than normal.

Revenue decoupling mechanisms in the US



Partial	At least one company has a mechanism in place and it is partial
Full	At least one company has a mechanism in place and it is full
Varies	Multiple companies have a mechanism, some are partial others are full
None	No companies have a decoupling mechanism in place

As of March 31, 2020.
* In Louisiana and Texas, there are two different regulatory commissions, with differing policies.
Map credit: Jose Miguel Fidel C. Javier
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

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As clean energy policies have gained momentum, driving ever-expanding energy efficiency initiatives, decoupling mechanisms have been implemented to reduce the disincentive for utilities in pursuing energy conservation programs by making the utilities whole for reductions in sales volumes and revenues associated with customer participation in these programs.

Some of these mechanisms also allow the utility to adjust rates to reflect fluctuations in customer usage that are brought about by broader economic issues, such as demographic shifts, the migration of large commercial/industrial customers to other service areas, the shutdown of such businesses due to changes in their respective industries, recessions and theoretically, crises such as the current COVID-19 pandemic.

RRA considers a decoupling mechanism that adjusts for all three of these factors to be a “full” decoupling mechanism and designates those that address only one or two of these factors as “partial” decoupling mechanisms.

Some the mechanisms include a cap on the percentage rates can change under the mechanism. Others only permit adjustments if the utility is earning below the authorized ROE or include performance criteria, such as achieving a targeted demand reduction level. RRA also classifies these type of plans as partial decoupling even if they do address all of the three factors.

Similar to the investment-related adjustment clauses noted above, decoupling mechanisms are included in this discussion of alternative regulation because they streamline the regulatory process and allow the company to reflect changes in usage/revenues in rates without the need for a rate case.

Also, in many instances the mechanisms were intended to encourage the utilities to pursue energy efficiency/demand side management programs rather building new generation, even if there were no specific demand reduction goals in the state, or in cases where there were goals to exceed those goals.

In addition, keeping revenue stable despite changes in these exogenous factors provides something of an "incentive" for management efficiency, as achieved cost savings can be retained until the next rate case, unless there is return cap built into the mechanism.

As of this writing, 21 jurisdictions had full decoupling mechanisms in place for at least one company, including six states that have different types of mechanisms for different companies. Partial revenue decoupling mechanisms were in place for companies in 28 jurisdictions, including six states that have different types of mechanisms for different companies and there are no decoupling mechanisms in place in 10 jurisdictions.

A more comprehensive discussion of adjustment clauses and rider mechanisms is provided in RRA' November 2019 report Adjustment Clauses — A State by State Overview and related data tables.

This information is also available in the Adjustment clauses sections of the state Commission Profiles.

Contributors: Charlotte Cox, Jim Davis, Russell Ernst, Lisa Fontanella, Monica Hlinka, Jason Lehman, Dan Lowrey and Amy Poszywak

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BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Jennifer E. Nelson

RATE OF RETURN ON EQUITY

Exh. JEN-15

August 29, 2025

Regulatory Focus Topical Special Report

Topical Report

July 18, 2022

Adjustment clauses: A state by state overview

Russell Ernst, Principal Analyst, Brian Collins, Senior Research Analyst, and Monica Hlinka, Research Analyst

Contributors: Jim Davis, Lillian Federico, Lisa Fontanella, Jason Lehmann and Dan Lowrey

This report covers the key adjustment clauses used by the largest electric and gas utilities in the 53 jurisdictions covered by Regulatory Research Associates, a group within S&P Global Commodity Insights.

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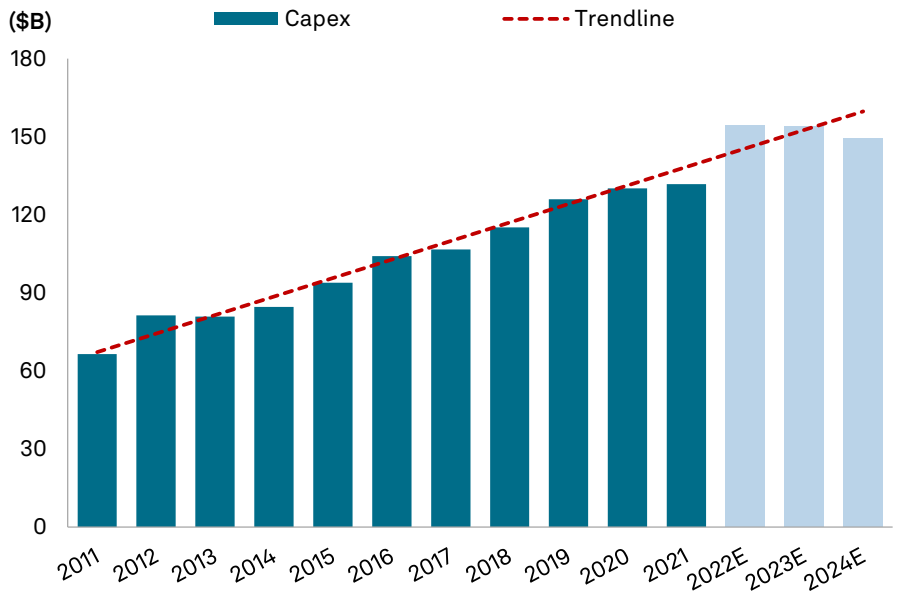
Introduction

In the face of the robust expansion of utility capital expenditures in recent years, increases in expenses attributable in part to increased levels of inflation and sluggish demand growth in some parts of the U.S., industry stakeholders have developed innovative strategies that support timely rate recognition of these costs. As shown in the image below, capex for 47 energy utilities covered by Regulatory Research Associates, a group within S&P Global Commodity Insights, is estimated to exceed $154 billion in 2022, well above the $131.8 billion of actual investment in 2021 by the same companies.

Energy utility actual and estimated capital expenditures



Data compiled March 30, 2022.
E = estimates
Source: S&P Global Market Intelligence

The electric and gas utilities' use of adjustment clauses to recover variations in costs outside of the traditional rate case process has its origins in the 1973 Arab oil embargo, when fuel costs skyrocketed, leaving the utilities with no way to recover the increased costs in a timely manner. At that time, the only remedy for the utilities was to file a rate case; however, rate proceedings frequently took more than a year to litigate, and fuel prices climbed more rapidly than the utilities could obtain rate recognition of the increased costs. Some jurisdictions permitted the utilities to have more than one rate case pending simultaneously, but most did not.

In the years following the embargo, utility earnings were under considerable pressure, prompting some jurisdictions to establish a more constructive framework to allow more timely recovery of cost increases that were beyond the utilities' control.

The result was the creation of the fuel adjustment clause, or FAC — a single-issue ratemaking process whereby a utility is permitted to implement periodic rate adjustments to reflect changes in its cost of fuel. The utility is generally authorized to defer incremental variations in its fuel costs to offset any effect on earnings from the variation. The deferred amount is then recovered from, or refunded to, ratepayers in the next FAC rate adjustment. In some circumstances, the FAC includes a forward-looking component that is subject to true-up provisions. In addition to fuel costs, most jurisdictions allow to include the utilities' purchased power expense in the FAC.

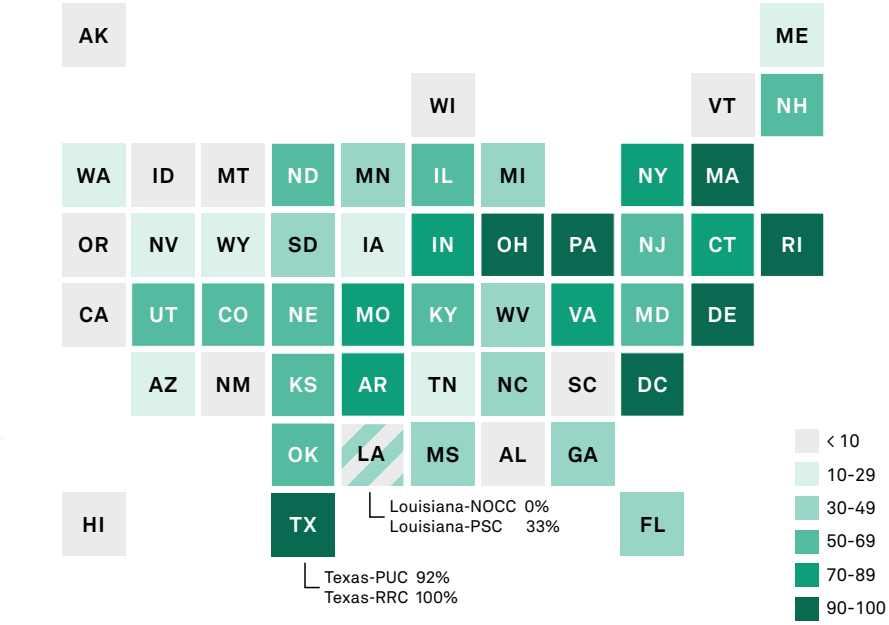
State utility commissions have approved adjustment clauses for recovery of environmental compliance, energy efficiency and conservation program expenses, transmission charges allocated to the utility by the Federal Energy Regulatory Commission and investments associated with meeting renewable resource requirements. Such mechanisms have also been approved to pass through to customers all or a portion of the margins that the company receives from selling excess power or pipeline capacity in the open market through off-system sales.

Another type of adjustment clause — a decoupling mechanism — enables utilities to offset the effect on revenues of fluctuations in sales caused by customer participation in energy efficiency programs, deviations from "normal" temperature patterns or economic conditions. RRA considers a decoupling mechanism that adjusts for these factors to be a "full" decoupling mechanism and designates those that address only one or two of these factors as "partial" decoupling mechanisms. RRA also assigns a partial decoupling tag to those mechanisms that include rate caps or other limitations.

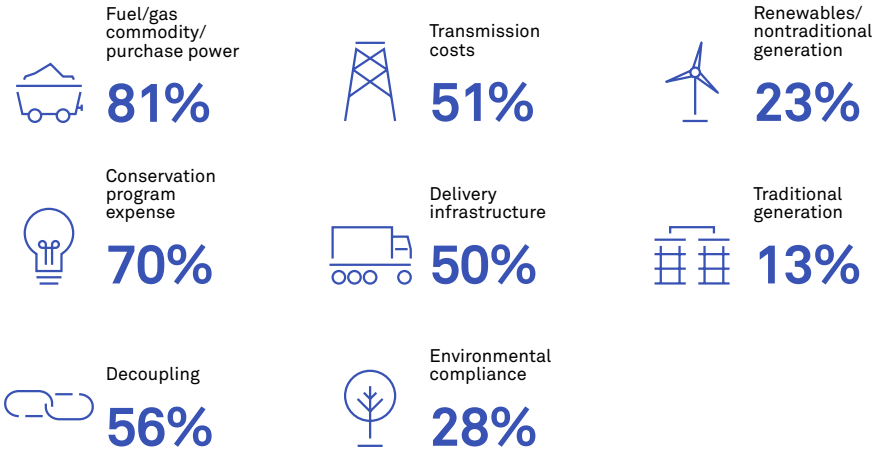
More recently and with greater frequency, commissions have approved mechanisms that permit the costs associated with the construction of new generation or delivery infrastructure to be used, effectively including these items in rate base without the need for a full rate case. In some instances, these mechanisms may even provide the utilities a cash return on construction work in progress.

As shown in the following infographic, certain types of adjustment clauses are more prevalent than others. For example, those that address electric fuel and gas commodity charges are in place in all jurisdictions. Also, about two-thirds of all utilities have riders in place to recover costs related to energy efficiency programs, and roughly half of the utilities have some type of decoupling mechanism in place.

Utilities with adjustment clauses for delivery infrastructure (%)



Adjustment clauses in use (%)



Data as of June 2022.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

About this report

This report covers the key adjustment clauses used by the largest electric and gas utilities in the 53 jurisdictions covered by RRA. This report does not address surcharges that have been approved to enable a utility to recover specific one-time items, e.g.,such as excess storm-restoration costs incurred in a given year, where the utility is recovering a fixed amount over a defined period.

This report also does not include expense trackers, which provide for the deferral of variations in costs for potential recovery at a future time when the commission will consider the accumulated balance for inclusion in rates. Although an expense tracker is designed to keep the utility's earnings whole, rates and cash flows do not change on a current basis. Expense trackers are sometimes authorized to account for variations in pension-related costs. While there are similarities between each of these types of ratemaking provisions, only adjustment clauses allow rates to change on an expedited basis in accordance with cost changes.

The accompanying table includes footnotes (denoted by "✓*" or "--*"), where clarification regarding the specific adjustment clause is necessary. Further details concerning the adjustment clauses included in this report can be found in each of RRA's Commission Profiles.

Regulatory agency abbreviations

ACC	Arizona Corporation Commission
BPU	Board of Public Utilities (New Jersey)
DPU	Department of Public Utilities (Massachusetts)
ICC	Illinois Commerce Commission
IUB	Iowa Utilities Board
KCC	Kansas Corporation Commission
NCUC	North Carolina Utilities Commission
NOCC	New Orleans City Council
OCC	Oklahoma Corporation Commission
PRC	Public Regulation Commission (New Mexico)
PSC	Public Service Commission
PUC	Public Utility(ies) Commission
PURA	Public Utilities Regulatory Authority (Connecticut)
RCA	Regulatory Commission of Alaska
RRC	Railroad Commission (Texas)
SCC	State Corporation Commission (Virginia)
URC	Utility Regulatory Commission (Indiana)
WUTC	Washington Utilities and Transportation Commission

The Take

A key component of innovative strategies supporting timely rate recognition has been the use of adjustment clauses to address recovery of utility investments, as well as issues related to rising/volatile costs. A defining characteristic of an adjustment clause is that it effectively shifts the risk associated with recovery of an expense from shareholders to customers. If the clause operates as designed, the company is able to change its rates to recover its costs on a current basis, without any negative effect on the bottom line and without the expense and delay that accompany a rate case filing.

The use of adjustment clauses has expanded significantly. These clauses are generally reserved for expenses that are outside the utility's control or are required by law or rule. Some jurisdictions have approved the use of adjustment clauses for recovery of environmental compliance, energy efficiency and conservation program expenses, transmission charges allocated to the utility by the Federal Energy Regulatory Commission and investments associated with meeting renewable resource requirements.

Use of adjustment clauses, as of June 2022

			Type of adjustment clause																	
						Decoupling				New capital										
State/Company	Ultimate parent ticker	Type of service	Electric fuel/gas commodity/ purch. power		Conserv. program expense	Full		Partial		Traditional generation		Renewables/ Non-traditional generation		Delivery infrastructure		Environmental compliance		Transmission costs	
ALABAMA																				
Alabama Power Co.	SO	Elec.	✓	*	--	--		--		✓	*	✓		--		✓	*	--	
Spire Alabama Inc.	SR	Gas	✓	*	--	--		✓	*	--		--		--		--		--	
Spire Gulf Inc.	SR	Gas	✓	*	--	--		✓	*	--		--		--		--		--	
ALASKA																				
Alaska Electric Light & Power Co.	AVA	Elec.	✓		--	--		--		--		--		--		--		--	
Enstar Natural Gas Co.	ALA	Gas	✓		--	--		--		--		--		--		--		--	
ARIZONA																				
Arizona Public Service Co.	PNW	Elec.	✓		✓	--		✓	*	--		✓		--		✓		✓	
Southwest Gas Corp.	SWX	Gas	✓		✓	✓		--	*	--		--		✓	*	--		--	
Tucson Electric Power Co.	FTS	Elec.	✓		✓	--		✓	*	--		✓		--		✓		✓	
UNS Electric Inc.	FTS	Elec.	✓		✓	--		✓	*	--		✓		--		--		✓	
UNS Gas Inc.	FTS	Gas	✓		✓	--		✓	*	--		--		--		--		--	
ARKANSAS																				
Arkansas Oklahoma Gas Corp.	--	Gas	✓		✓	✓	*	--		--		--		✓	*	--		--	
Summit Utilities Arkansas Inc.	--	Gas	✓		✓	✓	*	--		--		--		✓	*	--		--	
Entergy Arkansas LLC	ETR	Elec.	✓		✓	--		✓	*	✓	*	✓	*	✓	*	--		✓	
Oklahoma Gas & Electric Co.	OGE	Elec.	✓		✓	--		✓	*	✓		✓		✓		✓		✓	
Black Hills Energy Arkansas Inc.	BKH	Gas	✓		✓	✓	*	--		--		--		✓	*	--		--	
Southwestern Electric Power Co.	AEP	Elec.	✓		✓	--		✓	*	✓		--		--		✓		✓	
CALIFORNIA																				
Pacific Gas & Electric Co.	PCG	Elec.	✓		--	✓		--		--		--		--		--		--	
Pacific Gas & Electric Co.	PCG	Gas	✓		--	✓		--		--		--		--		--		--	
San Diego Gas & Electric Co.	SRE	Elec.	✓		--	✓		--		--		--		--		--		--	
San Diego Gas & Electric Co.	SRE	Gas	✓		--	✓		--		--		--		--		--		--	
Southern California Edison Co.	EIX	Elec.	✓		--	✓		--		--		--		--		--		--	
Southern California Gas Co.	SRE	Gas	✓		--	✓		--		--		--		--		--		--	
Southwest Gas Corp.	SWX	Gas	✓		--	✓		--		--		--		--		--		--	
COLORADO																				
Black Hills Colorado Electric Inc.	BKH	Elec.	✓		✓	--		--		✓	*	✓		--		--		✓	
Public Service Co. of Colorado	XEL	Elec.	✓		✓	--		✓	*	--		✓		--		--		✓	
Public Service Co. of Colorado	XEL	Gas	✓		✓	--		✓	*	--		--		✓	*	--		--	
Black Hills Gas Distribution LLC	BKH	Gas	✓		✓	--		--		--		--		✓	*	--		--	
CONNECTICUT																				
Connecticut Light and Power Co.	ES	Elec.	--	*	✓	✓	*	--		--		--	*	✓	*	--		✓	
Connecticut Natural Gas Co.	IBE	Gas	✓		✓	✓	*	--		--		--		✓	*	--		--	
Southern Connecticut Gas Co.	IBE	Gas	✓		✓	✓	*	--		--		--		✓	*	--		--	
United Illuminating Co.	IBE	Elec.	--	*	✓	✓	*	--		--		--	*	--		--		✓	
Yankee Gas Services Co.	ES	Gas	✓		✓	✓	*	--		--		--		✓	*	--		--	

Use of adjustment clauses, as of June 2022

			Type of adjustment clause															
						Decoupling		New capital										
State/Company	Ultimate parent ticker	Type of service	Electric fuel/gas commodity/ purch. power		Conserv. program expense	Full	Partial	Traditional generation		Renewables/ Non-traditional generation		Delivery infrastructure		Environmental compliance		Transmission costs
DELAWARE																		
Chesapeake Utilities Corp.	CPK	Gas	✓		--	--	--	--		--		✓	*	✓	*	--		
Delmarva Power & Light Co.	EXC	Elec.	--	*	✓	--	--	--		--		✓	*	--		✓		
Delmarva Power & Light Co.	EXC	Gas	✓		--	--	--	--		--		✓	*	✓	*	--		
DISTRICT OF COLUMBIA																		
Potomac Electric Power Co.	EXC	Elec.	--	*	--	--	✓	*	--		✓	*	✓	*	--		--	
Washington Gas Light Co.	ALA	Gas	✓		--	--	--	--		✓	*	✓	*	--		--		
FLORIDA																		
Florida Power & Light Co.	NEE	Elec.	✓		✓	--	--	✓	*	✓	*	--	*	✓		--		
Duke Energy Florida LLC	DUK	Elec.	✓		✓	--	--	✓	*	✓	*	--	*	✓		--		
Florida Public Utilities Co.	CPK	Elec.	✓		✓	--	--	✓	*	--		--	*	✓		--		
Florida Public Utilities Co.	CPK	Gas	✓		✓	--	--	--		--		✓	*	✓		--		
Peoples Gas System Inc.	EMA	Gas	✓		✓	--	--	--		--		✓	*	✓		--		
Pivotal Utility Holdings Inc.	NEE	Gas	✓		✓	--	--	--		--		✓	*	✓		--		
Tampa Electric Co.	EMA	Elec.	✓		✓	--	--	✓	*	✓	*	--	*	✓		--		
GEORGIA																		
Atlanta Gas Light Co.	SO	Gas	--	*	--	--	*	--		--		--		✓	*	✓	*	--
Georgia Power Co.	SO	Elec.	✓		--	--		--		✓	*	--		--		✓	*	--
Liberty Utilities (Peach State Nat. Gas) Corp.	AQN	Gas	✓	*	--	✓	*	--		--		--		--		--		--
HAWAII																		
Hawaiian Electric Co.	HE	Elec.	✓		✓	--		--		--		✓	*	--		--		--
Hawaii Electric Light Co.	HE	Elec.	✓		✓	--		--		--		--		--		--		--
Maui Electric Co.	HE	Elec.	✓		✓	--		--		--		✓	*	--		--		--
IDAHO																		
Avista Corp.	AVA	Elec.	✓	*	✓	✓	*	--		--		--		--		--		--
Avista Corp.	AVA	Gas	✓		✓	✓	*	--		--		--		--		--		--
Idaho Power Co.	IDA	Elec.	✓	*	✓	✓	*	--		--		--		--		--		--
PacifiCorp	BRK.A	Elec.	✓	*	✓	--		--		--		--		--		--		--
ILLINOIS																		
Ameren Illinois Co.	AEE	Elec.	--	*	✓	--	✓	*	--		✓		--		✓	*	✓	
Ameren Illinois Co.	AEE	Gas	✓		✓	--	✓	*	--		--		✓	*	✓	*	--	
Commonwealth Edison Co.	EXC	Elec.	--	*	✓	--	--	--		✓		✓	*	✓	*	✓		
Liberty Utilities (Midstates Natural Gas) Corp.	AQN	Gas	✓		✓	--	✓	*	--		--		--		--		--	
MidAmerican Energy Co.	BRK.A	Elec.	✓	*	✓	--	--	--		✓		--		--		--		✓
MidAmerican Energy Co.	BRK.A	Gas	✓		✓	--	--	--		--		--	*	--		--		--
North Shore Gas Co.	WEC	Gas	✓		✓	--	✓	*	--		--		✓	*	✓	*	--	
Northern Illinois Gas Co.	SO	Gas	✓		✓	--	✓	*	--		--		✓	*	✓	*	--	
Peoples Gas Light & Coke Co.	WEC	Gas	✓		✓	--	✓	*	--		--		✓	*	✓	*	--	

Use of adjustment clauses, as of June 2022

State/Company	Ultimate parent ticker	Type of service	Type of adjustment clause: Electric fuel/gas commodity/ purch. power	Conserv. program expense	Decoupling: Full	Decoupling: Partial	New capital: Traditional generation	New capital: Renewables/ Non-traditional generation	New capital: Delivery infrastructure	New capital: Environmental compliance	New capital: Transmission costs
INDIANA											
Duke Energy Indiana LLC	DUK	Elec.	✓	✓	--	✓ *	--	✓	✓ *	✓ *	✓
Indiana Gas Co.	CNP	Gas	✓	✓	✓	--	--	--	✓ *	--	--
Indiana Michigan Power Co.	AEP	Elec.	✓	✓	--	✓ *	--	✓	✓ *	✓ *	✓
Indianapolis Power & Light Co.	AES	Elec.	✓	✓	--	✓ *	--	✓	-- *	✓ *	✓
Northern Indiana Public Service Co.	NI	Elec.	✓	✓	--	✓ *	--	✓	✓ *	✓ *	✓
Northern Indiana Public Service Co.	NI	Gas	✓	✓	--	--	--	--	✓ *	--	--
Southern Indiana Gas & Electric Co.	CNP	Elec.	✓	✓	--	✓ *	--	--	✓ *	✓ *	✓
Southern Indiana Gas & Electric Co.	CNP	Gas	✓	✓	✓	--	--	--	✓ *	--	--
IOWA											
Black Hills Iowa Gas Utility Co.	BKH	Gas	✓	✓	--	--	--	--	✓	--	--
Interstate Power & Light Co.	LNT	Elec.	✓	✓	--	--	--	✓	--	✓	✓
Interstate Power & Light Co.	LNT	Gas	✓	✓	--	--	--	--	--	--	--
MidAmerican Energy Co.	BRK.A	Elec.	✓	✓	--	--	--	✓	--	✓	✓
MidAmerican Energy Co.	BRK.A	Gas	✓	✓	--	--	--	--	--	--	--
KANSAS											
Atmos Energy Corp.	ATO	Gas	✓	-- *	--	✓ *	--	--	✓ *	--	--
Black Hills/Kansas Gas Utility Co.	BKH	Gas	✓	-- *	--	✓ *	--	--	✓ *	--	--
Empire District Electric Co.	AQN	Elec.	✓	✓ *	--	--	--	--	--	✓	✓
Evergy Kansas Central Inc.	EVRG	Elec.	✓	✓ *	--	✓ *	--	✓	--	✓	✓
Evergy Kansas South Inc.	EVRG	Elec.	✓	✓ *	--	✓ *	--	✓	--	✓	✓
Evergy Metro Inc.	EVRG	Elec.	✓	✓ *	--	--	--	--	✓ *	--	✓
Kansas Gas Service Co.	OGS	Gas	✓	-- *	--	✓ *	--	--	✓ *	--	--
KENTUCKY											
Atmos Energy Corp.	ATO	Gas	✓	✓	--	✓ *	--	--	✓	--	--
Columbia Gas of Kentucky Inc.	NI	Gas	✓	✓	--	✓ *	--	--	✓	--	--
Delta Natural Gas Co.	WTRG	Gas	✓	✓	--	✓ *	--	--	✓	--	--
Duke Energy Kentucky Inc.	DUK	Elec.	✓	✓	--	✓ *	--	--	--	✓	--
Duke Energy Kentucky Inc.	DUK	Gas	✓	✓	--	✓ *	--	--	✓	--	--
Kentucky Power Co.	AEP	Elec.	✓	✓	--	✓ *	--	--	--	✓	--
Kentucky Utilities Co.	PPL	Elec.	✓	✓	--	✓ *	--	--	--	✓	--
Louisville Gas & Electric Co.	PPL	Elec.	✓	✓	--	✓ *	--	--	--	✓	--
Louisville Gas & Electric Co.	PPL	Gas	✓	✓	--	✓ *	--	--	✓	--	--
LOUISIANA-NOCC											
Entergy New Orleans LLC	ETR	Elec.	✓	✓	--	--	--	✓	--	✓ *	✓ *
Entergy New Orleans LLC	ETR	Gas	✓	--	--	--	--	--	--	--	--

Use of adjustment clauses, as of June 2022

State/Company	Ultimate parent ticker	Type of service	Type of adjustment clause: Electric fuel/gas commodity/ purch. power	Conserv. program expense	Decoupling: Full	Decoupling: Partial	New capital: Traditional generation	New capital: Renewables/ Non-traditional generation	New capital: Delivery infrastructure	New capital: Environmental compliance	New capital: Transmission costs
LOUISIANA PSC											
Atmos Energy Corp.	ATO	Gas	✓	--	--	✓ *	--	--	--	--	--
CenterPoint Energy Arkla	CNP	Gas	✓	--	--	✓ *	--	--	--	--	--
Cleco Power LLC	--	Elec.	✓	✓ *	--	✓ *	✓ *	✓ *	✓ *	✓ *	✓ *
Entergy Louisiana LLC	ETR	Elec.	✓	✓ *	--	✓ *	--	--	--	✓	--
Entergy Louisiana LLC	ETR	Gas	✓	--	--	--	--	--	✓ *	--	--
Southwestern Electric Power Co.	AEP	Elec.	✓	✓ *	--	✓ *	--	--	--	--	--
MAINE											
Central Maine Power Co.	IBE	Elec.	-- *	--	✓ *	--	--	--	--	--	✓
Maine Natural Gas	IBE	Gas	✓	--	--	--	--	--	--	--	--
Northern Utilities Inc.	UTL	Gas	✓	--	--	--	--	--	✓	✓	--
Versant Power	--	Elec.	-- *	--	✓ *	--	--	--	--	--	✓
MARYLAND											
Baltimore Gas & Electric Co.	EXC	Elec.	-- *	✓	✓	--	--	--	--	--	--
Baltimore Gas & Electric Co.	EXC	Gas	✓	✓	✓	--	--	--	✓	--	--
Columbia Gas of Maryland Inc.	NI	Gas	✓	✓	--	✓ *	--	--	✓	--	--
Delmarva Power & Light Co.	EXC	Elec.	-- *	✓	✓	--	--	--	--	--	--
Potomac Edison Co.	FE	Elec.	-- *	✓	--	--	--	--	--	--	--
Potomac Electric Power Co.	EXC	Elec.	-- *	✓	✓	--	--	--	✓	--	--
Washington Gas Light Co.	ALA	Gas	✓	✓	--	✓ *	--	--	✓	--	--
MASSACHUSETTS											
Eversource Gas Co. of Massachusetts	ES	Gas	✓	✓ *	✓	--	--	--	✓	✓ *	--
Berkshire Gas Co.	IBE	Gas	✓	✓ *	✓	--	--	--	✓	✓ *	--
Boston Gas Co.	NGG	Gas	✓	✓ *	✓	--	--	--	✓	✓ *	--
Fitchburg Gas & Electric Light Co.	UTL	Elec.	-- *	✓ *	✓	--	--	✓ *	✓	--	✓
Fitchburg Gas & Electric Light Co.	UTL	Gas	✓	✓ *	✓	--	--	--	✓	✓ *	--
Liberty Utilities (New England Natural Gas Co.) Corp.	AQN	Gas	✓	✓ *	✓	--	--	--	✓	✓ *	--
Massachusetts Electric Co.	NGG	Elec.	-- *	✓ *	✓	--	--	✓ *	✓	--	✓
NSTAR Electric Co.	ES	Elec.	-- *	✓ *	✓	--	--	✓ *	✓	--	✓
NSTAR Gas Co.	ES	Gas	✓	✓ *	✓	--	--	--	✓	✓ *	--
MICHIGAN											
Consumers Energy Co.	CMS	Elec.	✓	✓	-- *	--	--	✓	--	--	✓ *
Consumers Energy Co.	CMS	Gas	✓	✓	--	✓ *	--	--	--	--	--
DTE Electric Co.	DTE	Elec.	✓	✓	-- *	--	--	✓	--	--	✓ *
DTE Gas Co.	DTE	Gas	✓	✓	--	✓ *	--	--	✓	--	--
Indiana Michigan Power Co.	AEP	Elec.	✓	✓	--	✓ *	--	✓	--	--	--
Michigan Gas Utilities Corp.	WEC	Gas	✓	✓	--	-- *	--	--	✓	--	--
SEMCO Energy Gas Co.	ALA	Gas	✓	✓	--	--	--	--	✓	--	--
Upper Michigan Energy Resources Corp.	WEC	Elec.	✓	✓	-- *	--	--	✓	--	--	--
Upper Peninsula Power Co.	--	Elec.	✓	✓	--	✓ *	--	--	--	--	✓ *

Use of adjustment clauses, as of June 2022

State/Company	Ultimate parent ticker	Type of service	Type of adjustment clause: Electric fuel/gas commodity/ purch. power	Conserv. program expense	Decoupling: Full	Decoupling: Partial	New capital: Traditional generation	New capital: Renewables/ Non-traditional generation	New capital: Delivery infrastructure	New capital: Environmental compliance	New capital: Transmission costs
MINNESOTA											
Minnesota Power Enterprises Inc.	ALE	Elec.	✓	✓	--	--	--	✓	--	--	✓
CenterPoint Energy Resources Corp.	CNP	Gas	✓	✓	--	✓ *	--	--	--	--	--
Minnesota Energy Resources Corp.	WEC	Gas	✓	✓	--	✓ *	--	--	✓	--	--
Northern States Power Co. - Minnesota	XEL	Elec.	✓	✓	--	✓ *	--	✓	--	✓	✓
Northern States Power Co. - Minnesota	XEL	Gas	✓	✓	--	--	--	--	✓	--	--
Otter Tail Power Co.	OTTR	Elec.	✓	✓	--	--	--	✓	--	✓	✓
MISSISSIPPI											
Atmos Energy Inc.	ATO	Gas	✓	--	--	✓ *	--	--	✓	--	--
Entergy Mississippi LLC	ETR	Elec.	✓	--	--	✓ *	--	--	--	--	✓
Mississippi Power Co.	SO	Elec.	✓	--	--	✓ *	--	--	--	✓ *	--
MISSOURI											
Empire District Electric Co.	AQN	Elec.	✓	--	--	--	--	-- *	--	-- *	✓ *
Empire District Gas Co.	AQN	Gas	✓	--	--	--	--	--	--	--	--
Evergy Metro Inc.	EVRG	Elec.	✓	✓ *	--	✓ *	--	-- *	✓ *	-- *	✓ *
Evergy Missouri West Inc.	EVRG	Elec.	✓	✓ *	--	✓ *	--	✓ *	✓ *	-- *	✓ *
Spire Missouri Inc.	SR	Gas	✓	--	--	✓ *	--	--	✓	--	--
Liberty Utilities (Midstates Natural Gas) Corp.	AQN	Gas	✓	--	--	✓ *	--	--	✓	--	--
Union Electric Co.	AEE	Elec.	✓	✓ *	--	✓ *	--	✓ *	✓ *	-- *	✓ *
Union Electric Co.	AEE	Gas	✓	--	--	✓ *	--	--	✓	--	--
MONTANA											
MDU Resources Group Inc.	MDU	Elec.	✓	✓ *	--	--	--	--	--	--	--
MDU Resources Group Inc.	MDU	Gas	✓	✓	--	✓ *	--	--	--	--	--
NorthWestern Corp.	NWE	Elec.	✓ *	✓	--	--	--	--	--	--	--
NorthWestern Corp.	NWE	Gas	✓	✓ *	--	--	--	--	--	--	--
NEBRASKA											
Black Hills Nebraska Gas LLC	BKH	Gas	✓	--	--	--	--	--	✓	--	--
Northwestern Corp.	NWE	Gas	✓	--	--	--	--	--	--	--	--
NEVADA											
Nevada Power Co.	BRK.A	Elec.	✓	✓	--	✓ *	--	✓	--	--	--
Sierra Pacific Power Co.	BRK.A	Elec.	✓	✓	--	✓ *	--	✓	--	--	--
Sierra Pacific Power Co.	BRK.A	Gas	✓	--	--	--	--	--	--	--	--
Southwest Gas Corp.	SWX	Gas	✓	✓	✓	--	--	✓	✓	--	--
NEW HAMPSHIRE											
Liberty Utilities (EnergyNorth Natural Gas) Corp.	AQN	Gas	✓	✓	✓ *	--	--	--	--	✓	--
Liberty Utilities (Granite State Electric) Corp.	AQN	Elec.	-- *	✓	--	✓ *	--	--	✓ *	--	✓
Northern Utilities Inc.	UTL	Gas	✓	✓	--	✓ *	--	--	--	--	--
Public Service Co. of New Hampshire	ES	Elec.	✓ *	--	--	✓ *	--	--	✓ *	--	✓
Unitil Energy Systems Inc.	UTL	Elec.	-- *	✓	--	✓ *	--	--	✓ *	--	--

Use of adjustment clauses, as of June 2022

			Type of adjustment clause																	
							Decoupling				New capital									
State/Company	Ultimate parent ticker	Type of service	Electric fuel/gas commodity/ purch. power		Conserv. program expense		Full		Partial		Traditional generation		Renewables/ Non-traditional generation		Delivery infrastructure		Environmental compliance		Transmission costs	
NEW JERSEY																				
Atlantic City Electric Co.	EXC	Elec.	--	*	✓	*	--		✓	*	--		--		✓	*	✓	*	--	
Jersey Central Power & Light Co.	FE	Elec.	--	*	✓	*	--		✓	*	--		--		--	*	✓	*	--	
New Jersey Natural Gas Co.	NJR	Gas	--	*	✓	*	✓	*	--		--		--		✓	*	✓	*	--	
Elizabethtown Gas Co.	SJI	Gas	--	*	✓	*	--		✓	*	--		--		✓	*	✓	*	--	
Public Service Electric & Gas Co.	PEG	Elec.	--	*	✓	*	--		✓	*	--		--		✓	*	✓	*	--	
Public Service Electric & Gas Co.	PEG	Gas	--	*	✓	*	--		✓	*	--		--		✓	*	✓	*	--	
Rockland Electric Co.	ED	Elec.	--	*	✓	*	--		✓	*	--		--		--	*	✓	*	--	
South Jersey Gas Co.	SJI	Gas	--	*	✓	*	✓	*	--		--		--		--	*	✓	*	--	
NEW MEXICO																				
El Paso Electric Co.	--	Elec.	✓		✓		--		--		--		✓		--		--		--	
New Mexico Gas Co.	EMA	Gas	✓		✓		--		✓	*	--		--		--		--		--	
Public Service Co. of New Mexico	PNM	Elec.	✓		✓		--		--		--		✓		--		--		--	
Southwestern Public Service Co.	XEL	Elec.	✓		✓		--		--		--		✓		--		--		--	
NEW YORK																				
Brooklyn Union Gas Co.	NGG	Gas	✓		✓		✓		--		--		--		✓		✓	*	--	
Central Hudson Gas & Electric Corp.	FTS	Elec.	--	*	✓		✓		--		--		✓	*	✓	*	✓	*	--	
Central Hudson Gas & Electric Corp.	FTS	Gas	✓		✓		✓		--		--		--		✓	*	✓	*	--	
Consolidated Edison Co. of New York Inc.	ED	Elec.	--	*	✓		✓		--		--		✓	*	✓	*	--		--	
Consolidated Edison Co. of New York Inc.	ED	Gas	✓		✓		✓		--		--		--		✓		--		--	
KeySpan Gas East Corp.	NGG	Gas	✓		✓		✓		--		--		--		✓		--		--	
National Fuel Gas Distribution Corp.	NFG	Gas	✓		✓		✓		--		--		--		✓		--		--	
New York State Electric & Gas Corp.	IBE	Elec.	--	*	✓		✓		--		--		✓	*	✓	*	--		--	
New York State Electric & Gas Corp.	IBE	Gas	✓		✓		✓		--		--		--		✓	*	--		--	
Niagara Mohawk Power Corp.	NGG	Elec.	--	*	✓		✓		--		--		✓	*	--		--		--	
Niagara Mohawk Power Corp.	NGG	Gas	✓		✓		✓		--		--		--		✓		--		--	
Orange & Rockland Utilities Inc.	ED	Elec.	--	*	✓		✓		--		--		✓	*	--		--		--	
Orange & Rockland Utilities Inc.	ED	Gas	✓		✓		✓		--		--		--		--		--		--	
Rochester Gas and Electric Corp.	IBE	Elec.	--	*	✓		✓		--		--		✓	*	--		--		--	
Rochester Gas and Electric Corp.	IBE	Gas	✓		✓		✓		--		--		--		✓	*	--		--	
NORTH CAROLINA																				
Duke Energy Carolinas LLC	DUK	Elec.	✓		✓	*	--		--	*	--		✓	*	--		✓		--	
Duke Energy Progress LLC	DUK	Elec.	✓		✓	*	--		--	*	--		✓	*	--		✓		--	
Piedmont Natural Gas Co.	DUK	Gas	✓		✓	*	✓	*	--		--		--		✓	*	--		--	
Public Service Co. of North Carolina	D	Gas	✓		✓	*	✓	*	--		--		--		✓	*	--		--	
Virginia Electric & Power Co.	D	Elec.	✓		✓	*	--		--	*	--		✓	*	--		✓		--	
NORTH DAKOTA																				
MDU Resources Group Inc.	MDU	Elec.	✓		--		--		--		✓		✓		✓	*	✓	*	✓	*
MDU Resources Group Inc.	MDU	Gas	✓		--		--		✓	*	--		--		--		--		--	
Northern States Power Co. - Minnesota	XEL	Elec.	✓		--		--		--		--		✓	*	✓	*	--	*	✓	*
Northern States Power Co. - Minnesota	XEL	Gas	✓		--		--	*	--		--		--		--		--		--	
Otter Tail Power Co.	OTTR	Elec.	✓		--		--		--		✓	*	✓	*	✓	*	✓	*	✓	*

Use of adjustment clauses, as of June 2022

State/Company	Ultimate parent ticker	Type of service	Type of adjustment clause: Electric fuel/gas commodity/ purch. power	Conserv. program expense	Decoupling: Full	Decoupling: Partial	New capital: Traditional generation	New capital: Renewables/ Non-traditional generation	New capital: Delivery infrastructure	New capital: Environmental compliance	New capital: Transmission costs
OHIO											
Cleveland Elec. Illum./Ohio Edison/Toledo Edison	FE	Elec.	-- *	✓ *	--	✓ *	--	✓	✓ *	--	✓
Columbia Gas of Ohio Inc.	NI	Gas	-- *	✓	-- *	--	--	--	✓ *	--	--
Dayton Power & Light Co.	AES	Elec.	-- *	✓ *	--	✓ *	--	✓	✓ *	--	✓
Duke Energy Ohio Inc.	DUK	Elec.	-- *	✓ *	--	✓ *	--	✓	✓ *	--	✓
Duke Energy Ohio Inc.	DUK	Gas	✓ *	--	-- *	--	--	--	✓ *	✓ *	--
East Ohio Gas Co.	D	Gas	-- *	✓	-- *	--	--	--	✓ *	--	--
Ohio Power Co.	AEP	Elec.	-- *	✓ *	--	✓ *	--	✓	✓ *	--	✓
Vectren Energy Delivery of Ohio Inc.	CNP	Gas	-- *	✓	-- *	--	--	--	✓ *	--	--
OKLAHOMA											
Summit Utilities Oklahoma Inc.	--	Gas	✓	✓ *	--	✓ *	--	--	--	--	--
Oklahoma Gas & Electric Co.	OGE	Elec.	✓	✓ *	--	✓ *	--	--	✓ *	✓ *	✓ *
Oklahoma Natural Gas Co.	OGS	Gas	✓	✓ *	--	✓ *	--	--	--	--	--
Public Service Co. of Oklahoma	AEP	Elec.	✓	✓ *	--	✓ *	--	✓ *	✓	-- *	✓
OREGON											
Avista Corp.	AVA	Gas	✓	✓		✓ *	--	--	--	--	--
Cascade Natural Gas Corp.	MDU	Gas	✓	✓	--	✓ *	--	--	--	✓ *	--
Idaho Power Co.	IDA	Elec.	✓	✓	--	--	--		--	--	--
Northwest Natural Gas Co.	NWN	Gas	✓	✓ *	--	✓ *	--	--	--	✓ *	--
PacifiCorp	BRK.A	Elec.	✓	✓	--	--	✓ *	✓ *	--	✓ *	--
Portland General Electric Co.	POR	Elec.	✓	✓	--	--	✓ *	✓ *	--	✓ *	✓
PENNSYLVANIA											
Columbia Gas of Pennsylvania Inc.	NI	Gas	✓	--	--	✓ *	--	--	✓ *	--	--
Duquesne Light Co.	--	Elec.	-- *	✓	--	--	--	--	✓ *	--	✓
Equitable Gas Co.	--	Gas	✓	--	--	--	--	--	✓ *	--	--
Metropolitan Edison Co.	FE	Elec.	-- *	✓	--	--	--	--	✓ *	--	✓
National Fuel Gas Distribution Corp.	NFG	Gas	✓	--	--	--	--	--	-- *	--	--
PECO Energy Co.	EXC	Elec.	-- *	✓	--	--	--	--	✓ *	--	✓
PECO Energy Co.	EXC	Gas	✓	✓	--	--	--	--	✓ *	--	--
Pennsylvania Electric Co.	FE	Elec.	-- *	✓	--	--	--	--	✓ *	--	✓
Pennsylvania Power Co.	FE	Elec.	-- *	✓	--	--	--	--	✓ *	--	✓
Peoples Natural Gas Co.	--	Gas	✓	--	--	--	--	--	✓ *	--	--
PPL Electric Utilities Corp.	PPL	Elec.	-- *	✓	--	--	--	--	✓ *	--	✓
UGI Central Penn Gas Inc.	UGI	Gas	✓	--	--	--	--	--	✓ *	--	--
UGI Penn Natural Gas Inc.	UGI	Gas	✓	--	--	--	--	--	✓ *	--	--
UGI Utilities Inc.	UGI	Elec.	-- *	✓	--	--	--	--	✓ *	--	--
UGI Utilities Inc.	UGI	Gas	✓	--	--	--	--	--	✓ *	--	--
West Penn Power Co.	FE	Elec.	-- *	✓	--	--	--	--	✓ *	--	--

Use of adjustment clauses, as of June 2022

State/Company	Ultimate parent ticker	Type of service	Type of adjustment clause: Electric fuel/gas commodity/ purch. power	Conserv. program expense	Decoupling: Full	Decoupling: Partial	New capital: Traditional generation	New capital: Renewables/ Non-traditional generation	New capital: Delivery infrastructure	New capital: Environmental compliance	New capital: Transmission costs
RHODE ISLAND											
Narragansett Electric Co.	PPL	Elec.	-- *	✓	✓	--	--	--	✓ *	--	✓
Narragansett Electric Co.	PPL	Gas	✓	✓ *	✓	--	--	--	✓ *	✓ *	--
SOUTH CAROLINA											
Dominion Energy South Carolina	D	Elec.	✓	✓	--	--	✓ *	--	--	✓	--
Dominion Energy South Carolina	D	Gas	✓	✓	--	✓ *	--	--	--	--	--
Duke Energy Progress LLC	DUK	Elec.	✓	✓	--	--	-- *	--	--	✓	--
Duke Energy Carolinas LLC	DUK	Elec.	✓	✓	--	--	-- *	--	--	✓	--
Piedmont Natural Gas Co.	DUK	Gas	✓	✓	--	✓ *	--	--	--	--	--
SOUTH DAKOTA											
Black Hills Power Inc.	BKH	Elec.	✓	--	--	--	--	--	--	✓ *	✓ *
MDU Resources Group Inc.	MDU	Elec.	✓	--	--	--	--	--	✓	✓	✓
MDU Resources Group Inc.	MDU	Gas	✓	✓	--	✓ *	--	--	--	--	--
Northern States Power Co. - Minnesota	XEL	Elec.	✓	✓ *	--	✓ *	✓ *	--	✓ *	✓	✓
NorthWestern Corp.	NWE	Elec.	✓	✓	--	--	--	--	--	--	--
NorthWestern Corp.	NWE	Gas	✓	--	--	--	--	--	--	--	--
Otter Tail Power Corp.	OTTR	Elec.	✓	✓	--	--	✓ *	--	✓	✓	--
TENNESSEE											
Atmos Energy Inc.	ATO	Gas	✓	--	--	✓ *	--	--	--	--	--
Chattanooga Gas Co.	SO	Gas	✓	--	✓ *	--	--	--	--	--	--
Kingsport Power Co.	AEP	Elec.	✓	--	--	--	--	--	--	--	--
Piedmont Natural Gas Co.	DUK	Gas	✓	--	--	✓ *	--	--	✓	--	--
TEXAS PUC											
AEP Texas Inc.	AEP	Elec.	-- *	✓	--	--	--	--	✓	--	✓
CenterPoint Energy Houston Electric LLC	CNP	Elec.	-- *	✓	--	--	--	--	✓	--	✓
Cross Texas Transmission LLC	--	Elec.	-- *	--	--	--	--	--	✓	--	✓
El Paso Electric Co.	--	Elec.	✓ *	✓	--	--	-- *	--	✓	--	✓
Electric Transmission of Texas LLC	BRK.A/AEP	Elec.	-- *	--	--	--	--	--	✓	--	✓
Entergy Texas Inc.	ETR	Elec.	✓ *	✓	--	--	✓ *	--	✓	--	✓
Lone Star Transmission LLC	NEE	Elec.	-- *	--	--	--	--	--	✓	--	✓
Oncor Electric Delivery Co.	SRE	Elec.	-- *	✓	--	--	--	--	✓	--	✓
Sharyland Utilities LLC	--	Elec.	-- *	--	--	--	--	--	✓	--	✓
Southwestern Electric Power Co.	AEP	Elec.	✓ *	✓	--	--	-- *	--	✓	--	✓
Southwestern Public Service Co.	XEL	Elec.	✓ *	✓	--	--	-- *	--	--	--	✓
Texas-New Mexico Power Co.	PNM	Elec.	-- *	✓	--	--	--	--	✓	--	✓
Wind Energy Transmission Texas LLC	--	Elec.	-- *	--	--	--	--	--	✓	--	✓

Use of adjustment clauses, as of June 2022

State/Company	Ultimate parent ticker	Type of service	Type of adjustment clause: Electric fuel/gas commodity/ purch. power	Conserv. program expense	Decoupling: Full	Decoupling: Partial	New capital: Traditional generation	New capital: Renewables/ Non-traditional generation	New capital: Delivery infrastructure	New capital: Environmental compliance	New capital: Transmission costs
TEXAS RRC											
Atmos Energy Inc.	ATO	Gas	✓ *	--	--	✓ *	--	--	✓	--	--
CenterPoint Energy Resources Corp.	CNP	Gas	✓ *	--	--	--	--	--	✓	--	--
Texas Gas Service Co.	OGS	Gas	✓ *	--	--	✓ *	--	--	✓	--	--
UTAH											
PacifiCorp	BRK.A	Elec.	✓	✓	--	--	--	✓ *	--	--	--
Questar Gas Co.	D	Gas	✓	✓	✓ *	--	--	--	✓	--	--
VERMONT											
Green Mountain Power Corp.	--	Elec.	✓ *	--	--	--	--	--	--	--	--
VIRGINIA											
Appalachian Power Co.	AEP	Elec.	✓	✓	--	--	✓	--	--	✓	✓
Columbia Gas of Virginia Inc.	NI	Gas	✓	✓	--	✓ *	--	--	✓	--	--
Kentucky Utilities Co.	PPL	Elec.	✓	--	--	--	--	--	--	--	--
Roanoke Gas Co.	RGCO	Gas	✓	--	--	✓ *	--	--	✓	--	--
Virginia Electric & Power Co.	D	Elec.	✓	✓	--	--	✓	✓	✓	✓	✓
Virginia Natural Gas Inc.	SO	Gas	✓	--	--	✓ *	--	--	✓	--	--
Washington Gas Light Co.	ALA	Gas	✓	--	--	✓ *	--	--	✓	--	--
WASHINGTON											
Avista Corp.	AVA	Elec.	✓ *	✓	✓	-- *	--	--	--	--	--
Avista Corp.	AVA	Gas	✓	✓	✓	-- *	--	--	--	--	--
Cascade Natural Gas Corp.	MDU	Gas	✓	✓	--	✓ *	--	--	✓	--	--
Northwest Natural Gas Co.	NWN	Gas	✓	✓	--	--	--	--	--	--	--
PacifiCorp	BRK.A	Elec.	✓ *	✓	--	✓ *	--	✓	--	--	--
Puget Sound Energy Inc.	--	Elec.	✓ *	✓	--	✓ *	--	✓	--	--	--
Puget Sound Energy Inc.	--	Gas	✓	✓	--	✓ *	--	--	✓	--	--
WEST VIRGINIA											
Appalachian Power Co./Wheeling Power Co.	AEP	Elec.	✓	✓	--	--	-- *	--	-- *	✓	--
Hope Gas Inc.	D	Gas	✓	--	--	--	--	--	✓ *	--	--
Monongahela Power Co.	FE	Elec.	✓	✓	--	--	--	--	-- *	✓	--
Mountaineer Gas Co.	--	Gas	✓	--	--	--	--	--	✓ *	--	--
Potomac Edison Co.	FE	Elec.	✓	✓	--	--	--	--	-- *	--	--

Use of adjustment clauses, as of June 2022

			Type of adjustment clause															
							Decoupling		New capital									
State/Company	Ultimate parent ticker	Type of service	Electric fuel/gas commodity/ purch. power		Conserv. program expense		Full	Partial	Traditional generation		Renewables/ Non-traditional generation		Delivery infrastructure		Environmental compliance	Transmission costs
WISCONSIN																
Madison Gas & Electric Co.	MGEE	Elec.	✓	*	--	*	--	--	--	*	✓		--	*	--	--
Madison Gas & Electric Co.	MGEE	Gas	✓		--		--	--	--	*	--		--	*	--	--
Northern States Power Co. - Wisconsin	XEL	Elec.	✓	*	--	*	--	--	--	*	--		--	*	--	--
Northern States Power Co. - Wisconsin	XEL	Gas	✓		--		--	--	--	*	--		--	*	--	--
Wisconsin Electric Power Co.	WEC	Elec.	✓	*	--	*	--	--	--	*	✓		--	*	--	--
Wisconsin Electric Power Co.	WEC	Gas	✓		--		--	--	--	*	--		--	*	--	--
Wisconsin Gas LLC	WEC	Gas	✓		--		--	--	--	*	--		--	*	--	--
Wisconsin Power & Light Co.	LNT	Elec.	✓	*	--	*	--	--	--	*	--		--	*	--	--
Wisconsin Power & Light Co.	LNT	Gas	✓		--		--	--	--	*	--		--	*	--	--
Wisconsin Public Service Corp.	WEC	Elec.	✓	*	--	*	--	--	--	*	--		--	*	--	--
Wisconsin Public Service Corp.	WEC	Gas	✓		--		--	--	--	*	--		--	*	--	--
WYOMING																
Black Hills Wyoming Gas LLC	BKH	Gas	✓		✓		--	✓	*	--		--		✓		--	--
Cheyenne Light Fuel & Power Co.	BKH	Elec.	✓		✓		--	✓	*	--		--		--		--	--
MDU Resources Group Inc.	MDU	Elec.	✓		--		--	--		--		--		--		--	--
MDU Resources Group Inc.	MDU	Gas	✓		--		--	✓	*	--		--		--		--	--
PacifiCorp	BRK.A	Elec.	✓		✓		--	--		--		--		--		✓	--
Questar Gas Co.	D	Gas	✓		--		--	✓	*	--		--		--		--	--

Key:
✓ Adjustment clause exists for the company/state/operation.
* See text for further information.
-- Not applicable

Data as of June 2022.
Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights
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Related footnotes for data table — by state

Alabama

Electric fuel/gas commodity/purchased power — The certificated new plant, or Rate CNP, adjustment clause for Alabama Power Co. provides for recovery of costs, excluding fuel, associated with certified purchased power agreements. Adjustments under the clause are subject to a staff and Alabama PSC review process that includes public hearings. Alabama Power also utilizes an energy cost recovery adjustment clause. Spire Alabama Inc. and Spire Gulf Inc. utilize a competitive fuel clause that allows the companies to immediately adjust prices to compete with any alternate fuel or gas supply source, with no loss of earnings margin.

Decoupling — Spire Alabama and Spire Gulf operate under weather normalization adjustment, or WNA, mechanisms.

Traditional generation/environmental compliance — The Rate CNP adjustment clause used by Alabama Power provides for recovery of costs related to the commercial operation of certified generating facilities, certified purchased power agreements and environmental mandates. Recoverable environmental costs include applicable operation and maintenance expenses, depreciation and a return on capital beginning with investments made in 2005. Such costs are generally subject to review but not to a full evidentiary hearing.

Arizona

Decoupling — Arizona Public Service Co. utilizes a lost fixed cost recovery, or LFCR, mechanism designed to make the company whole for contributions to fixed-cost recovery that would otherwise be foregone due to customer participation in energy efficiency and distributed energy programs. The LFCR is capped at 1% of annual revenues, with any excess being deferred for future recovery. Arizona Public Service' LFCR also now includes an earnings test.

A full decoupling mechanism, called the delivery charge adjustment, is in place for Southwest Gas Corp. The mechanism compares actual revenues with revenues authorized in the company's last general rate case.

Tucson Electric Power Co. operates under an LFCR mechanism designed to mitigate the revenue impact of lost sales associated with the ACC's energy efficiency standards and the distributed generation requirements under the commission's renewable energy standards. The annual adjustments are capped at 2% of retail revenues, with any excess to be deferred for future recovery.

UNS Electric Inc. utilizes an LFCR mechanism under which the company is permitted to implement annual rate adjustments related to any shortfall in recovery of fixed costs due to energy efficiency and distributed generation. The LFCR is not intended to recover fixed costs due to other factors, such as weather or general economic conditions, and, as such, is not considered a full decoupling mechanism. The annual adjustments are to be capped at 1%, with any excess amount to be deferred for future recovery.

UNS Gas Inc. is subject to an incentive-based LFCR plan that allows the company to attain greater amounts of fixed-cost recovery as it meets commission-defined energy efficiency goals. Residential customers are permitted to opt out of the LFCR provisions if they agree to a rate structure that incorporates a higher basic service fixed monthly charge. The LFCR is capped at 1% of annual revenues, with any excess being deferred for future recovery.

Delivery infrastructure — A surcharge is in place for Southwest Gas that pertains to a distribution pipeline replacement program associated with pre-1970 vintage steel pipes. Southwest Gas also has a mechanism in place that provides for the recovery of costs associated with programs through which the company replaces certain assets located on customers' properties with assets that are owned and operated by the utility.

Arkansas

Decoupling — A generic framework, effectively a partial decoupling mechanism, is in place that provides for the electric and gas utilities to recover the lost contribution to fixed costs associated with energy efficiency-related usage reductions and to retain a portion of the net benefits related to these programs. The gas utilities have been using full decoupling mechanisms for several years.

Generation — Entergy Arkansas LLC, or EA, utilizes a capacity acquisition rider to recover costs associated with its investment in certain generation facilities and a capacity cost recovery rider to flow through the net costs related to the company's purchases of capacity to serve retail customers.

Delivery infrastructure — EA uses a rider to recover costs associated with certain government-mandated investments. A gas main replacement program is in place for Summit Utilities Arkansas Inc., or SUA, Black Hills Energy Arkansas Inc., or BHEA, and Arkansas Oklahoma Gas Corp., or AOG, under which the companies are authorized to recover the cost of replacing cast iron and bare steel gas mains and associated services through a mechanism. BHEA and SUA also have an at-risk meter relocation program rider in place to permit timely recovery of the costs associated with moving meters from customers' property lines to the structures being served.

Colorado

Decoupling — An adjustment clause is in place for Public Service Company of Colorado's, or PSCO's, gas operations that provides for recovery of lost revenues associated with customer participation in demand-side management programs.

PSCO's electric operations are subject to a pilot partial decoupling mechanism that applies to the company's residential and small commercial customers. The mechanism is to terminate Dec. 31, 2023. Annual adjustments under the mechanism are to be capped at 3% of class revenues.

Generation — Black Hills Colorado Electric Utility Inc., or BHCE, has a rider in place that reflects the company's investment in a gas-fired plant at the Pueblo Generating Station. Costs recovered through the rider are accorded a lower ROE than that established for BHCE's other Colorado jurisdictional operations. The rider is to remain in place until BHCE's next rate case.

Delivery infrastructure — PSCO operates under a pipeline system integrity adjustment mechanism for its gas operations, through which the company recovers the costs associated with reliability improvements and compliance with certain federal safety regulations. A similar mechanism, known as the system safety and integrity rider, is in place for Black Hills Gas Distribution LLC.

Connecticut

Electric fuel/gas commodity/purchased power — Connecticut Light and Power Co., or CL&P, and United Illuminating Co. no longer own generation, and both are permitted to recover, on a current basis, their full costs of providing generation service to those customers who do not choose an alternative supplier. These costs are allocated to ratepayers outside of a rate case.

Decoupling — State law mandates the adoption of decoupling mechanisms for the electric and gas utilities.

Renewables/Non-traditional generation — State law permits the electric distribution companies to recover prudently incurred costs associated with the energy storage pilot programs, first through a fully reconciling mechanism, and then through base rate cases following the utility's next rate case.

Delivery infrastructure — A system expansion reconciliation mechanism is in place that permits the gas utilities to reconcile gas-expansion-related revenue annually between rate cases. Yankee Gas Services Co., Connecticut Natural Gas Co. and Southern Connecticut Gas Co. also utilize a distribution integrity management program mechanism that allows for recovery, between rate cases, of the costs associated with main replacement activity. A capital tracker, referred to as the electric system improvements charge, is in place for CL&P for capital additions for system resiliency and grid modernization.

Delaware

Electric fuel/gas commodity/purchased power — In conjunction with the implementation of retail competition, Delmarva Power and Light Co.'s electric fuel adjustment was largely eliminated. Power to meet the standard offer service, or SOS, needs is now procured competitively and reflected in rates on a current basis.

Delivery infrastructure — State law allows electric and gas utilities to implement a distribution system improvement charge. Delmarva is permitted to recover the cost of relocation of aerial and underground facilities required or necessitated by the Department of Transportation or other government agency projects.

Environmental compliance — Chesapeake Utilities Corp. has a rider in place to recover environmental costs associated with cleaning up former manufactured gas plants. Delmarva has a mechanism in place for its gas operations to recover costs associated with the cleanup of a manufactured gas plant.

District of Columbia

Electric fuel/gas commodity/purchased power — Fuel and purchased power adjustment clauses are permitted by law. However, with the onset of electric retail competition, Potomac Electric Power Co., or Pepco, divested most of its generation assets and those not divested have since been retired. Pepco purchases the power to meet its SOS requirements via a competitive bidding process, and prices paid by SOS customers reflect the weighted average of the winning bids. SOS prices are adjusted on a current basis.

Decoupling — A bill stabilization adjustment mechanism is in place for Pepco that is designed to mitigate the volatility of revenues and customer bills caused by abnormal weather and customer participation in energy efficiency programs.

Renewables/non-traditional generation — The utilities' rates include a charge to fund the Sustainable Energy Trust Fund; amounts collected are remitted to the third-party — Sustainable Energy Utility. Additionally, Pepco and Washington Gas Light Co., or WGL, have in place a charge to contribute to the Energy Assistance Trust Fund.

Delivery infrastructure — State law provides for the district to issue bonds, finance or securitize a portion of the costs associated with a plan, under which Pepco is to relocate certain above-ground distribution facilities below ground. In addition, the bill authorizes the PSC to approve a mechanism to achieve rate recognition of the unsecuritized portion of the project. Pepco has a mechanism in place to recover costs associated with work performed to underground certain electric power lines in the district. The PSC has approved a $1 billion, 40-year accelerated pipeline replacement program for WGL and a related mechanism.

Florida

Traditional generation — Electric utilities are permitted to recover all prudently incurred site-selection and preconstruction costs, including carrying charges, for nuclear and integrated gasification combined-cycle, or IGCC, power plants through the capacity cost recovery clause, or CCRC. A cash return on construction work in progress for nuclear plant construction and uprates and IGCC construction is also reflected in the CCRC.

Renewables/non-traditional generation — Duke Energy Florida LLC is allowed to petition the Florida PSC for cost recovery for installation of solar generation capacity through a solar base rate adjustment, or SoBRA, mechanism. Tampa Electric Co. also has a SoBRA mechanism. Florida Power & Light Co. is authorized to recover the costs of solar generation through SoBRA upon each unit's commercial operation date if it is determined to be cost-effective and the costs are reasonable.

Delivery infrastructure — Peoples Gas System Inc. utilizes a rider to recover the costs associated with accelerating the replacement of cast-iron and bare-steel distribution pipes on its system. The smaller gas utilities — Florida Public Utilities Co., the Florida division of Chesapeake Utilities and Pivotal Utility Holdings Inc. — use similar riders.

State law allows for establishment of a storm protection plan cost recovery clause for electric utilities in the state. The law allows utilities to seek more timely recovery of storm-hardening investments outside of a general rate case. The law requires utilities to submit to the PSC a 10-year plan explaining "the systematic approach the utility will follow to achieve the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability." Such grid-hardening activities include burying transmission lines and vegetation management.

Georgia

Electric fuel/gas commodity/purchased power — As a result of the restructuring of the natural gas industry in Georgia, Atlanta Gas Light Co., or ATGL, no longer procures gas for its customers and, thus, is no longer subject to the purchased gas adjustment mechanism, or PGAM. The much smaller Liberty Utilities (Peach State Natural Gas) Corp., which is still regulated under a non-restructured framework, utilizes a non-automatic PGAM.

Decoupling — Liberty Utilities (Peach State Natural Gas) is subject to the Georgia rate adjustment mechanism, or GRAM — an alternative regulatory framework. The GRAM provides for a "revenue true-up," under which the company is to compare actual revenues to a previous revenue projection. ATGL operates under a straight fixed-variable rate design.

Traditional generation — A nuclear construction cost recovery tariff is in place for Georgia Power Co., or GP, that enables GP to earn a cash return on construction work in progress related to the Plant Vogtle Units 3 and 4 nuclear units.

Delivery infrastructure — Various infrastructure programs previously authorized by the PSC, including the Integrated Vintage Plastic Replacement Program to replace aging plastic pipes and the Integrated System Reinforcement Program to upgrade ATGL's distribution system and liquefied natural gas facilities continue under the GRAM, and the recovery of and return on the infrastructure program investments are included in annual rate adjustments.

Environmental compliance — ATGL is authorized to recover cleanup costs related to former manufactured gas plant sites through an environmental response cost recovery rider. Costs that are recoverable under this rider include investigation, testing, remediation and/or litigation costs or other liabilities. Georgia Power has in place a rider that allows for the recovery of environmental compliance costs.

Hawaii

Renewables/non-traditional generation — Riders are in place for Hawaiian Electric Co. Inc. and Maui Electric Co. Ltd. to address costs associated with the utilities' renewable energy infrastructure program projects.

Idaho

Electric fuel/gas commodity/purchased power — Avista Corp.'s power cost adjustment enables the company to defer, in a balancing account, for subsequent recovery/refund to customers, 90% of the difference between actual net power costs and the amount included in retail rates. Idaho Power Co., or IP, has a similar mechanism in place with a sharing provision under which annual rate adjustments reflect 95% of the cost variations associated with water supply for hydroelectric production, wholesale energy prices and retail load changes. An energy cost adjustment mechanism is in place for PacifiCorp that allows for the recovery of 90% of the difference between actual power costs and those included in rates.

Decoupling — IP operates under a decoupling mechanism referred to as a fixed cost adjustment, or FCA, which is designed to adjust the company's electric rates to recover fixed costs independent of the volume of energy sales. The FCA calculation reflects actual sales, and there is a 3% cap on annual rate increases that may be implemented under the mechanism. Unrecovered balances are to be carried forward to future years, with interest. Avista Corp. operates under an electric and gas decoupling mechanism, also referred to as an FCA. There is a 3% annual cap on rate increases that may be implemented under the mechanism. Unrecovered balances are to be carried forward to future years, with interest.

Illinois

Electric fuel/gas commodity/purchased power — Historically, the large electric utilities, namely Ameren Illinois Co., or AI, and Commonwealth Edison Co., or ComEd, were permitted to recover fuel costs and the energy component of purchased power costs through a fuel adjustment clause, or FAC. Their FACs were discontinued in conjunction with the implementation of electric industry restructuring. The power to meet the utilities' SOS obligations is now procured competitively. SOS costs and revenues are subject to an annual true-up mechanism. MidAmerican Energy Co. continues to use a FAC, as the company was not subject to all the provisions of the restructuring law and continues to own generation plants to serve its customers.

Decoupling — AI, Liberty Utilities (Midstates Natural Gas) Corp., Northern Illinois Gas Co., or NI-Gas, North Shore Gas Co. and Peoples Gas Light and Coke Co. have volume balancing adjustment riders in place that account for the impact on fixed cost recovery of energy efficiency efforts and weather.

Delivery infrastructure — AI, ComEd, North Shore and NI-Gas have riders in place to recover certain costs associated with maintaining infrastructure in accordance with requirements imposed by local governments. In accordance with state law, the ICC is permitted to approve adjustment clauses for the local gas distribution companies to recover the costs associated with their infrastructure replacement programs, and the ICC has done so for Peoples, NI-Gas and AI.

Environmental compliance — AI uses a hazardous materials adjustment clause rider, largely to address asbestos-related litigation and remediation costs. AI, ComEd, Peoples, North Shore and NI-Gas use riders to recover costs related to the investigation and cleanup of manufactured gas plants.

Indiana

Decoupling — Electric energy efficiency riders of Indianapolis Power and Light Co., or IP&L; Indiana Michigan Power Co., or IMP; Duke Energy Indiana Co., or DEI; Northern Indiana Public Service Company, or NIPSCO; and Southern

Indiana Gas and Electric, or SIGECO provide for the recovery of net lost revenues and shared savings, subject to commission approval.

Delivery infrastructure — State law allows the Indiana URC to authorize utilities to implement a transmission, distribution and storage system improvement charge rider to facilitate recovery of the costs associated with certain electric and gas infrastructure expansion projects, including those intended to improve safety or reliability, modernize the utility's system or improve an area's economic development prospects. The URC has approved such a rider for DEI, Indiana Gas Co., or IG, SIGECO's and NIPSCO's electric and gas operations and IP&L. IMP and NIPSCO use a rider to recover costs associated with certain government-mandated investments. SIGECO uses a rider to recover the costs associated with clean energy investments.

Environmental compliance — State law allows the URC to authorize electric utilities to recover, through a rate adjustment mechanism, 80% of the costs associated with certain federally-mandated emissions-control and transmission/distribution reliability projects. The remaining 20% of such costs are to be deferred for future recovery. Environmental cost recovery riders are in place for DEI, NIPSCO, IP&L, IMP and SIGECO. Through these riders, the utilities are permitted to recover the related operations and maintenance costs and depreciation expense after the environmental facilities become operational, as well as a return on the related investment.

Kansas

Conservation program expense/decoupling — State law allows electric and gas utilities to request KCC approval to implement energy efficiency-related cost-recovery mechanisms. Evergy Kansas Central Inc. and Evergy Kansas South Inc. participate in energy efficiency programs and recover program-related costs and related lost revenues through the companies' energy efficiency cost-recovery riders. WNA clauses are in place for Atmos Energy Corp., Black Hills/Kansas Gas Utility Co., or KGU, and Kansas Gas Service Co., or KGS.

Delivery infrastructure — Evergy Metro Inc. has a rider in place to recover the costs associated with projects to underground transmission and distribution infrastructure. State law permits local gas distribution companies to utilize a gas system reliability surcharge, or GSRS, mechanism to recover the costs associated with gas distribution system replacement projects between base rate proceedings. Atmos, KGS and KGU have a GSRS in place.

Kentucky

Decoupling — WNA mechanisms are in place for Atmos Energy Corp.; Columbia Gas of Kentucky Inc., or CGK; Delta Natural Gas Co.; and the gas operations of Duke Energy Kentucky Inc., or DEK, and Louisville Gas and Electric, or LG&E. DEK, LG&E, Atmos, CGK and Delta utilize energy efficiency riders to facilitate recovery of costs associated with gas energy efficiency programs; these riders include certain incentive provisions and permit recovery of lost revenues related to these programs. LG&E, DEK, Kentucky Utilities Co. and Kentucky Power Co. also utilize a similar mechanism for their electric businesses.

Louisiana - NOCC

Environmental compliance/transmission costs — An environmental adjustment clause and a rider associated with the Midcontinent Independent System Operator regional transmission organization are in place for Entergy New Orleans LLC's electric operations.

Louisiana PSC

Decoupling — An energy efficiency rider is in place for Cleco Power LLC, the electric operations of Entergy Louisiana LLC, or EL, and Southwestern Electric Power Co., or SWEPCO, through which the utilities recover costs associated with administering their programs and the lost contribution to fixed costs associated with customer participation in the programs. WNA mechanisms are in place for CenterPoint Energy Resources Corp. and Atmos Energy.

Renewables/non-traditional generation/delivery infrastructure/environmental compliance/transmission costs — Cleco Power has in place an infrastructure and incremental cost recovery rider through which the company may seek recovery of costs associated with, among other things, new generation capacity, renewables, environmental compliance, as well as transmission and delivery of assets/projects.

Delivery infrastructure — A gas infrastructure investment recovery rider is in place for EL's gas operations that addresses costs associated with the utility's pipeline replacement program.

Maine

Electric fuel/gas commodity/purchased power — Electric fuel adjustment clauses are no longer utilized due to the implementation of retail choice. For the most part, the state's electric utilities no longer own generation and, by law, are not allowed to provide SOS. SOS supply for the utilities is procured through a competitive process the Maine PUC conducts, and the cost of this supply is recovered from ratepayers.

Decoupling — Central Maine Power Co. and Versant Power are subject to a full decoupling mechanism, with any related annual adjustments capped at 2% of distribution revenues and any under-collections in excess of the capped to be deferred for future recovery. No cap is applied to the amount of over-collections to be returned to ratepayers.

Maryland

Electric fuel/gas commodity/purchased power — The electric fuel rate adjustment was eliminated coincident with the implementation of competition in the provision of electric supply. The power to meet default service requirements is obtained via competitive bids and the costs are recovered from ratepayers on a current basis.

Decoupling — Columbia Gas of Maryland Inc. and Washington Gas Light have revenue-normalization adjustment mechanisms in place for residential customers that address customer participation in energy efficiency/ conservation programs and WNA mechanisms in place that apply to all customer classes.

Delivery infrastructure — A grid resiliency program cost recovery mechanism is in place for Potomac Edison Co. that is to expire at the end of 2022.

Massachusetts

Electric fuel/gas commodity/purchased power — Electric fuel and purchased power adjustments were eliminated coincident with the start of retail competition. Rates for basic service, known as default service, are market-based and reflect the competitive contracts the distribution utility entered into for basic service supply. The utilities are not at risk for fluctuations in market prices.

Conservation program expense/environmental compliance — The Massachusetts DPU has adopted energy efficiency reconciliation factors, or EERF, for the state's electric utilities. The EERF is a fully reconciling funding mechanism designed to recover the costs associated with the state's electric energy efficiency investments that are in excess of the level collected from other funding sources, which include the systems benefits charge, proceeds from the forward capacity market and proceeds from the Regional Greenhouse Gas Initiative.

Local gas distribution adjustment clauses are in place to reflect the recovery of reconcilable distribution-related costs that are not included in base rates. Such expenses may include demand-side management costs, environmental response costs associated with manufactured gas plants, the revenue requirement on targeted infrastructure recovery factors and gas system enhancement plan, or GSEP, investment.

Renewables/non-traditional generation — The state's electric utilities utilize a solar cost adjustment mechanism to recover their investment and ongoing maintenance costs associated with their solar generation facilities. In addition, the electric utilities utilize a mechanism for long-term renewable energy contracts that allow for rates to be adjusted for the recovery of costs and contract remuneration arising in relation to long-term renewable energy contracts.

Delivery infrastructure — The state's electric utilities are subject to a grid modernization factor that provides for the recovery of incremental costs associated with their grid modernization plans.

A capital cost adjustment mechanism is in place for the electric division of Fitchburg Gas and Electric Co., or FG&E, that permits the company to recover costs associated with post-test-year capital additions. The mechanism contains an annual spending cap and a cap on annual rate increases under the mechanism of 1.5% of total revenues, with any amounts above the cap to be deferred for future recovery with carrying charges. To the extent that FG&E's capex exceed the amount it is allowed to recover through the mechanism, the company can seek to include such investments in rate base in its next base distribution rate proceeding.

Under state law, each of the local distribution companies files a GSEP with the DPU to address aging or leaking gas infrastructure and the related costs may be recovered through a GSEP provision.

Michigan

Decoupling — The Michigan PSC had approved implementation of electric revenue decoupling mechanisms, or RDMs, for Consumers Energy Co., or CE, Upper Peninsula Power Co., or UPP, and DTE Electric Co.; however, the Michigan Court of Appeals has ruled that the PSC does not have statutory authority to approve RDMs for electric utilities. State law now permits the PSC to adopt electric RDMs only for small electric utilities and Indiana Michigan Power and UPP have such a mechanism in place. State law permits a gas utility that spends at least 0.5% of its revenue on energy efficiency programs to institute an RDM. An RDM is currently in place for DTE Gas and CE.

Delivery infrastructure — DTE Gas utilizes an infrastructure recovery mechanism that enables it to earn a return of and on the costs associated with capital investment in the company's meter move-out, accelerated main replacement and pipeline integrity programs.

Transmission costs — CE, DTE Electric and UPP recover certain transmission costs through the power supply cost-recovery mechanism.

Minnesota

Decoupling — Minnesota Energy Resources Corp. is operating under a revenue decoupling mechanism, or RDM, that applies to the company's residential customers. There is a 10% symmetrical cap on revenue changes generated through the application of the RDM.

CenterPoint Energy Resources Corp. operates under an RDM that applies to all customer classes except market-rate customers and is subject to a cap on annual adjustments under the mechanism that is equal to 10% of non-gas margin revenue after removing conservation costs.

Northern States Power Co. - Minnesota has an electric RDM in place, such that decoupling is to be applied to residential and non-demand metered commercial customer classes subject to a 3% cap; an annual true-up with a 3% cap is to be utilized for the non-decoupled customer classes.

Mississippi

Decoupling — Atmos Energy utilizes a WNA rider. Entergy Mississippi LLC, Mississippi Power Co., or MP, and Atmos have energy efficiency riders in place that provide for recovery of the lost contributions to fixed costs associated with energy efficiency programs.

Environmental compliance — MP has in place a rider that establishes procedures to facilitate the PSC's review of the company's environmental compliance strategy and provides for recovery of the related costs, including the cost of capital, associated with PSC-approved environmental projects outside of a base rate case.

Missouri

Conservation program expense/decoupling — Evergy Metro Inc., Evergy Missouri West Inc. and Union Electric Co.'s, or UE, electric business have in place a mechanism that provides for recovery of demand-side management program-related costs and may provide for a performance incentive based upon measurable, verified energy efficiency savings. Spire Missouri Inc. and UE have a WNA rider in place, as does Liberty Utilities (Midstates Natural Gas) Corp.

Renewables/non-traditional generation — The PSC's rules specify that electric utilities may file for a renewable energy standards rate adjustment mechanism, or RESRAM, to reflect prudently incurred costs or a pass-through of benefits received as a result of compliance with the state's renewable energy standards. The RESRAM is to be capped at a 1% annual rate impact.

Delivery infrastructure — Evergy Metro, Evergy Missouri West and UE use a rider to recover costs associated with certain government-mandated investments.

Environmental compliance — The PSC's rules pertaining to environmental cost recovery mechanisms, or ECRMs, specify that a portion of the utility's environmental costs may be recovered through an ECRM, and a portion may be recovered through base rates. The annual recovery of these costs is to be capped at 2.5% of the utility's Missouri gross jurisdictional revenues, less certain taxes. None of the utilities currently have an ECRM in place.

Transmission costs — Empire's, Evergy Metro's, Evergy Missouri West's and UE's FACs reflect variations in certain transmission-related costs.

Montana

Electric fuel/gas commodity/purchased power — In accordance with the state's restructuring statutes, NorthWestern Corp. sold its generation assets and entered into purchased power contracts with competitive suppliers to serve provider-of-last-resort customers. NorthWestern recovers supply costs through a power costs and credits adjustment mechanism that allows the company to adjust for differences between the recovered and actual amounts of the utility's base power costs and credits, transitional costs and qualifying facility, or QF, costs. Regarding the base power costs and credits, 90% of the difference between the recorded and actual costs is rebated to customers, when costs are less than revenues, or recorded as a surcharge, when costs are greater than the revenues. For transitional and QF costs, 100% of the difference is rebated to customers when costs are less than the revenues or surcharged to ratepayers when costs are greater.

Conservation program expense — Universal system benefit charges are in place for the electric and gas customers of MDU Resources Group Inc. and NorthWestern, designed to recover costs associated with energy conservation efforts.

Decoupling — MDU Resources utilizes a mechanism to recoup revenues lost as a result of gas conservation programs.

Nevada

Decoupling — The lost revenues associated with energy efficiency and conservation programs for Sierra Pacific Power and Nevada Power are recovered using a periodically adjusted balancing account.

New Hampshire

Electric fuel/gas commodity/purchased power — Fuel and purchased power adjustment clauses had been utilized prior to the implementation of retail choice in the early 2000s. Public Service Co. of New Hampshire, or PSNH, now recovers its power costs through a periodically-adjusted default energy service charge, which recovers energy related costs incurred as a result of providing generation service supply to all customers that have not migrated to a competitive energy supplier. It also includes a reconciliation of the difference between the company's costs and revenues for the previous period. PSNH, Liberty Utilities (Granite State Electric) and Unitil Energy Systems have sold their generation and/or exited power supply contracts as part of their restructuring agreements. These distribution-only companies supply default energy service through a request-for-proposals process supervised by the PUC.

Decoupling — The PUC has established an energy efficiency resource standard, or EERS, for New Hampshire's electric and gas utilities and the utilities implemented lost revenue adjustment mechanisms, or LRAMs, to recover lost revenue due to the installation of energy efficiency measures. The PUC subsequently ordered the utilities to seek approval of a decoupling mechanism or other lost-revenue recovery mechanism as an alternative to the LRAM in their first distribution rate cases after the first EERS triennium, if not before.

Delivery infrastructure — Reliability enhancement and vegetation management programs and accompanying riders are in effect for Liberty Utilities (Granite State Electric), PSNH and Unitil Energy Systems. The programs provide for recovery of both the capital investment and increases to operation and maintenance expenses necessary for ongoing system reliability and vegetation management efforts.

New Jersey

Electric fuel/purchased power/gas commodity — Both electric and gas customers may purchase their respective commodity from competitive suppliers. The utilities provide default supply for customers that are not served by competitive suppliers. Costs associated with procurement of the supply are recovered on a current basis.

Conservation program expense — Costs associated with the NJ Clean Energy Program — a legislatively mandated initiative to encourage the initiation of energy efficiency and renewable energy programs — are included for recovery through a non-bypassable societal benefits charge on customer bills.

Decoupling — A version of a full revenue decoupling mechanism is in place for New Jersey Natural Gas Co., or NJNG, and South Jersey Gas Co., or SJG. The operation of the mechanisms is subject to an earnings test and a variable margin revenue adjustment and is contingent on the companies achieving certain capacity-reduction targets, as specified in their BPU-approved conservation incentive programs.

WNA clauses are in place for Elizabethtown Gas Co., or ETG, and the gas operations of Public Service Electric and Gas, or PSEG. Lost revenue adjustment mechanisms were approved for the electric utilities in the context of energy efficiency programs approved in 2020 and 2021.

Delivery infrastructure — The BPU directed utilities to develop mitigation and hardening infrastructure modernization plans and indicated that it would be open to innovative cost recovery mechanisms for such plans. The BPU subsequently approved modernization plans and related recovery mechanisms for several utilities. These have largely expired.

In 2017, the BPU adopted a rule outlining an infrastructure investment program, or IIP, framework that allows for expedited rate treatment of BPU-approved infrastructure improvement programs on an ongoing basis. IIPs have been approved for Atlantic City Electric Co., ETG, NJNG and PSE&G, for both electric and gas operations. IIP proposals filed by Rockland Electric Co. and SJG are pending.

Environmental compliance — Legislation enacted in 2018 required the BPU to establish a program to recognize the environmental and fuel diversity attributes of electricity generated by eligible nuclear power plants. Each investor-owned electric utility in the state must purchase zero emission credits on a monthly basis from each plant selected. Recovery of the related costs occurs via an irrevocable charge on the utility's customers. Certain other costs, including those associated with participating in the RGGI and the manufactured gas plant remediation, are recovered through the societal benefits charge.

New Mexico

Decoupling — New Mexico Gas Co. has a weather normalization adjustment mechanism in place.

New York

Electric fuel/gas commodity/purchased power — The state's electric distribution utilities are permitted to flow through the costs of power procured to serve customers who have not selected an alternative supplier. The electric utilities recover certain costs through the systems benefit charge for "clean energy activities" that include costs to comply with the state's renewable portfolio standards.

Renewables/non-traditional generation — The state's electric distribution companies are permitted to recover implementation costs, incremental costs and carrying charges associated with the procurement of qualified energy storage systems.

Delivery infrastructure/environmental compliance — New York State Electric and Gas Corp., or NYSEG, Rochester Gas and Electric Corp., or RG&E, and Central Hudson Gas and Electric Corp., or CHG&E, have rate adjustment mechanisms, or RAMs, in place that return to or collect from ratepayers eligible costs on a timely basis, subject to a cap. For NYSEG and RG&E, RAM-eligible deferrals include gas-leak-prone pipe-carrying costs.

For CHG&E's electric and gas operations, the RAM will return or collect the net balance of reconciliations for site investigation and remediation, or SIR, costs.

Brooklyn Union Gas Co. has a SIR mechanism in place. Consolidated Edison Co. of New York has a Safety and Reliability Surcharge Mechanism in place.

North Carolina

Conservation program expense — State law authorizes the NCUC to approve an annual rider outside of a general rate case for electric utilities to recover all reasonable and prudent costs incurred for the adoption and implementation of demand-side management, or DSM, and energy efficiency, or EE, programs. The NCUC has authorized the major electric utilities to retain a percentage of the net savings associated with their DSM/EE programs. In the most recent general rate cases involving Piedmont Natural Gas and Public Service Co. of North Carolina, or PSNC, the NCUC approved a three-year pilot program that includes several EE programs and an EE cost recovery rider.

Decoupling — Piedmont Natural Gas utilizes a margin decoupling mechanism that decouples the recovery of authorized margins from sales levels. PSNC also has such a mechanism in place.

Renewables/non-traditional generation — Costs incurred by electric utilities to procure renewable energy are recoverable through the FAC and the renewable energy portfolio standard, or REPS, rider, subject to certain caps. Incremental operations and maintenance costs are also recoverable through the REPS rider, as well as up to $1

million in annual research and development expenses. The cost of utility-owned renewable generating facilities is recovered through a combination of the FAC, the REPS rider and base rates.

Delivery infrastructure — Piedmont Natural Gas uses an integrity management rider, or IMR, that allows the company to track and recover capital expenditures incurred to comply with federal pipeline safety and integrity requirements outside of a general rate case. PSNC uses an IMR to recover capital expenditures related to the company's transmission and distribution pipeline integrity management programs.

North Dakota

Decoupling — MDU Resources' gas operations are subject to a WNA mechanism. Northern States Power - Minnesota, or NSP-M, operates under straight fixed-variable gas rates.

Traditional generation — Otter Tail Power established a generation cost recovery rider to reflect costs associated with the utility's Astoria Station and Merricourt Wind projects. Regarding the Hoot Lake plant, Otter Tail is to evaluate any retirement-related changes to costs of service and include them in the generation cost recovery rider until they can be transferred into base rates.

Environmental compliance/delivery infrastructure — Electric utilities are permitted to earn a cash return on construction work in progress through a separate rate adjustment mechanism for investments in transmission infrastructure and for federally-mandated environmental compliance projects. Once the facilities achieve commercial operation, the facilities are reflected in rate base as part of a general rate proceeding, and the surcharge terminates. NSP-M is operating under a transmission cost recovery rider. MDU and Otter Tail are operating under separate transmission and environmental cost recovery riders.

Ohio

Electric fuel/gas commodity/purchased power/delivery infrastructure — As a result of the electric industry restructuring, utilities operate under electric security plans, or ESPs, that provide for the pass-through of the utilities' cost of power to serve standard-service-offer customers.

The current ESPs for Cleveland Electric Illuminating Co., or CEI, Ohio Edison Co., or OE, and Toledo Edison Co., or TE, include delivery capital recovery riders that reflect a return of and on incremental distribution, sub-transmission and general plant-in-service investments not already included in the companies' base rates.

Under the current ESP with Duke Energy Ohio, or DEO, the company's generation requirements for non-switching customers are procured and priced through a competitive bid process, or CBP. The related riders are fully bypassable for switching customers.

Ohio Power Co.'s, or OP, ESP allows the company to utilize riders for costs related to distribution investment and enhanced service reliability.

East Ohio Gas Co., or EOG, Columbia Gas of Ohio Inc., or CGO, and Vectren Energy Delivery of Ohio, or VEDO, conduct auctions for competitive suppliers to bid to serve customers directly. The companies had previously obtained their gas supplies through negotiated bilateral contracts, but under the current plan, the companies conduct an auction that allows suppliers to compete to supply portions of the gas supply requirements. Customers who do not choose a specific competitive supplier are randomly assigned a supplier based on the auction results. DEO is the only major gas utility in the state to continue to use the gas cost recovery clause.

Conservation program expense/decoupling — The ESPs for each of the Ohio electric utilities include a rider that allows for the recovery of energy efficiency program costs and lost distribution margin associated with these programs. OP has a full decoupling mechanism in place for residential and small commercial customers. Ohio's gas distribution companies — namely EOG, CGO, VEDO and DEO —operate under straight fixed-variable prices.

Delivery infrastructure — The current ESPs in place for CEI/OE/TE, Dayton Power & Light and DEO include riders that reflect costs associated with incremental distribution-related investments not already included in base rates. OP's ESP allows the company to utilize riders for costs related to distribution investment. CGO has a rider in place for infrastructure replacement costs. VEDO has riders in place through which it recovers the costs associated with certain infrastructure replacement investments. EOG has riders in place to recover costs related to its pipeline infrastructure replacement program and its installation of automated meter-reading equipment. DEO uses a rider to recover the costs associated with its gas delivery infrastructure improvement program.

Environmental compliance — DEO recovers certain costs related to former manufactured gas plant sites through a rider.

Oklahoma

Conservation program expense/decoupling — Oklahoma Gas and Electric Co., or OG&E, and Public Service Co. of Oklahoma, or PSO, utilize riders to recover the costs associated with energy efficiency programs, related lost revenues and certain incentives.

Summit Utilities Oklahoma Inc. and Oklahoma Natural Gas Co., or ONG, utilize a WNA mechanism and also recover the costs associated with their energy efficiency programs and certain incentives through their performance-based ratemaking plan riders.

Renewables/non-traditional generation — PSO utilizes a wind facility asset rider designed to recover return on and of the wind facilities and operation and maintenance expenditures after the facilities commence commercial operation.

Delivery infrastructure/transmission costs — OG&E uses a rider for the Oklahoma jurisdictional costs associated with certain transmission projects that the Southwest Power Pool has approved and that have been completed. OG&E also utilizes a temporary grid enhancement mechanism that allows for interim recovery of the costs associated with its grid enhancement plan.

Environmental compliance — OCC rules permit the commission to approve requests to recover costs associated with environmental compliance through a rider.

Oregon

Conservation program expense/decoupling — Northwest Natural Gas, or NWNG, is authorized to recover costs associated with its energy efficiency program for industrial customers. NWNG uses a decoupling mechanism designed to counteract the impact on revenues of changes in the consumption patterns of average residential and commercial customers due to conservation efforts. The company has a separate weather-adjusted rate mechanism in place for these customers.

Cascade Natural Gas, or CNG, has a partial decoupling mechanism in place until Jan. 1, 2025, with a review to be completed by Sept. 30, 2024.

A decoupling mechanism is in place for Avista's residential and commercial rate groups.

Traditional generation — PacifiCorp is authorized to recover costs associated with its Lake Side 2 generation investment. Portland General Electric, or PGE, utilizes a mechanism to implement in rates its share of the revenue requirement for the Colstrip Power Plant units 3 and 4 and associated common facilities.

Renewables/Non-traditional Generation — PGE is authorized to recover through an adjustment clause the revenue requirement associated with qualifying company-owned or contracted new renewable energy resource and energy storage projects associated with renewable energy resources not otherwise included in rates. PacifiCorp utilizes a renewable adjustment clause to recover between rate cases the costs to construct or otherwise acquire facilities that generate electricity from renewable energy sources and for associated electricity transmission.

Environmental compliance — CNG employs an environmental remediation adjustment to recover costs for a former manufactured plant. NWNG utilizes a site remediation and recovery mechanism to provide for recovery of costs that have been incurred or will continue to be incurred for environmental remediation of legacy-manufactured gas plant operations. PGE has an environmental remediation cost recovery adjustment that recovers the costs and revenues associated with the Portland Harbor Superfund site and other environmental obligations. PacifiCorp utilizes an adjustment mechanism which recovers deferred amounts associated with the Deer Creek Mine closure.

Pennsylvania

Electric fuel/gas commodity/purchased power — In conjunction with electric industry restructuring, the electric energy cost rate was eliminated. The supply to meet provider-of-last-resort, or POLR, obligations for each company is competitively procured and prices for POLR service are adjusted on a current basis.

Decoupling — Columbia Gas of Pennsylvania has a WNA mechanism in place for residential customers.

Delivery infrastructure — State law allows the PUC to approve automatic adjustment clauses to recognize, between general rate cases, utility investments in certain infrastructure projects.

Rhode Island

Electric fuel/gas commodity/purchased power — Prior to the implementation of electric industry restructuring, automatic FACs were used by the utilities. In accordance with the restructuring law and PUC-approved restructuring plans, investor-owned utilities are to provide SOS to customers who do not select an alternative provider through 2020. The cost of providing this service is fully recoverable, with such rates reset on a periodic basis.

Conservation program expense/environmental compliance — Narragansett Electric Co., or NE, utilizes a distribution adjustment clause, or DAC, for its gas operations to recover costs associated with energy efficiency programs and environmental response.

Delivery infrastructure — State law permits NE to submit for PUC approval of annual infrastructure spending plans for its electric and gas operations and recovery of expenses associated with an inspection and maintenance program and a vegetation management program.

South Carolina

Decoupling — WNA mechanisms are in place for the gas operations of Dominion Energy South Carolina and Piedmont Natural Gas that apply only to residential and small commercial customers.

Traditional generation — The South Carolina Legislature in 2018, overrode the governor's veto of House Bill 4375, which among other things, repealed the state's Base Load Review Act, or BLRA; thus, no future projects could fall under its purview. Previously, under the BLRA, the PSC was permitted to issue a BLRA order, which constituted an upfront determination that a generating plant is "used and useful" and that associated capex are prudent and ultimately should be reflected in rates as long as the plant is constructed within the estimated construction schedule, including contingencies and capital budget.

South Dakota

Conservation program expense/decoupling — A DSM cost adjustment mechanism is in place for NSP-M through which the company recovers costs associated with DSM/efficiency programs. The mechanism includes a 30% bonus to account for lost margins related to DSM/efficiency measures. MDU Resources' gas business utilizes a WNA mechanism.

Environmental compliance — Black Hills Power Inc.'s, or BHP, environmental improvement adjustment was suspended for a six-year moratorium period effective July 1, 2017; however, in 2020, the South Dakota PUC extended the moratorium period by an additional three years, whereby the recovery mechanism will not be effective prior to July 1, 2026.

Traditional generation/delivery infrastructure — NSP-M utilizes an infrastructure rider to recover costs associated with certain generation, transmission and distribution capital additions once the related facilities have achieved commercial operation to reflect certain changes in property taxes. Otter Tail Power has a mechanism in place that allows the utility to recover costs associated with new generation facilities.

Transmission costs — BHP utilizes a transmission cost adjustment that reflects the flow-through of costs allocated to the utility by FERC. Additionally, BHP utilizes a transmission facility adjustment, or TFA. Similar to the utility's environmental improvement adjustment, the TFA was suspended for a six-year moratorium period effective July 1, 2017; however, in 2020, the PUC extended the moratorium period by an additional three years, whereby the recovery mechanism will not be effective prior to July 1, 2026.

Tennessee

Decoupling — WNA clauses are in place for Atmos Energy and Piedmont Natural Gas. A full revenue decoupling mechanism is in place for Chattanooga Gas' residential and small commercial customers, and a WNA rider is in place for the company's industrial, commercial and other customers that do not operate under the decoupling mechanism.

Texas PUC

Electric fuel/purchased power — For electric utilities operating in areas of the state where retail competition for generation service has not been implemented, fuel and purchased power costs are recovered through a separate

fuel factor. For companies that implemented retail competition, i.e., within the Electric Reliability Council of Texas, or ERCOT, the transmission and distribution utilities do not participate in generation procurement, and fuel/purchased power adjustment clauses were eliminated.

Traditional generation — Legislation enacted in 2019 and PUC rules promulgated in 2020 allow vertically integrated utilities — those outside of ERCOT — to seek the recovery of new generation investment through a rider. Such a rider is in place for Entergy Texas.

Texas RRC

Gas commodity — Purchased gas cost recovery factors are subject to the RRC's discretion.

Decoupling — WNA mechanisms are in place for Atmos Energy Inc. and Texas Gas Service Co.

Utah

Decoupling — A WNA mechanism is in place for Questar Gas; however, customers may choose not to participate in the WNA. Questar Gas also utilizes a conservation-enabling tariff, or CET, which decouples non-gas revenues from the volume of gas used by general service, or GS, customers. Incremental CET accruals that exceed the 5% cap do not earn interest. The amortization of CET accruals is limited to 2.5% of the total Utah-jurisdictional base distribution non-gas GS revenues. Together, the WNA and CET act as a full revenue decoupling mechanism.

Renewables/non-traditional generation — An adjustment mechanism is in place for PacifiCorp through which the company recovers costs associated with its solar program.

Vermont

Electric fuel/gas commodity/purchased power — Power cost adjustment mechanisms are permitted, provided that the mechanisms are part of an alternative regulation plan.

Virginia

Decoupling — WNA riders are in place for Virginia Natural Gas Inc., or VNG, WGL, Columbia Gas of Virginia, or CGV, and Roanoke Gas. A separate revenue normalization adjustment is also in place for WGL, VNG and CGV that is designed to mitigate the impact on revenues of customers' participation in energy conservation programs.

Washington

Electric fuel/gas commodity/purchased power — Avista Corp.'s energy recovery mechanism includes a graduated sharing of differences from a benchmark level. Power cost adjustment mechanisms are in place for PacifiCorp and Puget Sound Energy, or PSE, that allow for variations in power costs to be apportioned, on a graduated scale, between the company and customers.

Decoupling — Revenue decoupling mechanisms are in place for PSE's electric and gas operations. Full decoupling mechanisms for Avista's electric and gas operations are to be in place through March 2025, incorporate an earnings test and demand-reduction targets, and specify caps on the increases to be implemented under the mechanism. Cascade Natural Gas' decoupling mechanism incorporates an earnings test and a conservation target, as well as caps on annual increases. PacifiCorp's decoupling mechanism incorporates an earnings test and demand reduction targets, as well as cap increases that may be implemented under the mechanism.

West Virginia

Traditional generation/environmental compliance/delivery infrastructure — In the past, the PSC has approved temporary riders to provide recognition between rate cases of certain electric generation and infrastructure investments.

State law allows the PSC to approve expedited cost recovery mechanisms associated with commission-approved multiyear gas infrastructure improvement plans; such treatment has been approved for Mountaineer Gas and Hope Gas.

Wisconsin

Electric fuel/gas commodity/purchased power — Under the Wisconsin PSC's electric fuel rules, which apply to the state's five largest investor-owned utilities, each utility forecasts monthly and annual fuel and purchased power

costs on a prospective basis. If a company's actual fuel and purchased power costs are outside a monthly or cumulative monthly variance range around the forecasts and the utility can demonstrate that these costs will likely be outside the annual range, the PSC may conduct a hearing to establish new rates. Currently, the annual variance range is plus or minus 2%. An electric utility is permitted to defer any fuel costs that are outside of its annual symmetrical variance range for subsequent recovery or refund. However, the utility is prohibited from recovering deferrals if the company is found to be earning in excess of its authorized equity return.

Conservation program expense — Wisconsin has a statewide energy efficiency and renewable resources program that is funded through a non-bypassable charge on customer bills. Program cost recovery is handled via individual rate cases. A conservation escrow account is used for voluntary energy efficiency and programs. Program costs are recovered through rates, the money goes into an escrow account and the costs are then adjusted in the next rate case.

Traditional generation/delivery infrastructure — At times, the PSC has authorized the utilities to file a limited-issue reopener of a previously completed base rate case instead of a new rate case filing. The reopener provides for recognition of certain specified investments and/or expenses and does not involve the re-determination of rate of return.

Wyoming

Decoupling — Cheyenne Light Fuel and Power's, or CLF&P, demand-side management, or DSM, mechanism for its electric operations includes a provision for the recovery of lost margins associated with customer participation in DSM programs.

Black Hills Wyoming Gas has a partial decoupling mechanism in place for small and medium general service-class distribution customers. The mechanism does not address revenue variations due to weather. The utility, also formally part of CLF&P's gas operations, has a DSM mechanism similar to CLF&P's electric operations.

Questar Gas has a WNA mechanism in place, as does MDU Resources' gas business.

Further Reading

The rate case process: a conduit to enlightenment
Rate base: How would you rate your knowledge of this utility industry fundamental?
Postponing review of deferral mechanics hampers one's grasp of ratemaking tools
State Regulatory Evaluations – Energy
Major Rate Case Decisions January-March 2022
Utility Asset Securitization in the U.S.
The Commissions

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BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Jennifer E. Nelson

RATE OF RETURN ON EQUITY

Exh. JEN-16C

REDACTED VERSION

August 29, 2025

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BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Jennifer E. Nelson

RATE OF RETURN ON EQUITY

Exh. JEN-17

August 29, 2025

S&P Global
Ratings

Criteria | Corporates | General

Sector-Specific Corporate Methodology

April 4, 2024

(Editor's note: On March 10, 2025, we republished this criteria article to correct a publication error in the unregulated power and gas section. See the "Revisions And Updates" section for details.)

This criteria article describes the credit factors and assumptions S&P Global Ratings uses in its analysis of each of the sectors covered by "Corporate Methodology," published Jan. 7, 2024. For information about key changes, the impact on ratings, and superseded criteria, see our media release announcing the publication of these criteria, titled "Sector-Specific Corporate Methodology Published," published in conjunction with this article.

This criteria article should be read in conjunction with our corporate methodology, which provides the general framework. This framework is applied using:

- Sector-specific provisions contained in this methodology;
- Management and governance considerations, as contained in "Management And Governance Credit Factors For Corporate Entities," published Jan. 7, 2024;
- Adjustments to financial metrics and ratio calculations, as described in "Corporate Methodology: Ratios And Adjustments," published April 1, 2019; and
- Liquidity considerations, as described in "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," published Dec. 16, 2014.

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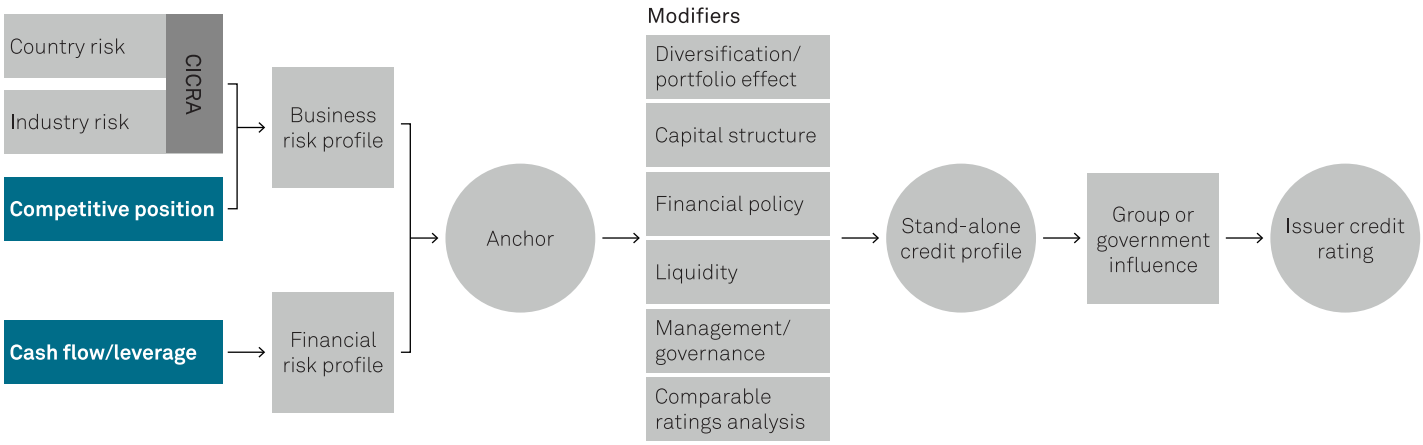
Methodology

Overview

These criteria primarily address sector-specific considerations related to competitive position, cash flow/leverage, and in some cases, certain of the modifiers shown in the framework below. The article applies globally to all corporate ratings and to certain nonbank financial institution entities that we rate using our global corporate methodology. Although our overall approach is the same for all sectors, we incorporate sector-specific provisions into our analysis.

Corporate criteria framework



Source: S&P Global Ratings.

Primarily, the criteria describe the relevant factors used to assess the competitive position for each sector as part of the business risk profile analysis. We assess competitive advantage; scale, scope, and diversity; and operating efficiency by reviewing a variety of subfactors that may reinforce or weaken each other. For any company, our assessment of these elements reflects the relative strengths and importance of its subfactors in the context of its industry.

In line with our corporate methodology, we assess each factor as strong, strong/adequate, adequate, adequate/weak, or weak. For each sector, the criteria include tables that summarize the characteristics that we typically expect to see across this range. The tables do not specify the characteristics expected at the adequate level: we assess a component as adequate if the characteristics fall between those for a strong or strong/adequate assessment, and those for an adequate/weak or weak assessment.

For each sector covered by these criteria, we list the competitive position group profiles (CPGPs) we would typically apply for each subsector. In some cases, the most appropriate CPGP differs from the one listed; for example, because the company has a monopoly position in its market or benefits from regulatory protection. The CPGP affects the weighting we ascribe to each element of our competitive position assessment within our framework.

The criteria also notes the sector-specific approaches we use when assessing the financial risk profile or the modifiers that apply to it, including the typical supplementary ratios used, the volatility adjustment and benchmark volatility tables, or the financial policy.

Please see appendix 1 for a glossary of terms, appendix 2 for the metrics we use to calculate volatility of profitability, and appendix 3 for the sector and industry variables.

Section 29 | Regulated Utilities

Business Risk Profile

Regulatory advantage

Market forces are not typically the main driver of competitive position for regulated utilities, and therefore we do not measure competitive advantage in the same way as we do for competitive firms. Instead, we assess regulatory advantage because the influence of the regulatory framework and regime is of critical importance. It defines the environment in which a utility operates and has a significant bearing on a utility's financial performance.

Regulations vary across different regulatory jurisdictions, that is, the area over which a regulator has oversight. Each regulatory jurisdiction can include one or more subsectors (water, gas, and power). A geographic region may have several regulatory jurisdictions.

We determine the regulatory advantage assessment by combining:

- Our preliminary regulatory advantage assessment, resulting from our review of the four subfactors that we believe are key for a utility to recover all its costs--on time and in full-- and to earn a return on the capital it deploys; and
- Our view of the utility's business strategy--in particular, its regulatory strategy and its ability to manage the tariff-setting process.

We assess the preliminary regulatory advantage assessment for each regulatory jurisdiction based on:

- Regulatory stability,
- Tariff-setting procedures and design,
- Financial stability, and
- Regulatory independence and insulation.

Regulatory stability: Our view is based on how transparent the key components of the rate-setting process are, and how they are assessed. We also monitor the predictability and consistency of the regulatory framework over time. Greater consistency reduces uncertainty for the utility and its stakeholders.

Tariff-setting procedures and design: Our view is based on whether all operating and capital costs can be recovered in full, and how the rate scheme balances the interests and concerns of all stakeholders. We look for incentives that are achievable, contained, and symmetrical (that is, mostly indexed to overperformance and underperformance).

Financial stability: If costs are recovered in a timely manner, cash flow volatility can be avoided. We see greater flexibility as favorable, because it allows for the recovery of unexpected costs. Financial stability also depends on the framework's ability to attract long-term capital, and the availability of capital support during construction, to alleviate funding and cash flow pressure when heavy investment is needed.

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Sector description

Companies that provide an essential or near-essential infrastructure product, commodity, or service that has few or no substitutes and are shielded from competition, while also being subject to comprehensive regulation by a regulatory body or oversight by a public body.

Subsectors	Typical CPGP
Electricity	National industry and utilities
Gas	National industry and utilities
Multi-utilities	National industry and utilities
Water	National industry and utilities

Other adjustments

To calculate a company's financial metrics, please refer to the sector-specific adjustments in "Corporate Methodology: Ratios And Adjustments."

Our sector-specific liquidity considerations are described in "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers."

Regulatory independence and insulation: We consider this to be stronger where the market framework and energy policies support the long-term financial stability of the utilities, are clearly enshrined in law, and protect the regulator's independence. Where there is limited risk of political intervention, the regulator is more able to efficiently protect the utility's credit profile, even during a stressful event.

Preliminary regulatory advantage: typical characteristics

Strong or strong/adequate	Adequate/weak or weak
From a credit perspective, the utility operates in a regulatory climate that is transparent, predictable, and consistent.	The utility operates in an opaque regulatory climate that lacks transparency, predictability, and consistency.
The utility can fully and timely recover all its fixed and variable operating costs, investments, and capital costs (depreciation and a reasonable return on the asset base).	The utility cannot recover its fixed and variable operating costs, investments, and capital costs (depreciation and a reasonable return on the asset base) fully and/or in a timely fashion.
Any regulatory incentives are limited and mainly symmetrical. The tariff setting includes mechanisms allowing for an adjustment for the timely recovery of volatile or unexpected operating and capital costs.	The utility must make significant capital commitments with no solid legal basis for the full recovery of capital costs.
The tariff setting may include a pass-through mechanism for major expenses--such as commodity costs--or a higher return on new assets, effectively shielding the utility from volume and input cost risks.	Ratemaking practices actively harm credit quality.
There is a record of earning a stable, compensatory rate of return in cash through various economic and political cycles and a projected ability to maintain that record.	There is a record of earning minimal or negative rates of return in cash through various economic and political cycles and a projected inability to improve that record sustainably.
The utility operates under a regulatory system that is sufficiently insulated from political intervention to protect the utility's credit risk profile, even during stressful periods. There is support for cash flow during construction of large projects, and preapproval of capital investment programs and large projects lowers the risk of subsequent disallowances of capital costs.	The utility is regularly subject to overt political influence.

Natural monopolies: Where a utility has a natural monopoly and its tariffs are controlled, but it is not subject to a detailed regulatory framework or oversight by a regulatory body, we may still assess regulatory advantage, rather than competitive advantage. We would assess it using the same four subfactors, as follows:

- For regulatory stability, we evaluate the stability of the setup, and give more emphasis to the historical record and our expectations regarding future changes.
- For tariff-setting procedures and design, we examine the utility's ability to fully recover operating costs, its investment requirements, and its debt-service obligations.
- For financial stability, we consider tariff flexibility, and whether this is sufficient to counter volume risk or commodity risk. In addition, we consider indirect competition, for example, while Nordic district heating companies operate under a natural monopoly, their tariff flexibility is partly restricted by customers' option to change to a different heating source if tariffs are increased significantly.
- For regulatory independence and insulation, we evaluate the risk that political intervention could change the setup, and in turn, affect the utility's credit profile. Although political intervention tends to be mostly negative, state ownership might positively influence tariff determination.

Because these four subfactors effectively capture the benefit of the close relationship with the state as owner, we do not typically modify our regulatory advantage assessment for natural monopolies based on business strategy.

Business strategy: After determining the preliminary regulatory advantage assessment, we assess the utility's business strategy as positive, neutral, negative, or very negative, and may modify the preliminary regulatory advantage assessment as a result. This factor chiefly addresses the effectiveness of a utility's regulatory risk management in the jurisdictions where it operates. In certain jurisdictions, a utility can create a sustainable competitive advantage through its regulatory strategy and ability to manage the tariff-setting process effectively. Ensuring that revenue changes with costs is a key regulatory risk factor, especially if the risk of political intervention is high. Our assessment of the utility's business strategy is informed by historical performance and business objectives in the context of industry dynamics and the regulatory climate.

We assess the utility's business strategy as positive and modify the preliminary regulatory advantage assessment upward if we consider the business strategy effectively bolsters the utility's regulatory advantage through favorable commission rulings, beyond what is typical for a utility in that jurisdiction. Where business strategy has limited effect relative to peers, our assessment is neutral. Where the business strategy leads to worse regulatory outcomes than peers, such as failing to achieve recovery of typical costs, we may see the implications as negative or very negative, and would apply the downward modifications as shown in the table below.

Regulated utilities: determining the final regulatory advantage assessment

	--Business strategy modifier--			
Preliminary regulatory advantage score	**Positive**	**Neutral**	**Negative**	**Very negative**
Strong	Strong	Strong	Strong/adequate	Adequate
Strong/adequate	Strong	Strong/adequate	Adequate	Adequate/weak
Adequate	Strong/adequate	Adequate	Adequate/weak	Weak
Adequate/weak	Adequate	Adequate/weak	Weak	Weak
Weak	Adequate/weak	Weak	Weak	Weak

Scale, scope, and diversity

We assess scale, scope, and diversity in the regulated utilities sector based on:

- Operational scale; and
- The geographic, economic, and regulatory diversity of a utility's markets and service territories.

These characteristics can contribute to cash flow stability while dampening the effect of economic and market threats. We generally believe a larger service territory--with a diverse customer base and average to above-average economic growth prospects--provides a utility with cushion and flexibility in the recovery of operating costs and ongoing investments (including replacement and growth capital spending). It also lessens the effect of external shocks (such as extreme local weather) because the incremental effect on each customer declines as the scale increases.

We consider that residential and small commercial customers have more stable usage patterns and are less exposed to periodic economic weakness, even after accounting for some weather-driven usage variability. Significant industrial exposure--combined with a local economy that largely depends on one or few cyclical industries--could contribute to the cyclicality of a utility's load and financial performance, magnifying the effect of an economic downturn.

A utility's cash flow generation and stability can benefit from operating in multiple geographic regions that exhibit average to better-than-average levels of wealth, and where employment and growth levels underpin the local economy and support long-term growth. Operating in a single geographic region carries a risk that can be ameliorated if the region is sufficiently large, demonstrates economic diversity, and has at least average demographic characteristics. In addition, if a utility operates in a single large geographic area and has a strong regulatory assessment, the benefit of diversity can be incremental.

Scale, scope, and diversity: typical characteristics

Strong or strong/adequate	Adequate/weak or weak
Stability of its revenue and profits limits its vulnerability to most combinations of adverse factors, events, or trends.	Revenue and profits are unstable and unsustainable, so that the utility is vulnerable to economic, competitive, or technological threats.
Customer base is large and diverse, with no meaningful customer concentration risk; that is, residential and small and midsize commercial customers typically provide most of the operating income.	Customer base is small and demonstrates customer or industry concentrations, combined with little economic diversity and average to below-average economic prospects.
Exposed to a wider range of service territories than others in the sector.	Exposed to a single service territory.
Operates in multiple regulatory jurisdictions where we assess the final regulatory advantage as adequate or stronger; or operates in a single regulatory jurisdiction where we assess final regulatory advantage as strong or strong/adequate.	Operates in a single regulatory jurisdiction where we assess the final regulatory advantage as adequate or adequate/weak.
No meaningful concentrations by asset or supplier that could weigh on operations; or assets and suppliers can easily be replaced.	Dependence on a single supplier or asset that cannot easily be replaced and that could damage the utility's operations.

Operating efficiency

We assess operating efficiency in the regulated utilities sector based on:

- A utility's compliance with the terms of its operating license--including safety, reliability, and environmental standards;
- Its cost management; and
- The scale, scope, and management of its capital spending.

We analyze management's record in these three key areas, relative to peers, and the resulting cash flow stability. In addition, we consider how management reduces the prospect of penalties for noncompliance; operating costs being greater than allowed; or capital projects running over budget and time--all of which could impair the company's ability to recover its full costs.

The relative importance of the above three factors, particularly cost and capital spending management, is determined by the type of regulation under which the utility operates. Utilities operating under robust cost-plus regimes tend to be more insulated given the high degree of confidence that costs will invariably be passed through to customers. Utilities operating under incentive-based regimes are likely to be more sensitive to achieving regulatory standards. This is particularly so where regulatory regimes involve active consultation between regulator and utility, and market testing, as opposed to just handing down an outcome on a more-arbitrary basis. In some jurisdictions, absolute performance standards are less relevant than how the utility

performs against the regulator's performance benchmarks. This performance will drive any penalties or incentive payments and can determine the utility's credibility on operating and asset management plans with its regulator.

Therefore, we believe that well-managed utilities are more likely to maximize the likelihood of cost recovery and full inclusion of capital spending in their asset bases. When regulatory resets are more at the discretion of the utility, effective cost management--including of labor--may allow for more control over the timing and magnitude of rate filings. This would maximize the chances of a constructive outcome--such as full operational and capital cost recovery--while protecting against reputational risks.

Operating efficiency: typical characteristics

Strong or strong/adequate	Adequate/weak or weak
Cost structure is better than that of peers and volatility is limited. Generates revenue and profits by minimizing costs, increasing efficiencies, and asset utilization.	Cost structure is worse than that of peers; its cost position and efficiency factors do not support profit sustainability; and volatility is above-average.
Asset profile (including age and technology) is such that we have confidence that it could sustain favorable performance against targets.	The capital spending program is so large and complex that overall operating efficiency is compromised.
Strong safety record.	Poor safety performance
Strong service reliability, with a record of meeting the operating performance requirements of stakeholders (including regulators).	Service reliability has been sporadic or nonexistent, with a track record of not meeting operating performance requirements of stakeholders (including regulators); we do not believe the utility can consistently meet performance targets without additional capital spending.
Where applicable, well-placed to meet current and potential future environmental standards.	Where applicable, the utility is challenged to comply with current environmental standards and is highly vulnerable to more onerous standards.
Management maintains very good control over both fixed and variable costs, in line with regulatory expectations (including labor and working capital management being in line with regulator's allowed collection cycles).	Management typically exceeds operating costs authorized by regulators.
Strong record of projects managed almost invariably within regulatory allowances for timing and budget.	Inconsistent project management skills, as demonstrated by cost overruns and delays, including for maintenance capital spending.

Profitability

A utility with above-average profitability would, relative to its peers, generally earn a rate of return at or above what regulators authorize and has minimal exposure to earnings volatility from affiliated unregulated business activities or market-sensitive regulated operations. Conversely, a utility with below-average profitability would generally earn rates of return well below the authorized return relative to its peers or have significant exposure to earnings volatility from affiliated unregulated business activities or market-sensitive regulated operations.

We typically use the EBITDA margin as key indicator of profitability, unless it is distorted--for example, by pass-through costs like congestion revenue or collection of third-party revenue, or by accelerated asset depreciation that we do not view as sustainable in the long run. In such cases, we would use ROC or ROE to benchmark the company against peers.

For regulated utilities subject to full cost-of-service regulation and return-on-investment requirements, we normally measure profitability using ROE, the ratio of net income available for common stockholders to average common equity. When setting rates, the regulator ultimately bases its decision on an authorized ROE. However, different factors--such as variances in costs and usage--may influence the return a utility is actually able to earn. Consequently, our analysis

of profitability for cost-of-service-based utilities centers on the utility's ability to consistently earn the authorized ROE.

Volatility of profitability: We may observe a clear difference between the volatility of actual reported profitability and the volatility of underlying regulatory profitability. In these cases, we could use the regulatory accounts as a proxy to judge earnings stability.

Financial Risk Profile

Accounting characteristics

Important accounting practices for utilities include:

- For integrated electric utilities that meet native load obligations partly by using third-party power contracts, we use our purchased power methodology to adjust measures for such contracts' debt-like obligations.
- Where substantial seasonal working capital requirements--for example, at natural gas distribution utilities--distort leverage measures, we adjust inventory and debt balances by netting the value of inventory against outstanding short-term borrowings. This adjustment informs balance sheet analysis by reducing seasonal debt balances when we are very confident of near-term cost recovery.
- We deconsolidate securitized debt (and associated revenue and expense) that has been accorded specialized recovery provisions.

In the U.S. and certain other regions, utilities employ "regulatory accounting," which permits a rate-regulated company to defer some revenue and expense to match the timing of the recognition of those items in rates, as determined by regulators. A utility subject to regulatory accounting therefore records assets and liabilities that an unregulated corporation--or even regulated utilities in other global regions--cannot record. We do not adjust GAAP earnings or balance-sheet figures to remove the effects of regulatory accounting. While IFRS does not currently provide for any recognition of the effects of rate-setting for financial reporting purposes, our financial analysis focuses on the economics and actual cash flow generation.

Volatility tables

We apply the low volatility benchmark table to regulated utilities where:

- They derive about two-thirds or more of their operating cash flows or profits from regulated operations that are predominantly at the low end of the utility risk spectrum (such as a network or distribution/transmission business unexposed to commodity risk and with very low operating risk);
- Their regulated operations have a regulatory advantage assessment of strong;
- They are expected to maintain their established record of achieving stable credit measures and low funding costs; and
- No other activities contribute significantly to the group's overall risk profile and are viewed as high-risk or volatile.

We apply the medial volatility table to regulated utilities that do not qualify for low volatility and that either:

- Derive about 50% or more of their operating cash flows or profits from regulated activities that have a regulatory advantage assessment of at least adequate and operate in a jurisdiction where the country risk is '4' or better; or
- Derive about one third or more of their consolidated operating cash flows or profits from regulated utility activities that have a regulatory advantage assessment of strong; or a regulatory advantage assessment of strong/adequate and a CICRA of '3' or better.

In both cases, the competitive position for the remaining activities must be assessed as at least satisfactory.

In all other cases, we use the standard volatility benchmark table.

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Key Changes From Previous Criteria

The criteria incorporate the changes described in "Request for Comment: Sector-Specific Corporate Methodology," published Dec. 11, 2023, and consolidate detailed sector-specific provisions for corporate entities, currently described in nine different articles, into a single article. Most of the changes relate to the overall presentation of the criteria. We have also incorporated a few updates to enhance transparency, usability, and comparability between sectors.

- In the transportation infrastructure, regulated utilities, and unregulated power and gas sectors, we revised some of the conditions for applying the benchmark volatility tables when assessing cash flow/leverage. This is to better encapsulate the benefit of supportive regulatory or contractual revenue frameworks, and to capture potential gradual transitions in credit risk.
- In the financial services finance companies sector, we revised our adjusted EBITDA calculation for distressed debt purchasers. We add 50% of the principal collections back to revenue and EBITDA when assessing cash flow/leverage, to provide a more-comprehensive picture of the company's debt repayment capacity. The cash flow associated with collections on distressed receivables could be used to support debt repayment.
- In the forest and paper sector, we removed a supplementary ratio specific to timber REITs because it adds unnecessary complexity.

Impact On Outstanding Ratings

Based on our testing, and assuming that the entities in scope of this criteria (about 5,000) maintain their credit risk characteristics, we expect to take fewer than 15 rating actions, all of only one notch. We expect most of these rating actions to be upgrades.

Revisions And Updates

This article was originally published on April 4, 2024.

Changes introduced after original publication:

- On Aug. 13, 2024, we republished this criteria article to correct a publication error in Appendix 3. Specifically, we included industry-specific SER parameters for real estate that inform our view of volatility of profitability. These parameters were inadvertently omitted when we consolidated sector-specific criteria that previously appeared in "Guidance: Corporate Methodology," which has since been archived.
- On Nov. 18, 2024, we republished this criteria article to make nonmaterial changes to sector and industry variables. Specifically, we refreshed the SER calibration by industry tables in Appendix 3 by rolling the seven-year period forward to include the financial year-end of Dec. 31, 2022 (2016-2022). We also corrected a publication error that appeared in the SER ranges in the prior version of the EBITDA margin table for financial market Infrastructure companies. Additionally, we updated contact information.

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- On March 10, 2025, we republished this criteria to correct a publication error in the unregulated power and gas section. Specifically, we included a paragraph to explain how we determine the industry cyclicality for this sector. This paragraph was inadvertently deleted from the original criteria in 2021.

Related Publications

Fully superseded criteria

- Key Credit Factors For The Midstream Energy Industry, Nov. 15, 2021
- Key Credit Factors For The Telecommunications And Cable Industry, June 22, 2014
- Key Credit Factors For The Pharmaceutical Industry, April 8, 2014
- Key Credit Factors For The Unregulated Power And Gas Industry, March 28, 2014
- Key Credit Factors For The Oil Refining And Marketing Industry, March 27, 2014
- Key Credit Factors For The Leisure And Sports Industry, March 5, 2014
- Key Credit Factors For The Homebuilder And Real Estate Developer Industry, Feb. 3, 2014
- Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013

Partly superseded criteria

- Corporate Methodology, Jan. 7, 2024

Retired guidance

- Guidance: Corporate Methodology, July 1, 2019

Related criteria

- Risk-Adjusted Capital Framework Methodology, April 30, 2024
- Corporate Methodology, Jan. 7, 2024
- Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- Methodology: The Impact Of Captive Finance Operations On Nonfinancial Corporate Issuers, Oct. 23, 2023
- Financial Institutions Rating Methodology, Dec. 9, 2021
- Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Commodities Trading Industry Methodology, Jan. 19, 2017
- Key Credit Factors For The Operating Leasing Industry, Dec. 14, 2016
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers Dec. 16, 2014
- Principles Of Credit Ratings, Feb. 16, 2011

Other related publications

- Sector-Specific Corporate Methodology Published, April 4, 2024
- RFC Process Summary: Sector-Specific Corporate Methodology, April 4, 2024
- S&P Global Ratings Definitions, updated from time to time

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BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Jennifer E. Nelson

RATE OF RETURN ON EQUITY

Exh. JEN-18

August 29, 2025

MOODY'S RATINGS

RATING METHODOLOGY

6 August 2024

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Rating Methodology

Regulated Electric and Gas Utilities

This rating methodology replaces the *Regulated Electric and Gas Utilities* methodology published on June 23, 2017. We have reordered and made editorial updates to various sections of the methodology. These updates do not change our methodological approach.

Scope

This methodology applies to rate-regulated electric and gas utilities globally whose predominant business is the sale of electricity and/or gas or related services under a rate-regulated framework, in most cases to retail customers. Companies in many industries are regulated. We use the term rate-regulated to distinguish companies whose rates (by which we also mean tariffs or revenues in general) are set by regulators. Rate-regulated utilities that own generating assets as any material part of their business, utilities whose charges or bills to customers include a meaningful component related to the electric or gas commodity, utilities whose rates are regulated at a sub-sovereign level (e.g., by provinces, states or municipalities), and companies providing an independent system operator function to an electric grid are also rated using this methodology. Companies rated using this methodology are primarily rate-regulated monopolies or, in certain circumstances, companies that may not be outright monopolies but where government regulation effectively sets prices and limits competition.

We generally consider a company to be predominantly a regulated electric and gas utility when a majority of its cash flows, prospectively and on a sustained basis, are derived from regulated electric and gas utility businesses. Since cash flows can be volatile (such that a company might have a majority of utility cash flows simply due to a cyclical downturn in its non-utility businesses), we may also consider the breakdown of assets and/or debt of a company to determine which business is predominant.

This methodology applies to a wide variety of companies, including vertically integrated utilities, transmission and distribution utilities with retail customers and/or sub-sovereign regulation, natural gas local distribution utility companies (LDCs), independent system operators, and regulated generation companies. These companies may be operating companies or holding companies.

This methodology does not apply to regulated electric and gas networks, which are rated using a separate methodology. Regulated electric and gas networks are companies whose predominant business is purely the transmission and/or distribution of electricity and/or natural gas without involvement in the procurement or sale of electricity and/or gas; whose charges to customers thus do not include a meaningful commodity cost component; which sell mainly (or in many cases exclusively) to non-retail customers; and which are rate-regulated under a national framework.

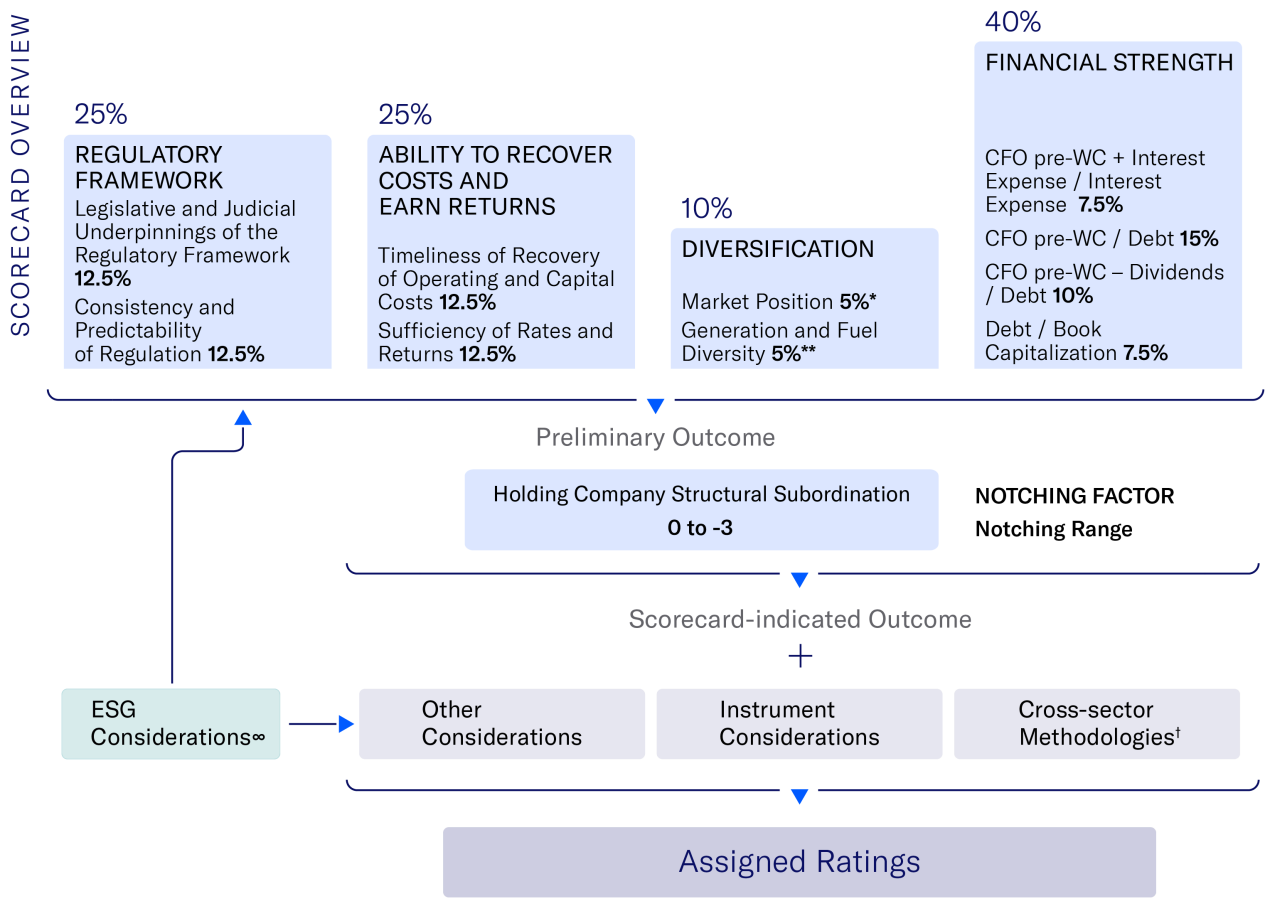
Unregulated utilities and power companies, public power utilities, municipal joint action agencies, electric cooperatives, regulated water companies, natural gas pipelines and midstream energy companies are also rated using separate methodologies.[1]

Rating approach

In this rating methodology, we explain our general approach to assessing credit risk of regulated electric and gas utilities globally, including the qualitative and quantitative factors that are likely to affect rating outcomes in this sector. We seek to incorporate all material credit considerations in ratings and to take the most forward-looking perspective that visibility into these risks and mitigants permits.

The following schematic illustrates our general framework for the analysis of regulated electric and gas utilities, which includes the use of a scorecard. The scorecard-indicated outcome is not expected to match the actual rating for each company. For more information, see the "Other considerations" and "Limitations" sections.

Exhibit 1
Illustration of the regulated electric and gas utilities methodology framework



* 10% weight for issuers that lack generation.
** 0% weight for issuers that lack generation.
∞ Environmental, social and governance (ESG) considerations, including, where available, our opinions of exposure to them as expressed in Issuer Profile Scores (IPSs), may affect scorecard factors and other considerations outside of the scorecard. For more information, see the "Other considerations" section.
† Some of the methodological considerations described in one or more cross-sector rating methodologies may be relevant to ratings in this sector. A link to a list of our sector and cross-sector methodologies can be found in the "Moody's related publications" section.
Source: Moody's Ratings

Regulated electric and gas utilities scorecard

For general information about how we use the scorecard and for a discussion of scorecard mechanics, please see the "Using the scorecard to arrive at a scorecard-indicated outcome" section. The scorecard does not include or address every factor that a rating committee may consider in assigning ratings in this sector. Please see the "Other considerations" and "Limitations" sections.

Exhibit 2

Regulated electric and gas utilities scorecard

	Weight	Aaa	Aa	A	Baa	Ba	B	Caa
Factor: Regulatory Framework (25%)								
Legislative and Judicial Underpinnings of the Regulatory Framework	12.5%	Utility regulation occurs under a fully developed framework that is national in scope based on legislation that provides the utility a nearly absolute monopoly [1] within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward-looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly [1] within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well-developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly[1] within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation,[1] a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well-developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions,[1] and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor-unfriendly nationalization or other significant intervention in utility markets or rate-setting.

	Weight	Aaa	Aa	A	Baa	Ba	B	Caa
Factor: Regulatory Framework (25%)								
Consistency and Predictability of Regulation	12.5%	The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.	We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions.	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.
Factor: Ability to Recover Costs and Earn Returns (25%)								
Timeliness of Recovery of Operating and Capital Costs	12.5%	Tariff formulas [2] and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward-looking costs.	Tariff formulas [2] and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward-looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas [2] or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non-refundable interim rates) can be collected, and permit inclusion of important forward-looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas.[2] Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.	There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.

	Weight	Aaa	Aa	A	Baa	Ba	B	Caa
Factor: Ability to Recover Costs and Earn Returns (25%)								
Sufficiency of Rates and Returns	12.5%	Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.	Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.
Factor: Diversification (10%)								
Market Position	5% [3]	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.
Generation and Fuel Diversity	5% [4]	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).[5]	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.	Modest diversification in generation and/or fuel sources such that the utility or rate-payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.

	Weight		Aaa	Aa	A	Baa	Ba	B	Caa
Factor: Financial Strength (40%)									
CFO pre-WC + Interest Expense / Interest Expense	7.5%		≥ 8x	6x - 8x	4.5x - 6x	3x - 4.5x	2x - 3x	1x - 2x	< 1x
CFO pre-WC / Debt	15%	Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
CFO pre-WC - Dividends / Debt	10%	Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5)% - 0%	< (5)%
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5)% - 0%	< (5)%
Debt / Book Capitalization[6]	7.5%	Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%
Preliminary outcome									
Notching factor									
Structural Subordination of Holding Companies									
0 to -3 notches									
Scorecard-indicated outcome									

[1] The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g., cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.
[2] Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.
[3] 10% weight for issuers that lack generation.
[4] 0% weight for issuers that lack generation.
[5] Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure. Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de-activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges.
[6] When debt/book capitalization is negative, the score is Caa.
Source: Moody's Ratings

Sector overview

Regulated electric and gas utilities globally are engaged in the production, transmission, coordination, distribution and/or sale of electricity and/or natural gas, and they are either investor-owned companies, commercially oriented government-owned companies or, in the case of independent system operators, not-for-profit or similar entities.

An over-arching consideration for regulated utilities is the regulatory environment in which they operate. The nature of regulation can vary significantly from jurisdiction to jurisdiction and is dynamic and subject to political intervention. The direct relationship that a regulated utility has with the retail customer, including billing for electric or gas supply that has substantial price volatility, can lead to a more politically charged rate-setting environment. Similarly, regulation at the sub-sovereign level is often subject to intervention from disaffected customers and influenced by public officials . Our views of regulatory environments evolve over time in accordance with our observations of regulatory, political and judicial events that affect issuers in the sector.

The principal categories of companies rated using this methodology include the following:

Vertically integrated utility: Vertically integrated utilities are regulated electric or combination utilities (see below) that own generation, distribution and (in most cases) electric transmission assets. Vertically integrated utilities are generally engaged in all aspects of the electricity business. They build power plants, procure fuel, generate power, build and maintain the electric grid (including high and low voltage lines, transformers and substations) that delivers power from a group of power plants to end-users , and generally meet all of the electric needs of the customers in a specific geographic area (also called a service territory). The rates or tariffs for all of these monopolistic activities are set by the relevant regulatory authority.

Transmission and distribution utility: Transmission and distribution utilities (T&Ds) typically operate in deregulated markets where generation is provided under a competitive framework. T&Ds own and operate the electric grid that transmits and/or distributes electricity within a specific state or region.

T&Ds provide electrical transportation and distribution services to carry electricity from power plants and transmission lines to retail, commercial, and industrial customers. T&Ds are typically responsible for billing customers for electric delivery and/or supply, and most have an obligation to provide a standard supply or provider-of-last-resort (POLR) service to customers that have not switched to a competitive supplier. These factors distinguish T&Ds from networks, whose customers are retail electric suppliers and/or other electricity companies. In a smaller number of cases, T&Ds rated using this methodology may not have an obligation to provide POLR services, but are regulated in sub-sovereign jurisdictions. The rates or tariffs for these monopolistic T&D activities are set by the relevant regulatory authority.

Natural gas local distribution company: Distribution is the final step in delivering natural gas to customers. While some large industrial, commercial, and electric generation customers receive natural gas directly from high capacity pipelines that carry gas from gas producing basins to areas where gas is consumed, most other users receive natural gas from their local gas utility, also called a local distribution company (LDC). LDCs are regulated utilities involved in the delivery of natural gas to consumers within a specific geographic area. Specifically, LDCs typically transport natural gas from delivery points located on large-diameter pipelines (that usually operate at fairly high pressure) to households and businesses through thousands of miles of small-diameter distribution pipe (that usually operate at fairly low pressure). LDCs are typically responsible for billing customers for gas delivery and/or supply, and most also have the responsibility to procure gas for at least some of their customers, although in some markets gas supply to all customers is on a competitive basis. These factors distinguish LDCs from gas networks, whose customers are retail gas suppliers and/or other natural gas companies. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Integrated gas utility : Integrated gas utilities are regulated utilities that deliver gas to all end users in a particular service territory by sourcing the commodity; operating transport infrastructure that often combines high pressure pipelines with low pressure distribution systems and, in some cases, gas storage, re-gasification or other related facilities; and performing other supply-related activities, such as customer billing and metering. The rates or tariffs for the totality of these activities are set by the relevant regulatory authority. Many integrated gas utilities are national in scope.

Combination utility: Combination utilities are those that combine an LDC or integrated gas utility with either a vertically integrated utility or a T&D utility. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Regulated generation utility: Regulated generation utilities (regulated gencos) are utilities that almost exclusively have generation assets, but their activities are generally regulated like those of vertically integrated utilities. This typically means that the purchasers of their output (typically other investor-owned, municipal or cooperative utilities) pay a regulated rate based on the total allowed costs of the regulated genco, including a return on equity, based on a capital structure designated by the regulator. Companies that have been included in this group include certain generation companies that are not rate-regulated in the usual sense of recovering costs plus a regulated rate of return on either equity or asset value.

Independent system operator: An independent system operator (ISO) is an organization formed in certain regional electricity markets to act as the sole chief coordinator of an electric grid. In the areas where an ISO is established, it coordinates, controls and monitors the operation of the electrical power system to assure that electric supply and demand are balanced at all times, and, to the extent possible, that electric demand is met with the lowest-cost sources. ISOs seek to assure adequate transmission and generation resources, usually by identifying new transmission needs and planning for a generation reserve margin above expected peak demand. In regions where generation is competitive, they also seek to establish rules that foster a fair and open marketplace, and they may conduct price-setting auctions for energy and/or capacity. The generation resources that an ISO coordinates may belong to vertically integrated utilities or to independent power producers. ISOs may not be rate-regulated in the traditional sense but fall under governmental oversight. All participants in the regional grid are required to pay a fee or tariff (often volumetric) to the ISO that is designed to recover its costs, including costs of investment in systems and equipment needed to fulfill their function. ISOs may be for profit or not-for-profit entities.

Transmission-only utility: Transmission-only utilities are solely focused on owning and operating transmission assets. The transmission lines these utilities own are typically high-voltage and allow energy producers to transport electric power over long distances from where it is generated (or received) to the transmission or distribution system of a T&D or vertically integrated utility.

Utility holding company (utility holdco): As detailed in Appendix B, regulated electric and gas utilities are often part of corporate families under a parent holding company. The operating subsidiaries of utility holdcos are overwhelmingly regulated electric and gas utilities.

Hybrid holding company (hybrid holdco): Some utility families contain a mix of regulated electric and gas utilities and other types of companies, but the regulated electric and gas utilities represent the majority of the consolidated cash flows, assets and debt. The parent company is thus a hybrid holdco.

Discussion of the scorecard factors

In this section, we explain our general approach for scoring each scorecard factor or sub-factor, and we describe why they are meaningful as credit indicators.

Factor: Regulatory Framework (25%)

Why it matters

The regulatory framework is important because it provides the basis for decisions that affect utilities, including rate-setting as well as the consistency and predictability of regulatory decision-making. Core aspects of a regulatory framework are its legislative and judicial underpinnings, and the consistency and predictability of regulatory decisions and rule-making.

Utility rates are set in a political/regulatory process rather than a competitive or free-market process; thus, the regulatory framework is a key determinant of the credit quality of a utility. In jurisdictions where utility revenues include material government subsidy payments, we consider utility rates to be inclusive of these payments, and we thus evaluate sub-factors under the first two factors in light of both rates and material subsidy payments. For example, we would consider the legal and judicial underpinnings and consistency and predictability of subsidies as well as rates. The regulatory framework has many components: the governing body and the utility legislation or decrees it enacts, the manner in which regulators are appointed or elected, the rules and procedures promulgated by those regulators, the judiciary that interprets the laws and rules and that arbitrates disagreements, and the manner in which the utility manages the political and regulatory process. In many cases, utilities have experienced credit stress or default because of a breakdown or obstacle in the regulatory framework – for instance, laws that prohibited regulators from including , in rates, the recovery of investments in uncompleted power plants or plants not deemed “used and useful,” or a disagreement about rate-making that could not be resolved until after the utility had defaulted on its debts.

How we assess it for the scorecard

Scoring for this factor is based on two sub-factors: Legislative and Judicial Underpinnings of the Regulatory Framework; and Consistency and Predictability of Regulation.

Legislative and Judicial Underpinnings of the Regulatory Framework

For this sub-factor, we consider the scope, clarity, transparency, supportiveness and granularity of utility legislation, decrees, and rules as they apply to the issuer. We also consider the strength of the regulator's authority over rate-making and other regulatory issues affecting the utility, the effectiveness of the judiciary or other independent body in arbitrating disputes in a disinterested manner, and whether the utility's monopoly has meaningful or growing carve-outs. In addition, we consider how well-developed the framework is – both how fully fleshed out the rules and regulations are and how well-tested it is – and the extent to which regulatory or judicial decisions have created a body of precedent that help determine future rate-making. We consider how effective the utility is in navigating the regulatory framework – both the utility's ability to shape the framework and adapt to it.

A utility operating in a regulatory framework that is characterized by legislation that is credit-supportive of utilities and eliminates doubt by prescribing many of the procedures that the regulators use in determining fair rates (which legislation may show evidence of being responsive to the needs of the utility in general or specific ways), a long history of transparent rate-setting, and a judiciary that has provided ample precedent by impartially adjudicating disagreements in a manner that addresses ambiguities in the laws and regulations typically receives higher scores for this sub-factor. A utility operating in a regulatory framework that, by statute or practice, allows the regulator to arbitrarily prevent the utility from recovering its costs or earning a reasonable return on prudently incurred investments, or where regulatory decisions may be reversed by politicians, typically receives a lower score.

In general, we view national utility regulation as being less susceptible to political intervention than regulation by state, provincial or municipal entities, so the highest scoring in this sub-factor is typically reserved for this category. However, we acknowledge that states and provinces in some countries may be larger than small nations, such that their regulators may be equally impartial. In such cases, issuers are likely to receive higher scores for this sub-factor.

The relevant judicial system can be a major factor in the regulatory framework, particularly in countries like the US, where disagreements between a utility and its state or municipal regulator may eventually be adjudicated in a federal district court or even by the US Supreme Court. In addition, bankruptcy proceedings in the US occur in federal courts, which have at times been able to impose rate settlement agreements on state or municipal regulators. As a result, the range of decisions available to state regulators may be effectively circumscribed by court precedent at the state or federal level, which we generally view as a favorable characteristic of the regulatory framework.

We consider regulated electric and gas utilities generally to have strong monopolies that are likely to continue, which allows these companies to have high leverage. Thus, the existence of a monopoly in itself is unlikely to be a driver of strong scoring in this sub-factor. On the other hand, a strong challenge to the monopoly could result in lower scores because of the potential loss of customers and revenue. A utility can only recover its costs and investments and service its debt if customers purchase its services. Examples of incursions into utilities' monopoly include the takeover of the utility by a municipality, self-generation such as rooftop solar panels, distributed generation with net metering, in which customers generate power and sell excess power to the utility, or unauthorized use beyond the level for which the utility receives compensation in rates. Incursions that are growing significantly or are having a meaningful impact on rates for customers that remain with the utility could have a negative impact on the scoring of this sub-factor and on the Ability to Recover Costs and Earn Returns factor.

The scoring of this sub-factor may not be the same for every utility in a particular jurisdiction. Some utilities appear to have greater sway over the relevant utility legislation and promulgation of rules than other utilities – even those in the same jurisdiction. The content and tone of publicly filed documents and regulatory decisions sometimes indicates that the management team at one utility has better responsiveness to and credibility with its regulators or legislators than the management at another utility.

While the underpinnings to the regulatory framework tend to change relatively slowly, they do evolve, and our scoring reflects that evolution. For instance, a new regulatory framework typically becomes tested over time as regulatory decisions are issued, or perhaps litigated, thereby setting a body of precedent. Utilities may seek changes to laws in order to permit them to securitize certain costs or collect interim rates, or a jurisdiction in which rates were previously recovered primarily in base rate proceedings may institute riders

and trackers. These changes would likely affect scoring of the Timeliness of Recovery of Operating and Capital Costs sub-factor, but they may also be sufficiently significant to indicate a change in the regulatory underpinnings.

The regulatory framework may also change as a result of a judiciary that had formerly been independent of the executive branch, but which may start to issue decisions that indicate it is conforming its decisions to the expectations of an executive branch that wants to mandate lower rates.

Consistency and Predictability of Regulation

In assessing this sub-factor, we consider the track record of regulatory decisions in terms of consistency, predictability and supportiveness. We evaluate the utility's interactions in the regulatory process as well as the overall stance of the regulator toward the utility.

In most jurisdictions, the laws and rules seek to make rate-setting a primarily technical process that examines costs the utility incurs and the returns on investments the utility needs to earn so it can make investments that are required to build and maintain the utility infrastructure, which includes power plants, electric transmission and distribution systems, and/or natural gas distribution systems. Where the process remains technical and transparent such that regulators can support the financial health of the utility while balancing their public duty to assure that reliable service is provided at a reasonable cost, and where the utility is able to align itself with the policy initiatives of the governing jurisdiction, the utility typically receives higher scores for this sub-factor. Where the process includes substantial political intervention, which could take the form of legislators or other government officials publicly second-guessing regulators, dismissing regulators who have approved unpopular rate increases, or preventing the implementation of rate increases, or where regulators ignore the laws/rules to deliver an outcome that appears more politically motivated, the utility typically receives a lower score for this sub-factor.

As with the prior sub-factor, we may score different utilities in the same jurisdiction differently, based on outcomes that are more or less supportive of credit quality over a period of time. Some utilities are better able to meet the expectations of their customers and regulators, whether through better service, greater reliability, more stable rates or simply more effective regulatory outreach and communication. These utilities typically receive more consistent and credit-supportive outcomes, so they typically score higher for this sub-factor. Conversely, if a utility has multiple, rapid rate increases, chooses to submit major rate increase requests during a sensitive election cycle or a severe economic downturn, has chronic customer service issues, is viewed as frequently providing incomplete information to regulators, or is tone-deaf to the priorities of regulators and politicians, it may receive less consistent and supportive outcomes and thus receive a lower score for this sub-factor.

In scoring this sub-factor, we primarily evaluate the actions of regulators, politicians and jurists rather than their words. Nonetheless, words matter when they are an indication of future action. We seek to differentiate between political rhetoric that is perhaps oriented toward gaining attention for the viewpoint of the speaker and rhetoric that is indicative of future actions and trends in decision-making.

Factor: Ability to Recover Costs and Earn Returns (25%)

Why it matters

The ability of a utility to recover its costs and earn a return, including during different market and economic conditions, directly affects its ability to generate cash flow and service its debt. Core aspects of this factor are the timeliness of recovery of operating and capital costs, and the sufficiency of rates and returns.

The ability to recover prudently incurred costs on a timely basis and to attract debt and equity capital are crucial credit considerations. The inability to recover costs, for instance if fuel or purchased power costs ballooned during a rate freeze period, has been one of the greatest drivers of financial stress in this sector, as well as the cause of some utility defaults. In a sector that is typically free cash flow negative (due to large capital expenditures and dividends) and that routinely needs to refinance very large maturities of long-term debt, investor concerns about a lack of timely cost recovery or the sufficiency of rates can, in an extreme scenario, strain access to capital markets and potentially lead to insolvency of the utility. While our scoring for this factor may primarily be influenced by our assessment of the regulatory relationship, it can also be highly affected by the management and business decisions of the utility.

The timeliness and sufficiency of rates are interrelated. Timeliness can have an impact on our view of what constitutes sufficient returns, because a strong assurance of timely cost recovery reduces risk. Conversely, utilities may have a strong assurance that they will earn a full return on certain deferred costs until they are able to collect them, or their generally strong returns may allow them to weather some rate lag on recovery of construction-related capital expenditures. The timeliness of cost recovery is particularly important in a period of rapidly rising costs. For example, fuel is a large component of total costs for vertically integrated utilities and for natural gas utilities, and fuel prices are highly volatile, so the timeliness of fuel and purchased power cost recovery is especially important.

The first two factors are closely interrelated, but utilities may receive different scores for each of these. For example, a utility could have a regulatory framework that causes considerable credit concerns, perhaps because it is untested or undergoing a transition to de-regulation, but where the track record of rate-case outcomes is positive. This could result in a higher score for the Ability to Recover Costs and Earn Returns factor than for the Regulatory Framework factor. Conversely, there may be instances of strong Legislative and Judicial Underpinnings of the regulatory framework where a commission ignores the framework, which affects the Consistency and Predictability of Regulation as well as the Ability to Recover Costs and Earn Returns. In some cases, a commission has used extraordinary measures to prevent or defer a rate increase that might have been justifiable from a cost perspective but would have caused rate shock.

Scoring for the Ability to Recover Costs and Earn Returns factor places more emphasis on our expectation of timeliness and sufficiency of rates over time; whereas financial metrics may be affected by one-time events, market conditions or construction cycles, which are trends that could normalize or even reverse.

How we assess it for the scorecard

Scoring for this factor is based on two sub-factors: Timeliness of Recovery of Operating and Capital Costs; and Sufficiency of Rates and Returns.

Timeliness of Recovery of Operating and Capital Costs

In assessing this sub-factor, we consider provisions and cost recovery mechanisms for operating costs, mechanisms that allow operating and/or capital expenditures to be trued up periodically in rates without having to file a rate case (this may include formula rates, rider and trackers, or the ability to periodically adjust rates for construction work in progress). We also consider the process and time frame of rate proceedings and the track record of recovery. For instance, having a formula rate plan is positive, but if the actual process has included reviews that are delayed for long periods, it may diminish the benefit to the utility. In addition, we consider the lag between the time that a utility incurs a major construction expenditure and the time that the utility will start to recover and/or earn a return on that expenditure.

Sufficiency of Rates and Returns

In assessing this sub-factor, we consider statutory protections that assure full cost recovery and a reasonable return for the utility on its investments, the regulatory mechanisms used to determine what a reasonable return should be, and the track record of the utility in actually recovering costs and earning allowed returns.

We examine outcomes of rate cases/tariff reviews and compare them to the request submitted by the utility, to prior rate cases/tariff reviews for the same utility and to recent rate/tariff decisions for a peer group of comparable utilities. In this context, comparable utilities are typically utilities in the same or similar jurisdiction. In cases where the utility is unique or nearly unique in its jurisdiction, we compare it to other peers with an adjustment for local differences, including prevailing rates of interest and returns on capital, as well as the timeliness of rate-setting . We consider regulatory disallowances of costs or investments, with a focus on their financial severity and also on the reasons provided by the regulator, in order to assess the likelihood that such disallowances will be repeated in the future.

Factor: Diversification (10%)

Why it matters

Diversification of overall business operations is important because it helps to mitigate the risk that economic cycles, material changes in a single regulatory regime, or commodity price movements have on the cash flow and credit quality of a utility. While utilities' sales

volumes have lower exposure to economic downturns than many non-financial corporate issuers, some sales components, including industrial sales, are directly affected by economic trends that result in lower production and/or plant closures. In addition, economic activity performs a role in the commercial sector or rate of customer growth in the service territory and, absent energy efficiency and conservation, can often affect usage per customer.

The economic strength or weakness of the service territory can affect the political and regulatory environment for rate increase requests by the utility. For utilities in areas prone to severe storms and other natural disasters, the utility's geographic diversity or concentration can be a key determinant for creditworthiness.

Diversity among regulatory regimes can mitigate the impact of a single unfavorable decision affecting one part of the utility's footprint.

For utilities with electric generation, fuel-source diversity can mitigate the impact to the utility and to its rate-payers of changes in commodity prices, hydrology and water flow, and environmental or other regulations affecting plant operations and economics; so fuel diversity typically leads to more stable rates over time.

Regulatory environments are most likely to become unfavorable during periods of rapid rate increases, which are more important than absolute rate levels. Fuel diversity can be important even if fuel and purchased power expenses are an automatic pass-through to the utility's rate-payers, because rapid price increases can cause regulators or utilities to seek recovery over a more prolonged period than the pass-through mechanism allows. Changes in environmental, safety and other regulations have caused vulnerabilities for certain technologies and fuel sources. These vulnerabilities have varied widely in different countries and have changed over time.

How we assess it for the scorecard
Scoring for this factor is based on two sub-factors: Market Position, and Generation and Fuel Diversity.

Market Position

In assessing market position, we consider the economic diversity of the utility's service territory and the diversity of its regulatory regimes, as well as the size and scale of a utility's operations. We also consider the diversity of utility operations (e.g., regulated electric, gas, water, steam) where there are material operations in more than one area.

Economic diversity is typically a function of the population, size and breadth of the territory and the businesses that drive its gross domestic product (GDP) and employment. For the size of the territory, we typically consider the number of customers and the volume of generation and/or throughput. For breadth, we consider the number of sizable metropolitan areas served, the economic diversity and vitality in those metropolitan areas, and any concentration in a particular area or industry. In our assessment, we may consider various information sources. We also consider the mix of the utility's sales volumes among customer types, as well as the track record of volume sales and any notable payment patterns during economic cycles. For diversity of regulatory regimes, we typically look at the number of regulators and the percentages of revenues and utility assets that are under the purview of each. Issuers regulated in multiple jurisdictions typically receive the highest scores in the Market Position sub-factor. Where there is only one regulator, we make a differentiation of regimes perceived as having lower or higher volatility. Size of the utility is also considered, since a larger utility can better absorb the impact of temporary, or one-time, adverse events.

Issuers with multiple supportive regulatory jurisdictions, a balanced sales mix among residential, commercial, industrial and governmental customers in a large service territory with a robust and diverse economy generally receive a higher score for this sub-factor than issuers that lack these characteristics. Issuers with a small service territory economy that has a high dependence on one or two sectors , especially highly cyclical industries, generally receive lower scores for this sub-factor, as do issuers with meaningful exposure to economic dislocations caused by natural disasters.

For issuers that are vertically integrated utilities having a meaningful amount of generation, this sub-factor has a weighting of 5%. For electric transmission and distribution utilities without meaningful generation and for natural gas local distribution companies, this sub-factor has a weighting of 10%.

Generation and Fuel Diversity

We consider the fuel type of the issuer's generation and important power purchase agreements, the ability of the issuer to shift its generation and power purchases when there are changes in fuel prices, the extent to which the utility and its rate-payers are exposed to or insulated from changes in commodity prices, and exposure to challenged sources and threatened sources (see the explanations for how we generally characterize these generation sources in the table below).

A regulated utility's capacity mix may not in itself be an indication of fuel diversity or the ability to shift fuels, because utilities may keep old and inefficient plants (e.g., natural gas boilers) to serve peak load. For this reason, we do not incorporate set percentages reflecting an "ideal" or "sub-par" mix for capacity or even generation. In addition to looking at a utility's generation mix to evaluate fuel diversity, we consider the efficiency of the utility's plants, their placement on the regional dispatch curve, and the demonstrated ability/inability of the utility to shift its generation mix in accordance with changing commodity prices.

Issuers having a balanced mix of fuel types as well as low exposure to challenged and threatened sources of generation typically receive higher scores for this sub-factor. Issuers that have concentration in one or two sources of generation, especially if they are threatened or challenged sources, typically receive lower scores.

In assessing an issuer's extent of exposure to challenged and threatened sources , we consider not only the existence of those plants in the utility's portfolio, but also the relevant factors that determine the impact on the utility and on its rate-payers. For instance, an issuer that has a fairly high percentage of its generation from challenged sources could be assessed very differently if its peers experience the same magnitude of those issues than if its peers have no exposure to challenged or threatened sources. In assessing threatened sources, we consider a utility's progress in its plan to replace those sources, its reserve margin, the availability of purchased power capacity in the region, and the overall impact of the replacement plan on the issuer's rates relative to its peer group. We also consider the extent to which the utility's generation resources plan is aligned with the relevant government's fuel/energy policy and the economic support of the underlying economy (e.g., if the fuel or plants are important sources of jobs and tax revenue).

Factor: Financial Strength (40%)

Why it matters

Financial strength is necessary for a regulated electric and gas utility to attract capital at a reasonable cost in order to invest in its generation, transmission and distribution assets, so the utility can fulfill its service obligations at a reasonable cost to rate-payers and service debt. The financial strength of utilities, which are characterized by large investments in long-lived property, plant and equipment, includes the ability to service debt and provide a return to shareholders.

The financial statements of regulated electric and gas utilities have certain aspects that affect financial analysis, including disparate treatment of certain elements under US Generally Accepted Accounting Principles (GAAP) compared with International Financial Reporting Standards (IFRS). Regulatory accounting may permit utilities to defer certain costs (thereby creating regulatory assets) that a non-utility corporate entity would have to expense. For instance, a regulated utility may be able to defer a substantial portion of costs related to recovery from a storm based on the general regulatory framework for those expenses, even if the utility does not have a specific order to collect the expenses from rate-payers over a set period. A regulated utility may be able to accrue and defer a return on equity (in addition to capitalizing interest) for construction work in progress for an approved project based on the assumption that it will be able to collect that deferred equity return once the asset comes into service. Because of the disparate treatment of certain elements under the different accounting standards , we focus more on a utility's cash flow than on its reported net income.

Conversely, utilities may collect certain costs in rates well ahead of the time they must be paid (for instance, pension costs), thereby creating regulatory liabilities. Many of our metrics focus on Cash Flow from Operations Before Changes in Working Capital (CFO Pre-WC) because, unlike Funds from Operations (FFO), it captures the changes in long-term regulatory assets and liabilities.

However, under IFRS the two metrics are essentially the same. In general, we view changes in working capital as being less useful in the financial analysis of a utility because such changes are often seasonal (for example, power demand is generally greatest in the summer) or caused by changes in fuel prices that are typically a relatively automatic pass-through to the customer. We nonetheless consider the impact of working capital changes in analyzing a utility's liquidity (see the "Liquidity" section in "Other rating considerations").

CFO Pre-Working Capital Plus Interest Expense / Interest Expense

This metric is an indicator of a utility's ability to cover the cost of its borrowed capital.

CFO Pre-Working Capital / Debt

This metric provides important indications of the cash-generating ability of a utility compared to its total debt.

CFO Pre-Working Capital Minus Dividends / Debt

This ratio is an indicator for financial leverage as well as an indicator of the strength of a utility's cash flow after dividend payments are made. Dividend obligations of utilities are often substantial, quasi-permanent outflows that can affect the ability of a utility to cover its debt obligations, and this ratio can also provide insight into the financial policies of a utility or utility holding company. The higher the level of retained cash flow relative to a utility's debt, the more cash the utility has to support its capital expenditure program.

Debt / Book Capitalization

This ratio is a traditional measure of balance sheet leverage. Total capitalization includes minority interest and deferred taxes in addition to total debt, preferred stock, other hybrid securities, and common equity. Since the presence or absence of deferred taxes is a function of national tax policy, comparing utilities using this ratio may be more meaningful among utilities in the same country or in countries with similar tax policies. High debt levels in comparison to capitalization can indicate higher interest obligations, can limit the ability of a utility to raise additional financing if needed, and can lead to leverage covenant violations in bank credit facilities or other financing agreements. We also examine debt/capitalization ratios as defined in applicable covenants (which typically exclude deferred taxes from capitalization) relative to the covenant threshold level. A high ratio may result from a regulatory framework that does not permit a robust cushion of equity in the capital structure, or from a material write-off of an asset, which may not have affected current period cash flows but could affect future period cash flows relative to debt.

How we assess it for the scorecard
Scoring for this factor is based on four quantitative sub-factors: CFO Pre-Working Capital Plus Interest Expense/Interest Expense ; CFO Pre-Working Capital/Debt; CFO Pre-Working Capital Minus Dividends/Debt; and Debt/Book Capitalization.

There are two sets of thresholds for three of these ratios based on the level of the issuer's business risk – the Standard Grid and the Lower Business Risk (LBR) Grid. In our view, the different types of utility entities rated using this methodology have different levels of business risk.

Generation utilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation, so we apply the Standard Grid. We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing potential asse t concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays.

Other types of utilities may have lower business risk, such that we consider that they are more appropriately assessed using the LBR Grid, due to factors that could include a generally greater transfer of risk to customers, very strong insulation from exposure to commodity price movements, good protection from volumetric risks, fairly limited capex needs and/or low exposure to storms, major accidents and natural disasters. For instance, we consider many US natural gas LDCs and certain US electric T&Ds , which lack generation but generally retain some procurement responsibilities for customers, as typically having a lower business risk profile than their vertically integrated peers. In cases of T&Ds that we do not view as having materially lower risk than their vertically integrated peers, we apply the Standard grid. This could result from a regulatory framework that exposes them to energy supply risk, large capital expenditures for required maintenance or upgrades, a heightened exposure to catastrophic climate events , increased regulatory scrutiny due to poor reliability or other considerations. The Standard Grid also applies to LDCs that in our view do not have materially lower risk; for instance, due to their ownership of high pressure pipes or older systems requiring extensive gas main replacements, where gas commodity costs are not fully recovered in a reasonably contemporaneous manner, where the LDC is not well-insulated from declining volumes, or if the jurisdiction of operation has aggressive policies to limit or reduce its business.

CFO Pre-Working Capital Plus Interest Expense / Interest Expense

The numerator is the sum of CFO Pre-WC and interest expense, and the denominator is interest expense.

CFO Pre-Working Capital / Debt

The numerator is CFO Pre-WC, and the denominator is total debt.

CFO Pre-Working Capital Minus Dividends / Debt

The numerator is CFO Pre-WC minus dividends, and the denominator is total debt.

Debt / Book Capitalization

The numerator is total debt, and the denominator is book capitalization.

Notching factor: Structural Subordination of Holding Companies

Our assessment of the Structural Subordination of Holding Companies may result in a downward adjustment to the preliminary outcome that results from the four weighted factors. We apply this adjustment in whole-notch increments, with a maximum of three alphanumeric notches down from the preliminary scorecard-indicated outcome to arrive at the scorecard-indicated outcome.

In cases where we consider that the credit weakness or credit strength represented by the notching factor is greater than the scorecard range, we incorporate this view into the rating, which may be different from the scorecard-indicated outcome. For a discussion of scorecard mechanics, please see the "Using the scorecard to arrive at a scorecard-indicated outcome" section.

Why it matters

Notching for the structural subordination of holding companies is important because in the regulated utility sector, barriers to movement of cash among companies in the corporate family can vary, depending on the regulatory framework. These barriers can lead to significantly different probabilities of default for holding companies (HoldCos) and operating subsidiaries (OpCos).

A typical utility company structure consists of a HoldCo that owns one or more OpCos. OpCos may be regulated utilities or non-utility companies. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries that are structured as equity, debt or even hybrid instruments.

Most HoldCos present their financial statements on a consolidated basis that blurs legal considerations about priority of creditors based on the legal structure of the family, and scorecard scoring is thus based on consolidated ratios. However, HoldCo creditors typically have a secondary claim on the group's cash flows and assets after OpCo creditors. We refer to this as structural subordination because it is the corporate legal structure, rather than specific subordination provisions, that causes creditors at each of the utility and non-utility subsidiaries to have a more direct claim on the cash flows and assets of their respective OpCo obligors. By contrast, the debt of the HoldCo is typically serviced primarily by dividends that are up-streamed by the OpCos. The HoldCo and OpCo may also have intercompany agreements, including tax sharing agreements, that can be another source of cash to the HoldCo. Under normal circumstances, these dividends are made from net income, after payment of the OpCo's interest and preferred dividends.

Structural subordination also affects loss given default. Under most default scenarios, an OpCo's creditors will be satisfied from the value residing at that OpCo before any of the OpCo's assets can be used to satisfy claims of the HoldCo's creditors. Actual priority in a default scenario will be determined by many factors, including the corporate and bankruptcy laws of the jurisdiction, the asset value of each OpCo, specific financing terms, inter-relationships among members of the family, etc. The prevalence of debt issuance at the OpCo level is another reason that structural subordination is usually a more serious concern in the utility sector than for investment-grade issuers in other non-financial corporate sectors.

The first four factors are primarily oriented to OpCos (and to some extent for HoldCos with minimal structural subordination; for example, there is no current structural subordination to debt at the operating company if all of the utility family's debt and preferred stock is issued at the HoldCo level, although there is structural subordination to other liabilities at the OpCo level). The additional risk from structural subordination is addressed via a notching adjustment to bring scorecard-indicated outcomes (on average) closer to the actual ratings of HoldCos.

How we assess it for the scorecard

Scorecard-indicated outcomes of holding companies may be notched down based on structural subordination. The risk factors and mitigants that impact structural subordination are varied and can be present in different combinations, such that a formulaic approach is not practical and case-by-case analyst judgment of the interaction of all pertinent factors that may increase or decrease its importance to the credit risk of an issuer is essential.

Some of the potentially pertinent features that could increase the extent or impact of structural subordination include the following:

» Regulatory or other barriers to cash movement from OpCos to HoldCo

» Specific ring-fencing provisions

» Strict financial covenants at the OpCo level

» Higher leverage at the HoldCo level While higher leverage at the HoldCo does not increase structural subordination per se, it exacerbates the impact of any structural subordination that exists.

» Significant dividend limitations at an important OpCo

» HoldCo exposure to subsidiaries with high business risk or volatile cash flows

» Strained liquidity at the HoldCo level

» The group's investment program is primarily in businesses that are higher risk or new to the group

Some of the potentially mitigating features that could decrease the extent and/or impact of structural subordination include the following:

» Substantial diversity in cash flows from a variety of utility OpCos

» Meaningful dividends to HoldCo from unlevered utility OpCos

» Dependable, meaningful dividends to HoldCo from non-utility OpCos

» The group's investment program is primarily in strong utility businesses

» Inter-company guarantees - however, in many jurisdictions the value of an upstream guarantee may be limited by certain factors, including by the value that the OpCo received in exchange for granting the guarantee

Notching for structural subordination within the scorecard may range from 0 to three downward notches. Instances of extreme structural subordination are relatively rare, so the scorecard convention does not accommodate wider differences, although in the instances where we believe it is present, actual ratings do reflect the full impact of structural subordination.

A related issue is the relationship of ratings within a utility family with multiple operating companies, and sometimes intermediate holding companies. Some of the key issues are the same, such as the relative amounts of debt at the holding company level compared to the operating company level (or at one OpCo relative to another), and the extent to which operating companies have credit insulation due to regulation or other protective factors. Appendix A has additional insights on ratings within a utility family.

Other considerations

Ratings may reflect consideration of additional factors that are not in the scorecard, usually because the factor's credit importance varies widely among the issuers in the sector or because the factor may be important only under certain circumstances or for a subset of issuers. Such factors can include financial controls and the quality of financial reporting; corporate legal structure; the quality and experience of management; assessments of corporate governance, as well as environmental and social considerations; exposure to uncertain licensing regimes; and possible government interference in some countries. Regulatory, litigation, liquidity, technology and reputational risk, as well as changes to consumer and business spending patterns, competitor strategies and macroeconomic trends can also affect ratings.

The following are examples of additional considerations that may be reflected in our ratings and that may cause ratings to be different from scorecard-indicated outcomes.

Environmental, social and governance considerations

Where environmental, social and governance (ESG) issues are meaningful for credit profiles, we incorporate them into our ratings analysis in a variety of ways in the application of our sector-specific methodologies. As one part of our overall credit analysis, we consider how ESG risks could affect the qualitative and quantitative factors and sub-factors in the scorecard.

Even where ESG considerations do not affect the measures in the scorecard, or where they cannot be quantified, we incorporate them into our overall analysis of credit drivers that are meaningful to the rating. As a result, we may incorporate these ESG risks qualitatively outside of the scorecard. As part of our ratings analysis, we may establish Issuer Profile Scores (IPSs), which indicate our opinion of the extent to which a given issuer is exposed to E, S and G risks (incorporating ESG-specific mitigants) or benefits from its exposure to E, S or G. The IPSs are inputs to credit ratings. For more information, please see our methodology that describes our general principles for assessing ESG risks.[2]

Increasing requirements and efforts to reduce greenhouse gas emissions (known as carbon transition) may lead to higher costs for many regulated electric and gas utilities. In addition, the ownership or operation of assets that may become "stranded" (i.e., assets that become unprofitable due to carbon transition) may indicate higher risk.

We also consider the impact of decarbonization efforts on the electrification of heating, transportation and industry. In our assessment of the net impact of decarbonization on issuers in this sector, we consider the share of generation in the business mix, the location of generation assets and the technology employed and exposure to natural gas transportation and distribution. Pressure for issuers to decarbonize and implementation timelines may be affected by regulation, policies and the potential for renewable energy to displace carbon intensive generation in each market. In general, carbon-intensive generation assets such as coal-fired plants are most exposed to carbon transition risk, followed by gas-fired plants. Renewable energy projects and other low-carbon power generation assets are well-positioned to benefit from carbon transition. Our assessment of the net impact of decarbonization also takes into account the central role of electricity networks in decarbonization efforts. In contrast, decarbonization may reduce demand for gas networks in many markets, particularly for residential heating supply.

We also consider waste and pollution risks, including emissions of non-carbon air pollutants, which can also impose significant compliance costs on thermal generators, as well as long-term storage costs for nuclear generators, particularly in regions where the generators are fully or partially responsible for those costs. Issuers in this sector are also exposed to physical risks associated with climate change, including damage to electricity networks caused by storms or wildfires. For example, operators of hydro generators and water-cooled thermal plants may experience lower output during periods of low rainfall. Conversely, generators in hydro-dominated markets may be exposed to lower electricity prices during unusually wet periods. Issuers in this sector are also exposed to weather-related disasters and other catastrophic events, including nuclear accidents and natural gas pipeline explosions, as well as costs to enhance climate resilience or remediate environmental damage.

Social issues are often important considerations. Regulated electric and gas utilities are highly exposed to socially driven policy agendas resulting from public concern about affordable energy, energy security and the environment, often enabled by the direct involvement of governments and regulators in setting energy policy. In addition to health and safety risks associated with maintaining heavy equipment and machinery, the sector is also prone to event risks with social risk repercussions, such as nuclear and hydropower disasters and gas pipeline explosions.

Among the areas of focus in corporate governance are audit committee financial expertise, the incentives created by executive compensation packages, related-party transactions, interactions with outside auditors, and ownership structure.

Liquidity

Liquidity is an important rating consideration for all electric and gas utilities, and extremely weak liquidity can heavily affect ratings in many cases. However, the relative strength or weakness of liquidity may not have a substantial impact in discriminating between two issuers with an otherwise similar credit profile. Liquidity can be particularly important where issuers have large short-term demands on liquidity, for example in highly seasonal operating environments where working capital needs must be considered. We form an

opinion on likely near-term liquidity requirements from the perspective of both sources and uses of cash. For more information on our approach, please see our liquidity cross-sector methodology.[3]

Liquidity encompasses a company's ability to generate cash from internal sources as well as the availability of external sources of financing to supplement these internal sources. Liquidity and access to financing are of particular importance in this sector. Utility assets can often have a very long useful life- 30, 40 or even 60 years is not uncommon, as well as high costs. Partly as a result of construction cycles, the utility sector has experienced prolonged periods of negative free cash flow – essentially, the sum of its dividends and its capital expenditures for maintenance and growth of its infrastructure frequently exceeds cash from operations, such that a portion of capital expenditures must routinely be financed by debt or equity. Utilities are among the largest debt issuers in the corporate universe and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility. Substantial portions of capital expenditures are non-discretionary (for example, maintenance, adding customers to the network, or meeting environmental mandates); however, utilities have been swift to cut or defer discretionary spending during economic downturns. Dividends represent a quasi-permanent outlay, because utilities typically only rarely cut their dividends. Liquidity is also important to meet maturing obligations, which can often be large,, and to meet collateral calls under any hedging agreements.

Due to the importance of liquidity, incorporating it as a factor with a fixed weighting in the scorecard would suggest an importance level that is often far different from the actual weight in the rating. In normal circumstances, most companies in the sector have good access to liquidity. The industry generally requires, and for the most part has, large, syndicated, multi-year committed credit facilities. In addition, utilities have demonstrated strong access to capital markets , even under difficult conditions. As a result, liquidity generally has not been an issue for most utilities, and a utility with very strong liquidity may not warrant a rating distinction compared to a utility with strong liquidity. However, when there is weakness in liquidity or liquidity management, it can be the dominant consideration for ratings.

Our assessment of liquidity for regulated utilities involves an analysis of total sources and uses of cash over the next 12 months or more, as is done for all corporates. Using our financial projections of the utility and our analysis of its available sources of liquidity (including an assessment of the quality and reliability of alternate liquidity such as committed credit facilities), we consider how its projected sources of cash (cash from operations, cash on hand and existing committed multi-year credit facilities) compare to its projected uses (including all or most capital expenditures, dividends, maturities of short and long-term debt, our projection of potential liquidity calls on financial hedges, and important issuer-specific items such as special tax payments). We assume no access to capital markets or additional liquidity sources, no renewal of existing credit facilities, and no cut to dividends. We assess a company's liquidity profile under this scenario, its ability to make adjustments to improve its liquidity position, and any dependence on liquidity sources with lower quality and reliability.

Management strategy

The quality of management is an important factor supporting the credit strength of a regulated utility or utility holding company. Assessing the execution of business plans over time can be helpful in assessing management's business strategies, policies, and philosophies and in evaluating management performance relative to performance of competitors and our projections. Management's track record of adhering to stated plans, commitments and guidelines provides insight into management's likely future performance, including in stressed situations.

We assess financial policy (including dividend policy and planned capital expenditures) and how management balances the potentially competing interests of shareholders, fixed income investors and other stakeholders. Dividends and discretionary capital expenditures are the two primary components over which management has the greatest control in the short term. For holding companies, we consider the extent to which management stretches its payout ratio (through aggressive increases or delays in needed decreases) in order to satisfy common shareholders. For a utility that is a subsidiary of a parent company with several utility subsidiaries, dividends to the parent may be more volatile depending on the cash generation and cash needs of that utility, because parents typically want to assure that each utility maintains the regulatory debt/equity ratio on which its rates have been set. The effect is that utility subsidiaries typically pay higher dividends when they have lower capital needs and lower dividends when they have higher capital expenditures or other cash needs. Any dividend policy that cuts into the regulatory debt/equity ratio is a material credit negative.

Size

Size can be a very important factor in our assessment of certain risks that affect ratings in this sector, including exposure to natural disasters, customer concentration, primarily to industrial customers in a single sector, and construction risks associated with large projects. While the scorecard incorporates the first two of these risks into the Diversification factor, for some issuers these considerations may be sufficiently important that the rating reflects a greater weight for these risks. Construction projects typically carry the risk of cost overruns and delays, but these risks are materially heightened for projects that are very large relative to the size of the utility.

While size brings certain economies of scale that can somewhat affect the utility's cost structure and competitiveness, rates are more heavily affected by costs related to fuel and fixed assets. Smaller utilities have sometimes been better able to focus their attention on meeting the expectations of a single regulator than their multi-state peers.

Interaction of utility ratings with government policies and sovereign ratings

Government actions can have a credit impact on regulated utilities directly through rate regulation, and indirectly through energy, environmental and tax policies. Government actions affect fuel prices, the mix of generating plants, the certainty and timing of revenues and costs, and the likelihood that regulated utilities will experience financial stress. While our evolving view of the impact of such policies and the general economic and financial climate is reflected in the ratings of each utility, some considerations do not lend themselves to incorporation in a simple scorecard.[4]

Non-utility operations

In some cases, regulated utilities have non-utility operations that are segments within the utility company, compared with the more common practice of housing such operations in one or more separate affiliates. In general, we evaluate the other businesses that are material in accordance with the appropriate methodology, and the rating on the regulated electric and gas utility reflects considerations from such methodologies. There may be analytical limitations in evaluating the utility and non-utility businesses where segment financial results are not fully available , and these may be addressed through estimation based on available information. Diversified non-utility operations generally increase the business risk profile of a regulated utility, which is a relatively low-risk business . To reflect this heightened risk, we may assign ratings that are lower than scorecard-indicated outcomes for companies with diversified operations.

Event risk

We also recognize the possibility that an unexpected event could cause a sudden and sharp decline in a utility's fundamental creditworthiness, which may cause actual ratings to be lower than the scorecard-indicated outcome. Event risks — which are varied and can range from leveraged recapitalizations to sudden regulatory changes or liabilities from an accident — can overwhelm even a stable, well-capitalized utility. Some other types of event risks include M&A, asset sales, spinoffs, shareholder distributions, litigation, pandemics, significant cybercrime events and geopolitical conflicts.

Financial controls

We rely on the accuracy of audited financial statements to assign and monitor ratings in this sector. The quality of financial statements may be influenced by internal controls, including the proper tone at the top, centralized operations, and consistency in accounting policies and procedures. Auditors' reports on the effectiveness of internal controls, auditors' comments in financial reports and unusual restatements of financial statements or delays in regulatory filings may indicate weaknesses in internal controls.

Parental support

Ownership can provide ratings lift for a particular company in the regulated electric and gas utilities sector if it is owned by a highly rated owner(s) and is viewed to be of strategic importance to those owners. In our analysis of parental support, we consider whether the parent has the financial capacity and strategic incentives to provide support to the issuer in times of stress or financial need (e.g., a major capital investment or advantaged operating agreement), or has already done so in the past. Conversely, if the parent puts a high dividend burden on the issuer, which in turn reduces its flexibility, the ratings would reflect this risk.

Government-related issuers may receive ratings uplift due to expected government support. However, for certain issuers, government ownership can have a negative impact on the underlying Baseline Credit Assessment.[5] For example, price controls, onerous taxation and high distributions can have a negative effect on an issuer's underlying credit profile.

Other institutional support

In some countries, large corporate issuers have received government or banking support in the event of financial difficulties because of their overall importance to the functioning of the economy. In Japan, our corporate ratings consider the support that has operated there for large and systemically important organizations. Over the years, this has resulted in lower levels of default than might otherwise have occurred. Our approach considers whether the presence of group and banking relationships may provide support when systemically important companies encounter significant financial stress.

Using the scorecard to arrive at a scorecard-indicated outcome

1. Measurement or estimation of factors in the scorecard

In the "Discussion of the scorecard factors" section, we explain our analytical approach for scoring each scorecard factor or sub-factor, and we describe why they are meaningful as credit indicators. When a factor comprises sub-factors, we score at the sub-factor level. Some factors do not have sub-factors, in which case we score at the factor level.

The information used in assessing the sub-factors is generally found in or calculated from information in the company's financial statements or regulatory filings, derived from other observations or estimated by Moody's analysts. We may also incorporate non-public information.

Our ratings are forward-looking and reflect our expectations for future financial and operating performance. However, historical results are helpful in understanding patterns and trends of a company's performance, as well as for peer comparisons. Financial metrics, unless otherwise indicated, are typically calculated based on an average of the most recent three years of reported results. However, the factors in the scorecard can be assessed using various time periods. For example, rating committees may find it analytically useful to examine both historical and expected future performance for periods of several years or more.

Given the long-term nature of utility assets and the often uneven nature of their capital expenditures, we consider a utility's historical financial performance as well as its prospective future performance. Multi-year periods are usually more representative of credit quality because utilities can experience swings in cash flows from one-time events, including such items as rate refunds, storm cost deferrals that create a regulatory asset, or securitization proceeds that reduce a regulatory asset. Nonetheless, we also look at trends in metrics for individual periods, which may influence our view of future performance and ratings.

All of the quantitative credit metrics incorporate our standard adjustments[6] to income statement, cash flow statement and balance sheet amounts for items such as restructuring, impairment, off-balance sheet accounts, receivable securitization programs, under-funded pension obligations, and recurring operating leases. We may also make other analytical adjustments that are specific to a particular issuer.

2. Mapping scorecard factors to a numeric score

After estimating or calculating each factor or sub-factor, each outcome is mapped to a broad Moody's rating category (Aaa, Aa, A, Baa, Ba, B, or Caa, also called alpha categories).

Qualitative factors are scored based on the description by broad rating category in the scorecard. The numeric value of each alpha score is based on the scale below.

Exhibit 3
Numeric equivalents for factor and sub-factor scores

Aaa	Aa	A	Baa	Ba	B	Caa	Ca
1	3	6	9	12	15	18	20

Source: Moody's Ratings

3. Determining the overall scorecard-indicated outcome

The numeric score for each weighted sub-factor (or each factor, when the factor has no sub-factors) is multiplied by the weight for that sub-factor (or factor), with the results then summed to produce an aggregate numeric score before notching factors (the preliminary outcome). We then consider whether the preliminary outcome that results from the four weighted factors should be notched downward in order to arrive at an aggregate numeric score after notching factors, based on Holding Company Structural

Subordination. Numerically, a downward notch adds 1 to the score, and an upward notch subtracts 1 from the score. In aggregate, the notching factor can result in a total of up to three downward notches from the preliminary outcome to arrive at the scorecard-indicated outcome.

The aggregate numeric score before and after notching factors is mapped to an alphanumeric]. For example, an issuer with an aggregate numeric score before notching factors of 11.7 would have a Ba2 preliminary outcome, based on the ranges in the table below. If the combined notching factors totaled two downward notches, the aggregate numeric score after notching factors would be 13.7, which would map to a B1 scorecard-indicated outcome.

Exhibit 4
Scorecard-indicated outcome

Aggregate numeric score	Scorecard-indicated outcome
x < 1.5	Aaa
1.5 ≤ x < 2.5	Aa1
2.5 ≤ x < 3.5	Aa2
3.5 ≤ x < 4.5	Aa3
4.5 ≤ x < 5.5	A1
5.5 ≤ x < 6.5	A2
6.5 ≤ x < 7.5	A3
7.5 ≤ x < 8.5	Baa1
8.5 ≤ x < 9.5	Baa2
9.5 ≤ x < 10.5	Baa3
10.5 ≤ x < 11.5	Ba1
11.5 ≤ x < 12.5	Ba2
12.5 ≤ x < 13.5	Ba3
13.5 ≤ x < 14.5	B1
14.5 ≤ x < 15.5	B2
15.5 ≤ x < 16.5	B3
16.5 ≤ x < 17.5	Caa1
17.5 ≤ x < 18.5	Caa2
18.5 ≤ x < 19.5	Caa3
x ≥ 19.5	Ca

Source: Moody's Ratings

In general, the scorecard-indicated outcome is oriented to the corporate family rating (CFR) for speculative-grade issuers and to the senior unsecured rating for investment-grade issuers. For issuers that benefit from rating uplift from parental support, government ownership or other institutional support, we consider the underlying credit strength or Baseline Credit Assessment for comparison to the scorecard-indicated outcome. For an explanation of the Baseline Credit Assessment, please refer to *Rating Symbols and Definitions* and to our cross-sector methodology for government-related issuers.[7]

Assigning issuer-level and instrument-level ratings

After considering the scorecard-indicated outcome, other considerations and relevant cross-sector methodologies, we typically assign a corporate family rating (CFR) to speculative-grade issuers or a senior unsecured rating for investment-grade issuers. For issuers that benefit from rating uplift from government ownership, we may assign a Baseline Credit Assessment.[8]

Individual debt instrument ratings may be notched up or down from the CFR or the senior unsecured rating to reflect our assessment of differences in expected loss related to an instrument's seniority level and collateral. The documents that provide broad guidance for such notching decisions are the rating methodology on loss given default for speculative-grade non-financial companies, the methodology for notching corporate instrument ratings based on differences in security and priority of claim, and the methodology for assigning short-term ratings.[9]

Key rating assumptions

For information about key rating assumptions that apply to methodologies generally, please see *Rating Symbols and Definitions*.[10]

Limitations

In the preceding sections, we have discussed the scorecard factors and many of the other considerations that may be important in assigning ratings. In this section, we discuss limitations that pertain to the scorecard and to the overall rating methodology.

Limitations of the scorecard

There are various reasons why scorecard-indicated outcomes may not map closely to actual ratings.

The scorecard in this rating methodology is a relatively simple tool that can be used in most cases to approximate credit profiles of issuers in this sector and to explain, in summary form, many of the factors that are generally most important in assigning ratings to these issuers. Credit loss and recovery considerations, which are typically more important as an issuer gets closer to default, may not be fully captured in the scorecard. The scorecard is also limited by its upper and lower bounds, causing scorecard-indicated outcomes to be less likely to align with ratings for issuers at the upper and lower ends of the rating scale.

The weights for each factor and sub-factor in the scorecard represent an approximation of their importance for rating decisions across the sector, but the actual importance of a particular factor may vary substantially based on an individual company's circumstances.

Factors that are outside the scorecard, including those discussed above in the "Other considerations" section, may be important for ratings, and their relative importance may also vary from company to company. In addition, certain broad methodological considerations described in one or more cross-sector rating methodologies may be relevant to ratings in this sector.[11] Examples of such considerations include the following: how sovereign credit quality affects non-sovereign issuers, the assessment of credit support from other entities, the relative ranking of different classes of debt and hybrid securities, and the assignment of short-term ratings.

We may use the scorecard over various historical or forward-looking time periods. Furthermore, in our ratings we often incorporate directional views of risks and mitigants in a qualitative way.

General limitations of the methodology

This methodology document does not include an exhaustive description of all factors that we may consider in assigning ratings in this sector. Companies in the sector may face new risks or new combinations of risks, and they may develop new strategies to mitigate risk. We seek to incorporate all material credit considerations in ratings and to take the most forward-looking perspective that visibility into these risks and mitigants permits.

Ratings reflect our expectations for an issuer's future performance; however, as the forward horizon lengthens, uncertainty increases and the utility of precise estimates, as scorecard inputs or in other considerations, typically diminishes. Our forward-looking opinions are based on assumptions that may prove, in hindsight, to have been incorrect. Reasons for this could include unanticipated changes in any of the following: the macroeconomic environment, general financial market conditions, industry competition, disruptive technology, or regulatory and legal actions. In any case, predicting the future is subject to substantial uncertainty.

Appendix A: Approach to ratings within a utility family

Typical composition of a utility family

A typical utility company structure consists of a HoldCo that owns one or more OpCos). OpCos may be regulated utilities or non-utility companies. Financing of these entities varies by region, in part due to the regulatory framework. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries or minority interests in other companies. However, in certain cases there may be material operations at the HoldCo level. Financing can occur primarily at the OpCo level, primarily at the HoldCo level, or at both HoldCo and OpCos in varying proportions. When a HoldCo has multiple utility OpCos, they will often be located in different regulatory jurisdictions. A HoldCo may have both levered and unlevered OpCos.

General approach to a utility family

In our analysis, we generally consider the stand-alone credit profile of an OpCo and the credit profile of its ultimate parent HoldCo (and any intermediate HoldCos), as well as the profile of the family as a whole, while acknowledging that these elements can have cross-family credit implications in varying degrees, principally based on the regulatory framework of the OpCos and the financing model (which has often developed in response to the regulatory framework).

In addition to considering individual OpCos under this (or another applicable) methodology, we typically[12] approach a HoldCo rating by assessing the qualitative and quantitative factors in this methodology for the consolidated entity and each of its utility subsidiaries. Ratings of individual entities in the issuer family may be pulled up or down based on the interrelationships among the companies in the family and their relative credit strength.

In considering how closely aligned or how differentiated ratings should be among members of a utility family, we assess a variety of factors, including:

- Regulatory or other barriers to cash movement among OpCos and from OpCos to HoldCo
- Differentiation of the regulatory frameworks of the various OpCos
- Specific ring-fencing provisions at particular OpCos
- Financing arrangements – for instance, each OpCo may have its own financing arrangements, or the sole liquidity facility may be at the parent; there may be a liquidity pool among certain but not all members of the family; certain members of the family may be better able to withstand a temporary hiatus of external liquidity or access to capital markets
- Financial covenants and the extent to which an Event of Default by one OpCo limits availability of liquidity to another member of the family
- The extent to which higher leverage at one entity increases default risk for other members of the family
- An entity's exposure to or insulation from an affiliate with high business risk
- Structural features or other limitations in financing agreements that restrict movements of funds, investments, provision of guarantees or collateral, etc.
- The relative size and financial significance of any particular OpCo to the HoldCo and the family

Our approach to a Hybrid HoldCo depends in part on the importance of its non-utility operations and the availability of information on individual businesses. If the businesses are material and their individual results are fully detailed in financial disclosures, we may be able to assess each material business individually by reference to the relevant Moody's methodologies to arrive at a composite assessment for the combined businesses.[13] If non-utility operations are material but are not available in financial disclosures, we may look at the consolidated entity under more than one methodology. When non-utility operations are less material but could still impact the overall credit profile, the difference in business risks and our estimation of their impact on financial performance will be qualitatively incorporated in the rating.

Higher barriers to cash movement with financing predominantly at the OpCos

Where higher barriers to cash movement exist at an OpCo or OpCos due to the regulatory framework or debt structural features, ratings among family members are likely to be more differentiated. The degree of separateness may be greater or smaller and is assessed on a case-by-case basis, because situational considerations are important.

One area we consider is financing arrangements. For instance, there will tend to be greater differentiation if each member of a family has its own bank credit facilities and difficulties experienced by one entity would not trigger events of default for other entities. While the existence of a money pool might appear to reduce separateness between the participants, there may be regulatory barriers within money pools that preserve separateness. For instance, non-utility entities may have access to the pool only as a borrower, only as a lender, and even the utility entities may have regulatory limits on their borrowings from the pool or their credit exposures to other pool members. If the only source of external liquidity for a money pool is borrowings by the HoldCo under its bank credit facilities, there would be less separateness, especially if the utilities were expected to depend on that liquidity source. However, the ability of an OpCo to finance itself by accessing capital markets must also be considered. Inter-company tax agreements can also have an impact on our view of how separate the risks of default are.

For a HoldCo, the greater the regulatory, economic, and geographic diversity of its OpCos, the greater its potential separation from the default probability of any individual subsidiary. Conversely, if a HoldCo's actions have made it clear that the HoldCo will provide support for an OpCo encountering some financial stress (for instance, due to delays and/or cost over-runs on a major construction project), we would be likely to perceive less separateness.

Even where high barriers to cash movement exist, onerous leverage at a parent company may not only give rise to greater notching for structural subordination at the parent, it may also pressure an OpCo's rating, especially when there is a clear dependence on an OpCo's cash flow to service parent debt.

While most of the regulatory barriers to cash movement are very real, they are not absolute. Furthermore, while it is not usually in the interest of an insolvent parent or its creditors to bring an operating utility into a bankruptcy proceeding, such an occurrence is not impossible.

The greatest separateness occurs where strong regulatory insulation is supplemented by effective ring- fencing provisions that fully separate the management and operations of the OpCo from the rest of the family and limit the parent's ability to cause the OpCo to commence bankruptcy proceedings as well as limiting dividends and cash transfers. Typically, most entities in US utility families (including HoldCos and OpCos) are rated within 3 notches of each other. However, it is possible for the HoldCo and OpCos in a family to have much wider notching due to the combination of regulatory imperatives and strong ring-fencing that includes a significant minority shareholder who must agree to important corporate decisions, including a voluntary bankruptcy filing.

Lower barriers to cash movement with financing predominantly at the OpCos

Our approach to rating issuers within a family where there are lower regulatory barriers to movement of cash from OpCos to HoldCos places greater emphasis on the credit profile of the consolidated group. Individual OpCos are considered based on their individual characteristics and their importance to the family, and their assigned ratings are typically banded closely around the consolidated credit profile of the group due to the expectation that cash will transit relatively freely among family entities.

Some utilities may have OpCos in jurisdictions where cash movement among certain family members is more restricted by the regulatory framework, while cash movement from and/or among OpCos in other jurisdictions is less restricted. In these situations, OpCos with more restrictions may vary more widely from the consolidated credit profile while those with fewer restrictions may be more tightly banded around the other entities in the corporate family group.

Appendix B: Regional and other considerations

Notching considerations for US first mortgage bonds

In most regions, our approach to notching between different debt classes of the same regulated utility issuer follows the guidance on notching corporate instrument ratings based on differences in security and priority of claim, including a one notch differential between senior secured and senior unsecured debt.[14] However, in most cases we have two notches between the first mortgage bonds and senior unsecured debt of regulated electric and gas utilities in the US. Wider notching differentials between debt classes may also be appropriate in speculative-grade issuers.[15]

First mortgage bond holders in the US generally benefit from a first lien on most of the fixed assets used to provide utility service, including such assets as generating stations, transmission lines, distribution lines, switching stations and substations, and gas distribution facilities, as well as a lien on franchise agreements. In our view, the critical nature of these assets to the issuers and to the communities they serve has been a major factor that has led to very high recovery rates for this class of debt in situations of default, thereby justifying a two-notch uplift. The combination of the breadth of assets pledged and the bankruptcy-tested recovery experience has been unique to the US.

In some cases, there is only a one-notch differential between US first mortgage bonds and the senior unsecured rating. For instance, this is likely when the pledged property is not considered critical infrastructure for the region, or if the mortgage is materially weakened by carve-outs, lien releases or similar creditor-unfriendly terms.

Securitization

The use of securitization, a financing technique utilizing a discrete revenue stream (typically related to recovery of specifically defined expenses) that is dedicated to servicing specific securitization debt, has primarily been used in the US, where it has been pervasive in the past. The first generation of securitization bonds were primarily related to recovery of the negative difference between the market value of utilities' generation assets and their book value when certain states switched to competitive electric supply markets and utilities sold their generation (so-called stranded costs). This technique was then used for significant storm costs (especially hurricanes) and was eventually broadened to include environmental related expenditures, deferred fuel costs, or even deferred miscellaneous expenses. In its simplest form, a securitization isolates and dedicates a stream of cash flow into a separate special purpose entity (SPE). The SPE uses that stream of revenue and cash flow to provide annual debt service for the securitized debt instrument. Securitization is typically underpinned by specific legislation to segregate the securitization revenues from the utility's revenues to assure their continued collection, and the details of the enabling legislation may vary from state to state. The utility benefits from the securitization because it receives an immediate source of cash (although it gives up the opportunity to earn a return on the corresponding asset), and ratepayers benefit because the cost of the securitized debt is lower than the utility's cost of debt and much lower than its all-in cost of capital, which reduces the revenue requirement associated with the cost recovery.

In the presentation of US securitization debt in published financial ratios, we make our own assessment of the appropriate credit representation but in most cases follow the accounting in audited statements under US Generally Accepted Accounting Principles (GAAP), which in turn considers the terms of enabling legislation. As a result, accounting treatment may vary. In most states, utilities have been required to consolidate securitization debt under GAAP, even though it is technically non-recourse.

In general, we view securitization debt of utilities as being on-credit debt, in part because the rates associated with it reduce the utility's headroom to increase rates for other purposes while keeping all-in rates affordable to customers. Thus, where accounting treatment is off balance sheet, we adjust the company's ratios by including the securitization debt and related revenues for our analysis. Where the securitized debt is on balance sheet, our credit analysis focuses on the ratios that exclude securitization debt and related revenues. Since securitization debt amortizes mortgage-style, including it makes ratios look worse in early years (when most of the revenue collected goes to pay interest) and better in later years (when most of the revenue collected goes to pay principal).

Appendix C: Treatment of Power Purchase Agreements ("PPAs")

Although many utilities own and operate power stations, some have entered into PPAs to source electricity from third parties to satisfy retail demand. The motivation for these PPAs may be one or more of the following: to outsource operating risks to parties more skilled in power station operation, to provide certainty of supply, to reduce balance sheet debt, to fix the cost of power, or to comply with regulatory mandates regarding power sourcing, including renewable portfolio standards. While we regard PPAs that reduce operating or financial risk as a credit positive, some aspects of PPAs may negatively affect the credit of utilities. The most conservative treatment would be to treat a PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station. At the other end of the continuum, the financial obligations of the utility could also be regarded as an ongoing operating cost, with no long-term capital component recognized.

Under most PPAs, a utility is obliged to pay a capacity charge to the power station owner (which may be another utility or an Independent Power Producer – IPP); this charge typically covers a portion of the IPP's fixed costs in relation to the power available to the utility. These fixed payments usually help to cover the IPP's debt service and are made irrespective of whether the utility calls on the IPP to generate and deliver power. When the utility requires generation, a further energy charge, to cover the variable costs of the IPP, will also typically be paid by the utility. Some other similar arrangements are characterized as tolling agreements, or long-term supply contracts, but most have similar features to PPAs and thus we analyze them as PPAs.

PPAs are recognized qualitatively to be a future use of cash whether or not they are treated as debt-like obligations in financial ratios

The starting point of our analysis is the issuer's audited financial statements – we consider whether the utility's accountants determine that the PPA should be treated as a debt equivalent, a capitalized lease, an operating lease, or in some other manner. PPAs have a wide variety of operational and financial terms, and it is our understanding that accountants are required to have a very granular view into the particular contractual arrangements in order to account for these PPAs in compliance with applicable accounting rules and standards. However, accounting treatment for PPAs may not be entirely consistent across US GAAP, IFRS or other accounting frameworks. In addition, we may consider that factors not incorporated into the accounting treatment may be relevant (which may include the scale of PPA payments, their regulatory treatment including cost recovery mechanisms, or other factors that create financial or operational risk for the utility that is greater, in our estimation, than the benefits received). When the accounting treatment of a PPA is a debt or lease equivalent (such that it is reported on the balance sheet, or disclosed as an operating lease and thus included in our adjusted debt calculation), we generally do not make adjustments to remove the PPA from the balance sheet.

However, in relevant circumstances we consider making adjustments that impute a debt equivalent to PPAs that are off-balance sheet for accounting purposes.

Regardless of whether we consider that a PPA warrants or does not warrant treatment as a debt obligation, we assess the totality of the impact of the PPA on the issuer's probability of default. Costs of a PPA that cannot be recovered in retail rates create material risk, especially if they also cannot be recovered through market sales of power.

Additional considerations for PPAs

PPAs have a wide variety of financial and regulatory characteristics, and we may treat each particular circumstance differently. Factors which determine where on the continuum we treat a particular PPA include the following:

» **Risk management:** An overarching principle is that PPAs have normally been used by utilities as a risk management tool and we recognize that this is the fundamental reason for their existence. Thus, we will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature.

- **Pass-through capability:** Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly we regard these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive or if regulatory support for cost recovery deteriorates, the ability to pass through costs may decrease and, as circumstances change, our treatment of PPA obligations will alter accordingly.
- **Price considerations:** The price of power paid by a utility under a PPA can be substantially above or below the market price of electricity. A below-market price will motivate the utility to purchase power from the IPP in excess of its retail requirements, and to sell excess electricity in the spot market. This can be a significant source of cash flow for some utilities. On the other hand, utilities that are compelled to pay capacity payments to IPPs when they have no demand for the power or at an above-market price may suffer a financial burden if they do not get full recovery in retail rates. We will focus particularly on PPAs that have mark-to-market losses, which typically indicates that they have a material impact on the utility's cash flow.
- **Excess reserve capacity:** In some jurisdictions, there is substantial reserve capacity and thus a significant probability that the electricity available to a utility under PPAs will not be required by the market. This increases the risk to the utility that capacity payments will need to be made when there is no demand for the power. We may determine that all of a utility's PPAs represent excess capacity, or that a portion of PPAs are needed for the utility's supply obligations plus a normal reserve margin, while the remaining portion represents excess capacity. In the latter case, we may impute debt to specific PPAs that are excess or take a proportional approach to all of the utility's PPAs.
- **Risk-sharing:** Utilities that own power plants bear the associated operational, fuel procurement and other risks. These must be balanced against the financial and liquidity risk of contracting for the purchase of power under a PPA. We will examine on a case-by case basis the relative credit risk associated with PPAs in comparison to plant ownership.
- **Purchase requirements:** Some PPAs are structured with either options or requirements to purchase the asset at the end of the PPA term. If the utility has an economically meaningful requirement to purchase, we would most likely consider it to be a debt obligation. In most such cases, the obligation would already receive on-balance sheet treatment under relevant accounting standards.
- **Default provisions:** In most cases, the remedies for default under a PPA do not include acceleration of amounts due, and in many cases PPAs would not be considered as debt in a bankruptcy scenario and could potentially be cancelled. Thus, PPAs may not materially increase Loss Given Default for the utility. In addition, PPAs are not typically considered debt for cross-default provisions under a utility's debt and liquidity arrangements. However, the existence of non-standard default provisions that are debt-like would have a large impact on our treatment of a PPA. In addition, payments due under PPAs are senior unsecured obligations, and any inability of the utility to make them materially increases default risk.

Methods for estimating a liability amount for PPAs

According to the weighting and importance of the PPA to each utility and the level of disclosure, we may approximate a debt obligation equivalent for PPAs using one or more of the methods discussed below. In each case, we look holistically at the PPA's credit impact on the utility, including the ability to pass through costs and curtail payments, the materiality of the PPA obligation to the overall business risk and cash flows of the utility, operational constraints that the PPA imposes, the maturity of the PPA obligation, the impact of purchased power on market-based power sales (if any) that the utility will engage in, and our view of future market conditions and volatility.

- **Operating cost:** If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, we may view the PPA as being most akin to an operating cost. Provided that the accounting treatment for the PPA is, in this circumstance, off-balance sheet, we will most likely make no adjustment to bring the obligation onto the utility's balance sheet.

- **Annual obligation x 6:** In some situations, the PPA obligation may be estimated by multiplying the annual payments by a factor of six (in most cases). This method is sometimes used in the capitalization of operating leases. This method may be used as an approximation where the analyst determines that the obligation is significant but cannot otherwise be quantified due to limited information.
- **Net present value:** Where the analyst has sufficient information, we may add the NPV of the stream of PPA payments to the debt obligations of the utility. The discount rate used will be our estimate of the cost of capital of the utility.
- **Debt look-through:** In some circumstances, where the debt incurred by the IPP is directly related to the off-taking utility, there may be reason to allocate the entire debt (or a proportional part related to share of power dedicated to the utility) of the IPP to that of the utility.
- **Mark-to-market:** In situations in which we believe that the PPA prices exceed the market price and thus will create an ongoing liability for the utility, we may use a net mark-to-market method, in which the NPV of the utility's future out-of-the-money net payments will be added to its total debt obligations.
- **Consolidation:** In some instances where the IPP is wholly dedicated to the utility, it may be appropriate to consolidate the debt and cash flows of the IPP with that of the utility. If the utility purchases only a portion of the power from the IPP, then that proportion of debt might be consolidated with the utility.

If we have determined to impute debt to a PPA for which the accounting treatment is not on-balance sheet, we will, in some circumstances, use more than one method to estimate the debt equivalent obligations imposed by the PPA, and compare results. If circumstances (including regulatory treatment or market conditions) change over time, the approach that is used may also vary.

Moody's related publications

Credit ratings are primarily determined through the application of sector credit rating methodologies. Certain broad methodological considerations (described in one or more cross-sector methodologies) may also be relevant to the determination of credit ratings of issuers and instruments. A list of sector and cross-sector methodologies can be found here.

For data summarizing the historical robustness and predictive power of credit ratings, please click here.

For further information, please refer to *Rating Symbols and Definitions*, which is available here.

Endnotes

1 A link to a list of our sector and cross-sector methodologies can be found in the "Moody's related publications" section.

2 A link to a list of our sector and cross-sector methodologies can be found in the "Moody's related publications" section.

3 A link to a list of our sector and cross-sector methodologies can be found in the "Moody's related publications" section.

4 For more information, see our cross-sector methodology that discusses general principles related to how sovereign credit quality can impact other ratings. A link to a list of our sector and cross-sector methodologies can be found in the "Moody's related publications" section.

5 For an explanation of the Baseline Credit Assessment, please refer to *Rating Symbols and Definitions* and to our cross-sector methodology for government-related issuers. A link to a list of our sector and cross-sector methodologies and a link to *Rating Symbols and Definitions* can be found in the "Moody's related publications" section.

6 For an explanation of our standard adjustments, please see the cross-sector methodology that describes our financial statement adjustments in the analysis of non-financial corporations.

7 A link to a list of our sector and cross-sector methodologies and a link to *Rating Symbols and Definitions* can be found in the "Moody's related publications" section.

8 For an explanation of the Baseline Credit Assessment, please refer to *Rating Symbols and Definitions* and to our cross-sector methodology for government-related issuers. A link to a list of our sector and cross-sector methodologies and a link to *Rating Symbols and Definitions* can be found in the "Moody's related publications" section.

9 A link to a list of our sector and cross-sector methodologies can be found in the "Moody's related publications" section.

10 A link to *Rating Symbols and Definitions* can be found in the "Moody's related publications" section.

11 A link to a list of our sector and cross-sector methodologies can be found in the "Moody's related publications" section.

12 See paragraph at the end of this section for approaches to Hybrid HoldCos.

13 A link to a list of our sector and cross-sector methodologies can be found in the "Moody's related publications" section.

14 A link to a list of our sector and cross-sector methodologies can be found in the "Moody's related publications" section.

15 For more information, see our cross-sector methodology that describes general principles related to loss given default for speculative-grade companies. A link to a list of our sector and cross-sector methodologies can be found in the "Moody's related publications" section.

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REPORT NUMBER 1394267

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BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Jennifer E. Nelson

RATE OF RETURN ON EQUITY

Exh. JEN-19C

REDACTED VERSION

August 29, 2025

THIS EXIBIT IS CONFIDENTIAL IN ITS ENTIRETY (PAGES 1-17)
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BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Direct Testimony of Jorge O. Moncayo

CAPITAL EXPENDITURES: BUDGETING/FORECASTING, MANAGEMENT APPROVAL AND PROJECT LIFECYCLES

Exh. JOM-1T

August 29, 2025

DIRECT TESTIMONY OF JORGE O. MONCAYO

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position with Northwest Natural Gas Company ("NW Natural" or "the Company").

A. My name is Jorge Moncayo, and I serve as the Business Planning Senior Director at NW Natural. I lead the Financial Planning and Analysis ("FP&A") group, Business Analytics, and the Project Management Office ("PMO"). My responsibilities include developing both short- and long-term financial plans, and preparing the annual Operations and Maintenance (O&M) budget, Capital Expenditures (CapEx) budget, and Income Statement budget.

Q. Please summarize your educational background and business experience.

A. I hold bachelor's degrees in Business Administration and Accounting from Universidad Catolica, Ecuador, as well as a Master of Business Administration and a Master of Science in Industrial Engineering from Oregon State University. Since joining NW Natural in 2003 as a market research analyst, I have held positions in Consumer Research and Analysis, Operations Support Services, Business Analysis and Finance. I have served in my current role since 2019.

Q. Please provide a summary of your testimony.

A. My testimony describes the Company's capital expenditures budgeting and forecasting processes, including management approval and project/program lifecycle phases.

II. CAPITAL EXPENDITURES: BUDGETING/FORECASTING, MANAGEMENT APPROVAL AND PROJECT LIFECYCLES

Q. Please provide a narrative description of NW Natural's capital expenditures budgeting and management approval processes.

A. NW Natural updates its capital expenditure forecast multiple times throughout the year. This forecast incorporates the most recent information based on requirements to maintain a safe and reliable system. The annual budget for the following year is based on the forecast created in December.

FP&A facilitates this process with the five individual business units that provide those forecasts: Engineering, Customer Acquisition, Information Technology and Services ("IT&S"), Facilities, and Transportation & Meter Shop. Each business unit uses a bottom-up approach to identify and prioritize projects, based on the need to support system reliability and safety, integrity, regulatory compliance, jurisdictional requirements, system expansion and customer growth. I will address the more specific processes used by each of these business units later in my testimony. Management and executives review and validate the assumptions and forecasts before FP&A aggregates them into the Company's overall forecast. The overall forecast is used to inform various groups on progress, adjust the Company's planned spend and incorporate impacts to the current and long-range forecast. FP&A also facilitates a monthly review of current year variances against the approved budget.

The business units coordinate with the Portfolio Management Committee ("PMC"), which meets to discuss, review, prioritize and approve new projects, considering factors like urgency, operational needs/customer benefit, financial impact,

and resource constraints. The business units triangulate with the PMC to ensure that projects are approved and included in the budget/forecasting process. Following approval, projects are included in the forecast cycle.

The final budget is presented to and approved by the Board of Directors. The Board then receives periodic updates on capital spend as compared to budget, including a comprehensive year-end report. If overall capital expenditures are expected to exceed the amount approved by the Board, management must seek additional authorization from the Board.

Q. Has NW Natural categorized these capital investments in accordance with the Commission's Used and Useful Policy Statement?

A. Yes. NW Natural has categorized its capital investments in alignment with the Washington Utilities and Transportation Commission's Used and Useful Policy Statement,[1] utilizing four main categories: Large and Discrete, Projected, Programmatic, and Short-Lived IT&S. Please see Table 3 in the prefiled Direct Testimony of Kyle T. Walker (Exh. KTW-1T) for a breakdown of these categories by rate year, including capital expenditure amounts for which the Company is seeking recovery in this rate case.

The primary drivers behind Large and Discrete capital expenditures are discussed in the prefiled Direct Testimonies of Daniel B. Kizer and Scott S. Johnson (Exh. DBK-SSJ-1T), Joe S. Karney (Exh. JSK-1T), Wayne K. Pipes (Exh. WKP-1T),

[1] *In the Matter of the Commission Inquiry into the Valuation of Public Service Company Property that Becomes Used and Useful after Rate Effective Date,* Docket U-190531, Policy Statement on Property that Becomes Used and Useful After Rate Effective Date (Jan. 31, 2020) ("Used and Useful Policy Statement").

and Holly J. Braun (Exh. HJB-1CT). Projected capital expenditures are discussed in this testimony and in the Direct Testimonies of Daniel B. Kizer and Scott S. Johnson (Exh. DBK-SSJ-1T) and Kyle T. Walker (Exh. KTW-1T). Programmatic capital expenditures are discussed in this testimony, as well as the Direct Testimonies of Daniel B. Kizer and Scott S. Johnson (Exh. DBK-SSJ-1T) and Kyle T. Walker (Exh. KTW-1T). The confidential and highly confidential Direct Testimonies of Brian E. Fellon (Exh. BEF-1CT and Exh. BEF-23HCT) discusses short-lived IT&S investments.

To forecast for Programmatic capital expenditures, the Company will generally rely on historical baselines and plans prepared in the regular course of business by managers in charge of each category. An example of Programmatic capital is vehicle replacements. Vehicle replacements are evaluated based on a combination of vehicle vintage, mileage, and industry standards for the lifecycle of vehicles and equipment. Each year, the list of vehicles that meets either the age or mileage limits are evaluated. That list creates the replacement list for the following year.

To forecast Projected capital expenditures, the Company generally relies on historical baselines and escalates costs for inflation. An example of Projected capital expenditures are public works/jurisdictionally required projects. For these projects, the Company forecasts an expected level of public works into the budget, because the Company has the historical experience to be certain that jurisdictions across its service territory will require NW Natural to support jurisdictional construction projects. NW Natural does not know the exact location or type of project that will be required from year to year, but NW Natural always forecasts that these types of projects will occur.

At the time when a jurisdiction notifies NW Natural of a specific public works project, NW Natural will treat that construction as a project under the purview of the PMO as described in detail below.

It is important to point out that for all capital expenditures, but specifically for Projected and Programmatic capital expenditures, NW Natural's forecast accuracy improves as the time horizon shortens. As described above, forecast projections for Projected and Programmatic capital expenditures further out in time necessarily rely on higher-level planning assumptions. As the planning cycle advances each year, previously longer-term Projected and Programmatic capital expenditures move into the near term and are refined with updated scope, cost estimates, and scheduling, which enhances the overall precision of the forecast. This means that, for example, the level of Projected capital expenditures for public works may be entirely based on historical experience in the outer years of the forecast, but in the upcoming year, NW Natural may know with specificity the jurisdictional work that needs to be completed and those project budgets will be based on the specifics of the jurisdictional work required.

Q. Turning next to the individual business units, please provide further details on the capital expenditures budgeting/forecasting processes used by the Engineering business unit.

A. For the Engineering business unit, capital expenditures cover all work on NW Natural's pipeline system and storage operations. Large and Discrete projects are based on need, as well as resource, operational and financial constraints. These capital expenditures can be identified years in advance based on planning that includes, but is not limited to, system modeling, long range plans, facility assessment reports, and equipment

studies. Priority is given to projects based on urgency and deadlines required by regulatory, jurisdictional and safety agencies.

Projected capital expenditures include costs to respond to unforeseen needs and to meet anticipated standard operational requirements. Unforeseen expenditures can be due to equipment unexpectedly failing or showing near end of life or to avoid potential pipeline safety impacts due to natural forces. These are Projected capital expenditures because NW Natural must forecast a certain amount of capital expenditures for these investments, even though the Company cannot say with specificity when and where these investments will be needed. As discussed more below, larger projects are individually assigned projects in the Company's PMO and have capital spend budgets and expected in-service dates that are managed through the duration of the project. Those are all individually tracked through the Company's PMO lifecycle review process.

Anticipated operational Projected capital expenditures include work such as Damages, Leakage, District Regulators, and Relocates. These capital expenditures are based on historical spending trends adjusted for inflation. Each are briefly described here:

- ***Damages*** - The Company's pipeline system incurs third-party damage each year. At the time of planning, the Company does not know where and when the damage will occur. The Company can rely on historical baselines adjusted for inflation to project the costs in the forecast.
- ***Leakage*** – Leakage costs represent replacements of services and mains to address leaks on the Company's system. Like damage and public works

projects, these projects are not necessarily identified in advance. However, the Company can rely on historical baselines adjusted for inflation to project the costs in the forecast.

- ***District Regulators*** – These costs represent the installation or replacement of district regulators due to system expansion, public works, system reinforcement, quality assurance remediation, and corrosion protection or compliance requirements. As noted above, there can be several reasons why district regulators are replaced, and therefore, the Company forecasts a level amount each year based on historical baselines adjusted for inflation.
- ***Relocates*** **–** These projects involve the relocation of pipe for safety and compliance purposes. Projections for relocates are based on historical baselines adjusted for inflation.

Programmatic capital expenditures include safety and integrity management programs, such as those required by the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration's (PHMSA) Transmission Integrity Management Program (TIMP), and Distribution Integrity Management Program (DIMP).

The Direct Testimony of Daniel B. Kizer and Scott S. Johnson (Exh. DBK-SSJ-1T) introduces and describes the Engineering business unit's distribution system and storage facility projects for which the Company is seeking recovery in this case.

Q. Please provide further details on the capital expenditures processes used by the IT&S business unit.

A. The collection of projects for the IT&S business unit reflects various business needs. Generally, these capital expenditures are categorized by several distinct but related business functions at the Company: Enterprise Applications, Information Security, Enterprise Architecture, Network, Infrastructure and Service, and Operational Technology. NW Natural classified these capital expenditures as Short-Lived IT&S because of the shorter depreciable lives of all of IT&S investments relative to other capital expenditures at the Company. Within these categories, there are Programmatic and Large and Discrete capital expenditures.

- ***Enterprise Applications*** – These projects are driven by new software and applications or changes to existing systems to support new or changed compliance requirements, or to support new business needs.
- ***Information Security*** – These projects follow the cybersecurity strategic plan. The highly confidential Direct Testimony of Brian E. Fellon (Exh. BEF-23HCT) describes this work.
- ***Enterprise Architecture –*** These projects are planned to build resilient modern platforms, optimize value of existing platforms, and build new capabilities as required.
- ***Network, Infrastructure and Service*** – These projects typically entail technical refresh cycles. This category includes radio/electronic equipment (e.g., radio, microwave, telemetry equipment).

- ***Operational Technology*** **–** These projects represent engineering projects that require IT&S execution, so this forecast follows the needs and projections of some of the Engineering business unit's capital plan.

The confidential Direct Testimony of Brian E. Fellon (Exh. BEF-1CT) introduces and describes the IT&S capital expenditures for which the Company is seeking recovery in this case.

Q. Please provide further details on the capital expenditures budgeting processes used by the Facilities business unit.

A. Potential projects for the Facilities business unit are identified by the business and/or Facilities department for consideration. Forecasts for each project are updated quarterly. Typically, Facilities projects are Large and Discrete. The Direct Testimony of Wayne K. Pipes (Exh. WKP-1T) introduces and describes the Large and Discrete Facilities project, as well as the Programmatic physical security upgrades the Company is undertaking at various sites, for which the Company is seeking recovery in this case.

Q. Please provide further details on the capital expenditures budgeting/forecasting processes used by the Customer Acquisition business unit.

A. The Customer Acquisition business unit forecasts customer growth capital expenditures necessary to connect new customers to the Company's system. These projects require extending mains and installing service lines, regulators, and meters, as well as related permitting. These capital investments are Programmatic. The Company uses housing start projections when developing new customer projections. Permits are based on previous-year actuals plus inflation. Meter installations are based on estimated number of units times cost per unit. The Company can accurately forecast

these costs based on its gross customer addition projections. Meter and regulator equipment cost trends are also influenced by periodic cause for change ("PCC") requirements (*e.g.*, replacements of faulty or outdated equipment). There are not Large or Discrete projects covered by the Customer Acquisition business unit for which the Company is seeking recovery in this case.

Q. Please provide further details on the capital expenditures budgeting/forecasting processes used by the Transportation, Tools, and Meters business units.

A. As explained above, vehicle replacements are Programmatic. Similarly, equipment and trailers are determined to be replaced based on the same process as vehicle replacements.

Tool replacement is also Programmatic. Tools are requested by field operation departments and are evaluated for business need and included on a list for purchasing the following year. Like transportation and equipment, the Company incurs costs each year to purchase and repair its small tools (items that can be small or larger in nature such as electronics that detect gas) that are necessary for employees to perform their job functions. These costs are projected based on annual trends, the Company's inventories, safety needs, and best practices for replacement of equipment at the end of its useful life.

Meter purchases and installations are Programmatic. Meter needs are developed based on current meter inventory, customer growth forecasts, meter change outs, PCC meters, as well as factoring in vendor lead times. The Direct Testimony of Joe S. Karney (Exh. JSK-1T) introduces and describes the Company's Meter

Modernization Program (MMP), which is the major meter-related project for which the Company is seeking recovery in this case.

Q. Now that you have described the capital expenditures budgeting/forecasting and management approval processes, please describe the lifecycle of capital projects.

A. To manage capital projects, NW Natural's Project Management Office (PMO) has developed a multi-phased project initiation, assessment, planning, execution, and completion process. That process is documented in the Company's General Procedure No. G-67 (Project Management Processes) (the "Procedure"), a copy of which is provided as the first exhibit to my testimony, Exh. JOM-2. In order to ensure that the Procedure continues to reflect current practices and applicable legal requirements, a regularly scheduled review of the Procedure is conducted every three years unless changes in the law or business needs supersede this requirement. Exh. JOM-2 is the current version of the Procedure, issued in June 2025. Additionally, the Company maintains a Project Management Handbook that provides the detailed step-by-step process for a project, a copy of which is provided as confidential Exh. JOM-3C.

Q. What is the purpose of the Procedure?

A. As stated in Exh. JOM-2, the Procedure outlines the process and requirements for managing projects through the full project lifecycle – starting with the proposal of the idea through Intake/Initiate, Assess, Plan, Execute and Close. I will describe each of these phases of a project later in my testimony. The Company has adopted the Procedure to ensure consistent treatment and appropriate due diligence on projects by establishing the following:

- Approval and stage gate requirements, which grant authority to proceed with the project expenditure.
- Tier definitions that guide the governance rigor of the project.
- Phase definition and key activities and requirements.
- Mechanism and approval process for change control (scope, budget variance, schedule, etc.).

Q. Does the Company have a central repository for all of the key information through the entire project lifecycle?

A. Yes. Key project information is captured in the Company's project management software, Planview. Planview serves as the system of record for the project delivery lifecycle.

Q. How are the tiers that guide the governance rigor of a capital project determined?

A. A project's tier (from Tier 5 down to Tier 0, as described in Exh. JOM-2) is initially determined by its estimated total cost (i.e., prior to any jurisdictional allocation), then further assessed for factors such as risk, impact, and complexity, which may elevate its classification. The project tier dictates the information and level of detailed documentation required for each lifecycle stage of the project and the approval requirements needed to move forward to the next stage. If project cost, risk, complexity or impact assessment change during the lifecycle of the project, the project will need to be evaluated for re-tiering. The processes outlined in the Procedure apply to all projects classed as Tier 1 or higher. Generally speaking, Tier 5 projects cost in excess of $10 million or have major risk/impact/complexity, Tier 4 projects cost between $2.5 million and $10 million or have significant risk/impact/complexity, Tier 3 projects cost

between $1 million and $2.5 million or have moderate risk/impact/complexity, Tier 2 projects cost between $250,000 and $1 million or have low risk/impact/complexity, and Tier 1 projects cost between $100,000 and $250,000 or have very low risk/impact/complexity. Tier 0 projects (less than $100,000 and very low risk/impact/complexity) are not governed by the Procedure but may follow it as a best practice.

Q. Please describe the phases and their requirements in the Procedure.

A. As noted earlier, the phases follow the full project lifecycle – starting with the proposal of the idea through Intake/Initiate, Assess, Plan, Execute and Close. Between each phase, projects submit a stage gate request, which is reviewed by approvers to grant approval to move to the next phase. Each gate is a critical point in the project where the project team evaluates the previous phase and confirms approval and readiness for the following phase.

Q. What happens in the Intake/Initiate phase?

A. The Intake/Initiate phase documents the decision to select a project. This task is accomplished through project sponsors for projects in Tiers 1 and 2. For projects in Tiers 3, 4 and 5, the project sponsor applies to the PMO to intake a project and submits it to the Portfolio Management Committee. The PMC reviews the project, validates the value of the core project or opportunity it addresses, confirms available funds and internal staff resources to support the project, and prioritizes the project within the Company's portfolio of other projects (e.g., Engineering, IT&S, Facilities). At completion of this phase, the project team may receive authorization to take action to move the project forward to the Assess phase. If so, a nominal budget is authorized for

internal labor to kick-off the project and further identify and develop the scope of resources and funds needed to complete the Assess phase.

Q. What is the purpose of the Assess phase?

A. In the Assess phase, the project team works to more fully develop project requirements, assess available options to address the project's needs and determine the alternatives, and perform feasibility and front-end engineering and design ("FEED") studies that lead to identification of the preferred solution. If a significant study is needed to explore various alternatives to a potential solution, the Assess phase is used to take the time for this evaluation. For projects estimated to cost more than $1 million (with construction overhead[2]), this phase culminates in the project sponsors and subject matter experts' completion of an Alternatives Analysis ("AA"). The AA is a document that explains why the Company needs to solve a problem, the possible solutions, and why the Company selected the chosen solution. Projects that require an AA do not advance to the Plan phase until the AA receives approval. The AA approval process requires approval from the Vice President of Regulatory Affairs & Resource Planning, Senior Director of Strategic Planning, Director of Business Analytics, and my position, Senior Director of Business Planning. Cost estimates developed at the Assess phase, such as in a FEED study, include some variability on the order of approximately -25% to +50%.

[2] Construction overhead ("COH") represents indirect capital costs that are applied to capital projects. COH rates are communicated by the FP&A team.

Q. Please describe the Plan phase.

A. In the Plan phase, the project team's focus is to develop a design, budget, and schedule for the preferred alternative selected during the Assess phase. The intent is to ensure that the project has a fully defined plan and approach for moving to execution. The Plan phase will have a budget to account for items such as engineering design, exploratory field work, and permits. The Plan phase may experience change orders if additional funds are needed to address Plan phase costs that were not foreseen when the initial Plan phase budget was prepared.[3] The first Execute phase cost estimate is developed during this phase. Pricing for materials, internal labor, external vendors and equipment is collected based on current market conditions and is used to develop the Execute phase cost estimate. Ideally, the level of uncertainty at the end of the Plan phase allows for the development of an Execute cost estimate with reduced variability on the order of approximately -10% to +10%.

Q. After the Plan phase, is the project constructed to completion?

A. Yes. This is called the Execute phase. The Execute phase has a budget to account for direct costs necessary for constructing the project and is in addition to funding approved for previous phases. Ideally, the level of uncertainty at the start of the Execute phase allows for development of cost estimates with a range of plus or minus 10%. The asset is placed in service at the end of the Execute phase.

[3] Approved changes must be documented in a project change order if contingency (which represents the amounts allocated to a project to be used, with approval, for unplanned expenses) needs to be used, the project is forecasted to be over budget and needs more funding, the project needs to use the final 20% of contingency, there are changes to the schedule that impact key milestones or the end date, or there is a material scope change (adding or deleting scope).

Q. What happens after the Execute phase is complete?

A. Finally, in the Close phase, the project team closes the project budget, saves all relevant project files, captures lessons learned, and releases the project team.

Q. So far, this testimony has focused on the lifecycle of individual capital projects. What is a program?

A. In addition to individual projects, the PMC may determine the need for a program if there are multiple projects with a connected goal, such that benefits of managing the collection outweigh managing projects as individual units or if those projects have multiple critical interdependencies. A program is submitted to the PMC for review, but each individual project that comprises the program is still subject to the lifecycle review process. To be clear, a PMO program would not necessarily be classified as Programmatic under NW Natural's interpretation of the Used and Useful standard. Under the PMO Procedure, a program could be a collection of Large and Discrete capital investments or Short-Lived IT&S investments. But a PMO program could also overlap with the Programmatic category; for example, the Meter Modernization Program is both a PMO program and falls within the Programmatic Used and Useful category. This program consists of a collection of thousands of small projects (meter and encoder receiver transmitters replacements) that have a high impact to the Company and its customers, and therefore, it was appropriate to classify the many capital investments into an overarching program that is project-managed through the PMO.

Q. Does this conclude your Direct Testimony?

A. Yes, it does

III. LIST OF EXHIBITS

Exh, JOM-2	General Procedure No. G-67 (Project Management Processes)
Exh, JOM-3C	Project Management Handbook (Confidential and Redacted)

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Jorge O. Moncayo

CAPITAL EXPENDITURES: BUDGETING/FORECASTING, MANAGEMENT APPROVAL AND PROJECT LIFECYCLES

Exh. JOM-2

August 29, 2025

GENERAL PROCEDURE

PROJECT MANAGEMENT PROCESSES

Index Number: 67

APPLICATION

This Procedure applies to all projects required to follow the Project Management Office (PMO) processes as defined below. This Procedure acts as an overview of PMO processes and works in conjunction with the PMO processes detailed in the Project Management Handbook. Please note there is a glossary of key terms located at the end of this document.

PURPOSE

This Procedure outlines the structure and requirements for managing projects for the full project lifecycle – starting with the proposal of the idea through intake, initiate, assess, plan, execute and close. The Company has adopted this Procedure to ensure consistent treatment and appropriate due diligence on projects by establishing the following:

- Approval and stage gate requirements, which grant authority to proceed with the project expenditure
- Tier definitions that guide the governance rigor of the project
- Phase definition and key activities and requirements
- Mechanism and approval process for change control (scope, budget variance, schedule, etc.).

PROCEDURE

TIER DEFINITIONS

A project's Tier is initially determined by its estimated cost, then further assessed for factors such as risk, impact, and complexity, which may elevate its classification. The project Tier dictates the tools and level of detailed documentation required to be completed during each lifecycle stage of the project and the approval requirements needed to move forward to the next stage. If project cost, risk, complexity or impact assessment change during the lifecycle of the project, the project will

need to be evaluated for re-tiering. The processes outlined in this Procedure apply to all projects classed as Tier 1 or higher. Tier 0 projects are not governed by these processes but may follow them as best practices.

	Gates	Gate + Change Order Approvals	Sponsorship Requirements	PMC Intake Approval
Tier 5: $10M+ or Major Risk / Impact / Complexity	Initiate Move to assess Move to plan Move to execute Close	Portfolio Manager Sponsor Exec Sponsor Finance Director Company President CFO CEO	C-Level Executive	Required
Tier 4: $2.5 - $10M or Significant Risk / Impact / Complexity	Initiate Move to assess Move to plan Move to execute Close	Portfolio Manager Sponsor Exec Sponsor Finance Director Company President	C-Level Executive	Required
Tier 3: $1M - $2.5M or Moderate Risk / Impact / Complexity	Initiate / Move to assess Move to plan Move to execute Close	Portfolio Manager Sponsor Exec Sponsor Finance Director Company President	C-Level Executive	Required
Tier 2: $250K - $1M or Low Risk / Impact / Complexity	Initiate / Move to plan Move to execute Close	Portfolio Manager Sponsor Exec Sponsor	VP or above	Required (Eng. projects without other teams exempt)
Tier 1: $100K- $250K and Very Low Risk / Impact / Complexity	Initiate / Move to plan Move to execute Close	Portfolio Manager Sponsor	Sr. Director or above	None (through sponsor approval only)
Tier 0: <$100K and Very Low Risk / Impact / Complexity	None	None required; initial PPM gate if using for funding	Director	None (through sponsor approval only)

Note: All estimates of project costs must include contingencies and allocations of appropriate internal resources that would be charged to capital. The total project costs, inclusive of these items, are used for determining tier level. Except where noted, project costs exclude AFUDC (Allowance for Funds Used During Construction) and COH (Construction Overhead).

GENERAL PROCEDURE

PHASES & GATES

All Tier 1 and above projects are governed by this Procedure and must follow the Stage Gating process. Between each phase, projects submit a Stage Gate request, which is reviewed by approvers to grant approval to move to the next phase. The specific gate requirements and approval authorities vary by project Tier. Each gate evaluates the previous phase and confirms approval and readiness for the following phase:

- **Intake / Move to Initiate (PMC review)**
    - **Goal**: Document the decision to select the project, based on officer priorities, confirmation of available resources and priority, and through validating the value of the core problem or opportunity it addresses.
        - For Tiers 4 and 5: Funds $50K to support pre-assessment resource gathering.
        - For Tiers 1, 2, and 3: Funds the first project phase (planning for Tier 1; assessment for Tiers 2 and 3).
    - **Required for:** Tiers 3, 4 and 5 through the PMC, Tiers 1 and 2 through sponsors.
    - **Key Documentation Reviewed at Gate:** Intake Form, Risk Assessment

- **Move to Assess**
    - **Goal**: Validate the project charter and confirm a plan is in place to assess the problem – including initial budget, schedule and resources. Funds the Assess phase.
    - **Required for**: Tiers 4 and 5
    - **Key Documentation Reviewed at Gate**: Initial Project Charter, Assess-Phase Schedule, Budget, Resource Plan

- **Move to Plan**
    - **Goal**: Confirm that the recommended solution and approach align with project goals. Validates that the estimated total budget is reasonable, represents a sound investment, and aligns with overall department budget constraints. Funds the Plan phase.

        - Additionally, for projects over $1M including COH: confirms successful completion of the Alternatives Analysis (AA) process.
    - **Required for:** Tiers 4 and 5
    - **Key Documentation Reviewed at Gate**: Full Project Charter, Plan-Phase Schedule, Budget, Resource Plan, AA (>$1M with COH)

- **Move to Execute**
    - **Goal**: Ensure that the project is sufficiently planned and designed for successful execution. Confirms that the execution budget aligns with NWN's financial strategy and delivers value for cost. Funds the Execute phase.
    - **Required for:** Tiers 1, 2, 3, 4 and 5
    - **Key Documentation Reviewed at Gate:** Execution Approach, Full Schedule, Full Budget, Full Resource Plan

- **Move to Close**
    - **Goal**: Verify that the project has been delivered as promised and the intended value has been achieved.
    - **Required for**: Tiers 1, 2, 3, 4 and 5
    - **Key Documentation Reviewed at Gate**: Project Closeout Report, Final Budget

Projects estimated to be greater than $1MM (with COH) submit an Alternatives Analysis (AA) during the Assess phase or at the point at which the expected project costs exceed that threshold – as enough information is gathered to understand the options forward, but before any decisions are made. The chart below shows the process for Tier 3 and 4 projects. As indicated above, projects that are smaller complete a modified intake and then begin their project work in Plan.

Between stage gates, projects progress through defined phases where key planning, analysis, and design activities take place. These phases build the foundation for informed decisions at each gate, ensuring the project is aligned, resourced, and ready to move forward. The following section

outlines the primary objectives, activities, and expected outputs for each phase. Additional deliverable requirements are assigned based on project type, focus and risk.

	Tier Requirements	Intent	Overview	Deliverables
Initiate	Tier 4 and 5 projects	Align on business case and resources needed to assess the project	Assemble core team, define governance structure, change control plan, and initiate tools (risk log, SharePoint, comms plan) Refine objectives and document initial Project Charter Develop assessment plan (e.g., studies, strategies, requirements), then create proposed Assess-phase budget and schedule	Assess-Phase Budget Assess-Phase Schedule Initial Project Charter Project Team Plans (RACI, etc.)
Assess	Tier 3, 4 and 5 projects	Develop requirements/designs, assess options, define preferred solution	Conduct studies and gather needed documentation (requirements, as-builts, surveys, etc.) Explore solution options; for >$1MM with COH, complete Alternatives Analysis Finalize Full Project Charter Define Plan-phase schedule and budget	Plan-Phase Budget Plan-Phase Schedule Full Project Cost Estimate Alternatives Analysis (*If >$1MM w/COH) Full Project Charter Status, Risk, Issue Reporting

GENERAL PROCEDURE

Plan	Tier 1–5 projects	Flesh out solution and define execution path	Complete final project design and scope approval Align stakeholders on governance/support after launch Define acceptance criteria Finalize Execution Schedule and Budget	Execution Budget / Full Budget Execution Schedule Final Designs and/or Specifications Status, Risk, Issue Reporting
Execute	Tier 1–5 projects	Track, monitor, and control project delivery	Monitor project progress against cost, schedule, and scope Support stabilization and operationalization upon completion	Status Reporting Risk Register, Issue Register, Change Orders (as needed)
Close	Tier 1–5 projects	Operationalize, adopt, and hand off project deliverables	Facilitate transition of projects to operations, including knowledge and documentation handover Capture lessons learned Complete final budget reconciliation	Lessons Learned Updated Documentation Final Budget

GENERAL PROCEDURE

CHANGE CONTROL PROCESS

It is not uncommon for elements of projects to change as plans develop and evolve. This could occur at any time after a project is started. The procedures to be followed by the Project Manager are based on when the change is identified. The Project Manager keeps the Project Plan updated and follows the stated process of Change Control for any requests for changes in cost, scope, or schedule, before actions are taken (e.g., budget is requested before additional budget is spent). Approved changes must be documented in a Project Change Order request if:

- Contingency needs to be used.
- Project is forecasted to be over budget and needs more funding.
- Project needs to use the final 20% of contingency.
- There are changes to the schedule that impact key milestones or the end date.
- There is a material scope change (adding or deleting scope).

The project's approvals (based on project tier) will evaluate change requests.

PROGRAM MANAGEMENT

In addition to individual projects, the PMC may determine the need for a program if there are multiple projects with a connected goal, such that benefits of managing the collection outweigh managing projects as individual units or those projects have multiple critical interdependencies. In this case, the program is submitted to the PMC for review, followed by the individual projects. Each project will continue to follow the project process defined above, and an additional "project" may be managed to handle any program-specific funding requests.

GENERAL PROCEDURE

KEY PROJECT ROLES

There are several key roles within a project organization that provide the necessary leadership structure. These roles are:

Project Requestor / Owning Department: Business unit or functional manager who will benefit from the project or who originates the idea for the project. In the case of Engineering, this may be the Project Manager.

Project Manager (PM): The PM is responsible for the successful delivery of a project, ensuring project deliverables are met within the agreed scope, schedule, and budget.

Project Sponsor: makes business decisions for the project or program. They are typically members of senior/director management – those with a stake in the project's outcome and the ultimate owner of the delivered asset.

Executive Sponsor: has ultimate authority and accountability for a project or program. They are typically members of officer/executive management and secures approval for funding.

Project Steering Committee: Projects with varied stakeholders may utilize a Steering Committee to provide strategic direction. While the Executive Sponsor holds authority and responsibility for a project or program, a project or program Steering Committee makes decisions beyond a single sponsor's purview.

Portfolio Management Committee: A group of key strategic business individuals who review proposed ideas, weigh them against company priorities and resources and select priority projects to start.

GENERAL PROCEDURE

GLOSSARY OF TERMS

Alternative Analysis (AA): A document created during the Assess phase that outlines why we need to solve a problem, the possible solutions and why we've selected the solution we chose. The AA applies to projects with an estimated cost greater than $1MM (including COH).

Change Order: A request to accept mid-stream changes to a project's budget, scope, or schedule.

Contingency: WBS cost line item representing the money allocated to a project to be used (with approval) for unplanned expenses.

Construction Overhead (COH): COH represents indirect capital costs that are applied to capital projects for back-office support. COH rates are communicated by the financial planning and budgeting team, with the latest rates stored on the Hub here

Planview: NW Natural's Project Portfolio Management (PPM) tool, the home for the full project lifecycle and the source of truth for project information.

Portfolio Management Committee (PMC): A group of key strategic business individuals who review proposed ideas, weigh them against company priorities and resources and select priority projects to start.

Program: Related projects that are managed as a group, with a holistic and strategic lens to allow a company to drive toward core objectives across teams

Project: A temporary endeavor undertaken to create a unique product, service, or result; in our case, projects of a specific size are managed through the PMO depending on their cost and impact on customers or the business

RACI/RAPID: Project documents that help organize work and decisions on a project.

Stage Gate: Critical points in a project where the project team pauses to review and approve. This is managed through Planview where PMs submit a request with documentation, and it is filtered to a defined set of approvers for sign off before moving forward.

Tier: A project categorization from 0 (low) to 5 (high) based on the project's anticipated cost, risk, complexity and impact.

GENERAL PROCEDURE

REVIEW OF PROCEDURE

In order to ensure that this Procedure continues to reflect current practices and applicable legal requirements, a regularly scheduled review will be conducted every three years unless changes in the law or business needs supersede this requirement.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Jorge O. Moncayo

CAPITAL EXPENDITURES: BUDGETING/FORECASTING, MANAGEMENT APPROVAL AND PROJECT LIFECYCLES

Exh. JOM-3C

REDACTED VERSION

August 29, 2025

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY (PAGES 1-51)
UNDER WAC 480-07-160 AND HAS BEEN REDACTED.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	Docket UG-250610

NORTHWEST NATURAL GAS COMPANY

Direct Testimony of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

Exh. DBK-SSJ-1T

August 29, 2025

DIRECT TESTIMONY OF DANIEL B. KIZER AND SCOTT S. JOHNSON

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I. INTRODUCTION AND SUMMARY

Q. Mr. Kizer, please state your name and position with Northwest Natural Gas Company dba NW Natural ("NW Natural" or "the Company").

A. My name is Daniel B. Kizer. I am the Engineering Senior Director at NW Natural. I am responsible for design, construction, operation, and maintenance of the gas transmission and distribution system (collectively herein, the "distribution system") and utility gas storage plants, and operations support services including work management functions, mapping and compliance.

Q. Mr. Kizer, please describe your education and employment background.

A. I graduated from Oregon State University with a Bachelor of Science in Civil Engineering, and I am a registered Professional Engineer. Before being promoted to my current position at NW Natural in June 2021, I was an Engineering Manager for the Company beginning January 2018. Prior to holding that position, I was a Field Engineer for the Company beginning May 2012. Before joining NW Natural, I worked as a Project Manager at Westech Engineering, Inc. from 1993 until 2012.

Q. Mr. Johnson, please state your name and position with NW Natural.

A. My name is Scott S. Johnson and I am Director of Gas Supply at NW Natural.

Q. Mr. Johnson, please describe your education and employment background.

A. I have a bachelor's degree in Accounting and started my career working at a public accounting firm where I focused on auditing utilities. I have worked at NW Natural for almost 15 years in various roles including financial reporting, gas and regulatory accounting and gas supply. I have worked in gas supply for 11 years.

Q. Which sections of this Direct Testimony are each of you sponsoring?

A. We are jointly sponsoring Sections II.B.5.a and b (Major Storage Facility Projects: Background of the Company's Storage Facilities, and Detailed Information about the Mist Storage Facility and the Natural Gas Market in the Pacific Northwest), and Mr. Kizer is individually sponsoring the remainder of this Direct Testimony.

Q. What is the purpose of your testimony?

A. The primary purpose of our testimony is to describe major distribution system projects (sponsored by Mr. Kizer) and storage facility projects (sponsored by Mr. Kizer and in part by Mr. Johnson) serving Washington customers that are included in this rate case. Our testimony covers Large and Discrete, Projected and Programmatic capital expenditures.[1] Before we do so, Mr. Kizer discusses aspects of the Company's long-term system planning and the Company's recent improvements to its system modeling. Mr. Kizer also discusses the Company's ongoing plans for discrete and non-discrete safety-driven system projects and programs. The Company's safety-related projects and programs address the Company's In-Line Inspection ("ILI") Conversion Projects, Proactive Excess Flow Valve ("EFV") Installation Program, and Probabilistic Distribution Risk Model Project. Finally, Mr. Kizer describes the Company's distribution system and gas storage pipeline safety operating and maintenance ("O&M") expenses.

[1] As described later in my testimony, in the testimony of Jorge O. Moncayo (Exh. JOM-1CT), and quantified in Table 3 in the testimony of Kyle T. Walker (Exh. KTW-1T), NW Natural has categorized its capital expenditures utilizing four main categories: Large and Discrete, Projected, Programmatic, and Short-Lived IT&S.

II. MAJOR DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

A. Long-Term System Planning

Q. Before addressing the major distribution system and storage facility projects included in this rate case, are there any aspects of the Company's long-term system planning that you wish to discuss here?

A. Yes. Distribution system planning has historically been conducted as just-in-time planning, where traditional pipeline solutions were not developed until areas of the system became constrained. While this type of planning has long benefited customers, it does not allow for the lead time needed for non-pipeline alternative ("NPA") solutions. Forward-looking planning is necessary to evaluate and implement NPAs. NW Natural is in the process of expanding its suite of NPA solutions in Washington, such as Geographically Targeted Demand Response ("GeoDR"), Geographically Targeted Energy Efficiency ("GeoEE"), as well as a system-wide demand response program. Using updated, more sophisticated modeling, NW Natural has identified several areas on the system that have the potential for early NPA solutions, as they do not currently violate system reinforcement criteria but are areas where the gas distribution system is either approaching these thresholds and/or is showing evidence of growth in demand that drive the need for a system reinforcement. In addition to GeoDR and GeoEE, the Company has hired an outside consultant to prepare a compressed natural gas ("CNG") or liquefied natural gas ("LNG") trucking study to help determine when CNG or LNG gas supplies may be a viable alternative to a pipeline solution for a peak weather event for areas of the Company's system that fall

below its minimum system planning threshold. The Company intends to evaluate and pursue as many of these opportunities as possible and will document those for which it is not feasible and why. The Company is conducting all of these efforts and analyses concurrently and has included this information in NW Natural's Integrated Resource Plan ("IRP") filed with the Washington Utilities and Transportation Commission ("Commission") on August 1, 2025 (docket UG-240312).

Q. Please describe the improvements to the Company's system modeling.

A. The Company recently completed implementation of its Customer Management Module ("CMM") into the Company's pressure system modeling software, Synergi™ Gas. CMM effectively creates a link between NW Natural's Geographical Information System (GIS), Customer Information System ("CIS"), and Synergi™ Gas.

Q. How is CMM different from past system modeling software?

A. CMM provides NW Natural with the ability to import each customer's recent historical gas usage data from CIS to calculate a customer-specific demand using daily temperature, as well as update customer information such as rate schedule, customer status (active or inactive) and changes in forecasted consumption. Previous modeling methods utilized area-specific averages for residential and small commercial customers, whereas CMM allows for customer-specific predicted usages based on each customer's recent historical consumption. CMM ties individual customer demands to their specific geographic location in the model, allowing customer model demands to be automatically assigned to their respective locations in the models. The overall benefit of CMM is that it more accurately models local system pressures by using individual historical customer usage, rather than local average customer usages.

Q. Did the transition to CMM change the Company's understanding of the adequacy of the distribution system during design peak cold weather conditions?

A. Yes. The differences in customer usage became apparent when the transition to CMM was completed. After the implementation of CMM, the Company's system modeling revealed that its distribution pressures for the design cold weather planning event, and for less-than-peak cold weather events in some locations, fell below the Company's minimum system planning threshold in areas where customer demands were higher than previously modeled, and that customers would experience loss of gas service during a peak cold weather event. Likewise, in areas where customer demands were less than previously modeled, the Company's system modeling showed better system pressures during the peak cold weather planning event. The Company's cold weather planning event system modeling only evaluates demands from firm customers, and the usage for interruptible rate schedule customers is disabled in the model.

Q. Are these newly revealed areas that fail the minimum system planning criteria isolated or extensive throughout the Company's distribution system?

A. In general, the areas are isolated and limited to geographical areas within the Company's distribution system where customers exhibit higher-than-previously-assumed average demands.

Q. Has the Company validated the results of the CMM modeling?

A. Yes. The Company uses Supervisory Control and Data Acquisition (SCADA), Electronic Portable Pressure Recorders ("EPPRs"), and field gauge measurements to validate CMM model results against actual pressure readings. The Company installed EPPRs in several locations where CMM showed NW Natural's system pressures to be

weak. Most recently, the EPPRs recorded hourly pressure and temperature data during the January 2024 cold weather event (i.e., from Friday, January 12, 2024, through Thursday, January 18, 2024), which was used to validate CMM system modeling under the temperature conditions experienced during this cold weather event. The pressure and temperature data collected for the 2024 cold weather event also validated the Company's CMM modeling findings that, in areas of its system where customer demands were higher than previously modeled, the Company can expect to see a loss of service to customers during a peak cold weather event, and in some cases, at temperatures similar to what the area experienced during the January 2024 ice storm event.

Q. How is the Company addressing these areas that CMM shows currently fail the minimum system planning threshold?

A. The Company has identified reinforcement projects to improve supply in areas where CMM modeling predicts a loss of service for customers where gas demands were higher than previously modeled. The Company determined that certain NPA solutions cannot be employed fast enough to address the immediate need for improved gas supply to these areas recently identified by CMM. NW Natural is conducting additional modeling to forecast future constraints where load growth might be expected to occur over the next five years.

B. Discussion of Major Distribution System and Storage Facility Projects

Q. Has the Company previously sought cost recovery for any major distribution system and storage facility projects that have been completed since November 1, 2022, the rate effective date for Year Two of the Company's 2021 rate case (docket UG-200994)?

A. Yes. In its last rate case, the Company sought cost recovery for a project called the SE 1st Street Grading Project (Phase 2). The SE 1st Street Grading Project (Phase 2) was the second phase of a City of Vancouver public works road improvement project between SE 164th Avenue and SE 192nd Avenue. The second phase of this roadway improvement project included roadway widening between SE 177th Avenue and SE 192 Avenue for bike lanes, turns lanes and the addition of sidewalks. It also included relocation of public sanitary sewer, water, storm drainage, lighting and signage as well as relocation work by multiple private utilities. Phase 2 also included full roadway reconstruction as the road grade was lowered by approximately 30 feet to improve grades for a new roundabout at the new intersection with SE 184th Avenue.

By its Order 05 in dockets UG-200994, UG-200995, UG-200996 and UG-210085 on October 21, 2021, the Commission approved the Full Multi-Party Settlement Agreement ("Agreement") (and its Attachment 1), which, in relevant part, required the Company to make a Year Two Pro Forma Filing that presented evidence sufficient to demonstrate the prudence of the Year Two distribution system and storage facility capital projects listed in paragraph 10 of the Agreement. The Company made its Year Two Pro Forma Filing on December 2, 2022. That filing included the Direct Testimony of Mr. Kizer (Exh. DBK-1T) that the SE 1st Street Grading Project (Phase

2) would not be completed before the November 1, 2022, rate effective date of Year Two and that all costs for that project were removed from the portfolio of projects included in Year Two and were not included in Year Two rates.

Q. Please provide an update of the SE 1st Street Grading Project (Phase 2).

A. The Company completed and placed in service the SE 1st Street Grading Project (Phase 2) in October 2024. The total cost to complete the SE 1st Street Grading Project (Phase 2) was $9.4 million. The Company has included the net cost of this project in its revenue requirement in this rate case.

Q. Please explain why the SE 1st Street Grading Project (Phase 2) cost approximately $9.4 million when the amount the Company forecasted in December 2020 was approximately $2.3 million.

A. There are multiple factors that contributed to the cost of the project increasing above the $2.3 million amount forecasted in UG-200994. The Company's gas facility relocation work on the SE 1st Street Grading Project (Phase 2) occurred two years later than originally forecasted in UG-200994, and the scope of the Company's gas facility relocation work that occurred in 2024 was greater than the relocation design forecasted to occur in 2021. The staging to lower the roadway grade near the SE 184th Avenue intersection changed over what was presented to the Company back in 2000 and 2001. Rather than lower one-half of the roadway and allow private utilities to move over to the lowered roadway section after the grade was lowered, the full width of the roadway was lowered all at once. To accommodate this full-width roadway lowering, the Company had to cut and abandon its existing high-pressure distribution 4-inch steel main and Class B local distribution mains and services so the City's contractor could

perform the excavation activities to lower the road grade. In addition, the Company had to route temporary services to the asphalt and concrete plants on the north side of the roadway, which were reconnected to the new Class B main in the SE 1st Street roadway after the roadway grade was lowered.

In addition, during the construction phase, the Company incurred an additional $2.6 million in change orders due to actions by third parties that were beyond the Company's control.[2] NW Natural had been coordinating utility relocation with the City of Vancouver as early as 2020. This road improvement project proved to be complex logistically as active and historical gravel mining operations have lowered the elevation of the land on both sides of the public right-of-way for the project roadway segment by approximately 35 to 50 feet. A land developer partnered with the City to improve this Phase 2 segment of the SE 1st Street roadway, and an agreement was made to lower the elevation of the middle segment of the SE 1st Street roadway by approximately 35 feet to improve the access of the existing and former gravel mining properties to the improved SE 1st Street roadway. The developer was redeveloping the formal gravel mining site south of the roadway for urban residential land uses and had future redevelopment interests for the active gravel mining site north of the roadway. The City project experienced multiple delays due to the logistical complexity of lowering the roadway and all of the active public and private (franchise) utilities within the limited public right-of-way available.

[2] Exh. DBK-SSJ-2 is the Company's documentation of the change orders.

Another complexity was that all public and private utility relocation work, as well as the excavation to lower the right-of-way elevation by 35 feet, had to occur within the City contractor's one summer season construction project schedule. Once the Company began work to relocate its facilities in conflict with the roadway improvements, material changes to the City's design and the City contractor's schedule led to numerous changes that affected the scope, schedule, and costs of the Company's gas main installations for the SE 1st Street Grading Project (Phase 2).

Q. Please identify the significant large and discrete distribution system and storage facility projects that are included for recovery in this rate case.

A. In addition to the one project mentioned above, the Company is requesting recovery for the following significant discrete distribution system and storage facility projects. Each of these is described more fully below:

- Reinforcement Projects:
  - Vancouver Reinforcement Project (December 2028) (Rate Year 3) ($15.5M)
- Gate Station Improvement Projects:
  - Camas Gate Station Rebuild Project (October 2023) ($3.9M)
  - Camas Gate Station Building Improvements Project (September 2025) (Pro Forma Year) ($1.3M)
  - Deer Island Gate Station Improvements Project (October 2027) (Rate Year 2) ($0.6M Washington-allocated)
  - Felida Gate Station Rebuild Project (July 2028) (Rate Year 3) ($1.9M)
- Line Heater and Gate Station Projects:
  - West Vancouver Gate Metering Project (July 2026) (Rate Year 1) ($0.7M)

- Ridgefield and Battleground Line Heater Projects (both August 2028) (Rate Year 3) ($1.6M each)
- West Vancouver Gate Odorant Depot Project (August 2027) (Rate Year 2) ($1.2M)

- Major Storage Facility Projects: The projects listed below are designed to replace equipment and facilities that reached the end of their useful life and to promote the integrity and reliability of the Mist Storage Facility ("Mist") or the Company's Portland LNG or Newport LNG storage facilities.
  - Mist Projects:
    - Mist GC500 Turbine Compressor Replacement Project (Oct. 2025) (Pro Forma) ($6.6M Washington-allocated) and Mist GC600 Turbine Compressor Replacement Project (December 2026) (Rate Year 1) ($1.6M Washington-allocated)
    - Mist Main Power Feed Replacement Project (October 2026) (Rate Year 1) ($0.5M Washington-allocated)
    - Mist Miller Bruer/Flora Gathering Separator Upgrades Project (August 2027) (Rate Year 2) ($0.4M Washington-allocated)
    - Mist Miller Bruer/Flora/Meyer Metering Upgrades Project (July 2027) (Rate Year 1) ($0.3M Washington-allocated)
    - Mist Calvin Creek Gathering Separator Upgrades Project (October 2028) (Rate Year 3) ($0.2M Washington-allocated)
    - Mist Miller Air Compressor and Receiver Tank Upgrades Project (July 2027) (Rate Year 2) ($0.2M Washington-allocated)

- Newport LNG Projects:
  - Newport LNG Pretreatment Improvements Project (December 2024) (Test Year) ($0.7M Washington-allocated)
  - Newport LNG Plant Supply Generator Project (December 2026) (Rate Year 1) ($0.3M Washington-allocated)
  - Newport LNG Cold Box Replacement Project (April 2027) (Rate Year 1) ($4.5M Washington-allocated)
  - Newport LNG Molecular Sieve Vessels Repair and Upgrades Project (June 2026) (Pro Forma Period) ($0.3M Washington-allocated)
- Portland LNG Project:
  - Portland LNG Electrical Distribution Upgrades (August 2026) (Rate Year 1) ($0.3M Washington-allocated)

Q. Please identify the near-term or completed programmatic distribution system projects that are described in this rate case.

A. The following programmatic distribution system projects are included for recovery in this rate case:

- P04 Camas Trans ILI Conversion Project ("TIMP")[3]
- SE 1st Street Grading Project (Phase 2) (Public Works) (described earlier in this testimony)
- Proactive EFV Installation Program

[3] "TIMP" is the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration's ("PHMSA's") Transmission Integrity Management Program.

- JANA DIMP[4] Probabalistic Risk Model Project (IT&S project to enhance engineering capabilities for Programmatic capital expenditures).

Q. Please describe the categories of Programmatic or Projected capital expenditures.

A. As described in the Direct Testimony of Jorge O. Moncayo (Exh. JOM-1T), the Company forecasts Programmatic and Projected capital expenditures that occur consistently and are related to the day-to-day operation of the Company. Programmatic capital expenditures include capital expenditures in furtherance of the Company's Transmission Integrity Management Plan (TIMP) and Distribution Integrity Management Plan ("DIMP").

Projected capital investments include work such as Damages, Leakage, District Regulators, and Relocates. These capital expenditures are based on historical spending trends adjusted for inflation. Each are briefly described here:

- ***Damages*** - The Company's pipeline system incurs third-party damage each year. At the time of planning, the Company does not know where and when the damage will occur. The Company can rely on historical baselines adjusted for inflation to project the costs in the forecast.
- ***Leakage*** – Leakage costs represent replacements of services and mains that result from leaks on the Company's system. Like damage and public works projects, these projects are not necessarily identified in advance. However, the Company can rely on historical baselines adjusted for inflation to project the costs in the forecast.

[4] "DIMP" is PHMSA's Distribution Integrity Management Program.

- ***District Regulators*** – These costs represent the installation or replacement of district regulators due to system expansion, public works, system reinforcement, quality assurance remediation, and corrosion protection or compliance requirements. As noted above, there can be several reasons why district regulators are replaced, and therefore, the Company forecasts a level amount each year based on historical baselines adjusted for inflation.
- ***Relocates –*** These projects involve the relocation of pipe for safety and compliance purposes. Projections for relocates are based on historical baselines adjusted for inflation.

1. Major Discrete Distribution System Projects

a. Vancouver Reinforcement Project

Q. Please describe the Vancouver Reinforcement Project.

A. The Company's high pressure distribution system in Clark County is supplied by gas from six gate stations, where gas is delivered to the Company's transmission and high-pressure distribution system from the interstate pipeline system. The high-pressure distribution system operating above design capacity has a maximum allowable operating pressure ("MAOP") of 250 pounds per square inch gauge ("psig"). Approximately 77,000 firm customers are served by the Company's transmission and high-pressure distribution system.

In 2022, the Company created a new Clark County hydraulic model incorporating forecasting data from the new (at the time) Customer Management Module (CMM). Initial system modeling using the new CMM data showed that pressures in the 250 psig MAOP high pressure distribution system would drop to 105

psig during a peak cold weather event. This system modeling turns off the demands for interruptible customers and only evaluates firm customer demands. A gas main pressure of 105 psig represents a 55 percent pressure drop from the 235 psig gate station delivery pressure on the 250 psig MAOP system. NW Natural's system planning criteria calls for system improvement measures to be taken when line pressures drop by 40 percent.[5] The 250 psig MAOP high pressure distribution system is constructed of a network of high pressure main consisting of 5.5 miles of 4-inch pipeline, 13.6 miles of 6-inch pipeline, 21.7 miles of 8-inch pipeline, and 5.4 miles of 12-inch pipeline. Modeling with the new CMM data showed that the 4-inch and 6-inch pipeline segments within the 250 psig MAOP high pressure distribution system were bottlenecks that restricted flow and contributed to the excess pressure drops modeled. EPPRs were placed in the field by the Company, and data collected during cold weather between 2023 and 2025 to confirm the CMM modeling findings.

On January 16, 2024, a Company EPPR recorded a pressure of 117.8 psig during a 43.5 Heating Degree Day ("HDD") on the 250 psig MAOP system when the average daily temperature was 21.5 degrees F, corresponding to a 41.3 percent pressure drop. On February 11, 2025, a Company EPPR recorded a pressure of 106.0 psig during a 37 HDD on the 250 psig MAOP system, corresponding to a 48.3 percent pressure drop.

[5] This standard is based on the Gas Engineering and Operating Practices (GEOP), Volume 3, Distribution, Book D-1, System Design Revised, Chapter 2: Gas Flow Calculations, page 111.

Q. What are the results of the CMM modeling for the existing local distribution system during a peak cold weather event?

A. The Company uses an HDD of 57.4 for peak cold weather system planning. The Company's latest modeling estimates that pressures would drop to 95 psig on the 250 psig MAOP high pressure distribution system during a 57 HDD peak cold weather event. The modeling results were validated using 2024 and 2025 EPPR data. Although gas would still flow at 95 psig, the flow rate is less than the maximum regulator capacity, which can lead to reductions in gas and pressure supplied to the local distribution system. Prior to the transition to the CMM, previous Company software models did not show system pressures to exceed the 40 percent pressure drop threshold.

Company system modeling for peak cold weather system planning shows large areas in the Vancouver core areas, between I-5 and I-205, with pressures between 0 and 10 psig (in red) as shown below in Figure 1 and in Exh. DBK-SSJ-3. Modeled low pressure in the 250 psig MAOP system lead to reduced inlet pressure and district regulator flow capacity for gas supply into the Class B local distribution system. Based on new CMM modeling since the 250 psig MAOP high pressure distribution system has experienced a greater than 40 percent pressure drop during recent cold weather events and has been modeled to exceed greater pressure drops during a peak cold weather event, the inlet supply to district (pressure) regulators has reached and passed a threshold where district regulator capacity will decrease with any small increases in load demand as shown below in Figure 2. Further reductions in the 250 psig MAOP system pressure will lead to increases in the number of customers with distribution pressure between 0 and 10 psig, and the areas shown in red in Figure 1 below will grow

with more customers expected to see meter inlet pressures between 0 and 10 psig, and with some losing pressure to their gas service during peak cold weather events.

Figure 1. Synergi CMM Vancouver and Clark County Area Class B Distribution Pressure System Map

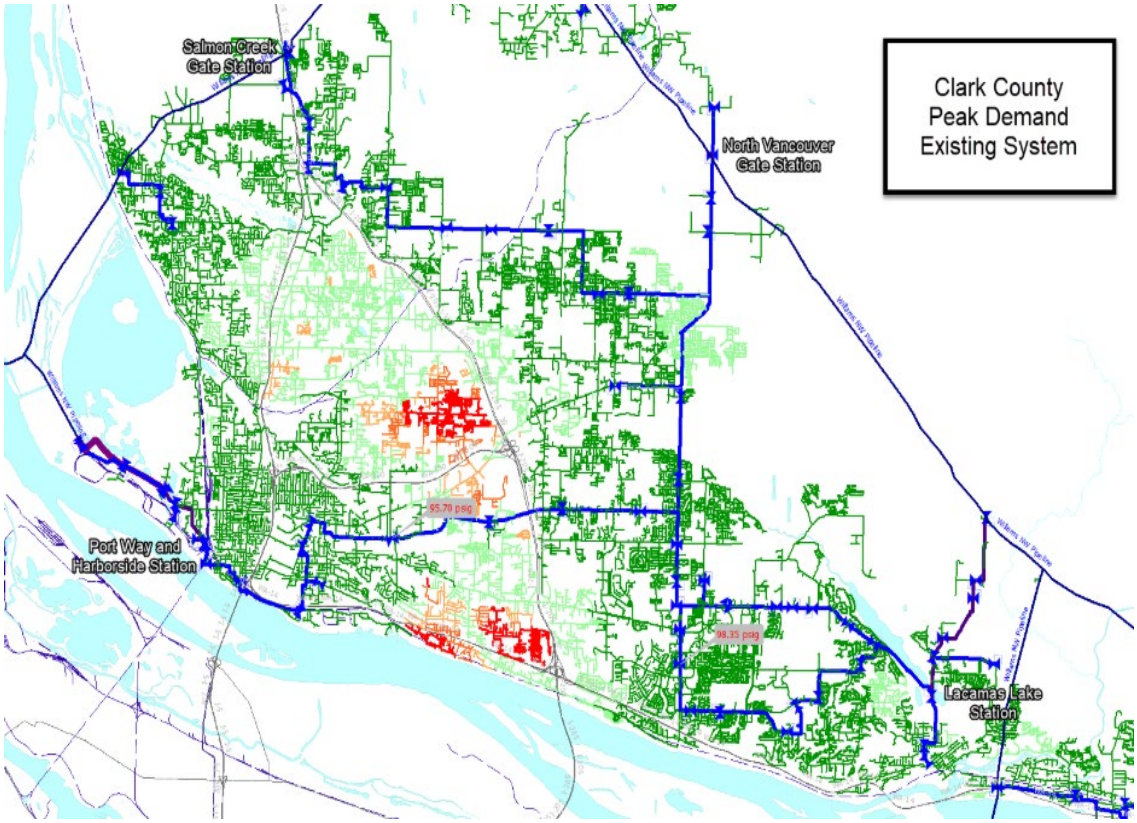

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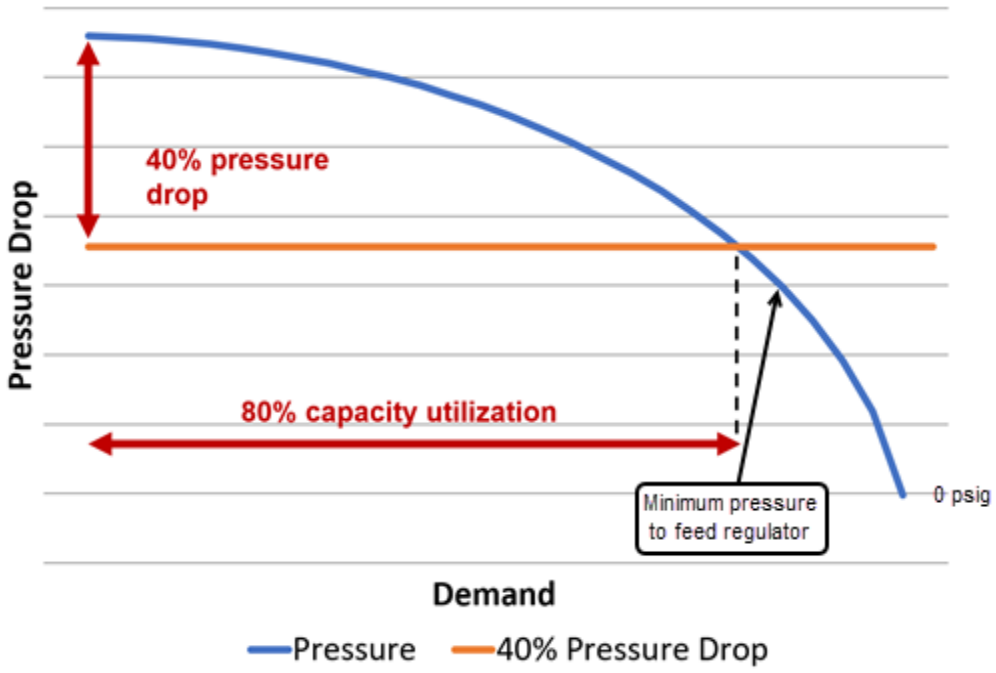
Figure 2. Pressure Loss Illustration



Q. How accurate is the Company's system modeling using CMM?

A. Models provide a good representation of expected system pressures during peak cold weather events, and the Company has utilized EPPRs to help field calibrate system modeling to make the system models as accurate as possible. CMM modeling is an improvement on the Company's previous modeling capabilities, but models are not perfect at predicting real-world conditions and there are unmodeled factors that could lead to unplanned use of the remaining capacity in the 250 psig MAOP system during peak cold weather events, which could lead to a reduction in district regulator flow capacity and lead to increases in customer gas service outages. This is reinforced by the fact that CMM modeling in 2022, before collection of EPPR data during cold weather events in 2024 and 2025, was 10 psig higher than after collection of the EPPR data and adjustment to the CMM model. The CMM modeling results showed the

Company that the pressures in the 250 psig MAOP high pressure distribution system are not as robust as previously calculated based on previous system modeling programs, and demands on the 250 psig MAOP system have reached a point where a large number of firm demand customers could lose their gas service during a single or multi-day cold weather event.

Q. How is NW Natural incorporating equity into its modeling for the Vancouver Reinforcement Project?

A. NW Natural is incorporating equity into its modeling for the Vancouver Reinforcement Project by first determining which areas of the system need this project the most. As explained above, the Vancouver Reinforcement Project is especially needed for those areas in Figure 1 that are shaded red (i.e., areas of the system that peak cold weather modeling indicates would experience pressures between 0 and 10 psig). Next, NW Natural examined the census tracts where these areas were located. Specifically, NW Natural overlaid the areas shaded in red in Figure 1 with the number of low-income customers that it serves in each census tract. Figure 3 below shows this overlay with the darker areas having a higher distribution of low-income customers. Specifically, Figure 3 shows the modeling results for the 250 MAOP system, with the lowest pressures in the 250 MAOP system found in the central Vancouver area along E. 18th Street and Burton Road, which are also areas with a high percentage of low-income customers.

Figure 3

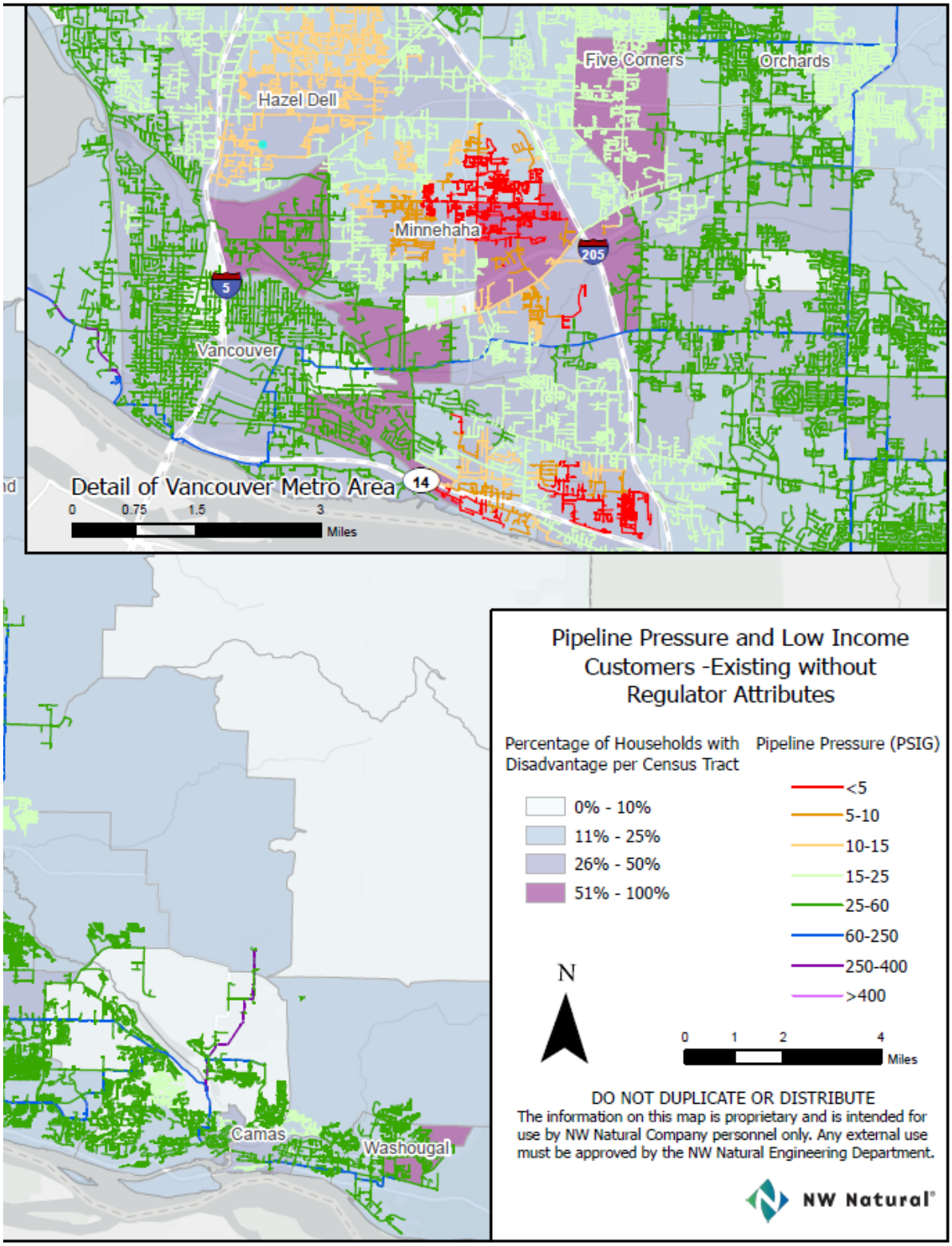

Five Corners
Orchards
Hazel Dell
Minnehaha
205
5
Vancouver
Detail of Vancouver Metro Area
14
0 0.75 1.5 3
Miles
Camas
Washougal
Pipeline Pressure and Low Income Customers -Existing without Regulator Attributes
Percentage of Households with Disadvantage per Census Tract
0% - 10%
11% - 25%
26% - 50%
51% - 100%
Pipeline Pressure (PSIG)
<5
5-10
10-15
15-25
25-60
60-250
250-400
>400
N
0 1 2 4
Miles
DO NOT DUPLICATE OR DISTRIBUTE
The information on this map is proprietary and is intended for use by NW Natural Company personnel only. Any external use must be approved by the NW Natural Engineering Department.
NW Natural

Figure 3 also shows that other areas of the system with low pressures during peak cold weather are in census tracts with differing income levels. Areas to the north of Minnehaha and along Highway 14, for instance, have fewer low-income customers.

NW Natural plans to incorporate the information from Figure 3 into both its near-term planning and its alternative analysis. In its near-term planning for the period before the Vancouver Reinforcement Project is complete, NW Natural will conduct geographically targeted demand response (GeoDR) outreach to customers in these lower-income census tracts so that these communities have the opportunity to take advantage of that program, along with additional energy efficiency efforts that can both help lower customers' bills and provide system benefits.

NW Natural will also incorporate equity as a factor in its alternatives analysis by examining the impact of each of the alternatives for the Vancouver Reinforcement Project on the communities the Company serves, with a special emphasis on those census tracts with a higher distribution of low-income customers. This analysis would involve the construction impacts, if any, of each option that is identified. It will also examine the community impacts of any non-pipeline alternatives (NPAs), such as the use of CNG or LNG trailers that could inject gas into the system during peak cold-weather events.

Q. Has the Company identified any options for the Vancouver Reinforcement Project?

A. Yes. Options are presented in Exh. DBK-SSJ-3, which is the summary of the Vancouver Reinforcement Project. The Company identified four potential options for the Vancouver Reinforcement Project. One alternative is a pipeline solution that would

construct approximately 2.5 miles of 12-inch gas main to reinforce a segment of 4-inch main near Lacamas Lake in the east Vancouver area. A second alternative is a non-pipeline alternative (NPA) that would uprate the operating pressure of the 250 psig MAOP high pressure distribution system to 300 psig MAOP, to increase the delivery capacity of the existing 250 psig MAOP pipeline network. A third alternative is an NPA that would inject gas from CNG or LNG trailers sited on a parcel of land in the east Vancouver area during peak cold weather events, as mentioned in the previous answer. A fourth alternative considered and ruled out was a demand response NPA. The CMM modeling revealed an immediate need for more gas supply, demand response or load reduction. The volume of gas supply reduction needed to avoid the project is approximately 4,500 therms/hour during a design cold weather event, which is equivalent to shedding the full load from an estimated 10,000 to 12,000 residential homes or demand response from about 24,000 to 38,000 residential customers.

Q. What is the status of the Vancouver Reinforcement Project?

A. The Vancouver Reinforcement Project is currently in the Assess Phase. The Company has identified pipeline and non-pipeline solutions for the Vancouver Reinforcement Project and is studying each of the alternatives. Once the studies are completed for each alternative, the Company will then prepare an alternatives analysis to identify the least cost alternative.

The Company will be hiring an engineering consultant to prepare a pipeline routing study with cost estimates for the pipeline solution in late 2025. In 2025, the Company has hired a consultant to prepare a CNG and LNG trucking study so the Company can determine the cost of service for developing and siting a CNG or LNG

fuel tank facility. This study will inform the Company about site infrastructure requirements and development costs for siting the CNG or LNG trailer each winter season, and will include the annual purchase and delivery of the trailers full of CNG or LNG fuel.

In late 2025, the Company will prepare an engineering study to determine the estimated cost to uprate the 250 psig MAOP high pressure distribution system to 300 psig MAOP. For the uprate option, the Company would need to seek a waiver from Commission regulation WAC 480-93-155(f), as the uprate to 300 psig MAOP would produce a hoop stress greater than 20 percent for some of the pipe segments in the 250 psig MAOP high pressure distribution system, and the Company does not possess the original welding standards and welder records otherwise required by WAC 480-93-155(f). To reduce the risk of outages in the distribution capacity constrained areas before the reinforcement project is completed by the end of 2028, the Company will pursue a geographically targeted demand response (GeoDR) effort from 2026 to 2028 along with the energy efficiency effort as already planned by Energy Trust for the same period. The GeoDR effort will include: a) elevating the marketing effort for the existing Bring Your Own Thermostat ("BYOT") program by providing enrollment and participation incentives higher than the system-wide BYOT program; and b) scoping and implementing a large commercial and industrial customer behavioral demand response program with performance-based incentives comparable to those paid to the BYOT DR residential and small commercial customers in the area in terms of dollars per therm of peak hour load reduced.

Q. What is the timing of the Vancouver Reinforcement Project?

A. The Company expects to complete the Vancouver Reinforcement Project by December 2028 (Rate Year 3). In the current Assess Phase, the Company also is evaluating whether the various alternatives can be on a timeline for completion in 2027, given the low pressures that are currently being recorded during cold weather events on the system. Permitting for the project will likely be the biggest obstacle to accelerating the timeline, and therefore, the Company has conservatively estimated 2028 for completion. Following the completion of the alternatives analysis for this project, NW Natural can provide updated information.

Q. What is the estimated total cost of the Vancouver Reinforcement Project?

A. The Company's preliminary estimate for the Vancouver Reinforcement Project is approximately $15.5 million.

2. Gate Station Improvement Projects

a. Camas Gate Station Rebuild Project

Q. Please describe the Camas Gate Station Rebuild Project.

A. The Camas Gate Station is a key custody transfer point in the Camas area, as it serves as a gate station between Williams Northwest Pipeline ("NWP") and NW Natural. At this station, gas is odorized and the pressure is reduced to deliver into the P04 Camas Transmission system. The scope of the project was a full modernization of Camas Gate Station, including the P04 inline inspection (ILI) launcher facility, replacement of the end-of-life odorizer with a new zero-emissions odorizer system, replacement of a bulk odorant storage tank with a modern tank that included full secondary containment, removal of a regulator building constructed in 1957 using asbestos-containing

materials, installation of custody-transfer grade check metering, and installation of a new, low-emissions, high-efficiency line heater system.

This project required a facility agreement with Williams NWP to utilize additional land to the east of the Company's approximately 1,500 square foot parcel to locate the gate station facilities. Due to the cost of the project exceeding $200,000 and the facility agreement with Williams NWP, NW Natural was required to take over regulation and overpressure protection at this station, which attributed to the bulk of the project's cost. The resulting project benefits customers by providing increased safety and protection from vehicle damages, modernization of the regulation facilities, reduction in emissions from odorization and line heating, and increased metering accuracy.

Q. What is the status of the Camas Gate Station Rebuild Project?

A. The Camas Gate Station Rebuild Project was put into service in October 2023. The alternatives analysis supporting the Camas Gate Station Rebuild Project is provided as Exh. DBK-SSJ-4.

Q. What was the total cost of the Camas Gate Station Project?

A. The total cost of the Camas Gate Station Project was $3.9 million, but only the net book value of the asset at the time of the upcoming rate effective date is included for cost recovery in this case.

b. Camas Gate Station Building Improvements Project

Q. Please describe the Camas Gate Station Building Improvements Project.

A. Before the 2023 Camas Gate Station Rebuild Project, a regulator building which dated from the station's original construction in 1957 was installed to provide noise reduction

for the station regulator runs. During the Camas Gate Station Rebuild Project, this building was removed due to conflicts with the station construction and the asbestos materials present in the building construction. With installation of the new gas regulators, aerodynamic noise has been noted at this station and in the adjacent neighborhood, leading to customer inquiries and crew callouts.

In response to customer noise complaints, the Company installed temporary noise curtains at the station. The temporary noise curtains are not designed for permanent installation, and are susceptible to wind and deterioration due to exposure to the sun. The Camas Gate Station Building Improvements Project will install a new steel-frame, insulated metal building, similar in footprint and scale to the original 1957 building. This building will reduce noise pollution and prolong the life of the regulator station equipment. An advanced insulation system will provide noise attenuation to ensure compliance with state and local codes.

Q. What is the status of the Camas Gate Station Building Improvements Project?

A. The project is currently in the Execution Phase. The alternatives analysis supporting the Camas Gate Station Building Improvements Project is provided as Exh. DBK-SSJ-5.

Q. What is the expected timing of the Camas Gate Station Building Improvements Project?

A. The Company expects to complete the Camas Gate Station Building Improvements Project in September 2025 (Pro Forma Year).

Q. What is the estimated total cost of the Camas Gate Station Building Improvements Project?

A. The Company's estimate for the Camas Gate Station Building Improvements Project is $1.3 million.

c. Deer Island Gate Station Improvements Project

Q. Please describe the Deer Island Gate Station Improvements Project.

A. The Deer Island Gate Station is a custody transfer station where gas from Williams NWP is delivered to the Company's system. The station delivers odorized gas to customers and Mist storage. As described later in our testimony, Mist storage benefits the Company's customers both in Oregon and Washington. This project will replace end-of-life odorization equipment with new, zero-emissions systems. Due to equipment obsolescence, the existing regulator runs will be replaced and re-configured to limit crew call-outs and increase reliability. Finally, check metering and metering upgrades for three station meters will be installed to provide situational awareness to NW Natural's Gas Control and System Modeling teams and to increase measurement accuracy.

Q. What is the status of the Deer Island Gate Station Improvement Project?

A. This project has not reached intake status with the Project Management Office. The Deer Island Gate Station Improvements Project is identified in the Company's 2025 Gate and Regional Stations 10-Year Plan, provided as Exh. DBK-SSJ-6.

Q. What is the expected timing for the Deer Island Gate Station Improvements Project?

A. The Company expects to complete the Deer Island Gate Station Improvements Project by October 2027, which would be classified as provisional capital in Rate Year 2.

Q. What is the preliminary total cost of the Deer Island Gate Station Improvements Project?

A. The Company's preliminary total cost of the Deer Island Gate Station Improvements Project is $0.6 million on a Washington-allocated basis. This is a preliminary estimate used for budgeting that relies on recent similar projects adjusted for inflation.

d. Felida Gate Station Rebuild Project

Q. Please describe the Felida Gate Station Rebuild Project.

A. The Felida Gate Station is a custody transfer station where gas from Williams NWP is delivered to customers in the Felida area. The station provides line heating, regulation, check metering and odorization for customers on the west side of the City of Vancouver. This project will replace an end-of-life injection pump odorizer with a new, zero-emissions odorizer system, and modernize the odorizer controls. To provide metering data to precisely measure odorant injection rates, the existing ultrasonic meter will be replaced with a modern, custody transfer grade meter. The new metering system will allow for finer control of odorization in warmer weather, and will improve measurement accuracy.

Q. What is the status of the Felida Gate Station Rebuild Project?

A. The Felida Gate Station Rebuild Project is identified in the Company's 2025 Gate and Regional Stations 10-Year Plan, provided as Exh. DBK-SSJ-6. This project has not reached intake status with the Project Management Office.

Q. What is the expected timing for the Felida Gate Station Rebuild Project?

A. The Company expects to complete the Felida Gate Station Rebuild Project by July 2028, which would be classified as provisional capital in Rate Year 2.

Q. What is the preliminary total cost of the Felida Gate Station Rebuild Project?

A. The Company's preliminary total cost of the Felida Gate Station Rebuild Project is $1.9 million. This is a preliminary estimate used for budgeting that relies on recent similar projects adjusted for inflation.

3. Metering and Line Heater Projects

a. West Vancouver Gate Metering Project

Q. Please describe the West Vancouver Gate Metering Project.

A. The West Vancouver Gate Station is a custody transfer gate station located in Clark County, northwest of downtown Vancouver. This station provides regulation, overpressure protection and odorization for gas deliveries from Williams NWP to the Vancouver area. This project consists of two phases. In the first phase, an end-of-life annubar-style meter will be replaced with a new ultrasonic meter. This meter is required to control the station's proportional-to-flow gas odorization system, and the existing meter is no longer supported by the manufacturer. A new meter will ensure reliability of the odorization system and the ability to maintain the meter in the future. In the second phase, a new low-emissions, high-efficiency line heater will be installed

to pre-heat gas deliveries prior to regulation. Due to the Joule-Thomson effect, gas is cooled when regulated to a lower pressure, and this cooling can result in low gas temperatures that can induce icing on downstream piping. At the West Vancouver Gate Station, icing has been noted on downstream piping, and this piping is at risk of frost heave, coating damage or mechanical damage due to ice accumulation.

The West Vancouver Gate Metering Project has been identified in the Company's 2025 Gate and Regional Station 10-Year Plan (Exh. DBK-SSJ-6). The Phase 2 West Vancouver Gate Line Heater Replacement Project is also shown to be completed in 2026 in the Company's 2025 Gate and Regional Station 10-year Plan, but the Company delayed the line heater project until 2027 due to resource constraints.

Q. What is the status of the West Vancouver Gate Metering Project?

A. Phase 1 of the West Vancouver Gate Metering Project is in the Intake phase with the Project Management Office. The Initial Project Charter for the Project Management Office is attached as Exh. DBK-SSJ-7. The project will be entering into the alternatives analysis phase and then the Plan Phase later in 2025. Phase 2, which is the installation of the line heater, will commence in 2026 as a separate, discrete project (West Vancouver Gate Line Heater Replacement Project) and has not yet reached the Intake status with the Project Management Office.

Q. What is the expected timing for the West Vancouver Gate Metering Project?

A. The Company expects to complete the West Vancouver Gate Metering Project in July 2026, which would be classified as Pro Forma capital in Rate Year 1. The Company expects to complete the West Vancouver Gate Meter Project Phase 2 (West Vancouver Gate Line Heater Replacement Project) in 2027.

Q. What is the estimated total cost of the West Vancouver Gate Metering Project?

A. The estimated total cost of the West Vancouver Gate Metering Project is $0.7 million.

b. Ridgefield Gate Line Heater Replacement Project and Battleground Gate Line Heater Replacement Project

Q. Please describe the Ridgefield Gate Line Heater Replacement Project and the Battleground Gate Line Heater Replacement Project.

A. The scope and timing of the Ridgefield Gate Line Heater Replacement Project and the Battleground Gate Line Heater Replacement Project are identical (they are just in different locations), so they are being discussed together. The Ridgefield Gate Station and the Battleground Gate Station are custody transfer gate stations where gas is delivered from Williams NWP to NW Natural in Clark County. Each station is responsible for gas regulation and overpressure protection. When natural gas is regulated from the higher pressure Williams NWP to NW Natural's high pressure distribution system, the temperature of the gas drops due to the Joule-Thomson effect. If the gas temperature drops below freezing, it can cause the surrounding piping and soil to freeze as well. Freezing and icing can result in equipment damage and frost heave. To ensure that the gas remains above freezing, it is pre-heated using a line heater prior to regulation. The line heaters installed at the Ridgefield and Battleground Gate Stations are glycol water bath type heaters, and over time have been determined to be undersized for their application due to flow demand through these gate stations. These projects will replace this equipment with new, high-efficiency, low-emissions vacuum boiler systems. These systems will add heating capacity and increase efficiency at the sites.

Q. What are the statuses of these projects?

A. The Ridgefield Gate Line Heater Replacement Project and the Battleground Gate Line Heater Replacement Project are identified in the Company's 2025 Gate and Regional Stations 10-Year Plan, provided as Exh. DBK-SSJ-6. These projects have not reached intake status with the Project Management Office.

Q. What is the expected timing for the Ridgefield Gate Line Heater Replacement Project and the Battleground Gate Line Heater Replacement Project?

A. The Company expects to complete the Ridgefield Gate Line Heater Replacement Project and the Battleground Gate Line Heater Replacement Project in August 2028, which would be classified as provisional capital in Rate Year 3.

Q. What is the preliminary total cost of the Ridgefield Gate Line Heater Replacement Project and the Battleground Gate Line Heater Replacement Project?

A. The preliminary total cost of the Ridgefield Gate Line Heater Replacement Project is $1.6 million. The preliminary total cost of the Battleground Gate Line Heater Replacement Project is $1.6 million. These are preliminary estimates used for budgeting that rely on recent similar projects adjusted for inflation.

4. West Vancouver Gate Odorant Depot Project

Q. Please describe the West Vancouver Gate Odorant Depot Project.

A. The Company purchases odorant in bulk shipments, usually consisting of a single trailer load that is shipped typically two to three times per year. The Company maintains 16 odorizer stations in Washington, which must be supplied with odorant to ensure proper odorization of gas. Due to supplier constraints and supplier equipment malfunctions, in January 2024 the Company had to utilize a backup odorant supplier to

transport a shipment when there was risk of running out of odorant in the Washington system and beyond. The West Vancouver Gate Station is a bulk odorant storage location, with a single 2,000-gallon bulk odorant storage tank, and a 120-gallon day tank used for day-to-day odorization. Company crews utilize the bulk storage tank to both supply the West Vancouver Gate Station and to fill other odorizers throughout the Company's service territory in Washington. This project will increase the capacity of the bulk odorant storage by adding a new, larger odorant tank at the West Vancouver Gate Station, to allow for local storage to provide risk mitigation for odorant shipment interruptions.

Q. What is the status of this project?

A. The project is identified in the Company's 2025 Gate and Regional Stations 10-Year Plan, provided as Exh. DBK-SSJ-6. This project has not reached intake status with the Project Management Office.

Q. What is the expected timing for the West Vancouver Gate Odorant Depot Project?

A. The Company expects to complete the West Vancouver Gate Odorant Depot Project in August 2027, which would be classified as provisional capital in Rate Year 2.

Q. What is the preliminary total cost of the West Vancouver Gate Odorant Depot Project?

A. The preliminary total cost of the West Vancouver Gate Odorant Depot Project is $1.2 million. This is a preliminary estimate used for budgeting that relies on recent similar projects adjusted for inflation.

5. Major Discrete Storage Facility Projects

a. Background of the Company's Storage Facilities

Q. Please identify the Company's storage facilities.

A. The Company has three storage facilities: Portland LNG, Newport LNG and Mist.

Q. Please describe the Company's Portland LNG facility.

A. The Portland LNG facility is a peak shaving facility located in Portland, Oregon and consists of a 600,000 dekatherms ("Dth") capacity storage tank, liquefaction facilities capable of processing about 2,150 Dth/day, and vaporization capacity of up to 133,920 Dth/day. This facility was constructed by Chicago Bridge and Iron and commissioned in 1969.

Q. Please describe the Company's Newport LNG facility.

A. The Newport LNG facility is a peak shaving facility located in Newport, Oregon and consists of a 1,000,000 Dth capacity storage tank, liquefaction facilities capable of processing about 5,500 Dth/day, and vaporization capacity of up to 100,000 Dth/day.[6] This facility was constructed by Chicago Bridge and Iron and commissioned in 1977.

Q. Please describe the Mist Storage Facility.

A. NW Natural's Mist Storage Facility, located in Mist, Oregon, began operations in 1989. It features a natural gas storage field consisting of seven different underground reservoirs, 21 injection/withdrawal wells, gathering lines, an operational hub called

[6] Because the Company's pipeline system limits Newport to serving the central coast and Salem market areas, the full 100,000 Dth/day vaporization rate is not achievable. Instead, 78,000 Dth/day is the effective limit on vaporization at Newport.

Miller Station,[7] and other related facilities. In all, the Mist Storage Facility is a 17.5 billion cubic feet ("Bcf") facility with 13.1 Bcf used to provide gas storage for core customers. We will provide much more detail about the Mist Storage Facility later in our testimony.

Q. Are the Company's storage facility projects allocated to both Washington and Oregon?

A. Yes. The Company allocates storage facility projects to both states. Gas acquisition, including both capacity and commodity costs, has historically been accomplished on a system basis, with customers in both states providing recovery of pipeline capacity and storage costs proportionally, even though gas from the storage facilities in Oregon is not physically deliverable to Washington. In that sense, storage is considered as a substitute for pipeline capacity, and the lower cost of storage as compared to pipeline demand is shared among the customers in both states.

Q. Please describe further how the storage facility projects affect the Company's Washington operations.

A. For its gas supply portfolio, NW Natural operates its three storage facilities in Oregon – Mist, Newport LNG, and Portland LNG – on an integrated basis with Washington. That is, gas supplies from those facilities work in tandem with supplies delivered by Willams NWP to serve the requirements of customers in Washington as well as in Oregon. For example, withdrawals from the Mist Storage Facility flow directly to

[7] Miller Station, with peak certificated injection and withdrawal capacities of 335 million standard cubic feet per day ("MMscfd") and 515 MMscfd, respectively, is the compressor station within the Mist Storage Facility that contains the operations and controls facility as well as the process equipment for conveying natural gas between the wells and utility pipelines, including the natural gas compression and dehydration systems.

Oregon customers in and around the Portland area, which in turn allows the Company to divert an equivalent volume of Williams NWP deliveries from interconnection points (gate stations) serving Oregon to gate stations serving Washington customers. Thus, while not physically connected or delivered to Washington, in this way, i.e., via displacement, Washington customers receive storage gas from the Company's storage facilities.

The gas supplies used to fill the three storage facilities come through Williams NWP and other upstream pipelines during the spring/summer/fall months when customer usage is low and the Company's agreements with Williams NWP are not fully utilized. Withdrawals from storage avoid the need for additional upstream pipeline capacity – and associated demand charges – during the winter months when customer usage is high. The costs of the Company's upstream pipeline agreements flow to Washington and Oregon customers through the purchased gas adjustment ("PGA") process. In the PGA, upstream pipeline demand charges are allocated between Washington and Oregon customers based on sales volumes. This allows the benefits created by storage through the reduction of upstream pipeline demand charges to flow to both states.

The treatment of storage on an integrated basis between Washington and Oregon is also reflected in the resource acquisition decisions determined in the Company's IRP process.

Q. Has the Commission approved or accepted the inclusion of the Company's storage facility projects in Washington rates?

A. Yes. The state allocation methodology has been in use since its first implementation in 2000 (UG-000073). The most recent application of the methodology was in the Company's 2021 rate case (UG-200994).

Q. How are the Company's storage facility projects allocated to Washington customers?

A. The Company's storage facility projects are allocated to Washington and Oregon customers on the basis of firm sales volumes. The Washington allocation factor for firm sales volumes is currently 10.97 percent. The Direct Testimony of Kyle T. Walker (Exh. KTW-1T) addresses the topic of allocation factors and their associated methodology.

b. Detailed Information About the Mist Storage Facility and the Natural Gas Market in the Pacific Northwest

Q. Please describe how the Mist Storage Facility operates, especially during the winter heating season and even more particularly during peak system demand.

A. The Mist Storage Facility's gas storage for core customers is about 14 percent of the gas the Company distributes through its gas sales in an average calendar year, and a higher percentage when focusing on just the winter months when the facility is actively withdrawing. The remaining 4.4 Bcf of the facility is not in customer rates and is currently contracted with other utilities, third-party marketers, and electric generators through the Company's interstate storage service ("ISS"); however, core customers have the right to recall this storage capacity on an as-needed incremental basis. Mist

recall is typically identified as the lowest reasonable cost option to serve customer needs in the IRP because NW Natural's core customers have the right to recall capacity increments at Mist at its depreciated net book value. The actual energy stored at the Mist Storage Facility depends on the energy content of the gas. In recent years, NW Natural has seen an uplift of between 6 percent to 9 percent with more energy-dense gas being shipped there on the pipeline system. This means the 17.5 Bcf Mist Storage Facility can store between 18.5 million Dth and 19.1 million Dth of natural gas. Figures 4 and 5 below are charts that outline the growth of the Mist Storage Facility over time and highlight its capacity and deliverability allocation between core customers (including recall capacity) and ISS.

Figure 4. Mist Storage Capacity

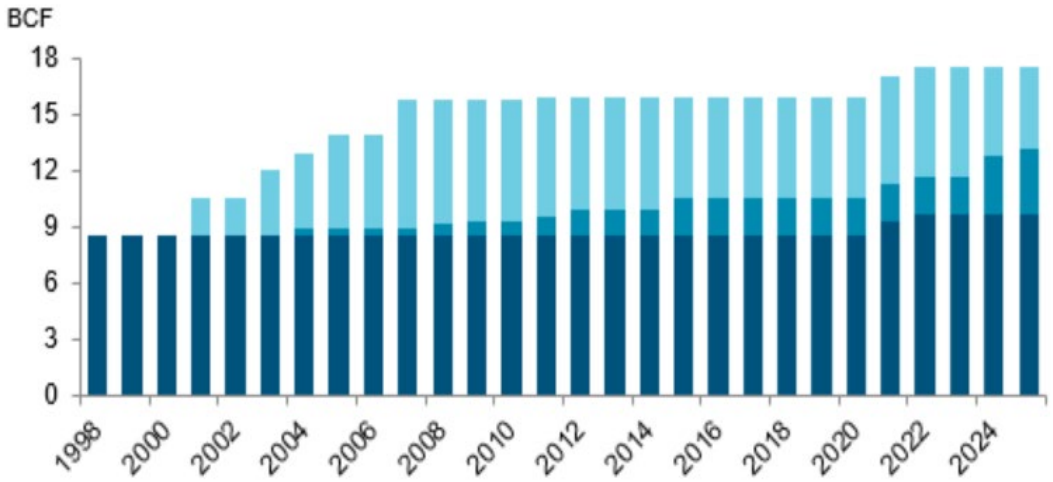
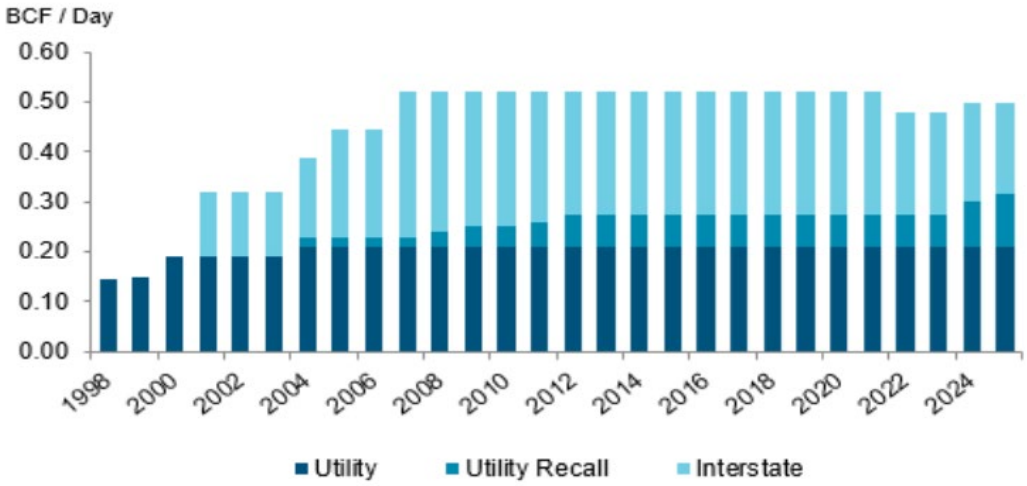


Figure 5. Mist Storage Deliverability



NW Natural's gas supply portfolio provides about 1 million Dth on a peak day. About one-third of this supply comes from the core utility service at the Mist Storage Facility. NW Natural's two LNG facilities contribute another 20 percent of that supply, bringing the total on-system supply to just over half of the Company's peak day. The Company's resource planning assumes all resources are available at their maximum output, so they need to be reliable. Utility peak day Mist Storage Facility supply of 340,000 Dth/day could serve over 460,000 average residential customers. The rest of the Mist Storage Facility, which is contracted through ISS, is also physically delivered onto the NW Natural system and those supplies could serve another 230,000 average residential customers.

Q. To what extent, if any, are upstream pipeline options available to replace the Company's reliance on the Mist Storage Facility?

A. NW Natural is connected exclusively to Williams NWP at all of its city gates. Williams NWP is fully subscribed, and no existing pipeline capacity is available to serve winter

season or peak day needs. In fact, the existing pipeline system has been strained past its design capacity during recent cold weather events. If NW Natural had to increase pipeline deliveries, it would need to participate in a pipeline expansion on Williams NWP. Such an expansion would require new pipe to be constructed either through the Columbia River Gorge or down the I-5 corridor between Canada and the NW Natural service territory. Pipeline capacity, while available 365 days a year, is not the best fit resource to satisfy the Company's needs that are currently met through use of the Mist Storage Facility. And when comparing the cost of such a pipeline expansion to costs of maintaining the Mist Storage Facility, the pipeline option would be orders of magnitude more expensive.

Figure 6 below is a map that shows the existing upstream pipeline and natural gas storage infrastructure in the Pacific Northwest.

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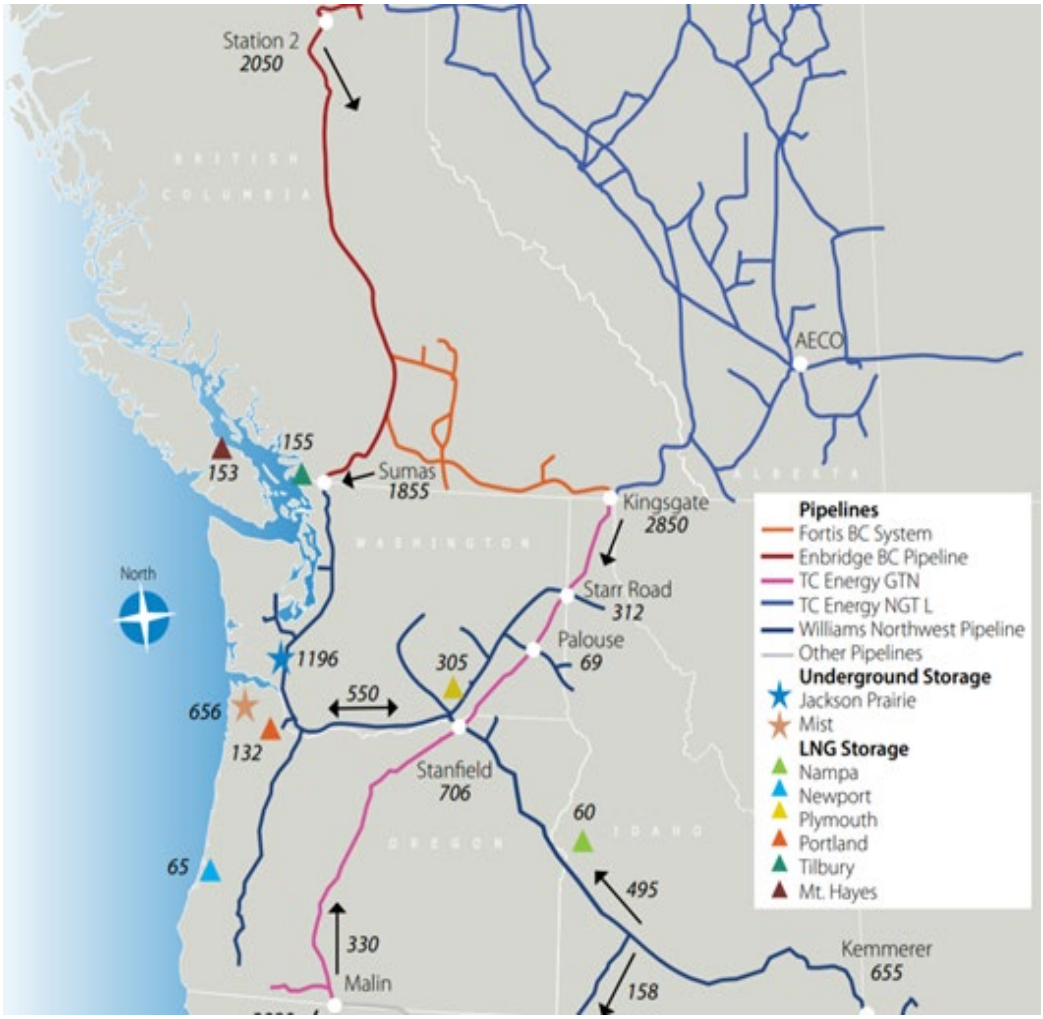
Figure 6. Pacific Northwest Interstate Pipeline and Storage Infrastructure



The Mist Storage Facility is designated as a tan star and noted as having 656,000 Dth/day of deliverability. This figure includes North Mist which is contracted exclusively to Portland General Electric. Williams NWP is shown in dark blue and runs down the I-5 corridor and through the Columbia River Gorge. The Woodfibre LNG facility is being constructed not far from the green triangle in southwestern British Columbia.

Q. How is the Woodfibre LNG facility expected to impact the gas market in the Pacific Northwest?

A. Pacific Northwest natural gas system infrastructure is highly utilized and operates past its design capacity on peak days. This system will become further constrained in 2027 when the Woodfibre LNG facility goes into service. Woodfibre is an LNG export terminal which is currently under construction in southern British Columbia and will liquefy 0.3 Bcf/day. Woodfibre LNG has already secured the pipeline capacity needed to supply the facility. This pipeline capacity is currently available in the broader market, but when the facility comes online it will be used solely by Woodfibre LNG. When the Woodfibre LNG facility comes online in 2027, it will have the impact of removing approximately 15 percent of the supply from the Sumas market.

Forward prices are up for the 2027-28 winter due to these fundamental market risks. An example of a similar energy constrained time period was in 2018, when the pipeline serving the Sumas market ruptured and flows from British Columbia were limited throughout the 2018/19 winter. Flows initially dropped by about one-third in November and December 2018, and then rebounded to a decrease of around 17 percent in January through March 2019. While the 2018/19 winter started out warmer than normal, February 2019 was quite cold and by early March 2019, regional storage was low and Sumas prices rose to approximately $200/Dth during a cold event.

The Company has seen growth in natural gas demand in the Pacific Northwest since 2018, and during this prior event certain industries shut down due to inadequate and/or prohibitively high-priced gas supplies. There is a chance the Company will see

demand destruction beginning in 2027 when the Woodfibre LNG facility comes online, especially if it is a cold winter.

Q. Is NW Natural doing anything with its gas supply portfolio to prepare for the expected impact of the Woodfibre LNG facility on the Pacific Northwest gas market?

A. Yes. At this time, NW Natural relies on 60,700 Dth/day of segmented pipeline capacity on Williams NWP as a peak day resource. Two things must happen for segmented capacity to be an effective resource. First, the path on Williams NWP cannot be constrained. Segmented capacity is not primary firm capacity, so constraints in the shipping path would not allow supplies to flow. Through analysis in its IRP, the Company notes that cold weather in the Pacific Northwest has historically caused pipeline dynamics that allow enough pipeline space for these supplies to flow. NW Natural is not expecting this dynamic to change when the Woodfibre LNG facility comes online in 2027.

Second, NW Natural needs to have sufficient liquidity in the Sumas spot (next day) market to purchase the 60,700 Dth/day of supplies. The Sumas market is already tight, and it can be difficult to procure this volume of supply in the current environment. When the Woodfibre LNG facility comes online, the Company expects liquidity to deteriorate past the level it would be comfortable relying on making purchases for a peak day.

Accordingly, NW Natural is planning to cease peak day reliance on segmented pipeline capacity when the Woodfibre LNG facility comes online in 2027. As a result, the Company's IRP currently indicates the need to recall Mist capacity in place of this

segmented capacity resource. A Mist recall of 60,000 Dth/day would shift this deliverability (and the related capacity) from NW Natural's ISS customers to its core customers. Assuming no other recalls in the interim, this would increase the core customer Mist Storage Facility portfolio from 340,000 Dth/day of deliverability to 400,000 Dth/day. In percentage terms, this would shift about 6 percent of NW Natural's peak day supply from pipeline resources to the Mist Storage Facility, thereby increasing the Company's reliance on the Mist Storage Facility to almost 40 percent of its portfolio on a peak day.

Q. Are there any other LNG export projects that could impact gas supplies in the West?

A. Yes. Construction is approximately 85 percent complete on the Costa Azul LNG facility, which is another LNG export facility on the West Coast. The Costa Azul LNG facility is located in Baja California, Mexico and will liquefy 0.4 Bcf/day in phase one which is expected to be in service in the summer of 2026. Phase two would add 1.6 Bcf/day, but it has not reached final investment decision. An outage on the El Paso pipeline in 2022/23 decreased flows into California and that, plus cold weather, drove prices up to approximately $50/Dth in the West. The Costa Azul LNG facility could have a similar impact. Figure 7 below is a map showing how Costa Azul LNG connects to the natural gas system in the Southwest.

Figure 7. Costa Azul LNG and Southwest Regional Pipelines

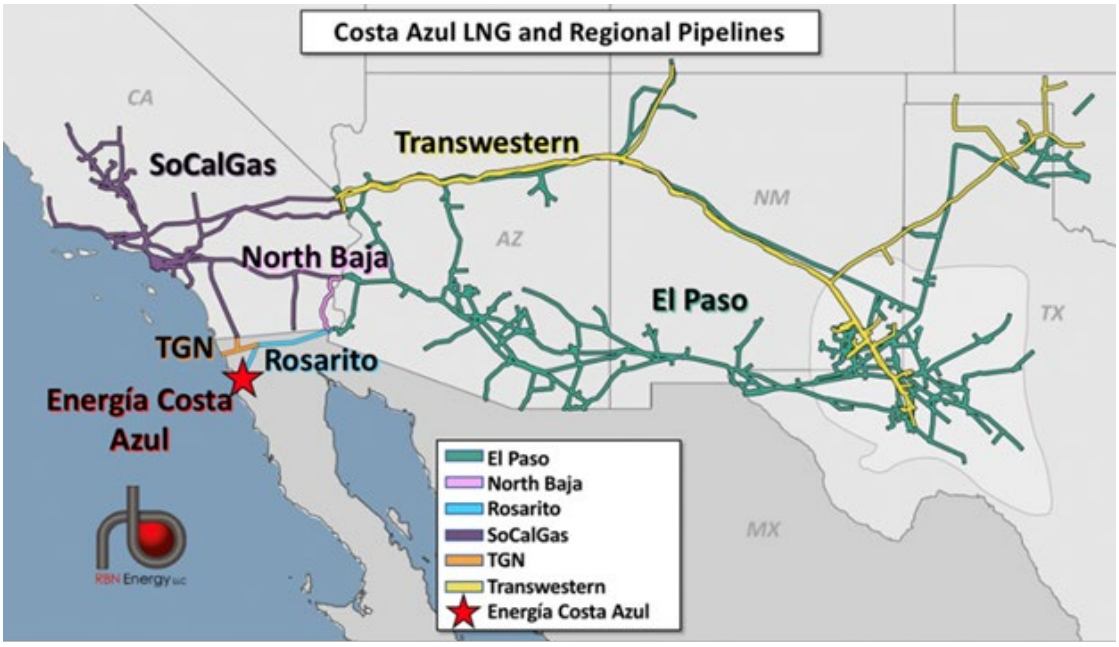
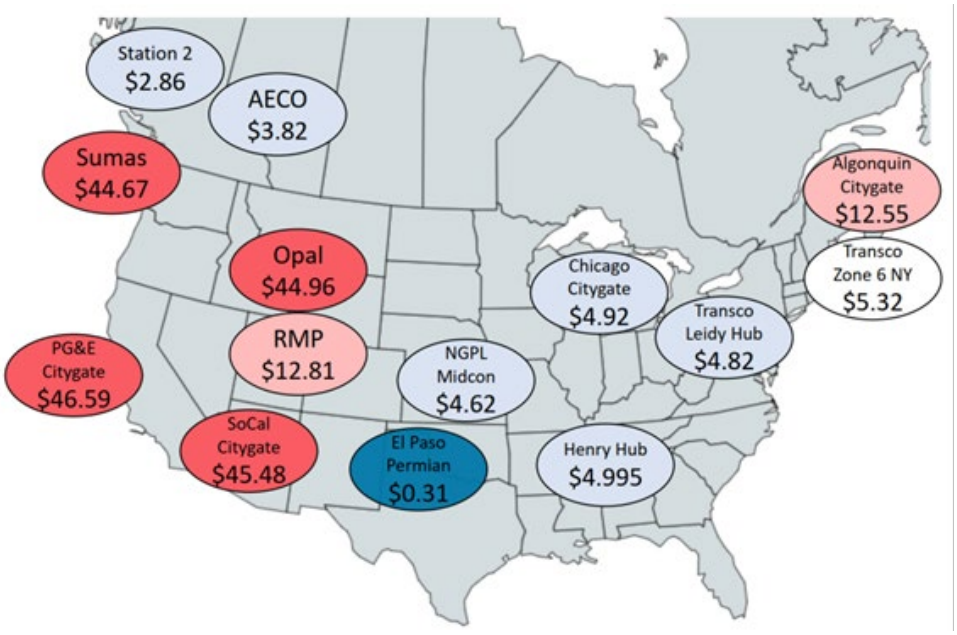


Figure 8 below is a spot market price map from December 9, 2022, that shows the impact of constrained infrastructure due to the outage on El Paso pipeline in 2022/23 in the West.

Figure 8. Spot Market Price Map December 9, 2022



Pricing in markets that NW Natural participates in, such as Sumas and Opal, are directly impacted by regional markets in California, while abundant gas supplies in Canada cannot be accessed in adequate quantities due to existing pipeline constraints.

c. Mist Projects

i. *Mist GC500 Turbine Compressor Replacement Project and Mist GC600 Turbine Compressor Replacement Project*

Q. Has the Company studied the Mist Storage Facility to identify areas of concern and needed improvements?

A. Yes. In June 2016, the Company completed an engineering facility assessment of the Mist Storage Facility ("2016 Mist Storage Facility Assessment") and identified a number of needed improvements to the facility to improve site reliability, resulting in the Mist Reliability Program.[8] The Company also completed a study of the compressor units in June 2020 ("2020 AECOM Compressor Study")[9] and a focused turbine compressor study in December 2022 ("2022 Burns and McDonnell Turbine Compressor Study" or "2022 Turbine Compressor Study").[10]

Q. Please describe the GC500 and GC600 compressor units at Miller Station of the Mist Storage Facility.

A. The GC500 unit (5,500 horsepower ("hp")) and GC600 unit (7,200 hp), installed in 1998 and 2001-2002, respectively, perform the bulk of the compressive work for withdrawal and injection activities when they are available for operation. Although

[8] Confidential Exhibit DBK-SSJ-8C is the 2016 Mist Storage Facility Assessment.

[9] Confidential Exhibit DBK-SSJ-9C is the 2020 AECOM Compressor Study.

[10] Confidential Exhibit DBK-SSJ-10C is the 2022 Burns and McDonnell Turbine Compressor Study.

each turbine compressor unit has the same three major components (i.e., a gas generator, a power turbine and a centrifugal compressor), they are not identical and have different operational strengths. The GC600 unit is more effective operating in lower compression ratios, such as early in the withdrawal season when gas reservoir pressures are higher. The GC600 unit also is used in connection with the Company's ISS; about one-third of its costs are allocated to core utility service and the other two-thirds of its costs are allocated to ISS. The GC500 unit is more effective operating in high compression ratios, such as later in the withdrawal season when the gas reservoir pressures are lower. The 2016 Mist Storage Facility Assessment recommended that the Company replace over a period of time the compressor units at Miller Station, which have exceeded their expected compressor core lifetime, in order to right-size the units for the facility's ongoing and future operations.

Q. How did the GC500 and GC600 compressor units perform after the Company completed the 2016 Mist Storage Facility Assessment?

A. The compressor units experienced multiple failures each year from the start of the 2018-2019 withdrawal season to present. The GC500 unit experienced several turbine engine failures, requiring complete removal of the unit for repair due to turbine blade fractures, oil leaks, gear failures and valve malfunctions, taking it out of operation for significant periods of time between Summer 2018 all the way up to the month prior to the planned GC500 unit's final decommissioning, where the unit experienced a power turbine failure. The GC600 unit experienced several turbine engine failures as well. A combustion chamber failure was found during an outage inspection in April 2019, resulting in a repair outage lasting 16 months. In order to meet operational needs for

two heating seasons, a leased turbine from Fortis BC was obtained. Since then, the GC600 unit had to be taken out of operation several times to address cracked vanes, failed combustion air seals, bleed valve failures, and oil leaks. Additionally, an ongoing problem with the acoustic-vibration harmonic response characteristics of the combustion chamber has plagued the small fleet of KC7 units, which is the GC600 unit's turbine engine model. These harmonics have resulted in field failures as soon as 10 days after returning to service, with a fleet outage of 67 percent.

Q. What caused those failures and outages?

A. The 2020 AECOM Compressor Study and the 2022 Burns and McDonnell Turbine Compressor Study found that the issues with the compressor units were caused by age, outdated and unsupported systems, mechanical fatigue, and non-ideal operation. The 2022 AECOM Compressor Study recommended modifying the GC500 turbine compressor and purchasing a GC600 turbine driver with upgrades to the latest service bulletins to be used as a cold spare. With three more years of operational experience with continued outages and reliance of the turbine compressor original equipment manufacturer ("OEM"), NW Natural became much more informed about the vulnerability associated with operating the existing turbine compressor units to supply storage gas to its customers. Based on that additional operational experience, the 2022 Turbine Compressor Study recommended replacing the end-of-life GC500 and GC600 turbines all together.

Q. Do you anticipate that the GC500 and GC600 turbine compressor units would continue to experience failures and outages without corrective action?

A. Yes. As both units have exceeded their useful life expectancy -- the GC500 unit currently has over 59,000 hours of operation and has been in service for over 27 years and the GC600 unit has over 48,700 hours of operation and has been in service for over 23 years – frequent failures and outages were expected to continue until corrective action was taken as many of the major core components are original and the OEM support for the two-shaft series turbine continues to diminish.

Q. What typically happens when the GC500 or GC600 units fail?

A. Failures commonly require the return of the turbine compressor core to the Maintenance Repair and Overhaul Center ("MROC") in Houston, Texas, consuming three to six months or more before it can be returned to service. The manufacturer, Siemens, does not offer any cores or core exchange program for the specific turbine configuration used at NW Natural, so during repair times there is no replacement compression at Miller Station. The absence of a core exchange program from Siemens became apparent in April 2019, when a combustion chamber failure was discovered resulting in a repair outage of 16 months. To ensure operational continuity for two heating seasons, NW Natural leased a turbine from Fortis BC. Siemens also does not carry substantial inventory to support the GC500 or GC600 turbine series. Parts are commonly made to order as needed, resulting in long lead times for parts and components. The make-to-order strategy can extend outages out past two years, as seen with other operators of the same series turbines found on NW Natural's GC500 and GC600 compressors. Due to the uniqueness of the GC500 and GC600 and make-

to-order strategy, an existing supply chain does not exist. In response to the poor OEM support, NW Natural in 2024 acquired two cold spares detailed further in this testimony.

Q. As a result of those continuing failures and outages, did the Company reevaluate and update the 2020 AECOM Compressor Study?

A. Yes. In December 2022, the Company completed the 2022 Turbine Compressor Study. Through the 2022 Turbine Compressor Study, NW Natural became much more informed about the vulnerability of operating the existing turbine compressor units to supply storage gas to its customers. As a result of the 2022 Turbine Compressor Study, the Company implemented the Mist GC500 Turbine Compressor Cold Spare Project and the Mist GC600 Turbine Compressor Cold Spare Project.

Q. Please describe the Mist GC500 and GC600 Turbine Compressors Cold Spare Projects.

A. The Company completed the Mist GC500 and GC600 Turbine Compressors Cold Spare Projects in 2024. Through those projects, the Company acquired a gas generator, a power turbine and standby spare parts from Siemens for each of the GC500 and GC600 turbine compressor units. The gas generator and power turbine operate at extreme conditions, such as high temperatures and speeds, which make those two components most at risk of major downtime. Acquiring these critical cold standby spares has mitigated the risk of prolonged outages down to less than a month (from a previous average downtime of three to six months) and has improved resiliency at Miller Station. It has been the most cost-effective and viable option for the most recent and upcoming winter seasons. Because many of the components are not new and

consist of multiple used out-of-service turbine packages to assemble a single serviceable cold spare, the acquisition of spare compressor components is a short-term, risk mitigation plan to extend the life of the GC500 and GC600 compressor units until the Mist GC500 and GC600 Turbine Compressors Replacement Projects are completed.

Q. Are the Mist GC500 and GC600 Turbine Compressors Cold Spare Projects a long-term solution for reliability at the Mist Storage Facility?

A. No. The Mist GC500 and GC600 Turbine Compressors Cold Spare Projects are necessary to ensure the immediate reliability of Mist only for the near term. This is evident as operational issues persist even with the GC500 and GC600 cold spares. For example, during an outage in Spring 2024, damage was found on the GC500 unit's gas generator that exceeded operating limits. Continued operation of the GC500 unit would have resulted in significant damage to the turbine end. Additionally at this time, it was identified that the GC600 unit was due for an overhaul of the cold section of its gas generator. Due to the historical frequency and lengthy outages of the GC500 unit, the utilization of the GC600 unit had increased significantly. With these discoveries during the Spring 2024 outage, the GC500 and GC600 units had their gas generator cold spares installed to allow operations to continue into the injection season. Without these cold spares, 82 percent of the compression horsepower would not have been available at the start of the injection season.

Within the first half of the injection season, the removed original GC500 gas generator was field-repaired, and the removed original GC600 gas generator was sent

to the MROC for an overhaul. In the latter half of the injection season, both gas generator cold spares installed during the Spring 2024 outage also experienced failures.

The cold spare GC500 unit failed in August 2024, but the repaired original GC500 gas generator was then available and reinstalled, enabling operations to complete the injection season. Although the GC600 unit was operational at this time, it is a high-flow, low-compression-ratio compressor and was not ideal for operation.

The cold spare GC600 unit was found to have failures during an outage in October 2024, as substantial damage was discovered in the combustion section of the cold spare GC600 unit's gas generator. The original GC600 gas generator removed in the Spring 2024 outage and sent for overhaul was still undergoing rework. To return the GC600 unit to service quickly, parts were taken from the original GC600 gas generator undergoing overhaul to field-repair the cold spare gas generator that is currently installed.

With continued operational failures, the Mist GC500 and GC600 Turbine Compressors Cold Spare Projects do not address the long-term viability of the GC500 and GC600 units. Namely, complete overall compressor skids have exceeded their operational lives, and failures and outages have already occurred and continue to occur. The existing turbine compressors are not supported by the OEM and there are several core components that are no longer able to be sourced globally even with the OEM's support.

Q. Has NW Natural's service territory recently experienced severe winter weather that highlights the importance of reliable operations at the Mist Storage Facility?

A. Yes. In mid-January 2024, NW Natural's service territory experienced severe winter weather, highlighting the importance of reliable operations at the Mist Storage Facility. On January 13, 2024, as temperatures dropped to 15°F in the Vancouver-Portland metro area, NW Natural delivered 9 million therms of natural gas to homes and businesses throughout its service territory, virtually matching its previous record set in December 2022 for a single gas day, and approximately doubling its average daily winter send out. NW Natural delivered approximately 8 million therms of natural gas for each of the following three days. In addition to matching a single gas day delivery record and sustaining high volumes of natural gas delivery to its customers, NW Natural also broke previous Mist Storage Facility send out records for five consecutive days and delivered over 4.5 million therms (421 MMscfd) of stored natural gas on January 13, 2024. During these types of cold weather events, the importance of the Mist Storage Facility cannot be overstated. It is absolutely crucial to ensuring that NW Natural can provide safe and reliable service to its customers throughout the winter months.

Q. What would be the impact on NW Natural customers if the GC500 unit or GC600 unit were to fail during such cold weather events?

A. During cold weather events, such as those the Company experienced in January 2024, NW Natural has estimated that the loss of the GC500 unit or GC600 unit would lead to a loss of gas service to approximately 200,000 customers (25 percent of its current customer count). Once NW Natural loses gas pressure to a customer, gas restoration

is a three-step process, with the third step of restoration only possible when system gas pressure is assured. The January 2024 cold weather would have caused repeated, daily low-pressure outages in the Company's distribution system and loss of service due to lack of pressure. It is estimated that the recent, January 2024 cold weather would have prohibited the start of service restoration for six days, should NW Natural have experienced failure of the GC500 unit or the GC600 unit at the beginning of the recent cold weather that the Company experienced.

The estimated time and resources required to complete service restoration for 200,000 customers, once weather warmed and system pressures were stabilized, is beyond any scale the Company has experienced. For reference, NW Natural has recent experience resourcing a smaller system outage. In that situation, after a Williams NWP gate station was damaged by a motor vehicle in White Salmon, Washington in December 2020, NW Natural lost service to nearly 5,600 customers in White Salmon and in Hood River and Odell, Oregon, and the restoration process took nearly one week with the mutual assistance of staff from neighboring utilities.

Q. Do the Mist GC500 and GC600 Turbine Compressors Replacement Projects address the long-term viability of the GC500 and GC600 units?

A. Yes.

Q. Please describe the Mist GC500 and GC600 Turbine Compressors Replacement Projects.

A. NW Natural is replacing the existing GC500 and GC600 compressors with two new turbine compressors with an established and active supply chain, with parts readily available to support the operational needs of NW Natural and the needs of its

customers. Removal of the existing GC500 and GC600 compressors also requires removal of their existing foundation, associated oil coolers, lube oil systems, gas coolers, gas scrubbers, piping and valves, intake filters, exhaust silencers, fuel gas filter, regulation and measurement equipment, electrical distribution and control panels and other associated items. As a replacement, NW Natural is installing a Solar Turbine ("Solar") Taurus 60 with two new turbine-driven compressors of approximately 15,400 brake horsepower ("BHP") (7,700 BHP each). The replacement work will include installing foundations for the new turbine/compressor packages, installing associated oil coolers, gas coolers, gas scrubbers, piping and valves, intake filters, exhaust silencers, electrical distribution and control panels, and other associated minor items.

NW Natural plans to replace the GC500 turbine compressor unit by October 2025 and the GC600 turbine compressor unit by December 2026. The Company will replace the GC500 unit first because it is the older unit and will use the GC600 unit to support injection operations during this time. During the next injection season (2026), the Company will replace the GC600 unit and will use the replacement GC500 unit to support operations during this time.

Q. Did the Company assess alternatives to the Mist GC500 and GC600 Turbine Compressors Replacement Projects?

A. Yes. The Company considered a variety of Solar turbine options; electric compression; and the 2020 AECOM Compressor Study's recommendation of modifying the GC500 turbine compressor package, installing the repaired original GC600 gas generator, and purchasing an identical GC600 gas generator with upgrades to the latest service bulletins to be used as a cold spare. The lack of available space for an expansion and

the wide range of operating pressures and flows drove careful consideration of each alternative. NW Natural immediately disqualified replacing the GC500 and/or GC600 with reciprocating compressors due to the lack of market availability of the needed unit size. The Company also disqualified using other turbine manufacturers such as Vericor, which offers lower horsepower one-off turbine packages that would have put the Company in the same predicament that it is trying to fix now, or Baker Hughes/GE, which offers well supported turbine package solutions in a much higher horsepower range that would have been oversized for NW Natural's needs.

Q. What Solar turbine options did the Company consider?

A. Solar originally suggested a Taurus 60 with a single compressor unit, but the maximum flow rate offered by a single compressor unit would have been below the flow rate required for multiple design cases and it would not have been able to achieve the necessary minimum flow rate.

The next option Solar turbine considered was a Taurus 70 with a singular compressor unit. The Taurus 70 solution faced similar constraints to that of the Taurus 60 when using a single compressor unit. Though the maximum flowrates could be met, it would have been oversized for the needed applications. Multiple minimum flow rate scenarios would not have been covered in the full range of design cases needed and would have required a new compressor building or an extension to the existing building.

Solar then proposed a tandem option using two compressors attached to a single gas turbine. This allowed the two compressors to operate in parallel or series, greatly

expanding the operational range to meet the full range of design case requirements. This became the selected option described above.

Q. Please explain why the Company did not select an electric compression option.

A. Although electric-driven compressors were evaluated as a potential option, it was not considered feasible for several reasons. First, any power outage would cause a complete shutdown of the units. Second, two power feeds from different sources would have likely been required to maintain power availability and reliability of the units during the peak seasons. Third, the cost of the electric driven compressor unit project at the needed size would have been comparable to the gas turbines. Fourth, to be able to maintain the electric driven compressor units running, a full-size back up power generator would have needed to be installed. Fifth, electric power rates in the area are some of the highest in the country.

Q. Why did the Company not select the 2020 AECOM Compressor Study recommendation of modifying the GC500 turbine compressor and purchasing a GC600 turbine driver with upgrades to the latest service bulletins to be used as a cold spare?

A. Simply stated, there were many notable disadvantages that far outweighed any interim and minimal improvement offered by the 2020 AECOM Compressor Study recommendation to replace the GC500 gas generator with a new Siemens SGT100 gas generator, rewheel the GC500 compressor for more efficiency and swap out the Fortis-owned gas generator of the GC600 unit with a NW Natural gas generator.

First, replacing the GC500's gas generator with a new Siemens SGT100 gas generator with the compressor rewheeled would have several long-term disadvantages.

Similar to the existing GC500's gas generator and overall package, a SGT100 gas generator installed in the GC500 package would be a one-of-a-kind solution. SGT100 gas generator fleets in the North/South American market do not exist. There are no field subject matter experts in the United States. SGT100 specific parts and cold spares do not have inventory in the North/South American market. Additionally, the rewheeling would not have any significant benefit to operations, the remainder of the skid would continue to be non-standard and supported poorly, and failure issues of auxiliary items would continue to occur.

Second, replacing the Fortis owned gas generator with the same newly repaired original NW Natural GC600 gas generator would have similar disadvantages to the SGT100 solution. This turbine compressor package is one of a kind, with only a few remaining units in operation in the world. NW Natural and the two other operators of this type of unit with the same model gas generator have had the same experiences with the lack of spare parts, reliability, support, and turnaround times of those units. The NW Natural gas generator for the GC600 unit has proven to be unreliable, and continued operations are unsustainable. Additionally, with the repeated failures of the GC500, the GC600 has been relied on more heavily. The GC600's run hours are approaching the same hours as the GC500. Based on the similarities of the two units and the track record of the GC500 unit, the same failures and reliability issues of the GC500 unit were expected and are being realized as the GC600 unit approaches the operating hours of the GC500 unit.

Third, the 2020 AECOM Compressor Study's recommendations rely on the existing turbine compressor vendor for support. The existing turbine compressor

vendor is a conglomeration of companies with no standards or asset management plan for legacy turbine compressor packages. This has proven to be a challenge for lifecycle support of the equipment, as every solution is a research and development exercise. This has led to more costly one-off experimental solutions and repeated failures to identify the true root cause corrective action.

Q. Please provide an overview and the status of the regulatory approval process before the Oregon Department of Energy's Energy Facility Siting Counsel ("EFSC").

A. On March 15, 2024, NW Natural filed an application with EFSC to amend the Company's current site certificate to allow for the replacement of the compressor units. Due to the need to complete this project as expeditiously as possible, NW Natural had already procured the GC500 compressor replacement and performed the final engineering in advance of site certificate approval. On August 15, 2024, EFSC issued a draft proposed order finding that NW Natural's application should be approved. A public comment period ensued through September 19, 2024, on which date EFSC held a public hearing. On November 21, 2024, EFSC issued a proposed order finding that NW Natural's application should be approved. On January 17, 2025, EFSC approved NW Natural's application to amend the Company's then-current site certificate to allow for the replacement of the entire GC500 and GC600 turbine compressor units.

Q. What is the status of the Mist GC500 and GC600 Turbine Compressors Replacement Projects?

A. The project is in the Execution phase. The alternatives analysis supporting the Mist GC500 and GC600 Turbine Compressors Replacement Projects is provided as Exh. DBK-SSJ-11.

Q. Do you have any additional updates on the status of the project?

A. Yes. The Company's Engineering, Procurement and Construction ("EPC") contractor began decommissioning, isolation and excavation activities early, on February 24, 2025, due to an unplanned GC500 failure. Currently, the GC500 unit and the balance of plant equipment has been decommissioned and removed from service. The GC700 unit, which is the new Solar turbine compressor replacing the GC500 unit, and the new balance of plant equipment have arrived at site and installation between the system and the integration to the existing facility is ongoing. Substantial completion of the GC700 unit is expected in early September 2025, with it being in-service and used and useful in early October 2025.

The GC600 unit is currently still in service and operational. Early procurement for the GC800 unit, which is the new Solar turbine compressor replacing the GC600 unit, is complete and is set to arrive on site in April 2026. The GC800 unit is expected to be installed, in service and used and useful by December 2026.

Q. What is the estimated total cost of the Mist GC500 and GC600 Turbine Compressors Replacement Projects?

A. The GC500 Replacement Project is a 100 percent utility asset. The total cost of the Mist GC500 Turbine Replacement Project (GC700) is expected to be approximately

\$6.6 million on a Washington-allocated basis. The GC600 Replacement Project (GC800) is currently a 33 percent utility asset. The total utility cost of the Mist GC600 Turbine Replacement Project is expected to be approximately \$1.6 million on a Washington-allocated basis.

ii. Mist Main Power Feed Replacement Project

Q. Please describe the Mist Main Power Feed Replacement Project.

A. Miller Station is currently fed from a substation with above-ground 12.5kV power lines that run along the highway to NW Natural's meter. From there, a NW Natural-owned 12.5kV power line is fed up to Miller Station. The conductors are end of life, use above-ground junction boxes, and have been damaged and repaired twice. For this project, the electric utility will construct a new substation located along the mainline near an existing electrical vault. The substation will connect Miller Station directly with the 115kV lines from Bonneville Power Administration, thus bypassing the 12.5kV lines that run along the highway. This work is being initiated and requested by NW Natural to improve reliability and resiliency of the Company's winter operations. The electric utility is requiring the Company to pay for this project.

Q. What is the status of the Mist Main Power Feed Replacement Project?

A. The Mist Main Power Feed Replacement Project is currently in the Assess phase with the Project Management Office. The Initial Project Charter is attached as Exh. DBK-SSJ-12. The Company is currently working on an alternatives analysis for this project.

Q. What is the timing of the Mist Main Power Feed Replacement Project?

A. The Company expects to complete the Mist Main Power Feed Replacement Project by October 2026, which would be moved into rates in Rate Year 2 because the Company is not seeking provisional capital in Rate Year 1.

Q. What is the estimated total cost of the Mist Main Power Feed Replacement Project?

A. The estimated total cost of the utility portion of the Mist Main Power Feed Replacement Project is approximately $0.5 million on a Washington-allocated basis.

iii. Mist Miller Bruer/Flora Gathering Separator Upgrades Project

Q. Please describe the Mist Miller Bruer/Flora Gathering Separator Upgrades Project.

A. At the inlet of Miller Station for the northern reservoirs—Flora, Bruer, and Meyer—four separators installed as early as 1988 were designed to remove free water, slugs, and particulates before gas enters the compression and dehydration systems. Over time, process conditions have changed, with increased liquid loading and higher flow rates leading to the existing separators becoming inadequate for current operating demands. As part of this project, the separators will be replaced with new separators that match the current process demands. This will ensure reliable operation and protect downstream equipment. Additionally, the scope includes replacing two end-of-life ultrasonic meters used for inventory and flow measurement, which are no longer supported by the OEM, do not meet NW Natural's metering accuracy requirements, and do not meet current industry best practices.

Q. What is the status of this project?

A. The Mist Miller Bruer/Flora Gathering Separator Upgrades Project is identified in the Company's 2025 Mist Gas Storage Facility 10-Year Plan, provided as Exh. DBK-SSJ-13. This project has not reached intake status with the Project Management Office.

Q. What is the timing of the Mist Miller Bruer/Flora Gathering Separator Upgrades Project?

A. The Company expects to complete the Mist Miller Bruer/Flora Gathering Separator Upgrades Project by August 2027, which would be classified as provisional capital in Rate Year 2.

Q. What is the preliminary total cost of the Mist Miller Bruer/Flora Gathering Separator Upgrades Project?

A. The preliminary total cost of the utility portion of the Mist Miller Bruer/Flora Gathering Separator Upgrades Project is approximately $0.4 million on a Washington-allocated basis.

iv. Mist Miller Bruer/Flora/Meyer Metering Upgrades Project

Q. Please describe the Mist Miller Bruer/Flora/Meyer Metering Upgrades Project.

A. The Mist Miller Bruer/Flora/Meyer Metering Upgrades Project involves the phased replacement of five ultrasonic meters and eight senior fitting orifice meters across the Bruer/Flora/Meyer wellpads due to end-of-life concerns. The existing ultrasonic meters are obsolete, no longer supported by the OEM, and do not meet NW Natural's metering accuracy requirements. Similarly, the eight Daniel Senior Orifice Fitting meters, located downstream of the wellhead separators, are several decades old with limited documentation and are showing signs of wear. The lack of traceability, aging

hardware, and observed degradation of the orifice meters warrant a full replacement. These replacements will ensure inventory accuracy and prevent the overflow of individual injection-withdrawal wells, leading to continued reliable and safe operations.

Q. What is the status of this project?

A. The Mist Miller Bruer/Flora/Meyer Metering Upgrades Project is identified in the Company's 2025 Mist Gas Storage Facility 10-Year Plan, provided as Exh. DBK-SSJ-13. This project has not reached intake status with the Project Management Office.

Q. What is the timing of the Mist Miller Bruer/Flora/Meyer Metering Upgrades Project?

A. The Company expects to complete the Mist Miller Bruer/Flora/Meyer Metering Upgrades Project by July 2027, which would be moved into rates in Rate Year 2 because the Company is not seeking provisional capital in Rate Year 1.

Q. What is the preliminary total cost of the Mist Miller Bruer/Flora/Meyer Metering Upgrades Project?

A. The preliminary total cost of the utility portion of the Mist Miller Bruer/Flora/Meyer Metering Upgrades Project is approximately $0.3 million on a Washington-allocated basis.

v. Mist Calvin Creek Gathering Separator Upgrades Project

Q. Please describe the Mist Calvin Creek Gathering Separator Upgrades Project.

A. At the inlet of Miller Station serving the southern reservoirs, no separators are currently installed to remove free water, slugs, and particulates before gas enters the compression and dehydration systems. Since the original installation, process conditions have

changed significantly, with increased liquid loading making the current configuration inadequate. In low-flow scenarios, free liquids can accumulate, and when flow increases, liquid slugging may occur, posing a risk of damage to upstream equipment. The Mist Calvin Creek Gathering Separator Upgrades Project addresses those risks by installing appropriate inlet separation to align with current operating conditions and protect downstream systems.

Q. What is the status of the Mist Calvin Creek Gathering Separator Upgrades Project?

A. The Mist Calvin Creek Gather Separator Upgrades Project is identified in the Company's 2025 Mist Gas Storage Facility 10-Year Plan, provided as Exh. DBK-SSJ-13. This project has not reached intake status with the Project Management Office.

Q. What is the timing of the Mist Calvin Creek Gathering Separator Upgrades Project?

A. The Company expects to complete the Mist Calvin Creek Gathering Separator Upgrades Project by October 2028 (Rate Year 3).

Q. What is the preliminary total cost of the Mist Calvin Creek Gathering Separator Upgrades Project?

A. The preliminary total cost of the utility portion of the Mist Calvin Creek Gathering Separator Upgrades Project is approximately $0.2 million on a Washington-allocated basis.

vi. Mist Miller Air Compressor and Receiver Tank Upgrades Project

Q. Please describe the Mist Miller Air Compressor and Receiver Tank Upgrades Project.

A. A compressed air usage study completed in 2024 confirmed that the current instrument air system can support existing emergency shutdown ("ESD") events and plant operations, but it lacks capacity for any future expansion beyond the Mist GC500 and GC600 Turbine Compressors Replacement Projects. Following the Mist GC500 and GC600 Turbine Compressors Replacement Projects, no margin will remain for additional equipment, valves or new air users. To address this limitation and ensure system reliability, especially during ESD events, this project will install a new air compressor system sized to accommodate both current and upcoming demands. A new air receiver will also be added to provide reserve capacity, enabling a full station ESD and safe transition during a power outage.

Q. What is the status of the Mist Miller Air Compressor and Receiver Tank Upgrades Project?

A. The Mist Miller Air Compressor and Receiver Tank Upgrades Project is identified in the Company's 2025 Mist Gas Storage Facility 10-Year Plan, provided as Exh. DBK-SSJ-13. This project has not reached intake status with the Project Management Office.

Q. What is the timing of the Mist Miller Air Compressor and Receiver Tank Upgrades Project?

A. The Company expects to complete the Mist Miller Air Compressor and Receiver Tank Upgrades Project by July 2027 (Rate Year 1).

Q. What is the preliminary total cost of the Mist Miller Air Compressor and Receiver Tank Upgrades Project?

A. The preliminary total cost of the Mist Miller Air Compressor and Receiver Tank Upgrades Project is approximately $0.2 million on a Washington-allocated basis.

d. Newport LNG Facility Projects

i. Newport LNG Pretreatment Improvements Project[11]

Q. Please describe the Newport LNG Pretreatment Improvements Project.

A. Following the completion of the Company's 2022 Newport LNG Pretreatment Regen Optimization Project, which coincided with the early planning phase of the Newport LNG Cold Box Replacement Project (discussed later in this testimony), the Company's engineering consultant recommended additional improvements to the pretreatment system prior to replacement of the Newport LNG Cold Box. The memorandum provided by consultant Sanborn, Head & Associates ("Sanborn Head"), dated May 5, 2023, is provided as confidential Exh. DBK-SSJ-14C.

The Newport LNG Cold Box Replacement Project was presented in the Company's 2018 IRP Update (UG-170911). Upon receipt of the recommendation to build more improvements to the Newport LNG pretreatment system, the Company updated the cost-of-service analysis for the Newport LNG Cold Box Replacement Project. The memorandum summarizing the updated cost of service analysis is provided as Exh. DBK-SSJ-15. The Newport LNG Pretreatment Improvements Project included two changes to the gas pretreatment system at the Newport LNG facility. The

[11] The Newport LNG Pretreatment Improvements Project previously was referred to as the Newport LNG Molecular Sieve Vessels Repair/Upgrade Project.

first change was a new thermal oxidizer system, in order to improve the efficiency of the existing regeneration gas system. The second change was the replacement of the molecular sieve media in the dehydration and carbon dioxide removal systems, as the molecular sieve was at end of life. In addition, small valve and piping changes were made to add safety features during the installation of the molecular sieve.

Q. What is the purpose of the Newport LNG Pretreatment Improvements Project?

A. As noted above, during the front-end engineering design phase of the Newport LNG Cold Box Replacement Project (discussed later in this testimony), the design contractor, Sanborn Head, recommended two modifications to the existing gas pretreatment system, prior to installing the new cold box. The recommendations were provided in a project memo, to ensure the quality of the natural gas being processed by the new cold box equipment was within the parameters of the new cold box. Ensuring the gas quality is within specifications reduces variability in contractor bids, reduces performance risk for the new cold box system, and allows the Company to secure a performance guarantee by the cold box vendor. The Newport LNG Pretreatment Improvements Project was designed to accomplish these recommendations by optimizing dehydration and carbon dioxide removal from the liquefaction gas stream. The pre-existing gas pretreatment system used a molecular sieve media to remove water and carbon dioxide from natural gas. That media had a finite lifetime and had to be replaced when it became no longer effective. This project replaced the media with new media that allows the system to perform to the specifications of the new cold box.

During liquefaction operations, the molecular sieve media also must be regenerated with high-temperature natural gas. The successful operation of the

regeneration system is a key concern in the design of the new cold box, as inadequate regeneration of the molecular sieve media would result in break-through of carbon dioxide or water, which would cause freezing and plugging in the new cold box. By installing the thermal oxidizer, the regeneration gas system increased flow through the gas pretreatment system, which enhances the regeneration capabilities. In addition, this system allows for regeneration of the media while the liquefaction process is offline, an ability that allows the plant to test systems, perform additional molecular sieve regeneration, and increase reliability without running the entire liquefaction process.

Q. What is the status of the Newport LNG Pretreatment Improvements Project?

A. The Newport LNG Pretreatment Improvements Project was completed in December 2024.

Q. What is the total cost of the Newport LNG Pretreatment Improvements Project?

A. The total cost of the Newport LNG Pretreatment Improvements Project was approximately $0.7 million on a Washington-allocated basis.

ii. Newport LNG Plant Supply Generator Project

Q. Please describe the current emergency generator configuration at the Newport LNG facility, and the need for emergency power.

A. A single 625kW natural gas standby generator is located at the Newport LNG facility. This generator is capable of powering the plant's critical electrical systems, safety systems and LNG tank boil-off compression during a power outage. During a power outage, the LNG tank pressure must be maintained below the maximum allowable operating pressure, which is accomplished using two boil-off compressor units that can be run using generator power. However, other systems, including the LNG

vaporization system, are unavailable when using emergency power due to the large electrical loads required by the LNG pumps and LNG vaporizers. During a power outage, the plant can safely stay in "holding mode," but is unable to deliver LNG gas from storage to customers in volumes larger than the tank boil-off, which is a minimal amount of supply. During a winter event in January 2024 when the Newport LNG facility should have been vaporizing LNG at maximum capacity to support customer loads, the facility experienced a multi-day power outage during which it stayed in "holding mode," and was not able to deliver storage gas.

Q. Please describe the Newport LNG Plant Supply Generator Project.

A. The Newport LNG Plant Supply Generator Project will evaluate several alternatives to provide backup electrical power, to allow the Newport LNG facility to operate the vaporization system during a power outage. Due to the large electrical loads required, it is expected that a new generator will be installed in parallel with the existing standby generator that is currently sized for the critical plant "holding" electrical loads. This project will install a new standby generator to supply power to the Newport LNG facility for the operation of vaporization equipment in the event of the loss of utility power. The ability to provide peak-shaving natural gas supply to utility customers, even when no utility power is available, will mitigate the higher costs otherwise paid by customers for spot gas supply to support the system during cold weather events.

Q. What is the status of this project?

A This project is in the Assess phase. The Initial Project Charter is included as Exh. DBK-SSJ-16. The Company is currently working on an alternatives analysis for this project.

Q. What is the timing of the Newport LNG Plant Supply Generator Project?

A. The Company expects to complete the Newport LNG Plant Supply Generator Project by December 2026, which will be included in rates in Rate Year 2.

Q. What is the estimated total cost of the Newport LNG Plant Supply Generator Project?

A. The total cost of the Newport LNG Plant Supply Generator Project is expected to be approximately $0.3 million on a Washington-allocated basis.

iii. Newport LNG Cold Box Replacement Project

Q. Please describe the purpose of the Newport LNG Cold Box.

A. The Newport LNG Cold Box is an essential component in the Newport LNG liquefaction plant, as it is where natural gas is cooled to cryogenic temperatures to convert the gas to liquid. Once liquefied, it is pumped from the Newport LNG Cold Box to the onsite insulated storage tank where it can later be used as wintertime peaking supply and also a source of supply for emergency situations and pipeline maintenance.

Q. What is the current status of the Newport LNG Cold Box?

A. The Cold Box at Newport LNG is more than 48 years old. This places it well past its nominal 25- to 30-year design life, and it is currently showing signs of its age through performance problems. In particular, contamination has fouled the interior of the heat exchangers, causing differential pressure in the system that is higher than design limits, reducing production capacity.

Q. Please describe the operation of the Newport LNG Cold Box leading up to its current performance problems.

A. While an initial consultant recommended replacing the Newport LNG Cold Box in a 2014 study, it was later determined the estimate they provided for the cost of replacement was drastically low. Additionally, in 2016 NW Natural installed a new pretreatment system to address high CO_2 in the supply of gas, which was making it through the liquefier and into the LNG tank. The new pretreatment process dramatically improved the quality of gas entering the Newport LNG Cold Box. However, the original pretreatment design required additives such as methanol to be injected ahead of the Newport LNG Cold Box to absorb moisture. The methanol was then removed after liquefaction. Although that was no longer required with the new pretreatment process, without the additive, contaminants were able to easily foul the Newport LNG Cold Box causing increased differential pressure in the system and reducing production. Inspections to understand this issue revealed contaminants on the interior surfaces within the Newport LNG Cold Box heat exchangers, which compound flow restriction issues caused by poor gas quality entering the system. The differential pressure is higher than design allows in the first two exchangers within the Newport LNG Cold Box. This is believed to be due to several issues, including internal contamination upon inspection. The Newport LNG Cold Box itself is not the only contributor to operational issues, as higher levels of heavy hydrocarbons are contained within the gas stream than were present at the time of the original design of the facility. Heavier hydrocarbons tend to freeze at higher temperatures and can create blockages

in the system, which also contribute to higher operating pressures within the Newport LNG Cold Box.

Q. Please describe the Newport LNG Cold Box Replacement Project.

A. The Company is replacing the Newport LNG Cold Box at the Newport LNG facility. NW Natural presented the Newport LNG Cold Box Replacement Project on pages 29-37 of its 2018 IRP Update filed in docket UG-170911 on March 1, 2021 (Exh. DBK-SSJ-17), documented its exemption from completing the alternatives analysis form in August 2022 (Exh. DBK-SSJ-18) and provided further update and analysis in a Company Memorandum dated September 13, 2023 (Exh. DBK-SSJ-15).

Q. Why is the Newport LNG Cold Box Replacement Project necessary?

A. The Newport LNG Cold Box Replacement Project is necessary to be able to continue to rely upon Newport LNG as a firm resource to serve NW Natural's current needs. Should the Newport LNG Cold Box fail, the ramifications to the plant would be significant. A replacement unit would require approximately two years to install. Repairs to this type of equipment can be very costly or even impractical. If a failure were to occur at the beginning of the production season, this would leave the facility without a reasonable means to refill the storage tank. As a result, all remaining LNG may boil off prior to equipment replacement (depending on the tank level at the time of failure), which in turn, would allow the large LNG tank to warm significantly, inducing stress on the tank due to thermal expansion. Customers would also be left

without the benefit of backup storage to support periods of peak demand during cold weather or other supply constraints.

Q. Did NW Natural assess alternatives to the Newport LNG Cold Box Replacement Project in its 2018 IRP Update?

A. Yes. The Company assessed two alternatives: (A) Contract with Williams NWP for additional pipeline capacity from Sumas south to city gates on Williams NWP's Grants Pass Lateral ("Alternative A"); and (B) Construct a 25-mile-high pressure transmission facility between Newburg and the Central Coast Feeder coupled with additional Mist Recall ("Alternative B"). As stated in its 2018 IRP Update, the Company determined that even the lower end of the *annual* costs of Alternative A was higher than the *total* capital costs of the Newport LNG Cold Box Replacement Project. The Company also determined that the total cost of the Newport LNG Cold Box Replacement Project was *multiple times less than* Alternative B from the perspective of the present value of revenue requirement of portfolios over the planning horizon.

Q. Did the Commission accept the 2018 IRP Update filing that included the Newport LNG Cold Box Replacement Project?

A. Yes. The Commission, by letter dated March 31, 2021, accepted the Company's filing that included the Newport LNG Cold Box Replacement Project.

Q. What is the status of the project?

A. The project is currently in the Planning Phase.

Q. What is the timing of the Newport LNG Cold Box Replacement Project?

A. The Company currently expects to complete the Newport LNG Cold Box Replacement Project by April 2027, which will be included in rates in Rate Year 2. The Company

had expected to complete the project in October 2026, but recently discovered that the pretreatment media vessels suffered insulation failures, thus allowing carbon dioxide and moisture to bypass the treatment media. This bypass results in inlet feed gas composition that does not satisfy the performance criteria for the cold box design. To ensure the cold box performance remains as designed, the vessels will be re-insulated with a new liner system and insulation to prevent the gas bypass and correct the feed gas composition. This work is described in the next project below.

Q. What is the estimated total cost of the Newport LNG Cold Box Replacement Project?

A. The total cost of the Newport LNG Cold Box Replacement Project is expected to be approximately $4.5 million on a Washington-allocated basis.

iv. Newport LNG Molecular Sieve Vessels Repair and Upgrades Project

Q. Please describe the function of the Newport LNG Molecular Sieve Vessels.

A. The molecular sieve vessels are part of the gas pretreatment process and their function is to scrub out impurities such as water, CO_2, and gas odorants from the natural gas flow stream before the gas is cryogenically cooled by the cold box equipment for storage in the LNG plant storage tank. If these impurities are not removed prior to the gas liquefaction process, they risk fouling or freezing within the heat exchangers in the cold box and thus shutting down or damaging the liquefaction process.

Q. Please describe the Newport LNG Molecular Sieve Vessels Repair and Upgrades Project.

A. The Company had experienced small amounts of CO_2 slipping by the molecular sieves for several years. After the vessels were emptied and new media installed in 2024, the CO_2 removal rate unexpectedly dropped and heat leakage through the insulated vessels to the outer shell of the vessels increased. The Company consulted owners' engineers and a consulting engineering firm, as well as a molecular sieve vendor, to perform a root cause analysis and develop a return to service plan. After inspecting the vessels, the Company was advised that the vessel internal insulation had failed, pulling back from the wall of the vessels and thereby allowing process gas to bypass contact with the molecular sieve media. To address this failure, the dehydration and CO_2 removal vessels need to be modified to repair the internal insulation failure and eliminate the ability for process gas to bypass the molecular sieve media. This project will remove the vessels from service, and a pressure vessel contractor will install internal steel liners and new insulation in the vessel. These modifications are designed to enhance the high-temperature regeneration performance and ensure that process gas cannot bypass the molecular sieve media.

Q. Did the Newport LNG Molecular Sieve Vessels Repair and Upgrades Project delay the schedule for the Newport LNG Cold Box Replacement Project discussed earlier in your testimony?

A. Yes. Due to the need to repair and upgrade the molecular sieve vessels, the Company informed the Newport LNG Cold Box Replacement Project contractor of the need to delay the replacement of the cold box by one year.

Q. Why was it necessary to delay the schedule for the Newport LNG Cold Box Replacement Project?

A. The Company was concerned that malfunctioning molecular sieve vessels could lead to the new cold box not performing as designed by the Company's EPC contractor, which could have voided the warranty of the new cold box equipment. As the Company is responsible for the process gas composition in the equipment warranty, if the process gas cannot be held within the specifications of the new cold box, the cold box vendor would be released from their equipment performance obligation.

Q. What is the status of the project?

A. The project is currently in the Planning Phase in the Project Management Office. The alternatives analysis supporting the Newport LNG Molecular Sieve Vessels Repair and Upgrades Project is provided as Exh. DBK-SSJ-19.

Q. What is the timing of the Newport LNG Molecular Sieve Vessels Repair and Upgrades Project?

A. The Company expects to complete the Newport LNG Molecular Sieve Vessels Repair and Upgrades Project by June 2026 (Proforma Period) for inclusion in rates in Rate Year 1.

Q. What is the estimated total cost of the Newport LNG Molecular Sieve Vessels Repair and Upgrades Project?

A. The total cost of the Newport LNG Molecular Sieve Vessels Repair and Upgrades Project is expected to be approximately $0.3 million on a Washington-allocated basis.

e. Portland LNG Facility Projects

i. Portland LNG Electrical Distribution Upgrades Project

Q. Please describe the function of the Portland LNG electrical distribution system.

A. The Portland LNG electrical distribution system consists of the electrical supply to the Portland LNG facility, including switchgear, circuit breakers, motor control center equipment and an electrical transformer. This system provides power to the plant from the electric utility to run critical motor loads, including boil-off compression to manage tank pressure, and the LNG pumps and vaporizers blowers, to deliver liquefied natural gas to the vaporization system for customer use.

Q. Please describe the Portland LNG Electrical Distribution Upgrades Project.

A. A third-party engineering load study found that operating both LNG pumps P-1 and P-2 and all three vaporizers (H-5, H-6 and H-7) simultaneously would result in a load of 1270A, which exceeds the Motor Control Center current rating of 1200A, risking a 480V electrical outage. The incoming switchgear that provides utility power is sized for 1000kVA, which is undersized for the full load condition. As a result, the Portland LNG facility is unable to run at full capacity, and vaporization capacity has been temporarily reduced from 133,920 Dth/day to 100,440 Dth/day. This project will update the 480V electrical distribution system at the Portland LNG facility, replacing the existing 1000kVA transformer and motor control center with a new 1500kVA transformer, manual transfer switch and incoming 480V switchgear. The new electrical infrastructure will allow the plant to return to its full vaporization capabilities of 133,920 Dth/day.

Q. Why is it necessary to complete the Portland LNG Electrical Distribution Upgrades Project prior to the completion of the Portland LNG Seismic Vulnerability Analysis?[12]

A. The reduction in vaporization capacity from 133,920 Dth/d to 100,440 Dth/day results in a reduction in total gas storage delivery capacity that would need to be balanced with the purchase of spot gas on days when the Portland LNG facility is required to vaporize to support the gas distribution system, if available. The cost of spot gas could potentially be much higher than the cost of LNG storage.

Q. What is the status of the project?

A. The project is currently in Planning Phase in the Project Management Office. The alternatives analysis supporting the Portland LNG Electrical Distribution Upgrades Project is provided as confidential Exh. DBK-SSJ-20C.

Q. What is the timing of the Portland LNG Electrical Distribution Upgrades Project?

A. The Company expects to complete the Portland LNG Electrical Distribution Upgrades Project by August 2026, which will be included in rates in Rate Year 2.

Q. What is the estimated total cost of the Portland LNG Electrical Distribution Upgrades Project?

A. The total cost of the Portland LNG Electrical Distribution Upgrades Project is expected to be approximately $0.3 million on a Washington-allocated basis.

[12] NW Natural submitted a Facility Seismic Vulnerability Assessment pursuant to OAR 340-300 for the Portland LNG facility to Oregon Department of Environmental Quality ("Oregon DEQ") on December 20, 2024. This study required an analysis of the plant, using current Codes and Standards, and a detailed geotechnical hazard analysis of the underlying soils and subsurface geology. As part of the plant analysis, the liquefaction system, which includes the cold box, was studied, along with the LNG tank, vaporization system and balance of the plant. The Assessment is currently under review by Oregon DEQ.

III. SAFETY-RELATED PROJECTS AND PROGRAMS

Q. Please describe the Company's Programmatic safety-related projects on its distribution system.

A. NW Natural manages several safety-related capital expenditures that are classified as Programmatic. NW Natural estimates for 2025 that it will invest approximately $18.8 million in capital to comply with PHMSA's TIMP, DIMP and other federal and state regulations.[13] For discussion in this testimony, significant projects and programs include:

- ILI Conversion Projects (including the discrete P04 Camas Trans ILI Project);
- Proactive EFV Installation Program; and
- Probabilistic Distribution Risk Model Project.

A. ILI Conversion Projects

Q. Please describe NW Natural's ILI Conversion Projects.

A. Federal regulation, 49 C.F.R. Part 192 Subpart O, requires natural gas operators to develop an integrity management program to assess natural gas transmission lines and address the threats to the natural gas transmission system. These assessment methods include but are not limited to: Inline Inspection (ILI), External Corrosion Direct Assessment ("ECDA"), or pressure testing. On balance, ILI represents the most complete assessment method to cover the largest number of threats. NW Natural has been proactively upgrading its transmission facilities based on risk to allow for increased use of ILI as the primary form of integrity assessment to address threats to

[13] The Company also expects to incur approximately $6.4 million of expenses to address and comply with DIMP, TIMP, damage prevention and public awareness.

the natural gas transmission system. For many of the Company's transmission pipelines, NW Natural will need to invest in pipeline facilities such as pipeline inspection gauges ("pig") launchers and receivers and removal of reduced port fittings that prevent passage of cleaning, sizing and inspection pigs for inline assessment. This is a one-time investment to upgrade these facilities to allow for inline inspection. Inline inspection tools have the advantage over direct assessment and pressure testing because they cover the largest number of threats to the transmission system and assess the entire pipeline segment, between the pig launcher and pig receiver, maintaining constant contact with the inner wall providing data allowing for the identification of interacting anomalies such as pipe deformation, corrosion, and manufacturing defects. As such, ILI is a more complete assessment of the pipeline, is able to detect more threats to the pipeline and provides a greater level of safety to the public as this assessment gives NW Natural a better view of the pipeline and the potential defects. Also, with the advancements in ILI technology, NW Natural is utilizing inspection tools that allow NW Natural a greater understanding of the material properties of the transmission pipeline system, which assures NW Natural that the transmission pipeline system is in alignment with original design records.

In contrast, ECDA is performed only in High Consequence Areas ("HCAs"), Moderate Consequence Areas ("MCAs") and identified sites, thus limiting the assessment to only certain sections of the pipeline. The threats identified by ECDA are limited to threats that are associated with coating damage. Therefore, ECDA assessment can miss defects such as third-party damage or natural forces damage where

the coating was not disturbed, and does not identify any threats outside of the HCAs, MCAs and identified sites.

Pressure testing is another method of assessment that can be utilized to comply with Code requirements for transmission line inspection. This methodology typically involves isolating a segment of transmission pipe and filling it with water to pressurize the pipe to 1.5 times the Maximum Allowable Operating Pressure (MAOP) to validate the integrity of the pipe. While this assessment method addresses most of the threats to the NW Natural transmission system, this assessment method is not preferred by NW Natural and other natural gas operators. The reason for this is that pressure testing requires a shutdown of the pipeline for an extended period resulting in a loss of supply for large number of customers.

NW Natural believes that its ILI conversion projects allow it to have a better understanding of the transmission pipeline system, which results in a safer and more reliable natural gas system.

Q. Can you provide an example showing the enhanced safety value of ILI conversion projects compared with ECDA?

A. Yes. In the past, the Company's S22 Albany to Corvallis ten-inch transmission pipeline in Oregon had been inspected by ECDA. In August 2024, the Company changed the ECDA assessment methodology to ILI for the approximately 12 miles of pipeline from the Albany Gate Station to the Corvallis Granger Regional Station, and then conducted an ILI inspection after that conversion. In September 2024, NW Natural received the preliminary report from the smart tool vendor stating the pipeline had five immediate anomalies (four dents with metal loss and one 77 percent metal loss anomaly). The

Company quickly mobilized crews to repair the anomalies within a few days, making that pipeline much safer than had been possible in the past with ECDA inspections.

Q. Which ILI Conversion Project are you addressing in your testimony?

A. In 2023, NW Natural changed the assessment methodology of the P04 Camas Transmission pipeline, which is the Company's only transmission main in Washington, from ECDA to ILI. Doing so required modifications to the pipeline that included installation of ILI facilities and replacement of fittings to allow for a successful ILI assessment. This project was included in the Company's 2023 ECDA to ILI Assessment 10-Year Plan, which is provided as Exh. DBK-SSJ-21. The alternatives analysis supporting the P04 Camas Trans ILI Project is provided as Exh. DBK-SSJ-22.

Q. Please describe the P04 Camas Trans ILI Project.

A. The P04 Camas Trans ILI Project changed the ECDA assessment methodology to ILI for this approximately 3.5 miles of the 8-inch transmission pipeline in Camas that starts at the Camas Gate Station and ends at NE Lake Road south of Lacamas Lake. The Company completed this project and placed it in service in October 2023, at a total cost of $4.9 million.

B. Proactive EFV Installation Program

Q. What are EFVs and how do they work?

A. An excess flow valve (EFV) is a device installed in a service line near the point of connection to the gas main. EFVs will "trip" and stop the flow of gas if there is a full line failure, such as a damaged or severed service line.

Q. Why is the installation of EFVs important to increase safety?

A. In the event of a damaged or severed service line, EFVs are effective in mitigating the escape of gas.

Q. How has NW Natural approached the installation of EFVs?

A. Consistent with federal pipeline safety requirements, NW Natural includes EFVs on all newly installed and fully replaced service lines to single family residences. In addition, the Company installs EFVs for multifamily residences and small commercial customers served by a single service line with a known customer load not exceeding 5,000 standard cubic feet/hour (50 therms/hour). To date, the Company has installed more than 56,000 EFVs on residential and commercial services in Washington. For customers with larger known loads, a shut-off valve, instead of an EFV, is installed on the service. Additionally, NW Natural provides notice to its customers of their right to request EFV installation, and they are currently installed at the requesting customer's cost. The Company provides this notice to customers via its website, annual safety notifications, and new customer welcome packets.

Q. Please describe the Company's program to proactively install EFVs on existing service lines.

A. Starting in 2020, as part of the Company's DIMP, NW Natural has been installing EFV retrofits on service lines based on the likelihood and potential consequence of damage. The 2025 DIMP is provided as Exhibit DBK-SSJ-23. Factors included in its analysis are population density, service pipe diameter, service material, business districts, and special buildings. In 2025, the Company expects to invest approximately $0.3 million

on a Washington-allocated basis, as part of the Company's DIMP budget on EFV retrofits in high consequence areas.

C. Probabilistic Distribution Risk Model Project

Q. What is a probabilistic risk model, and why is the Company undertaking this project for its distribution system?

A. A probabilistic risk model is a model that determines the probability of failure in the system and quantifies the consequences of a failure per threat. In 2023, NW Natural initiated a project to partner with a data analysis consultant, JANA, to implement a probabilistic risk model to assess NW Natural's distribution system. Probabilistic risk models have been identified by PHMSA as a best practice to proactively manage threats to the natural gas distribution system. A probabilistic risk model will allow the Company to rank threats, measure risk reduction with each threat mitigation, and determine the most cost-effective risk reduction actions. None of these benefits are available with the Company's current relativistic risk model. While this particular project is not a Programmatic capital expenditure, it is included here because this project is being pursued to strengthen the Company's analysis and forecasting for Programmatic distribution system capital expenditures. The confidential Direct Testimony of Brian E. Fellon (Exh. BEF-1CT) describes the Company's JANA Probabilistic Risk Model Project, provides its status, and quantifies its estimated cost.

IV. DISTRIBUTION SYSTEM AND GAS STORAGE PIPELINE SAFETY O&M EXPENSES

Q. Please describe the types of actions related to pipeline safety that the Company is required to perform each year as required by CFR 192.

A. The Company is required to comply with 49 C.F.R. 192 Subpart A, Subpart I, Subpart L, Subpart M and Subpart O to ensure distribution system pipeline safety and underground gas storage safety. The Company must take many actions to comply with these federal regulations. This testimony describes the non-payroll O&M expenses associated with some of these ongoing efforts related to pipeline safety, including gas facility locating and marking, leakage surveys, transmission pipeline assessments, and well integrity inspections.

Q. Please describe the Damage Prevention Program.

A. The Company is required by 49 C.F.R. Section 192.614 to carry out a written damage prevention program, which includes participation in a qualified one-call system that provides the pipeline operator (the Company) an opportunity to locate and mark its underground facilities in advance of excavation activities. The Company manages its Damage Prevention Program with Company personnel. The Company employs the services of a third-party contractor, Heath Consultants Incorporated ("Heath Consultants"), to provide locating and marking services to the Company.

Q. Please describe Right-of-Way Patrol and Leakage Survey Programs.

A. The Company is required by 49 C.F.R. 192 Subpart M to perform right-of-way patrols and leakage surveys for transmission and distribution system pipelines, services and above ground facilities at time intervals not to exceed the time limits specified in this

federal regulation. The Company performs right-of-way patrols and leakage surveys for its transmission system with Company personnel. The Company employs the services of a third-party contractor, Heath Consultants, to provide leakage surveys for the Company's distribution system mains and services.

Q. Please describe the Pipeline Inspection Integrity Program.

A. The Company is required by 49 C.F.R. 192 Subpart O to develop and maintain an integrity management program to address threats to the Company transmission pipeline system. The Company prioritizes the use of inline inspection (ILI) to assess the Company's 6-inch diameter through 24-inch diameter transmission pipe in the system. As noted above, inline inspection has proven to be a more complete assessment of the Company's transmission system and addresses the largest number of threats to the transmission system. Each year's inspections can vary by the transmission pipeline's diameter being inspected, the pipeline length being inspected, and the location of the pipeline such as in urban areas or rural areas. Each of these variables impacts the Company's transmission pipeline assessment vendor and internal labor costs. In summary, the Company's transmission assessment costs vary by year due to the variability in pipeline, size, length and location of pipeline to be assessed. The Company hires outside vendors to perform transmission pipeline assessments and Company crews will assist the inline inspection vendors with access to the Company's transmission pipelines.

Q. Please describe the Well Casing Inspection Program.

A. In December 2016, PHMSA published in the Federal Register an interim final rule that revised the federal pipeline safety regulations to address critical safety issues related to

downhole facilities, including wells, wellbore tubing, and casing, at underground natural gas storage facilities.

In accordance with 49 C.F.R. Section 192.12(d)(2), NW Natural initiated a rig-based casing inspection program in 2017 to satisfy the integrity management baseline risk assessment requirement. The current well-work schedule supports completing the baseline casing inspection program in 2025. The baseline casing inspection program work was capitalized and completed in 2024. Beginning in 2024, NW Natural began its first re-inspection program to perform re-assessments consistent with intervals established from the baseline casing inspection logs and updated risk analyses to satisfy the conditions of 49 CFR Section 192.12(d)(3). This reassessment work is an O&M expense. The expense each year is heavily dependent on the number of rig-based casing inspections being performed which can vary from every 5, 10 or 15 years based on the results of the individual well-risk assessments. Outside of the final baseline casing inspection in 2024, the Company performed zero rig-based interventions. In 2025, the Company will perform two rig-based interventions, and has planned two for 2026, three for 2027, one for 2028 and one for 2029.

Q. Where does the Company address the impact to O&M in this case related to these programs?

A. The confidential Direct Testimony of Tobin F. Davilla (Exh. TFD-1CT) quantifies the impact to O&M in this case related to the programs described above.

Q. Does this conclude your Direct Testimony?

A. Yes.

VI. LIST OF EXHIBITS

Exh. DBK-SSJ-2	SE 1st Street Grading Project (Phase 2) – Change Orders
Exh. DBK-SSJ-3	Vancouver Reinforcement Project Summary – 250 psig MAOP Reinforcement
Exh. DBK-SSJ-4	Camas Gate Station Rebuild Project – Alternatives Analysis
Exh. DBK-SSJ-5	Camas Gate Station Building Improvements Project – Alternatives Analysis
Exh. DBK-SSJ-6	2025 Gate and Regional Stations 10-Year Plan (for the Deer Island Gate Station Improvements Project, Felida Gate Station Rebuild Project, Ridgefield and Battleground Gate Line Heater Replacement Projects, and West Vancouver Gate Odorant Depot Project)
Exh. DBK-SSJ-7	West Vancouver Gate Metering Project – Initial Project Charter
Exh. DBK-SSJ-8C	2016 Mist Storage Facility Assessment (Confidential and Redacted)
Exh. DBK-SSJ-9C	2020 AECOM Compressor Study (Confidential and Redacted)
Exh. DBK-SSJ-10C	2022 Burns and McDonnell Turbine Compressor Study (Confidential and Redacted)

Exh. DBK-SSJ-11	Mist GC500 and GC600 Turbine Compressors Replacement Projects – Alternatives Analysis
Exh. DBK-SSJ-12	Mist Main Power Feed Replacement Project - Initial Project Charter
Exh. DBK-SSJ-13	2025 Mist Gas Storage Facility 10-Year Plan (for the Mist Miller Bruer/Flora Gathering Separator Upgrade Project, Mist Miller Bruer/Flora/Meyer Metering Upgrade Project, Mist Calvin Creek Gathering Separator Upgrades Project, and Mist Miller Air Compressor and Receiver Tank Upgrades Project)
Exh. DBK-SSJ-14C	Newport LNG Pretreatment Improvements Project, Memorandum from Sanborn Head, dated May 5, 2023
Exh. DBK-SSJ-15	Newport LNG Cold Box Replacement Project Updated Cost of Service Memo (Newport LNG Pretreatments Improvement Project)
Exh. DBK-SSJ-16	Newport LNG Plant Supply Generator Project – Initial Project Charter
Exh. DBK-SSJ-17	Pages 29-37 of NW Natural's 2018 IRP Update filed in docket UG-170911 on March 1, 2021 (Newport LNG Cold Box Replacement Project)

Exh. DBK-SSJ-18	Newport LNG Cold Box Replacement Project – Exemption from Alternatives Analysis
Exh. DBK-SSJ-19	Newport LNG Molecular Sieve Vessels Repair and Upgrades Project – Alternatives Analysis
Exh. DBK-SSJ-20C	Portland LNG Electrical Distribution Upgrades Project – Alternatives Analysis (Confidential and Redacted)
Exh. DBK-SSJ-21	2023 ECDA to ILI Assessment 10-Year Plan
Exh. DBK-SSJ-22	System Integrity ECDA to ILI Assessment Program (P04 Camas Trans ILI Conversion Project) – Alternatives Analysis
Exh. DBK-SSJ-23	2025 Distribution Integrity Management Plan

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	Docket UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

Exh. DBK-SSJ-2

August 29, 2025

Change Detail for SE 1st St Grading Improvements Phase 2 – CO #1

Skip over navigation
Related Information: LifeCycle Team Content

⊞ Move ⊞ Transfer

⊞ Work Breakdown Structure

Description	Work-ID	Scheduled Start	Scheduled Finish	SMI	Seq-ID
Project SE 1st Street Grading Improvements Phase 2	1000676	7/1/2020	8/12/2025	0	16547

⊟ Basic History Update

Name	SE 1st St Grading Improvements Phase 2 – CO #1
ID	C-76610
CRI Status	Approved
CRI Priority	Medium
Description	**Project Name: SE 1st Street Grading Improvements Phase 2** **Project Overview:** The City of Vancouver initiated a public works project to improve SE 1st Street between SE 177th Ave and SE 192nd Ave. The scope includes full road reconstruction, widening, sidewalks, bike paths, and new water, storm, and sanitary utilities. NW Natural was required to relocate 3,700 feet of a 4" Class D main, replace it with a 12" Class D main per System Modeling, install 5,800 feet of Class B poly pipeline, and decommission one district regulator and three service regulators. The total approved budget for the project is $4,718,500, which includes a contingency of $708,000. The total actual cost of the project to date is $2,985,842. This change order requests the full use of the existing $708,000 contingency and an additional funding $1,794,605 to align the current authorized budget with the forecasted project costs. There are currently approximately $3.4 million in unpaid invoices. The estimated total cost of the project after the approval of this change order, will be $6,513,105 **Change Order Detail: ** During Construction, project encountered several unforeseen issues which significantly impacted the project's budget, schedule, and scope, resulting in a 34-day delay beyond the original 33-day timeline. Below is a summary of the issues, outlining their overall impact on the project. **1. Delays Due to City of Vancouver's GC, Colf Construction– $479,500** Location: SE 1st St between SE 177th Ave and SE 192nd Ave Colf Construction's grading delays slowed NW Natural's installation rate from 120 to 80 feet per day, extending the schedule by eight days resulting in added costs for labor, material, trucking, shoring and equipment. **2.Night work due to the delay by Colf Construction – $387,000** Location: SE 1st St between and SE 192nd Ave Colf Construction's delay in grading on SE 184th Ave forced NW Natural's contractor to shift to SE 192nd Ave, requiring night work per the city. Night work was not a part of the original city of Vancouver's permit requirements. This resulted in a six-day delay with added costs for labor, trucking, equipment, material imports, and shoring. **3.Delays Due to Slope Grading by Colf Construction – $202,700** Colf Construction's failure to complete slope grading far enough from NW Natural pipe alignment prevented NW Natural's contractor from safely excavating near the base of the slope, requiring the area to be stabilized and the excavation plan to be adjusted for safety. This resulted in a 4-day delay with added costs for labor, trucking, equipment, material, and shoring. **4.City Design Change for Water Line – $260,100** Location: SE 1st St between SE 177th Ave and SE 190th Ave The City of Vancouver revised water main depths without prior notice, resulting in NW Natural's contractor to have to install the 12" gas steel main deeper than planned. This adjustment delayed the project by four days, increasing costs for trucking, materials, shoring, labor, and equipment.

Owner	Kumar, Manoj
Email	manoj.kumar@nwnatural.com
Phone	
Target Date	12/13/2024
Type of Change Request Required	Will Be Tier 4 After CO:CO for Budget or >50% Cont

5.City's Plans Utility depth conflicts – $184,150
Location: SE 1st St between SE 177th Ave and SE 190th Ave
The City of Vancouver's design had conflicting utility depths that were not communicated to NW Natural prior to the start of construction. NW Natural's contractor had to temporarily halt trenching to resolve these conflicts. This resulted in a four-day delay with added costs for labor, equipment and shoring.

6.City Design Change to Stormwater Line – $124,950
Location: SE 1st St between SE 177th Ave and SE 190th Ave
The City of Vancouver's stormwater line was deeper than projected, requiring NW Natural's contractor to install a 45-degree offset at greater depth. This resulted in a three-day delay with added costs for trenching, material imports, and shoring.

7.Unmarked Power Conduit Strike – $45,830
Location: SE 1st St and SE 177th Ave
Clark Public Utilities (PUD) identified unmarked po wer conduits, prompting NW Natural's contractor to pothole and locate utilities. However, power utilities were not found. This was an inaccurate information from PUD. This resulted in a one-day delay, incurring additional labor and vacuum truck costs.

8.Fiber Optic Utility Strike – $42,800
Location: SE 1st St and SE 184th Ave
The City of Vancouver's as-built plans misrepresented fiber utility locations, resulting in an unintended strike. NW Natural's contractor installed an offset for proper clearance, causing a one-day delay with added co sts for labor, materials, trucking, and shoring.

9.4" Poly main As-Built Plan discrepancy – $48,120
Location: 17806 SE 1st St
The existing 4" poly main was installed at lower elevation shown on the as-builts. This created a clearance issue with the 12" steel gas main that needed to be installed below it, resulting in installing 12" steel gas main much deeper than anticipated. This resulted in a 1 day delay with added costs for labor, materials, trucking and shoring.

10. Pipeline Location discrepancy in As-Built Plans – $38,840
Location: SE 1st St between SE 177th Ave and SE 192nd Ave
The as-built plans did not clearly the locations of existing 6" and 4" gas mains, requiring NW Natural's contractor to use a vacuum truck to locate and verify pipeline positions. This resulted in a 1-day delay with added costs for labor, materials, trucking and shoring.

11.Poly Gas Service conflict – $35,000
Location: 17908 SE 1st St
The poly service gas line depth of installation coflicted with the proposed 12" steel main installation and did not meet clearance requirements. Depth adjustments resulted in a 1 day delay with added costs for labor and vacuum truck.

12.Additional unbudget costs – $185,513
The additional costs included approximately $20,000 for flagging, $15,505 for a street sweeper, $13,200 for a water tanker truck to dispose of hydrotest water, $19,950 for laydown yard rental, and $116,858 for additional paving.

**13.The total cost of this change order is $1,631,459.08 without contingency. **
The project team is requesting a 10% contingency of $163,145.92 to cover NW natural labor costs needed to close the project, along with construction trailing charges.

This change order requests a total of $1,794,605, including a 10% contingency.

Change Detail Attributes & Change Details Update

Name	SE 1st St Grading Improvements Phase 2 – CO #1
Description	**Project Name: SE 1st Street Grading Improvements Phase 2** **Project Overview:** The City of Vancouver initiated a public works project to improve SE 1st Street between SE 177th Ave and SE 192nd Ave. The scope includes full road reconstruction, widening, sidewalks, bike paths, and new water, storm, and sanitary utilities. NW Natural was required to relocate 3,700 feet of a 4" Class D main, replace it with a 12" Class D main per System Modeling, install 5,800 feet of Class B poly pipeline, and decommission one district regulator and three service regulators. The total approved budget for the project is $4,718,500, which includes a contingency of $708,000. The total actual cost of the project to date is $2,985,842. This change order requests the full use of the existing $708,000 contingency and an additional funding $1,794,605 to align the current authorized budget with the forecasted project costs. There are currently approximately $3.4 million in unpaid invoices. The estimated total cost of the project after the approval of this change order, will be $6,513,105 **Change Order Detail: **

During Construction, project encountered several unforeseen issues which significantly impacted the project's budget, schedule, and scope, resulting in a 34-day delay beyond the original 33-day timeline. Below is a summary of the issues, outlining their overall impact on the project.

1. Delays Due to City of Vancouver's GC, Colf Construction– $479,500
Location: SE 1st St between SE 177th Ave and SE 192nd Ave
Colf Construction's grading delays slowed NW Natural's installation rate from 120 to 80 feet per day, extending the schedule by eight days resulting in added costs for labor, material, trucking, shoring and equipment.

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The project team is requesting a 10% contingency of $163,145.92 to cover NW natural labor costs needed to close the project, along with construction trailing charges.

This change order requests a total of $1,794,605, including a 10% contingency.

Kind of Change Request	Change Request
Type of Change Request	Budget: Forecast over budget, needs more funding

Details for Change Request or Early Purchase

New NWN Change Detail Attributes

Details for an Alternatives Analysis (AA) Change Request

NWN Late Stage Alternatives Analysis (AA) Detail

CRI Approval

Executive Sponsor	✓ (Primary selection) ✓ 1. Karney, Joseph
Program/Project Manager	Kumar, Manoj
Portfolio Manager	Acevedo, Manuel

Created By : Kumar, Manoj Created On : 12/6/2024 3:49:30 PM

Last Updated By : Kumar, Manoj Last Updated On : 1/3/2025 10:40

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	Docket UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

Exh. DBK-SSJ-3

August 29, 2025

System Reinforcement 10 Year Plan- Project Summary Document

Project Name: Vancouver HP Replacements **Year of Plan:** 2025

Expected Completion Year: 2027 or 2028 **Project Initiator:** E Thurman

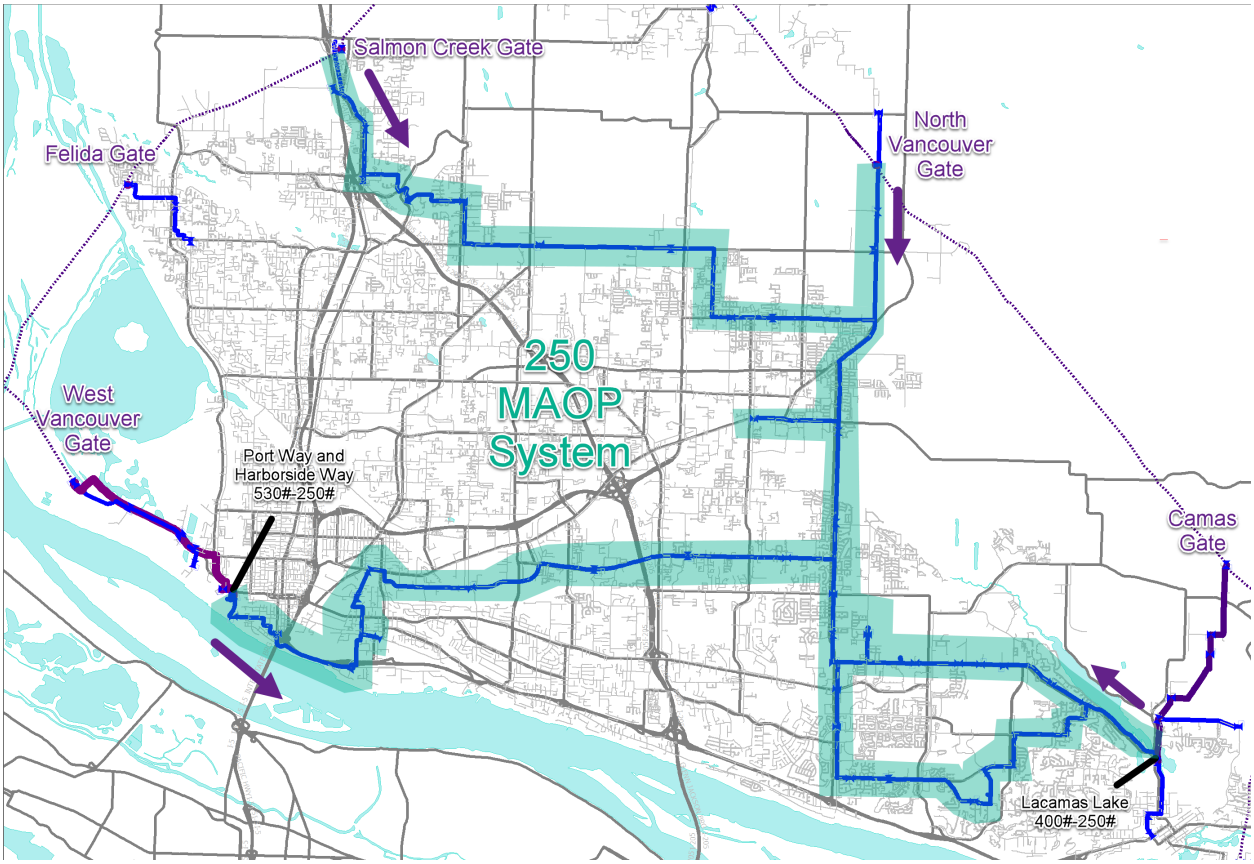
System Analysis and Issues:

Vancouver's 250 MAOP system serves as the high pressure backbone for the core of Vancouver, Washington. The system is highlighted in blue in Figure 1 below. The 250 MAOP system supplies gas to customers in Vancouver, Camas, Salmon Creek, Brush Prairie, and portions of Ridgefield. The system includes approximately 46 miles and includes 4"(W), 6"(W), 8"(W), and 12"(W) high pressure mains.

The 250 MAOP system is fed from four different locations:

1) Salmon Creek Gate
2) North Vancouver Gate
3) Port Way and Harborside District Regulator from West Vancouver Gate
4) Lacamas Lake Regional Station from Camas Gate

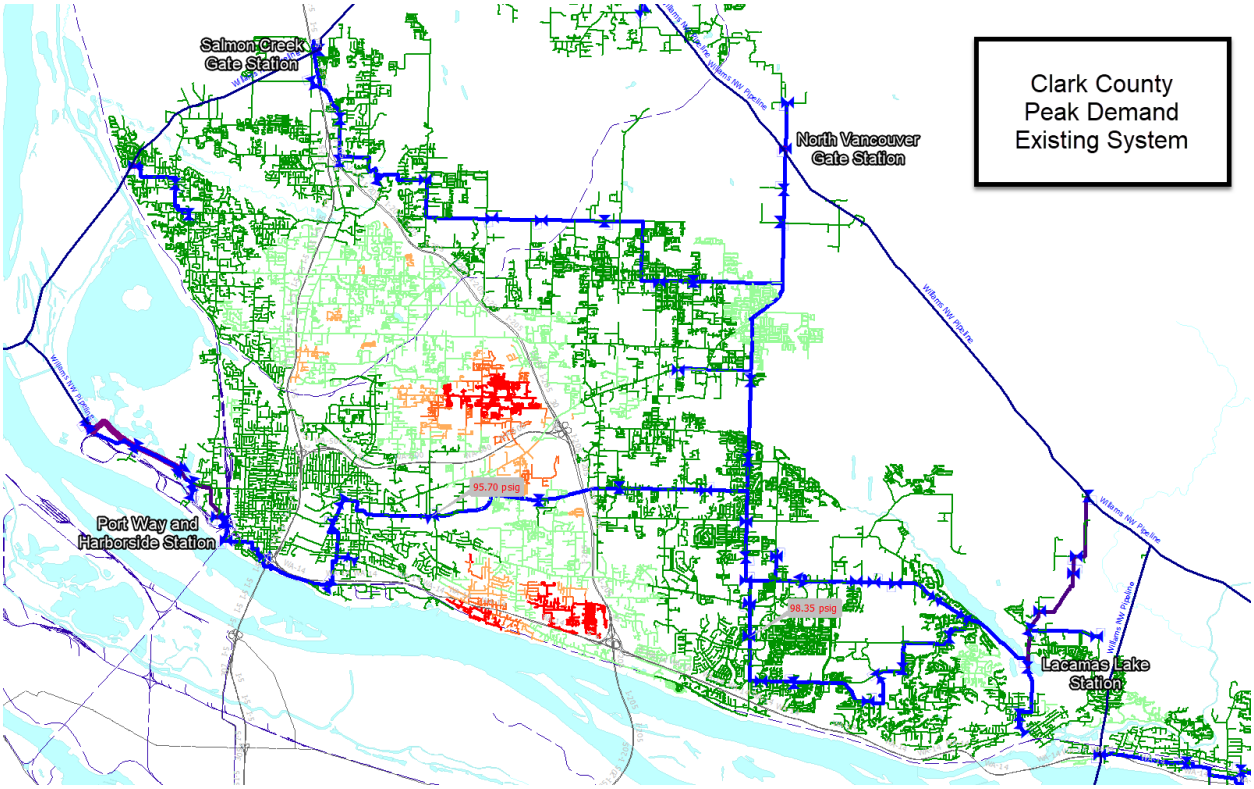
Figure 1 - 250 MAOP System



In 2022, a new Vancouver model was developed using Customer Management Module (CMM) predicted demands. CMM links Synergi with NW Natural's Customer Information System (CIS) and establishes a relationship between temperature and consumption to forecast customer demands used in the model. This approach provides more accurate demand estimates than the legacy method, which applied average Usage Per Customer (UPC) values by region for residential and small commercial customers. A benefit of CMM is the ability to incorporate new customer demands more seamlessly. New customers in legacy were added manually, leading to a lag when customer demands were added to the model. Because of the manual process growth was not accurately captured in Legacy models.

CMM modeling showed that the demands are higher than what was modeled in the legacy models. CMM modeling indicates that the system is operating beyond its design capacity during cold weather. Synergi results using CMM forecasted demands show pressures on the 250 MAOP system dropping to 95.7 psig, which has a corresponding 59.3% pressure drop. NW Natural's high pressure reinforcement criteria includes addressing pressure drops exceeding 40% from the source to the end of the system. A system with a pressure reduction of 40% equates to an 80% level of capacity utilization.

Figure 2 - Existing System Model



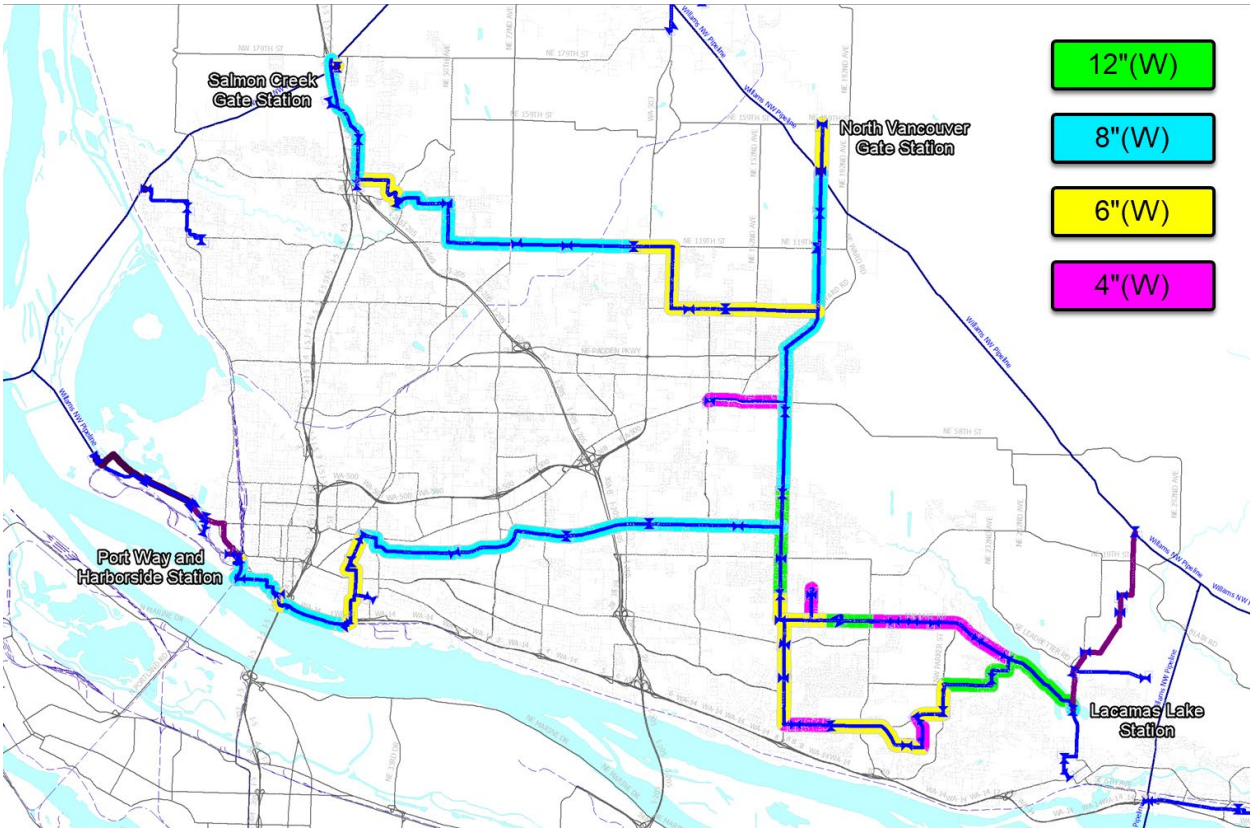
The low pressures found in the model are a result of pressures losses due to bottlenecks on the 250 MAOP system. A breakdown of the sizes and lengths of the pipe are provided below.

Size (in)	Length (mi)
4	5.5
6	13.6

8	21.7
12	5.4
Total	46.2

Modeling shows that the 6”(W) and 4”(W) creates significant losses on the system causing low pressures to be seen on the southern part of the 250 MAOP system. Figure 3 illustrates locations of the bottlenecks on the system. The magenta polygons indicate locations of 4”(W) while the yellow polygons show instances where 6”(W) is installed. The remaining portions of the system consist of 8”(W) and 12”(W).

Figure 3 - 250 MAOP System By Pipe Size



Recorded Pressures

Source Pressures:

The SCADA tags listed below provides the source pressures for the Vancouver 250 MAOP system.

0162A_PRESS_OUTLT_1 : North Vanc Gate Pressure Outlet 1
0195A_PRESS_OUTLT_1 : Salmon Creek Gate Pressure Outlet 1
0025A_PRESS_OUTLT_1 : Lacamas Lake Regs Pressure Outlet 1
0295A_PRESS_OUTLT_1 : Port of Vancouver Pressure Outlet 1

System Pressures:

Engineering has been recording pressures data through two Electronic Portable Pressure Recorders (EPPR) on the Vancouver 250 MAOP system since the 22/23 Heating Season. One located at DR DR 1-015-035-R02 and another at DR 1-015-045-R02. The lowest pressure captured by the EPPRs was 117.8 psig, which corresponds to a 41.3% pressure drop. This lowest pressure occurred while interruptible customers active and average daily temperature of 21.5 Deg F (43.5 HDD).

District Regulator 1-015-045-R02

Date/Time	Avg Pressure	Max Pressure	Min Pressure
1/16/2024 23:00	189.72	191.22	186.9
1/16/2024 22:00	183.83	185.39	181.71
1/16/2024 21:00	179.82	181.06	178.57
1/16/2024 20:00	176.96	177.95	176.25
1/16/2024 19:00	173.04	175.1	170.95
1/16/2024 18:00	168.63	170.42	166.9
1/16/2024 17:00	166.07	166.67	165.68
1/16/2024 16:00	167.13	168.38	166.19
1/16/2024 15:00	170.65	172.53	168.75
1/16/2024 14:00	167.23	170.81	163.25
1/16/2024 13:00	163.2	164.87	161.05
1/16/2024 12:00	159.52	161.17	156.79
1/16/2024 11:00	146.36	154.21	135.15
1/16/2024 10:00	127.87	132.18	125.61
1/16/2024 9:00	121.8	125.93	117.81
1/16/2024 8:00	125.38	130.8	119.34
1/16/2024 7:00	134.15	142.63	127.48
1/16/2024 6:00	147.9	154.89	141.87
1/16/2024 5:00	161.36	164.49	158.17
1/16/2024 4:00	167.9	170.98	165.1
1/16/2024 3:00	173.29	174.13	171.81
1/16/2024 2:00	176.12	178.44	174.15
1/16/2024 1:00	180.57	181.19	179.38
1/16/2024 0:00	181.85	182.34	181.4

Pressure data was also collected during the 24/25 Heating Season. An EPPR located at the inlet of District Regulator 1-009-043-R01 recorded a low pressure of 105.99 psig during a 37 HDD on February 11, 2025.

District Regulator 1-009-043-R01

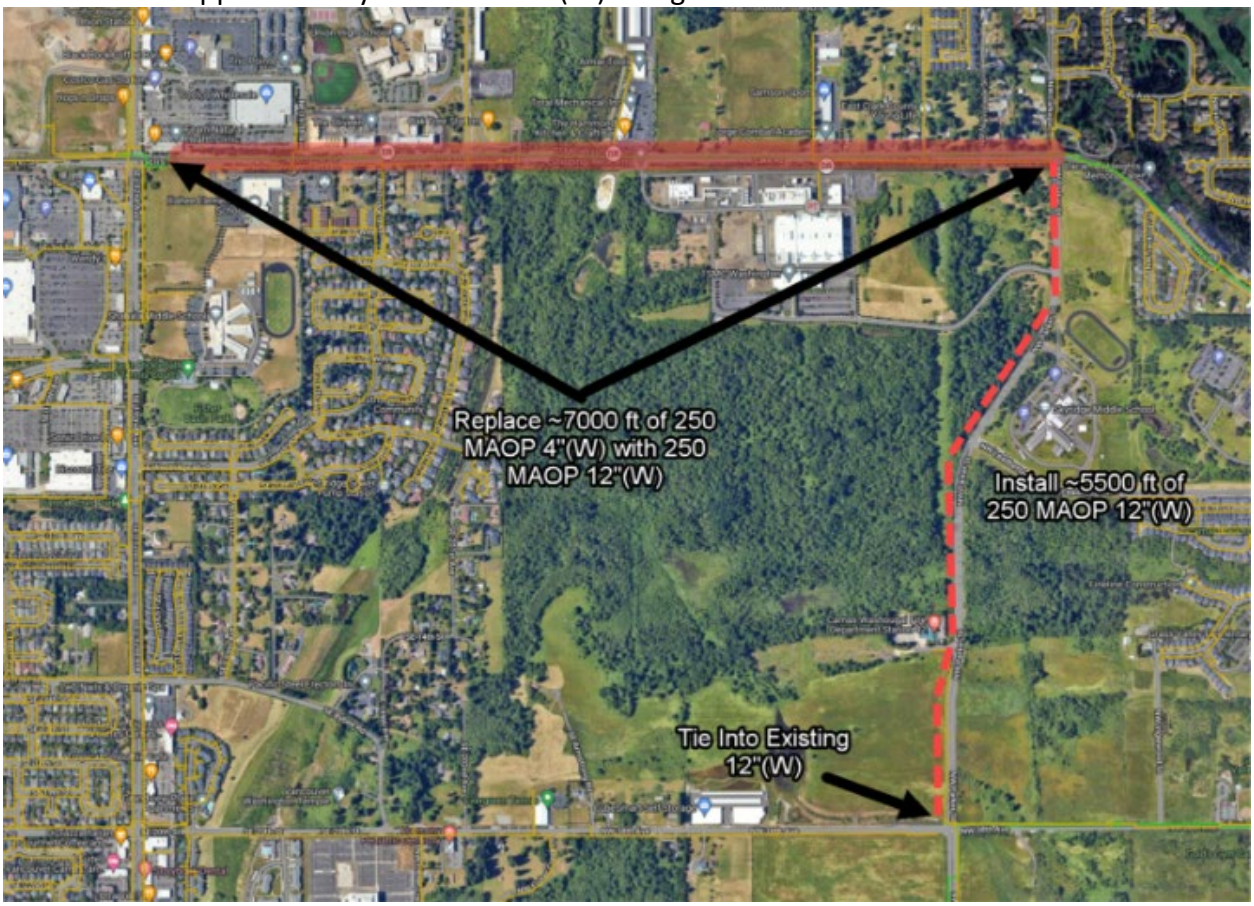
Date/Time	Avg Pressure 2	Max Pressure 2	Min Pressure 2
2/11/2025 23:00	173.28	174.99	171.1
2/11/2025 22:00	168.14	169.59	165.59
2/11/2025 21:00	164.39	165.13	163.6
2/11/2025 20:00	164.51	165.27	163.66
2/11/2025 19:00	167.39	168.62	165.88
2/11/2025 18:00	173.16	176.95	169.4
2/11/2025 17:00	180.3	182.02	177.55
2/11/2025 16:00	183.96	184.99	182.49
2/11/2025 15:00	184.55	185.46	182.82
2/11/2025 14:00	179.28	182.1	177.13
2/11/2025 13:00	173.63	175.69	171.76
2/11/2025 12:00	166.09	170.48	161.82
2/11/2025 11:00	153.86	159.69	147.14
2/11/2025 10:00	135.91	144.23	127
2/11/2025 9:00	110.47	117.11	106.66
2/11/2025 8:00	106.75	108.34	105.99
2/11/2025 7:00	121.66	133.16	107.7
2/11/2025 6:00	141.11	149.13	133.66
2/11/2025 5:00	157.43	161.87	152.33
2/11/2025 4:00	167.31	169.53	163.73
2/11/2025 3:00	173.64	175.69	170.87
2/11/2025 2:00	178.49	180.12	176.86
2/11/2025 1:00	182.93	184.24	180.78
2/11/2025 0:00	183.63	184.03	183.32

Proposed Projects:

Option 1 - Installation of new 400 MAOP 12”(W) main and replacing existing 400 MAOP 4”(W) main with 400 MAOP 12”(W) main

The System Reinforcement Includes:

- Replace approximately 7000 ft of 4”(W) with 12”(W) on NW Lake Rd
- Install approximately 5500 ft of 12”(W) along NW Parker St.



Option 2 - Construct 6535’ of 8”(W) looping existing 6”(W) 530 MAOP line, starting at West Vancouver Gate and heading east on Lower River Rd.

The System Reinforcement Includes:

New 8” 530 MAOP line, approximately 6,355’ long

Location where new pressure control would be needed and uprate from 250 to 350 psig would begin.

Extents of 350 MAOP uprate:

Close-up of east end of 350 MAOP uprate section.

Option 3 – Uprate the Entire 250 MAOP System to 300 MAOP

The System Reinforcement Includes:

Uprate approximately 46 miles of high-pressure main from an MAOP of 250 psig to 300 psig
- Potentially uprate/replace 12 service regulator inlets
- Potentially uprate/replace 45 district regulator inlets

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	Docket UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

Exh. DBK-SSJ-4

August 29, 2025

NW Natural
PROGRAM / PROJECT ALTERNATIVES NARRATIVE

Program/Project Name: E-202729_Camas Gate Station Rebuild
Date: *01/30/2023*
Project Sponsor: Daniel Kizer
Executive Sponsor: Jon Huddleston
Project Manager: Jorge Souto
Preparer: Lindsey Robison, Jorge Souto

The purpose of the Alternative Analysis requirement is to choose the best solution for NWN's need and to make sure we are utilizing resources in the most efficient manner.

BUSINESS NEED/JUSTIFICATION *What is the issue intended to be addressed and why is it needed?*
The Camas Gate Station is a key delivery point for the East Vancouver, Camas, and Washougal areas. This site serves as a gate station, houses an odorizer, and contains a single-walled 2000-gallon bulk odorant storage tank. Replacement of the odorizer and bulk odorant storage tank were originally included in the Engineering 10-year plan for execution in 2025. However, due to proximity to recent vehicle damage, the age and condition of the bulk odorant storage tank, and an adjacent project to install a pig launcher, this project proposes to move the execution to 2023. Williams NW Pipeline will also be providing NW Natural with a credit due to valves that need to be replaced at the site. Williams NW Pipeline is also requesting NW Natural take over regulation and overpressure protection at Camas Gate Station due to a Williams policy requiring customers to install, own, and operate overpressure protection when a major upgrade exceeding $200,000 is required. This major upgrade is required due to work for the P04 ILI project and the relocation of the odorizer and bulk odorant storage tank.

OBJECTIVE *Clearly define the objective.*
The project aims to update the design standards of the Camas Gate Station, modernizing the station by removing the existing single-containment bulk odorant storage tank and odorizer. The station will be reconfigured to accommodate a new pig launcher and a modern odorizer. At the project's completion, vehicle protection will be installed to protect the station from vehicle damage.

RECOMMENDED OPTION *Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option.*	
Description	Modernize the station to meet current design standards, replacing the existing single containment bulk odorant storage tank with a smaller, fully contained tank. Replace the existing odorizer with a modern, zero-emission odorizer. To accommodate spacing for the odorizer and the new pig launcher (installed during a concurrent project), reconfigure the station and move the odorizer into the existing Williams building, which will be transferred by Facility Agreement to NW Natural. Install a new, billing-quality check meter downstream of the custody transfer meter for meter quality at custody transfer sites. Reconfigure station piping, take ownership of the over overpressure protection, regulation, and line heating by agreement with Williams Pipeline, and install new vehicle protection. Williams pipeline will build a new, modern meter run, eliminating the existing orifice meter run, to increase metering accuracy. The station design is being modified to incorporate the P04 ILI project, due by the end of October 2023.

Decision Criteria	The most cost effective, viable option.
Pros	Address contractual obligation, bring station to current standards, meet current demand.
Cons	Due to the single-fed system, design will need to be coordinated with the Williams team to provide a bypass to downstream customers while systems are switched over from Williams supply to NW Natural customers.

POTENTIAL COST			
Capital	**Direct + Contingency**	**COH (20%)**	**Total**
	$3,250,000	$650,000	$3,900,000
O&M	**Program/Project**	**Ongoing Maintenance & Support**	
	$0.00	No forecasted change from existing station	
Source/ Method of Cost Data	Williams' contract estimate and internal NWN cost estimates from recent gate station projects.		

ALTERNATIVE 1 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option*	
Description	Satellite LNG Facility, providing alternate source of supply to reduce peak demands on existing Camas Gate Station.
Pros	Provides peak-shaving capacity and reduces peak demand requirements at Camas Gate Station.
Cons	High cost of construction and high operations and maintenance costs. Project contains significant siting difficulties and potential long permit timeline. These are significant schedule risks.

POTENTIAL COST			
Capital	**Direct + Contingency**	**COH (26%)**	**Total**
	$16,900,000	$4,394,000	$21,294,000
O&M	**Program/Project**	**Ongoing Maintenance & Support**	
		$373,000	
Source/ Method of Cost Data	Conceptual Design and Budget for Community Based LNG Satellite Stations spreadsheet, produced by Jenmar Concepts calculator, with inputs for these station design considerations by NW Natural Engineering		
Explain why this alternative is not recommended	Higher capital and O&M cost than recommended option, and higher constructability and schedule risk for construction.		

ALTERNATIVES CONSIDERED NOT VIABLE *Provide a description of any additional alternatives that were considered but rejected up front as not viable, and explain why*		
	Description	**Why the Alternative is not viable**
Alternative 2	Do nothing	High operational risk for existing bulk odorant storage tank and odorizer. NWN is working to eliminate single-containment odorant tanks because they do not meet code today and are at a higher risk for spills. Relocating existing piping required to install vehicle protection. The site

		has been identified in Vehicle Protection study as a high priority for installation of new vehicle protection measures.
Alternative 3		

**Add rows for any additional alternatives considered not viable*

FURTHER ANALYSIS NOT REQUIRED *Describe why further analysis is not required. Please explain in enough detail that others can assess whether the existing justification is sufficient.*

PMO USE ONLY ***ELECTRONIC APPROVALS***		
Title	**Name**	**Date/Time Approved**
PMO Specialist		
AA Approver		

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	Docket UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

Exh. DBK-SSJ-5

August 29, 2025

NW Natural
PROJECT ALTERNATIVES NARRATIVE

Program/Project Name: E203083 Camas Gate Station Building
Date: 4/10/2025
Project Sponsor: Joe Karney
Executive Sponsor: Dan Kizer
Project Manager: Abraham Jaimes
Preparer: Abraham Jaimes, Austin Garcia, Roland Buckner, Mike McKenzie

SECTION 1: BUSINESS CASE

This section should be solution-agnostic, and about the overarching problem we're trying to solve no matter which route we end up taking

OBJECTIVES *Why are we tackling this project?*	
Current State What is happening now? Where are we starting?	Before the 2023 Camas Gate Station Rebuild Project, a regulator building dating from the Station's original construction in 1957 was installed to provide noise reduction at the regulator runs. During the 2023 Rebuild project, the regulator building was removed due to the asbestos material construction and conflict with the modern regulator design. With the installation of the new regulators, aerodynamic noise has been noted around the station and into the adjacent neighborhood, leading to customer inquiries and Sys Ops crew callouts. Camas Gate Station is located just outside the Camas, WA city limits in rural Clark County, and is subject to noise ordinances in Clark County Code and the Washington Administrative Code (WAC). These Codes specify a maximum noise level at property line of 60dBA. While typically Code would reduce the noise limitation to 50dBA in a Residential zone during the hours of 10pm to 7am, WAC 173.60 exempts natural gas utilities from this requirement. This exemption eases compliance for this Station but is easy to overlook or misunderstand from a customer perspective. There have been several years of concerns over noise and odor expressed by neighbors regarding Camas Gate operations. These concerns have been documented through regular complaints submitted to NW Natural, Clark County, and the Southwest Washington Clean Air Agency. In response to these complaints and to demonstrate our commitment to addressing community concerns, we have indicated the construction of a new building on the site. This development is intended to mitigate noise propagation and to serve as a visible indication of NW Natural as a responsible neighbor. In response to customer noise complaints, the Company performed a sound study in September 2024. The scientific noise study determined a maximum noise level of 59 dBA, indicating the station had not exceeded the Clark County/WAC 173-60 noise limitation of 60 dBA. In anticipation of larger Winter gas flow, temporary noise curtains were installed, and the noise study was performed again in December 2024. This study resulted in a maximum noise reading of 54 dBA outside of the noise curtains and determined that with high heating-season gas flows, the temporary noise curtains were required to stay within Clark County Code limits. These temporary noise curtains are not designed for permanent installation.

	This project aims to provide permanent noise mitigation by installing a building to reduce overall noise at the station and ensure compliance with Clark County Code. Additionally, a worker-monitor regulator run will be installed in parallel to the existing regulators to accommodate for lower flow conditions during summer months for operational efficiency and to further reduce noise.
Problem Statement In simple terms, what are we trying to solve? What is the business need this is tackling? Why is this a problem worth solving (e.g. why is the current state not working)?	NW Natural has received numerous noise complaints from adjacent neighbors and we are proposing a solution to decrease noise pollution from the site. The existing regulator runs do not contain sufficient noise dampening. NW Natural has installed noise reducing insulation blankets and temporary noise curtains, but these methods are not a permanent solution. The Company needs a permanent solution that will ensure code compliance and result in noise reduction, reducing or eliminating customer complaints, while ensuring safety and ease of maintenance for Camas Gate Station.
Desired Deliverables What high level output / scope / deliverables are core to this project?	The preliminary scope of gas facility work includes requests for a new building design, ordering materials, requesting 3rd party engineering for foundation design, requesting permitting for new building, coordinating with contractors for installation, and installation of a worker monitor regulator run in parallel with existing regulators to accommodate lower flow conditions during summer months and reduce noise.

SECTION 2: ALTERNATIVES SUMMARY

OVERVIEW *How did we review these options?*	
Review Process Summarize how options were chosen, who was involved in the choice and how options were evaluated. If some criteria were considered more important based on the type of project, please explain here.	The team has reviewed multiple options for reducing overall noise pollution at this site. The review process includes the installation of a building, the use of permanent sound walls/barriers around the site, utilizing noise reducing curtains, rebuilding the regulators in underground vaults, and or leaving the station in its current state.
DECISION CRITERIA *Describe the criteria used to determine the selection from the various alternatives considered. For example, is this a program/project where the least cost option should be selected? Are there other factors, such as safety or quality that come into play? Include both quantitative and qualitative factors as appropriate.*	
Criteria: Cost/Scope	This summary will review the costs and scope associated with each option analyzed. Lower cost options may not remediate the issues currently at hand.
Criteria: Building Construction	This summary will review the building materials available for attenuating sound and how they either meet or do not meet code requirements. New building construction must meet International Building Code, WAC 51-50 and International Fire Code, and other applicable Codes.
Criteria: Safety	This summary will review the safety aspects and how each option either meets or does not meet the requirements. Design requirements must include adequate ventilation, must meet electrical area classification requirements (NFPA 70, NFPA 497), and provide adequate building access for operations and maintenance.
Criteria: Risks/Benefits	This summary will review the risks and benefits associated with each option analyzed. Alternatives resulting in a beneficial noise reduction and lower overall audio/visual footprint will be ranked higher.

SECTION 3: ALTERNATIVES DETAIL

RECOMMENDED OPTION *Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option. If positive /neutral/negative observations do not exist, enter N/A*		
Description	Install New Building and Regulator Run	
In brief, why is this the recommended option?	The recommended option proposes installation of a new custom building, similar in footprint and scale to the original 1957 Regulator Building and the addition of a new regulator run to reduce noise at the site. The new building and regulator run will reduce noise pollution, improve efficiency of flow during summer months, and prolong life of station regulator equipment by utilizing a new Summer-season run to reduce low-flow conditions through the larger, heating-season sized regulator runs.	
Assessment	**Analysis Against Criteria:** Cost/Scope	There is a high cost associated with the implementation and installation of a new building over the regulators. The building will need to be custom to fit the design profile of the regulator runs and meet all area classification, ventilation, and safety requirements. Additionally, the installation of a new regulator run will require engineering and construction resources to install.
	Analysis For Criteria: Building Construction	The building will be custom to fit the current regulator configurations and meet the necessary local and fire code requirements. The custom building will be tailored to the site to avoid any conflicts with underground utilities.
	Analysis For Criteria: Safety	The new building will aid in noise attenuation by absorbing scattered and reflected sounds waves that are currently spreading to the neighboring communities. The building entry points will be in specified locations for ease of maintenance and access to equipment. Additionally, building materials will meet necessary electrical area classifications.
	Analysis Against Criteria: Risks	• It is possible that despite improvements, neighbors may continue to escalate noise concerns at the gate station. This risk will be mitigated by ensuring that the final design meets or exceeds all applicable noise ordinances and Local/County Codes. • Permitting with local jurisdictions may have additional requirements that could change the overall design of the project and increase scope and cost. Risk is mitigated – during Plan phase, building permit has been received and all permits are in hand. • The new building will need to be installed during busy summer construction months as the station will need to be shut-in. • Tariffs and Market impacts increase the risk of price hikes on materials.
	Analysis For Criteria: Benefits	• Noise attenuation at the site and overall noise reduction outside of the building by utilizing a noise-attenuating insulation assembly and physical noise barriers. • Improved working environment for operations and maintenance personnel. • Protection of equipment and pipe from the elements. • Overall improvement of site layout and aesthetics.

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$750,000 - $1,250,000	$165,000 - $275,000	$1,015,000 - $1,525,000
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	

	$0	$0
Source/ Method of Cost Data	Project costs are based on material and contractor estimates for the construction and installation of the new building and regulator run.	

ALTERNATIVE 1 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*		
Description	Install Prefabricated Building	
In brief, why is this option not recommended?	A prefabricated building option was examined to investigate potential cost savings over a custom-build steel frame building. The prefabricated building alternative is not recommended because it does not allow for room to customize and change entry points for the building. Additionally, size constraints do not allow for the additional summer regulator run installation. The prefabricated buildings in the appropriate dimensions and configurations do not have the adequate electrical area classifications to be used for a gas facility.	
Assessment	**Analysis Against Criteria:** Cost/Scope	Although prefabricated buildings are generally more cost effective, the cost to install the building will be similar to that of a custom building. Additionally, the prefabricated buildings do not meet the scope requirements for this project.
	Analysis Against Criteria: Building Construction	The use of a prefabricated building is not an option because of the size requirements needed to fit around the regulators as well as the inability to make modifications to the building to fit NW Natural's needs. The building doors need to be in specific locations to provide necessary access to equipment inside the building and provide ease of maintenance.
	Analysis Against Criteria: Safety	An adequately sized prefabricated building does not have the Class 1, Div 2 specifications required for electrical code compliance. Modifications to meet Code would increase project cost and complexity.
	Risks	• Installation of a prefabricated building will require staging and rigging to set into place. The site is located near powerlines and could pose potential issues with install. • Lack of communication from manufacturer may pose risks in design and selection of the building required by NW Natural.
	Benefits	• Smaller scope and lower cost associated with the purchase of a prefabricated building. • Prefabricated buildings would have a much shorter lead time.

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$500,000 - $750,000	$110,000 - $165,000	$610,000 - $915,000
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$0	$0	
Source/ Method of Cost Data	Cost estimate is based on preliminary budgetary estimates from prefabricated building suppliers and construction costs associated with permitting, building foundation, rigging, and electrical install.		

ALTERNATIVE 2 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*	
Description	Permanent Sound Walls

In brief, why is this option not recommended?	The sound walls still leave the site open above the regulators, allowing sound to escape above the top of the sound walls. This alternative provides the equipment with no protection from the elements. The sound walls would be permanent but would require costly, deep foundations to account for wind and seismic loads. Sound wall foundations will cause conflicts with underground utilities, requiring relocating underground piping. This alternative is intended to be a concrete or CMU/masonry wall around the perimeter of the entire station. These walls will need to be greater than 8' tall and incorporate security elements to prevent unauthorized access. While the walls may stop the horizontal propagation of noise, they will not prevent noise from traveling over the walls, continuing to impact the adjacent neighborhood. This alternative incorporates construction risk in that material costs and bids may be higher than originally modeled in this alternative. Foundation designs will require extensive work with Williams, whose pipelines are also within the station, to determine if the foundations can be built over existing pipelines and around existing equipment. These design risks increase cost and schedule risks beyond the selected alternative.	
Assessment	**Analysis Against Criteria:** Cost/Scope	Installation of sound walls will include significant costs associated with installation of adequate foundations to account for wind loads. This may require relocating of underground utilities if the sound wall foundations interfere with existing underground gas or electrical utilities.
	Analysis Against Criteria: Building Construction	To make sound walls structurally sound, footings for walls will need to be wind load rated which may include considerable amounts of structural and construction costs. Construction would involve permitting, purchasing sound wall materials, and procuring construction contractor for the installation.
	Analysis Against Criteria: Safety	The sound walls still leave space above the regulators open and noise from the regulators will escape. Coverage required for noise attenuation limits access into and out of the regulator area in ways that are more restrictive than a permanent building, which has operable doors.
	Risks	• Noise may potentially leak out above the sound walls. • Reduced life equipment as they will still be exposed to the elements. • Sound panels will need to be replaced in the future, leading to on-going costs as the panels age and deteriorate. • Sound panels may also reduce station access for future construction and accessibility.
	Benefits	• Installation of sound walls would be the lowest cost option for materials and construction.

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$400,000 - $600,000	$88,000 - $132,000	$488,000 - $732,000
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$0	$0	
Source/ Method of Cost Data	Preliminary method of cost data includes materials estimate from the Sound Wall vendor and construction estimates for rigging, concrete, and sound wall material installation.		

**Copy/Add table for any additional alternatives*

ALTERNATIVES CONSIDERED NOT VIABLE *Provide a description of any additional alternatives that were considered but rejected up front as not viable, and explain why*		
	Description	**Why the Alternative is not viable**
Alternative 3	Sound Curtains	The use of sound curtains is not a permanent option as they include the use of additional

		chain-link fencing around the regulators. This is not a long-term solution as they create an additional obstruction around the station equipment and are not designed for wind loads. Additionally, sound curtains decay with prolonged sun exposure.
Alternative 4	Rebuild Station Underground	The station was rebuilt in 2023 and cost for the station rebuild was $2.84MM. Rebuilding the station underground would include additional engineering design and construction which would exceed the cost of a building installation.
Alternative 5	Do Nothing	Doing nothing is not recommended, it does not address the noise complaints from the neighbors and provides no ability to maintain existing code compliance. Neighbors have already filed a Code Enforcement action, which was closed after the noise curtains were installed. There is a risk that during high flows, or with failure of the temporary noise curtains, the station will exceed noise limitations. With an active and engaged neighborhood monitoring noise levels, there is risk of compliance or regulatory action, up to and including Legal action.

**Add rows for any additional alternatives considered not viable*

SUPPLEMENTARY INFORMATION

As needed, you may include any useful information gathered during the assessment phase including analysis like cost benefit / risk analysis / sensitivity analysis, etc.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	Docket UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

Exh. DBK-SSJ-6

August 29, 2025

Gate and Regional Station

Planning Document
2025 – 10 year plan
Date updated: 8/14/2025

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Scope

This 10 year plan is for Gate and Regional Station projects. There are projects that have been identified in the IRP to serve load. Other projects have been identified based on supply, end of life obsolescence, projected growth or modernization.

Gate and Regional Station Criteria

Projects in this plan were selected utilizing the following criteria:

Gates and Regional Stations:

- Estimated cost w/o COH greater than $500K.
- Design parameters set to Peak Heating Day load requirements.
- Modeling shows that with potential growth components within the Gate or Regional Station such as regulators, meters, line heaters, odorizers or any other equipment could become undersized.
- Analysis of Williams contract or design capacity of Gate Station shows that Gate Station is undersized.
- End of life for critical components such as line heaters and odorizers where repair equipment may not be available
- System Reinforcement Projects which will impact flow from a Gate or Regional Station.
- Identified in the IRP for supply requirements or needs.
- Identified by Gas Control as necessary for operation of the gas distribution system.
- Identified as a station in need of vehicle protection upgrade.
- Cost estimate ranges reflect PMO Guidance of +100% / -50%

Note: Projects may move on the schedule depending on growth, winter operations, and other circumstances. Where systems are stable, special consideration may be determined prior to Gate or Regional Station modification

Section One – 1 to 3 years (2025 to 2027)

Projects in this category will follow current Engineering or Project Management Office processes to finalize design and refine the cost estimate.

2025

Rock Creek Regional Station Valve Replacement (E-202765)

- Plat 1-025-014, OR
- Replace existing undersized worker control valve with a larger valve to increase station flow capacity. The site is vital during winter operations to ensure the regional gas delivery meets peak demands necessary during critical cold weather days.
- $600K

Willamette Valley Odorizer – Chromatograph Install

- Plat 1-015-059, Fern Prairie, WA
- This station is the main gas odorant injection site for all gate stations on the Williams system south of Washougal, WA.
- Installation of chromatograph at site to improve regional metering data.
- Install new station controls to activate cold standby odorizer system so that it can be used as a hot standby to provide alternatives in the event of equipment failure.
- $150K

Turner Gate System Metering

- Plat 1-119-000, Turner, OR
- System Reinforcement 10-year plan includes a project to uprate the Santiam Valley Feeder. This project will provide the IRP and system modeling team with accurate flow demands for this potential IRP project.
- Allows Gas Control to determine flow to Salem to optimize Kuebler Blvd Reinforcement Project and add valves and piping facilities to separate the 400 MAOP and 225 MAOP systems.
- Station is ranked high risk for vehicle protection. Add vehicle protection barriers to protect gate station facilities.
- Gas Control monitoring, system modeling and IRP team will utilize this data for safety, BTU calculation, and modeling purposes. New meter will meet Internal Audit guidance to add check metering at gate stations when a gate station is rebuilt.
- $2.1M

Camas Gate Building

- Plat 1-013-057, Camas, WA
- During the 2023 Camas Gate Station Rebuild project, a 1956 vintage regulator building was removed to facilitate the station construction project, and due to asbestos remediation. This gate station requires noise mitigation methods to prevent aerodynamic regulator noise from exceeding Clark County Code requirements.
- This project will install a new building over regulator runs to mitigate station noise and ensure noise levels meet County Code requirements.
- $1.1M

KB Pipeline to North Coast Feeder Gate Rebuild

- Columbia County, OR
- An existing gate station exists between the KB Pipeline and the Company's North Coast Feeder pipeline, located in the PGE Beaver Meter Yard in Columbia County. NW Natural maintains a contractual delivery obligation of 20,000 Dth/d from KB Pipeline to the Utility at this station, however the station does not have automatic controls and cannot flow unless operated by on site personnel.
- This project will modernize the KB to North Coast Feeder Gate to allow for full remote operation by NW Natural Gas Control. New facilities will include a filter/separator, new meter, valves and controls, and a gas chromatograph to

ensure accurate measurement and reliable remote control to utilize this gas supply resource.
- $1.2M

2026

Shaw and BPA Line Heater Replacement
- Plat 1-034-013, Beaverton, OR
- Replace line heater reaching end of life which has been flagged as an operational liability. Project will evaluate whether the burner management system may be replaced to extend the life of the heater, or whether the heater requires a complete replacement. At this time the burner management system is obsolete and at end of life.
- $860k

Aurora Line Heater Replacement
- Plat 1-067-020, Aurora, OR
- Replace line heater reaching end of life which has been flagged as an operational liability. Project has evaluated whether the burner and burner management system may be replaced to extend the life of the heater, or whether the heater requires a complete replacement, and determined that the heater requires complete replacement.
- $860k

North Vancouver Metering Installation
- Plat 1-002-046, Vancouver, WA
- Installation of ultrasonic metering to replace existing end of life annubar meter which is no longer supported by the manufacturer. This annubar meter is critical to measure gas flow for odorant injection. A new meter will provide flow data for odorization and additional custody-transfer grade check metering through the station, a best practice and meeting Internal Audit guidance to add check metering at gate stations when a gate station is rebuilt.
- $750k

West Vancouver Metering Installation
- Plat 1-012-023, Vancouver, WA
- Phase 1: Installation of ultrasonic metering to replace existing end of life annubar meter which is no longer supported by the manufacturer. This annubar meter is critical to measure gas flow for odorant injection. A new meter will provide flow data for odorization and additional custody-transfer grade check metering through the station, a best practice and meeting Internal Audit guidance to add check metering at gate stations when a gate station is rebuilt.
- Installation of chromatograph at site to improve regional metering data, and a check against Williams gas quality data.
- Phase 2: Installation of a new low-emission, high-efficiency line heater to prevent icing downstream of regulation due to the Joule-Thomson effect in which the gas temperature decreases downstream of regulation from a higher pressure to a lower pressure. This station currently sees icing during high flow and/or cold

weather conditions, due to the gas temperature being below freezing. Icing can lead to physical damage, coating damage and frost heave.
- $1.5M

Deer Island Kalama Metering
- Plat 4-035-013, Kalama, WA
- Installation of ultrasonic metering by Williams Northwest Pipeline at Williams owned facility, which measures gas flows to NW Natural system. This is a contractual obligation for NW Natural to be financially responsible due to Passive Ownership of this station.
- $550k

2027

McMinnville Amity Gate
- Plat 1-097-015, Silverton, OR
- Installation of ultrasonic check metering and taking over pressure protection from Williams to increase station capacity based on downstream flows exceeding contractual limits for the gate station. Williams has reported the existing station is undersized for the current customer load, and will require NW Natural to improve capacity at the station to meet customer demand.
- Installation of high efficiency line heater and zero-emissions odorizer.
- $3M

West Vancouver Odorant Depot
- Plat 1-012-023, Vancouver, WA
- Installation of a large-scale odorant storage tank to increase NWN's resilience by expanding on-site odorant capacity. This need was identified as critical during a nationwide odorant shortage when long procurement lead times posed a risk to maintaining safe pipeline operations.
- $1M

Salmon Creek Line Heater Replacement
- Plat 4-002-031, Mt. Vista, WA
- Replace line heater reaching end of life which has been flagged as an operational liability. Project will evaluate whether the burner management system may be replaced to extend the life of the heater, or whether the heater requires a complete replacement. At this time the burner management system is obsolete and at end of life.
- $1.25M

Molalla Gate Metering
- Plat 1-078-031, Molalla, OR
- Installation of ultrasonic metering by Williams Northwest Pipeline at Williams owned facility, which measures gas flows to NW Natural system. This is a contractual obligation for NW Natural to be financially responsible due to Passive Ownership of this station.

- Installation of ultrasonic metering at NW Natural side of facility. New meter will meet Internal Audit guidance to add check metering at gate stations
- $1.5M

Deer Island Gate Rebuild

- Plat 4-035-10, Reuben, OR
- Installation of ultrasonic metering for odorant controls and stronger system modelling capabilities. Replace existing, end of life system meters and single-path ultrasonic meter that is no longer supported by the manufacturer. The new meter is critical to measure gas flow for odorant injection.
- Rebuild odorization system including replacement of odorization building, new tanks, and controls. New odorizer will meet zero-emissions standards.
- Replace inlet regulation to reduce maintenance requirements and increase reliability.
- $4.1M

Sauvie Island Gate

- Plat 1-016-016, Sauvie Island, Portland, OR
- Installation of ultrasonic metering. New meter will meet Internal Audit guidance to add check metering at gate stations when a gate station is rebuilt. Meter is critical to measure gas flow for odorant injection.
- Rebuild odorization system including replacement of odorization building, new tanks and controls. New odorizer will meet zero-emissions standards.
- Installation of chromatograph at site to improve regional metering data.
- Station is ranked high risk for vehicle protection. Rerouting piping and adding vehicle protection barriers will protect gate station facilities.
- $2M

Section Two – 4 to 7 years (2028 to 2031)

Each project in this category will include a high level cost estimate, project description, preliminary modeling documentation and preliminary schedule date.

2028

NE Gate Station Rebuild (202892)

- Plat 1-027-055, Portland, OR
- Installation of ultrasonic metering. New meter will meet Internal Audit guidance to add check metering at gate stations when a gate station is rebuilt.
- Replace hard-to-operate valves identified by operations and remediate associated slip-on flanges. Also includes replacing 150 feet of transmission main within the station that has insufficient test documentation based on modern requirements.
- $2M

Felida Gate Station Rebuild

- Plat 1-003-025, Felida, WA
- Replacement of line heater reaching end of life.
- Replacement of existing ultrasonic meter which is no longer supported by the manufacturer, and at end of life.
- Replace end of life odorizer flagged as operational liability. New odorizer will meet zero-emissions standards.
- $1.5M

Ridgefield Line Heater Replacement

- Plat 4-016-029, Ridgefield, WA
- Replacement of line heater that is undersized for current system load with a new, low-emission high-efficiency line heater.
- Installation of ultrasonic meter for check metering. New meter will meet Internal Audit guidance to add check metering at gate stations.
- $1.25M

Battleground Line Heater Replacement

- Plat 4-005-041, Battleground, WA
- Replacement of line heater that is undersized for current system load with a new, low-emission high-efficiency line heater.
- Installation of ultrasonic meter for check metering. New meter will meet Internal Audit guidance to add check metering at gate stations.
- $1.25M

Albany Gate Metering

- Plat 2-157-003, Albany, OR
- Replacement of regulation with remote setpoint capabilities.
- Installation of ultrasonic metering for check metering. New meter will meet Internal Audit guidance to add check metering at gate stations.
- Upgrade station vehicle protection barriers.
- $900k

Mid-Willamette Valley Feeder to Albany System Metering

- OR
- Installation of metering to measure from the 600 MAOP Central Coast Feeder to the 400 MAOP to Albany (near Albany)
- Gas Control monitoring, system modeling and IRP team will utilize this data for safety and modeling purposes
- $1M

2029

Creswell Gate Rebuild

- Plat 2-251-009, Creswell, OR
- This site is part of a proposed MAOP uprate from 150psi to 300psi as stated in the IRP.

- This rebuild will require taking over regulation and overpressure protection from Williams Northwest Pipeline. No change to gate capacity is expected, this project is to increase the takeaway capacity downstream due to pressure drop in the small diameter high pressure distribution system.
- $3.1M (Design: $100K)

Gasco Mixer Station Rebuild (E-202893)

- Plat 1-023-021, Portland, OR
- Rebuild of station to remove abandoned runs, install more efficient runs and cools.
- Building replacement or alternative noise abatement, asbestos remediation, and demolition of existing structures. Hazardous soils in the area will be addressed during permitting/design to manage project risk.
- Approximately $4M (AA: $250K, Design: $250K)

Marquam Bridge Regional Station Rebuild

- Plat 1-032-029, Portland, OR
- Rebuild the station and replace remote valve actuators. This site was identified as critical in a seismic risk study. Reliable valve actuation at this site is essential for isolating multiple pipeline systems during a major earthquake
- $1.5M

Gresham Gate Metering

- Plat 1-032-054, Gresham, OR
- Installation of ultrasonic meter for check metering. New meter will meet Internal Audit guidance to add check metering at gate stations.
- $1.5M

2030

Johnson Creek Gate

- Plat 1-035-049, Gresham, OR
- Due to expansion in east Portland this gate exceeds Williams contractual flow limits.
- This rebuild will require taking over regulation and overpressure protection, installation of a line heater, improved metering and controls. Gas Control monitoring, system modeling and IRP team will utilize this data for safety, BTU calculation, and modeling purposes.
- $3.25MM (Design: $250K)

Salem Gate Station Rebuild

- Plat 1-112-008, Salem, OR
- Installation of ultrasonic meter for check metering. New meter will meet Internal Audit guidance to add check metering at gate stations.
- Replace hard-to-operate valves identified by operations and remediate associated slip-on flanges.
- $1.5M

Brownsville Halsey Gate Metering
- Plat 2-189-010, Halsey, OR
- Installation of ultrasonic meter for check metering. New meter will meet Internal Audit guidance to add check metering at gate stations.
- $500K

South Eugene Gate Rebuild and Metering
- Plat 2-238-007, Eugene, OR
- Upgrade to site telemetry to modern standards.
- Installation of ultrasonic meter for check metering. New meter will meet Internal Audit guidance to add check metering at gate stations.
- Replace hard-to-operate valves identified by operations.
- $2M

Oregon City Gate Metering
- Plat 1-060-040, Oregon City, OR
- Installation of ultrasonic meter for check metering. New meter will meet Internal Audit guidance to add check metering at gate stations.
- $1M

La Center Metering
- Plat 4-019-027, LaCenter WA
- Installation of ultrasonic meter for check metering. New meter will meet Internal Audit guidance to add check metering at gate stations.
- $500K

2031

Mt. Angel Metering
- Plat 1-096-016, Mt Angel, OR
- Installation of ultrasonic meter for check metering. New meter will meet Internal Audit guidance to add check metering at gate stations. Project will provide the IRP and system modeling team with accurate flow demands
- $500K

Section Three – 7 to 10 years (2032 to 2035)

Each project in this category will include a high level estimate and preliminary modeling documentation. Project planning is only conceptual for projects at this point.

2032

Rivergate Station Metering
- Plat 1-016-019, Portland, OR

- Installation of station metering to local the low pressure system. Additional metering will provide system modelling data for safety, BTU calculation, and modelling purposes.
- $500K

2033

TBD Metering

- OR
- Installation of ultrasonic meter for check metering.
- $500K

2034

TBD Metering

- OR
- Installation of ultrasonic meter for check metering.
- $500K

2035

TBD Metering

- OR
- Installation of ultrasonic meter for check metering.
- $500K

Section Four – Projects Completed in Prior Year

The following projects were completed last year. These projects were listed in prior 10 year planning documents accordingly.

2024

SE Gate Station Rebuild (E-202891)

- Portland, OR
- Replacement of difficult to operate/inoperable valves
- Replacement of end-of-life line heater
- Installation of ultrasonic check metering
- Relocation and tech refresh of telemetry
- $4.47M

Toledo Regional Station – Oil Slug Catcher (E-202841)

- OR
- Installation of an additional slug catcher upstream of regulation
- Oil slugs due to Newport LNG vaporization are migrating and overwhelming the existing coalescing filter at the station, and fouling downstream regulators
- $400k

Cornell and BPA Line Heater Replacement (E-202896)
- Cedar Mill, OR
- Replacement of end-of-life line heater
- $810k

Columbia and Adriatic Line Heater Replacement (E-202894)
- Portland, OR
- Replacement of end-of-life line heater
- $1.02M

North Vancouver Line Heater Replacement (E-202990)
- Vancouver, WA
- Replacement of end-of-life line heater with new, low emission high-efficiency line heater.
- $766k

Molalla Line Heater Replacement (E-202898)
- Molalla, OR
- Replacement of end-of-life line heater
- $375k

Sherwood Intertie System Metering / Brookman Rd (E-202900)
- Sherwood Intertie, Sherwood, OR
- Install metering for measurement of gas to West Portland and Newberg, 720 MAOP and 400 MAOP
- $1.75M

Brooks System Metering (E-202899)
- Brooks, OR
- Adds 2 system meters to measure Willamette Valley Feeder and Central Coast Feeder to Salem 400 MAOP
- Gas Control monitoring and IRP Team requirement
- $2.22M

West Linn Crossing Measurement (E-202901)
- West Linn, OR
- Installation of metering to measure gas crossing the Willamette River from the east into West Linn. Flow information will be used by Gas Control and IRP Team
- Will assist with IRP forecasting and Mist/PLNG flows to the East side of Portland.
- Provides situational awareness for Gas Control
- $1.35M

Rivergate Regional Station (E-202895)
- Portland, OR
- Original scope involved a minor station rebuild to address inoperable valves, remediate SOF, and installation of annubar metering
- Valve maintenance was performed to make onerous valves operable again and reduced scope to only install annubar metering. The scope reduction met

compliance and safety requirements, and a future project is potentially necessary.

- $40k

BEFORE THE

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NORTHWEST NATURAL GAS COMPANY

Exhibit of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

Exh. DBK-SSJ-7

August 29, 2025

Intake Request

Basic Details

Title

West Vancouver Gate Metering

Owning Department

Engineering

Business Case

- The existing annubar meter is legacy and needs replaced. If we lose the existing meter, we lose the odorizer which can lead to larger issues with unknown levels of odorant injection. The old meter needs to be replaced to update to current standards and improve measurement accuracy.
- The West Vancouver Gate Station currently has no check metering.
- The installation of an Ultrasonic Flow meter will provide flow quantity measurements and contribute to Gas Control monitoring, System Modeling BTU calculations, and IRP modeling forecasting.
- The site additionally does not possess a chromatograph for gas quality measurements.

Program

Not associated with a program

Discipline

Engineering

Discretionary?

Discretionary

Does this address a Safety or High Risk issue?

High Risk Issue

If safety or high risk, Please Explain

If the annubar flow meter were to be lost, NWN would have to rely on Williams flow data for odorant injection which would lead to a single point of failure. The inability to correclty inject odorant into our pipelines poses great safey risks.

Time constraints to start or complete initiative?

Complete new ultrasonic meter installation by Q4 of 2026.

Requested Start Date

9/2/2025

Alignment

Is this initiative called out as an officer goal?

No

Officer Goals

Is this work on your departmental roadmap?

Yes

If yes, please describe roadmap alignment

The West Vancouver Gate Metering project is included in Station Design's 10-year engineering plan.

Solving This Problem will:

Name
Be necessary for us to maintain operations
Will improve the way we currently do things

If any, explain current or future capabilities

This project will provide quantifiable station flow data for System Modeling and IRP forecasting.

Primary Benefit

The primary benefit of the installation of a new station ultrasonic meter is for check metering and gas flow measurement. Additionally, the addition of a chromatograph will provide BTU content for system modeling and quality measurements.

Upside

Initiative will lead to

Name
None of the above

Please explain growth opportunity or cost savings

None at this time.

Risks of company not tackling this initiative

- The main risk of not tackling this initiative would include the potential risk of losing the existing flow meter and losing the ability to correctly inject odorant into the pipeline.
- The risk of not tackling this initiative is that no higher resolution metering data will be provided for System and IRP modeling.
- Additionally, we would continually be reliant on metering data from Williams/NW Pipeline.
- Would not provide gas quality measurements for the gas flowing at the station.

Project Information

Roles & Responsibilities

Program/Project Manager

Jaimes, Abraham

Lifecycle Administrator

Jaimes, Abraham

If your project is likely to be >$500K, your executive sponsor must be an executive (e.g. for engineering this is likely Kim, for IT this is likely Frank). You may also select multiple executive sponsor (e.g. for an engineering project, please select both Kim and Jon as an executive sponsor so they have visiblity to your work).

Executive Sponsor

Primary	Name
◎	Karney, Joseph

Project Sponsor

Primary	Name
◎	Kizer, Daniel

Triage

Unless this is an engineering project, the following questions are optional for the project requestor. If you can answer them, it will help the Business Analyst complete the triage effort. If this is an Engineering project, you'll want to complete the triage now, completing the below information and then noting any resources needed in the schedule set up.

Rough Order of Magnitude: Cost

<$1MM

Rough Order of Magnitude: Effort

2 - Medium

Rough Order of Magnitude: Benefits

1 - High

Rough Order of Magnitude: Timeline

>12 months

Risks Associated with This Project

The risks associated with this project may include the addition of scope during the assessment and planning phases of the project. Initial scope is to install an ultrasonic flow meter, tie into existing RTU panel, reconfigure station piping to accomodate new flow meter, and assess documentation of station piping if needing replaced. Additionally, long lead time for the ultrasonic meter may impact project scheduling. Also, there is an existing building at the West Vancouver Gate Station and working around the building may pose challenges for construction.

Known Assumptions at Initiation Phase

- It is assumed that any updates to the existing building at the site and are out of scope.
- Engineered pipe design will be completed by NWN Station Design Engineers.
  Work will be completed by internal northwest natural crews.
- The existing RTU panel will be utilized to tie in the new ultrasonic meter and flow conditioner.
- Assuming all work will be completed within the existing station fence and no permits will be required for construction.
- Station piping will be assessed for proper documentation and will be included in scope if documentation needs to be updated.

Triage - Effort

What teams would need to be involved in implementing this project?

Teams involved in implementation

Name	Please select (VH, H, M, L or VL)
Accounting	L
Engineering	H
Gas Control	M
Infrastructure and Control Systems	H
Project Management Office	H
Purchasing	M
Safety	L
Utility Operations	M

Anyone we should talk to while estimating project?

- Transmission Supervisors - Jon Rose & Miles Broderson
- Welding Supervisor - James Greger
- System Operations - Ryan Ruiz & Richard Ahrendt
- System Modeling - Edward Thurman & Roger Haley
- Station Design - Roland Buckner & Mike McKenzie
- Project Management - Abraham Jaimes & Jorge Souto

If you want to attach additional content, please select the content button below and create a URL link to any documents in SharePoint.

Content

Required for Engineering Projects Only

Project Details

Location

003-Vancouver

Preliminary Scope of Gas Facility Work

The preliminary scope of the West Vancouver Metering project includes installation of a new ultrasonic check meter and chromatograph for gas quality measurements. This includes modifying existing gas piping to accomodate the new ultrasonc meter, installation of the new chromatograph, integrating new telemetry equipment into existing RTU panel, activating pipeline and commissioning equipment.

Is there an IT impact?

Yes

Project Details

Project Gas Plat Number(s)

1-012-023

Primary Applicant Code

0011 - MISC IMPROVEMENTS-GAS SUP

(Attach Visual Fusion or Map Frame Image of Project Area)

Link to Project Location Map

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DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

Exh. DBK-SSJ-8C

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August 29, 2025

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DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

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DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

Exh. DBK-SSJ-10C

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NORTHWEST NATURAL GAS COMPANY

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DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

Exh. DBK-SSJ-11

August 29, 2025

NW Natural
PROJECT ALTERNATIVES NARRATIVE

Program/Project Name: ***Mist GC500/GC600 Turbine Compressor Replacement***
Date: *01/21/2024*
Project Sponsor: *Daniel Kizer*
Executive Sponsor: *Dave Weber, Joe Karney*
Project Manager: *Brion Larson*
Preparer: *Michael Hwang, Brion Larson*
Was this project part of IRP: *NO*

SECTION 1: BUSINESS CASE

This section should be solution-agnostic, and about the overarching problem we're trying to solve no matter which routes we end up taking

OBJECTIVES *Why are we tackling this project?*	
Current State What is happening now? Where are we starting?	*NW Natural operates two Siemens turbine compressor units, which are critical to NW Natural's underground gas storage operations (GC500 and GC600 turbine compressor units).* *Without the availability of core and structural replacements from Siemens (The Original Equipment Manufacturer), the Mist Miller Compressor Station has faced operational and maintenance challenges due to the operation of turbine compressor assets beyond their useful life. As equipment approach the end of their useful life, operational and maintenance issues exponentially accelerate. This is being clearly witnessed in the field today and reliable service of these assets is no longer sustainable.* *The existing GC500 and GC600 turbines were installed in 1998 and 2001, respectively. Both units have an expected compressor core lifetime of 20 years which has been exceeded. Additionally the OEM no longer supports or produces parts for these specific units. As the GC 500 experienced more operations and equipment breakdown issues in recent years, the dependance on usage of the GC600 has dramatically increased. In 2016 the GC500 had 47,000hrs and the GC600 had 18,000hrs. Current day the GC500 has 56,500 hrs. and the GC600 has 42,500 hrs. Due to this sharp increase in utilization of the GC600, the GC600 has accelerated towards the end of its useful life.* *Despite efforts to repair and improve reliability of these assets and reduction of failure duration, failures are still occurring more frequently. The odds of a failure occurring during a winter event will only increase as the assets further age and outages become more frequent. Figure 1 illustrates the culmination of major outages of both NW Natural's turbine assets (GC500 and GC600). This chart does not capture maintenance events but is still an accurate indicator of the equipment's exponential decay.*

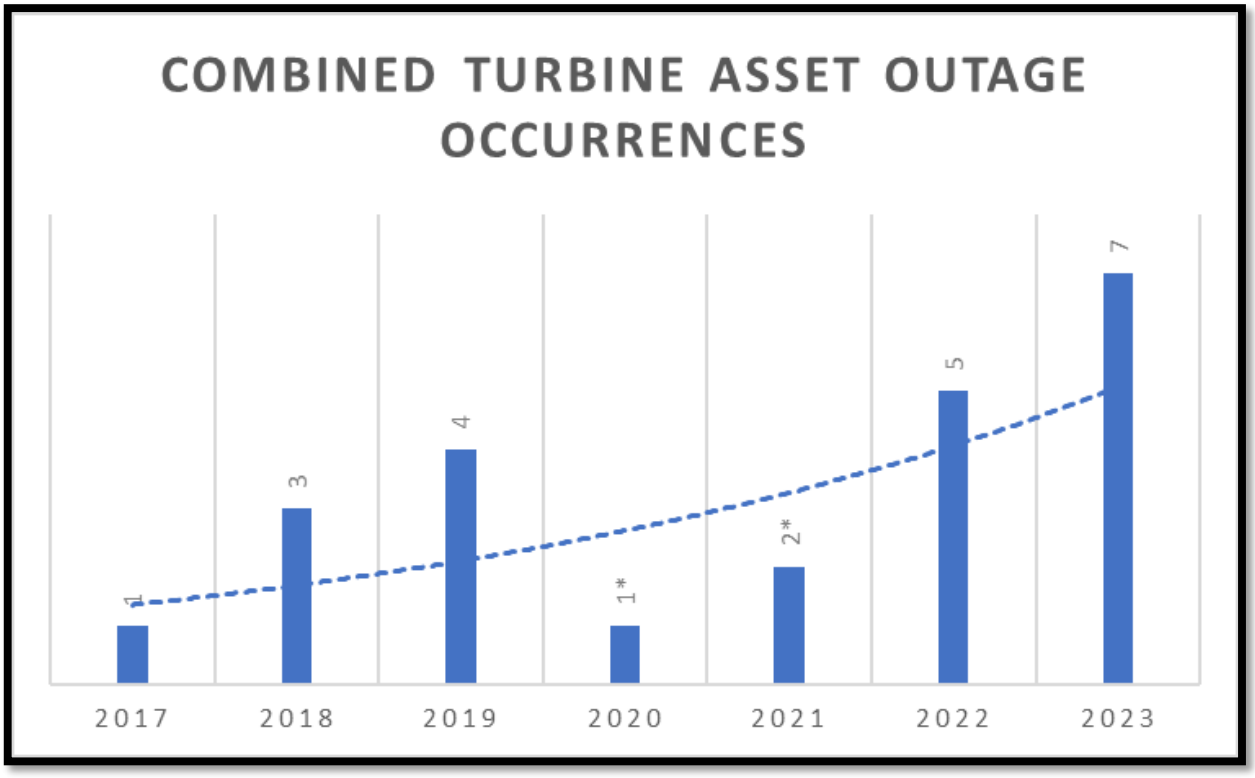


Figure 1: Turbine Asset Major Outages Cumulative Incidents by Year
**GC500 Turbine was not available for regular operations and was not utilized*

The importance of reliable storage gas delivery was demonstrated during the recent five record days of Mist withdrawal (between January 12 and 18, 2024). The age of the compressor equipment, high cost and potential limited availability of gas on the spot market as well as the inability to procure compressor parts in a timely manner, long lead times to manufacture parts, and the unknown reliability of the spare units has necessitated the urgency to replace the existing equipment as quickly as possible.

During cold weather events, such as those we experienced in January 2024, NW Natural has estimated that the loss of one turbine compressor would lead to a loss of gas service to approximately 200,000 customers (25% of our current customer count). Once NW Natural loses gas pressure to a customer, gas restoration is a 3-step process, with the third step of restoration only possible when system gas pressure is assured. The January 2024 cold weather would have caused repeated, daily low-pressure outages in our distribution system and loss of service due to lack of pressure. It's estimated that the recent, January 2024 cold weather would have prohibited the start of service restoration for six days, should NW Natural have experienced failure of one of the turbine compressors at the beginning of the recent cold weather that we experienced. The estimated time and resources required to complete service restoration for 200,000 customers, once weather warmed and system pressures were stabilized, is beyond any scale we've experienced.

NW Natural has recent experience resourcing a smaller, large system outage. After a Williams gate station was damaged by a motor vehicle in White Salmon, WA in December 2020, NW Natural lost service to nearly 5,000 customers in White Salmon, WA, Hood River and Odell, OR and the restoration process was nearly one week, which was achieved with the mutual assistance of staff from neighboring utilities. During the recent January 2024 cold weather our neighboring utilities experienced power supply and gas supply challenges that would have limited their ability to supply personnel resources to NW Natural should NW Natural have lost service to 200,000 customers. This fact presented a significant additional risk and increases the need for NW Natural to ensure reliability of our storage compression equipment.

The reliability risk extends beyond a peak-day event and involves many variables. A less severe winter event could still cause an outage affecting thousands, with the impact varying on a graduated scale depending on customer demand. NW Natural has a firm pipeline withdrawal allowance and relies on Mist storage as part of the baseline gas load. Without Mist Storage, NW Natural's pipeline withdrawal allowance would very likely be insufficient during any winter event. During a prolonged outage without NW Natural's turbine compressors in the heating season, it is almost certain that NW Natural will experience a large customer outage.

	Additional risk of outages outside of winter events exist, considering that the GC600 and GC500 turbine compressors were designed to operate at their peak during different times of the season due to their non-identical nature, NW Natural lacks full redundancy when one compressor is down. A single turbine compressor outage at our lower inventory levels could cause significant outages similar to losing both turbine compressors. *The GC600 is more effective when operating at lower compression ratios, such as early in the withdrawal season when gas reservoir pressures are higher. The GC500 is more effective at high compression ratios, such as later in the withdrawal season when gas reservoir pressures are lower. At the end of the withdrawal and injection season, an unplanned loss of one turbine compressor could leave Mist Miller without any available turbine compression, resulting in 83% of the compression horsepower being unavailable. The reduction of 83% of compression horsepower at 50% inventory would result in a 405 mmscfd reduction.* *A real scenario during the month of February 2023 highlights the high resiliency risk of NW Natural's existing turbine compressor assets. In that month, the GC500 experienced two consecutive showerhead failures. Faced with an impending winter event and only about a week to prepare, NW Natural had no choice but to reuse the non-serviceable combustion liners that lead to the overheating of our turbine and the reuse of non-serviceable first-stage blades, as seen in Figure 2. NW Natural managed to operate for around 72 hours successfully, getting past the winter storm, before experiencing another showerhead failure. This failure led to a 4-5 month outage.* *Figure 2: Borescope Image of the Non-Serviceable 1st Stage Blades* *Figure 2 shows metal deposition on the air-cooled 1st stage blades for the combustion liner showerhead failure. This metal deposition will cause cooling and balance issues. This level of metal deposition deemed the 1st stage blades as non-serviceable.*
Problem Statement In simple terms, what are we trying to solve? What is the	*Currently, the GC500 and GC600 have exceeded their operational useful life. Due to the age of the turbine equipment, Siemens engineering's lack of familiarity of these one-off legacy compressors, lack of spare parts available for purchase (globally), lead time to manufacture replacement parts, increasing major equipment outages, and the time to install a spare turbine increases the chances for failure of one or both existing turbines disrupting the supply of storage gas to our utility customers. Even with NW Natural owned cold spares, a gas generator failure could take one week, and a power turbine failure could take one month.*

business need this is tackling? Why is this a problem worth solving (e.g., why is the current state not working)?	*During the recent record Mist withdrawal days in January 2024, its estimated the loss of one turbine compressor could result in the potential loss of approximately 200,000 customers.* *Failures commonly require the return of the turbine compressor core to the Maintenance Repair and Overhaul Center (MROC) in Houston, Texas. The GC500 was sent to MROC in 2022 and 2023 for overhauls, consuming four to six months before it was returned to service each of those years.* *Additionally, very few of the same units exist and are operated regularly. Due to the one-off nature of these turbine compressor packages, common failure modes are unknown, true mean time statistical data between failures is limited, and replacement parts need to be reengineered and manufactured individually. This is evidenced by the GC500's overheating issues taking over three years to resolve, the GC500's showerhead failure taking one year to resolve, the GC500's combustion liner harmonics still under investigation, and the GC600's partial showerhead failure still under investigation. Furthermore, the GC500's rear turbine support case and power turbine shaft are needed critical spares. These components have been in process with Siemens engineering for over a year due to the supply chain and manufacturing processes needing to be redeveloped and engineered.*
Desired Deliverables What high level output / scope / deliverables are core to this project?	*The desired deliverable is to replace the two turbine units with Solar Taurus 60 units. These compressor units were identified during a recent Front End Engineering Study (FEED) performed by one of our engineering consultants of record. The FEED studied looked at past Mist operational send out records and system operational parameters and identified the compressor that best fits our operational requirements. There are 2000 like for like Solar units in operation and not only do these units have a track record of years of dependability, but also have statistical data to support their mean time between overhauls. Solar's mean time between overhauls prevents operators operating the units to failure. The two new turbine compressors will be identical allowing for flexibility for each unit to operate in all ranges of pressures and conditions independently. Thus, creating more flexibility, increasing resiliency, and reducing the quantity of spare part required in storage at NW Naturals operations.* *Recently NW Natural had procured spare compressor units for the GC600 and the GC500 to provide emergency backup should one of them experience a failure. The spares were purchased for backup purposes and the Company had decided to move forward with the replacement of the GC500 and GC600 in 2026 and 2027. 2026 and 2027 construction allowed the Company to procure the Oregon Department of Energy (ODOE) Energy Facility Siting Council (EFSC) permit before proceeding with compressor procurement, final engineering and construction. Recent weather events and five record setting Mist storage gas delivery days in January 2024, has increased the urgency to replace the existing units, accelerating construction by one year to the years 2025 and 2026. Under this new, accelerated schedule, the Company has elected to proceed with procurement of the GC500 compressor replacement and final engineering before the Oregon DOE EFSC permit is received.* *NW Natural will first begin construction on the older GC500 while keeping the GC600 online to support injection operations. During this time, the heavier dependence of the GC600 will further accelerate the end of life of this asset, hours on the GC600 are estimated to exceed 50,000hrs. Because of the heavier utilization in the recent years, the replacement of the GC600 will follow the GC500 the next injection season. During the construction of the GC600, the replacement GC500 will continue to support operations.*

SECTION 2: ALTERNATIVES SUMMARY

OVERVIEW *How did we review these options?*

Review Process Summarize how options were chosen, who was involved in the choice and how options were evaluated. If some criteria were considered more important based on the type of project, please explain here.	*Burns & McDonnell, Michael Hwang, P.E., Brion Larson, and Miller Station operations were involved in choosing these options.* *Resiliency, time of implementation, equipment support, and costs were considered in the evaluation of options.* *Reference Burn & McDonnell's Sim and Unit Selection Report*
DECISION CRITERIA *Describe the criteria used to determine the selection from the various alternatives considered. For example, is this a program/project where the least cost option should be selected? Are there other factors, such as safety or quality, that come into play? Include both quantitative and qualitative factors as appropriate.*	
Criteria: Resiliency	*The project goal is to provide a unit with a proven track record of reliability and with plentiful field data to avoid operating until failure. Additionally, a unit that is diverse enough to independently work in all potential operational conditions existing at the Miller storage facilities.*
Criteria: Time of implementation	*The time of implementation of the recommended alternative is crucial for operational reliability.* *The existing GC500 and GC600 turbines were installed in 1998 and 2001, respectively. Both units have an expected compressor core lifetime of 20 years which has been exceeded, additionally the manufacture no longer supports or produces many parts for these units.* *Construction is scheduled for a two-year timeline, one unit per year to maintain the operation of the Mist Miller storage facility during the injection and withdrawal season. Construction is expected to begin post heating season and prior to February. This scope of work was originally scheduled for 2026 and 2027. However, with the five-record setting gas delivery days, availability of spare parts and the increasing trend of mechanical outages has increased the urgency to replace the existing units, accelerating construction years to 2025 and 2026.*
Criteria: Equipment Support	*The goal is to select a vendor/product with a proven track record of reliability and support. Including the availability of spare parts and technician availability to react to issues that may occur.*
Criteria: Cost /Benefit	*The analysis should be based on the most cost-effective, reliable and manufacturer supported option.*

SECTION 3: ALTERNATIVES DETAIL

RECOMMENDED OPTION *Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option. If positive /neutral/negative observations do not exist, enter N/A*	
Description	*In the fourth quarter of 2022, Burns & McDonnell partnered with NW Natural to evaluate the existing Mist Miller Storage facility needs, specifically the replacement of the existing gas turbine compressors. Burns & McDonnell prepared a study that addressed operational issues and concerns related to the existing gas turbine compressors and proposed to the NW Natural team to acquire two new gas turbine compressors and associated equipment to replace the existing units.* *The report evaluated multiple unit and compressor combinations before coming up with the final replacement recommendation of the existing turbines in operation at the Mist Miller Compressor/Storage facility. Based on Burns & McDonnell's assessment the following modifications were recommended after evaluating the multiple scenarios:* • *Replace the existing GC500 and GC600 Siemens Gas Turbines and compressor units with new two Solar Turbine Taurus 60s with Tandem compressors.* • *Install a new fuel gas system to condition the fuel supply to the gas turbines.* • *Replace the existing gas aftercoolers with new coolers to improve the operational range of the turbine compressors*
In brief, why is this the recommended option?	*Local Service Support (Oregon): Solar Turbines has a regional office based in Irvine, CA to support customers in the Western US, including Oregon. Operating out of this facility and Simulation and Units strategically located in the area, Solar has personnel locally to ensure highest equipment availability and support:* • *District Service Manager* • *Aftermarket Account Manager* • *Two (2) Field Office Coordinators* • *Two (2) Field Service Supervisors* • *Regional Field Engineer* • *Fleet Manager(s)* • *Eighteen (18) Field Service Representatives* *On-Time Delivery: Solar understands that delivery is important to their clients and has developed a proven order execution strategy which has resulted in a > 99 % on-time delivery for customers in the past 11 years. This proven strategy also means quicker and more comprehensive production of engineering deliverables to support our customers.* *Expertise: Over 2,000 like for like units are in operations. Known failure modes have been eliminated and operators can reliably operate until the mean time between overhaul limits.* *Proven Performance & Emissions: With Solar's experience globally, they recognize the criticality of meeting environmental requirements. The Taurus 60's offered will meet 25 ppm NOx and 25 ppm CO, with an expansive range from 50% to 100% load, utilizing Solar's proven SoLoNOx technology. This provides significant operational flexibility, while still maintaining ultra-low emissions. The Taurus 60 compression solution meets all the site process conditions provided to Solar at an optimal efficiency.* *Total Lifecycle Support: Solar's commitment is to provide complete lifecycle support to our customer. Solar will ensure a seamless handover between business development, project management, and field service for a successful commissioning and startup. Throughout the life of operations Solar will provide comprehensive support for field service, spare parts, overhauls and upgrades, package system updates, asset optimization, and more. Solar also offers many comprehensive service programs which can be tailored to meet NW Natural's needs. Additionally, due to the large fleet of identical Taurus 60 units, Solar stocks turbine cores and provides a 14-day turnaround for emergency replacements. (Impeller of the centrifugal are application specific, spares will be purchased)*

<table>
<tr><td></td><td colspan="2">With a Solar Turbine Taurus 60 as the selected solution, current day challenges and risks will be greatly reduced.

The current day and problem statement synopses from above are as follows:
• Turbine Compressor Unit Reliability
• Between 2016 to 2023, 78 out of 96 months at least one turbine compressor has been out of service from unplanned outages.
• Major outage frequency is increasing
• Our ability to provide reliable service to our customers during peak cold weather events is becoming a greater unknown due to equipment unreliability.
• GC500 currently has 56,500 hrs. and the GC600 has 42,500 hrs.
• GC600's reliability is at risk as the usage approached the GC500's
• Lack of OEM support and knowledge of NW Naturals one of a kind compressor units
• Spot gas will need to be purchased, AECOM in 2020 estimates one day of downtime is $12m
• If spot gas is not available (Peak Day Event), outages exceeding 200,000 customers is possible</td></tr>
<tr><td rowspan="4">Assessment</td><td>Criteria: Resiliency</td><td>Solar Turbines has been an energy solutions provider for over 95 years. Solar has shipped over 16,000 gas turbines and 6,500 gas compressors which are supported globally by their Customer Services organization. The Taurus 60 was first introduced in 1987 and Solar has sold over 2000 Taurus 60 packages. Solar has proven durability and experience in critical applications, with an emphasis on low emissions. Solar also has extensive experience providing products and services for similar applications, with a proven track record, and ease of execution with North America based manufacturing. With such a large fleet of Taurus 60's, spare cores are available within 14 days in the event of an unplanned failure.</td></tr>
<tr><td>Criteria: Time of implementation</td><td>Solar understands that delivery is important to our clients and has developed a proven order execution strategy which has resulted in a > 99 % on-time delivery for our customers in the past 11 years. This proven strategy also means quicker and more comprehensive production of engineering deliverables to support our customers.</td></tr>
<tr><td>Criteria: Equipment Support</td><td>Solar's commitment is to provide complete lifecycle support to our customer. Solar will ensure a seamless handover between business development, project management, and field service for a successful commissioning and startup. Throughout the life of operations Solar will provide comprehensive support for field service, spare parts, overhauls and upgrades, package system updates, asset optimization, and more. Solar also offers many comprehensive service programs which can be tailored to meet NW Natural's needs.</td></tr>
<tr><td>Criteria: Cost</td><td>Having a reliable, original equipment manufacturer (OEM) supported equipment package that has a proven, successful operational track record is the most cost-effective option.

One form is the reduction of purchasing spot gas. When storage gas is unavailable, gas must be purchased at market price. At times of high demand, this cost can be in the magnitude of millions of dollars per day more.

The other form of cost offsets is the avoidance of major customer outages. The importance of reliable storage gas delivery is evidenced by the recent five record Mist withdraw days and during these recent record Mist withdraw days, the loss of one turbine compressor could be the loss of approximately 200,000 customers.</td></tr>
</table>

<table>
<tr><td rowspan="2">Assessment</td><td>Additional Risks</td><td>• Timely process approvals, negotiating terms and conditions, and procurement of the Taurus 60 package.
• Completing construction within the allotted schedule (weather delays, fire season,
• Supply chain delays beyond the quoted lead times
• Approval of the EFSC permit prior to May 1, 2025</td></tr>
<tr><td>Additional Benefits</td><td>• Construction 2025 mitigates the risk of failure one year earlier than the original schedule of 2026. One full heating season earlier than originally estimated.</td></tr>
<tr><td colspan="4">POTENTIAL COST (EXCLUDING CONTINGENCY)</td></tr>
<tr><td rowspan="2">Capital Range</td><td>Direct</td><td>CURRENT COH (TBD)</td><td>Total</td></tr>
<tr><td>$61,562,000</td><td>TBD</td><td>TBD</td></tr>
<tr><td rowspan="2">O&M Range</td><td colspan="2">Program/Project</td><td>Ongoing Maintenance & Support</td></tr>
<tr><td colspan="2">$0,00</td><td></td></tr>
<tr><td>Source/ Method of Cost Data</td><td colspan="3">Original detailed engineering estimate</td></tr>
</table>

ALTERNATIVE 1 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*	
Description	*Do nothing.*
In brief, why is this option not recommended?	*By maintaining the status quo, the project team will not address the root causes of major structural component failures. With the existing units exceeding their operational usefulness due to the age of the turbine equipment, lack of spare parts available for purchase (globally), lead time to manufacture replacement parts, increasing number of major outages and the unknown reliability of the spare turbines, significantly increases the chances for failure of one or both existing turbines. Additionally, for the same reasons increasing the likelihood of failure, time to repair those failures will increase with each additional failure. Failures will continue to be unpredictable.* • *Age of existing equipment: The existing GC500 and GC600 turbines were originally installed in 1998 and 2001, respectively. Both units have an expected compressor core lifetime of 20 years which has been exceeded, additionally the manufacture no longer supports or produces parts for these specific units. Also, highlighting that since 2016 the GC500 has ran approximately 8,000 hours and the GC600 operated 24,000 hours. The importance of this consideration is that the GC600 is approaching the total hours the GC500 had in 2016, when the string of unplanned outages started to increase in frequency and duration.* • *Repair parts availability/ lead times/ expertise: Rebuilding the GC500 in 2022 and 2023, rendering the unit unavailable for 4 and 6 months respectively. This has emphasized the lack of knowledge at Siemens required for overhauls in addition to the lack of parts. The lack of knowledge and parts, combined with the frequency of unit failures has highlighted the urgency for replacement. During the most recent 2023 overhaul, the Maintenance Repair Overhaul Center (MROC) took over 10 bench tests to correctly pass factory acceptance. In 2018/19 the Siemens authorized MROC did not trim the 4th stage blades properly. This factory error identified post installation at the Mist Miller facility, resulted in immediate failure and the turbine was returned to MROC.* *With the low fleet numbers of identical units and the GC500 being the only of its kind regularly operated, Siemens does not have the expertise to support our turbine compressors. Common failure modes are unknown, true mean time statistical data between failures is limited, and replacement parts need to be reengineered and manufactured individually.* *This is further proven by the GC500's overheating issues taking over three years to resolve, the GC500's showerhead failure taking one year to resolve, the GC500's combustion liner harmonics still under investigation, and the GC600's partial showerhead failure still under investigation. Furthermore, the GC500's rear turbine support case and power turbine shaft are needed critical spares. These components have been in process with Siemens engineering for over a year due to the supply chain and manufacturing issues needing to be redeveloped and engineered.* • *Outage Frequency / Duration: As depicted in Figure 1 on Page 2, the frequency of major outages has increased over a 7-year period. Due to the anomalies in 2020 and 2021, the GC500 was mostly out of service for those two years. As stated above, as outage frequency increases the duration of the outage has decreased; however, with every repair to the units' spare parts have become less available and we expect that soon the durations will increase dramatically.* • *Spare Turbines: In 2022, NWN began researching the purchase of spare turbines. Two gas generators were identified and negotiated, and these units were purchased and rebuilt in 2023. units are in storage at the Mist Miller compressor station. However, these units are a combination of five decommissioned units sourced globally of unknown vintage, their reliability in our system is untested, and the availability of parts beyond what NW Natural owns today are not manufacturable without significant engineering of a new manufacturing process and supply chain. The power turbines are more unique and are still undergoing investigation with Siemens engineering.*

	Since 2017, approximately $15M has been spent to ensure reliability and maintain service to our customers. Combined with the uncertainty and reliability of the units has increased the urgency for replacement accelerating installation into the 2025 construction season. *Doing nothing as an alternative will result in extra cost to our customers due to compressor downtime. Spot gas will need to be purchased when compressors are unavailable. In the 2020 AECOM study, they estimate the additional cost of spot gas for one day of downtime to be $12M If spot gas is not available which is common during a peak day event, a force majeure will be required and outages which could exceed 200,000 customers is a possibility.*	
Assessment	**Analysis Against Criteria: Resiliency**	*Taking no action will not resolve operational issues or other issues related to OEM unresponsiveness, lack of spare parts, etc.*
	Analysis Against Criteria: Time of Implementation	*Taking no action will result in increasing risk of significant downtime, impacting Plant availability and reducing overall flow capacity.*
	Criteria: Equipment Support	*OEM support of the equipment will still be poor and will likely get worse as fleet numbers decrease.*
	Analysis Against Criteria: Cost	*This alternative will not require any funds.*
	Additional Risks	*Taking no action will not improve site resiliency.*
	Additional Benefits	*None.*

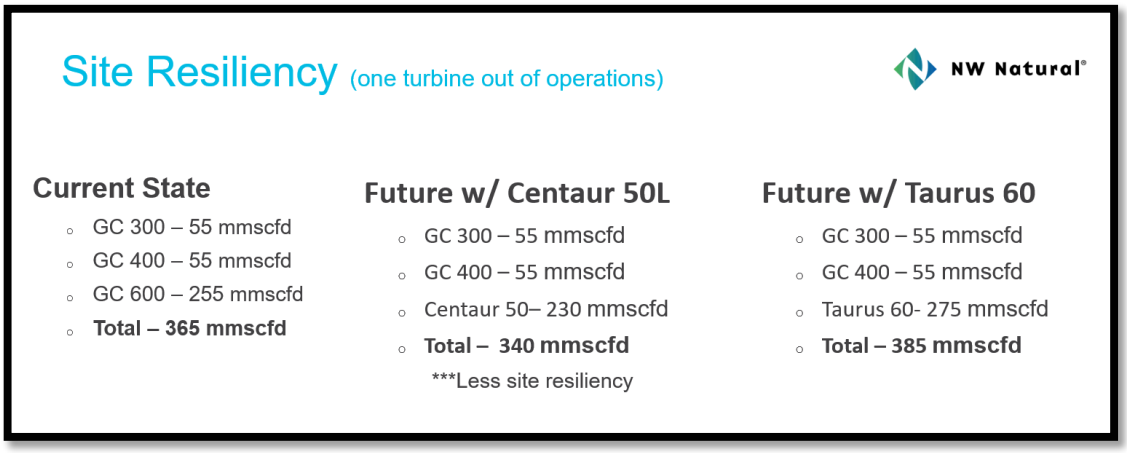
POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$0.00	$0.00	$0.00
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$0.00	$0.00	
Source/ Method of Cost Data	N/A.		

**Copy/Add table for any additional alternatives*

ALTERNATIVE 2 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*	
Description	*Replace the existing GC500 with a Siemens SGT-100 equivalent driver and re-wheel the existing compressor. Continue to operate the GC600 as is. This was the original recommendation from the 2020 AECOM study. With 3 more years of operational experience, this option was no longer recommended as described in Burns & McDonnell's Turbine Study Report.*
In brief, why is this option not recommended?	*Replacing the existing GC500 with a Siemens SGT-100 equivalent driver will not provide a long-term solution to NWN due to the reliability and availability of the existing gas turbine compressor units, as well as lack of response from the original equipment manufacturer (OEM), lack of spare parts, and extended lead times. In North America, only one other SGT-100 is in operations.* *The GC600 unit is approaching the same usage as the GC500. The two units are near identical, except for the high compressor discharge pressure leading to more horsepower out of the GC600.*

	The GC600 will have the same issues as the GC500 as it ages with unplanned failures and OEM support. *This alternative only offers a partial solution. Maintenance and failure issues will continue based on the historical experience with the same model that the operations team has used for decades.*	
Assessment	**Criteria: Resiliency**	*This alternative will not offer a long-term solution to NWN, as operational issues are related to the reliability and availability of the existing gas turbine compressor units. The alternative will not remediate other issues related to the lack of response from the OEM, lack of spare parts, etc.* *Replacing the GC500 driver with a Siemens SGT-100 equivalent driver will potentially lead to the same issues Operations has been facing for years. There is only one SGT-100 in use in North America. Additionally, this alternative does not address the aging GC600 that soon could have reliability issues as it approaches the same usage as the GC500. Since 2016 the GC500 has ran approximately 8,000 hours and the GC600 operated 24,000 hours. The importance of this consideration is that the GC600 is approaching the total hours the GC500 had in 2016, when the string of unplanned outages started to increase in frequency and duration.*
	Criteria: Time of Implementation	*This alternative timeline is similar to the recommended option.*
	Criteria: Equipment Support	*OEM support of the equipment will still be poor*
	Criteria: Cost	*The cost of implementation of approximately $8.2MM, with minimal change to OEM support and limited availability to the parts does not improve the unit reliability enough to justify the cost.*
	Additional Risks	*This alternative does not consider redundancy of the units or increasing the flow rate of each gas turbine unit.*
	Additional Benefits	

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH (TBD)**	**Total**
	$8,200,000	**TBD**	**TBD**
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$0,00	$0,00	
Source/ Method of Cost Data	*AECOM – Compressor Evaluation Study. Burns & McDonnell- Turbine Compressor Study*		

ALTERNATIVE 3 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*	
Description	*Replace the existing GC500 and GC600 with two Centaur 50L turbine compressors*
In brief, why is this option not recommended?	*The Centaur 50L turbine compressor, a considered lower horsepower alternative, presented operational challenges and did not meet NW Natural's resiliency requirements. The overall lower throughput of the Centaur 50L would worsen NW Naturals current state, due to lower daily send out capacity, as seen in Figure 3.*  *Figure 3: Site Resiliency, One Turbine Out of Service Max Deliverability at 50% Inventory* *The Centaur 50L is less common than the Taurus 60 and Centaur 50 (50L designates a different configuration) due to the utilization of a more unique power turbine. Although the Centaur 50L is currently supported, there is less business incentive, given the lower fleet number, to continue its lifecycle management. Additionally, because of the lower fleet numbers, obtaining spare parts may be more challenging, and technical expertise will be more limited compared to the Taurus 60 and Centaur 50. Currently there are no known Centaur 50L's in our service region. The Centaur 50L also offers no advantages over the Taurus 60, with the centrifugal compressor selection and overall package size remaining the same. The overall cost difference to the project would be less than 3%.* *Furthermore, a Centaur 50L would not have enough horsepower to stay out of surge at certain operating conditions, such as the end of NW Natural's injection season. At the tail end of NW Natural's injection season, ambient temperatures may reach 100f. As seen in Figure 4, the Centaur 50L would not be capable of operating in 100f conditions due to the reduced efficiency at the higher ambient temperature and would run out of horsepower. The Centaur 50L would need to stop operations until ambient temperatures drop.*

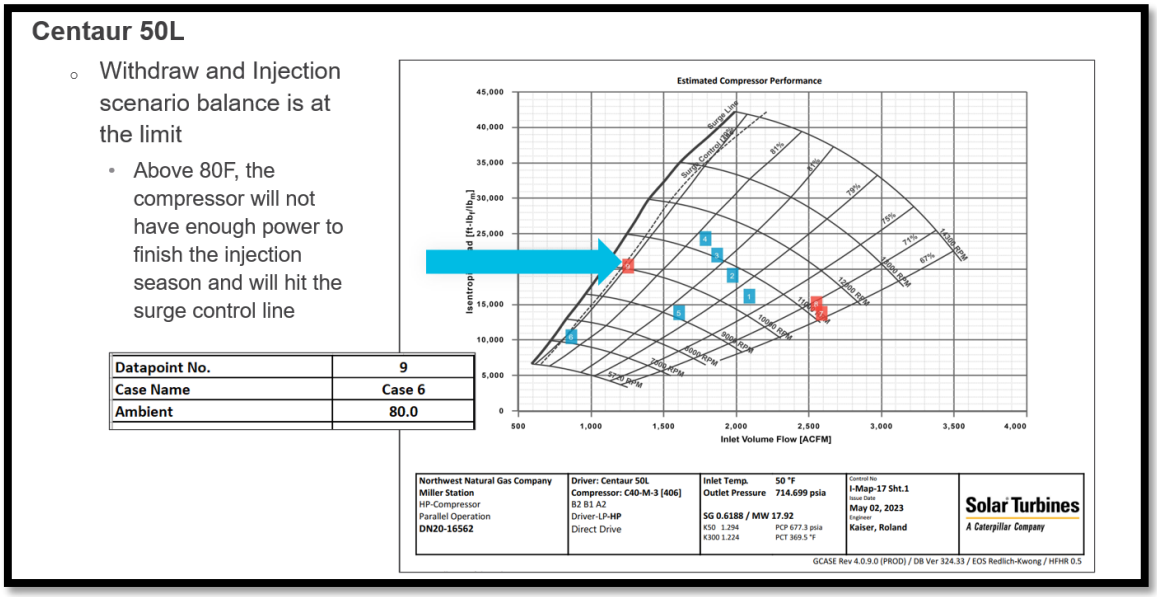


Figure 4: Centaur 50L Compressor Map

In summary, the Centaur 50L, being a more unique turbine, would expose NW Natural to greater future support risks, create a less resilient compressor station, and be unable to operate in high differential conditions at the end of our injection season. For these reasons, the Centaur 50L was not selected.

Assessment	**Analysis Against Criteria: Resiliency**	*The Centaur 50L turbine compressor did not meet NW Natural's resiliency requirements. The overall lower throughput of the Centaur 50L would worsen NW Naturals current state as seen in Figure 3. Additionally, the Centaur 50L, being a more unique turbine, would expose NW Natural to greater future support risks.*
	Analysis Against Criteria: Time of Implementation	*The duration would be the same as NW Naturals recommended option*
	Criteria: Equipment Support	*Currently there are no known Centaur 50L's in our service region. Obtaining spare parts may be more challenging, and technical expertise will be more limited compared to the Taurus 60 and Centaur 50. The Centaur 50L is less common than the Taurus 60 and Centaur 50 (50L designates a different configuration) due to the utilization of a more unique power turbine. Although the Centaur 50L is currently supported, there is less business incentive, given the lower fleet number, to continue its lifecycle management.*
	Analysis Against Criteria: Cost	*This alternative requires a lower cost of project implementation of about $60,352,000, mainly regarding the cost of the turbine compressor, design, material, and construction cost.*
	Additional Risks	*Long lead time for the permit approval process and OPUC acknowledgment.*
	Additional Benefits	
POTENTIAL COST (EXCLUDING CONTINGENCY)		

Capital Range	Direct	CURRENT COH	Total
	$60,082,000	TBD	TBD
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$0.00	$0.00	
Source/ Method of Cost Data	*Burns & McDonnell - Simulation and Unit Selection report.* Solar Equipment Budgetary Estimates		

ALTERNATIVE 4 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*	
Description	*Replace the existing GC500 and GC600 with a single Mars 90 turbine compressor*
In brief, why is this option not recommended?	*A singular Mars 90 turbine compressor would be oversized 99% of the time. Peak events represent extreme conditions. Sizing a single compressor for peak events would make it challenging to control and operate under normal conditions. A more recommended practice would be to stage compressors sized more closely to the median flow rates required in parallel and to bring them online sequentially as needed.* *Excessive recycling of gas from the discharge back into the suction of the compressor would be necessary with a singular Mars 90 turbine compressor. Figure 5 represents the daily quantity of withdrawn gas in mmscfd over 6 years. 75% of the time, the flow rate demand was less than 180mmscfd. Additionally, 25% of the time, the flow rate was below 55mmscfd. The minimum flow rate requirement at Mist Miller is 30mmscfd for the turbine compressors. To comply with NW Naturals' emission permit limits, a Mars 90 should not fall below 7,000-8,000 horsepower. Figure 6, a high-level simulation demonstrates that 320mmscfd of recycling would be necessary to keep the compressor adequately loaded to meet our minimum flow rate requirements due to emission regulations. This is not an industry best practice, and this alternative was not recommended by three independent engineering firms. The turbine compressor would operate at 50% load almost indefinitely, excluding peak events. This would be an abnormal operating condition that no other operators would have experience operating in for a prolonged period, and unplanned/unknown issues may arise when operating a turbine compressor in this manner.* *The Mars 90 compressor is 48' with a single centrifugal compressor. NW Natural's Mist Storage field has a wide operating range from 250psig to 1200psig. To accommodate this large operating range, a tandem centrifugal compressor configuration will be needed, reference Figure 8. This will further increase the length of the single Mars 90 turbine compressor to 55'-60'. NW Naturals' existing building is 75'x50'. The added room to comply with NEC 70 electrical code and room for rotor maintenance is beyond what the existing building could feasibly be expanded to. The unit must be installed 90 degrees from the existing compressor orientation. The existing compressor orientation can be seen in Figure 9. This would result in both turbine compressors being out of commission for the entire injection season. The reduction of 83% of compression horsepower at 50% inventory would result in a 405 mmscfd reduction. This would present major operational challenges and put Mist Miller at risk of not being able to fill the storage reservoirs sufficiently, leading to a shortage of storage gas and an increased need to purchase spot gas.* *Furthermore, being a singular large compressor making up 83% of the available compression horsepower, Mist Miller would be less resilient post project completion. This singular Mars 90 would essentially become a single point of failure, as seen in Figure 10.* *Considering the Mars 90 being greatly oversized 99% of the time, the abnormal unique operating conditions, the impact on operations during construction, the single point of failure, and the reduction in site resiliency, the Mars 90 is not a recommended solution.*

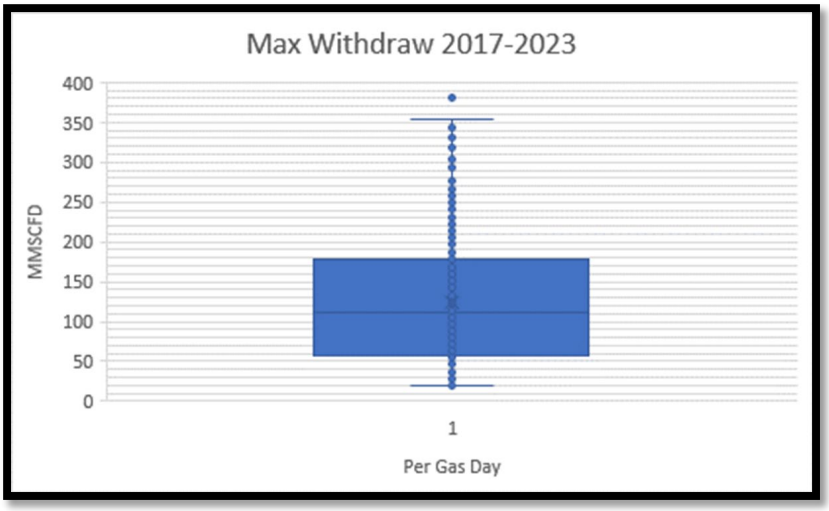


Figure 5: Box and Whisker of Withdrawn Gas by Day Rate

Figure 5 is a box and whisker plot; the outer whiskers represent 100% of the statistically significant data. The box represents the 25th and 75th quartile of the data set and the line the in middle of the box is the median.

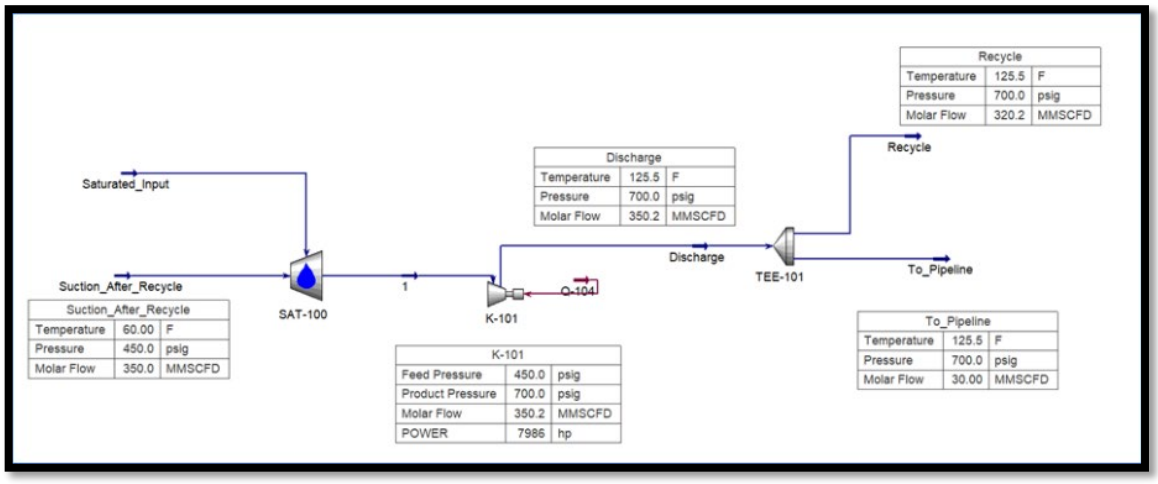


Figure 6: Mars 90 50% power Minimum Flow Rate Simulation

This simulation represents the minimum flow rate required to maintain 50% power at our 50% inventory level. 50% power is needed to maintain our emissions profile. Operating below this power threshold, emissions would no longer be guaranteed and would not be permitted.

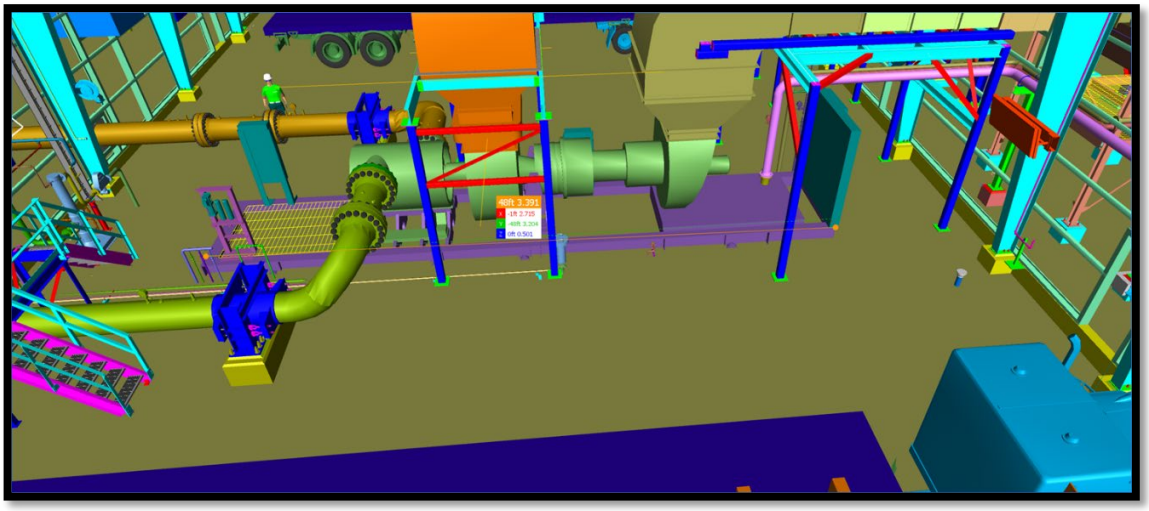


Figure 7: Mars 90 Skid Size, Single Compressor

The overall length of a Mars 90 is 48”, Figure 7 shows a model of a typical Mars 90 skid.

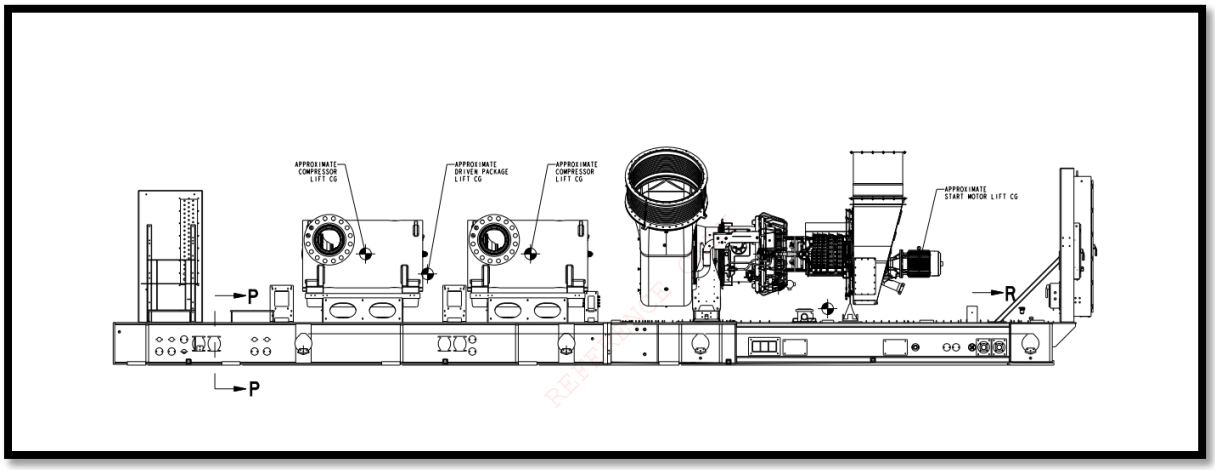


Figure 8: Solar Tandem Compressor Example

A tandem centrifugal compressor configuration is needed when more operational flexibility is needed. One centrifugal compressor is a high-pressure compressor and the other is a low-pressure centrifugal compressor. When compression ratios are low, the tandem compressors will operate in parallel. When compression ratios are high, the tandem compressors will operate in series.

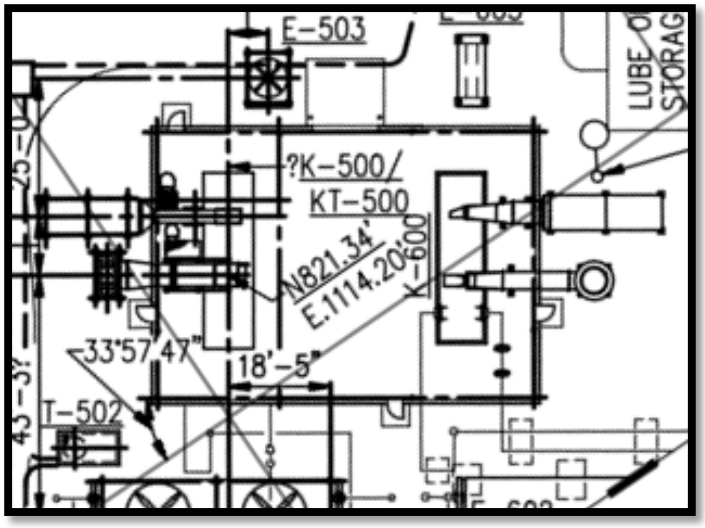


Figure 9: Mist Miller Compressor Building Existing Layout

Figure 9 is Mist Millers existing turbine building. The building is 75'x50'. A Mars 90 unit would need to be installed 90 degrees from the existing turbine compressors orientation. This would take both existing turbine compressors out of commission for the entirety of the injection season.

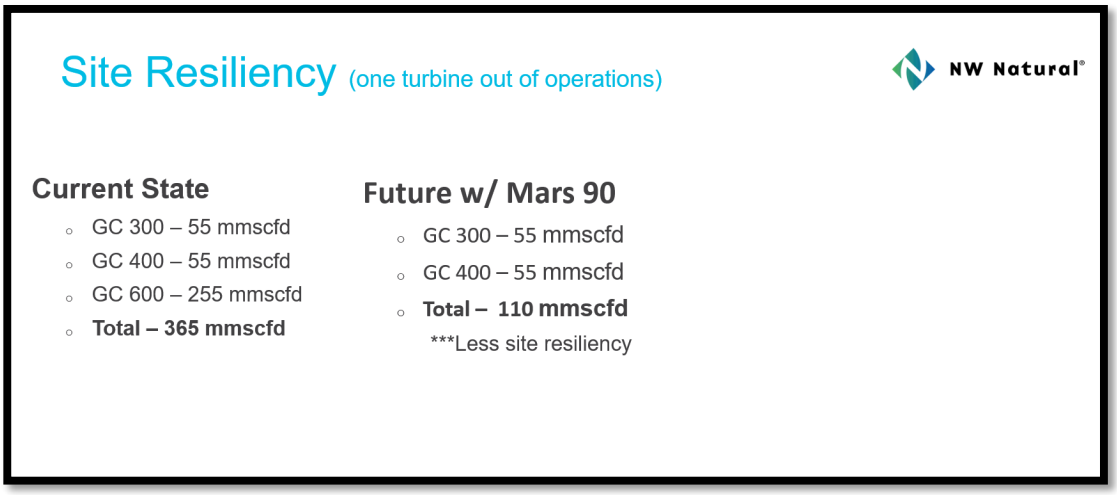


Figure 10: Site Resiliency, One Turbine Out of Service Max Deliverability at 50% Inventory

Assessment	**Analysis Against Criteria: Resiliency**	*Being a singular large compressor making up 83% of the available compression horsepower, Mist Miller would be in a less resilient state post project completion. This singular Mars 90 turbine compressor would essentially become a single point of failure as seen in Figure 10.*
	Analysis Against Criteria: Time of Implementation	*The unit must be installed 90 degrees from the existing compressor orientation. This would result in both existing turbine compressors being out of commission for the entire injection season.*

	Criteria: Equipment Support	*As stated in the recommended option, Solar's commitment is to provide complete lifecycle support to our customer, and they are well known for providing that service.*
	Analysis Against Criteria: Cost	*This alternative requires a lower cost of project implementation of about $47MM, mainly regarding the cost of the turbine compressor, design, material, and construction cost.*
	Additional Risks	*Long lead time for the permit approval process and OPUC acknowledgment.*
	Additional Benefits	

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$47,000,000	TBD	TBD
O&M Range	**Program/Project**		**Ongoing Maintenance & Support**
	$0.00		$0.00
Source/ Method of Cost Data	*Burns & McDonnell*		

ALTERNATIVES CONSIDERED NOT VIABLE *Provide a description of any additional alternatives that were considered but rejected up front as not viable, and explain why*		
	Description	**Why the Alternative is not viable**
Alternative 4		
Alternative 5		
Alternative 6		

**Add rows for any additional alternatives considered not viable*

SUPPLEMENTARY INFORMATION

As needed, you may include any useful information gathered during the assessment phase including analysis like cost benefit / risk analysis / sensitivity analysis, etc.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	Docket UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

Exh. DBK-SSJ-12

August 29, 2025

Initial Project Charter

The initial project charter is intended to document the team's initial approach to analyzing the problem. Completed at the end of initiate, this will serve as the foundation for performing any studies or analysis as the project team weighs potential options for solving the underlying business case.

Initial

Project Description

Western Oregon Electric Co-Op will construct a new sub station located along the mainline at the 8-mile mark. This substation will be spliced into the existing feed between Miller Station and North Mist to individually feed both stations

or

Install a new feed parallel to the existing feed from Highway 202, up to Miller Station. An EFSC permit would need to be filed to proceed.

Project Cost will be split between North Mist App 564 (17%) and Miller App 18 (83%)

Business Case

NW Natural executed on a 2021 Miller Station Electrical Reliability Study with Harris Group identifying high level scopes of work recommended in tiers of priority.

NW Natural in 2023 executed on a front end engineering design (FEED) with Burns & McDonnell and determined the existing power feed was end of life and warranted a timely replacement due to the criticality and impact to Miller Station in the event of a failure.

The 2024 Burns & McDonnell Facility Assessment Study NW Natural will also include a recommendation to upgrade the end of life main power feed

The power feed to Miller Station, and subsequently to North Mist, needs to be replaced with a reliable solution to prevent any risk of failure. This will ensure that both facilities can maintain reliable operation and meet customer and contractual obligations.

Key Objectives and Outcomes

The power feed to Miller Station, and subsequently to North Mist, needs to be replaced with a reliable solution to prevent any risk of failure. This will ensure that both facilities can maintain reliable operation and meet customer and contractual obligations.

Rough Cost/Benefit Analysis Summary

Miller Station is currently fed by an underground cable circuit that runs from Highway 202 up to the station. The circuit consists of three single-conductor 1/0 cables, which terminate at Miller Station's switchgear. This switchgear also delivers power to North Mist and the well pads.

The existing cable is 29 years old and uses above-ground cable junction boxes located along the mainline. In the early 2000s, the cable was damaged by a dozer, which led to a subsequent failure several years later.

The power feed to Miller Station, and subsequently to North Mist, needs to be replaced with a reliable solution to prevent any risk of failure. This will ensure that both facilities can maintain reliable operation and meet customer and contractual obligations.

Rough Scope

Perform study to determine best path to install a new feed.

Third party engineering study will be performed to evaluate options for achieving a new power feed. This would include but not limited to:
-A new line ran along the access road up to Miller Station or Paying West O to drop a new sub station along the path between North Mist and Miller Station. This would feed North Mist and back feed to Miller Station.-Perform the engineering analysis and design (2025)
-This may include time and payment for West O company to install their facilities.

-Construction/Installation (2026)

Initial -Cont.

Known Constraints at Initiation Phase

Either option selected will have long lead materials that need to be ordered early,

Known Assumptions at Initiation Phase

Oregon DOE EFSC permit will be granted
This project will have Mixed Utility and Non-Utility Costs.
This project will have a portion allocated to North Mist

Change Control Plan

Standard NWN Change Control Plan

Project Information

Roles & Responsibilities

Initial Project Team & Roles

Alex Hada- Project Engineer
Jake Petersen- Project Manager

Project Governance Structure

Standard NWN Governance Structure

Roles & Responsibilities

Lifecycle Administrator

Petersen, Jake

Program/Project Manager

Petersen, Jake

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	Docket UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

Exh. DBK-SSJ-13

August 29, 2025

Mist Gas Storage Facility

Planning Document
2025 – 10-year plan
Date updated: February 24th, 2025.

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Scope

This plan is for the Mist Gas Storage facility. Capital construction projects included in this plan are based upon projects identified in the 2016 EN Engineering Facility Assessment Study of the Mist Gas Storage Facility, a 2020 AECOM Mist Gas Storage Compression Assessment of all four compressors, a 2022 Burns and McDonnell Mist Gas Storage Turbine Compressor Assessment, and a 2024 Burns and McDonnell Mist Gas Storage15-Year Facility Assessment.

End-of-life assets may include and have several determinants, such as functional degradation, failure risks, or regulatory requirements. End-of-life indicators include:

- Severe corrosion within a component or system due to atmospheric, galvanic corrosion, or minor issues with insulation over time.
- Mechanical wear effects of any of the rotating equipment onsite.
- Fatigue caused by cycling in materials, particularly in systems with significant temperature changes.
- Technology that has become unsupported and at risk for failure without the ability to support a repair.

All required projects going forward will be constructed to contemporaneous seismic standards. This may require replacement of an original foundation with foundation systems designed to accommodate updated standards and ground liquefaction issues.

All required projects going forward will be constructed to contemporaneous cathodic protection standards. This usually requires isolation of above ground piping and the addition of jumper bonds to continue the cathodic protection of sub surface piping.

Project execution dates may be required to vary in the future from those identified due to:

- Unplanned failure of the gas storage systems and assets.
- New information obtained on the facility/component condition, resulting in a change to the urgency of the project.
- An opportunity to improve execution efficiency.
- The need to prevent and/or reduce interruptions to facility distribution system operations.
- Permitting.
- Loss of resources redirected to issues which require near term resolutions.
- The IRP processes.

Estimated or actual costs specified in this document do not include construction overhead (COH). These costs are also assumed to be in the current year of the plan and do not include escalation.

Selection Criteria

Each project is included in the plan for one or more of the following reasons:

- Replacement of equipment is at end-of-life.
- Refurbishment or preventative maintenance to extend the asset's useful life.
- Compliance with environmental or safety regulations or concerns.
- Identified within the reliability program

Section 1– 1 to 4 years (2025 to 2028)

Mist 2025

Mist Miller Custody Transfer Meters, Year 2

- The 15-year facility assessment performed by Burns and McDonnell identified the Custody transfer meter as an end-of-life asset due to support from the original manufacturer. This scope includes replacing the meter tubes and associated electrical components.
- Upgrading to NWN standard meters promotes operational resiliency and safety through maintenance, design practices, and standard functions.
- Accurate measurement of Injection/Withdrawal is critical for operational functions as well as billing and financial planning.
- Cost in 2025: $385,000 (Construction)
- Total project cost (2024/2025) $516,500. (+50%/-25%, $.75M/$0.387M)
- 100% Utility asset

Mist Fuel Filtration, Year 3

- In 2020 and 2023, NW Natural executed on an internal Root Cause Analysis (RCA) for the multiple turbine combustion system failures. A separate RCA was also performed by Siemens Energy (Original Equipment Manufacturer)
- Found liquids in the fuel supply for all fuel burning equipment have been identified as a contributor to the many outages and service interruptions.
- NW Natural performed an additional detailed assessment with Norwest summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- The 15-year facility assessment performed by Burns and McDonnell also identified this fuel supply to our fuel burning equipment as a risk to reliability. Burns and McDonnell recommends a fuel filtration system immediately downstream of the fuel supply tie in due to the significant elevation change further reducing risk of liquid accumulation slugs.
- Cost in 2025: $830,000 (Construction)
- Total project cost (2023-2025) $1,240,000. (+10%/-10%, $1.36M/$1.16M)
- 100% Utility Asset

Mist Well Pad Power Gas Hydrate Elimination

- NW Natural executed a project in 2023 and 2024 upgrading 13 Methanol injection systems. This includes new tanks and pump injection systems to mitigate hydrate formation on the control and metering equipment.
    - After installation and commissioning of this new equipment, an additional risk of hydrate formation has been identified in the power gas lines through the facilities, requiring modifications within the power gas lines that were not in included in the previous scope. Hydrates on these lines could cause valve failure to operate as designed.
    - This project is being categorized as "Break Fix" to maintain consistent operation of the injection system.
- Cost in 2025: $525,000 (+100%/-50%, $1.05M/$262K)
- Mix of Utility and Interstate Gas Storage Assets
    - Utility $351K
    - Non-Utility $173K

Mist Busch Manifold Flow Control Valve, Year 2

- NW Natural executed on a 2024 Facility Assessment Study with Burns and McDonell identifying high level scopes of work recommended for plant reliability. The Busch Manifold Flow Control Valves replacements were included as a recommended project to replace end of life equipment.
- When initiated, NW Natural will utilize a third-party engineering service provider to perform a detailed Basis of Design report containing technology selection justification.
    - During the assessment phase of the project launched in 2024, the existing control valves began to operate in a non-reliable manner and failed. A temporary installation of an on-hand control valve was executed to maintain operation through withdrawal season.
- NW Natural will procure and replace Busch Manifold Flow Control Valves.
- Cost in 2025: $1,384,600 (Construction)
- Total project cost (2024/2025) $1,536,000. (+50%/-25%, $2.3M/$1.15M)
- Mix of Utility and Interstate Gas Storage Assets
    - Utility $399K
    - Non-Utility $1.136M

Mist GC500/GC600 Turbine Comp Replacement, Year 3

- In response to the discovery that the 2020 AECOM Compressor Study had feasibility issues, a restudy of the turbine compressors was warranted. The frequency of part and equipment failures has accelerated since the study was performed.
- NW Natural performed a 2022 Turbine Compressor Assessment Study with Burns and McDonnell. Within this study it identified the lack of sustainability of the existing turbine compressors and highlighted the operational risks.
    - The GC500 has 55,000 hours and is past end of life.
    - The GC600 has 47,000 hours and is past end of life.

- The continued increase in the frequency of part and equipment failures has justified a more accelerated timeline since the 2022 Turbine Compressor Assessment Study with Burns and McDonnell.
    - GC500 replacement in 2025
    - GC600 replacement in 2026
- NW Natural utilized a third-party engineering service provider to perform a detailed Basis of Design report containing technology selection justification.
- Oregon DOE EFSC and Oregon DEQ air permits are required for both new compressors.
- Execution completed by Q3 2025 and 2026
- Cost in 2025: $43,983,000 (Construction)
- Total project cost (2023-2027) $86,017,000. (+10%/-10%, $94.6M/$77.4M)
- Mix of Utility and Interstate Gas Storage Assets
    - Utility $60.8M
    - Non-Utility $25.2M

Mist Well Separator Replacements 2025-2029, Year 1

- In 2021, NW Natural identified new process conditions from the reworked wells posing risk to site deliverability and compliance (192.165).
    - Liquid loading of the process gas has increased due to the well rework program.
    - NW Natural executed on a 2021 Miller Station Filtration Engineering Assessment with Harris Group identifying high level scopes of work recommended for immediate risks and further investigation to be performed.

- In 2022, NW Natural identified more risk associated with the separators. Separators were inspected per API recommendations and significant wall loss was found.
    - Separators found beyond the corrosion allowance were immediately removed out of service.

- NW Natural has remediated the immediate reliability and compliance risks.
- The Burns and McDonnell 15-year Facility Assessment included a detailed Basis of Design report containing technology selection justification with a recommended schedule of replacement.
- Cost in 2025: $840,000 (Construction)
- Total project cost $11,695,000. (+50%/-25%, $17.5M/$8.77M)
- Mix of Utility and Interstate Gas Storage Assets
    - Utility $7.367M
    - Non-Utility $4.327M

Mist Main Power Feed, Year 1

- NW Natural executed on a 2021 Miller Station Electrical Reliability Study with Harris Group identifying high level scopes of work recommended in tiers of priority.
- NW Natural in 2023 executed on a front-end engineering design (FEED) with Burns & McDonnell and determined the existing power feed was end of life and warranted a timely replacement due to the criticality and impact to Miller Station in

the event of a failure. This analysis will be referenced in the 2024 Facility Assessment Study with Burns and McDonell
- The 2024 Burns & McDonnell Facility Assessment Study NW Natural also included a recommendation to upgrade the end-of-life main power feed.
- NW Natural will perform an updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and alternative selection justification.
- Oregon DOE EFSC permit is required for this work. NW Natural is pursuing options that would not require an EFSC permit.
- Execution completed by Q3 2026
- Cost in 2025: $50,000 (Engineering/Design)
- Total project cost (2025-2026) $3,800,000. (+100%/-50%, $7.6M/$1.9M)
- 100% Utility asset

Mist-Birkenfeld Fire Pond Improvements
- This project will include replacement of the pumping facility as well as the associated equipment necessary to operate in the event of a power failure.
- This is an investment into the rural fire department as a prerequisite for the North Mist expansion EFSC permit.
- A signed agreement with the rural fire department is necessary to proceed with the permitting for the new station.
- Cost in 2025: $525,000. (+100%/-50%, $.787M/$0.393M).
- Mix of Utility and Interstate Gas Storage Assets, and North Mist Costs
    - Utility $310K
    - Non-Utility $215K
    - North Mist $99K

Mist/Miller Tier 1 & 2 Projects 2025 (Run Rate)
- Tier 1 projects have expenditures up to $250k while Tier 2 projects have expenditures ranging from $250k-$500k.
- Cost in 2025 for Tier 1 and 2 Projects: $500,000. (+100%/-50%, $1M/$0.25M).
- 100% Utility asset.

Mist 2026

Mist Miller Bruer/Flora/Meyer Metering Upgrade, Year 1
- The 15-year facility assessment performed by Burns and McDonnell identified these reservoir inventory meters as an end-of-life asset due to support from the original manufacturer. This scope only includes replacing the meter tubes and associated electrical components.
- The 15-year facility assessment performed by Burns and McDonnell also identified the individual IW well meters as end of life due to their age and wear and tear.
- Upgrading to NWN standard meters promotes resiliency and safety through maintenance, design practices, and standard functions.

- Accurate measurement of Injection/Withdrawal is critical for operational functions, safety, and as well as financial planning.
- Evaluate elimination of Meyer/Flora Math Meter
- Metering and IW well connectivity upgrade from copper to fiber with controls IO upgrade
- Cost in 2026: $120,000 (Engineering/Design)
- Total project cost (2025-2026) $3,360,000. (+100%/-50%, $6M/$1.5M)
- Mix of Utility and Interstate Gas Storage Assets
    - Utility $1.89M
    - Non-Utility $472K

Mist GC500/GC600 Turbine Comp Replacement, Year 4

- In response to the discovery that the 2020 AECOM Compressor Study had feasibility issues, a restudy of the turbine compressors was warranted. The frequency of part and equipment failures has accelerated since the study was performed.
- NW Natural performed a 2022 Turbine Compressor Assessment Study with Burns and McDonnell. Within this study it identified the lack of sustainability of the existing turbine compressors and highlighted the operational risks.
    - The GC500 has 55,000 hours and is past end of life.
    - The GC600 has 47,000 hours and is past end of life.
- The continued increase in the frequency of part and equipment failures has justified a more accelerated timeline since the 2022 Turbine Compressor Assessment Study with Burns and McDonnell.
    - GC500 replacement in 2025
    - GC600 replacement in 2026
- NW Natural utilized a third-party engineering service provider to perform a detailed Basis of Design report containing technology selection justification.
- Oregon DOE EFSC and Oregon DEQ air permits are required for both new compressors.
- Execution completed by Q3 2025 and 2027 (TBD)
- Cost in 2026: $28,840,000 (Engineering/Design)
- Total project cost (2023-2027) $86,017,000. (+10%/-10%, $94.6M/$77.4M)
- Mix of Utility and Interstate Gas Storage Assets
    - Utility cost $60.817M
    - Non-Utility $25.199M

Mist Well Separator Replacements 2025-2029, Year 2

- In 2021, NW Natural identified new process conditions from the reworked wells posing risk to site deliverability and compliance (192.165).
    - Liquid loading of the process gas has greatly increased due to the well rework program.
    - NW Natural executed on a 2021 Miller Station Filtration Engineering Assessment with Harris Group identifying high level scopes of work recommended for immediate risks and further investigation to be performed.

- In 2022, NW Natural identified more risk associated with the separators. Separators were inspected per API recommendations and significant wall loss was found.
    - Separators found beyond the corrosion allowance were immediately removed out of service.
- NW Natural has remediated the immediate reliability and compliance risks.
- The Burns and McDonnell 15-year Facility Assessment included a detailed Basis of Design report containing technology selection justification with a recommended schedule of replacement.
- Cost in 2026: $2,875,000
- Total project cost $11,695,000. (+100%/-50%, $23M/$5.75M)
- Mix of Utility and Interstate Gas Storage Assets
    - Utility $7.367M
    - Non-Utility $4.327M

Mist/Miller Tier 1 & 2 Projects 2026 (Run Rate)

- Tier 1 projects have expenditures up to $250k while Tier 2 projects have expenditures ranging from $250k-$500k.
- Cost in 2026 for Tier 1 and 2 Projects: $500,000. (+100%/-50%, $1M/$0.25M).
- 100% Utility asset.

Mist Miller Bruer/Flora Gathering Separator, Year 1

- The 15-year facility assessment performed by Burns and McDonnell identified separators at the Flora and Bruer separators to be at their end of life and undersized as evidenced from the produced liquids infiltrating Mist Compression equipment.
- This assessment produced the following recommendations:
    - Removal of water from the wells by installing more efficient filters
    - Catch slugs, solid and water removal of 0.3 microns and larger at the inlet of Miller Station.
    - Protect the equipment and valves at Miller station
- NW Natural will perform an updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- Cost in 2026 $700,000
- Total project cost (2026/2027) $3,900,000. (+100%/-50%, $8M/$2M)
- Mix of Utility and Interstate Gas Storage Assets
    - Utility $3.326M
    - Non-Utility $573K

Mist Main Power Feed, Year 2

- NW Natural executed on a 2021 Miller Station Electrical Reliability Study with Harris Group identifying high level scopes of work recommended in tiers of priority.
- NW Natural in 2023 executed on a front-end engineering design (FEED) with Burns & McDonnell and determined the existing power feed was end of life and warranted a timely replacement due to the criticality and impact to Miller Station in

the event of a failure. This analysis will be referenced in the 2024 Facility Assessment Study with Burns and McDonell

- The 2024 Burns & McDonnell Facility Assessment Study NW Natural also included a recommendation to upgrade the end-of-life main power feed.
- NW Natural will perform an updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- Oregon DOE EFSC permit is required for this work. NW Natural is pursuing options that would not require an EFSC permit.
- Execution completed by Q3 2026
- Cost in 2026: $3,750,000 (Construction)
- Total project cost (2025-2026) $3,800,000. (+100%/-50%, $6M/$1.5M)
- 100% Utility asset

Mist Miller Power Gas Elimination Assessment and Pilot, Year 1

- NW Natural has historically operated above and beyond regulatory requirements. Though the Utilities are exempt from the proposed ban of natural gas driven pneumatic devices, NW Natural would like to pilot opportunities to reduce natural gas fugitive emissions for future technology selection best practices.
- The 15-year facility assessment performed by Burns and McDonnell identified areas of opportunities and potential pilot sites to reduce fugitive emission from pneumatically driven devices.
- NW Natural will perform an updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- Planning/Design and Project execution will be performed in 2027.
- Final report and assessment will be performed in 2028.
- Cost in 2026: $200,000 (Construction)
- Total project cost (2027-2028) $1,000,000. (+100%/-50%, $2M/$.5M)
- 100% utility asset

Mist Miller Air Compressor and Receiver Tank Upgrades, Year 1

- A compressed air usage study was performed in 2024, and the current Instrument air system has enough capacity for the current system demand for ESD and plant operations. After the GC500/600 replacement projects, the air system will have no additional capacity for any new equipment that would be added or upgraded to the facility.
- The back up air compressor will be needed for ESD events.
- This project will address this shortage of capacity for ESD events and add enough capacity to cover all current demand as well as anticipated future needs.
- Additionally, a receiver will act as an accumulator, in the event of a power outage, the accumulator will be sized to allow for the facility to ESD and move to a safe state.
- Cost in 2026: $100,000 (Engineering/Design)
- Total Project Cost: $1,100,000 (+100%/-50%, $2.2M/$0.505M)

Mist 2027

Mist Miller Bruer/Flora Gathering Separator, Year 2

- The 15-year facility assessment performed by Burns and McDonnell identified separators at the Flora and Bruer separators to be at their end of life and undersized as evidenced from the produced liquids infiltrating Mist Compression equipment.
- This assessment produced the following recommendations:
    - Removal of water from the wells by installing more efficient filters
    - Catch slugs, solid and water removal of 0.3 microns and larger at the inlet of Miller Station.
    - Protect the equipment and valves at Miller station
- NW Natural will perform an updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- Cost in 2027: $3,200,000 (Construction)
- Total project cost (2026/2027) $3,900,000. (+100%/-50%, $8M/$2M)
- Mix of Utility and Interstate Gas Storage Assets
    - Utility $3.326M
    - Non-Utility $573K

Mist Miller Power Gas Elimination Assessment and Pilot, Year 2

- NW Natural has historically operated beyond regulatory requirements. Though the Utilities are exempt from the proposed ban of natural gas driven pneumatic devices, NW Natural would like to pilot opportunities to reduce natural gas fugitive emissions for future technology selection best practices.
- The 15-year facility assessment performed by Burns and McDonnell identified areas of opportunities and potential pilot sites to reduce fugitive emission from pneumatically driven devices.
- NW Natural will perform an updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- Planning/Design and Project execution will be performed in 2026.
- Final report and assessment will be performed in 2027.
- Cost in 2027: $700,000 (Construction)
- Total project cost (2026/2027) $1,100,000. (+100%/-50%, $2M/$0.505M)
- 100% utility asset

Mist Well Separator Replacements 2025-2029, Year 3

- In 2021, NW Natural identified new process conditions from the reworked wells posing risk to site deliverability and compliance (192.165).
    - Liquid loading of the process gas has greatly increased due to the well rework program.
    - NW Natural executed on a 2021 Miller Station Filtration Engineering Assessment with Harris Group identifying high

level scopes of work recommended for immediate risks and further investigation to be performed.

- In 2022, NW Natural identified more risk associated with the separators. Separators were inspected per API recommendation and significant wall loss was found.
    - Separators found beyond the corrosion allowance were immediately removed out of service.

- NW Natural has remediated the immediate reliability and compliance risks.
- The Burns and McDonnell 15-year Facility Assessment included a detailed Basis of Design report containing technology selection justification with a recommended schedule of replacement.
- Cost in 2027: $2,990,000
- Total project cost (2027) $11,695,000. (+100%/-50%, $23M/$5.75M)
- Mix of Utility and Interstate Gas Storage Assets
    - Utility $7.367M
    - Non-Utility $4.237M

Mist Small Dehydration System Replacement (2028 IRP), Year 1

- NW Natural executed on a 2016 Facility Assessment Study with EN Engineering identifying high level scopes of work recommended for plant reliability. An area of risk highlighted was Miller Stations Small Dehydration System.
- The 15-year Facility Assessment Study performed by Burns and McDonnell refreshed EN Engineering's 8-year-old study with modern recommendations with considerations from the new assessment of the equipment's health and changes in process conditions.
- In response to the 2016 and 2024 Facility Assessment Study recommendations, NW Natural will perform an additional updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- NW Natural will replace the small dehydration system.
- Cost in 2027: $700,000 (Engineering/Design)
- Total project cost (2027-2030) $18,650,000. (+100%/-50%, $37.3M/$9.3M)
- Mix of Utility and Interstate Gas Storage Assets
    - Utility cost $6.154M
    - Non-Utility $12.495M

Mist/Miller Tier 1 & 2 Projects 2027 (Run Rate)

- Tier 1 projects have expenditures up to $250k while Tier 2 projects have expenditures ranging from $250k-$500k.
- Cost in 2027 for Tier 1 and 2 Projects: $1,500,000. (+100%/-50%, $3M/$0.75M).
- 100% Utility asset.

Mist Miller Bruer/Flora/Meyer Metering Upgrade, Year 2

- The 15-year facility assessment performed by Burns and McDonnell identified these Reservoir inventory meters as an end-of-life asset due to support from the

original manufacturer. This scope only included replacing the meter tubes and associated electrical components.
- The 15-year facility assessment performed by Burns and McDonnell also identified the individual IW well meters as end of life due to their age and wear and tear.
- Upgrading to NWN standard meters promotes safety through maintenance, design practices, and operational functions.
- Accurate measurement of Injection/Withdrawal is critical for operational functions as well as billing and financial planning.
- Evaluate elimination of Meyer/Flora Math Meter
- Metering and IW well connectivity upgrade from copper to fiber with controls IO upgrade
- Cost in 2027: $2,240,000 (Construction)
- Total project cost (2026-2027) $2,360,000. (+100%/-50%, $4.6M/$1.15M)
- Mix of Utility and Interstate Gas Storage Assets
    - Utility cost $1.888M
    - Non-Utility $472K

Mist Miller Air Compressor and Receiver Tank Upgrades, Year 2
- A compressed air usage study was performed in 2024, and the current Instrument air system has enough capacity for the current system demand for ESD and plant operations. After the GC500/600 replacement projects, the air system will have no additional capacity for any new equipment that would be added or upgraded to the facility.
- The back up air compressor will be needed for ESD events.
- This project will address this shortage of capacity for ESD events and add enough capacity to cover all current demand as well as anticipated future needs.
- Additionally, a receiver will act as an accumulator, in the event of a power outage, the accumulator will be sized to allow for the facility to move to a safe state.
- Cost in 2027: $1,000,000 (Construction)
- Total Project Cost: $1,100,000 (+100%/-50%, $2.2M/$0.505M)
- 100% Utility asset.

Mist Calvin Creek Gathering Separator
- The 15-year facility assessment performed by Burns and McDonnell identified separators are needed from the Calvin Creek/Twin 16 feed. Separators existing at the pools but do not exist at the plant inlet.
- These are needed for residual liquids that may be left within the line between the pools and the station due to low flow.
- The separator performance needs to be the following:
    - Removal of water from the wells by installing more efficient filters
    - Catch slugs, solid and water removal of 0.3 microns and larger at the inlet of Miller Station.
    - Protect the equipment and valves at Miller station
- NW Natural will perform an updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.

- Cost in 2027: $200,000 (Engineering/Design)
- Total project cost (2027-2028) $1,900,000. (+100%/-50%, $4M/$1M)
- Mix of Utility and Interstate Gas Storage Assets
    - Utility $1.324M
    - Non-Utility $575K

Mist 2028

Mist Miller Power Gas Elimination Assessment and Pilot, Year 2

- NW Natural has historically operated beyond regulatory requirements. Though the Utilities are exempt from the proposed ban of natural gas driven pneumatic devices, NW Natural would like to pilot opportunities to reduce natural gas fugitive emissions for future technology selection best practices.
- The 15-year facility assessment performed by Burns and McDonnell identified areas of opportunities and potential pilot sites to reduce fugitive emission from pneumatically driven devices.
- NW Natural will perform an updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- Planning/Design to be performed in 2026.
- Project execution will be performed in 2027.
- Final report and assessment will be performed in 2028.
- Cost in 2028: $100,000 (Trailing costs)
- Total project cost (2026-2028) $1,000,000. (+100%/-50%, $2M/$0.5M)
- 100% Utility Asset

Mist Oil Storage Secondary Containment

- NW Natural developed a Spill Prevention, Control, and Countermeasure (SPCC) Plan in 2013. Within this plan, several plant upgrades were needed for compliance to the SPCC plan.
- The 15-year facility assessment performed by Burns and McDonnell reidentified the oil drums, totes, and other misc. liquids as a spill and contamination risk and will make recommendation to remedy these risks.
- NW Natural will execute on the construction of secondary containment for the fuel tanks and fueling locations.
- Total project cost (2028) $550,000. (+100%/-50%, $1.1M/$0.275M)
- 100% Utility asset

Mist Miller Controls Modernization

- NW Natural executed on a 2016 Facility Assessment Study with EN Engineering identifying high level scopes of work recommended for plant reliability. An area of significant risk highlighted was Miller Stations Control System. This system was upgraded and modernized in 2019.
- The 15-year Facility Assessment Study performed by Burns and McDonnell refreshed EN Engineering's 8-year-old study with modern recommendations with

considerations of the new control systems health and changes in the industry best practices.
- NW Natural will perform an updated 3rd party focused assessment of the Instrument and Controls summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- Cost in 2028: $500,000 (Engineering/Design)
- Total project cost (2028/2029) $2,000,000. (+100%/-50%, $4M/$1M)
- 100% Utility

Mist Miller 300/400 Compressor Replacement (2030 IRP), Year 1
- NW Natural executed on a 2020 Compressor Assessment with AECOM. An area of significant risk highlighted was Miller Stations Recip Control System. This system was upgraded and modernized in 2021.
- The 15-year Facility Assessment Study performed by Burns and McDonnell refreshed AECOM's 3-year-old study with modern recommendations with considerations of the new control systems health and changes in the industry best practices.
- The 15-year Facility Assessment Study performed by Burns and McDonnell extrapolated the usage of the recip to make recommendations ensuring long term reliability.
- NW Natural will perform an additional updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- Cost in 2028: $500,000 (Engineering/Design)
- Total project cost (2028-2032) $28,700,000. (+100%/-50%, $57.4M/$14.4M)
- 100% Utility

Mist Small Dehydration System Replacement (2028 IRP), Year 2
- NW Natural executed on a 2016 Facility Assessment Study with EN Engineering identifying high level scopes of work recommended for plant reliability. An area of risk highlighted was Miller Stations Small Dehydration System.
- The 15-year Facility Assessment Study performed by Burns and McDonnell refreshed EN Engineering's 8-year-old study with modern recommendations with considerations from the new assessment of the equipment's health and changes in process conditions.
- In response to the 2016 and 2024 Facility Assessment Study recommendations, NW Natural will perform an additional updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- NW Natural will replace the small dehydration system.
- Cost in 2028: $1,950,000
- Total project cost (2027-2030) $18,650,000. (+100%/-50%, $37.2M/$9.3M)
- Mix of Utility and Gas Storage Assets
    - Utility cost $0.64 M
    - Non-Utility $1.35M

Mist Well Separator Replacements 2025-2029, Year 4

- In 2021, NW Natural identified new process conditions from the reworked wells posing risk to site deliverability and compliance (192.165).
    - Liquid loading of the process gas has increased due to the well rework program.
    - NW Natural executed on a 2021 Miller Station Filtration Engineering Assessment with Harris Group identifying high level scopes of work recommended for immediate risks and further investigation to be performed.

- In 2022, NW Natural identified more risk associated with the separators. Separators were inspected per API recommendation and significant wall loss was found.
    - Separators found beyond the corrosion allowance were immediately removed out of service.

- NW Natural has remediated the immediate reliability and compliance risks.
- The Burns and McDonnell 15-year Facility Assessment included a detailed Basis of Design report containing technology selection justification with a recommended schedule of replacement.
- Cost in 2028: $2,990,000
- Total Project Cost $11,695,000 (+100%/-50%, $6M/$1.5M)
- Mix of Utility and Interstate Gas Storage Assets
    - Utility $7.367M
    - Non-Utility $4.327M

Calvin Creek Area Meter Modernization-UT meter Replacement, Year 1

- The 15-year facility assessment performed by Burns and McDonnell identified these Reservoir inventory meters as an end-of-life asset due to support from the original manufacturer. This scope only included replacing the meter tubes and associated electrical components.
- Upgrading to NWN standard meters promotes safety through maintenance, design practices, and operational functions.
- Accurate measurement of Injection/Withdrawal is critical for operational functions as well as billing and financial planning.
- Cost in 2028: $200,000 (Engineering/Design)
- Total project cost (2028/2029) $1,450,000. (+100%/-50%, $2.8M/$0.725M)
- Mix of Utility and Gas Storage Assets
    - Utility cost $1.01M
    - Non-Utility $439K

Mist Calvin Creek Gathering Separator, Year 2

- The 15-year facility assessment performed by Burns and McDonnell identified separators are needed from the Calvin Creek/Twin 16 feed. Separators existing at the pools but do not exist at the plant inlet.
- These are needed for residual liquids that may be left within the line between the pools and the station due to low flow.

- The separator performance needs to be the following:
    - Removal of water at the wells by installing more efficient filters
    - Catch slugs, solid and water removal of 0.3 microns and larger at the inlet of Miller Station.
    - Protect the equipment and valves at Miller Station
- NW Natural will perform an updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- Cost in 2028: $1,700,000 (Construction)
- Total project cost (2027/2028) $1,900,000. (+100%/-50%, $4M/$1M)
- Mix of Utility and Gas Storage Assets
    - Utility $1.324M
    - Non-Utility $575K

Mist Miller Valve and Actuator Replacements 2028

- The 15-year facility assessment performed by Burns and McDonnell identified a need to budget to replace valves and actuators at a regular interval. This scope includes replacing valves and associated actuators if applicable. Burns and McDonnell noted some valves are leaking by, have leaks in the stem, or do not operate as intended.
- The recommendation includes performing an assessment of the existing valves and actuators within the facility to assess the operation of the actuators and observe any leaks to prioritize the order of replacement.
- Cost in 2028: $700,000 (+100%/-50%, $1.4M/$0.35M)
- 100% Utility Asset

Mist/Miller Tier 1 & 2 Projects 2028 (Run Rate)

- Tier 1 projects have expenditures up to $250k while Tier 2 projects have expenditures ranging from $250k-$500k.
- Cost in 2028 for Tier 1 and 2 Projects: $2,000,000. (+100%/-50%, $4M/$1M).
- 100% Utility asset.

Section Two – 5 to 6 years (2029 to 2030)

Mist 2029

Mist Diesel Generator, Year 1

- NW Natural executed on a 2016 Facility Assessment Study with EN Engineering identifying high level scopes of work recommended for plant reliability. An area of risk highlighted was Miller Stations Diesel Generator.
- The 15-year Facility Assessment Study performed by Burns and McDonnell refreshed EN Engineering's 8-year-old study with modern recommendations with considerations from the new assessment of the equipment's health and changes in electrical load.

- NW Natural will perform an updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- NW Natural will replace the Diesel generator system.
- Cost in 2029: $1,100,000 (Design/Material Purchase)
- Total project cost (2029/2030) $2,100,000. (+100%/-50%, $4.2M/$1.05M)
- 100% Utility

Mist Miller Controls Modernization, Year 2

- NW Natural executed on a 2016 Facility Assessment Study with EN Engineering identifying high level scopes of work recommended for plant reliability. An area of significant risk highlighted was Miller Stations Control System. This system was upgraded and modernized in 2019.
- The 15-year Facility Assessment Study performed by Burns and McDonnell refreshed EN Engineering's 8-year-old study with modern recommendations with considerations of the new control systems health and changes in the industry best practices.
- NW Natural will perform an updated 3rd party focused assessment of the Instrument and Controls summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- Cost in 2029: $1,500,000 (Construction)
- Total project cost (2028/2029) $2,000,000. (+100%/-50%, $4M/$1M)
- 100% Utility Asset

Mist Miller 300/400 Compressor Replacement (2030 IRP), Year 2

- NW Natural executed on a 2016 Facility Assessment Study with EN Engineering identifying high level scopes of work recommended for plant reliability. An area of risk highlighted was 300/400 Compressors.
- NW Natural executed on a 2020 Compressor Assessment with AECOM in response to En Engineering's 2016 Facility Assessment Study. Recommendations were made to extend the useful life of the existing Miller Stations Recip were made and executed on in 2021.
- The 15-year Facility Assessment Study performed by Burns and McDonnell refreshed EN Engineering's and AECOM's studies with modern recommendations with considerations of the refurbished equipment's health and changes in the industry best practices.
- The 15-year Facility Assessment Study performed by Burns and McDonnell also extrapolated the usage of the recips to make recommendations ensuring long term reliability.
- NW Natural will perform an additional updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- NW Natural will replace the 300/400 Compressors.
- Cost in 2029: $100,000 (Engineering/Design)
- Total project cost (2028-2032) $28,700,000. (+100%/-50%, $57.4M/$14.4M)
- 100% Utility Cost

Mist Well Separator Replacements 2025-2029, Year 5

- In 2021, NW Natural identified new process conditions from the reworked wells posing risk to site deliverability and compliance (192.165).
    - Liquid loading of the process gas has greatly increased due to the well rework program.
    - NW Natural executed on a 2021 Miller Station Filtration Engineering Assessment with Harris Group identifying high level scopes of work recommended for immediate risks and further investigation to be performed.

- In 2022, NW Natural identified more risk associated with the separators. Separators were inspected per API recommendation and significant wall loss was found.
    - Separators found beyond the corrosion allowance were immediately removed out of service.

- NW Natural has remediated the immediate reliability and compliance risks.
- The Burns and McDonnell 15-year Facility Assessment included a detailed Basis of Design report containing technology selection justification with a recommended schedule of replacement.
- Cost in 2029: $2,070,000. (Construction)
- Total Project Cost $11,695,000 (+100%/-50%, $6M/$1.5M)
    - Mix of Utility and Interstate Gas Storage Assets
    - Utility $7.367M
    - Non-Utility $4.327M

Mist Miller Station Oily Wastewater Containment

- NW Natural developed a Spill Prevention, Control, and Countermeasure (SPCC) Plan in 2013. Within this plan, several plant upgrades were needed for compliance to the SPCC plan.
- The 15-year facility assessment performed by Burns and McDonnell reidentified these as a spill and contamination risk and will make recommendation to remedy these risks.
- NW Natural will execute on the construction of secondary containment for the Oily Wastewater tanks.
- Cost in 2029: $350,000 (Engineering)
- Total project cost (2029/2030) $850,000. (+100%/-50%, $1.7M/$0.425M)
- 100% Utility asset

Mist Small Dehydration System Replacement (2028 IRP), Year 3

- NW Natural executed on a 2016 Facility Assessment Study with EN Engineering identifying high level scopes of work recommended for plant reliability. An area of risk highlighted was Miller Stations Small Dehydration System.
- The 15-year Facility Assessment Study performed by Burns and McDonnell refreshed EN Engineering's 8-year-old study with modern recommendations with considerations from the new assessment of the equipment's health and changes in process conditions.

- In response to the 2016 and 2024 Facility Assessment Study recommendations, NW Natural will perform an additional updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- NW Natural will replace the small dehydration system.
- Cost in 2029: $5,000,000 (Construction)
- Total project cost (2027-2030) $18,650,000. (+100%/-50%, $36.3M/$9.3M)
    - Mix of Utility and Interstate Gas Storage Assets
    - Utility cost $6.154M
    - Non-Utility $12.495M

Mist Calvin Creek Area Meter Modernization-UT meter Replacement, Year 2

- The 15-year facility assessment performed by Burns and McDonnell identified these Reservoir inventory meters as an end-of-life asset due to support from the original manufacturer. This scope only included replacing the meter tubes and associated electrical components.
- Upgrading to NWN standard meters promotes safety through maintenance, design practices, and operational functions.
- Accurate measurement of Injection/Withdrawal is critical for operational functions as well as billing and financial planning.
- Cost in 2029: $1,250,000 (Construction)
- Total project cost (2028-2029) $1,450,000. (+100%/-50%, $2.8M/$0.725M)
    - Mix of Utility and Interstate Gas Storage Assets
    - Utility cost $1.01M
    - Non-Utility $493K

Mist/Miller Tier 1 & 2 Projects 2029 (Run Rate)

- Tier 1 projects have expenditures up to $250k while Tier 2 projects have expenditures ranging from $250k-$500k.
- Cost in 2029 for Tier 1 and 2 Projects: $1,500,000. (+100%/-50%, $3M/$0.75M).
- 100% Utility asset.

Mist 2030

Mist Miller 300/400 Compressor Replacement (2030 IRP), Year 3

- NW Natural executed on a 2016 Facility Assessment Study with EN Engineering identifying high level scopes of work recommended for plant reliability. An area of risk highlighted was 300/400 Compressors.
- NW Natural executed on a 2020 Compressor Assessment with AECOM in response to En Engineering's 2016 Facility Assessment Study. Recommendations were made to extend the useful life of the existing Miller Stations Recip were made and executed on in 2021.
- The 15-year Facility Assessment Study performed by Burns and McDonnell refreshed EN Engineering and AECOM's studies with modern recommendations with considerations of the refurbished equipment's health and changes in the industry best practices.

- The 15-year Facility Assessment Study performed by Burns and McDonnell also extrapolated the usage of the recips to make recommendations ensuring long term reliability.
- NW Natural will perform an additional updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- NW Natural will replace the 300/400 Compressors.
- Cost in 2030: $100,000 (Engineering/Design)
- Total project cost (2028-2032) $28,700,000. (+100%/-50%, $57.4M/$14.4M)
- 100% Utility Cost

Mist Cathodic Protection, Year 1

- In 2023, during the construction of the new GC300/400 discharge filters, significant underground coating damage was found. The pipe coating exhibited significant blistering and peeling. A more thorough inspection was conducted by the integrity engineering group, and it was determined that the damage was not caused by cathodic disbondment. However, during the more thorough inspection, it was discovered that the cathodic protection is not properly isolated within the fence line of Miller Station. There is stray current affecting electrical conduit, above ground pipe, steel structures, and the buildings. This poses an electrical shock risk.
- The 15-year facility assessment (Specific to Cathodic Protection) performed by Entrust made high level recommendations to remedy the stray current issue and other reliability end of life related issues.
- NW Natural will implement an immediate short term safety plan to protect personnel from electrical shock.
- NW Natural will perform a detailed assessment summarized by an engineering memo on the developed the scope of work, technology selection, and justification.
- NW Natural will execute to the developed scope of work.
- Cost in 2030: $250,000
- Total project cost $2,000,000. (+100%/-50%, $4M/$1M)
- 100% Utility asset

Mist Small Dehydration System Replacement (2028 IRP), Year 4

- NW Natural executed on a 2016 Facility Assessment Study with EN Engineering identifying high level scopes of work recommended for plant reliability. An area of risk highlighted was Miller Stations Small Dehydration System.
- The 15-year Facility Assessment Study performed by Burns and McDonnell refreshed EN Engineering's 8-year-old study with modern recommendations with considerations from the new assessment of the equipment's health and changes in process conditions.
- In response to the 2016 and 2024 Facility Assessment Study recommendations, NW Natural will perform an additional updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- NW Natural will replace the small dehydration system.
- Cost in 2030: $11,000,000 (Construction)
- Total project cost (2027-2030) $18,650,000. (+100%/-50%, $36.3M/$9.3M)

- Mix of Utility and Interstate Gas Storage Assets
    - Utility cost $6.154M
    - Non-Utility $12.495M

Mist Diesel Generator, Year 2

- NW Natural executed on a 2016 Facility Assessment Study with EN Engineering identifying high level scopes of work recommended for plant reliability. An area of risk highlighted was Miller Stations Diesel Generator and the studies recommendations were implemented in 2020.
- The 15-year Facility Assessment Study performed by Burns and McDonnell refreshed EN Engineering's 8-year-old study with modern recommendations with considerations from the new assessment of the equipment's health and changes in electrical load.
- NW Natural will perform an updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- NW Natural will replace the Diesel Generator system.
- Cost in 2030: $1,100,000 (Construction)
- Total project cost (2029/2030) $2,100,000. (+100%/-50%, $4.2M/$1.05M)
- 100% Utility

Mist Compressor Fugitive Methane Capture, Year 1

- Mist Miller is designed to have minimal fuel and natural power gas emissions by utilizing air systems, recent EPA regulations have been approved and are more stringent on emissions.
    - The 15-year Facility Assessment Study performed by Burns and McDonnell made recommendations to assess the fugitive methane emissions from the station equipment.
    - Technologies will be recommended after this assessment, but some may include process gas recovery, seal gas recompression, enhanced instrument air systems and upgraded air receiver.
- Cost in 2030: $550,000 (Engineering/Design)
- Total Project Cost: $2,050,000 (+100%/-50%, $4M/$1M)
- 100% Utility Asset

Mist Miller Station Oily Wastewater Containment, Year 2

- NW Natural developed a Spill Prevention, Control, and Countermeasure (SPCC) Plan in 2013. Within this plan, several plant upgrades were needed for compliance to the SPCC plan.
- The 15-year facility assessment performed by Burns and McDonnell reidentified these as a spill and contamination risk and will make recommendation to remedy these risks.
- NW Natural will execute on the construction of secondary containment for the Oily Wastewater tanks.
- Cost in 2030: $500,000
- Total project cost (2029/2030) $850,000. (+100%/-50%, $1.7M/$0.425M)
- 100% Utility asset

Mist/Miller Tier 1 & 2 Projects 2030 (Run Rate)

- Tier 1 projects have expenditures up to $250k while Tier 2 projects have expenditures ranging from $250k-$500k.
- Cost in 2030 for Tier 1 and 2 Projects: $1,500,000. (+100%/-50%, $3M/$0.75M).
- 100% Utility asset.

Section Three – 7 to 10 years (2031 to 2034)

Mist 2031

Mist Miller 300/400 Compressor Replacement (2030 IRP), Year 4

- NW Natural executed on a 2016 Facility Assessment Study with EN Engineering identifying high level scopes of work recommended for plant reliability. An area of risk highlighted was 300/400 Compressors.
- NW Natural executed on a 2020 Compressor Assessment with AECOM in response to En Engineering's 2016 Facility Assessment Study. Recommendations were made to extend the useful life of the existing Miller Stations Recip were made and executed on in 2021.
- The 15-year Facility Assessment Study performed by Burns and McDonnell refreshed EN Engineering and AECOM's studies with modern recommendations with considerations of the refurbished equipment's health and changes in the industry best practices.
- The 15-year Facility Assessment Study performed by Burns and McDonnell also extrapolated the usage of the recips to make recommendations ensuring long term reliability.
- NW Natural will perform an additional updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- NW Natural will replace the 300/400 Compressors.
- Cost in 2031: $5,000,000 (Construction)
- Total project cost (2028-2032) $28,700,000. (+100%/-50%, $57.4M/$14.4M)
- 100% Utility asset.

Mist Cathodic Protection, Year 2

- In 2023, during the construction of the new GC300/400 discharge filters, significant underground coating damage was found. The pipe coating exhibited significant blistering and peeling. A more thorough inspection was conducted by the integrity engineering group, and it was determined that the damage was not caused by cathodic disbondment. However, during the more thorough inspection, it was discovered that the cathodic protection is not properly isolated within the fence line of Miller Station. There is stray current affecting electrical conduit, above ground pipe, steel structures, and the buildings. This poses an electrical shock risk.
- The 15-year facility assessment (Specific to Cathodic Protection) performed by Entrust made high level recommendations to remedy the stray current issue and other reliability end of life related issues.

- NW Natural will implement an immediate short term safety plan to protect personnel from electrical shock.
- NW Natural performed a detailed assessment summarized by an engineering memo on the developed the scope of work, technology selection, and justification.
- NW Natural will execute to the developed scope of work.
- Execution completed by Q2 2027
- Cost in 2031: $1,750,000 (Construction)
- Total project cost (2030-2031) $2,000,000. (+100%/-50%, $4M/$1M)
- 100% Utility asset

Mist Compressor Fugitive Methane Capture, Year 2

- Mist Miller is designed to have minimal fuel and natural power gas emissions by utilizing air systems, recent EPA regulations have been approved and are more stringent on emissions.
  - The 15-year Facility Assessment Study performed by Burns and McDonnell made recommendations to assess the fugitive methane emissions from the station equipment.
  - Technologies will be recommended after this assessment, but some may include process gas recovery, seal gas recompression, enhanced instrument air systems and upgraded air receiver.
- Cost in 2031: $1,500,000 (Construction)
- Total Project Cost: $2,050,000 (+100%/-50%, $4M/$1M)
- 100% Utility Asset

Mist Miller Valve and Actuator Replacements, 2031 (Run Rate)

- The 15-year facility assessment performed by Burns and McDonnell identified a need to budget to replace valves and actuators at a regular interval. This scope includes replacing valves and associated actuators if applicable. Burns and McDonnell noted some valves are leaking by, have leaks in the stem, or do not operate as intended.
- The recommendation includes performing an assessment of the existing valves and actuators within the facility to assess the operation of the actuators and observe any leaks to prioritize the order of replacement.
- Cost in 2031: $1,400,000
- Total Project Cost: $ 3,500,000 (+100%/-50%, $7M/$1.75M)
- 100% Utility Asset

Mist Miller North Facility Power

- Land acquisition to the North of Miller station will require power for equipment operation and development.
- This project will provide a power drop from the existing power feed to Miller Station and any infrastructure upgrades needed to electrify the site.
- The recommendation includes performing an assessment of the site to develop the full project scope and power demand for the site.
- Cost in 2028: $850,000 (+100%/-50%, $1.6M/$0.425M)
- 100% Utility Asset

Mist/Miller Tier 1 & 2 Projects 2031 (Run Rate)

- Tier 1 projects have expenditures up to $250k while Tier 2 projects have expenditures ranging from $250k-$500k.
- Cost in 2031 for Tier 1 and 2 Projects: $1,500,000. (+100%/-50%, $3M/$1.75M).
- 100% Utility asset.

Mist 2032

Mist Miller 300/400 Compressor Replacement (2030 IRP), Year 5

- NW Natural executed on a 2016 Facility Assessment Study with EN Engineering identifying high level scopes of work recommended for plant reliability. An area of risk highlighted was 300/400 Compressors.
- NW Natural executed on a 2020 Compressor Assessment with AECOM in response to En Engineering's 2016 Facility Assessment Study. Recommendations were made to extend the useful life of the existing Miller Stations Recip were made and executed on in 2021.
- The 15-year Facility Assessment Study performed by Burns and McDonnell refreshed EN Engineering and AECOM's studies with modern recommendations with considerations of the refurbished equipment's health and changes in the industry best practices.
- The 15-year Facility Assessment Study performed by Burns and McDonnell also extrapolated the usage of the recips to make recommendations ensuring long term reliability.
- NW Natural will perform an additional updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- NW Natural will replace the 300/400 Compressors.
- Cost in 2032: $13,000,000 (Construction)
- Total project cost (2028-2032) $28,700,000. (+100%/-50%, $57.4M/$14.4M)
- 100% Utility asset.

Mist Miller Large Dehy Modernization, Year 1

- NW Natural executed on a 2024 Facility Assessment Study with Burns and McDonnell identifying high level scopes of work recommended for plant reliability. An area of risk highlighted was the Large Dehy.
- NW Natural will perform an updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- The burner management system and large thermal oxidizer will need to be upgraded and/or replaced.
- Planning/Design to be performed in 2032.
- Project execution will be performed in 2033.
- Cost in 2032: $250,000 (Engineering/Design)
- Total project cost (2032-2033) $1,450,000. (+100%/-50%, $3M/$.75M)
- 100% Utility Asset

Mist/Miller Tier 1 & 2 Projects 2032 (Run Rate)

- Tier 1 projects have expenditures up to $250k while Tier 2 projects have expenditures ranging from $250k-$500k.
- Cost in 2032 for Tier 1 and 2 Projects: $1,500,000. (+100%/-50%, $3M/$0.75M).
- 100% Utility asset.

Mist 2033

Mist Miller 300/400 Compressor Replacement (2030 IRP), Year 6

- NW Natural executed on a 2016 Facility Assessment Study with EN Engineering identifying high level scopes of work recommended for plant reliability. An area of risk highlighted was 300/400 Compressors.
- NW Natural executed on a 2020 Compressor Assessment with AECOM in response to En Engineering's 2016 Facility Assessment Study. Recommendations were made to extend the useful life of the existing Miller Stations Recip were made and executed on in 2021.
- The 15-year Facility Assessment Study performed by Burns and McDonnell refreshed EN Engineering and AECOM's studies with modern recommendations with considerations of the refurbished equipment's health and changes in the industry best practices.
- The 15-year Facility Assessment Study performed by Burns and McDonnell also extrapolated the usage of the recips to make recommendations ensuring long term reliability.
- NW Natural will perform an additional updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- NW Natural will replace the 300/400 Compressors.
- Cost in 2033: $10,000,000 (Construction)
- Total project cost (2028-2032) $28,700,000. (+100%/-50%, $57.4M/$14.4M)
- 100% Utility asset.

Mist Miller Large Dehy Modernization, Year 2

- NW Natural executed on a 2024 Facility Assessment Study with Burns and McDonnell identifying high level scopes of work recommended for plant reliability. An area of risk highlighted was the Large Dehy.
- NW Natural will perform an updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- The burner management system and large thermal oxidizer will need to be upgraded and/or replaced.
- Planning/Design to be performed in 2032.
- Project execution will be performed in 2033.
- Cost in 2033: $1,200,000 (Construction)
- Total project cost (2032/2033) $1,450,000. (+100%/-50%, $3M/$.75M)
- 100% Utility Asset

Mist Miller Main Flow Control Valve, Year 1

- NW Natural executed on a 2024 Facility Assessment Study with Burns and McDonnell identifying high level scopes of work recommended for plant reliability. An area of risk highlighted was the general valve reliability and operation. By 2033 the main control valve for Miller Station will be at its end of life and a replacement will need to be identified.
- NW Natural will perform an updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- Cost in 2033: $500,000 (Engineering/Design)
- Total Project Cost: $1,750,000 (+100%/-50%, $3.5M/$0.875M)
- 100% Utility Asset

Mist Miller Air Compressors

- NW Natural executed on a 2024 Facility Assessment Study with Burns and McDonnell identifying high level scopes of work recommended for plant reliability. An area of risk highlighted was the Air Compressors.
- NW Natural will perform an updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- Air compressors will be at or near their end of life in 2033. Replacement and upgrade will facilitate increased reliability as well as scale to current facility requirements.
- Cost in 2033: $500,000 (Construction)
- 100% Utility Asset

Mist/Miller Tier 1 & 2 Projects 2033 (Run Rate)

- Tier 1 projects have expenditures up to $250k while Tier 2 projects have expenditures ranging from $250k-$500k.
- Cost in 2033 for Tier 1 and 2 Projects: $1,500,000. (+100%/-50%, $3M/$0.75M).
- 100% Utility asset.

Mist 2034

Mist Miller Valve and Actuator Replacements 2034 (Run Rate)

- The 15-year facility assessment performed by Burns and McDonnell identified a need to budget to replace valves and actuators at a regular interval. This scope includes replacing valves and associated actuators if applicable. Burns and McDonnell noted some valves are leaking by, have leaks in the stem, or do not operate as intended.
- The recommendation includes performing an assessment of the existing valves and actuators within the facility to assess the operation of the actuators and observe any leaks to prioritize the order of replacement.
- Cost in 2034: $1,400,000 (+100%/-50%, $2.8M/$0.700M)
- 100% Utility Asset

Mist Miller GC700 Overhaul

- The GC500 and GC600 account for approximately 82% of the compression capacity at Miller Station. AECOM's 2020 compressor studies estimate a $12m loss per day if compression at Miller Station is unavailable during withdraw season. With a loss of 82% of compression capacity during withdraw season this would be estimated at $9.84M loss per day.
    - The GC700 will be installed for the GC500 in 2025,
- An overhaul project in anticipation of the GC700 engine hours that would require a scheduled overhaul to prevent an unscheduled outage.
- Cost in 2034: $2,000,000 (+100%/-50%, $4M/$1M)
- 100% Utility Asset

Mist Miller Main Flow Control Valve, Year 2

- NW Natural executed on a 2024 Facility Assessment Study with Burns and McDonnell identifying high level scopes of work recommended for plant reliability. An area of risk highlighted was the general valve reliability and operation. By 2033 the main control valve for Miller Station will be at its end of life and a replacement will need to be identified.
- NW Natural will perform an updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- Cost in 2034: $1,250,000 (Engineering/Design)
- Total Project Cost: $1,750,000 (+100%/-50%, $3.5M/$0.875M)
- 100% Utility Asset

Mist Miller Flora/Bruer Flow Control Valve Replacement, Year 1

- NW Natural executed on a 2024 Facility Assessment Study with Burns and McDonnell identifying high level scopes of work recommended for plant reliability. An area of risk highlighted was the general valve reliability and operation. By 2034 the control valves for Flora/Bruer will be at their end of life and replacements will need to be identified.
- NW Natural will perform an updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification
- Cost in 2034: $100,000
- Total Project Cost: $850,000 (+100%/-50%, $1.7M/$0.425M)
- Mix of Utility and Interstate Gas Storage Asset
    - Utility $725K
    - Non-Utility $125K

Mist/Miller Tier 1 & 2 Projects 2034 (Run Rate)

- Tier 1 projects have expenditures up to $250k while Tier 2 projects have expenditures ranging from $250k-$500k.
- Cost in 2034 for Tier 1 and 2 Projects: $1,500,000. (+100%/-50%, $3M/$0.75M).
- 100% Utility asset.

Mist 2035

Mist Miller GC700/800 Turbotronics Upgrade

- The GC700/800 turbines installed in 2025/2026 will have been in service for over 10 years going into 2035.
- At that time, the control system of the turbines will be due for an overhaul and integration work will also need to be performed in the control room to accommodate new functionality.
- Main benefit with help operators maintain efficient operation and minimize risk of unplanned outage due to improper operation.
- Cost in 2035: $2,000,000 (+100%/-50%, $4M/$1M)
- Mix of Utility and Interstate Gas Storage Asset
    - Utility $1.32M
    - Non-Utility $660K

Mist Miller GC800 Overhaul

- The GC500 and GC600 account for approximately 82% of the compression capacity at Miller Station. AECOM's 2020 compressor studies estimate a $12m loss per day if compression at Miller Station is unavailable during withdraw season. With a loss of 82% of compression capacity during withdraw season this would be estimated at $9.84M loss per day.
    - The GC800 will be installed for the GC600 in 2026.
- An overhaul project in anticipation of the GC700 engine hours that would require a scheduled overhaul to prevent an unscheduled outage.
- Cost in 2035: $2,000,000 (+100%/-50%, $4M/$1M)
- Mix of Utility and Interstate Gas Storage Assets
    - Utility $660K
    - Non-Utility $1.34M

Mist Miller Flora/Bruer Flow Control Valve Replacement

- NW Natural executed on a 2024 Facility Assessment Study with Burns and McDonnell identifying high level scopes of work recommended for plant reliability. An area of risk highlighted was the general valve reliability and operation. By 2034 the control valves for Flora/Bruer will be at their end of life and replacements will need to be identified.
- NW Natural will perform an updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification
- Cost in 2034: $750,000
- Total Project Cost: $850,000 (+100%/-50%, $1.7M/$0.425M)
- Mix of Utility and Interstate Gas Storage Asset
    - Utility $725K
    - Non-Utility $125K

Mist/Miller Tier 1 & 2 Projects 2035 (Run Rate)

- Tier 1 projects have expenditures up to $250k while Tier 2 projects have expenditures ranging from $250k-$500k.

- Cost in 2035 for Tier 1 and 2 Projects: $1,500,000. (+100%/-50%, $3M/$0.75M).
- 100% Utility asset.

Section Four – Projects Completed in 2024

Mist 2024

Mist Miller Busch Schlicker 13B-11 Separator.

- The 15-year facility assessment performed by Burns and McDonnell identified areas of opportunities and potential pilot sites to reduce fugitive emission from pneumatically driven devices.
- In 2021, NW Natural identified new process conditions from the reworked wells posing risk to site deliverability and compliance (192.165).
    - Liquid loading of the process gas has increased due to the well rework program.
    - NW Natural executed on a 2021 Miller Station Filtration Engineering Assessment with Harris Group identifying high level scopes of work recommended for immediate risks and further investigation to be performed.
    - Larger separators needed to intercept the increased liquid loading coming from wells post well rework.
- NW Natural will perform an updated detailed assessment summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- Actuals in 2024: $1.27M
- 100% Utility asset

Mist GC600 Overhaul

- The GC600 accounts for approximately 47% of the compression capacity at Miller Station. AECOM's 2020 compressor studies estimate a $12m loss per day if compression at Miller Station is unavailable during withdraw season. With a loss of 47% of compression capacity during withdraw season this would be estimated at $5.6m loss per day
- An overhaul project completed in 2022 and resulted in a failure. The result of the failure will require a second overhaul.
  The GC600 accounts for approximately 47% of the compression capacity at Miller Station. AECOM's 2020 compressor studies estimate a $12m loss per day if compression at Miller Station is unavailable during withdraw season. With a loss of 38% of compression capacity during withdraw season this would be estimated at $5.6m loss per day
- Actuals in 2024: $126K
- Mix of Utility and Interstate Gas Storage Assets

Mist Fuel Filtration, Year 2

- In 2020 and 2023, NW Natural executed on an internal Root Cause Analysis (RCA) for the multiple turbine combustion system failures. A separate RCA was also performed by Siemens Energy (Original Equipment Manufacturer)
- Found liquids in the fuel supply for all fuel burning equipment have been identified as a contributor to the many outages and service interruptions.
- The 15-year facility assessment performed by Burns and McDonnell also identified this fuel supply to our fuel burning equipment as a risk to reliability. Burns and McDonnell will recommend a fuel filtration system immediately downstream of the fuel supply tie in due to the significant elevation change further reducing risk of liquid accumulation.
- NW Natural performed an additional detailed assessment with Norwest summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- Actuals in 2024: 125K
- 100% Utility asset

Mist GC500/GC600 Turbine Comp Replacement, Year 2

- In response to the discovery that the 2020 AECOM Compressor Study had feasibility issues, a restudy of the turbine compressors was warranted. The frequency of part and equipment failures has accelerated since the study was performed.
- NW Natural performed a 2022 Turbine Compressor Assessment Study with Burns and McDonnell. Within this study it identified the lack of sustainability of the existing turbine compressors and highlighted the operational risks.
    - The GC 500 has 55,000 hours and is past end of life.
    - The GC 600 has 47,000 hours and is past end of life.
- The continued increase in the frequency of part and equipment failures has justified a more accelerated timeline since the 2022 Turbine Compressor Assessment Study with Burns and McDonnell.
    - GC500 replacement in 2025
    - GC600 replacement in 2027
- NW Natural will complete the 30% detailed design to support permit, scope, and cost finalization.
- When initiated, NW Natural will utilize a third-party engineering service provider to perform a detailed Basis of Design report containing technology selection justification.
- Oregon DOE EFSC and Oregon DEQ air permits are required for both new compressors.
- Execution completed by Q3 2025 and 2027 (TBD)
- Actuals in 2024: $12.95M
- Mix of Utility and Interstate Gas Storage Assets

Mist GC 500 Cold Spare, Year 2

- NW Natural performed a 2022 Turbine Compressor Assessment Study with Burns and McDonnell. It was discovered that the 2020 AECOM Compressor Study had feasibility issues that warranted a restudy of the turbine compressors.

Within this study it identified the lack of sustainability of the existing turbine compressors. EX. Replacement parts must be custom manufactured through new supply chain avenues, as they were not stocked or regularly produced by compressor part suppliers. The 2022 study noted that the GC500 was past typical end of life (55,000 hours).

- NW Natural will acquire an NWN-owned turbine compressor cores as a short-term stop gap to ensure reliable deliverability of storage gas to customers until the GC500 can be replaced.
- Actuals in 2024: $197K
- 100% Utility asset

Mist GC 600 Cold Spare, Year 2

- NW Natural performed a 2022 Turbine Compressor Assessment Study with Burns and McDonnell. It was discovered that the 2020 AECOM Compressor Study had feasibility issues that warranted a restudy of the turbine compressors. Within this study it identified the lack of sustainability of the existing turbine compressors. EX. Replacement parts must be custom manufactured through new supply chain avenues, as they were not stocked or regularly produced by compressor part suppliers. The 2022 study that the GC600 was approaching end of life (47,000 hours).
- NW Natural will acquire NWN-owned turbine compressor cores as a short-term stop gap to ensure reliability deliverability of storage gas to customers until the GC600 can be replaced.
- Actuals in 2024: $2.45M
- Mix of Utility and Interstate Gas Storage Assets

Mist Electrical System Upgrades Phase 2, Year 2

- NW Natural executed on a 2021 Miller Station Electrical Reliability Study with Harris Group identifying high level scopes of work recommended in tiers of priority.
- As identified high level in the 2021 Harris Group Study, NW Natural will upgrade end of life components such as the Mechanical MCC, South MCC, refeed Bruer, and add disconnects to 100/200/300/400 buildings.
- NW Natural performed an additional updated detailed assessment with JHI in 2023 summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- Phase 1 was completed in 2022.
- Phase 2 execution scheduled for Q3 2024
- Actuals in 2024: $2.24M
- Mix of Utility and Interstate Gas Storage Assets

Mist Instrument and Controls Upgrade Phase 3, Year 2

- NW Natural executed on a 2016 Facility Assessment Study with EN Engineering identifying high level scopes of work recommended for plant reliability. An area of significant risk highlighted was Miller Stations Instrument and Controls.

- In response to the 2016 Facility Assessment Study, NW Natural has performed an additional updated detailed assessment with JHI in 2023 summarized by an engineering memo on the final refinement of the scope of work and technology selection justification.
- As identified, NW Natural will upgrade end of life components such as moisture analyzers, flow transmitters, pressure transmitters, chromatographs, etc.
- NW Natural will make instrumentation upgrades (switches, connectors, etc...).
- Phase 2 was completed in 2020.
- Actuals in 2024: $1.62M
- Mix of Utility and Interstate Gas Storage Assets

Mist Methanol Injection Upgrade at Wellheads, Year 2

- NW Natural executed on a 2016 Facility Assessment Study with EN Engineering identifying high level scopes of work recommended for plant reliability. An area of highlighted risk was the methanol injection system's level gauge. After a more thorough internal investigation of the methanol injection system and tracking of the location of hydrate formations, the entire methanol injection system was identified as end of life and a reliability risk.
- In 2023 NW Natural hired Norwest and 3rd party engineering service provider to perform a reassessment of the methanol injection system at the wellheads. The scope of work since 2016 has evolved as signs of corrosion and vapor locking have appeared. Through this updated 3rd party engineering service provider assessment, an engineering memo on the final refinement of the scope of work and technology selection justification was developed.
- In 2017 NW Natural began the well inspection program as required by code. After a well inspection has been performed, the increased gas moisture content has led to an increase in hydrate formation downstream of reworked well.
- NW Natural in recent years has operated the underground storage reservoirs at higher pressures closer to the native reservoir pressure increasing the formation of hydrates.
- NW Natural will replace as recommended the methanol injection system at 14 IW Wells.
- NW Natural will procure a mobile methanol injection system to address hydrate issues outside of the wellheads, likely to target pipelines downstream of reworked wells.
- Actuals in 2024: $4.6M
- Mix of Utility and Interstate Gas Storage Assets

15 Year Plan, Mist Facility Assessment

- To ensure the safe and reliable supply of Mist Storage Gas to our customers, a holistic reassessment of the original 10-year plan is required, looking 15 years forward.
- The capital construction projects outlined in this 10-year plan are based on projects identified in the 2016 EN Engineering Facility Assessment. These recommendations have either been implemented or modified. As the 2016 original facility assessment ages, recommendations are becoming obsolete and out of date. Follow-up reassessments are becoming increasingly common at an

individual project level due to the ever-changing condition of field equipment. Additionally, the study is nearing the end of its scope of work, as the study is nearly 8 years old.

- A third-party engineering firm will conduct a new facility assessment of the Mist Miller Compressor Station, including surface equipment at the IW wells. This assessment will investigate the activities required to maintain the plant's reliability, safety, and efficiency over the next 10-15 years.
- The assessment will include a review of the condition of critical plant equipment through visual inspection and a review of facility operation and maintenance records. It will also involve gathering information related to equipment operation (run time, failures, and repair costs), reviewing manufacturer operation and maintenance recommendations, recommending a path forward, and establishing a timeline for needed reassessment of individual pieces of equipment.
- The priority of activities will depend on the current systems condition and the ranking of criticality from Tier 1 through 3, with Tier 3 being the most critical.
- Long-term lifecycle asset management plans will be developed, and procedures will be included.
- A follow up assessment will be performed every 8 to 10 years.
- Actuals in 2024: $290K
- 100% Utility asset

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	Docket UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

Exh. DBK-SSJ-14C

REDACTED VERSION

August 29, 2025

SANBORN HEAD
Building Trust. Engineering Success.

MEMORANDUM

To: Hunter Wiencken

From: Heather James

File: 4661.03

Date: 5/5/2023

Re: 2022 NLNG Pretreatment Performance Post System Modifications, Rev 1

cc: Chris Finnegan, Charles King

Executive Summary

Northwest (NW) Natural completed a successful modification of the pretreatment system at the Newport LNG Facility. The system was commissioned and performance tested in May and June 2022. A summary of the performance test results is provided within this document and resulted in the following recommendations. The System Performance Summary provides additional information to support the recommendations.

1. Replace the dehydration vessel LNG-5 molecular sieve with RK-34 molecular sieve.
2. Replace the CO_2 adsorber vessel LNG-5 molecular sieve with new LNG-5 molecular sieve.
3. Install a flare, thermal oxidizer, or other fuel-consuming equipment to increase the CO_2 Adsorber regen fresh makeup flow. An added benefit of the fuel-consuming equipment is that it would allow for the pretreatment system to be regenerated without the liquefaction system operating.
4. Resolve E-H501 performance with the heat exchanger vendor.
5. Install an automated valve at F-504 liquids drain and a new level transmitter or level switch to allow for automatic draining of the vessel as required.
6. Replace the hot oil expansion tank or add an additional tank in parallel to provide the expansion capacity required for the hot oil system from cold start to hot operating temperatures.

NW Natural has developed plans to replace this facility's cold box. To ensure the performance and warrantability of the new cold box, it is highly recommended that the first three recommendations above be completed prior to its installation.

Background

NW Natural completed modification of the pretreatment system at the Newport LNG Facility in Spring of 2022 to address the following performance challenges:

1. Water and Carbon Dioxide (CO_2) were present in the cold box inlet gas due to limitations of the previous system design. This resulted in plugging of the cold box heat exchanger passes due to freezing of the water and CO_2. The plugging led to

liquefier plant shutdowns after 1.5-2 weeks of liquefier operation when the system should be capable of operating for the entire liquefaction season without shutdown. The limitations of the original design included:

   a. Drier Regen Cooling Outlet Gas was mixed with the dehydrated gas to the CO_2 adsorber which carries water to the downstream CO_2 adsorber.
   b. CO_2 adsorber cooling gas was mixed with the clean gas (CO_2 free gas) to the cold box which added contaminants (CO_2 and water) to the clean gas.

2. Cold Box Inlet Temperature swing after a pretreatment bed switch due to a portion of warm sieve remaining within the bed after cooling. This resulted in MRL refrigeration loop imbalance after every bed switch.
3. Dehydration regen heating and CO_2 regen heating utilized the same heat exchanger, limiting the available heat and flexibility for regen heating adjustments for the two systems.
4. Boiloff gas was recirculated into the plant feed gas or cold box inlet feed gas stream via C-1/C-2, causing nitrogen buildup in the cold box feed gas due to the nitrogen flashing at the LNG tank and exiting the tank in the boiloff vapor. This phenomenon would eventually cause the need for a plant shutdown.
5. Dehydration Tail Gas Separator S-A01 appeared to carry over liquids as liquids had been found downstream at the F-A02 filter and in the fuel gas system supply. Liquid carryover in the fuel gas could cause damage to the gas turbine.

System Performance Summary

The following system performance was observed after commissioning completion of the pretreatment system modifications on June 13, 2022.

1. Dehydration
   a. Design vs. Observed Performance

	Design [1]	Observed	Notes
Adsorption			
Time (hours)	48	48	
Flow (MMSCFD)	7.4	6.9	
Pressure (psig)	335	333	
Temperature (F)	50	54	
Inlet H_2O (ppm)	150	Not Available	Normal pipeline gas moisture levels, typically 30-105 ppm, 150 ppm is tariff limit (7 lb/MMSCF)
Outlet H_2O (ppm)	0.1	0 - 0.03	Success. Prior to modifications, outlet water ranged from 0.3 – 5 ppm per 10/22/2020 data.
Regen Heating			
Time (hours)	2.5	~7.5	This is longer than design. See findings/discussion below.
Flow (MMSCFD)	0.9	0.89	

	Design [1]	Observed	Notes
Pressure (psig)	316	316	
Inlet Temp (F)	500	575	Inlet temperature can be lowered to 500 F or the temperature required to achieve 450 F outlet temperature minimum at the end of the cycle.
Outlet Temp (F), @ End of Cycle	450 (or >400 F for 2 hrs)	470	
Regen Cooling			
Time (hours)	1.5	~5	This is longer than design. See findings/discussion below.
Flow (MMSCFD)	0.9	0.89	
Pressure (psig)	316	316	
Inlet Temp (F)	100	83	
Outlet Temp (F), @ End of Cycle	110	93	Goal = 10 F differential from inlet temp.
[1] Design values per attached UOP Design Summary Sheet for V-A03, V-A04, and V-A05. [2] Refer to attached pretreatment screen shots-trends, 6-13-22, to support observed data.			

b. Findings/Discussion
   i. Dehydration system is removing water from the incoming gas as designed and required. It is not evident that water is carrying over to the CO_2 adsorbers anymore.
   ii. The regen heating and cooling times are longer than design.
      1. Causes: This may be due to the slightly lower design flow which is limited by the plant fuel gas system. Another cause may be due to the vessel internal insulation which is insufficient. The vessels were in the process of being externally insulated at the time which will offer improvement.
      2. Path Forward: The longer than design cycle times can be accommodated by the available standby time so as long as the regeneration design heating and cooling temperatures are achieved, the extended time is acceptable.
      3. Recommendations:
         a. Consider limiting the cooling time to the minimum needed to achieve the required cooling temperatures. This is due to the regen gas supply containing CO_2 and heavy hydrocarbons from the CO_2 adsorber regen heating process. Limiting the extended cooling time will

limit the adsorption of the contaminants during the cooling cycle.

b. Consider replacing the LNG-5 molecular sieve with RK-34 molecular sieve designed for water and mercaptan removal. This will further limit the adsorption of the contaminants during the regen cooling cycle.

iii. Regen heating temperatures to the dehydrator are more consistent due to new separate heat exchanger E-H501. However, there appears to be a performance issue with E-H501 as it is using more hot oil flow than design to achieve the outlet gas temperature setpoint. This causes the hot oil system capacity to be exceeded after a CO_2 adsorber bed switch when the CO_2 regen heat requirement is at its highest which then causes the dehy regen heating temperature to fall to 500-510 F.

1. Recommendations: Resolve E-H501 performance with vendor.

2. CO_2 Vessels

a. Design vs. Observed Performance

	Design [3]	Observed	Notes
Adsorption			
Time (hours)	2.3	0.5-0.75	Set time to 3 hours to extend regeneration heating time to work to drive out water of molecular sieve. However, CO_2 breakthrough observed early in cycle. See discussion below.
Flow (MMSCFD)	7.4	6.9	
Pressure (psig)	330	329	
Temperature (F)	50	54	
Inlet CO_2 (ppm)	20000	3590	
Outlet CO_2 (ppm)	<50	>100	Exceeded 50 ppm at 30 mins for V-A03 and V-A05, 45 mins for V-A04. See discussion below.
Regen Makeup			
Flow (MMSCFD)	1.1	0.89-0.91	Not enough fresh makeup flow. See discussion below.
Regen Heating			
Time (hours)	1.9	1.6	
Flow (MMSCFD)	3.5	3.5-4.76	Varies as B-A01 suction temperature rises throughout the cycle.

	Design [3]	Observed	Notes
Pressure (psig)	306	306	
Inlet Temp (F)	550	580	Ran higher temperature to work to drive out the water in the molecular sieve
Outlet Temp (F), @ End of Cycle	450	515	Success. Achieved 65 F difference between inlet and outlet temperature prior to design regen heating time. Design is 50-100 F.
Regen Cooling			
Time (hours)	1.9	1.9	
Flow (MMSCFD)	4.9	5.23-5.32	
Pressure (psig)	327	327	
Inlet Temp (F)	109	88	
Outlet Temp (F), @ End of Cycle	120	95	Success. Achieved 7 F difference between inlet and outlet temperature by regen cooling time. Design is 10 F.

[3] Design values per attached UOP Design Summary Sheet for V-A03, V-A04, and V-A05.
[4] Refer to attached pretreatment screen shots-trends, 6-13-22, to support observed data.

b. Findings/Discussion
   i. CO_2 adsorption is not meeting design CO_2 removal performance:
      1. Causes: Molecular sieve is expected to be contaminated by water due to the previous issue with water carryover from the dehydrators. The water is taking up adsorption capacity within the bed, preventing CO_2 from being adsorbed in a large portion of the bed. Unfortunately, once water is adsorbed into molecular sieve reserved for CO_2 removal, it is difficult to fully regenerate, drive the water out, and free up the space for CO_2.
      2. Recommendation: Replace the molecular sieve in the CO2 adsorbers now that the upstream performance issues with water carryover have been resolved.
   ii. Regen heating and cooling flows, temperatures, and time meet or exceed design.
   iii. Regen makeup flow is not achieving design which is driven by fuel gas (regen tail gas) consumption. Lack of sufficient regen makeup flow will prevent full regeneration of the CO_2 adsorber beds which will reduce design adsorption capability over time and could shorten the life cycle of the molecular sieve product.
      1. Project Efforts to Achieve Design Makeup Flow

a. Hot oil heater burner tuning to allow consumption of varying quality fuel gas. This was successful but the burner only burns ~ 0.004 MMSCFD so has minimal effect on consumption.
b. B system controls installed to allow consumption of the fuel gas when the quality falls within tariff values. This provided the additional fuel gas consumption to achieve design makeup flow. However, the fuel gas (regen tail gas) exceeds the tariff limits after 15-20 minutes into the regen cycle, requiring flow to be stopped to the B system. This prevents the added flow consumption from being consistently available.

2. Recommendation:
   a. Install a flare, thermal oxidizer or other fuel consuming equipment that will provide the following benefits:
      i. Increase Regen Fresh Makeup Flow to Meet or Exceed Design.
      ii. Allow for the pretreatment system to be operated for regeneration purposes only prior to and after liquefaction operation, which is recommended for successful performance, especially if the liquefaction system trips off when a bed is in the middle of a regeneration cycle. Currently, the plant needs to startup on a partially used bed while the regen heating bed restarts its regen heating cycle.

3. Other System Enhancements and Performance
   a. Pretreatment After Cooler, E-A503
      i. Successfully provides consistent inlet gas temperature to the cold box at +/- 5 F of water/glycol supply temperature which eliminates the previous temperature swing after a pretreatment bed switch which caused MRL refrigeration loop imbalance.
   b. Boiloff Use for CO_2 Regen Fresh Makeup Supply
      i. Successful use of boiloff for regen fresh makeup supply via new F-505, reducing the amount of boiloff recirculated to the cold box inlet gas stream.
   c. Dehydration Liquids Removal at S-500 and F-504
      i. Liquids removal from the fuel gas is successful. However, it was found that F-504 captured more liquids than expected requiring operations to open the manual valve to drain the liquids to V-10 more often than expected.
         1. Recommendation: Consider addition of automated valve at F-504 liquids drain and addition of level transmitter or level switch to allow for automatic draining of the vessel as required. This would eliminate continuous manual valve

operation by operations which, if left unattended, could cause carryover of liquids into the fuel gas system.

d. Hot Oil System
   i. The hot oil heater temperature controls were tuned to respond to system load changes and prevent overshoot. Heater outlet temperature overshoot causes the heater to shutdown and then go through purge cycles to restart which causes a drop in system supply temperatures. Additional heater outlet temperature tuning may be required once the E-H501 performance issues are resolved.
   ii. The existing hot oil expansion tank was found to be undersized as the level would often rise to the high-level switch during operation which would trip the heater offline. Operations would reduce the liquid level to allow restart of the heater. However, if the system was shutdown and system temperatures dropped, hot oil addition was required to achieve the minimum liquid level to start.
      1. Recommendation: Consider replacing the hot oil expansion tank or adding an additional tank in parallel to provide the expansion capacity required for the system from cold start to hot operating temperatures.
   iii. Cold Box Performance
   - Refer to attached Liquefaction Performance Tends, 2021 vs. 2022
      1. Under the previous pretreatment system design, the E-2 Heat Exchanger B Pass differential pressure would increase from ~7 psi on liquefaction operation day 1 to 12.4 psi by day 5.
      2. Although the adsorber molecular sieve requires replacement and the CO_2 levels to the cold box are better but still higher than design, the E-2 Heat Exchanger B Pass differential pressure is consistent around 6 psid. This is a good sign of decreased contaminants to the cold box, including elimination of water.

Attachments:
UOP Data Sheets: CO_2, Dehy (Current LNG-5), Dehy (Recommended RK-34)
Pretreatment Screen Shots-Trends, 6-13-22
Liquefaction Performance trends, 2021 vs. 2022

CTK/CJF/HNJ: hnj

P:\4600s\4661.03\Work\Project Closeout\Performance Memo\4661.03 Pretreatment Performance Memo_R1.docx

PAGES 8 THROUGH 22 OF THIS EXHIBIT ARE CONFIDENTIAL IN THEIR ENTIRETY UNDER WAC 480-07-160 AND HAVE BEEN REDACTED.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	Docket UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

Exh. DBK-SSJ-15

August 29, 2025

MEMORANDUM

9/13/2023

Background:

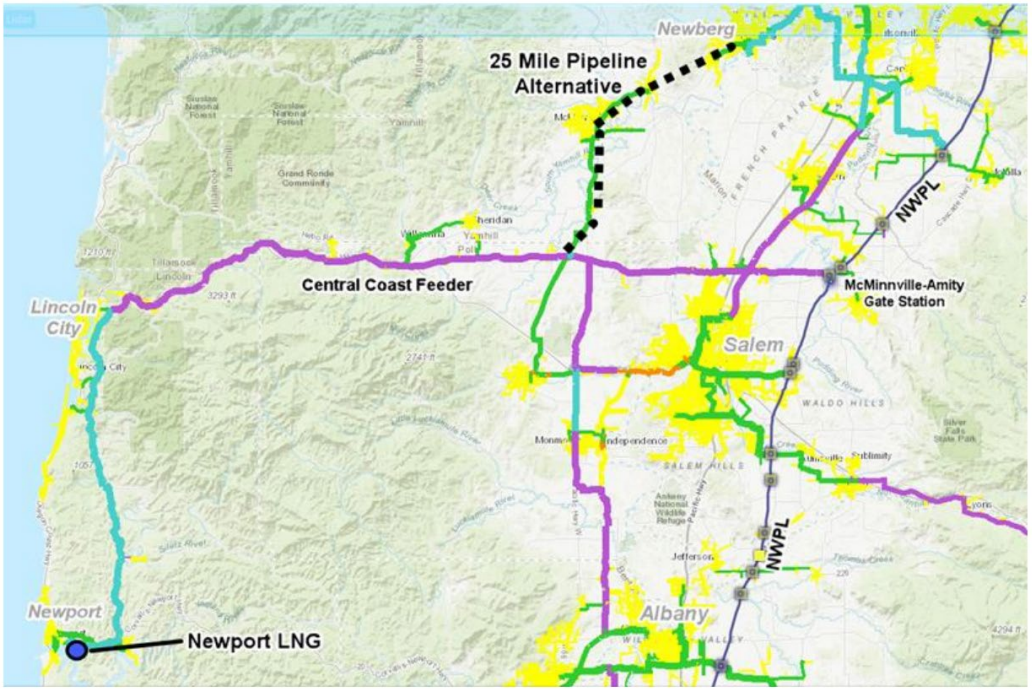
On March 1, 2021, NW Natural filed the 2018 IRP Update #3. In this update we evaluated an investment in the Newport cold box relative to alternative options that would be needed to reliably serve customers. As described in the 2018 IRP update #3, Newport is a critical source of gas supply needed to deliver 60,000 Mcf/day (64,500 Dth/day) of gas into the system to meet peak day requirements. Without replacing the cold box the Newport facility would not be able to fill the tank with LNG during summer months reliably and could terminate to function at any point. This would effectively decommission the LNG facility and removes 60,000 Mcf of firm gas delivery from NW Natural's resource stack to meet peak day resource requirements.

Two alternatives to the Newport Cold box were considered in the IRP Update #3.

> Alternative A: Contract with NWP for additional pipeline capacity from Sumas south to city gates on NWP's Grants Pass Lateral
>
> Alternative B: Construct a 25-mile-high pressure transmission facility between Newburg and the Central Coast Feeder coupled with additional Mist Recall

Alternative B is the lower cost option of these two alternatives and would require a 25-mile pipeline to be constructed in order to deliver the Mist gas onto the central coast feeder in order to reliably serve customers that Newport LNG current supports during a extreme cold event (i.e., West Salem, Dallas, Lincoln City, and Newport). It must be coupled with Mist Recall to replace the daily deliverability for a peak day requirement currently being served by the Newport LNG facility. This pipeline alternative was evaluated in the 2018 IRP Update #3 (shown in Figure 21 from the filing).

Figure 21: Alternative Pipeline Route



Since the 2018 IRP Update #3 we've experienced an increase in the cost of the Newport Cold Box project dues to two primary reasons.

1) Increase in costs due to inflation
2) Additional scope of the project identified as necessary investments after the IRP Update #3 was filed. The additional scope was identified in our Newport LNG 10-year plan and during detailed project planning. This additional scope added $5.5 million to the Current Estimate.

Table 1 shows the costs estimated in the 2018 IRP Update #3 in 2019 dollars, what those costs would be today after adjusting for inflation (2022 $) and the current build cost estimates for the Newport Cold Box project and the 25-miles pipeline need to bring Mist gas to the central coast feeder.

Table 1: Build Costs

		IRP Update #3 Cost Estimate		Current Estimate
		2019$	2022$	2022$
1	Newport Cold Box Project	$18,154,000	$20,222,000	$27,100,000
2	25-mile Pipeline Alternative	$170,830,000	$190,479,000	$190,479,000

When evaluating long-term investment decisions, build costs are not the only metric to consider. Newport is a critical resource to be able to serve system capacity during extreme cold events both today and in the future. If system peak requirements continue to grow, the absence of the Newport LNG facility, could increase the costs of alternative system capacity resources needed in the future. The analysis below considers the current cost estimates for the Newport cold box project and examines 4 scenarios:

1) Expected cold box cost estimates; Continued peak growth over the planning horizon
2) Expected cold box cost estimates; Declining peak growth starting in 2024
3) High cold box cost estimates; Continued peak growth over the planning horizon
4) High cold box cost estimates; Declining peak growth starting in 2024

These scenarios are evaluated on the net present value revenue requirement that each option requires taking into consideration the benefits and additional costs (besides build costs) that each option is forecasted to incur.

Analysis:

The Newport Cold box project and the pipeline alternative are different types of investments and are categorized under different FERC accounts as well as receiving different rates for cost-of-overhead (COH). For a full picture, we analyze these costs using a cost-of-service model, which accounts for the full cost that would filter into customer rates, including but not limited to taxes, COH, cost-of-debt, and O&M costs.

In addition, to the costs associated with the Newport Cold box project, there are other forecasted costs associated with continuing to operate the Newport Facility over the next 10 years. These costs would not be incurred if the Newport facility were decommissioned. We use a cost-of-service model to account for the full costs of these additional expenses.

For the pipeline alternative option, NW Natural would look to mothball or fully decommission the Newport facility. The costs to decommission the Newport facility would be significant and could vary drastically. We did not attempt to estimate these costs as it would only add additional costs to the

pipeline alternative option, which we show to be the more expensive alternative across the four scenarios, even without considering these cost. Table 2 show the net present value cost-of-service for all associated costs from 2025-2050 for option 1, keep operating the Newport facility.

Table 2: Net present value 2025-2050 cost-of-service for option 1, Keep Newport Facility Operating

	Expected Cost-of-Service	High Cost-of-Service Estimate
Newport Cold Box Project	$45,144,000	$56,429,000
Other Newport	$28,815,000	$46,655,000
Total Cost	$73,959,000	$103,085,000

There are both cost and benefits that are considered for option 2, build a 25-mile pipeline coupled with Mist Recall. The costs include the cost-of-service for the 25-mile pipeline and cost-of-service for Mist Recall. Additionally, if Newport LNG is decommissioned and we continue to see continued peak growth then Mist Recall is exhausted in 2034 and we would need additional system capacity resources to meet the peak demand requirement. If Newport LNG is decommissioned, the marginal system capacity resource after Mist Recall would be a Mist expansion. There are gas commodity savings from additional storage capacity from both Mist Recall and a Mist expansion. Additional storage capacity provides a benefit to customers through increased seasonal arbitrage of summer and winter gas prices spreads. This analysis uses the resources optimization planning model (i.e., PLEXOS) to estimate the value of commodity cost savings from the additional Mist capacity over the planning horizon. Table 3 provides the net present value cost estimates for each of these components for two peak demand growth scenarios.

Table 3: Net present value 2025-2050 cost-of-service for option 2, 25-mile pipeline coupled with Mist Recall

	Continued peak growth	Declining Peak Growth
25-mile pipeline	$564,126,000	$564,126,000
Mist Recall to Replace Newport LNG peak deliverability (64,500 Dth/day)	$34,937,000	$34,937,000
Additional Future Peak Day Capacity Need (i.e., Mist Expansion)	$218,727,000	$0
Decommissioning Newport LNG	Not Estimated	Not Estimated
Commodity Costs Savings	-$36,383,000	-$26,940,000
Total Cost	$781,407,000	$572,123,000

Table 4 combines the total cost from Table 2 and Table 3 into 4 rows see the difference across the 4 scenarios

Table 4: Net present value 2025-2050 total cost comparison

	Newport Facility Cost Assumption	Peak Assumption	Option 1: Keep Newport Facility Operating	Option 2: 25-mile pipeline coupled with Mist Recall	Delta[1]
1	Expected	Continued peak growth	$73,959,000	$781,407,000	>$707,448,000
2	Expected	Declining Peak Growth	$73,959,000	$572,123,000	>$498,164,000
3	High	Continued peak growth	$103,085,000	$781,407,000	>$678,322,000
4	High	Declining Peak Growth	$103,085,000	$572,123,000	>$469,038,000

[1] Does not reflect decommissioning costs which would only increase this delta. The greater than symbol ">" is used to represent this cost exclusion.

Recommendation:

Given the analysis across these four-scenarios indicates that cold box investment is lower cost relative to the pipeline alternative, we recommend moving forward with the Newport Cold box project.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	Docket UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

Exh. DBK-SSJ-16

August 29, 2025

Initial Project Charter

The initial project charter is intended to document the team's initial approach to analyzing the problem. Completed at the end of initiate, this will serve as the foundation for performing any studies or analysis as the project team weighs potential options for solving the underlying business case.

Initial

Project Description

Newport LNG has experienced electricity outages that prevent operation of the production or vaporization send-out systems. Most recently, Newport LNG had such an outage and was unable to supply gas to customers during a peak winter event. The risk of being unable to send gas to the system during winter storms is untenable to customers. Winter weather typically coincides with vaporization needs, which also correspond to likely power outages.

This project would solve this operational problem by installing a generator that meets all of the facility's electrical demand.

Business Case

Newport LNG has experienced electricity outages that prevent operation of the production or vaporization send-out systems. Most recently, Newport LNG had such an outage and was unable to supply gas to customers during a peak winter event. The risk of being unable to send gas to the system during winter storms is untenable to customers. Winter weather typically coincides with vaporization needs, which also correspond to likely power outages.

Key Objectives and Outcomes

- Increase the reliability of Newport LNG's electricity supply.
- Potentially, convert waste gas to electricity (instead of flaring it).

Rough Cost/Benefit Analysis Summary

By implementing the new generation operation at the Newport LNG facility, which will be capable of supporting vaporization operations, this project will offset the potential of purchasing "penalty" gas in the event of simultaneous utility power loss and vaporization requirement.

Rough Scope

- Survey and assess generation alternatives.
- Analyze alternatives.
- Perform process, electrical, and detailed engineering design.
- Permit new generator(s).
- Buy a generator.
- Contract one or more installation contractors.
- Install the generator(s).
- Create procedures and manuals.
- Commission the generator(s).

Initial -Cont.

Known Constraints at Initiation Phase

- Generators have long lead times.
- Generators are expensive.
- Newport LNG's permitted air emissions are almost at a threshold that would shift this facility's classification.

Known Assumptions at Initiation Phase

N/A

Change Control Plan

We would manage changes in Planview.

Project Information

Roles & Responsibilities

Initial Project Team & Roles

- Tim Murphy: Project Engineer
- Travis Vandervort: Project Manager

Project Governance Structure

- Project Sponsor: Daniel Kizer
- Executive Sponsor: Joseph Karney

Roles & Responsibilities

Lifecycle Administrator

Davis, Thaniel

Program/Project Manager

Shreffler, Andrew

Project Sponsor

Primary	Name
◎	Kizer, Daniel

Executive Sponsor

Primary	Name
◎	Karney, Joseph

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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Exh. DBK-SSJ-17

August 29, 2025

estimated cost of the project - far exceed that of the proposed pipeline uprate project. Table 5 summarizes the costs of the proposed project and satellite LNG option.

Table 5: North Coast Feeder System Reinforcement Alternatives Costs

Alternative	Estimated Cost (with COH)	20-year PVRR
Feeder Uprate	$4.6M - $9.1M	$5.1M - $10.2M
Satellite LNG Alternative	$19.6M	$26.3M

3.B Newport Cold Box

Newport LNG Background

The Newport LNG Plant (Newport) is located in Newport Oregon at the western end of NW Natural's Central Coast Feeder Pipeline (See Figure 9). The Central Coast Feeder Pipeline runs approximately 90 miles from Williams NW Pipeline McMinnville-Amity Gate Station to Lincoln City and south to Newport. This pipeline serves as the sole source of natural gas to the towns of Lincoln City, Newport and the surrounding communities and the primary source of gas for McMinnville, Sheridan, Willamina, Dallas, Independence, Monmouth and many other smaller communities during peak events.

It consists of a 1,008,500 Dth capacity storage tank, liquefaction facilities capable of processing about 6,000 Dth/day, and vaporization capacity of up to 108,500 Dth/day. Due to CO_2 and seismic constraints the maximum fill level of the plant is at 90% full, or 976,500 Dth. Because the Company's pipeline system limits Newport to serving the central coast and Salem market areas, the full 108,500 Dth/day vaporization rate is not achievable. Instead, 65,100 Dth/day is the effective limit on vaporization at Newport.[16] The Newport LNG plant (Newport) was constructed by Chicago Bridge and Iron and commissioned in 1977. The facilities and major process components of the Newport LNG plant were designed for a nominal 25-30-year life and Newport is now 44 years old. The Company has replaced many of the primary components of the facility over the last few years.

Primary Role Played by Newport LNG

Newport is a valuable resource for meeting our customer's peak needs. To understand the operational significance of the Newport LNG facility, it is important to first provide background information about the Company's storage facilities. NW Natural relies on four existing storage facilities to augment the supplies transported from British Columbia, Alberta and the Rockies. These consist of underground storage at Mist and Jackson Prairie, along with LNG plants located in Portland (referred to as PDX-LNG) and Newport, Oregon. The Company owns and operates Mist, PDX-LNG, and Newport LNG, all of which reside within the Company's service territory. These three storage facilities are considered 'on-system'

[16] All of the values listed are based on a gas heat content of 1,085 Btu/cf

gas supply resources. Gas is typically placed into storage at these facilities during off-peak periods, which is also known as 'injecting' (for underground storage) or 'liquefaction' (for the LNG facilities). When needed, these on-system resources do not require further transportation on the NW Pipeline interstate pipeline system, but rather use 'withdrawal' or 'vaporization' from Mist or the LNG facilities, respectively, to supply gas directly to NW Natural's system.

In contrast, Jackson Prairie storage is located about 80 miles north of Portland near Centralia, Washington, i.e., outside the Company's service territory. Jackson Prairie has been owned and operated by other parties since its commissioning in the 1970s. The Company contracts for Jackson Prairie storage service from NW Pipeline, which also contracts separately for the transportation service from Jackson Prairie to the citygates to NW Natural's system.

Table 6 shows the daily supply capacity of these resources.

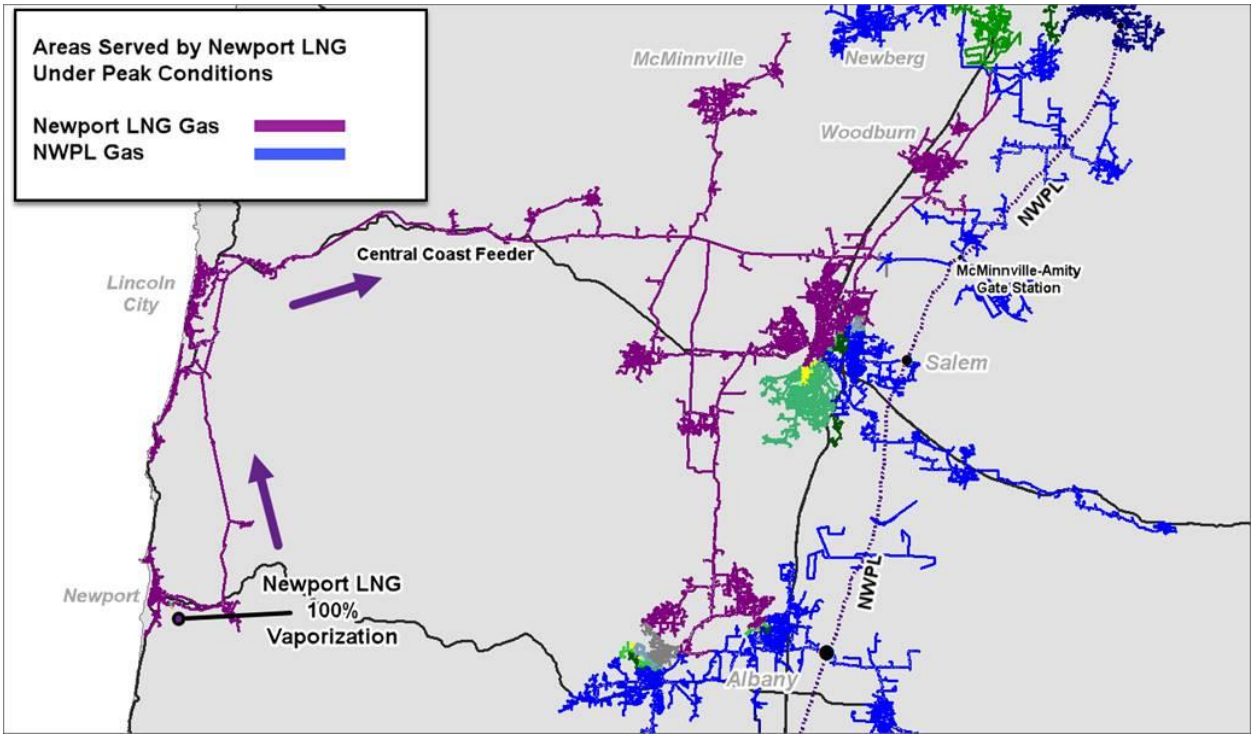
Table 6: Firm Storage Resources[17]

Facility	Maximum Daily Rate (Dth/day)
Jackson Prairie	46,030
Mist (reserved for core)	305,000
Newport LNG	65,100 *
PDX-LNG	129,480 *

Figure 17 shows how the gas from the facility flows under peak conditions to the coastal and southern service area of NW Natural's system.

[17] The numbers in Table 6 with an asterisk originated from volumetric units (e.g., Bcf) that have been converted to energy units (Dth) using the current heat content (Btu per cf) of the applicable facility. The other numbers included do not need to be adjusted for heat content because they originate from contracts (Jackson Prairie) or deliverability calculations (Mist) that are specified in energy units.

Figure 17: Newport LNG Gas Flows



Additional Roles the Newport LNG Facility Plays

The Newport plant serves as not just a wintertime peaking supply but as a source of supply for emergency situations and pipeline maintenance. Any significant damage or event along the 90-mile-long pipeline length can interrupt gas flow which could cause outages to thousands of customers downstream of the event if an alternate supply (Newport LNG) were not available. The Newport LNG plant represents a source of supply that can be used to maintain reliable service to customers.

The Echo Mountain Wildfire in September 2020 served as an example of this capability as it damaged the primary district regulator station serving Lincoln City. To safely operate NW Natural's high-pressure system, a portion the Central Coast Feeder pipeline was shut down near Lincoln City to reduce risk and damage. While the segment of the Central Coast Feeder was shut down, the primary gas feed from the Williams NWPL McMinnville-Amity gate station was severed. During the shutdown, the Newport LNG plant was used to continue serving approximately 10,000 customers in Newport, Toledo and Lincoln City. Newport LNG gas was used to serve affected customers from September 9, 2020 through September 16, 2020. The Central Coast Feeder was reestablished to regular operations on September 16 after state fire managers determined it was safe to do so.

Cold Box Project Background

The Cold Box is an essential component in an LNG liquefaction plant, it is where natural gas is cooled to cryogenic temperatures to convert the gas to liquid. Once liquefied, it is pumped from the Cold Box to the onsite insulated storage tank where it can later be used in the winter. A Cold Box, see Figure 18, is

made up of multiple aluminum heat exchangers, which are stacked on top of each other and encased in a single unit measuring approximately 30 feet in height. The Cold Box at Newport LNG is 44 years old. This places it well past its design life and it is currently showing signs of its age through performance problems.

Figure 18: Cold Box Illustration

While an initial consultant recommended replacing the Cold Box in a 2014 study, it was later determined the estimate they provided for the cost of replacement was drastically low. Additionally, in 2016 NW Natural installed a new pretreatment system to address high CO_2 in the supply of gas, which was making it through the liquefier and into the LNG tank. The new pretreatment process dramatically improved the quality of gas entering the Cold Box. However, the original pretreatment design required additives such as methanol to be injected ahead of the Cold Box to absorb moisture. The methanol was then removed after liquefaction. This is no longer required. Nevertheless, Without the additive, contaminants were able to easily foul the Cold Box causing increased differential pressure in the system and reducing production. Inspections to understand this issue revealed contaminants on the interior surfaces within the Cold Box heat exchangers, which compound flow restriction issues caused by poor gas quality entering the system. The differential pressure is higher than design allows in the first two exchangers within the Cold Box. This is believed to be due to several issues, including internal contamination as shown in Figure 19 upon inspection. The Cold Box itself is not the only contributor to operational issues, as higher levels of heavy hydrocarbons are contained within the gas stream than were present at the time of the original design of the facility. Heavier hydrocarbons tend to freeze at higher temperatures and can create blockages in the system, which also contribute to higher operating pressures within the Cold Box.

Figure 19: Contaminated Heat Exchanger

After learning the original cost estimate from the consultant for Cold Box replacement was quite low NW Natural's engineering team reviewed a lower-cost alternative: to clean the Cold Box to improve its near-term operation and possibly extend its life. A consultant was engaged to perform the cleaning. After discussion with the consultant (a vendor of the manufacturer), an agreement could not be made to have the Cold Box cleaned that did not seem to introduce more risk to damaging the Cold Box, and it was not guaranteed to fix the problem.

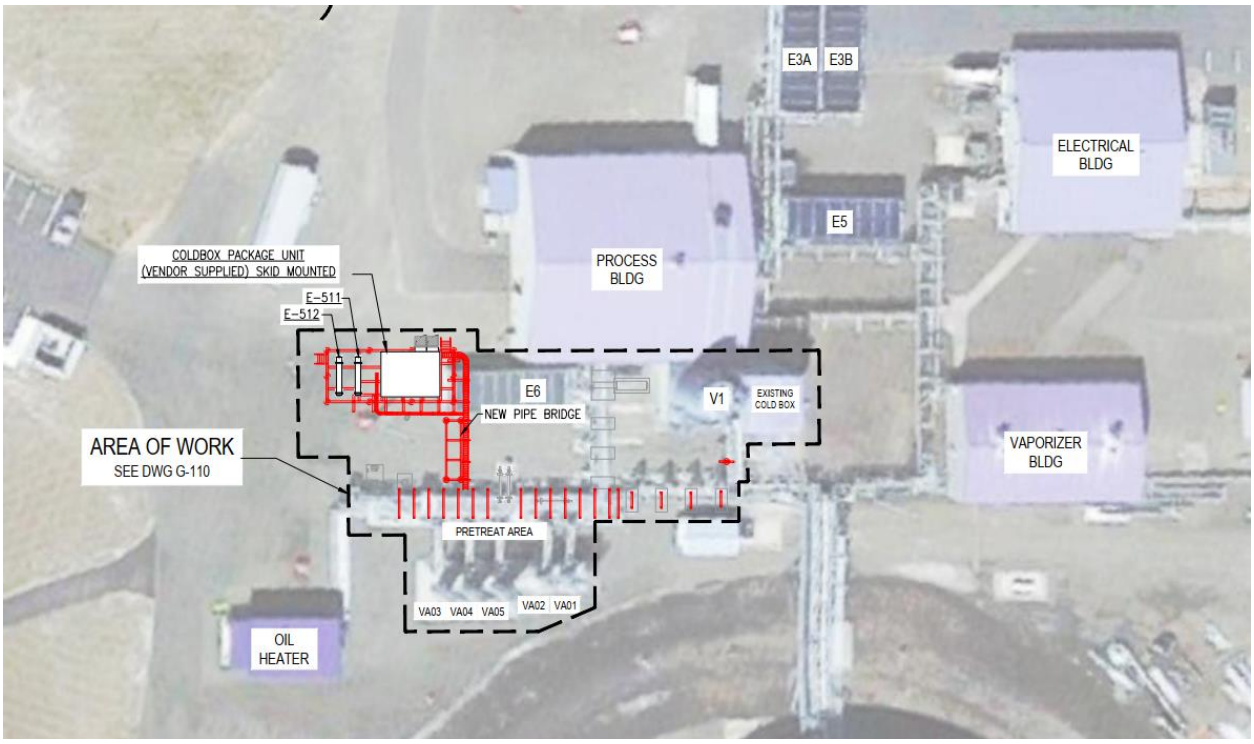
At this time NW Natural engaged another consultant that specializes in LNG to provide a report and recommendation specific to the Cold Box at the Newport facility. This study, completed by Sanborn, Head, and Associates determined that continued operation of the Newport LNG facility without replacement of the Cold Box and upgrading the pretreatment system equipment is not recommended and provided the following conclusions[18]:

> *Aging equipment – The design and construction of the existing Cold Box heat exchangers are outdated. Industry experience with this type of equipment has demonstrated that it is significantly more prone to failure than newer designs. This Cold Box has reached its end of life and should it fail, repair is most likely not possible. A failure and replacement could cause significant downtime for the facility, at least 1.5 years on the most accelerated schedule.*
>
> *Reliability - The current liquefaction system at Newport is unreliable. Ongoing issues with Cold Box freezing, and carbon dioxide (CO2) build-up in the storage tank require that upgrades including new equipment and system modifications be implemented.*
>
> *Modernization - Replacement of the Cold Box with a modern design would allow one heat exchanger to be installed in place of the existing two exchangers. This would improve system reliability and minimize downtime. It would also allow removal of the aging Cryex CO2 removal vessel. This vessel is a remnant of the previous (original) pretreatment system. Its removal would eliminate an original, 10,000-gallon LNG pressure vessel, which was installed in 1977, without any secondary containment.*

[18] From page 3 of the Sanborn Head NWN Cold Box Replacement Engineering Study

At this point the Cold Box replacement is necessary to be able to continue to rely upon Newport LNG as a firm resource to serve NW Natural's current needs. Should the Cold Box fail, the ramifications to the plant would be significant. A replacement unit would require approximately two years to install. Repairs to this type of equipment can be very costly or even impractical. If a failure occurred at the beginning of the production season, this would leave the facility without a reasonable means to refill the storage tank. As a result, all remaining LNG may boil off prior to equipment replacement (depending on the tank level at the time of failure), which in turn, would allow the large LNG tank to warm significantly, inducing stress on the tank due to thermal expansion. Customers would also be left without the benefit of backup storage to support periods of peak demand during cold weather or other supply constraints.

Figure 20: Overview Map of Project Area



Sanborn Head also identified potential improvements in the pretreatment system which could be implemented to ultimately aid in reducing stresses on the Cold Box. These suggested improvements are being addressed now. This project and a broader update on activities at the Newport LNG facility can be found in Appendix E.

Cost Estimate of Cold Box Replacement

Table 7 lists the major project components as well as their costs. These capital costs include a 30% contingency. For the total costs for the cost-of-service modeling there are also additions for allowance for funds used during construction (AFUDC) and associated taxes. There is also a 3% cost of overhead adder bring the total for COS modeling to just over $18 million.

Table 7: Newport Cold Box Cost Estimates

Project Components	Cost (includes 30% Contingency)
Engineering & Overhead	$4,275,793
Major Equipment	$4,384,600
Demolition	$594,935
Civil/Site Construction	$1,166,853
Structural Construction	$1,348,780
Mechanical Construction	$2,953,791
Electrical Construction	$734,563
Instrumentation/Control	$1,490,819
Startup and Commissioning	$318,500
Training	$71,500
Freight	$260,694
Subtotal	$ 17,600,827
COH 3%	$528,750
AFUDC/Taxes	$24,172
Total	$ 18,153,747

Alternatives Analysis

For the alternative to replacing the Cold Box the Company looked at solutions similar to those in the 2014 IRP. The alternatives examined then are still the alternatives most appropriate to examine today. These alternatives are discussed below.

Alternative A: Contract with NWP for additional pipeline capacity from Sumas south to city gates on NWP's Grants Pass Lateral

Alternative B: Construct a 25-mile-high pressure transmission facility between Newburg and the Central Coast Feeder coupled with additional Mist Recall

To receive the same capacity benefit of Newport, Alternative A would require annual demand payments of $23-$43 million, in addition to potential gate station and distribution upgrades. Table 8 shows the potential costs associated with additional capacity additions.

There are two possibilities for securing additional pipeline capacity, with the least expensive option being a regional expansion from Sumas to Molalla. This would occur in the event NW Pipeline held an open season and could justify the expansion based upon demand from multiple parties in addition to NW Natural (i.e. this option in not in NW Natural's control and is unlikely to be a viable option in the near term). An estimated cost for capacity under this option is $0.98/Dth/day. The higher cost option

would require NW Natural to contract with NW Pipeline for a NW Natural-specific buildout. Estimated costs here are nearly double the regional expansion at $1.80/Dth/day.

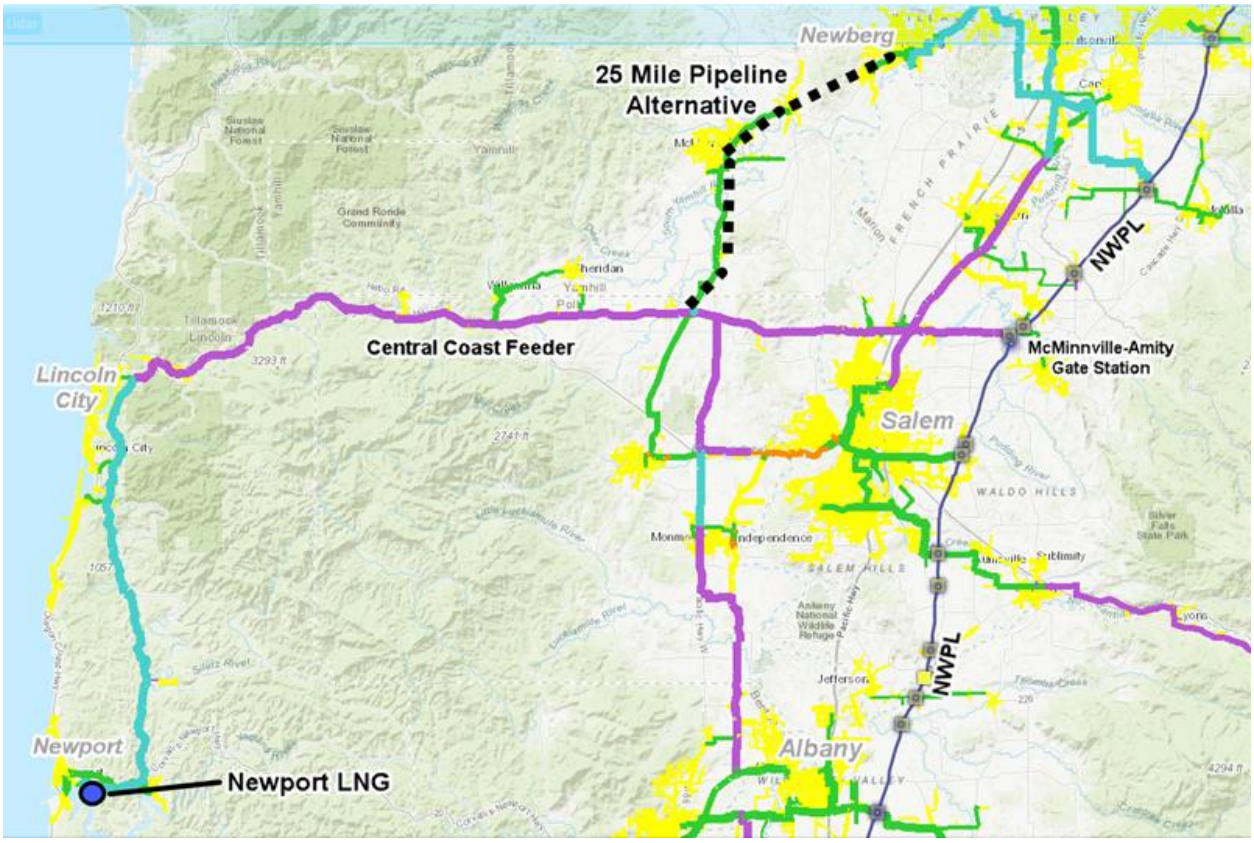
Table 8: Pipeline Expansion Cost Estimates

	$/Dth/day	Dth	Annual Cost
Regional Expansion from Sumas to Molalla	$0.98	65,000	$23,250,500
Local Expansion from Sumas to Molalla	$1.80	65,000	$42,705,000

Alternative A was not considered to be cost-effective option following the initial analysis, given that the annual costs, even at the lower end (for an option that NW Natural cannot control), are higher than the total capital costs associated with the Cold Box of approximately $18 million. As such this option was not analyzed further.

Alternative B, a new 25-mile pipeline, is less expensive, but still much costlier with an installed cost of approximately $171 million. Figure 21 shows the potential route, highlighted in blue.

Figure 21: Alternative Pipeline Route



For the final cost analysis, NW Natural used SENDOUT® to determine whether the Company should replace the Newport Cold Box or pursue Alternative B. Table 9 shows the present value of revenue requirement (PVRR) of portfolios over the planning horizon (2021-2050) associated with each of the two courses of action.

Table 9: Portfolio Cost Comparison

	Fixed Storage Costs	Fixed Pipeline Costs	Supply Variable Costs	Other Variable Costs	Total Portfolio Costs
Cold Box Replacement	$63 M	$1,162 M	$10,548 M	$69 M	$11,841 M
Alternative Pipeline	≥$58 M	≥$1,312 M	$10,542 M	$70 M	≥$11,986 M
Delta	-$5 M	$150 M	-$2 M	$1 M	≥$145 M

As shown, the portfolio including Newport after the $18 million Cold Box replacement project has a NPVRR savings of approximately $145 million versus the next best option.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	Docket UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

Exh. DBK-SSJ-18

August 29, 2025

NW Natural
PROGRAM / PROJECT ALTERNATIVES EXEMPTION

Program/Project Name: Newport LNG Cold Box
Date: 08/30/2022
Preparer: Shane Melski (PMO)

DESCRIPTION	
ISSUE TO BE ADDRESSED BY PROGRAM/ PROJECT	Replacement of the Cold Box at Newport facility due to its end of useful life.
OBJECTIVE	Replacement of the Cold Box at Newport facility to extend useful life, and ensure deliverability.
BUSINESS CASE	The Newport LNG cold box equipment has been in service since 1977. A 2021 study by Sanborn Head concluded that the existing cold box should be replaced given: 1) Aging equipment – The design and construction of the existing cold box heat exchangers are outdated. Industry experience with this type of equipment has demonstrated that it is significantly more prone to failure than newer designs. This cold box has reached its end of life and should it fail, repair is most likely not possible. A failure and replacement could cause significant downtime for the facility, at least 1.5 years on the most accelerated schedule. 2) Reliability - The current liquefaction system at Newport is unreliable. Ongoing issues with cold box freezing and carbon dioxide (CO2) build-up in the storage tank require that upgrades including new equipment and system modifications be implemented. 3) Modernization - Replacement of the cold box with a modern design would allow one heat exchanger to be installed in place of the existing two exchangers. This would improve system reliability and minimize downtime. It would also allow removal of the aging Cryex CO2 removal vessel. This vessel is a remnant of the previous (original) pretreatment system. Its removal would eliminate an original, 10,000-gallon LNG pressure vessel, which was installed in 1977, without any secondary containment.

POTENTIAL COST			
Capital	***Direct***	***COH***	***Total***
	$17,600,00	$529,000 (3%)	$18,129,000
O&M	***Program/Project***	***Ongoing Maintenance & Support***	
	$0	$0	

FURTHER ANALYSIS NOT REQUIRED		
☐ **REQUIRED:** Regulatory Requirement makes this specific program/project mandatory	☐ **EMERGENCY EXEMPTION:** Program/Project supports a critical business function and this specific program/project is required to continue that function.	☒ **OTHER**

EXPLAIN

Describe why an alternative analysis does not apply to this program/project. Please explain in enough detail that others can assess from the information provided whether this should be exempted from the Alternatives Analysis requirement.

An Alternatives Analysis was included with the "NW NATURAL 2018 INTEGRATED RESOURCE PLAN UPDATE" Docket No. LC 71/UG-170911 submitted to the Public Utility Commission of Oregon (OPUC) and UG-170911 to the Washington Utilities and Transportation Commission (WUTC).

PMO USE ONLY ***ELECTRONIC APPROVALS***		
Title	**Name**	**Date/Time Approved**
PMO Specialist		
AA Approver		

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	Docket UG-250610

NORTHWEST NATURAL GAS COMPANY

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DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

Exh. DBK-SSJ-19

August 29, 2025

NW Natural
PROJECT ALTERNATIVES NARRATIVE

Program/Project Name: NLNG Molecular Sieve Vessels repair/upgrade (E-203361)
Date: 6/3/2025
Project Sponsor: Dan Kizer
Executive Sponsor: Joe Karney
Project Manager: Andrew Chin-Shreffler/Tim Murphy
Preparer: Andrew Chin-Shreffler

SECTION 1: BUSINESS CASE

This section should be solution-agnostic, and about the overarching problem we're trying to solve no matter which route we end up taking

OBJECTIVES *Why are we tackling this project?*	
Current State What is happening now? Where are we starting?	The Newport LNG Pre-Treatment System removes Carbon Dioxide (CO_2) and entrained water (H_2O) from the natural gas stream before liquefaction. This process is critical to the liquefaction process, as CO_2 and H_2O freeze at a higher temperature than the natural gas liquefies. If not removed successfully, the liquefaction system can become plugged with frozen solids and fail, and/or CO_2 can build up in solid form in the LNG tank. After having issues with removal of CO_2 and H_2O during pretreatment operation in 2024, a team consisting of NW Natural operations and engineering, Sanborn Head, CB&I (owners and consulting engineers) and UOP (molecular sieve media vendor) conferred and reviewed process data over the course of several months. Based on this review, the troubleshooting team assigned the issues with CO_2 and H_2O to deficiencies in the molecular sieve vessel internal insulation pulling back from itself and from the shell of the vessel, allowing process gas to bypass contact with the molecular sieve media and preventing complete regeneration. These vessels will need to be upgraded for implementation of a stainless steel liner to restore functionality and ensure proper operation in place of existing blankets supported by wire mesh. Addressing these issues is critical to maintaining normal liquefaction operations and meeting the performance requirements for the upcoming Cold Box Replacement project.
Problem Statement In simple terms, what are we trying to solve? What is the business need this is tackling? Why is this a problem worth solving (e.g. why is the current state not working)?	Address the deficiencies in the molecular sieve vessels' ability to scrub CO_2 and H_2O. This is required to be completed to execute on the installation of the new Cold Box unit. The design basis that CB&I has been working off is <50ppm CO2 and 0.1ppm H2O. Failure to meet these requirements could result in plugging of the cold box passes or sending solids to cold box. Additionally, these values are called out by CB&I as part of performance guarantee
Desired Deliverables What high level output / scope / deliverables are core to this project?	The project goal will modify the pretreatment vessels to prevent the bypassing scenario, thus returning pretreatment system to desired performance (<50ppm CO_2 and 0.1ppm H_2O) to ensure that the facility can return to normal liquefaction operations in 1st quarter 2026 and meet feed gas requirements for CB&I.

SECTION 2: ALTERNATIVES SUMMARY

OVERVIEW *How did we review these options?*	
Review Process Summarize how options were chosen, who was involved in the choice and how options were evaluated.	In consultation with NWN Plant Operations, Engineering and 3rd Party subject matter experts (SMEs), the list of potential solutions was created. The 3rd party SME evaluated the viability, cost, and schedule of each option. This information was compiled by the team and is summarized below.

If some criteria were considered more important based on the type of project, please explain here.	
DECISION CRITERIA *Describe the criteria used to determine the selection from the various alternatives considered. For example, is this a program/project where the least cost option should be selected? Are there other factors, such as safety or quality that come into play? Include both quantitative and qualitative factors as appropriate.*	
Criteria: Safety	The solution provides the highest level of safety for employees both during construction and in operation.
Criteria: System integrity and reliability	The solution will permanently address the system integrity and reliability issues for the lifespan of the equipment selected.
Criteria: Schedule	The solution can be constructed during the allowable window of November 2025 through March 2026, which ensures availability of the plant for the liquefaction season.
Criteria: Cost	The solution is the lowest cost option that meets the gas quality requirements of the pretreatment system.

SECTION 3: ALTERNATIVES DETAIL

RECOMMENDED OPTION *Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option. If positive /neutral/negative observations do not exist, enter N/A*		
Description	The desired option will be to perform a shop modification for installation of stainless steel liner in place of the blanket insulation. This will keep inner diameter (ID) the same for flow characteristics, but a solid liner will mitigate the ability for the gas stream to bypass the molecular sieve media. This will be executed for all five vessels offsite, which will then be recertified and shipped back to site for installation on existing foundation/anchors and loading of molecular sieve.	
In brief, why is this the recommended option?	This option is recommended due to combination of cost and efficacy. Based on analysis with the team, a solid, stainless steel liner will be required to prevent this bypassing. By shipping offsite, we can perform the work in a controlled, certified environment while avoiding the costs of new vessels. Due to window between T-1 top-off in fall 2025 and desired startup in April 2026, we will be able to achieve this in the "normal" liquefaction window, without affecting plant availability.	
	Analysis Against Criteria: Safety	Wet winter weather conditions are prevalent between November and April each year and attempting to repair the vessels on-site creates mitigatable risks of slips, trips, and falls and a work product that is more prone to errors. This option removes the vessels and ships them to a manufacturer for indoor work which is a safer work environment for the shop fabricator and ensures a better work product from the vendor. Additionally, this option avoids potential safety issues related to a large welding project with substantial hot work within the LNG fence line.
	Analysis Against Criteria: System Integrity and Reliability	This option provides a system that is sound and will have integrity and reliability for decades to come. Upgrading the design and repairing the vessels in an offsite location with a controlled environment will ensure the vessels are repaired satisfactorily and allow for the effectiveness of the new Cold Box unit which is pending installation. Wet winter weather conditions are prevalent between November and April each year and attempting to repair the vessels on-site creates challenges with hardening the work site against the weather elements and leads to slower work production and a work product that is more prone to errors. Removing the vessels and shipping them to a manufacturer for indoor work creates a better controlled work environment for the shop fabricator and ensures a higher quality product from the vendor.
Assessment	**Analysis Against Criteria: Schedule**	Longest downtime duration, but still within acceptable window for work. Construction window opens in November after liquefaction operations are complete. Installation of the liners will take 12-16 weeks for modifications, resulting in the vessels returning for the month of March for vessel install and reloading the molecular sieve media.

	Analysis Against Criteria: Cost	This is the lower cost option due to savings vs new vessels.
	Additional Benefits	Warranty for work performed at factory

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$2.4M	$625k	$3.025M
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$0 - $0	$0 -	
Source/ Method of Cost Data	Budgetary quotes for shop work and logistics, quote for molecular sieve media, engineering estimate for mechanical scope. Budget level estimates plus 2023 COH rates for Applicant 529 (26%)		

ALTERNATIVE 1 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*		
Description	This option would purchase five new vessels matching the height and diameter of existing vessels + nozzle locations and anchoring, with new stainless steel liners in place of blankets. The old vessels would be unloaded following liquefaction 2025 and vessels would be swapped out and reloaded. This is high-cost option and if unable to meet anchor plan, may require geotechnical and structural modifications. This option also addresses the deficiencies in the pretreatment system so that it is sound and will remove CO2 and water as per the pretreatment specifications necessary to ensure the reliable performance of the existing and new Cold Box and prevent the buildup of frozen CO2 and water in the liquefaction system and LNG tank. This alternative was evaluated to reduce plant liquefaction system downtime, however due to the need to reevaluate geotechnical and structural designs, could potentially carry schedule risk. This option would require the highest level of up-front design.	
In brief, why is this option not recommended?	This will be the highest cost option with potential for additional structural scope required for structural. While this option may potentially reduce the liquefaction system downtime, the high cost and additional design risks for the structural design resulted in this option not being recommended.	
Assessment	**Analysis Against Criteria: Safety**	No substantive difference to recommended option.
	Analysis Against Criteria: System Integrity and Reliability	No substantive difference to recommended option.
	Analysis Against Criteria: Cost	Highest cost option due to procuring new vessels vs. modifying existing vessels. Foundation pads may need to be upgraded, both structurally and geotechnically, adding to cost and schedule risk.
	Analysis Against Criteria: Schedule	Geotech and modifications to the foundations have potential to extend the duration of the overall schedule.
	Additional Risks	Potentially highest lead time option but can be implemented with shortest window.
	Additional Benefits	All new equipment.

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$3.0M to $3.5M	$780k to $910k	$3.78M to $4.41M
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$0	$0	
Source/ Method of Cost Data	Budget level estimate plus 2023 COH rates for Applicant 529 (26%) Price range for replacement vessels comes from similar vessel price provided by owners engineers, quote for molecular sieve media, engineering estimate for mechanical scope.		

ALTERNATIVE 2 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*

Description	Do nothing. Leave the system as-is	
In brief, why is this option not recommended?	This will continue to allow for gas bypass and inefficient scrubbing of the product. It is likely to continue to degrade over time. Without addressing this issue, this lower gas quality will impact the new Cold Box performance and performance guarantee. This work is scheduled for 2026/2027. The design basis for the Cold Box Replacement project (which will remove the CryEx system) requires a better gas quality for CO_2 and H_2O concentrations the Pre-Treatment System is currently able to provide, resulting in potential clogging and damage to Cold Box, and will impact NW Natural's ability to hold CB&I to the contractual performance guarantee.	
Assessment	**Analysis Against Criteria: Cost**	Least costly from a capital standpoint but will continue to result in reliability issues and inability to meet gas quality requirements laid out in CB&I performance guarantee.
	Analysis Against Criteria: Safety	This is the safest option in the near term due to no construction activities. There is potential for unknown safety issues in the long term due to poor gas quality.
	Analysis Against Criteria: Schedule	There will be no effect on schedule. Normal LNG top off and startup will be unaffected by the do-nothing option.
	Analysis Against Criteria: System Integrity and Reliability	There was a significant decrease in performance of the system when molecular sieve media was removed and replaced in 2024. It appears that the insulation was de-laminating or broken during this process. At current schedule, the media will be replaced in 2031 and a similar step change may result in liquefaction system reliability issues. This option will void the performance guarantee for the Cold Box project.
	Additional Risks	As noted above, if performance continues to worsen, it may require this work to interfere with normal operating windows and create issues producing LNG during the spring/summer months.
	Additional Benefits	No planned downtime (although increases likelihood of unplanned downtime)

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$0	$0	$0
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$0	Unknown	
Source/ Method of Cost Data	No capital costs, unable to quantify the O&M costs for ongoing performance issues.		

**Copy/Add table for any additional alternatives*

ALTERNATIVES CONSIDERED NOT VIABLE *Provide a description of any additional alternatives that were considered but rejected up front as not viable, and explain why*		
	Description	**Why the Alternative is not viable**
Alternative 3	Remove insulation blankets, wire mesh and clips. In its place, install a poured non-porous refractory at same thickness as blankets that will not allow gas bypassing or "pull back" from wall.	Conversations with refractory companies do not indicate this is a viable solution, a non-porous cast refractory is not available for this application. This can not be considered further.
Alternative 4	Remove blankets that are pulling back from wall and separating from other blankets and return to "design" conditions.	When reviewing this alternative, even if the insulation was returned to design condition, performance of the media would be insufficient to meet the requirements of the Cold Box performance guarantee, thus, removal and replacement of the blankets is insufficient to address the failure of the pretreatment system performance. Previous removal and replacement of the media led to worsened performance of the pretreatment system, which indicates that the issue with the pretreatment system is due to gas bypassing the blankets rather than failed molecular sieve media. Gas bypassing the blankets indicates that the root cause of the issue is due to a faulty design which will not be resolved by the replacement of the blankets.

		Additionally, this option carries further risks, including: - Voiding performance guarantees for future Cold Box project due to not meeting gas quality requirements. - Safety risks due to performing hot work in a confined space. - This work will occur during winter at Newport, creating high likelihood of water ingress to insulation causing potential to wet the media and/or affect adhesive, causing failure of this alternative. - The base cost of molecular sieve media removal and replacement is present in all alternatives, including the selected alternative, which results in reduced savings for this alternative.
Alternative 5	Leave vessels in place and install new shell on outside of vessels, removing the failed blankets and allowing the outer shell to become the liner and the new shell becomes the exterior of the vessel.	This was not recommended by ASME vessel shop, too many variables for performing code vessel work in field. From a safety standpoint, doing work vertically was not recommended. Marine environment makes extended "open" vessel time undesirable Additionally, this will affect the flow characteristics of the gas through the vessels. The height/inner diameter ratio will be changed in this option, as will the gas distribution, resulting in potential for additional modifications to the system to achieve recommended flow dynamics.

**Add rows for any additional alternatives considered not viable*

SUPPLEMENTARY INFORMATION

Figure 1 - Pretreatment Vessels

Figure 2 - Current Vessel Insulation System

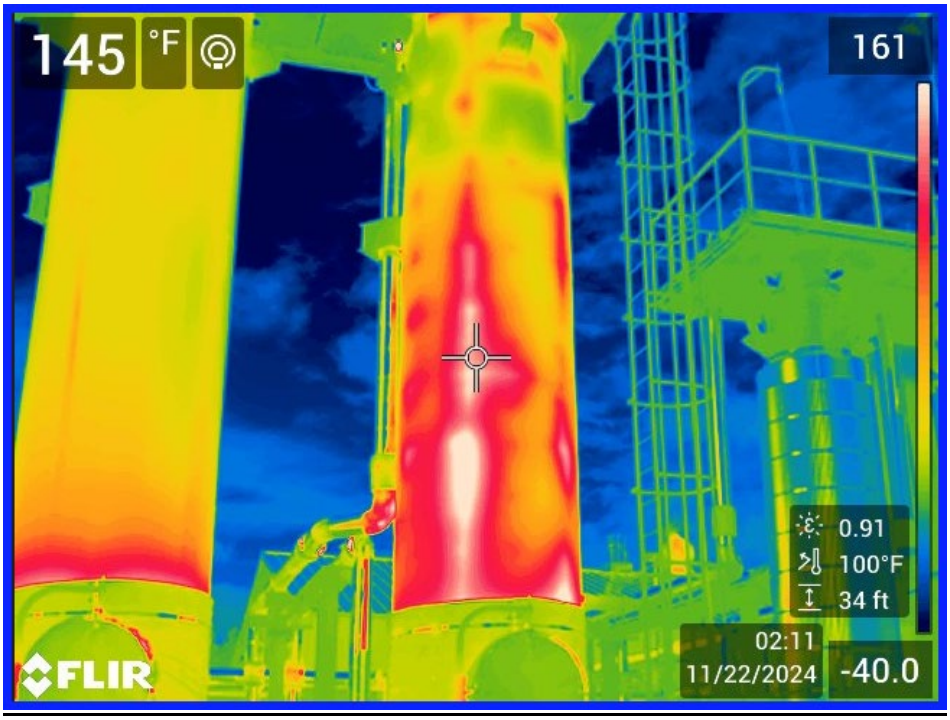

Figure 3 - Thermal Image Showing Gas Bypassing (As Shown in the White Seams Between Blankets)

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	Docket UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

Exh. DBK-SSJ-20C

REDACTED VERSION

August 29, 2025

NW Natural
PROJECT ALTERNATIVES NARRATIVE

Program/Project Name: E203010 _AA - PLNG Elect Distribution Upgrade
Date: *04/24/2024*
Project Sponsor: *Daniel Kizer*
Executive Sponsor: *Joe Karney*
Project Manager: *Jorge Souto*
Preparer: *Tim Murphy, Jorge Souto*
Was this project part of IRP: NO

SECTION 1: BUSINESS CASE

This section should be solution-agnostic, and about the overarching problem we're trying to solve no matter which routes we end up taking

OBJECTIVES *Why are we tackling this project?*	
Current State What is happening now? Where are we starting?	*This project is part of the Portland LNG 10-year plan refurbishment efforts, and the overall business objective is to deliver safe, reliable firm gas supplies for NW Natural customers.* *The incoming switchgear trip is set at 1200A, so attempts to operate this way will result in 480V outage at PLNG until condition is corrected and breaker is reset. It is currently not possible to operate this way.* *A third-party engineering load study found that operating both LNG pumps (P1 and P2) and all three vaporizers (H5, H6, H7) simultaneously would exceed MCC-1 current rating of 1200A, risking a 480V outage. The Plant incoming switchgear trip setpoint is 1200A and attempts to operate in this configuration will result in the breaker tripping and a complete 480V system outage, preventing PLNG from vaporizing. Additionally, the incoming transformer is sized for 1000kVA, which is undersized for the full load condition, and will need to be replaced with a transformer with increased to accommodate desired plant output. The undersized MCC current rating, coupled with the undersized incoming transformer, reduced overall Plant vaporization capacity from 120 MMSCF/D to 90 MMSCF/D.*
Problem Statement In simple terms, what are we trying to solve? What is the business need this is tackling? Why is this a problem worth solving (e.g., why is the current state not working)?	*To mitigate the overcurrent scenarios associated with MCC-1 frame rating of 1200A, PLNG is unable to operate 2 LNG pumps and 3 vaporizers simultaneously, reducing Plant vaporization capacity from 120 MMSCF/D to 90 MMSCF/D.* *Per an engineering load study performed by Sanborn Head as part of C4 Detailed Design, this operating scenario requires 1270A, and would trip incoming switchgear breaker set at 1200A. Therefore, only two LNG pumps and two vaporizers can run simultaneously due to the 1270A required for operating loads above, surpassing the 1200A switchgear trip setting and causing a 480V outage.*
Desired Deliverables What high level output / scope / deliverables are core to this project?	*The project aims to update the PLNG 480V electrical distribution system, replacing the existing 1000kVA transformer and MCC-1 with a new 1500kVA transformer (capable of 1800A of 3-phase 480V), manual transfer switch, and incoming 480V switchgear. The new electrical infrastructure will allow the Plant to return to its full availability of 120 MMSCF/D, allowing two LNG pumps and three vaporizers simultaneously. The new system will also be designed for planned expansion of MCC capabilities for the PLNG Boiloff Compressor project, as both MCC-1 and MCC-2 are physically limited for new starters and drives*

SECTION 2: ALTERNATIVES SUMMARY

OVERVIEW *How did we review these options?*	
Review Process Summarize how options were chosen, who was involved in the choice and how options were evaluated. If some criteria were considered more important based on the type of project, please explain here.	*Project Engineer, Tim Murphy and PLNG operations were involved in choosing these options from a FEED study completed by Norwest Engineering.* *Reliability, time of implementation, and costs were considered in the evaluation of options.*
DECISION CRITERIA *Describe the criteria used to determine the selection from the various alternatives considered. For example, is this a program/project where the least cost option should be selected? Are there other factors, such as safety or quality, that come into play? Include both quantitative and qualitative factors as appropriate.*	
Criteria: Reliability	*The Recommended Option will update the PLNG electrical distribution system, enabling the facility to operate without equipment damage or power outage, and return the Plant to its design vaporization capacity of 120 MMSCF/D.*
Criteria: Time of implementation	*Acquiring the switchgear and associated MCC equipment includes lead times of up to one (1) year, so purchasing them now will facilitate project implementation in the summer next year, ensuring availability for commissioning by winter 2025.*
Criteria: Cost /Benefit	*The analysis should also be based on the most cost-effective and viable option.*

SECTION 3: ALTERNATIVES DETAIL

RECOMMENDED OPTION *Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option. If positive /neutral/negative observations do not exist, enter N/A*		
Description	*PLNG is unable to operate at its full capacity of 120 MMSCF/D, using both LNG pumps and three vaporizers simultaneously. Only two LNG pumps and two vaporizers can run simultaneously due to the 1270A required for operating loads above, surpassing the 1200A switchgear trip setting and causing a 480V outage. Per engineering load study, this operating scenario (Case 5 in attached file) requires 1270A and would trip incoming switchgear breaker set at 1200. This option will install new electrical switchgear, transformer, and manual transfer switch to ensure the Plant can supply the 1270A required load to operate both LNG pumps and all three vaporizers simultaneously.*	
In brief, why is this the recommended option?	*The preliminary analysis has concluded that enhancing the PLNG electrical distribution system is the best alternative. The upgrade will enable the facility to operate without any equipment damage or power outage at its full nameplate capacity of 120 MMSCF/D.*	
Assessment	**Criteria: Reliability**	*The upgrade will empower the facility to handle power levels of 1270A or more without causing equipment damage or power outages. This enhancement will enable the simultaneous operation of two LNG pumps and three vaporizers, returning plant to 120 MMSCFD of vaporization capability with capability for enhanced data quality and expansion that meets the requirements of the PLNG Boiloff Compressor project.*
	Criteria: Time of implementation	*The electrical equipment has an estimated lead time of one year. Therefore, the acquisition process must commence early in the project's lifecycle to ensure expanded capabilities by Winter 2025. Ordering the equipment promptly is imperative.*
	Criteria: Cost	*This is not the low-cost option, although it does increase power distribution capability and reliability, while making operations safer and reducing 480V downtime during power cutover.*
Assessment	**Additional Risks**	*Due to lead time of equipment, the plant will operate at a reduced capacity of 90 MMSCF/D during winter 2024 and risk of electrical equipment failure is still possible.*
	Additional Benefits	*Despite its higher cost, this option stands out as the best and preferred choice recommended by the consultants, and it has received approval from both engineering and operations.*

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH (26%)**	**Total**
	$1,540,000	$400,400	$1,940,400
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$000	$0.00	
Source/ Method of Cost Data	*Total cost is based on the Norwest Engineering report and estimate, attached to this AA, plus internally produced engineering estimate.*		

ALTERNATIVE 1 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*		
Description	*Alternative 1 proposes to install a new 1200A breaker into the first section of MCC-1 and demolish existing cables from MCC-1 bus tap to the 600A MCC-2 main breaker. New cables would be installed from the incoming switchgear to the MCC-2 600A main circuit breaker.* *The cables for the new 1200A MCC-1 main circuit breaker will be spliced in the vault underneath the main switchboard with the existing MCC-1 feeder cables.* *This would eliminate the 600A load feeding MCC-2 from MCC-1, allowing us to operate the electrical systems independently, but not operating at full capacity without upsizing transformer.*	
In brief, why is this option not recommended?	*This does not eliminate the kVa limitations, simply divorces the MCC-1 from MCC-2. This was investigated before incoming transfer limit was discovered and only will mitigate MCC-1 frame rating issue.* *The proposed location for the new 1200A main breaker for MCC-1 has two available sections, neither of which are sized appropriately for new breaker gear. MCC-1 could be rearranged to create new space, but this would eliminate all spare MCC sections. This also assumes that the 1200A breaker section will fit in 12" MCC section.* *When implemented, the alternative will fix the problem with the small 1200A breaker in the switchgear. However, the full vaporization load will be too much for the transformer, so it won't solve the transformer size issue. As a result, PLNG won't be able to run 2 LNG pumps and 3 vaporizers at the same time, limiting the plant to only 90 MM capacity.*	
Assessment	**Criteria: Reliability**	*If one or more of the assumptions mentioned above are not valid, Alternative 1 is likely not feasible.*
	Criteria: Time of Implementation	*This option offers a quicker solution, targeting smaller modifications to enhance the current electrical system.*
	Criteria: Cost	*It is a cheaper option but does not include an overall update of the PLNG electrical distribution system for addition kVa capacity.*
	Additional Risks	*The full vaporization load will exceed the transformer rating, so it won't resolve the transformer sizing issue, and PLNG will be unable to operate 2 LNG pumps and 3 vaporizers simultaneously.*
	Additional Benefits	*N/A*

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH (26%)**	**Total**
	$375,000	$97,500	$472,500
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$0,00	$0,00	
Source/ Method of Cost Data	*Total cost is based on the Norwest Engineering report and estimate, attached to this AA, plus internally produced engineering estimate.*		

ALTERNATIVE 2 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*		
Description	*Alternative 2 will install a new main service switchboard with an incoming 1600A breaker with a downstream 1200A breaker for MCC-1 and a 600A for MCC-2. The existing feeder conductors for MCC-1 will be spliced in the new vault if required and new conduits and conductors will be installed over the building to feed MCC-2.* *For the new equipment's installation, the existing main service switchboard will be demolished along with the existing vault and any associated above-ground conduits.* *This will eliminate one downside in Alternative 1 on limited MCC-1 space but does not resolve the kVa limitation.*	
In brief, why is this option not recommended?	*This does not eliminate the kVa limitations, simply divorces the MCC-1 from MCC-2. This was investigated before incoming transfer limit was discovered and only will mitigate MCC-1 frame rating issue and MCC-1 space issues IDed in Alternative 1.*	
Assessment	**Analysis Against Criteria: Reliability**	*Alternative 2 will eliminate the connection from MCC-1 and MCC-2 and help with space in MCC-1. It will not allow for full vaporization.*
	Analysis Against Criteria: Time of Implementation	*Like Alternative 1, this option offers a quicker solution, targeting punctual changes to enhance the current electrical system.*
	Analysis Against Criteria: Cost	*It is a cheaper option but does not include an overall update of the PLNG electrical distribution system for addition kVa capacity.*
	Additional Risks	*If implemented, full vaporization load will exceed the transformer rating, so it won't resolve the transformer sizing issue, and PLNG will be unable to operate 2 LNG pumps and 3 vaporizers simultaneously.*
	Additional Benefits	*None.*

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$580,000.00	$150,800.00	$730,800.00
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$0.00	$0.00	
Source/ Method of Cost Data	*Total cost is based on the Norwest Engineering report and estimate, attached to this AA, plus internally produced engineering estimate.*		

**Copy/Add table for any additional alternatives*

ALTERNATIVES CONSIDERED NOT VIABLE *Provide a description of any additional alternatives that were considered but rejected up front as not viable, and explain why*		
	Description	**Why the Alternative is not viable**
Alternative 3	*Do nothing.*	*By maintaining the status quo, PLNG is unable to operate 2 LNG pumps and 3 vaporizers simultaneously. If we attempted to operate out of range of limitation, there is potential to damage MCC-1 or incoming transformer at which point the plant will require significant repairs before returning to operation. This limitation and potential arc flash safety issue would be addressed with continuing procedural limitations.*

**Add rows for any additional alternatives considered not viable*

SUPPLEMENTARY INFORMATION

As needed, you may include any useful information gathered during the assessment phase including analysis like cost benefit / risk analysis / sensitivity analysis, etc.

PAGES 7 THROUGH 22 OF THIS EXHIBIT ARE CONFIDENTIAL IN THEIR ENTIRETY UNDER WAC 480-07-160 AND HAVE BEEN REDACTED.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	Docket UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

Exh. DBK-SSJ-21

August 29, 2025

System Integrity ECDA to ILI Assessment

Planning Document
2023 – 10 year plan
Date updated: May 31, 2023

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Scope

Develop a 10 year plan for discretionary System Integrity work related to Inspection of Transmission and High Pressure Distribution Feeders using Inline Inspection (ILI).

Transmission Assessment Criteria

Projects in this plan were selected utilizing the following criteria:

- Transmission or High Pressure Distribution System
- High Risk Ranking using the risk Rank Tool described below
- Estimated cost for ILI modifications w/o COH greater than $750k.
- ILI tool availability (currently 6” diameter or greater).
- Other pipelines deemed necessary through independent evaluation.

Note: Project order is subject to change based on risk score or other requirements, regulations, and rules that may be imposed upon NW Natural by regulatory agencies. In some instances site conditions or other outside factors may necessitate a change in the schedule.

Section One – 1 to 3 years (2023 to 2025)

Each project in this category will include a project planning document including a high level cost estimate, system modeling documents, initial route selection, and an alternative analysis. Projects in this category will follow current process to finalize design and refine the cost estimate. Projects are anticipated to be completed in the year listed – preliminary design may start up to 2 years before construction.

2023

SP Newsprint (P83)

- ILI of 7.1 miles of 12” & 16” transmission pipeline from Sherwood Intertie to SP Newsprint
- Rebuild will include installation of launchers/receivers and assessment of 12” to 16” transition.
- Cost $2M (+100%/-50%).
- In 2023 it was determined that this pipe could not be assessed using in line technology due to lack of flow. Pipe will be reassessed in 2030 to determine assessment process.

Camas (P04)

- ILI of 3.5 miles of 8” transmission pipeline from the Camas Gate to LaCamas Regional Station
- Installation of launcher, receiver and removal of two known plug valves.
- Cost $2M (+100%/-50%).

North Eugene Trans (E04)

- ILI of approximately 5.8 miles of 6” and 8” transmission pipe between Crescent Rd. and River Rd. in NE Eugene
- Work to inspect this line includes installation of launcher and receivers on both ends of the pipeline.
- Work also includes inspection of 5 valves and one bridge crossing to verify ability to inspect these sections. If areas are unpiggible they will be modified to allow for inline inspection.
- Cost $3M (+100%/-50%) 5.8 miles of 6” & 8” inspection in North Eugene

2024

Albany – Corvallis Trans (S22)

- ILI 12.7 miles of 10” transmission pipeline from Albany Gate to HWY 20.
- According to the transmission risk model this line is the fifth highest risk pipeline that has not been assessed with ILI.
- Work to inspect this line includes cutout of an unpiggable tee, removal of a bridle at the Willamette River, installation of a launcher at Albany Gate and installation of a temporary receiver at HWY 20.
- Cost $1.5M (+100%/-50%).

Granger Independence Trans (S24)

- ILI 5 miles of 6” transmission pipeline from Granger Station to valve station east of Independence Hwy on HWY 20.
- Work to inspect this line includes cutout of an unpiggable Mueller fittings and installation of launcher/receiver on Hwy 20.
- Cost $1.5M (+100%/-50%).

Mid-Willamette Valley Feeder (S36)

- ILI of 12” from Christensen Bridle to Independence Hwy
- Rebuild will involve installation of launcher and receiver.
- Cost $2M (+100%/-50%).

2025

Salem Bypass (S03)

- ILI of 5.5 miles of 8" transmission pipeline from Hwy 99E and Blossom Dr. to Center St. Regional Station in Salem
- Installation of launcher, receiver and removal of one known plug valve and Mueller fittings
- Cost $2M (+100%/-50%).

Salem Trans (S06)

- ILI of 3 miles of 12" transmission pipeline from Salem Gate to Bethel Station in Salem
- Installation of launcher, receiver, and analysis to remove any unpiggable fittings.
- Cost $2M (+100%/-50%).

Willamette Valley Trans (S18)

- ILI of 4.2 miles of 12" transmission pipeline from Brooks Regional Station to Hwy 99 and Blossom Rd. NE.
- Installation of launcher, receiver and potential unpiggable fittings to be replaced in order to facilitate in line inspection.
- Cost $2M (+100%/-50%).

Review of ILI facilities at NE 74th and Jonesmore – I-84 crossing (P48)

- Review of pigging facilities located on the north and south side of the I-84 crossing at NE 74th and Jonesmore to determine if the I-84 crossing can be included in a reassessment run for P48
- Cost $1M (+100%/-50%)

Section Two – 4 to 7 years (2026 to 2029)

Each project in this category will include a high level cost estimate, project description, preliminary modeling documentation and preliminary schedule date.

2026

Columbia City/St. Helens Trans (P09.04,.05,.06,.07)

- ILI of 19 miles of 6" & 8" transmission pipeline from 12th and Columbia St. in St. Helens to Sauvie Island Gate.
- Rebuild of station at 12th & Columbia in St. Helen's, installation of receiver at Sauvie Island, removal of 3 plug valve, removal of 2 Mueller line stopper fitting and unpiggable fittings in order facilitate in line inspection
- Need to address 2000' of 12" pipe installed in 1980 to facilitate complete 6" x 8" ILI run
- Cost $5M (+100%/-50%).

St. Helens Columbia Trans (P08.01)

- ILI of 1.6 miles of 16" transmission pipeline from Columbia City Regional Station to "E" St. and Hwy 30 in Columbia City
- Installation and launcher and receiver stations at Columbia City Regional Station and "E" St. and Hwy 30 in Columbia City. Assess pipe to determine if use of robotic assessment is more cost effective
- Cost $1M (+100%/-50%).

Columbia City Trans (P09.02,.03)

- ILI of 1.7 miles of 6" transmission pipeline from Columbia City Regional Station to "E" St. and Hwy 30 in Columbia City .
- Installation and launcher and receiver stations at Columbia City Regional Station and "E" St. and Hwy 30 in Columbia City. Assess pipe to determine if use of robotic assessment is more cost effective
- Cost $1M (+100%/-50%).

Dyno Nobel (P09.01)

- Assess 800' of 10" unodorized Transmission Main near the Columbia City near the Columbia City Regional Station utilizing robotic technology.
- Cost $1M (+100%/-50%)

2027

NE Division-LSI/Fujitsu (Cleveland & Division) (P81)

- ILI of approximately 2.5 miles of 10" transmission pipe from Gresham Gate to SE 212th and Stark
- Will require installation of launchers and receivers with assessment and rebuild of tee at NE Division and NE Cleveland.
- Cost $2M (+100%/-50%)

Front Ave Trans (Rvr to Harborway) (P53.03)

- Assess 1000 ft. of 16" transmission main from River Pkwy to the Marquam bridge station utilizing inline robotic technology
- Cost $1M (+100%/-50%)

181st and Sandy Blvd Lateral to DR (P25.09)

- Replace 300 ft. of 8" transmission main on NE 181st St. from Sandy Blvd to regulator station to higher grade pipe such that pipe is no longer classified as transmission.
- Cost $1M (+100%/-50%)

Rivergate – Columbia Blvd (P25.03, 04, 06, 07, 08)

- Review of approximately 2.5 miles of 10" and 12" transmission main along Killingsworth and Wygant Blvd to see if it can be incorporated as part of the P25.02 reassessment .
- Cost $2M (+100%/-50%)

West Linn 10" (P11.02, 03)

- Review of approximately 1 mile of 10" transmission main from Skyline to Broadway and I-205 to see if it can be incorporated as part of the P11.02 reassessment.
- Cost $2M (+100%/-50%)

2028

Harrisburg Trans (E33)

- ILI of approximately 13 miles of 6" transmission pipe from the Brownsville Gate to Harrisburg
- Will require installation of launchers and receivers with assessment and replacement of unpiggable fittings.
- Cost $4M (+100%/-50%)

North Eugene Trans (E04)

- ILI of approximately 11 miles of 6" transmission pipe between Clear Lake Rd. in north Eugene to the west bank of the Willamette River north of Junction City

- Work to inspect this line includes installation of launchers and receivers on both ends of the pipeline.
- Work also includes inspection of valves and fittings to verify ability to in line inspection these sections. If areas are unpiggible they will be modified to allow for in line inspection.
- Cost $3M (+100%/-50%)11 miles of 6” inspection from North Eugene to Junction City

2029

At this time all pipelines to be assessed are not capable of being assessed using ILI based on ILI technology in 2023 due to the pressure and flow profiles of these pipelines. Below are the pipelines due to be assessed using ECDA and potential options for assessment

SW Intertie (P68.02)

- Approximately 1 mile of 10” transmission main routed along Virginia Ave. between Slavin and Boones Ferry in SW Portland
- This pipe currently operates at 125 psig but has an MAOP of 400 psig which qualifies this pipe as transmission main.
- Decision to be made as to whether to downrate the pipe to 125 psig or inspect this section using robot technology
- Cost for robot technology $1M (+100%/-50%)

SE Trans (SE Clatsop St.) (P20.02.17)

- Approximately ¼ mile
- Study in 2023 determined that this line and regulator at SE Clatsop and SE Flavel (DR 1-038-036-R-01) is required to support load in SE Portland
- Decision to inspect line utilizing robotic technology or replace line with higher grade pipe
- Cost $1M (+100%/-50%) for robot technology or replacement

SW Intertie Trans (P69.01)

- Replace 100 ft. of 6” transmission main at Barbur and Bancroft to higher grade pipe such that pipe is no longer classified as transmission.
- Cost $1M (+100%/-50%)

Service to Cascade Steel - McMinnville (P75.01)

- Replace 100 ft. of 6” transmission main which serves as a lateral to the service for Cascade Steel in McMinnville to higher grade pipe such that pipe is no longer classified as transmission.
- Cost $1M (+100%/-50%)

Section Three – 7 to 10 years (2030 to 2032)

Each project in this category will include a high level estimate and preliminary modeling documentation. Project planning is only conceptual for projects at this point.

2030 - 2032

Utilize Robot Technology

- At this time a majority of the major pipelines would have been converted from ECDA to ILI per 2022 technology would have been completed.

- It is anticipated that regulations and improved robot tool technology will increase the assessment scope at this time.
- Locations that will be investigated for use of robot technology or improved assessment technology are:
    - SP Newsprint (P83)
    - Coos Bay (E34)
    - Halsey-Harrisburg Trans (La Salle to James River) (S33.01, .02)
    - Philomath Trans (3rd St. to Reservoir Rd.) (S26.01)
    - Willamette Valley – Hubbard Hwy to Aurora 12" (S02.01.35)
    - Uprated pipelines to transmission.

Section Four – Projects Completed in 2022

2022

Springfield Trans (E08)

- ILI 2.7 miles of 8" transmission pipeline from Coburg road to Springfield Hwy and Q street.
- According to the transmission risk model this line is the third highest risk pipeline that has not been assessed by ILI.
- Work to inspect this line includes construction and installation of temporary launcher and receivers and the removal of a plug valve.
- Actual Cost $2M

McMinnville (P31)

- ILI 12.2 miles of 6-5/8" Grade B Class D pipe from Perrydale to McMinnville
- Installation of launchers/receivers.
- Removal of 9 known plug valves and Mueller fittings
- Actual Cost $4.5M

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	Docket UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

Exh. DBK-SSJ-22

August 29, 2025

NW Natural
PROGRAM ALTERNATIVES ANALYSIS NARRATIVE

Program/Project Name: System Integrity ECDA to ILI Assessment Program
Date: 11/11/2021
Project Sponsor: Scott Lundgren
Executive Sponsor: Jon Huddleston
Project Manager: Jorge Souto
Preparer: Jorge Souto

SECTION 1: BUSINESS CASE

This section should be solution-agnostic, and about the overarching problem we're trying to solve no matter which route we end up taking

OBJECTIVES Why are we tackling this Program?	
Current State What is happening now? Where are we starting?	NW Natural complies with the Federal Pipeline Safety Regulations Guidelines regarding pipeline integrity assessment by implementing the Integrity Management (IM) program. The Program uses the Direct Assessment (DA) method, specifically the External Corrosion Direct Assessment (ECDA) to inspect transmission pipelines within High Consequences Areas (HCA's). The IM program has identified potential threats and risk ranked the transmission pipelines using factors including, but not limited to, the pipeline's age, operating system pressure, the likelihood of third-party damages, prior leaks, etc. Based on this risk ranking, NW Natural has progressively expanded the assessment of these pipelines seeking to increase the level of safety associated with the transportation of gas, including the In-Line Inspection (ILI) method since the initiation of the Pipeline Integrity Rule in 2006.
Problem Statement In simple terms, what are we trying to solve? What is the business need this is tackling? Why is this a problem worth solving (e.g. why is the current state not working)?	Based upon the PG&E incident in San Bruno, PHMSA addressed on July 1st, 2020, the 49 CFR Part 192, also known as the Final Rule, requiring operators to perform integrity assessments on the pipelines outside of HCA's. Before this rule's publication, integrity assessments were only required for pipelines in HCA's. The Final Rule also recommends operators to "expand the range of permissible assessment methods, as well as promote the use of ILI technologies, combined with further research and development by PHMSA and stakeholders to make ILI testing more accurate to drive innovation in pipeline integrity testing technologies that lead to improved safety and system reliability through better data collection and assessment." The current ECDA method does not provide a complete assessment of the entire pipeline. It can only be used to validate specific threats related to internal and external corrosion only. According to 49 CFR Ch. I Part 192.710 "Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed." ILI is the industry-preferred assessment method for transmission pipelines. NW Natural is committed to improving the safety of the Natural gas system by exceeding code requirements such as the elimination of bare steel and cast iron, when able. The next step in NWN safety commitment is to implement a defined program to inspect transmission pipelines outside HCA's and expand the use of the In-Line Inspection method.
Desired Deliverables What high level output / scope / deliverables are core to this Program?	• Projects covered in this Alternative Analysis Program are defined in the System Integrity ECDA to ILI 10-year plan which was initiated in 2016 and is updated annually. • The projects in the System Integrity ECDA to ILI 10-year plan are projects that identify pipelines to be converted from ECDA to ILI assessment per the Compliance year that the assessment is due. • The scope of the projects in the 10-year plan involves 2 to 3 pipelines per year with an estimate project cost of $2M - $5M per pipeline • The general scope of the ECDA to ILI projects require upgrades to the pipelines, that include installing launchers and receivers to allow the use of the ILI smart tools and removal of unpiggable fittings to allow for inline inspection.

	• After the full inspection is complete, the project will include the repair of all detected anomalies meeting NW Natural TIMP Plan requirements.

SECTION 2: ALTERNATIVES SUMMARY

OVERVIEW How did we review these options?	
Review Process Summarize how options were chosen, who was involved in the choice and how options were evaluated. If some criteria were considered more important based on the type of project, please explain here.	Options were chosen according to PHMSA requirements, stated on 49 CFR Part 192. According to the rule, operators generally choose between three pipeline testing methods to evaluate a pipeline's integrity. • In-Line Inspection (ILI) • Direct Assessment (in this case ECDA) • Hydrostatic Pressure Testing (Hydrostatic test) Options were evaluated according to: • Compliance with Federal Regulations • Accurate level of the integrity assessment • Cost and Implementation approach
DECISION CRITERIA Describe the criteria used to determine the selection from the various alternatives considered. For example, is this a program/project where the least cost option should be selected? Are there other factors, such as safety or quality that come into play? Include both quantitative and qualitative factors as appropriate.	
Criteria: <Compliance with Federal Regulations**>**	ILI meets regulatory requirements, and PHMSA has addressed the 49 CFR Part 192 recommending and encouraging operators to "expand the range of permissible assessment methods, as well as, promote the use of ILI technologies, combined with further research and development by PHMSA as well as stakeholders to make ILI testing more accurate to drive innovation in pipeline integrity testing technologies that leads to improved safety and system reliability through better data collection and assessment."
Criteria: < Accurate level of the integrity assessment>	The ECDA is the current assessment method to inspect the pipe integrity, but it is only performed on selected segments or sections of the entire pipeline, especially within the HCAs. According to the Final Rule, page 22 "Direct Assessment may not give an accurate representation of the condition of lengths of entire pipeline segments" and "can only be used to validate specific threats, an operator that relies solely on a DA without performing a thorough risk analysis or running multiple tools specific to multiple threats might be leaving other threats unremediated in their pipelines." ILI assessment provides a more detailed data of physical damage on the pipeline and allows the inspection of the entire extension of the pipeline, including Moderate Consequence Areas (MCA's) meeting the new Federal Regulation. In previous ILI assessments, NW Natural has identified defects outside of HCA's that, in the event of a rupture, had the potential to have a significant impact on property and the NW Natural transmission system. More information can be found on the Supplementary Information Section

Criteria: < Costs + Implementation Approach >	ECDA and Hydrostatic tests will not require any implementation. In the short term, the cost of implementing ILI inspections will be higher due to the required installation of smart tool launchers and receivers. After the implementation, the ILI inspection method will not require any further investment. For future assessment, when including HCA's and MCAs to meet new Federal Requirements, ILI would be as cost-effective as ECDA.

SECTION 3: ALTERNATIVES DETAIL

<table>
<tr><th colspan="3">RECOMMENDED OPTION
Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option. If positive /neutral/negative observations do not exist, enter N/A</th></tr>
<tr><td>Description</td><td colspan="2">In-line Inspection (ILI) refers to the process of evaluating pipes or pipelines using smart ILI tools, also referred to as "smart pigs." The smart tools are usually pushed through a pipeline by the pressure of the gas being transported. As it travels through the pipeline, it identifies and records potential pipe defects and record irregularities, including internal and external corrosion, deformations, or manufacturing defects.

ILI tools utilize nondestructive examination procedures to accurately detect and determine the size of internal damage in pipes and metal loss. The in-line inspection technologies are invaluable in the gas industry, and most pipeline operators prefer them as they are cost-effective.</td></tr>
<tr><td>In brief, why is this the recommended option?</td><td colspan="2">The proposed ILI method will provide more detailed and assessment data of physical damage on the pipeline. In addition, with the excessive costs of performing ECDA, especially in HCA's, converting pipeline to ILI will put future assessment costs more in line with the ECDA costs.

The evaluation of pipelines using other techniques, such as EDCA, can be more expensive and time-consuming when used on a wide scale as well as associated costs due to permitting requirements, traffic control plans, potential repair of paved roads, and noise ordinances during pre-assessment.

According to the Final Rule, pg 22 "Direct assessment can be prohibitively expensive to use on a wide scale and may not give an accurate representation of the condition of lengths of entire pipeline segments when the high expense leads the operator to select an insufficient number of observations."

This Program includes a high-pressure distribution pipeline that contains at least one MCA's. In following industry best practices, NW Natural is pursuing ILI assessment of MCA's of transmission pipelines.</td></tr>
<tr><td rowspan="2">Assessment</td><td>Analysis Against Criteria:
<Compliance with Federal Regulations></td><td>Pros:
ILI meets 49 CFR 192 Federal Pipeline Safety Regulations. PHMSA recommends pipeline operators increase the use of ILI tools on future integrity tests since it is a more thorough and effective method to detect potential defects and/or damages on this line than the other assessment methods.
The industry-accepted interpretation of newly added federal code (commonly referred to as The Mega Rule) 49 CFR 192.710 regarding the assessment of MCA's that operate over 30% Specified Minimum Yield Strength (SMYS) In that condition, the pipeline's operator should make efforts to allow ILI assessment of those transmission pipelines.
This option presents opportunities to replace transmission pipe where material certifications are no longer available and replace it with transmission pipe with material certifications.
Cons: (None)</td></tr>
<tr><td>Analysis Against Criteria:
<Accurate level of the integrity assessment></td><td>Pros:</td></tr>
</table>

		• ILI method provides a very detailed records of potential threats on the covered pipeline segment, including metal loss, third party damages, manufacturing, and construction defects • ILI inspection provides a fully accurate location, pointing out where and how large all anomalies on a pipeline are. Cons: • ILI technology cannot reliably detect coating damage that is not associated with pipeline defects.
	Analysis Against Criteria: <Costs + Implementation Approach >	Pros: • During ILI assessment, this work can be performed with the pipeline in service, unlike pressure testing, where the pipeline has to be taken out of service for testing to occur. This can lead to high costs to the operator and possible service disruptions to consumers. • Unlike Pressure Testing, ILI does not risk destroying the pipe, and it is typically less costly to perform on a per-unit basis than other assessment methods. • Future assessments will be cost-equivalent to the ECDA method since it requires modifications to the existing pipeline will already be completed. Cons: • In the short term, the cost of implementing ILI inspections will be higher than the ECDA inspection costs since the transmission pipeline has multiple non-piggable fittings that need to be remediated or removed to make the pipeline able to be in-line inspected. • Requires the installation of launcher or receiver facilities to safely relieve pressure in the barrel before inserting or removing ILI tools.
	Additional Risks	Unknown previous damage may require additional repairs in the pipeline to run the ILI smart tools.
	Additional Benefits	PMI material testing tasks shall also be performed throughout the remediation of the non-piggable fitting digs, contributing to more completed records of material certs for the NW Natural transmission pipeline.

POTENTIAL COST OF ILI ASSESSMENT (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$160,000	$25,200	$185,200
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$	$160,000 (Direct cost, once every 7 years)	
Source/ Method of Cost Data	The direct cost includes mobilization, inspection and report cost for ILI inspection costs, based on the E15 S Eugene Trans ILI project. The cost of the In-Line Inspection itself is about $100 thousand plus about $60,000 of NWN internal costs.		

<table>
<tr><th colspan="3">ALTERNATIVE 1
Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.</th></tr>
<tr><td>Description</td><td colspan="2">External Corrosion Direct Assessment (ECDA) is a structured process that identifies coating defects that ultimately impact a pipeline’s structural integrity. The ECDA involves four phases: Pre-assessment, Indirect inspection, Direct examination, and Post assessment.</td></tr>
<tr><td>In brief, why is this option not recommended?</td><td colspan="2">The ECDA is the appropriate method to identify that the cathodic protection (CP) and coating are performing as intended at all points. However, it won’t detect damage that might have occurred in the past, or if recent upgrades to a CP system have been implemented, it may conceal past deficiencies.

The data produced from ECDA inspections are not as detailed as the data produced from ILI inspections. ECDA inspections call out where possible coating anomalies are. Still, it cannot confirm the type of anomaly (dent, gouge, corrosion, milling errors, internal metal loss, etc.) or exact dimensions of the anomaly like an ILI inspection can.

Since ECDA inspections are performed in High Consequence Areas (HCA’s) and Identified Sites as defined in our TIMP manual, it will trigger high costs related to City Permits, Traffic Control Plans, public impact, etc.</td></tr>
<tr><td rowspan="2">Assessment</td><td>Analysis Against Criteria: <Compliance with Federal Regulations></td><td>Pros:
ECDA meets regulatory requirements and can be a powerful tool for pipelines unable to be accessed by other means.
Cons:
49 CFR 192 recommends operators to expand the range of permissible assessment methods, as well as promote the use of ILI technologies.
Based on conversations with other operators NW Natural’s interpretation of recent comments made in the documentation submitted by PHMSA in the Final Rule, ILI assessment is the preferred method of assessing natural gas transmission pipelines.</td></tr>
<tr><td>Analysis Against Criteria:<Accurate level of the integrity assessment></td><td>Pros:
ECDA assessment is the best method to detect if the cathodic protection (CP) and coating are performing as intended of lengths of entire pipeline segments.
Cons:
ECDA does not provide a complete analysis of the pipeline, and hidden anomalies may exist based on the performance of the CP system therefore introducing unforeseen risks to the pipeline in the future. ECDA cannot measure the exact dimensions or severity of an anomaly like an ILI, which helps determine which anomalies can be monitored versus which ones should be repaired.
ECDA methods can show where CP and coating issues are present but cannot detect physical damage to a pipeline.
49 CFR 192, pg. 22 states that “as ECDA can only be used to validate specific threats, an operator that relies solely on a ECDA without performing a thorough risk analysis or running multiple tools specific to multiple threats might leave other threats unremediated in their pipelines.”</td></tr>
</table>

	Analysis Against Criteria: < Costs + Implementation Approach >	Pros: • Persevering with ECDA inspections can be, in the short term, a low-cost method, as it will not require any investment for its implementation. Cons: • The inclusion of MCA's on future assessment will trigger higher cost for ECDA inspections since more lengths of entire pipeline segments will be added to the inspection. • Higher costs associated during ECDA inspections due to permitting requirements, traffic control plans, potential repair of paved roads, and noise ordinances during pre-assessment. • High cost within segments considered hard surface due to the required drillings to perform the tests.
	Additional Risks	• NWN's transmission pipelines have had past damages since its 1960 installation. There are likely many unidentified damages that an ECDA method won't be able to detect. • Permitting restrictions, Traffic Control implementation, and Public Impact.
	Additional Benefits	• No implementation costs

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$	$	$
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$	$155,000 (Direct costs, once every 7 years)	
Source/ Method of Cost Data	It was estimated by looking at previous ECDA inspection costs with similar pipeline lengths and a similar amount of hard surface inspection, including city permits and traffic control costs.		

<table>
<tr><th colspan="3">ALTERNATIVE 2
Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.</th></tr>
<tr><td>Description</td><td colspan="2">Hydrostatic Pressure Testing (Hydrostatic test) is a way in which pressure pipeline systems can be tested for strength and leaks, and involves filling the vessel or pipe system with a liquid, usually water, and pressurization of the vessel to the specified test pressure for a Code defined duration.</td></tr>
<tr><td>In brief, why is this option not recommended?</td><td colspan="2">Hydrostatic pressure testing can result in substantial costs, disruptions in service, methane emissions due to the routine evacuation of natural gas from pipelines before tests and can be a destructive method. Although the Hydrostatic test is considered a non-destructive testing method, if defects on a component are severe, then the component may rupture during the testing
According to the 49 CFR Part 92, page 22 “Regulators and operators agree that improving ILI methods as an alternative to hydrostatic testing is better for risk evaluation and management of pipeline safety.”</td></tr>
<tr><td rowspan="4">Assessment</td><td>Analysis Against Criteria:
<Compliance with Federal Regulations></td><td>Pros:
• Hydrostatic test meets regulatory requirements and can be a powerful tool for pipelines unable to be assessed by other means.
Cons:
• ILI is a preferred alternative to hydrostatic testing is better for risk evaluation and management of pipeline safety.
• Hydrostatic testing method of defect identification is the failure of the pipe.</td></tr>
<tr><td>Analysis Against Criteria:
<Accurate level of the integrity assessment></td><td>Pros:
• Hydrostatic test is more effective than ECDA for identifying pipe conditions that are related to stress corrosion cracking defects.
Cons:
• Hydrostatic test does not provide an accurate pipeline analysis and associated anomalies when compared to ILI assessment.
• Hydrostatic tests utilize failure to determine the defects in the pipeline. There may be defects in the pipeline that passes a hydrotest but are potentially harmful defects that need to be addressed to make the pipeline safer.</td></tr>
<tr><td>Analysis Against Criteria:
< Costs + Implementation Approach ></td><td>Pros:
• This method would prove that the line can support the current MAOP and that no leaks or weak points were found in the pipeline.
Cons:
• Hydrostatic test is costly since it requires excavating, access, and cutting several pipeline sections to perform the procedure.
• Operationally it is not a feasible option while maintaining deliveries in the area.
• Hydrostatic test will generate a large amount of wastewater that would have to be disposed of with special permitting conditions.
• Hydrostatic test can be a destructive testing method, so that pipeline can rupture and fail if the inspection exceeds a specified test pressure, or a small crack propagates rapidly.</td></tr>
<tr><td>Analysis Against Criteria:
<insert></td><td></td></tr>
</table>

	Additional Risks	• Disposing of the contaminated wastewater will be expensive • If there is a failure in the pipeline, then the failed section will have to be repaired, replaced, and the hydro test procedure shall be repeated. • Failure during the hydrostatic test could be dangerous/disruptive if the test is performed in high consequence areas (HCA's) • Failure of the test can result in various main artillery roads to be closed due to the release of contaminated water and odor calls
	Additional Benefits	NA.

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$1,200,000	$504,000 (42%)	$1,704,000
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$	$1,200,000 (Direct costs, once every 7 years)	
Source/ Method of Cost Data	Rough estimate from typical water costs and an unknown amount of sections to cutout and remove for performing the hydrostatic tests. Note: As stated, this is a rough estimate, and not a "not to exceed amount". The total cost could easily surpass $1.5M depending non the number of failures in the pipeline during tests.		

*Copy/Add table for any additional alternatives

ALTERNATIVES CONSIDERED NOT VIABLE Provide a description of any additional alternatives that were considered but rejected up front as not viable, and explain why		
	Description	**Why the Alternative is not viable**
Alternative 3		
Alternative 4		
Alternative 5		

*Add rows for any additional alternatives considered not viable

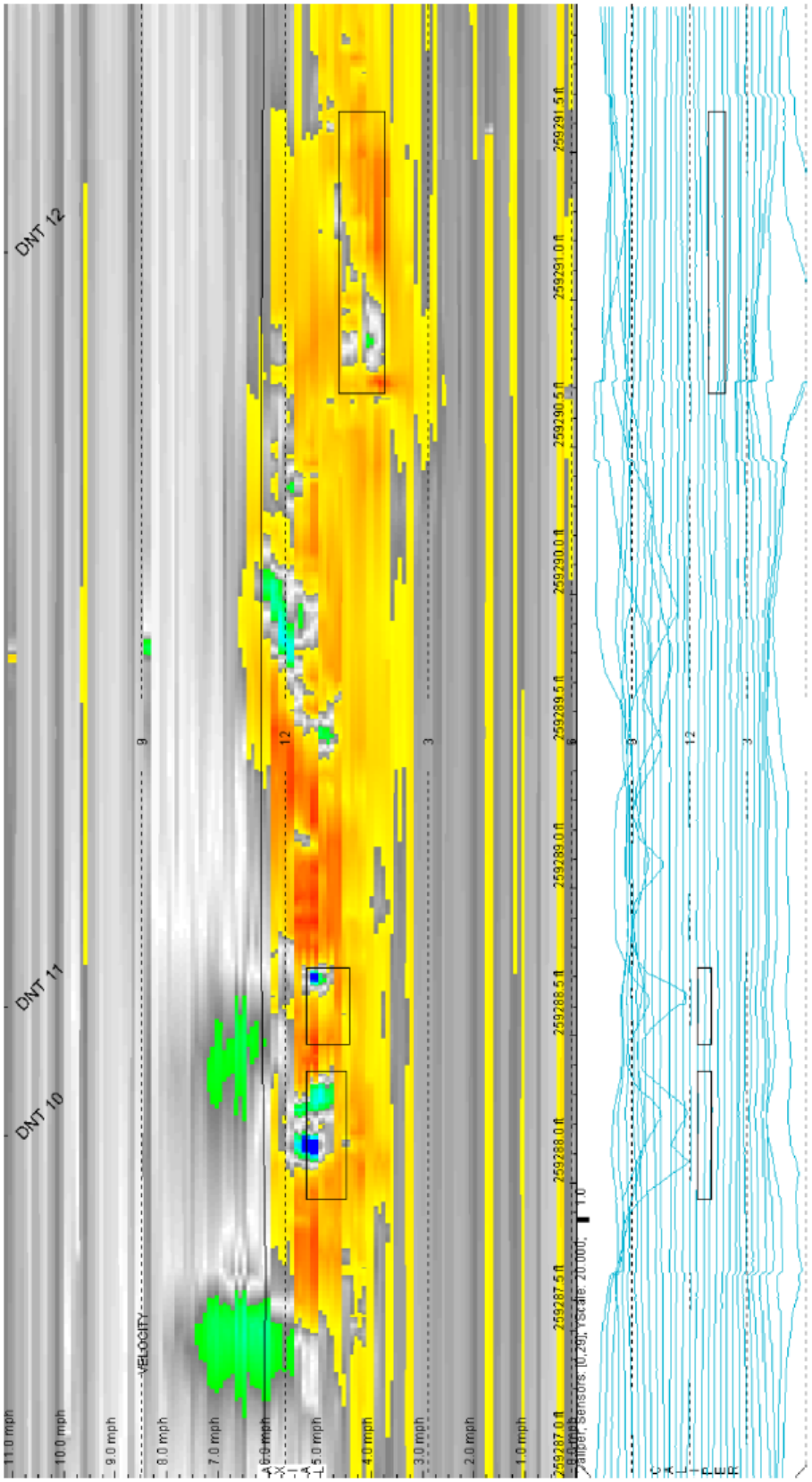
SUPPLEMENTARY INFORMATION

On this supplementary information we have added some pictures from an ILI run performed on the Central Coast Feeder line in 2019 and the anomaly dig excecuted in 2020. The anomaly was located at the east of Gleneden Beach, OR and in this case, it is not located in a HCA's.

P30 12-inch Central Coast Feeder

ODO 259287 to 259290 (DNT's 10-12)
Three Dents on Top of Pipe
2.5%, 2.5%, 1.4%

P30 12-inch Central Coast Feeder



ODO 259287 to 259290 (DNT's 10-12)

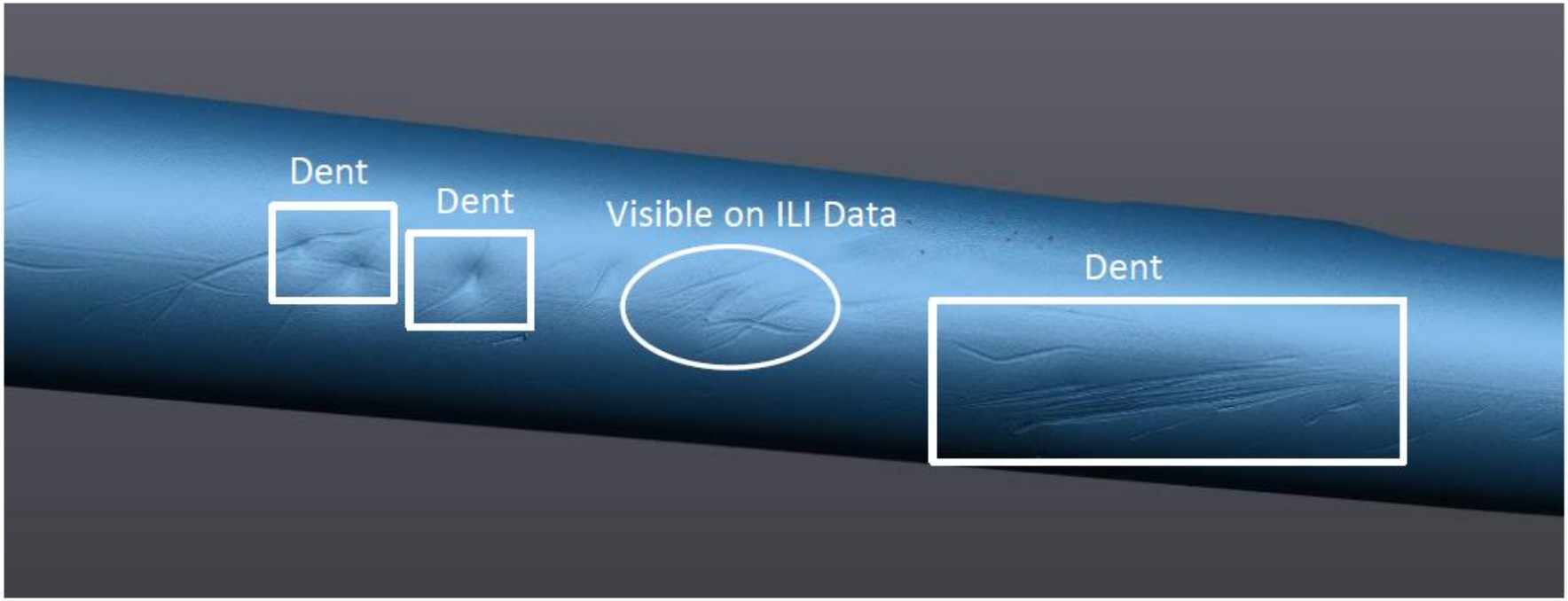
Three Dents on Top of Pipe

2.5%, 2.5%, 1.4%

Third indication visible downstream, at ODO 259304.5, not called out.

Note: Dents under 2% were not specifically itemized in report

P30 12-inch Central Coast Feeder



7 foot long view of pipe. Image rendering from VXelements Software

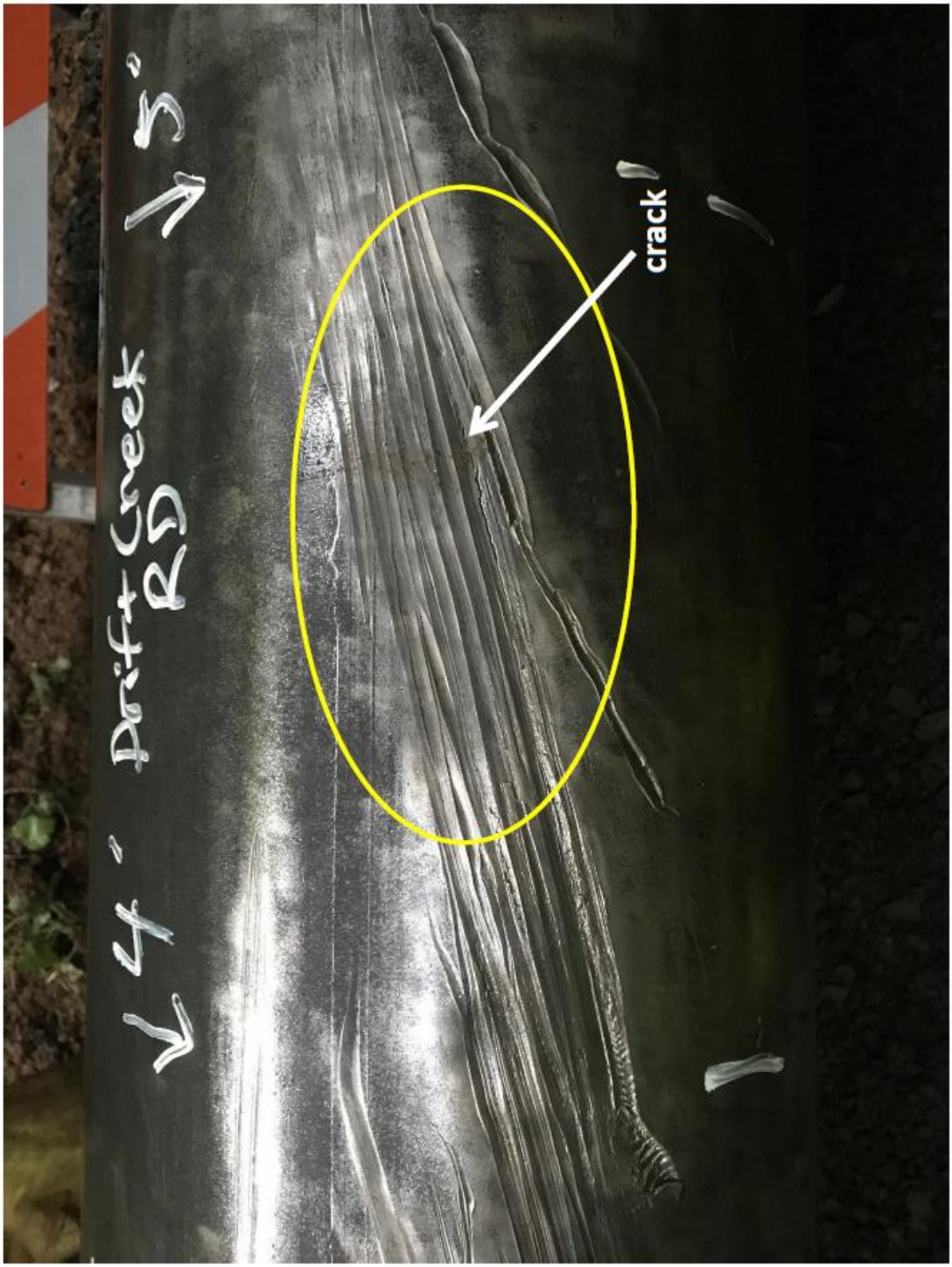
Dents and metal loss can be seen on the ILI Software Screenshot

P30 12-inch Central Coast Feeder

P30 12-inch Central Coast Feeder

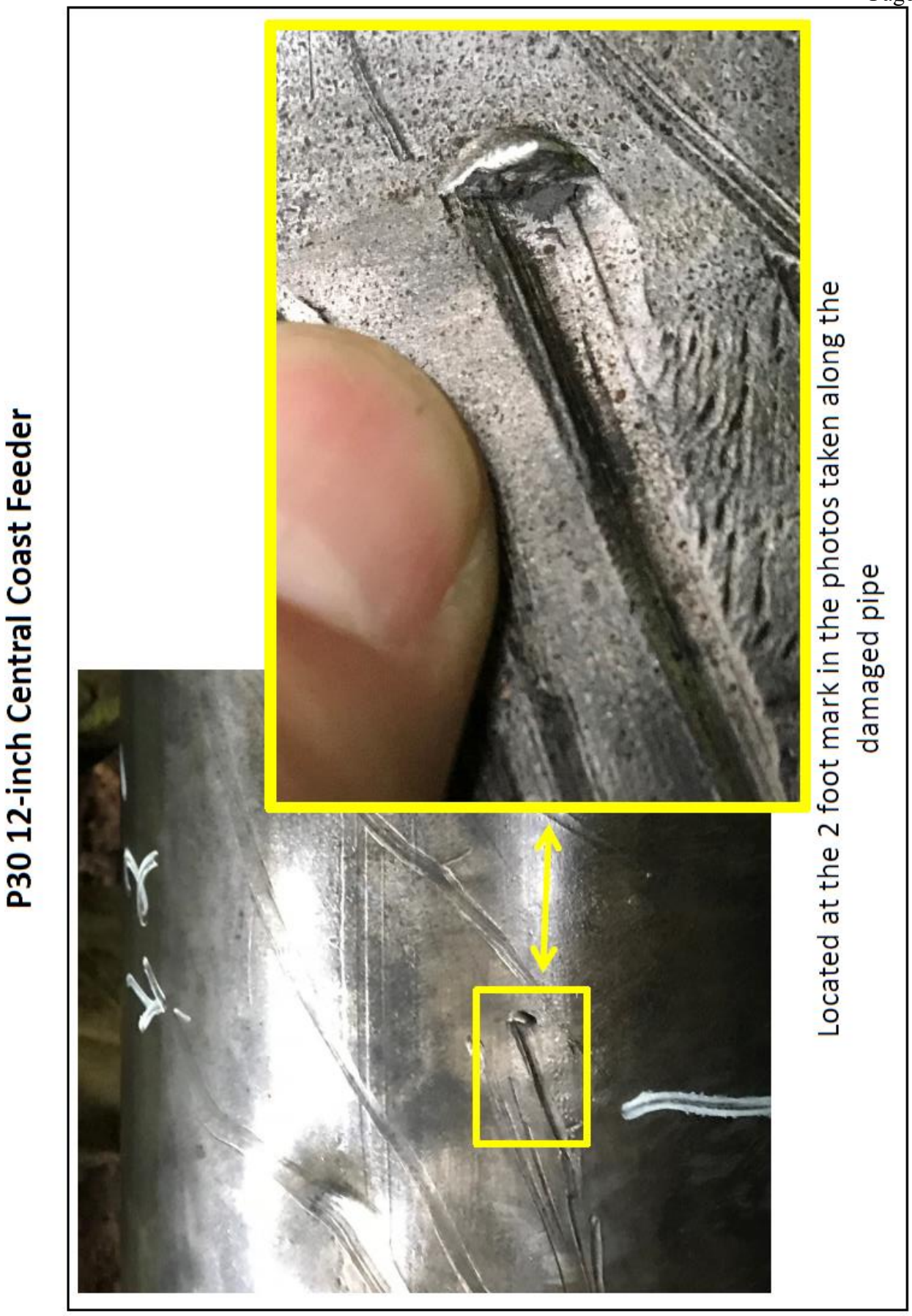
P30 12-inch Central Coast Feeder

P30 12-inch Central Coast Feeder



P30 12-inch Central Coast Feeder

P30 12-inch Central Coast Feeder


P30 12-inch Central Coast Feeder
Located at the 2 foot mark in the photos taken along the damaged pipe

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	Docket UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Daniel B. Kizer and Scott S. Johnson

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

Exh. DBK-SSJ-23

August 29, 2025

NW Natural

Distribution Integrity Management

Program Plan

March 31, 2025

250 SW Taylor Street
Portland, Oregon 97204

Original plan

Aug. 1st 2011

NW Natural

Distribution Integrity Management Program
Program Plan

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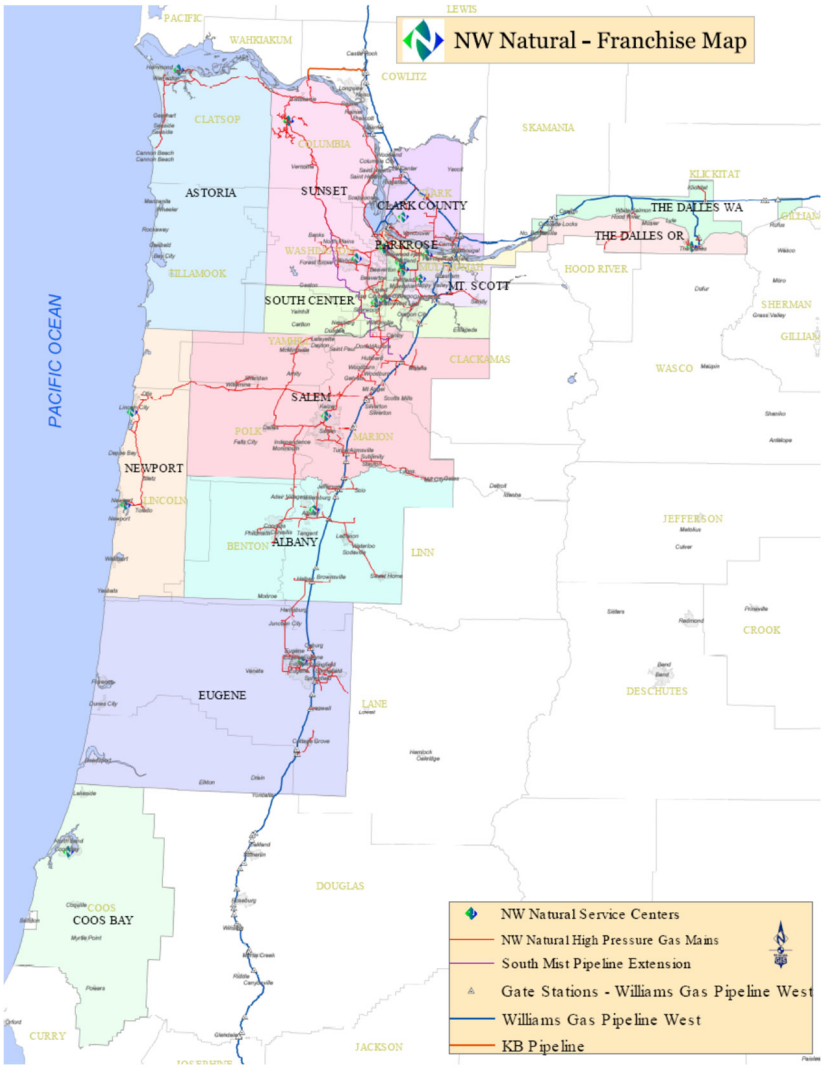
NW Natural

Distribution Integrity Management Program
Program Plan

1. COMPANY OVERVIEW

Headquartered in Portland, Oregon, NW Natural delivers natural gas to approximately 800,000 residential, commercial and industrial customers. The service territory is depicted in Figure 1-0 below.

Figure 1-0: NW Natural Service Terrirory



2. SCOPE

This document is the Distribution Integrity Management Program Plan for NW Natural and is intended to meet the requirements of 49 CFR, Part 192, Subpart P, Distribution Integrity Management Programs (DIMP). This written plan addresses the seven following required elements of DIMP:

- Knowledge
- Identify Threats
- Evaluate and Rank Risk
- Identify and Implement Measures to Address Risks
- Measure Performance, Monitor Results, and Evaluate Effectiveness
- Periodic Evaluation and Improvement
- Report Results

This written plan applies to gas distribution facilities operated by NW Natural in Oregon and Washington and was initially implemented on August 1, 2011. Gas distribution facilities include the associated mains, services and other appurtenances not meeting the definition of gathering line or transmission line and under jurisdiction of 49 CFR, Part 192.

This plan does not cover:

Gathering lines – pipelines and associated facilities that transport gas from a current production facility to a transmission line or main. (NW Natural does not currently own nor operate gathering lines).

Transmission lines – as defined by SPO/SPW 001. Although the processes and procedures defined in this written plan may be used on transmission pipelines outside an HCA.

LNG Facilities – as defined by SPO/SPW 001 and covered under the jurisdiction of 49 CFR, Part 193.

2.1 Correlation with Other NW Natural Programs and Documentation

This IMP plan describes the processes of NW Natural's program for distribution integrity management but does not repeat elements of the program that are already in place as existing documented procedures. Sections of the following NW Natural manuals are relevant to some of the processes and procedures of the Integrity Management Program.

- Standard Practices (SPO/SPW)—includes written policies for conducting pipeline operations and maintenance activities and handling abnormal operations and emergencies. The policies are in accordance with 49 CFR 192. A committee reviews the Standard Practices manual once each calendar year and updates it as necessary. A set of Standard Practices are written for both Oregon (SPO) and Washington (SPW).
- Field Operations Manual (FOM)—includes written procedures for conducting pipeline construction, operations, and maintenance activities. The procedures are in accordance with 49 CFR 192. A committee reviews the FOM once each calendar year and updates it as necessary.

- Operator Qualifications (OQ) Procedures and Abnormal Operating Conditions (AOCs)—include procedures for performing all OQ covered tasks in accordance with 49 CFR 192, Subpart M.
- NW Natural Engineering Specifications – Engineering Specifications that provide detailed descriptions of materials purchased by NW Natural. A committee reviews these specifications every 3 years
- NW Natural Engineering Standards – Engineering Standards for approved parts and materials used in the NW Natural Distribution System. A committee reviews these standards every 3 years.
- NW Natural Engineering Procedures – Field and design procedures that document processes implemented by NW Natural Engineers. A committee reviews these procedures every 3 years.

3. PURPOSE AND OBJECTIVES

The purpose of the DIMP is to enhance safety by identifying and reducing gas distribution integrity risks. Managing the integrity and reliability of the gas distribution pipeline has always been a primary goal for NW Natural; with design, construction, operations and maintenance activities performed in compliance with CFR 49, Part 192 requirements. The objective of this written DIMP Plan is to establish the minimum requirements to comply with the Code of Federal Regulations (CFR 49) Subpart P, pertaining to integrity management for gas distribution pipelines.

This written plan does not address how NW Natural may deviate from the required periodic inspections as provided for in §192.1013.

3.1 Company Roles

Integrity management is a company-wide program that involves the entire NW Natural organization. The Integrity Management Group (IMG) is charged with the development of the IMP Plan and for the accomplishment of its processes. The key team members involved in the development and distribution of this program are listed in Table 1.

Table 1. IMP Organization Chart

Name	Title	Function
Justin Palfreyman	President and CEO NW Natural Holdings	Chief Executive
Kim Rush	President NW Natural Gas Company	Chief Executive
Joe Karney	Vice President, Engineering and Utility Operations	Project Sponsor
Dan Kizer	Senior Director, Engineering	Steering Committee Member
Scott Lundgren	Manager of System Integrity	Program Manager, Steering Committee Member
Ryan Van Gordon	Corrosion Supervisor	Corrosion Engineer
Lindsey Robison	Integrity Management Engineer	Integrity Management Engineer
Christian Ching	Integrity Management Engineer	Integrity Management Engineer
Jonathan Kopp	Integrity Management Engineer	Integrity Management Engineer
Matthew Knapik	Integrity Management Engineer	Integrity Management Engineer
Jordan Carabajal-Johnson	Materials Engineer	Materials Engineer

Willy Druig	Engineering Specialist	Integrity Management Specialist
Deane Poirier	Engineering Specialist	Integrity Management Specialist
Ryan Pemberton	GIS Analyst	GIS Analyst
Laurel Garrett	GIS Analyst	GIS Analyst
Ryan Truair	Senior Manager, Code Compliance	Steering Committee Member

3.1.1 Vice President, Engineering and Utility Operations

The Vice President, Utility Operations has overall responsibility to assure that the DIMP Plan processes are implemented by the organization in accordance with this DIMP Plan and associated regulatory requirements. The Vice President, Engineering and Utility Operations, may delegate some or all of these responsibilities to others within the organization.

3.1.2 Manager of System Integrity

The Manager of System Integrity has the responsibility for day-to-day program oversight and responsibility to assure that the plan is implemented effectively. This Plan assigns authority to the Manager of System Integrity for approval of documents and plans. The Manager of System Integrity may delegate some or all of these responsibilities. Roles for this position include:

- Monitors and controls costs and scheduling
- Determines DIMP budget requirements and makes associated Capital and O&M budget requests

- Assures effective implementation of the seven elements of the DIMP process
- Authorizes and approves changes and revisions to the DIMP Plan
- Initiates communication with other departments within the Company
- Participates in annual effectiveness reviews and complete plan re-evaluations
- Gathers data for annual reports to PHMSA and State Safety Regulators

Reviews and approves Exception Requests

3.2 Personnel Qualifications

The IMG (Integrity Management Group) is charged with the development, implementation, and maintenance of the DIMP Plan. The authority for this charge is imparted with the acceptance of a candidate for the described job. NW Natural maintains specific job descriptions and organizational charts for integrity management positions that outline the specific responsibilities and lines of reporting for personnel that perform integrity management activities.

4. DEFINITIONS

The following definitions and acronyms shall apply to this DIMP Plan. This section supplements SPO/SPW 001 – Definitions, as found in the Standard Practice Manual.

COF: Consequence of Failure

DIRT (Damage Information Reporting Tool): Reporting tool mangaged by the Common Ground Alliance (CGA) for excavation damages. An annual DIRT report is issued each year that documents and provides analysis for damages to below ground facilities in the Unites States and Canada.

DIMP (Distribution Integrity Management Program): an overall approach used by NW Natural to ensure the integrity of its gas distribution system (reference §192.1001)

DIMP Files: NW Natural's records, databases, and/or files that contain either material incorporated by reference in the Appendices of the DIMP Plan or outdated material that was once contained in the DIMP Plan Appendices but is being retained in order to comply with record keeping requirements.

DIMP Plan (Distribution Integrity Management Program Plan): a written explanation of the mechanisms or procedures NW Natural will use to implement its integrity management program and to ensure compliance with subpart P of CFR 49, Part 192(reference §192.1001)

DIMP Rule: CFR 49, Part 192, Subpart P

Distribution Line: as defined in SPO/SPW 001

DOGAMI: Oregon Department of Geology and Mineral Industries

Excavation Damage: as defined in SPO/SPW 001

EFV (Excess Flow Valve): as defined in SPO/SPW 001

ERV (Engineering Records Viewer): Intranet based pipeline records search tool and viewer.

FOF (Frequency of Failure): synonymous with Likelihood of Failure

Hazardous Leak: a leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous (reference §192.1001)

Main: as defined in SPO/SPW 001

MDPE: Medium Density Polyethylene

NTSB: The National Transportation Safety Board

PHMSA: The U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration

Pipeline: as defined in SPO/SPW 001

Region: areas within a distribution system consisting of mains, services, and other appurtenances with similar characteristics and reasonably consistent risk.

Risk: a relative measure of the likelihood of a failure associated with a threat and the potential consequences of such a failure

Risk Model: the integration of facility data, operational data, SME input, and established algorithms to estimate the relative risk associated with a gas distribution system threat

Service Line: as defined in SPO/SPW 001

SLIDO: Statewide Landslide Information Database for Oregon

SME (Subject Matter Expert): A SME is an individual who is judged by NW Natural to have specialized knowledge based on their expertise or training. Typically the individual will have firsthand experience or knowledge of a topic under consideration. The background and experience will vary with the information that is requested.

SPO: Standard Practice – Oregon

SPW: Standard Practice - Washington

Sub-Threat: a threat type within one of the primary threat categories specified in §192.1007(b)

Ticket: a notification from the one-call notification center to NW Natural, providing information of pending excavation activity for which NW Natural is to locate and mark its facilities.

5. KNOWLEDGE OF FACILITIES

This section describes NW Natural's methodology for demonstrating an understanding of its gas distribution system. NW Natural uses reasonably available information as the foundation for DIMP. This section will include, at minimum, the following:

- NW Natural will identify the characteristics of the distribution pipeline's design and operations and the environmental factors that are necessary to assess the applicable threats and risks to its gas distribution pipeline.
- NW Natural will consider the information gained from past designs, operations and maintenance.
- NW Natural will identify additional information needed and provide a plan for gaining that information over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).
- NW Natural will develop and implement a process by which the DIMP will be reviewed once per calendar year, and will be refined and improved as needed per section 10 of this plan.
- NW Natural will provide for the capture and retention of data on any new distribution pipeline installed. The data must include, at a minimum, the location where the new pipeline is installed and the material of which it is constructed. An attribute list of current information gathered on new distribution pipelines can be found in Appendix A-2.

The requirements of this section will be met using the design and construction records stored in the GIS (Geographic Information System) and compliance inspection records

including leak history, corrosion control records and continuing surveillance records stored in SAP. When applicable, NW Natural will utilize the collective judgment of SMEs to fill in gaps for missing and inaccurate or incomplete records. NW Natural will also use available external data sets to identify the characteristics of the distribution system's environmental factors (for example, census data, FEMA flood plain, DOGAMI and SLIDO). NW Natural will continually evaluate and may gather additional information as appropriate to improve system knowledge.

The knowledge of the distribution system will be used to evaluate each threat and prioritize risks as listed in Section 6.0 (Threat Identification) and Section 7.0 (Evaluation and Ranking of Risk) in this Plan.

Figure 5-0 illustrates the procedure to confirm Knowledge of the System.

Figure 5-0 illustrates the procedure to confirm Knowledge of the System.

Process to Confirm Knowledge of the System

The purpose of this process is to verify complete and current knowledge of the gas distribution system, to identify gaps in knowledge and to fill those gaps to meet the requirements of "Know Your System". This process can be initiated by any member of the Integrity Management Group at any time.

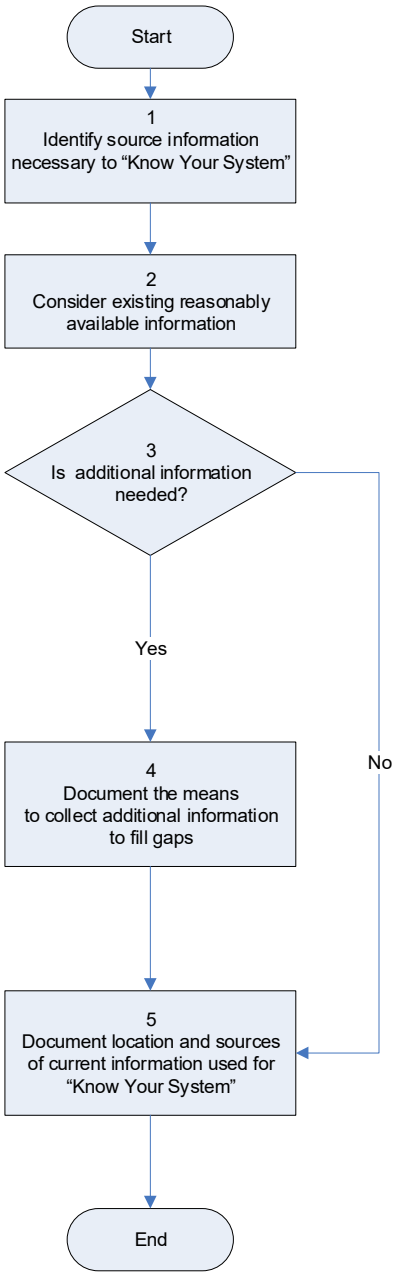
1. The Integrity Management Group identifies the records necessary to "Know Your System", and demonstrate an understanding of its gas distribution system developed from reasonably available information.

2. Consider existing reasonably available information including data contained in GIS, SAP, Sharepoint, ERV, Clevest, Annual Report and SME knowledge. Data considered will include information gained from past design, operations and maintenance activities.

3. Determine if records provide the most current data and information available. Also, does the information identify the characteristics of the distribution pipeline's design and operations and the environmental factors that are necessary to assess the applicable threats and risks to its gas distribution pipeline? Is the information gained from past designs, operations and maintenance considered? Is information needed to fill gaps?

4. Provide a plan for gaining information over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).

5. Document location and sources of existing records, including electronic (ERV, GIS), paper and subject matter experts.



5.1 Type and Location of Records

5.1.1 GIS (Geographic Information System)

- The primary record of NW Natural's distribution system resides in the GIS, which is a map of the entire NW Natural system, Approx. 2,000 sq. miles of above ground and underground facilities. It includes specific records of pipe size, material, installation date, location, MAOP (Maximum Allowable Operating Pressure), business district and other information as available. The platform allows for external records to be overlaid, such as census data, FEMA flood plain, DOGAMI and SLIDO. A summary of the data sets used to demonstrate an understanding of its gas distribution system is found in Appendix A, and an attribute table for Distribution and HP Distribution is shown in Appendix A-2. Operations and Engineering personnel utilize IQGeo Asset Map Viewer to access information stored in GIS.
- In some cases, NW Natural may be unable to determine the materials or characteristics of some of the components of the system. This is due to earlier practices not capturing this information or inaccurate, incomplete or missing records. This will be accomplished by using Section 5.2 Missing Data and will be documented and kept within Integrity Management files.
- Information about an existing system will be updated when new or better information becomes available. NW Natural will not dig up its facilities for the purpose of gathering data. This information will be gathered during existing operating or maintenance activities and installation of new facilities on an existing infrastructure. NW Natural will rely on existing processes to accomplish this, such as the data gathered by the Pipe Inspection Report (PIR).

- NW Natural's continual improvement efforts may include capturing facility information and the development of a process for notating "assumed values", based on information provided by SMEs.

5.1.2 SAP

- NW Natural uses the electronic database SAP to schedule, track and record compliance programs for leakage, corrosion, valve maintenance, district regulators, service regulators, meter sets, odorometer sites, long couplings, flex lines for houseboats, water crossings and bridge line inspections.
- The SAP data is referenced into the GIS to overlay on the existing system data.

5.1.3 SharePoint - ERV

- NW Natural uses SharePoint - ERV, to store procedures, pressure test documents and as-built's. This information is archived from paper and electronic records created at the time of installation. These files contain additional information that may be used in the future. In 2013 remaining microfilm and some original paper records were digitized/scanned and archived in ERV. Additional records may be scanned into ERV as NW Natural deems necessary. The pertinent information for identifying the characteristics of the pipeline's design is stored in the GIS.

5.1.4 Damage Prevention Records Sharepoint/SQL /RLMAN (Risk and Land Management System)

- NW Natural stores historical information related to damages in the Damage Prevention Audit Site which pulls from the Damage Prevention Forms that

are saved on SharePoint. For damages prior to 2012 this historical information is stored on RLMAN, accessed through the SQL server. This information includes the date, location, responsible party and reason for the damage. Reports related to damages including locates received, locates completed and third party damages are stored on Sharepoint and are used to determine a damage ratio, damages per 1000 locates.

5.1.5 Clevest

- Clevest is a dispatch tool, used to gather information and manage field construction and compliance activities. The data collected in Clevest is stored and accessible through the SQL server. Clevest collects data from field activity to better define system characteristics.

5.1.6 Annual Report

- The annual report to DOT summarizes the basic knowledge of what is in NW Natural's distribution system, including a breakdown of the mains and service lines by material, diameter and installation decade. This report is electronically filed for Oregon and Washington annually with PHMSA and is stored with Compliance Management. The information contained in this report is used to complement the understanding and knowledge of the system. Beginning in 2010, the report includes the following sections:
    - Part A- Operator Information.
    - Part B - System Description, which reports the miles and number of services in the NW Natural system at the end of the year.
    - Part C - Total Leaks and Hazardous Leaks Eliminated/Repaired During Year provides a breakdown of eliminated/repaired leaks by

leak cause for mains and for service lines, and the number of known system leaks scheduled for repair. Includes number of leaks due to mechanical fitting failure.

- Part D - Excavation Damage reports the total number of excavation damages and the total number of locate tickets.
- Part E - Reserved
- Part F - Total Number of Leaks on Federal Lands Repaired or Scheduled for Repair
- Part G - Percent of Unaccounted for Gas as a percent of total input for the 12 months ending June 30 of the reporting year.
- Part H - Additional Information
- Part I - Preparer and Authorized Signature

5.2 Missing Data

The Integrity Management team has reviewed and evaluated the aggregated data to identify areas where data may be insufficient or missing. Based on the evaluation, there is no need to actively research missing or insufficient data for the initial implementation of this plan, as documented in Appendix A-3.

The current Pipe Inspection Report process requirements supplement the Knowledge of the System. Pipe Inspection Reports are completed by NW Natural personnel and historical information is stored in the SQL server. Errors discovered in the mapping system are corrected by using the Add Object tool in IQGeo and creating a Map Correction.

When additional information is required, the Integrity Management team will develop the methods necessary to gather the appropriate information. New Additional or Accelerated (A/A) actions may require additional data to be gathered. The missing data and the process to gather that data will be identified as part of the A/A action.

5.3 Review

The process for periodic review, refinement, and improvement is discussed in Section 10.

5.4 Data Capture for New Construction and Ongoing Operations & Maintenance

Records for all piping systems installed after the effective date of this plan will be captured and retained by NW Natural. Records shall include newly installed facilities and facilities that are abandoned or taken out of service as a result of the newly installed facilities. This will include the location where new piping and appurtenances are installed,the material of which they are constructed and location of abandoned or taken out of service facilities as a result of the newly installed facilities. For material specifications of newly installed pipe refer to “Engineering Specification MTS-003” and “Engineering Standard 19-001 for Poly Pipe” and “Engineering Specification MTS-00” and “Engineering Standard 27-001 for Steel Pipe.” This shall be accomplished on electronic as builds through Clevest, and IQ-Geo. For larger projects information may be obtained from paper as-builts and documents. An attribute list of current information gathered on new distribution pipelines can be found in Appendix A-2.

6. THREAT IDENTIFICATION

This section describes NW Natural's methodology for identifying existing and potential threats to the gas distribution pipeline. The following categories of threats shall be considered for each gas distribution pipeline (trailing # equals threat order):

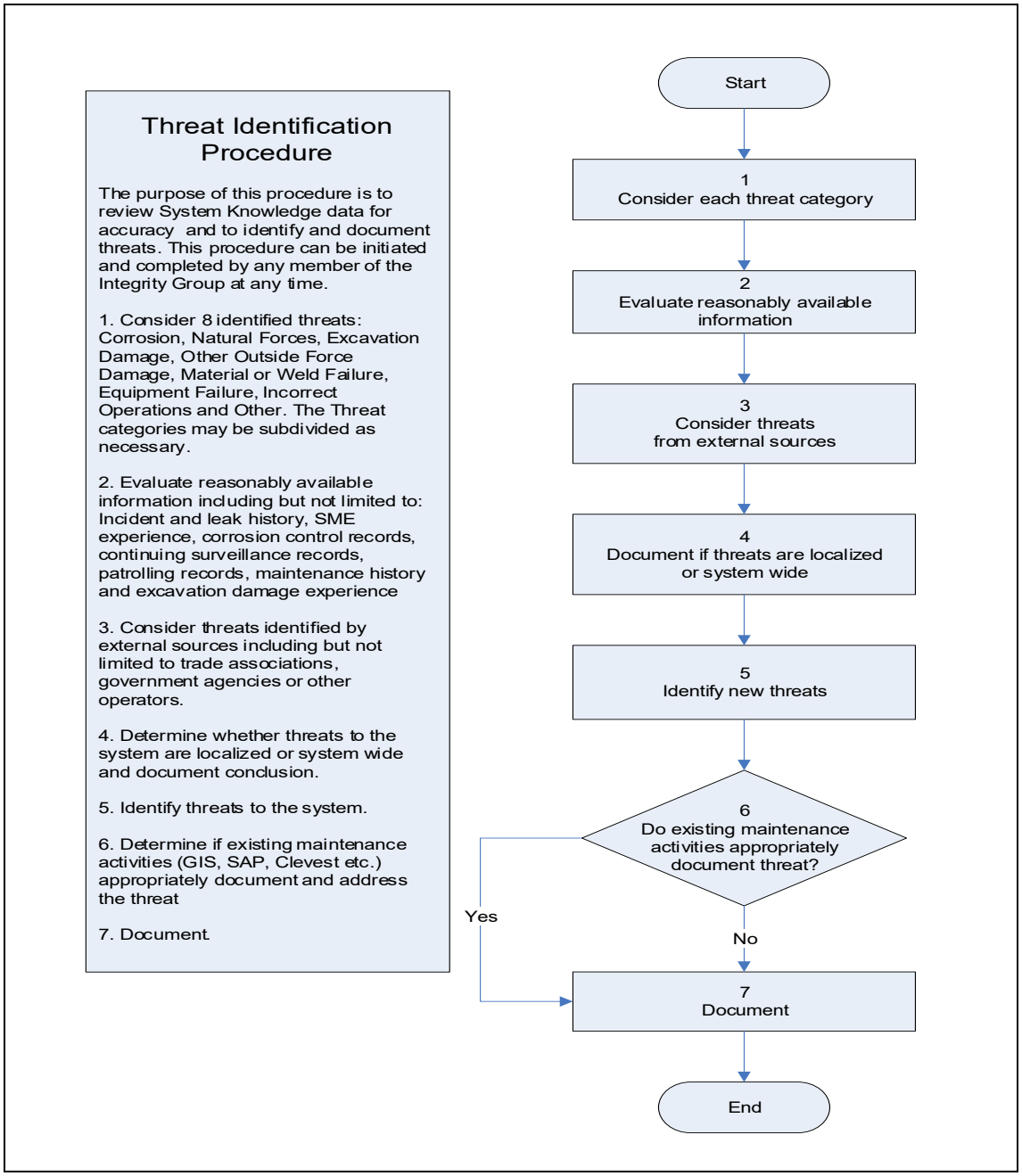
- Corrosion (3)
- Natural Forces (7)
- Excavation Damage (1)
- Other Outside Force (8)
- Material, Weld or Joint Failure (2)
- Equipment Failure (4)
- Incorrect Operation (6)
- Other concerns that could threaten the integrity of the gas distribution pipeline. (5)

NW Natural will review information gathered for Section 5.0 and reasonably available information to identify existing and potential threats. Sources of data may include, but are not limited to, incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

NW Natural

Distribution Integrity Management Program
Program Plan

Figure 6-0 illustrates the procedure used to identify threats.



6.1 Threat Identification

NW Natural relies on over 165 years of operating experience and actively participates in industry and PHMSA integrity forums. Where possible, NW Natural uses a data centric approach, supplemented with SME and industry data.

6.1.1 Data Centric Approach to Existing Threat Identification

NW Natural will use the best information available in order to understand the system and identify threats. The data centric approach is a Threat Identification methodology that uses available leak repair and incident data to identify threats that have a known history. The results are then reviewed by the SME(s) to make a final conclusion as to which threats are applicable. NW Natural will document the Threat Identification results in the written DIMP Plan.

If it is found that the level of detail available from leak repair and incidents does not fully support this approach, NW Natural will consider the SME Centric approach outlined in Section 6.1.2. NW Natural may also wish to combine the data centric and SME centric approaches in order to have as complete an evaluation as possible.

6.1.2 SME Centric Approach to Threat Identification

NW Natural may not have leak repair or other key data that is detailed enough to support the threat identification approach described in Section 6.1.1 and/or may wish to leverage the knowledge and experience of SMEs to perform threat identification. The available SME centric approach to Threat Identification uses SME input to identify threats that have a known history to NW Natural’s personnel.

6.1.3 Threat Identification from External Sources

Additionally, NW Natural may become aware of potential new threats by routinely monitoring information from sources that include:

- National Transportation and Safety Board (NTSB) Reports and Recommendations applicable to Pipeline Accidents.
- Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) Advisory Bulletins
- Membership in American Gas Association, Western Energy Institute, Gas Technology Institute and Northwest Operators Group.
- Involvement in Association workshops and forums that share knowledge regarding distribution pipeline threats
- Review of trade journals and magazines that publish material regarding gas distribution

As Integrity Management group becomes aware of new threats from external sources the team will utilize the procedure documented in Figure 6-0 to document the threat.

6.2 Corrosion

Corrosion is the 3rd largest threat in the NW Natural gas distribution system, representing approximately 1% of all recorded leak repairs from 2010 to 2020.

Corrosion is a systematic threat. The Integrity Management Group evaluated the corrosion threat and determined the following sub-threats were applicable for the NW Natural Distribution system. The results of these threat assessments are discussed

below. Leak data is used to identify areas where isolated localized issues may occur. Pipe condition gathered during normal system maintenance identifies potential future issues.

6.2.1 Pipe Material

The primary potential driver for external corrosion system-wide is installed pipe material. The NW Natural Distribution main system is approximately 55% poly, 45% coated and cathodically protected steel. There is no corrosion threat associated with poly pipe. A corrosion threat exists for coated and cathodically protected steel, but existing code compliance and current system practices adequately mitigate the threat system-wide. Isolated localized issues may occur. NW Natural has completed a cast iron mitigation program, eliminating all cast iron within the system as of 1998. NW Natural has also completed the Bare Steel mitigation program, eliminating all known bare steel mains within the system as of 2015.

6.2.2 Casings

Casings are primarily used to protect or facilitate installation of mains and services. Casings are typically equipped with vents for air circulation, casing spacers to provide isolation between the carrier pipe and casing, test leads for monitoring electrical isolation effectiveness and end seals to prevent water from accumulating in the casing.

NW Natural has coated steel pipe installed in casing system-wide and monitors for the electrical isolation between the distribution main and the casing annually, per the corrosion procedures(Standard Practices 465 and 467). While there have been no corrosion related failures in casing, the threat of corrosion can exist under certain conditions.

Properly installed and maintained steel pipe in steel casing has a slightly higher threat than non-cased pipeline installations. Steel pipe installed in plastic casing has a slightly elevated threat of corrosion than direct buried pipeline installation. Cased crossings that have an identified or confirmed short (electrolytic or contact) are considered to have an elevated threat of corrosion.

NW Natural is aware of areas where coated steel pipe was inserted into abandoned steel pipe without spacers. While no corrosion leaks have been associated with this steel-in-steel installation, NW Natural considers this area to have an elevated threat of corrosion compared to direct buried steel main.

6.2.3 Atmospheric Corrosion

NW Natural's system includes facilities that may be subject to the threat of atmospheric corrosion. Steel pipe with inadequate coating that is exposed to marine atmospheres, may be particularly vulnerable to atmospheric corrosion. These regions are stored in the GIS.

Risers, regulators, station piping, bridge crossings and other above ground facilities are all subject to the threat of atmospheric corrosion. NW Natural's atmospheric corrosion survey frequency is based upon Standard Practice 480.

NW Natural's atmospheric corrosion mitigation plan includes protective coating applications (epoxy/paint), the use of corrosion resistant materials and replacement as required.

6.2.4 Corrosion Factors Discussed But Not Considered a Threat

There is no ductile iron or copper pipe within the NW Natural system and NW Natural has not identified in its operating history the results of internal corrosion in any distribution pipeline. Issues with the cathodic protection system are fixed upon discovery and are not used for threat identification at this time.

6.3 Natural Forces

Damage by Natural Forces is the 7th largest threat to the NW Natural gas distribution system, representing less than 1% of all recorded leak repairs from 2010 to 2020. Natural Forces is a localized threat.

6.3.1 Seismically Active Zones

NW Natural's system is in a seismically active zone and the threat exists throughout the system. The primary risks associated with this threat are considered to be earth movement or landslides triggered by seismic activity, and differential settlement at bridge crossings. Earth movement/landslides are addressed in Section 6.3.2. Bridge crossings are identified in the GIS system.

6.3.2 Areas Susceptible to Earth Movement/Landslide

Earth movement due to landslides may damage gas distribution facilities and result in gas leaks. The NW Natural system exists in areas known to be susceptible to earth movement as identified by state, local and federal agencies, patrolling and NW Natural's historical records. These areas may warrant mitigative measures such as increased monitoring and valve installation.

6.3.3 Heavy Rains / Floods/Water Crossings

Areas of NW Natural's system are susceptible to flooding. NW Natural has identified flood zones throughout the system using FEMA Flood Plain maps.

Water crossings have an increased risk of failure due to washouts. Water crossings are identified in the GIS system.

6.3.4 Natural Forces Discussed But Not Considered a Threat

Frost heave is not a threat within the NW Natural system.

6.4 Excavation Damage

Excavation damage is the largest threat to the NW Natural gas distribution system, representing approximately 86% of all recorded leak repairs from 2010 to 2020. Excavation damage is a system wide threat. The most significant root-cause factors are discussed below.

6.4.1 Improper Excavation Practice

NW Natural actively engages in educating employees and contractors about excavation procedures, using state dig laws and industry best practices. NW Natural employees are trained per OP101-01. Contractors and third party excavators are monitored per the requirements of OP102-01. NW Natural risk ranks locate tickets as they are entered into the system which allows NW Natural to appropriately engage with excavators to ensure that proper excavation practices are followed.

6.4.2 Facility Not Located or Marked

NW Natural is a participating member in the one call state system and responds to all one call tickets received. NW Natural experiences a low volume of this type of incident, which is due to a failure to request locates, locates requested in the wrong location or locates not completed on time.

6.4.3 One Call Notification Center Error

Locates may not be completed due to errors that occur at the one call notification center. NW Natural tracks one call activity and there have been no damages caused by one call notification center error in the past 15 years.

6.4.4 Mis-marked Facilities

Mis-marked facilities may be due to deficiencies in training, job execution, or equipment. NW Natural investigates every mis-mark.

If a NW Natural employee is responsible for a mis-mark, their direct supervisor and the Damage Prevention Department are notified. An investigation by the Damage Prevention Department and a Quality Assurance review are completed and the results are shared with the supervisor for further follow up and training if needed. NW Natural follows the same procedure for a contracted locating company.

6.4.5 Incorrect Facility Records

Gas Distribution facilities may be mis-marked or left unmarked due to inaccurate facility maps. NW Natural has a process in place within the IQGeo Asset Map Viewer to allow Operations and Engineering personnel to correct and update facility maps as any inaccuracies are identified.

6.4.6 Other

Other root causes include difficult to locate facilities (e.g. broken wire on plastic main or interference due to congested Right-of-Ways).

6.5 Other Outside Force Damage

Other Outside Force Damage is the 8th largest threat to the NW Natural gas distribution system, representing less than 1% of all recorded leak repairs from 2010 to 2020. Other Outside Force Damage is a localized threat.

6.5.1 Vehicle Damage to Risers and Meters

When installing new services or relocating service facilities, NW Natural employs protective measures on new construction to protect the gas riser and gas meter from vehicular damage. NW Natural retroactively employs protective measures to protect or to relocate the riser/meter when changes made by the property owner or historic design requirements do not sufficiently protect the meter/riser. NW Natural employs additional protection or relocation to mitigate the risk of damage that could result in a gas leak or damage to a meter per Standard Practice 361.

6.5.2 Vehicle Damage to Above-Ground Equipment / Stations

NW Natural employs protective measures to protect above-ground sections of gas mains, gas services, and regulator station piping which may be subject to damage by vehicular traffic.

6.5.3 Vandalism

NW Natural employs protective measures to protect gas valves and station equipment from vandalism that could result in the unsafe operation of a gas distribution system and measures to prevent or reduce the likelihood of such vandalism.

6.5.4 Fire or Explosion

NW Natural employs scenario-based and classroom training to educate internal and external first responders to mitigate this risk.

6.6 Material, Weld or Joint Failure

Material, weld, or joint failure is the 2nd largest threat to the Northwest Natural gas distribution system, representing approximately 9% of all recorded leak repairs from 2010 to 2020. Material, Weld or Joint Failure is a system wide threat.

6.6.1 Plastic Pipe Installed from 1960s to 1980s

NW Natural makes every effort to identify all pre-1982 plastic pipe installations, analyze leak histories, evaluate any conditions that may impose high stresses on the pipe, and take appropriate remedial action, including replacement, to mitigate any risks to public safety.

6.6.2 PVC

Polyvinylchloride (PVC) plastic pipe has not been installed for transportation of natural gas by NW Natural. PVC is used as a sleeve and conduit by NW Natural.

6.6.3 ABS

NW Natural installed Acrylonitrile-Butadiene-Styrene (ABS) services from the late 1950s through the early 1970s. All know ABS services were removed from NW Natural's system in 2022.

6.6.4 Plexco Service Tee Celcon Caps

NW Natural is aware of industry issues regarding Plexco Service Tee Celcon Caps possibly leaking when over-tightened during installation. These caps exist within the NW Natural system and are scheduled for replacement if leaks are identified.

6.6.5 PE Fusion Failure

NW Natural has a robust training and QA/QC program in place to ensure proper poly fusion quality. This is achieved by annual testing, qualification and ongoing training. Poly-fusions are visually inspected and pressure tested per Engineering SPO/SPW 511, and installed per OP130-01.

6.6.6 Material, Weld or Joint Discussed But Not Considered a Threat

HDPE pipe and Delrin Insert Tap Tees are not used within the NW Natural System.

6.6.7 Aldyl A

NW Natural installed Century Products MDPE 2306, Aldyl A services from the late 1950s through the early 1970s. All known Aldyl A services were removed from NW Natural's system in 2013.

6.7 Equipment Failure

Equipment Failure is the 4th largest threat to the NW Natural gas distribution system, representing approximately 1% of all recorded leak repairs from 2010 to 2020. Equipment Failure is a system wide threat.

6.7.1 Valves

Many valves are vital to the safe operation of a gas distribution system. NW Natural has in place a key operating valve inspection and maintenance program, per SPO/SPW 405 and OP831-01. Key valves that are inoperable, inaccessible, and/or paved over are identified and maintained as needed.

6.7.2 Pressure Control / Relief Equipment

NW Natural has an established inspection and maintenance program in place for Pressure Control/Relief Equipment, per SPO/SPW 743 and OP800-01.

6.7.3 Mechanical Couplings

Pipe may pull out from compression couplings due to pullout forces that could include cyclic fatigue from changes in the temperature of the natural gas as a result of the Joule-Thomson effect, ground movement from earthquakes or after heavy rains, improper installation, and deterioration of the coupling. Mechanical couplings may also leak through the seal between the coupling and the pipe. Contributing factors may include a degradation of the seal over time or a change in the gas quality in the distribution system.

6.7.4 Other

Other types of equipment failure may occur in the gas distribution system. Failure reports may be reviewed to detect trends of equipment failure occurring within the distribution system.

6.8 Incorrect Operation

Incorrect operation is the 6th largest threat to the NW Natural gas distribution system, representing less than 1% of all recorded leak repairs from 2010 to 2020. Incorrect Operations is a system wide threat.

6.8.1 Operating Errors

NW Natural has qualification and training programs in place to prevent operating errors, found in the Operator Qualifications manual, established in 2004. The procedures and AOCs are part of NW Natural's O&M Manual.

6.8.2 Gas lines cross-bored through Sewer Laterals

NW Natural recognizes the industry issue associated with cross-boring through sewer pipelines and takes immediate action upon discovery. NW Natural interacts with sewer municipalities within its region to minimize the incidents of boring through sewers. No historical incidents from this issue have been identified, but NW Natural recognizes the threat to its system. In 2013 NW Natural implemented a sewer cross-bore program to identify areas and facilities that are at a higher risk of sewer cross-bores and perform inspections of those facilities to address risk.

6.9 Other

Leaks classified as Other represent 1% of total reported leaks, the 5th largest amount within the NW Natural Distribution system.

Pending a full investigation of an incident or leak, NW Natural may initially classify an incident as “other” until an actual cause can be determined.

6.9.1 Build-Over

Build-overs are when a building is built on top of an existing pipeline facility and are classified as an Other threat. NW Natural has developed procedure to identify these build-overs and remediate them (NW Natural General Procedure G-42 Build-Over Compliance).

7. EVALUATION AND RANKING OF RISK

Objective

This section describes NW Natural's methodology for evaluating and ranking the risks associated with its distribution pipelines. In this evaluation, NW Natural will determine the relative importance of each threat and estimate and rank the risks posed to its distribution pipeline. To complete this evaluation, NW Natural will:

- Consider each applicable current and potential threat
- Consider the likelihood of failure associated with each threat
- Consider the potential consequences of such a failure
- Estimate and rank the risks (i.e. determine the relative importance) posed to the distribution pipeline
- Consider the relevance of threats in one location to other areas

7.1 Risk Assessment Process

Information from the GIS, Annual Reports, written documentation, SME knowledge and other electronic database data is used to populate NW Natural's DIMP risk model. The foundation is a mathematical or algorithm model with SME data added as appropriate. The data used includes pipe diameter, material and coating, installation date, MAOP, leak data, scheduled inspections, presence of EFVs, geographical area and population density/business districts.

NW Natural groups facilities by common traits and problems, which allows each group to be risk-ranked as a unit. The process is an analysis that assigns a relative risk value and may result in recommendation for action. "Relative risk" does not indicate an absolute measure of risk; it only indicates a comparative value relative to other NW

Natural facilities. It may be determined that facilities or groups of facilities that do not experience problems can be removed from the risk evaluation and no further action necessary.

The risk model assigns values to each facility or group of facilities based on the data gathered by threat and considers two factors to determine risk: Likelihood and Consequence.

7.1.1 Likelihood

Likelihood refers to the possibility of an issue occurring within NW Natural's Distribution system and is modeled using data from three sources: Past incidents or failures, near-misses or partial failures, and facilities susceptible to failure. Past incidents or failure data is gathered typically from leak data, near misses are gathered from normal maintenance activities and facilities susceptible to failure data is based on industry knowledge.

In this risk evaluation system, the likelihood of an event occurring is addressed by the relative scoring of the items within each index. The score of each item reflects the importance of that item relative to the other items in the index. This importance is based upon NW Natural's experience and general industry knowledge.

NW Natural created a likelihood of failure risk value for each of the eight threats listed in Section 6.0.

The foundation for this risk assessment was the DIMP Tool Set, developed by ESRI, using the ArcGIS ModelBuilder environment. Using the GIS environment allows NW Natural to overlay internal and external data sets on the distribution system. This is accomplished by segmenting the service territory into user

defined grids or raster's, which facilitate linking internal and external data to distribution facilities. NW Natural uses a 50'x 50' raster size, which is common practice for ESRI users.

Adequate information was readily available for this process, and as applicable in the future, NW Natural will capture additional relevant information during routine operations and maintenance activities.

The current algorithm used for Risk Assessment (the evaluation and ranking of risk) shall be documented and included by reference in Appendix C. Prior risk assessment algorithms shall be retained and stored in the Integrity Management files.

7.2.1 Consequence

Consequence refers to the potential impact an incident or failure may have on the area surrounding a pipeline facility. Consequence is modeled using data from two primary sources: Number of people impacted and the amount of gas that could potentially escape as the result of a failure.

NW Natural created one consequence score, which is used system wide to evaluate each of the eight likelihood threats.

To determine Consequence, census data (representative of where people live and work) and business districts (representative of where people work) were used to evaluate the number of people impacted, which is then combined with MAOP, pipe diameter and the presence of EFVs to determine the amount of gas that could escape. The value created represents the relative consequence score if failure occurs.

7.3 Total Relative Risk

Total relative risk is equal to the weighted average of the likelihoods multiplied by the consequence. Risk can be analyzed by total relative risk or by individual threat risk or by sub-threat risk.

The current risk assessment (likelihood, consequence, and resultant risk ranking) shall be stored in the GIS. Prior risk assessment results shall be retained and stored in the Integrity Management files.

7.4 Risk Assessment Validation

The Integrity Management team validates that the results of the risk assessment are valid and accurately represent the NW Natural distribution system. The results of the risk assessment and the operations and maintenance records focus on the same facilities or groups of facilities, and the results agree with the experiences of NW Natural's SMEs and if they are reasonable in comparison to historical leak repair data for the threat type.

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Figure 7-0 illustrates the procedure to validate the DIMP Risk Model

Process to Validate the DIMP Risk Model Results

The purpose of this process is to validate the DIMP Risk Model results. This process can be initiated by any member of the Integrity Management Group at any time.

1. The Integrity Management Group manages the process to populate the ArcGIS DIMP Risk Model, using data sources shown in Appendix C-1 "DIMP Risk Model Architecture".

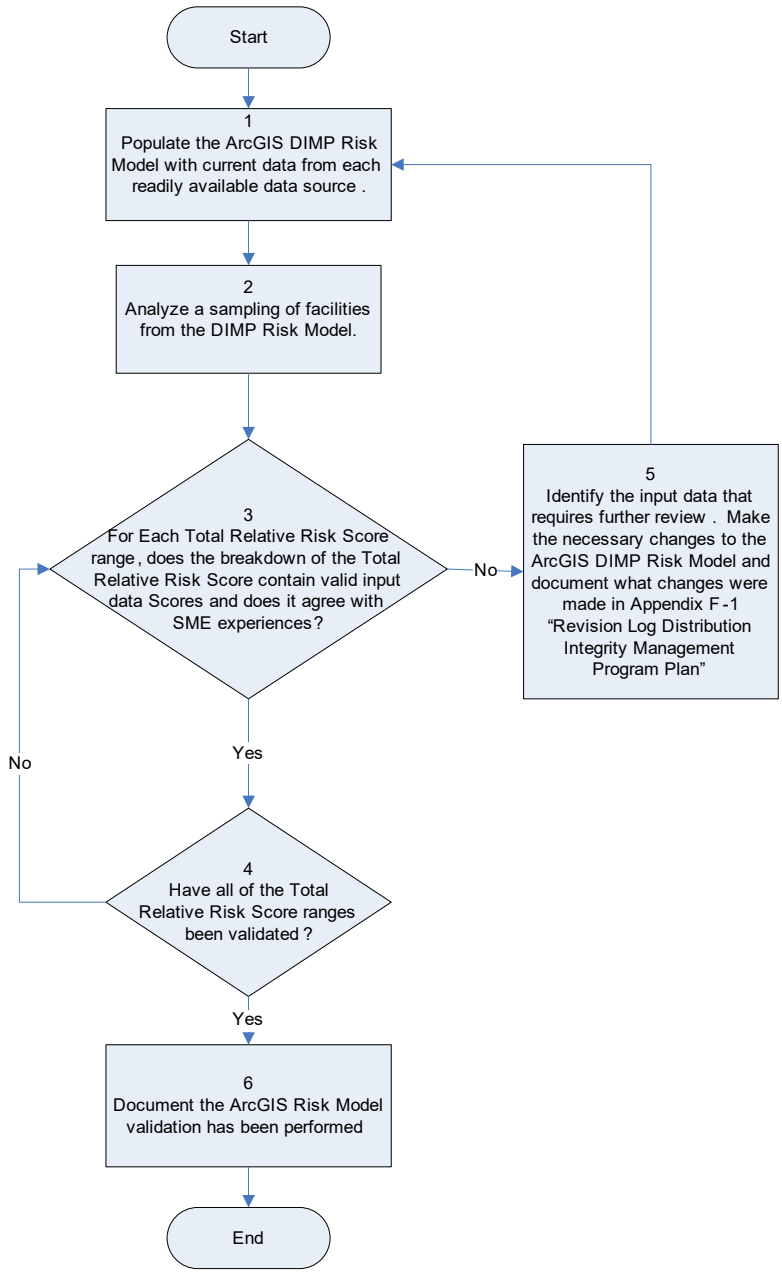
2. Analyze a small sampling of facilities from the Risk Model. The sample should include locations with low and high risk scores and areas of the system with in-depth SME knowledge.

3. Analyze each Primary and/or Sub Threat Score included in the Total Relative Risk Score for the facility segments being reviewed. Refer to Appendix C-2 "Risk Algorithm" to check for valid Scores for the Threats that are shown applicable to the facility segment being reviewed. Do the results agree with the experiences of NW Natural's SMEs and are they reasonable in comparison to historical leak repair data?

4. Ensure that each Total Relative Risk Score range has been sampled and analyzed.

5. When a modification to the DIMP Risk Model Algorithm is determined to be needed, make the necessary changes to the Risk Model and document the changes that were made in Appendix F-1 "Revision Log Distribution Integrity Management Program Plan". After making the changes, repeat Step #1 to ensure that the changes are applied to the entire Risk Model.

6. After completing the sampling for the DIMP Risk Model document that the validation has been completed in the DIMP files.



7.5 Risk Assessment Process Improvement

Risk Evaluation and Ranking is an ongoing process that responds to changes in the distribution system and continuous improvements in risk evaluation and ranking methodology will be necessary. NW Natural's Integrity team will evaluate the Risk Model annually. As new threats arise, system knowledge evolves, or as potential improvements are identified, the Risk Model will be updated. Changes to the Risk Model will be documented in Appendix C – Evaluating and Ranking Risk and in Appendix F – Revision Log.

8. IDENTIFICATION AND IMPLEMENTATION OF MEASURES TO ADDRESS RISKS

This section describes NW Natural's existing and proposed measures to address the threats that have been identified in Section 6.0 and the resulting risks that have been evaluated and prioritized in Section 7.0.

The general purpose of this section is to determine and implement measures designed to reduce the risks from failures of its gas distribution pipeline. NW Natural Integrity Management group uses this process to first evaluate whether existing safety related compliance activities and standard operating procedures adequately address risks to NW Natural distribution facilities. Where existing compliance activities and procedures need to be supplemented to address risks, an A/A (Additional and Accelerated) Action will be identified to mitigate the risk. The risk can be managed by eliminating or reducing the likelihood or by lessening the consequence of a potential issue. A/A Actions may address one or more identified threats. Analysis of the risk data may be by total risk or by individual threats within the risk model.

Figure 8-0 illustrates the procedure to address risks

Process to Identify and Implement Measures to Address Risk

The purpose of this process is to identify high risk areas evaluated for Accelerated Actions. This process is typically completed annually or as necessary and can be initiated by any member of the Integrity Management Group. High risk areas are selected according to the Risk Model or as identified by SMEs.

1. The Integrity Management Group identifies high risk facilities using the Risk Model and /or SME input.

2. Identify and document the compliance activities currently performed at high risk facilities. (leakage, corrosion, water crossing surveys, etc).

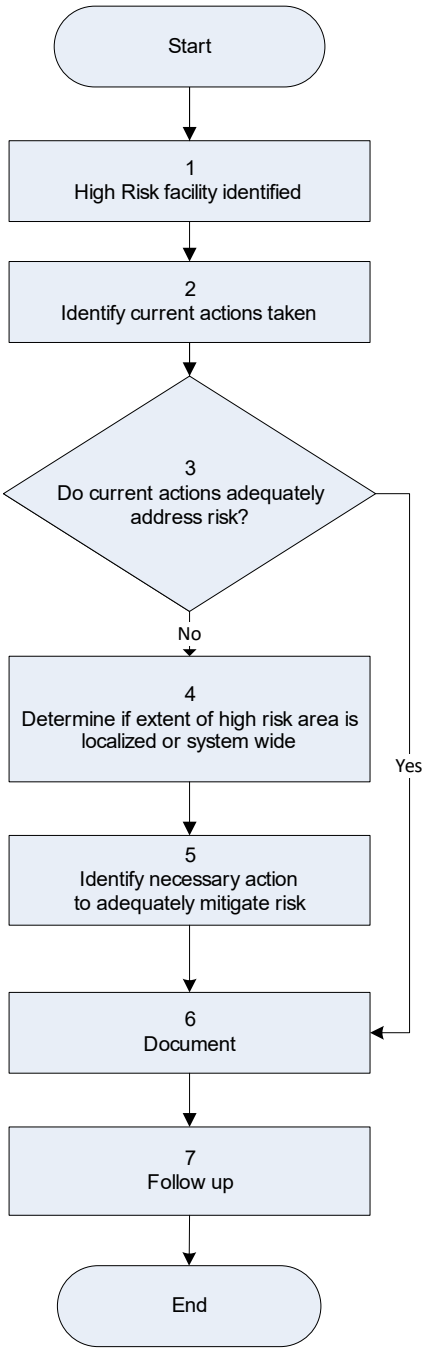
3. Do current compliance activities adequately address risk?

4. Determine if implementation of Accelerated Actions should be isolated or system wide

5. Identify the necessary Accelerated Actions to adequately mitigate risk (gather more information, schedule more frequent inspections, replace pipe, etc).

6. Document A/A Action including analysis of high risk area measure selected, how it will be implemented, and risk it is addressing.

7. Follow up to determine that Accelerated Actions have been completed.



8.1 Additional or Accelerated Actions

Using the process shown in Figure 8-0, the A/A actions have been identified and are documented in Appendix D.

8.1.1 A/A Action Documentation

When A/A actions are implemented as a result of DIMP, they shall be documented using form “Additional or Accelerated Action Implementation” found in Appendix D-2. The documentation will contain at a minimum:

- Description of A/A action being implemented
- Threat(s) that the A/A action addresses
- Description of the location that the A/A action is being implemented
- A/A action duration and/or schedule
- Date that the A/A action is to be implemented
- Date the A/A action will be completed (if applicable)

This form will be attached to the Project charter if the Project Charter is required. All forms will be kept in the Integrity Management files.

8.2 Leak Management Program

The Leak Management program is established in SPO/SPW 707 and 709. Additionally, the Field Operations Manual – Investigating Leaks and Odors, outlines the procedures of the existing program.

NW Natural uses this program to maintain the integrity of its distribution system. Many factors specific to NW Natural’s geographic location and Distribution system are

considered to evaluate the severity of leaks and determine the appropriate actions to mitigate the risk associated with the leaks.

NW Natural's program contains the following basic elements:

Locate the leaks in the distribution system;

Evaluate the actual or potential hazards associated with these leaks;

Act appropriately to mitigate these hazards;

Keep records; and

Self-assess to determine if additional actions are necessary to keep people and property safe.

8.2.1 Locate the Leaks

NW Natural detects and locates leaks through the use of leak detection equipment when conducting leak surveys and investigating notifications of gas odors. Leak surveys are performed per SPO/SPW 707.

8.2.2 Evaluate Leaks

When located, the hazards associated with the leaks are evaluated according to established classification criteria, per SPO/SPW 709. These classification criteria take into consideration the safety risk posed by each leak:

- Class A – A leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until safe conditions are restored.
- Class B – A leak that is non-hazardous but justifies scheduled repair.
- Class C – A leak that is non-hazardous and can reasonably be expected to remain unchanged until the next scheduled check.

8.2.3 Act Appropriately

Once a leak has been located and classified, NW Natural takes actions that are consistent with the classification of that leak, per SPO/SPW 709. This may include temporary or permanent repair of non-hazardous leaks. NW Natural takes immediate action to repair hazardous leaks.

8.2.4 Keep Records

NW Natural collects and records data to evaluate the effectiveness of the leak management program, per SPO/SPW 709. These records provide sufficient data to allow all regulatory reports to be filed and to allow for continual leakage program improvements. NW Natural uses historical leak data as an indicator of potential future hazards. These records are stored in DNV-GL Essentials.

8.2.5 Self-Assess Key Performance Metrics & Analysis of Effectiveness

The Leak Management Program key performance metrics (those that establish program effectiveness) shall be documented, or included by reference, in Appendix D. Prior documentation shall be retained and stored in the DIMP files. The current performance metric evaluates the number of overall leaks as reported on the PHMSA Annual Distribution Report.

9. MEASUREMENT OF PERFORMANCE, MONITORING RESULTS, AND EVALUATING EFFECTIVENESS

This section of the plan establishes performance measures that NW Natural will monitor from an established baseline in order to evaluate the effectiveness of the DIMP. The performance measures detailed in Sections 9.1 through 9.10, summarized in the bullets below, have been established in order to monitor performance and assist in the ongoing evaluation of threats.

- Number of hazardous leaks either eliminated or repaired (or total number of leaks if all leaks are repaired when found), categorized by cause;
- Number of excavation damages;
- Number of excavation tickets (receipt of information by NW Natural from the notification center);
- Total number of leaks either eliminated or repaired, categorized by cause;
- Number of hazardous leaks either eliminated or repaired (or total number of leaks if all leaks are repaired when found); categorized by material
- Number of known system leaks at end of year scheduled for repair
- Number of Vintage Plastic services in system at end of year and;
- Any additional measures to evaluate the effectiveness of NW Natural's DIMP in controlling each identified threat.

Using the current, representative data, the initial baselines for these performance measures were created by a member of the Integrity Management Team at the time the DIMP was established or at the time the corresponding A/A Action was created. Baselines for each performance measure and A/A Action are documented in Appendix E of this plan. The Distribution Annual Report, used to track select performance

measures, is filled out and submitted per SPO/SPW 003. A reference copy of that report is in Appendix E of this plan.

9.1 Number of Hazardous Leaks either Eliminated or Repaired, per §192.703(c), Categorized by Cause

The baseline and ongoing performance of the number of hazardous leaks either eliminated or repaired, per §192.703(c), categorized by cause, shall be documented in the Distribution Annual Report.

9.2 Number of Excavation Damages

The baseline and ongoing performance of the number of excavation damages shall be documented in the Distribution Annual Report.

9.3 Number of Excavation Tickets (received from the notification center)

The baseline and ongoing performance of the number of excavation tickets received from the notification center(s) shall be documented in the Distribution Annual Report.

9.4 Total Number of Leaks either Eliminated or Repaired, Categorized by Cause

The baseline and ongoing performance of the total number of leaks either eliminated or repaired, categorized by cause, shall be documented in the Distribution Annual Report.

9.5 Number of Hazardous Leaks Either Eliminated or Repaired, per §192.703(c), Categorized by Material

The baseline and ongoing performance of the number of hazardous leaks either eliminated or repaired, per §192.703(c), categorized by material, shall be documented in the Hazardous Leaks Repaired, Categorized by Material, (HLR-M) Reports. Data for

the HLR-M Reports is collected via NW Natural's leak report forms. Reference copies of the HLR-M Reports are in Appendix E.

9.6 Number of Miles of Bare Steel Main in the System at End of Year

The baseline and ongoing performance of the number of miles of bare steel main at end of year shall be documented in the Distribution Annual Report. Completed in 2015.

9.7 Number of Bare Steel Services in the System at End of Year

The baseline and ongoing performance of the number of bare steel services at end of year shall be documented in the Distribution Annual Report.

9.8 Number of Known System Leaks at End of Year Scheduled for Repair

The baseline and ongoing performance of the number of known system leaks at end of year scheduled for repair shall be documented in the Distribution Annual Report.

Also see chart in Appendix D-3.

9.9 Number of ABS Services in System at End of Year

The baseline and ongoing performance of the number of ABS services in system at end of year shall be documented in the Distribution Annual Report.

9.10 Additional Performance Measures

If it is determined that additional performance measures are needed to evaluate the effectiveness of the DIMP in controlling an identified threat, the performance measures shall be documented, or included by reference in Appendix E.

9.11 Effectiveness Measures

A member of the Integrity Management Team created each Effectiveness Measure, seen in Appendix E-1, by determining what trends or results accurately represent the

intent or expectation of a Performance Measure or A/A Action. Effectiveness Measures were either created at the time the DIMP was established or at the time the corresponding A/A Action was created. Effectiveness Measures are subject to change if the Integrity Management Team determines that they are no longer appropriate representations of performance.

9.12 Monitoring Performance Measures and Effectiveness Review

The data collected for a Performance Measure will be reviewed by NW Natural once per calendar year to determine if the risk management technique or practice (A/A action) implemented is effective. The effectiveness review shall include the following:

- During review, the data that supports the Effectiveness Measure, defined in Appendix E-1, for a risk management technique or practice (A/A action) will be collected and analyzed. The analysis will examine whether the data indicates the practice or action is, or is not, managing the targeted task by comparing it to the desired trend, as described by the corresponding Effectiveness Measure. NW Natural will then decide whether to continue or discontinue with the action, accelerate or decelerate its pace, modify how it is being implemented, or choose another action. NW Natural may conclude that it is too early to tell or that currently there is insufficient data to tell how well an action is working.
- Through analysis, NW Natural will examine if the performance measure selected is providing information useful in analyzing the impact of the practice or action. If the impact is unclear, NW Natural will include other data in the review or select a different performance measure.

The effectiveness review shall be documented in Appendix E of this plan with charts and or data.

10. PERIODIC EVALUATION AND IMPROVEMENT

This section describes NW Natural's periodic re-evaluation of the program.

10.1 Plan Updating, Review Frequency and Documentation

The process for comprehensive review of DIMP Operations is outlined in Figure 10-0 and will be performed once per calendar year. The process will be utilized to reflect changes and improvements that have occurred in process, procedures and analysis for each element of the program. A complete program re-evaluation will be completed at least every 5 years or sooner if required. The review will include at a minimum:

- Verification of general information (e.g. contact information, form names, action schedules, etc)
- Incorporation of new system information (per Section 5 of this plan)
- Determine if there are new federal regulations, state enforcement or other guidelines provided by regulatory bodies in effect which would affect the plan and require revision to the plan.
- Determine if any continual improvements, best practices or industry driven changes need to be incorporated into the plan.
- Re-evaluation of threats and risk (per Section 6 of this plan)
- Re-evaluation of A/A Actions and Implementation Schedules (per Table D-1 of this plan)
- Review the frequency of the measures to reduce risk (per Section 9 of this plan) Review performance measures and baseline measurements for completeness to ensure that all threats and risk are monitored.
- Review the effectiveness of the measures to reduce risk (per Section 9 of this plan) Modify the A/A Actions, Implementation Schedules, and/or measures to reduce risk and refine/improve as needed (per Section 9 of this plan)

Review performance measures, their effectiveness, and if they are not appropriate, refine/improve (per Section 9 of this plan). NW Natural will maintain a record demonstrating that the plan review was performed even if no changes were made. All changes to the written plan, inclusive of material from the appendices, shall be recorded on the Revision Log in Appendix F.

However, changes to material in the appendices that is included by reference need not be recorded on the Revision Log.

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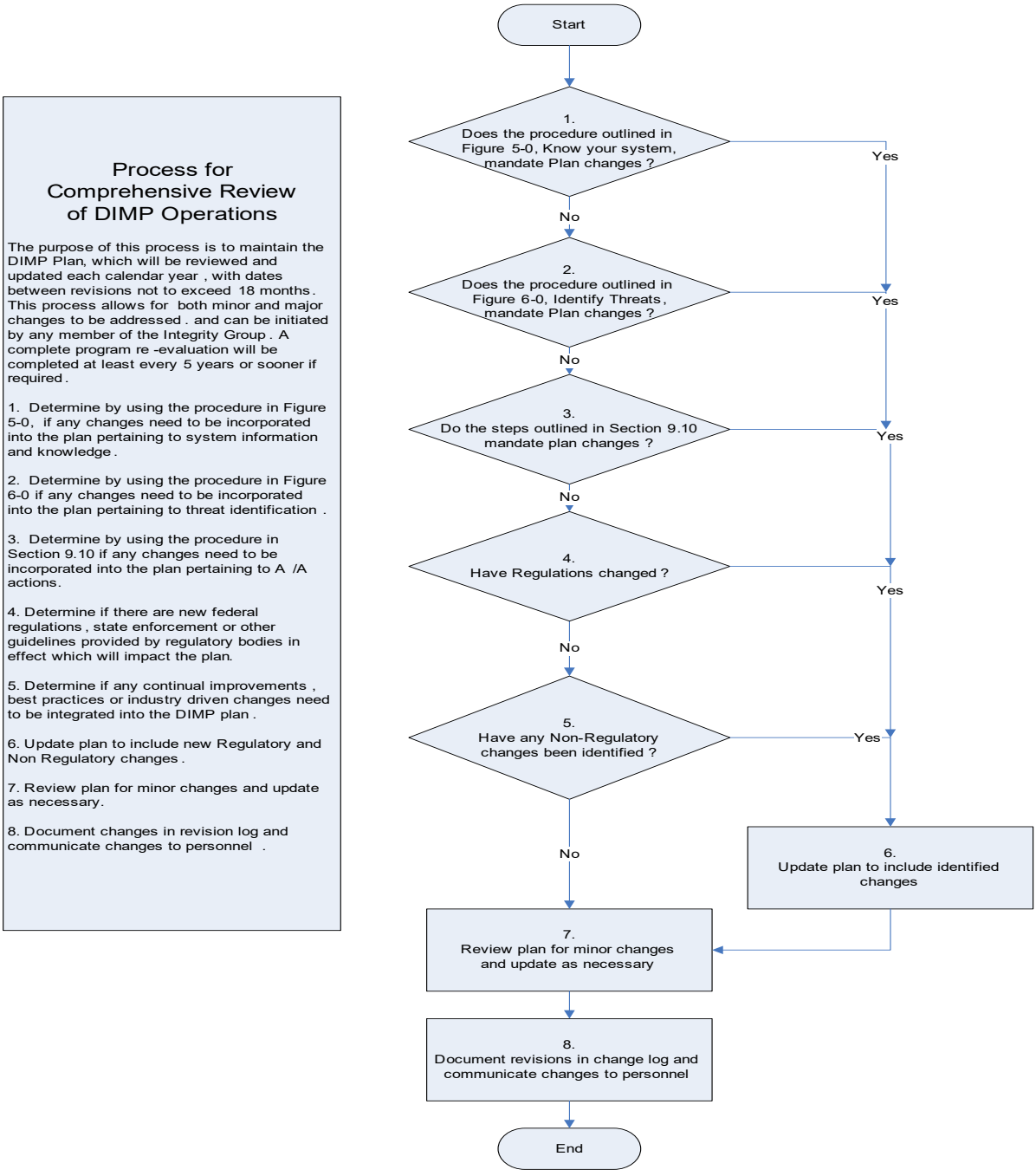
Figure 10-0 illustrates the procedure to review DIMP Operations.



10.2 Notification of Plan Changes

Plan changes that may impact other work groups shall be communicated to the appropriate operating personnel. Changes that may require internal communications include but are not limited to modifications to data captured in the field, operating procedures, new A/A actions and/or reporting requirements.

Local state regulatory agencies will be provided an updated plan once per calendar year with all other company O&M manuals as detailed in Section 11 of this plan.

11. REPORTING RESULTS

11.1 State & Federal Annual Reporting Requirements

The following five measures shall be reported, annually by March 15, to PHMSA as part of the annual report required by CFR 49, § 191.11 and submitted per SPO/SPW 003:

- Number of hazardous leaks either eliminated or repaired (or total number of leaks if all leaks are repaired when found), per § 192.703(c), categorized by cause
- Number of excavation damages
- Number of excavation tickets (receipt of information by NW Natural from the notification center)
- Total number of leaks either eliminated or repaired, categorized by cause
- Number of Hazardous leaks involved mechanical joint failure.

If a State exercises jurisdiction over the pipeline, these five measures shall also be reported to the State Pipeline Safety Authority in the State where the gas distribution pipeline is located. A copy of the reports shall be maintained in the Integrity Management files.

12. DOCUMENT AND RECORD RETENTION

The following records shall be retained in the DIMP files.

- The most current as well as prior versions of this written DIMP Plan
- Documents supporting Knowledge of Facilities (material supporting Appendix A of the DIMP Plan)
- Documents supporting threat identification(material supporting Appendix B of the DIMP Plan)
- Documents supporting risk evaluation and ranking (material supporting Appendix C of the DIMP Plan)
- Documents supporting the identification and implementation of measures to address risks (material supporting Appendix D of the DIMP Plan)
- Documents supporting measurement of performance, monitoring results and evaluating effectiveness (material supporting Appendix E of the DIMP Plan)
- Effectiveness Reviews (material supporting Appendix F of the DIMP Plan)
- Annual Reports to PHMSA (as required by §191.11) and State pipeline safety authorities
- Mechanical Fitting Failure Reports submitted between 2011 and 2020.

Documentation demonstrating compliance with the requirements of CFR 49, Part 192, Subpart P shall be retained for at least 10 years or longer per NW Natural's Document Retention Schedule.

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APPENDIX A
Chapter 5.0
Knowledge of Facilities

Appendix A-1. A summary of the data sets used to demonstrating an understanding of the gas distribution system

Input Data	Data Source	Collection Method	Data Type	GIS Type
3rd Party Damage	RL Man	Risk Agent	Table	Point
Atmospheric Corrosion Buffer	NWN GIS	GIS Buffer from State Boundary Line	Feature Layer	Polygon
Business Districts	NWN GIS	GIS Creation with Leakage Group Validation	Feature Layer	Polygon
Casings	NWN GIS	Construction AsBuilt	Feature Layer	
Census Block groups	US Census Bureau	Internet Download	Feature Layer	Polygon
Census Employment Data	US Census Bureau	Internet Download	Feature Layer	Polygon
District Regulators	NWN GIS	Construction AsBuilt	Feature Layer	Point
Exposed Pipe Inspection	Clevest Data	Clevest Data point	Table or Raster Layer	Line
FEMA Floodplain	FEMA	Internet Download	Feature Layer	Polygon

Input Data	Data Source	Collection Method	Data Type	GIS Type
Gas Distribution Mains	NWN GIS	Construction AsBuilt	Feature Layer	Line
Gas High Pressure Mains	NWN GIS	Construction AsBuilt	Feature Layer	Line
Gas Services	NWN GIS	Construction AsBuilt	Feature Layer	Line
Gas Valve	NWN GIS	Construction AsBuilt	Feature Layer	Point
Gas Valve Inspections	SAP		Table	Point
Leak Data	SAP	Leakage Crew	Table or Raster Layer	Point
Non-Controllable Fitting	NWN GIS	Construction AsBuilt	Feature Layer	Point
OneCallTickets	Locates Database	One Call Center, Inc.	Table	Point
Railroads	Oregon GEO	Internet Download	Feature Layer	Line
Risers	NWN GIS	Construction AsBuilt	Feature Layer	Point
Roads	Federal TIGER Data	Internet Download	Feature Layer	Line

Input Data	Data Source	Collection Method	Data Type	GIS Type
Service Regulators	NWN GIS	Construction AsBuilt	Feature Layer	Point
Water	Oregon GEO/ WAGIC	Internet Download	Feature Layer	Line
Slope	USGS DEM (10M)	Internet Download	Raster	Raster
Landslide SLIDO v1-Oregon	DOGAMI	Internet Download	Feature Layer	Polygon
Landslide Washington	WA. Dept. of Natural Resources	Internet Download	Feature Layer	Polygon
Landslide NWN	NWN / GeoEngineer Reports			
Fittings	NWN GIS	Construction AsBuilt/ Auto-Populate During Data Model Migration	Feature Layer	Point
Gas Lamp	NWN GIS	Construction AsBuilt	Feature Layer	Point

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APPENDIX A-2

Chapter 5.0

Knowledge of Facilities

Attributes list.

Attributes required for new Distribution Mains and Services.

1. Work Order ID
2. Project Number (if applicable)
3. Material
4. Installation Date
5. Nominal Diameter
6. Operating Pressure
7. Wall Thickness
8. Installation Method
9. Pipe Grade
10. Bonded Indicator (for CP system/if applicable)
11. Physical Location of Facility

Attributes required for new High Pressure Distribution Mains and Services.

1. Work Order ID
2. Project Number (if applicable)
3. Material
4. Installation Date
5. Nominal Diameter
6. Design Pressure
7. MAOP
8. Operating Pressure
9. Wall Thickness
10. Installation Method
11. Pipe Grade
12. Segment ID (if applicable)
13. Segment Name (if applicable)
14. Line name (if applicable)
15. Pressure Test Date*
16. Pressure Test Duration*
17. Pressure Test Min Pressure Actual*
18. Pressure Test Medium (Hydro, Nitro, Gas)*
19. Pressure Test #*
20. Physical Location of Facility

* For High pressure services pressure test information is verified, but not an attribute in GIS

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APPENDIX A-3

Chapter 5.0

Knowledge of Facilities

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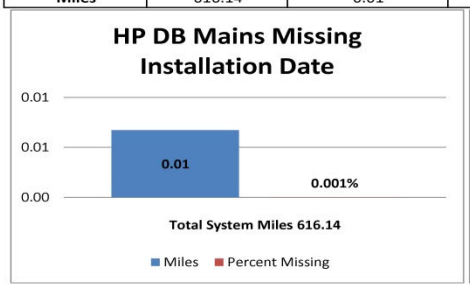
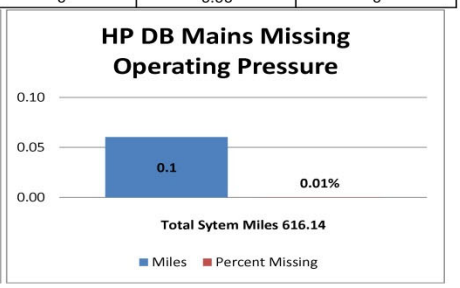
- GIS query on entire distribution system for missing data taken 9/10/2012.

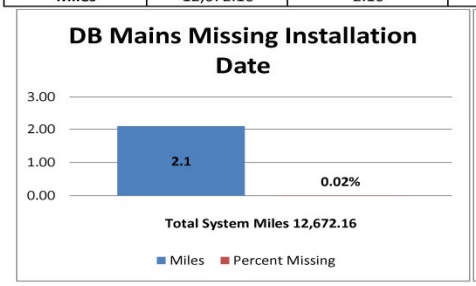
Attribute Query for Distribution

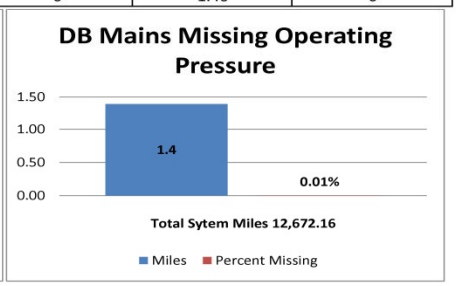
HP DB Main	Overall	Installation Date	Nominal Diameter	Operating Pressure	Material
Seg. Count		2	0	3	0
Total Footage	3,253,214.24	35.60	0	318.94	0
Percent Missing		0.001%		0.01%	
Miles	616.14	0.01	0	0.06	0



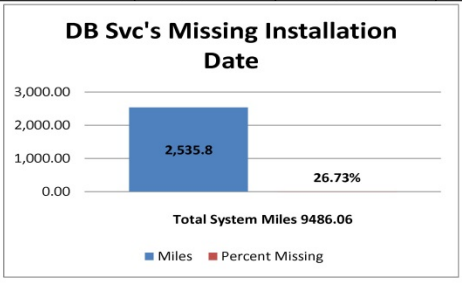


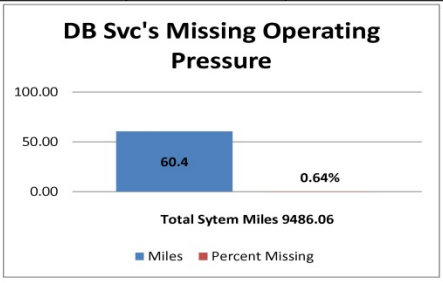
DB Main	Overall	Installation Date	Nominal Diameter	Operating Pressure	Material
Seg. Count		88	0	59	0
Total Footage	66,908,985.63	11,076.89	0	7,368.81	0
Percent Missing		0.02%		0.01%	
Miles	12,672.16	2.10	0	1.40	0





DB Service	Overall	Installation Date	Nominal Diameter	Operating Pressure	Material
Seg. Count		193,122.00	0	5,182.00	0
Total Footage	50,086,421.39	13,389,116.04	0	319,019.74	0
Percent Missing		26.73%		0.64%	
Miles	9,486.06	2,535.82	0	60.42	0





APPENDIX B

Chapter 6.0

Threat Identification

Appendix B is reserved for future supporting documents related to Threat Identification.

APPENDIX C

Chapter 7.0

Evaluation and Ranking of Risk

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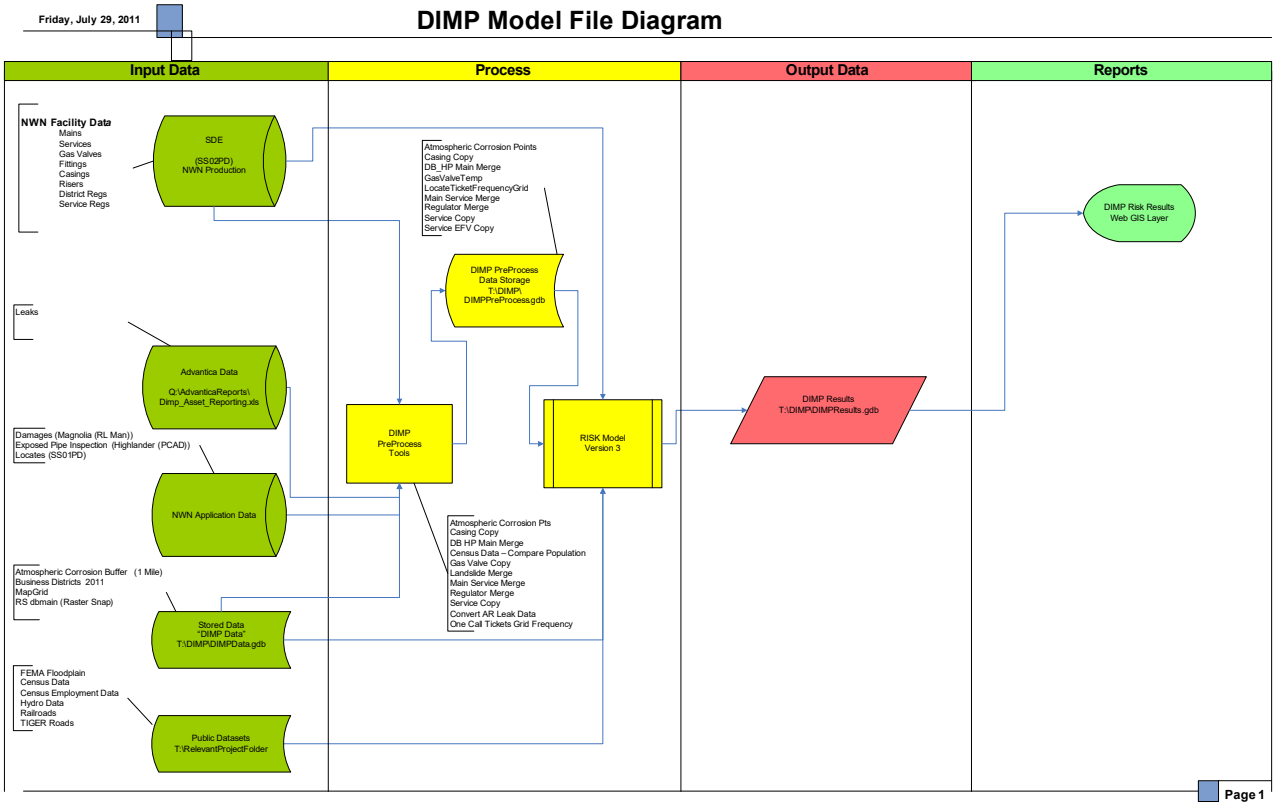
Appendix C-1. DIMP Risk Model Architecture.



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Appendix C-2. Risk Algorithm

Likelihood of Failure x Consequence = Risk Score

CONSEQUENCE				
Threat Category	**Sub-Threat**	**Input**	**Score**	**Total Score**
Consequences				
	Population			**0 to 18**
		< 100	0	
		>= 100 AND < 500	2	
		>= 500 AND < 1000	4	
		>= 1000 AND < 2000	6	
		>= 2000 AND < 5000	8	
		>= 5000 AND < 5000	9	
	Business Districts			**0 to 18**
		NWN Business Districts	1	
	Gas Main-Service			**0 to 18**
		Nominal Diameter *.25 + Operating Pressure Integer	2 - 8	
	EFV Protected			**0 to 18**
		(Nominal Diameter *.25 + Operating Pressure Integer) * 0.50	2 - 4	

LIKELIHOOD OF FAILURE				
Threat Category	**Sub-Threat**	**Input**	**Score**	**Total Score**
Corrosion				
	Leaks			**0 to 24**
		Repaired Leaks caused by Corrosion Active Mains	8	
		Repaired Leaks caused by Corrosion Active Services	8	

	Casing			**0 to 24**
		Steel Casing with Steel Pipe	1	
	Atmospheric Corrosion Points			**0 to 24**
		Service Risers, Service Regulators & Districts Regulators within 1 mile form Coast Line	1	
	Material			**0 to 24**
		Wrapped Service/ Main	3	
		Bare Service/ Main	9	
	Exposed Pipe Inspections			**0 to 24**
		Corrosion Type		
		Major	5	
		Minor	2	
		Rust	1	
		Erosion		
Other				
	Leaks			**0 to 16**
		Repaired Leaks caused by "Other" on Active Mains	8	
		Repaired Leaks caused by "Other" on Active Services	8	
		Active Leaks on Active Mains		
		"A" Leak - Becomes a Repaired Leak	0	
		"B" Leak	4	
		"C" Leak	1	
		Active Leaks on Active Services		
		"A" Leak - Becomes a Repaired Leak	0	
		"B" Leak	4	
		"C" Leak	1	

Incorrect Operations				
	Leaks			**0 to 8**
		Leaks caused by "Incorrect Operations" on Active Mains	8	
		Leaks caused by "Incorrect Operations" on Active Services	8	
	Sewer Cross Bores			**0 to 8**
		Poly Services Where Installation Method Involved Trenchless Construction (Incomplete)	0	
Natural Forces				
	Leaks			**0 to 35**
		Repaired Leaks Caused by "Natural Forces" on Active Mains	8	
		Repaired Leaks Caused by "Natural Forces" on Active Services	8	
	Water Crossings			
		1. Service Water Crossings		
		□ Exposed Pipe (Bridge Xing)	6	
		□ Non-HDD	2	
		□ HDD	0	
		2. Main Water Crossings		
		□ Exposed Pipe (Bridge Xing)	6	
		□ Non-HDD	2	
		□ HDD	0	
	GeoHazards			
		1. Slope (Slope DEM)		
		□ Mains on Slopes < 20%	2	
		□ Services on Slopes < 20%	2	
		2. Landslide (GeoEngineer Reports)		

		□ Mains in Active Landslide Areas	7	
		□ Services in Active Landslide Areas	7	
		3. Landslide (SLIDO/ DNR Data)		
		□ Mains in Historic Landslides	1	
		□ Services in Historic Landslides	1	
	Flooding			
		1. Regulator Stations		
		□ Zone 'A' - 100 Year Floodplain, no elevations provided	5	
		□ Zone 'AE' - 100 Year Floodplain, base flood elevations provided	5	
		□ Zone 'AH' - 100 Year Floodplain, pond, average depth = 1 to 3 ft.	2	
		□ Zone 'AO' - 100 Year Floodplain, near River or Stream, average depth = 1 to 3 ft.	2	
		□ Zone 'AR' - Areas w/ Temporary increased risk due to building/ restoration of flood control system	2	
		□ Zone 'A99' - Areas w/ Historical 100 year floodplain, yet protected by flood control system.	0	
		□ Zone 'X' - Upland, not in floodplain	0	
		□ Zone 'B' - Between Areas of 100 year and 500 year old floodplains	2	
		□ Zone 'V' - 100 Year Coastal Floodplain, no elevations	5	
		□ Zone 'D' - Areas w/ possible but undetermined flood hazards	5	
		□ Zone 'X500' - 500 Year Floodplain	1	
		□ ELSE - Legacy Codes	5	
Outside Force				
	Leaks			**0 to 30**
		Leaks caused by "Outside Forces" on Active Mains	8	
		Leaks caused by "Outside Forces" on Active Services	8	

	Railroad Crossings			
		Gas Mains Crossing Railroads	1	
		Gas Services Crossing Railroads	1	
		Risers	3	
		Regulators: District & Service	3	
		Reliefs	3	
	Major Road Crossings			
		Gas Mains Crossing Major Roads	1	
		Gas Services Crossing Major Roads	1	
		Risers	3	
		Regulators	3	
		Reliefs	3	
	Casings			
		Gas Pipe Casing Crossing Major Roads/ Railroads	-1	
Material				
	Leaks			
		Leaks caused by Material on Active Mains	8	
		Leaks caused by Material on Active Services	8	
	Material			
		Services		
		Poly Material on Service older than 1983	6	**0 to 20**
		ABS Material on Services	6	
		Poly Material on Service with Null Install Date	6	
		Bare Material on Services	4	
		Mains		
		Poly Material on Main older than 1983	6	
		Bare Material on Mains	4	

Excavation				
	Leaks			0 to 19
		Leaks caused by Excavation on Active Mains	8	
		Leaks caused by Excavation on Active Services	8	
	Damages < 10 Years	**Damages**		
		Type of Damage		
		Bent	8	
		Broken	8	
		Coating Damage	4	
		Scratch	4	
		Null	6	
	Locates < 3 Years	**Locates Frequency Grid**		
		Low (1 - 35)	1	
		Medium (35 - 70)	2	
		High (>70)	3	
Dependent on Incomplete/ Inaccurate PCAD EPI Data		**Depth OF Cover (EPI Data incomplete - No Risk Score Assessed)**		
		Standard Depth	1	
		Shallow	3	
		Deep 10' or greater	0	
Equipment Failure				
	Leaks			0 to 28
		Leaks caused by "Equipment Failure" on Active Mains	8	
		Leaks caused by "Equipment Failure" on Active Services	8	

	Gas Equipment			
		Valves		
		Steel Valves on Mains & Services	3	
		Poly Valves on Mains & Services	1	
		EFV	1	
	Regulator: District & Service		3	
		Reliefs	3	
		Risers	1	
		Gas Lamp	1	
		Fittings		
		Coupling	1	
		Curb Service	1	
		Cut Service	1	
		End of Main	1	
		End OF Service	1	
		Insulated Flange	1	
		Insulated Coupling	1	
		Tees - Service	1	
		Tees - Main	1	
Joint Failure				
	Leaks			
		Leaks caused by Faulty Material or Welds on Active Mains - **Accounted for in Material Model**	0	
		Leaks caused by Faulty Material or Welds on Active Services - **Accounted for in Material Model**	0	**0 to 6**
	Mains			
		Pre 1970 Steel Pipe (Double Submerged Arc Weld DSAW Pipe)		
		< 4"	1	
		> 4"	3	

	Operator Qualifications			
		Mains & Services		
		Pipe Installed after OQ Practices (>10/28/2002)	0	
		Pipe Installed before OQ Practices (<10/28/2002)	3	

APPENDIX D

Chapter 8.0

Identification and Implementation of Measures to Address Risks

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Table D-1: DIMP A/A Actions

Dimp A/A Actions

Threat	A/A Action	Implementation Schedule	Effectiveness Measure	Est. Completion Year
Corrosion				
Bare Steel	Replace all Bare Steel	Replace all known Bare Steel mains and svc's by 2015	A reduction in the number of open leaks reported annually. Also given the industry accepted best practice to remove bare steel from the system a measurement of miles of main and a count of services in service at year end with a goal of zero by 2015.	2015/ Completed
Sunshields	Remove Sunshields	Create and implement mitigation plan to remove all known shields through normal inspection	Reduce corrosion to risers within the NWN Distribution System.	2030
Inside Service Lines	Assement and repair of inside service lines	Perform baseline assessment of inside service lines in 2019	A remediation of corrosion on service lines located in buildings	2025
Natural Forces				
Land Movement	Specific mitigation plans for identified high risk active areas on land movement	Create and implement mitigation plan within one year of identifying high risk area	Maintain low (near zero) leak rate for natural force leaks as reported on PHMSA Annual Report.	

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Threat	A/A Action	Implementation Schedule	Effectiveness Measure	Est. Completion Year
Excavation Damage				
Damage Prevent Action	Actively reduce damages through training, education, and enforcement as implemented by Damage Prevention Team.	Continuous improvement	Measure of damages per 1000 locates.	
HP Dist Markers	Investigate the current state of pipeline markers on HP Dist. Pipelines and bring to current standards	Identify areas of concern and remediate high risk areas by end of 2013	Measure of damages per 1000 locates	2015/ Completed
Other Outside Forces Damage				
Meter Protection	Guard Posts	Install guard posts on new installations per company procedures. Continue program to identify areas of poor installation and bring to current standards.	Maintain low (near zero) leak rate for other outside force damage leaks as reported on PHMSA Annual Report.	
Regulator protection	District regulator Relocate	Relocate Dist reg. by end of 2014	History of vehicle damage to this facility, relocate to reduce risk.	2014
Threat	**A/A Action**	**Implementation Schedule**	**Effectiveness Measure**	**Est. Completion Year**

Material, Weld or Joint Failure				
Vintage Plastic	Replace ABS/Vintage services	Identify all likely locations by the end of 2011. Create replacement schedule by end of 2012.	A decrease of ABS services in service at years end as reported on Annual Report with a goal of zero.	2022/Completed
Service Tee Caps	Service Tee caps	Identify areas of increased service tee cap failure by end of 2012. Create monitoring and replacement program by end of 2013	A decrease in the number of Hazardous leaks associated with Material, Weld or Joint Failure.	Upon Discovery
In-effective Coating	Evaluate NWN known coatings	review and identify pipeline coating that could be in-effective or failing Future Project	Reduce the amount of in-effective coating with-in system.	Upon Discovery
Steel in Steel pipe	Evaluate NWN's known Steel in Steel piping.	review and identify piping that has been installed in steel casing. On going	Decrease issues that could arise from steel in steel installations.	2025
Dithiazine	Evaluate regulators that have the potential of being impacted by Dithiazine	Annual maintenance of district regulator stations.	Decrease issues on regulators where performance could be impacted by Dithiazine	Upon Discovery
Equipment Failure				
Coastal Riser Valves	Replace riser valve in Coastal areas that have had historic issues	Identify all likely problematic riser valves by end of 2015 and systematically replace.	A decrease in the number of Hazardous leaks associated with Equipment Failure.	
Difficult to Turn Valves	Reduce or replace valves that have operational issues.	review pipeline system and implement plan to repair or replace valves.	Reduce the number of valves in the system that are hard to operate by repairing or replacing. Increasing effectiveness of valves.	Upon Discovery
Wayne Manf. Risers	Replace risers manufactured by Wayne Manf.	review system installation records to reduce failing risers.	Reduce leaks associated with riser fails in the system	Upon Discovery

Class B to Class A Service Regulator Remediation	Remediation of existing Class B to Class A service regulators to NW Natural Standards	Review of the 62 Class B to Class A service regulators. Remove and rebuild these services as necessary to eliminate the regulator	Remove Class B to Class A service regulators to remove the threat of equipment failure on these regulators	2025
Incorrect Operations				
Facility Hazard	Sewer Cross Bores	Evaluate potential exposure of sewer cross bores and develop a plan to address risk by end of 2012.	Maintain low (near zero) leak rate for Incorrect Operations leaks as reported on the PHMSA Annual Report.	On going
Other				
Dwellings over Facilities	Build-Over's	Address and remediate Build-Over's as they are identified per General Procedure G42	A decrease in the number of Build-Over's.	Upon Discovery
Records	Digitize records	2014 - Digitize records to make more assessable by company personnel	Reduce time to locate records and installation documents	2015/Completed
Records	Convert records	2015 Convert records from retired software system to new data format and tool. 2015	Reduce inconsistencies with records and metadata associated reducing time to locate records.	2016/Completed
SIP Video	System Integri ty Awareness	Create a video to promote System Integrity awareness	Informational plan	2015/Completed
MAOPs separated by valves	Review system where MAOPs are separated by single valves	Eliminate valves between MAOPs outside of regulator stations	OPUC, GIS, Engineering Services, Gas Control, Compliance, Sys. Ops, Field Personnel	2028
Enhanced EFV Remediation	Installation of EFV on services installed prior to EFV Rule	Ongoing project to address services that were installed prior to EFV rule and install EFV a EFV valve on these services	Reduce the number services that do not have an EFV or curb valve.	On going
Idle Risers	Review and develop remediation strategies to protect/remove idle risers	Ongoing project to identify risers where the meter set has been removed (idle risers) and develop a strategy to remediate high risk idle risers	Reduce the number of idle risers	On going

Appendix D-2: Additional or Accelerated (A/A) Action Documentation Form

Additional or Accelerated (A/A) Action Documentation Form

Date:

Originator:

A/A Action:

DESCRIPTION OF A/A ACTION

THREAT(S) A/A ADDRESSES
List threats (per DOT Distribution Annual Report)

METHOD THREAT WAS IDENTIFIED
__ Risk Model
__ SME
__ Industry Identified Threat

CURRENT COMPLIANCE ACTIVITIES THAT ADDRESS THREAT
For example, leakage surveys, CP surveys, patrols…

DO CURRENT COMPLIANCE ACTIVITIES ADEQUATELY ADDRESSING THREAT
Explain how the A/A Action will improve system safety beyond the current compliance activities

DESCRIPTION OF LOCATION(S) THAT A/A WILL BE IMPLEMENTED
Give a detailed description of location(s) that will be covered by this A/A action.

WILL ADDITIONAL DATA NEED TO BE GATHERED?
List any additional data that will need to be gathered for the A/A action

PERFORMANCE METRIC
List performance metric or effectiveness measure

FUNDING
For example DIMP Capital or DIMP Bare, include appropriate accounting string.

IMPLEMENTATION DATE/DURATION
Start date: XX/XX/XXXX
Proposed completion date: XX/XX/XXXX

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Appendix D-3: Leak Management Program Key Performance Metrics

	OR- Number of Main Leaks Repaired	OR- Number of Service Leaks Repaired	OR - Number of Leaks scheduled for repair at end of year	WA- Number of Main Leaks Repaired	WA- Number of Service Leaks Repaired	WA - Number of Leaks scheduled for repair at end of year
2005	328	700	80	29	66	4
2006	218	461	67	23	65	6
2007	360	691	39	77	55	2
2008	327	599	63	63	46	2
2009	287	474	49	36	39	0
2010	263	453	35	19	43	2
2011	234	379	60	21	38	1
2012	215	352	63	29	44	0
2013	248	441	61	20	58	1
2014	251	447	70	39	35	0
2015	225	468	44	37	57	4
2016	231	536	52	28	41	1
2017	231	536	52	28	41	1
2018	193	528	40	35	48	1
2019	180	458	66	38	43	2
2020	199	472	74	30	49	11
2021	223	459	40	34	53	2
2022	170	505	102	27	36	4
2023	230	546	127	25	31	1
2024	257	539	166	40	42	7

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APPENDIX E

Chapter 9.0

Measure Performance, Monitor Results, and Evaluate Effectiveness

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Appendix E-1. Performance Measures for Code Requirements and A/A Actions.

Code Requirement or A/A Action	Performance Measure	Effectiveness Measure	Baseline Measurements
CFR 49 Part 192.1007(e)(1)(i)	Number of hazardous leaks either eliminated or repaired (or total number of leaks if all leaks are repaired when found), categorized by cause	Maintain a low or decreasing trend in the number of hazardous leaks either eliminated or repaired, categorized by cause on the PHMSA Annual Report	Per 2010 Annual Report • OR - Corrosion Hazardous Leaks - 6 • OR - Natural Forces Hazardous Leaks - 0 • OR - Excavation Damage Hazardous Leaks - 3 • OR - Other Outside Force Damage Hazardous Leaks - 0 • OR - Material or Welds Hazardous Leaks - 51 • OR - Equipment Hazardous Leaks - 0 • OR - Incorrect Operations Hazardous Leaks - 0 • OR - Other Hazardous Leaks - 1 • WA - Corrosion Hazardous Leaks - 0 • WA - Natural Forces Hazardous Leaks - 0 • WA - Excavation Damage Hazardous Leaks - 2 • WA - Other Outside Force Damage Hazardous Leaks - 0 • WA - Material or Welds Hazardous Leaks - 4 • WA - Equipment Hazardous Leaks - 0 • WA - Incorrect Operations Hazardous Leaks - 0 • WA - Other Hazardous Leaks - 0
CFR 49 Part 192.1007(e)(1)(ii)	Number of excavation damages	Maintain a low or decreasing trend in the number excavation damages, reported on the PHMSA Annual Report	Per 2010 Annual Report • OR - Excavation Damages - 499 • WA - Excavation Damages - 55
CFR 49 Part 192.1007(e)(1)(iii)	Number of excavation tickets (receipt of information by NW Natural from the notification center)	Maintain a low or decreasing trend in the measure of Damages per 1000 locates	Per 2010 Annual Report • OR – 499 damages on 159,342 locates = 3.1 damages/1000 locates • WA – 55 damages on 17,370 locates = 3.2 damages/1000 locates

CFR 49 Part 192.1007(e)(1)(iv)	Total number of leaks, either eliminated or repaired, categorized by cause	Maintain a low or decreasing trend in the total number of leaks either eliminated or repaired, categorized by cause in the PHMSA Annual Report	Per 2010 Annual Report • OR - Corrosion Leaks - 22 • OR - Natural Forces Leaks - 0 • OR - Excavation Damage Leaks - 402 • OR - Other Outside Force Damage Leaks - 0 • OR - Material or Welds Leaks - 220 • OR - Equipment Leaks - 0 • OR - Incorrect Operations Leaks - 0 • OR - Other Leaks - 11 • WA - Corrosion Leaks - 1 • WA - Natural Forces Leaks - 0 • WA - Excavation Damage Leaks - 47 • WA - Other Outside Force Damage Leaks - 0 • WA - Material or Welds Leaks - 8 • WA - Equipment Leaks - 0 • WA - Incorrect Operations Leaks - 0 • WA - Other Leaks - 0
CFR 49 Part 192.1007(e)(1)(v)	Number of hazardous leaks either eliminated or repaired (or total number of leaks if all leaks are repaired when found), categorized by material	Maintain a low or decreasing trend in the number of hazardous leaks either eliminated or repaired, categorized by material in the PHMSA Annual Report	Per 2010 HLR-M Report • OR - Hazardous Leaks on Coated Steel - 39 • OR - Hazardous Leaks on Poly – 38 • OR - Hazardous Leaks on Bare Steel – 5 • OR - Hazardous Leaks on ABS – 0 • WA - Hazardous Leaks on Coated Steel - 1 • WA - Hazardous Leaks on Poly – 4 • WA - Hazardous Leaks on Bare Steel – 0 • WA - Hazardous Leaks on ABS – 0
Replace Bare Steel	Number of known system leaks at end of year scheduled for repair	All known bare steel has been removed from the system, therefore this A/A Action is no longer measured. Should bare steel be discovered as a result of normal maintenance activies, the bare steel will be removed and DIMP team will determine if A/A needs to be reinstated.	Per 2010 Annual Report • OR - Bare Steel Main - 22 miles • OR - Bare Services - 167 • OR - Leaks Scheduled for Repair - 35 • WA - Bare Steel Main - 4 miles • WA - Bare Steel Services – 5 • WA - Leaks Scheduled for Repair - 2

Specific mitigation plans for identified high risk active areas on land movement	Number of leaks cause by natural forces	Maintain low (near zero) leak rate for natural force leaks as reported on PHMSA Annual Report.	Per 2010 Annual Report • OR – Natural Forces Leaks – 0 • WA – Natural Forces Leaks - 0
Actively reduce damages through training, education, and enforcement as implemented by Damage Prevention Team.	Measure of damages per 1000 locates	Maintain a low or decreasing trend in the measure of damages per 1000 locates.	Per 2010 Annual Report • OR – 499 damages on 159,342 locates = 3.1 damages/1000 locates • WA – 55 damages on 17,370 locates = 3.2 damages/1000 locates
Investigate the current state of pipeline markers on HP Dist. Pipelines and bring to current standards	Measure of damages per 1000 locates	Maintain a low or decreasing trend in the measure of damages per 1000 locates	Per 2011 Annual Report • OR – 536 damages on 153305 locates = 3.5 damages/1000 locates • WA – 67 damages on 16134 locates = 4.2 damages/1000 locates
Guard Posts	Number of leaks causes by Other Outside Forces	Maintain low (near zero) leak rate for other outside force damage leaks as reported on PHMSA Annual Report.	Per 2010 Annual Report • OR – Other Outside Force Leaks – 0 • WA – Other Outside Force Leaks - 0
Replace ABS services	Total number of ABS services	A count of ABS services in service at years end as reported on Annual Report with a goal of zero.	Per 2010 Annual Report • OR – 154 ABS services • WA – 5 ABS services
Service Tee caps	Number of hazardous leaks caused by Material or Weld Failure	A decrease in the number of Hazardous leaks associated with Material or Weld Failure.	Per 2010 Annual Report • OR – Material or Welds Hazardous Leaks – 0 • WA – Material or Welds Hazardous Leaks – 0
Replace riser valve in Coastal areas that have had historic issues	Number of hazardous leaks cause by Equipment Failure	A decrease in the number of Hazardous leaks associated with Equipment Failure.	Per 2011 Annual Report • OR – Hazardous Equipment Failure Leaks – 711 • WA – Hazardous Equipment Failure Leaks – 0
Sewer Cross Bores	Number of leaks cause by Incorrect Operations	Maintain low (near zero) leak rate for Incorrect Operations leaks.	Per 2010 Annual Report • OR- Incorrect Operations Leaks – 0 • WA – Incorrect Operations Leaks - 0

Proactive EFVs	Number of leaks caused by excavation damage	A decrease in the number of Hazardous leaks on services associated with excavation damage	Per 2020 Annual Report • OR- Excavation Damage Leaks - services – 285 • WA – Excavation Damage Leaks – services - 39
Sunshields	Number of leaks caused by corrosion	A decrease in the number of Hazardous leaks on services associated with corrosion	Per 2020 Annual Report • OR- Corrosion leaks – services - 5 • WA – Corrosion leaks - services - 0

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Appendix E-2, PHMSA Distribution Annual Report – Oregon, 2010- 11

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed 100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.		OMB NO: 2137-0522 EXPIRATION DATE: 01/31/2014
U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Form Type:**	ORIGINAL
	ID:	3011
	(DOT use only)	

ANNUAL REPORT FOR
CALENDAR YEAR 2010
GAS DISTRIBUTION SYSTEM

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0522. Public reporting for this collection of information is estimated to be approximately 16 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

PART A - OPERATOR INFORMATION

1. Name of Operator	NORTHWEST NATURAL GAS CO
2. LOCATION OF OFFICE (WHERE ADDITIONAL INFORMATION MAY BE OBTAINED)	
2a. Street Address	220 NW 2nd Ave
2b. City and County	Portland,Multnomah
2c. State	OR
2d. Zip Code	97209
3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER	13840
4. HEADQUARTERS NAME & ADDRESS	
4a. Street Address	220 N.W. SECOND AVENUE
4b. City and County	PORTLAND
4c. State	OR
4d. Zip Code	97209
5. STATE IN WHICH SYSTEM OPERATES	OR

PART B - SYSTEM DESCRIPTION

1.GENERAL

	STEEL									
	UNPROTECTED		CATHODICALLY PROTECTED							
	BARE	COATED	BARE	COATED	PLASTIC	CAST/ WROUGHT IRON	DUCTILE IRON	COPPER	OTHER	TOTAL
MILES OF MAIN	21.000	0.000	1.000	6249.000	5298.000	0.000	0.000	0.000	0.000	11569.000
NO. OF SERVICES	52.000	0.000	115.000	193417.000	398452.000	0.000	0.000	0.000	0.000	592036.000

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2.MILES OF MAINS IN SYSTEM AT END OF YEAR

MATERIAL	UNKNOWN	2" OR LESS	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8" THRU 12"	OVER 12"	TOTAL
STEEL	0.000	4850.000	886.000	479.000	49.000	7.000	6271.000
DUCTILE IRON	0.000	0.000	0.000	0.000	0.000	0.000	0.000
COPPER	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CAST/WROUGHT IRON	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLASTIC PVC	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLASTIC PE	0.000	4479.000	705.000	114.000	0.000	0.000	5298.000
PLASTIC ABS	0.000	0.000	0.000	0.000	0.000	0.000	0.000
OTHER PLASTIC	0.000	0.000	0.000	0.000	0.000	0.000	0.000
OTHER	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	0.000	9329.000	1591.000	593.000	49.000	7.000	11569.000

3.NUMBER OF SERVICES IN SYSTEM AT END OF YEAR — **AVERAGE SERVICE LENGTH: 77**

MATERIAL	UNKNOWN	1" OR LESS	OVER 1" THRU 2"	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8"	TOTAL
STEEL	0.000	192583.000	824.000	152.000	23.000	2.000	193584.000
DUCTILE IRON	0.000	0.000	0.000	0.000	0.000	0.000	0.000
COPPER	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CAST/WROUGHT IRON	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLASTIC PVC	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLASTIC PE	8.000	396579.000	1559.000	144.000	8.000	0.000	398298.000
PLASTIC ABS	0.000	154.000	0.000	0.000	0.000	0.000	154.000
OTHER PLASTIC	0.000	0.000	0.000	0.000	0.000	0.000	0.000
OTHER	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	8.000	589316.000	2383.000	296.000	31.000	2.000	592036.000

4.MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION

	UNKNOWN	PRE-1940	1940-1949	1950-1959	1960-1969	1970-1979	1980-1989	1990-1999	2000-2009	2010-2019	TOTAL
MILES OF MAIN	3.000	11.000	1.000	279.000	2826.000	1970.000	1646.000	2874.000	1932.000	27.000	11569.000
NUMBER OF SERVICES	169679.000	7.000	7.000	318.000	5130.000	16009.000	55800.000	191088.000	148567.000	5431.000	592036.000

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PART C - TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING THE YEAR

CAUSE OF LEAK	MAINS		SERVICES	
	TOTAL	HAZARDOUS	TOTAL	HAZARDOUS
CORROSION	17	1	5	5
NATURAL FORCES	0	0	0	0
EXCAVATION DAMAGE	80	2	322	1
OTHER OUTSIDE FORCE DAMAGE	0	0	0	0
MATERIAL OR WELDS	131	25	89	26
EQUIPMENT	0	0	0	0
INCORRECT OPERATIONS	0	0	0	0
OTHER	7	0	4	1

NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR : 35

PART D - EXCAVATION DAMAGE

NUMBER OF EXCAVATION DAMAGES: 499

NUMBER OF EXCAVATION TICKETS : 159342

PART E-EXCESS FLOW VALUE(EFV) DATA

NUMBER OF EFV'S INSTALLED THIS CALENDER YEAR ON SINGLE FAMILY RESIDENTIAL SERVICES: 4445

ESTIMATED NUMBER OF EFV'S IN SYSTEM AT THE END OF YEAR: 152449

PART F - LEAKS ON FEDERAL LAND

TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED TO REPAIR: 0

PART G-PERCENT OF UNACCOUNTED FOR GAS

UNACCOUUNTED FOR GAS AS A PERCENT OF TOTAL INPUT FOR THE 12 MONTHS ENDING JUNE 30 OF THE REPORTING YEAR.

INPUT FOR YEAR ENDING 6/30: 46%

PART H - ADDITIONAL INFORMATION

PART I - PREPARER AND AUTHORIZED SIGNATURE

Kerry Shampine,Compliance Manager
(Preparer's Name and Title)

(503) 226-4211
(Area Code and Telephone Number)

kfs@nwnatural.com
(Preparer's email address)

(Area Code and Facsimile Number)

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Distribution Integrity Management Program
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NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed 100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.		OMB NO: 2137-0522 EXPIRATION DATE: 01/31/2014
U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Form Type:**	INITIAL
	ID:	10144
	(DOT use only)	20120887-15945

ANNUAL REPORT FOR
CALENDAR YEAR 2011
GAS DISTRIBUTION SYSTEM

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0522. Public reporting for this collection of information is estimated to be approximately 16 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

PART A - OPERATOR INFORMATION

1. Name of Operator	NORTHWEST NATURAL GAS CO
2. LOCATION OF OFFICE (WHERE ADDITIONAL INFORMATION MAY BE OBTAINED)	
2a. Street Address	220 NW 2nd Ave
2b. City and County	Portland,Multnomah
2c. State	OR
2d. Zip Code	97209
3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER	13840
4. HEADQUARTERS NAME & ADDRESS	
4a. Street Address	220 N.W. SECOND AVENUE
4b. City and County	PORTLAND
4c. State	OR
4d. Zip Code	97209
5. STATE IN WHICH SYSTEM OPERATES	OR

PART B - SYSTEM DESCRIPTION

1.GENERAL

	STEEL									
	UNPROTECTED		CATHODICALLY PROTECTED							
	BARE	COATED	BARE	COATED	PLASTIC	CAST/ WROUGHT IRON	DUCTILE IRON	COPPER	OTHER	TOTAL
MILES OF MAIN	16.000	0.000	1.000	6226.000	5334.000	0.000	0.000	0.000	0.000	11577.000
NO. OF SERVICES	52.000	0.000	59.000	192048.000	403850.000	0.000	0.000	0.000	0.000	596009.000

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2.MILES OF MAINS IN SYSTEM AT END OF YEAR

MATERIAL	UNKNOWN	2" OR LESS	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8" THRU 12"	OVER 12"	TOTAL
STEEL	0.000	4832.000	884.000	471.000	49.000	7.000	6243.000
DUCTILE IRON	0.000	0.000	0.000	0.000	0.000	0.000	0.000
COPPER	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CAST/WROUGHT IRON	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLASTIC PVC	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLASTIC PE	0.000	4499.000	719.000	116.000	0.000	0.000	5334.000
PLASTIC ABS	0.000	0.000	0.000	0.000	0.000	0.000	0.000
OTHER PLASTIC	0.000	0.000	0.000	0.000	0.000	0.000	0.000
OTHER	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	0.000	9331.000	1603.000	587.000	49.000	7.000	11577.000

3.NUMBER OF SERVICES IN SYSTEM AT END OF YEAR | **AVERAGE SERVICE LENGTH: 77**

MATERIAL	UNKNOWN	1" OR LESS	OVER 1" THRU 2"	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8"	TOTAL
STEEL	0.000	191177.000	810.000	147.000	23.000	2.000	192159.000
DUCTILE IRON	0.000	0.000	0.000	0.000	0.000	0.000	0.000
COPPER	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CAST/WROUGHT IRON	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLASTIC PVC	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLASTIC PE	0.000	401946.000	1605.000	145.000	9.000	0.000	403705.000
PLASTIC ABS	0.000	145.000	0.000	0.000	0.000	0.000	145.000
OTHER PLASTIC	0.000	0.000	0.000	0.000	0.000	0.000	0.000
OTHER	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	0.000	593268.000	2415.000	292.000	32.000	2.000	596009.000

4.MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION

	UNKNOWN	PRE-1940	1940-1949	1950-1959	1960-1969	1970-1979	1980-1989	1990-1999	2000-2009	2010-2019	TOTAL
MILES OF MAIN	2.000	10.000	1.000	273.000	2808.000	1965.000	1642.000	2869.000	1935.000	72.000	11577.000
NUMBER OF SERVICES	155496.000	7.000	9.000	316.000	5546.000	21677.000	62155.000	190853.000	149634.000	10316.000	596009.000

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PART C - TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING THE YEAR

CAUSE OF LEAK	MAINS		SERVICES	
	TOTAL	HAZARDOUS	TOTAL	HAZARDOUS
CORROSION	10	1	4	0
NATURAL FORCES	0	0	0	0
EXCAVATION DAMAGE	65	2	281	2
OTHER OUTSIDE FORCE DAMAGE	1	0	0	0
MATERIAL OR WELDS	71	16	81	30
EQUIPMENT	78	6	6	1
INCORRECT OPERATIONS	0	0	0	0
OTHER	9	1	7	2

NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR : 60

PART D - EXCAVATION DAMAGE

NUMBER OF EXCAVATION DAMAGES: 536

NUMBER OF EXCAVATION TICKETS : 153305

PART E-EXCESS FLOW VALUE(EFV) DATA

NUMBER OF EFV'S INSTALLED THIS CALENDER YEAR ON SINGLE FAMILY RESIDENTIAL SERVICES: 3079

ESTIMATED NUMBER OF EFV'S IN SYSTEM AT THE END OF YEAR: 156224

PART F - LEAKS ON FEDERAL LAND

TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED TO REPAIR: 0

PART G-PERCENT OF UNACCOUNTED FOR GAS

UNACCOUUNTED FOR GAS AS A PERCENT OF TOTAL INPUT FOR THE 12 MONTHS ENDING JUNE 30 OF THE REPORTING YEAR.

INPUT FOR YEAR ENDING 6/30: .44%

PART H - ADDITIONAL INFORMATION

PART I - PREPARER AND AUTHORIZED SIGNATURE

Kerry Shampine,Manager, Code Compliance
(Preparer's Name and Title)

(503) 226-4211
(Area Code and Telephone Number)

kerry.shampine@nwnatural.com
(Preparer's email address)

(Area Code and Facsimile Number)

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Distribution Integrity Management Program

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Appendix E-3, PHMSA Distribution Annual Report – Washington, 2010-11

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed 100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.		OMB NO: 2137-0522 EXPIRATION DATE: 01/31/2014
U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Form Type:**	ORIGINAL
	ID:	3025
	(DOT use only)	

ANNUAL REPORT FOR
CALENDAR YEAR 2010
GAS DISTRIBUTION SYSTEM

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0522. Public reporting for this collection of information is estimated to be approximately 16 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

PART A - OPERATOR INFORMATION

1. Name of Operator	NORTHWEST NATURAL GAS CO
2. LOCATION OF OFFICE (WHERE ADDITIONAL INFORMATION MAY BE OBTAINED)	
2a. Street Address	220 N.W SECOND AVE
2b. City and County	PORTLAND,MULTNOMAH
2c. State	OR
2d. Zip Code	97209
3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER	13840
4. HEADQUARTERS NAME & ADDRESS	
4a. Street Address	220 N. W. SECOND AVENUE
4b. City and County	PORTLAND,MULTNOMAH
4c. State	OR
4d. Zip Code	97209
5. STATE IN WHICH SYSTEM OPERATES	WA

PART B - SYSTEM DESCRIPTION

1.GENERAL

	STEEL									
	UNPROTECTED		CATHODICALLY PROTECTED							
	BARE	COATED	BARE	COATED	PLASTIC	CAST/ WROUGHT IRON	DUCTILE IRON	COPPER	OTHER	TOTAL
MILES OF MAIN	3.000	0.000	1.000	368.000	1317.000	0.000	0.000	0.000	0.000	1689.000
NO. OF SERVICES	5.000	0.000	0.000	4275.000	61541.000	0.000	0.000	0.000	0.000	65821.000

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2.MILES OF MAINS IN SYSTEM AT END OF YEAR

MATERIAL	UNKNOWN	2" OR LESS	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8" THRU 12"	OVER 12"	TOTAL
STEEL	0.000	222.000	86.000	61.000	3.000	0.000	372.000
DUCTILE IRON	0.000	0.000	0.000	0.000	0.000	0.000	0.000
COPPER	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CAST/WROUGHT IRON	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLASTIC PVC	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLASTIC PE	0.000	1095.000	189.000	33.000	0.000	0.000	1317.000
PLASTIC ABS	0.000	0.000	0.000	0.000	0.000	0.000	0.000
OTHER PLASTIC	0.000	0.000	0.000	0.000	0.000	0.000	0.000
OTHER	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	0.000	1317.000	275.000	94.000	3.000	0.000	1689.000

3.NUMBER OF SERVICES IN SYSTEM AT END OF YEAR — **AVERAGE SERVICE LENGTH: 62**

MATERIAL	UNKNOWN	1" OR LESS	OVER 1" THRU 2"	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8"	TOTAL
STEEL	0.000	4225.000	43.000	10.000	2.000	0.000	4280.000
DUCTILE IRON	0.000	0.000	0.000	0.000	0.000	0.000	0.000
COPPER	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CAST/WROUGHT IRON	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLASTIC PVC	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLASTIC PE	1.000	61321.000	200.000	9.000	5.000	0.000	61536.000
PLASTIC ABS	0.000	5.000	0.000	0.000	0.000	0.000	5.000
OTHER PLASTIC	0.000	0.000	0.000	0.000	0.000	0.000	0.000
OTHER	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	1.000	65551.000	243.000	19.000	7.000	0.000	65821.000

4.MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION

	UNKNOWN	PRE-1940	1940-1949	1950-1959	1960-1969	1970-1979	1980-1989	1990-1999	2000-2009	2010-2019	TOTAL
MILES OF MAIN	0.000	0.000	0.000	27.000	127.000	104.000	191.000	719.000	516.000	5.000	1689.000
NUMBER OF SERVICES	3770.000	0.000	0.000	12.000	217.000	505.000	2951.000	29463.000	27920.000	983.000	65821.000

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PART C - TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING THE YEAR				
CAUSE OF LEAK	MAINS		SERVICES	
	TOTAL	HAZARDOUS	TOTAL	HAZARDOUS
CORROSION	1		0	
NATURAL FORCES	0		0	
EXCAVATION DAMAGE	10	1	37	1
OTHER OUTSIDE FORCE DAMAGE	0		0	
MATERIAL OR WELDS	5	2	3	2
EQUIPMENT	0		0	
INCORRECT OPERATIONS	0		0	
OTHER	0			
NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR : 2				

PART D - EXCAVATION DAMAGE	PART E-EXCESS FLOW VALUE(EFV) DATA
NUMBER OF EXCAVATION DAMAGES: 55	NUMBER OF EFV'S INSTALLED THIS CALENDER YEAR ON SINGLE FAMILY RESIDENTIAL SERVICES: 985
NUMBER OF EXCAVATION TICKETS : 17370	ESTIMATED NUMBER OF EFV'S IN SYSTEM AT THE END OF YEAR: 29670
PART F - LEAKS ON FEDERAL LAND	**PART G-PERCENT OF UNACCOUNTED FOR GAS**
TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED TO REPAIR: 0	UNACCOUUNTED FOR GAS AS A PERCENT OF TOTAL INPUT FOR THE 12 MONTHS ENDING JUNE 30 OF THE REPORTING YEAR. INPUT FOR YEAR ENDING 6/30: .46%

PART H - ADDITIONAL INFORMATION

PART I - PREPARER AND AUTHORIZED SIGNATURE	
Kerry Shampine (Preparer's Name and Title)	(503) 226-4211 (Area Code and Telephone Number)
kfs@nwnatural.com (Preparer's email address)	(Area Code and Facsimile Number)

NW Natural

Distribution Integrity Management Program
Program Plan

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed 100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.		OMB NO: 2137-0522 EXPIRATION DATE: 01/31/2014
U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Form Type:**	INITIAL
	ID:	10155
	(DOT use only)	20120885-15943

ANNUAL REPORT FOR
CALENDAR YEAR 2011
GAS DISTRIBUTION SYSTEM

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PART A - OPERATOR INFORMATION

1. Name of Operator	NORTHWEST NATURAL GAS CO
2. LOCATION OF OFFICE (WHERE ADDITIONAL INFORMATION MAY BE OBTAINED)	
2a. Street Address	220 N.W SECOND AVE
2b. City and County	PORTLAND,MULTNOMAH
2c. State	OR
2d. Zip Code	97209
3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER	13840
4. HEADQUARTERS NAME & ADDRESS	
4a. Street Address	220 N. W. SECOND AVENUE
4b. City and County	PORTLAND,MULTNOMAH
4c. State	OR
4d. Zip Code	97209
5. STATE IN WHICH SYSTEM OPERATES	WA

PART B - SYSTEM DESCRIPTION

1.GENERAL

	STEEL									
	UNPROTECTED		CATHODICALLY PROTECTED							
	BARE	COATED	BARE	COATED	PLASTIC	CAST/ WROUGHT IRON	DUCTILE IRON	COPPER	OTHER	TOTAL
MILES OF MAIN	3.000	0.000	1.000	364.000	1327.000	0.000	0.000	0.000	0.000	1695.000
NO. OF SERVICES	2.000	0.000	0.000	4213.000	62555.000	0.000	0.000	0.000	0.000	66770.000

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2.MILES OF MAINS IN SYSTEM AT END OF YEAR

MATERIAL	UNKNOWN	2" OR LESS	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8" THRU 12"	OVER 12"	TOTAL
STEEL	0.000	219.000	86.000	60.000	3.000	0.000	368.000
DUCTILE IRON	0.000	0.000	0.000	0.000	0.000	0.000	0.000
COPPER	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CAST/WROUGHT IRON	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLASTIC PVC	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLASTIC PE	0.000	1102.000	190.000	35.000	0.000	0.000	1327.000
PLASTIC ABS	0.000	0.000	0.000	0.000	0.000	0.000	0.000
OTHER PLASTIC	0.000	0.000	0.000	0.000	0.000	0.000	0.000
OTHER	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	0.000	1321.000	276.000	95.000	3.000	0.000	1695.000

3.NUMBER OF SERVICES IN SYSTEM AT END OF YEAR | **AVERAGE SERVICE LENGTH: 62**

MATERIAL	UNKNOWN	1" OR LESS	OVER 1" THRU 2"	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8"	TOTAL
STEEL	0.000	4161.000	42.000	10.000	2.000	0.000	4215.000
DUCTILE IRON	0.000	0.000	0.000	0.000	0.000	0.000	0.000
COPPER	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CAST/WROUGHT IRON	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLASTIC PVC	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLASTIC PE	0.000	62331.000	205.000	9.000	5.000	0.000	62550.000
PLASTIC ABS	0.000	5.000	0.000	0.000	0.000	0.000	5.000
OTHER PLASTIC	0.000	0.000	0.000	0.000	0.000	0.000	0.000
OTHER	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	0.000	66497.000	247.000	19.000	7.000	0.000	66770.000

4.MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION

	UNKNOWN	PRE-1940	1940-1949	1950-1959	1960-1969	1970-1979	1980-1989	1990-1999	2000-2009	2010-2019	TOTAL
MILES OF MAIN	0.000	0.000	0.000	27.000	125.000	104.000	190.000	717.000	516.000	16.000	1695.000
NUMBER OF SERVICES	3274.000	0.000	0.000	11.000	216.000	602.000	3271.000	29446.000	28273.000	1677.000	66770.000

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Distribution Integrity Management Program

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PART C - TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING THE YEAR

CAUSE OF LEAK	MAINS		SERVICES	
	TOTAL	HAZARDOUS	TOTAL	HAZARDOUS
CORROSION	0	0	1	0
NATURAL FORCES	0	0	0	0
EXCAVATION DAMAGE	13	0	36	0
OTHER OUTSIDE FORCE DAMAGE	0	0	0	0
MATERIAL OR WELDS	4	0	1	1
EQUIPMENT	0	0	0	0
INCORRECT OPERATIONS	0	0	0	0
OTHER	4	0	0	0

NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR : 1

PART D - EXCAVATION DAMAGE

NUMBER OF EXCAVATION DAMAGES: 67

NUMBER OF EXCAVATION TICKETS : 16134

PART E-EXCESS FLOW VALUE(EFV) DATA

NUMBER OF EFV'S INSTALLED THIS CALENDER YEAR ON SINGLE FAMILY RESIDENTIAL SERVICES: 580

ESTIMATED NUMBER OF EFV'S IN SYSTEM AT THE END OF YEAR: 30578

PART F - LEAKS ON FEDERAL LAND

TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED TO REPAIR: 0

PART G-PERCENT OF UNACCOUNTED FOR GAS

UNACCOUUNTED FOR GAS AS A PERCENT OF TOTAL INPUT FOR THE 12 MONTHS ENDING JUNE 30 OF THE REPORTING YEAR.

INPUT FOR YEAR ENDING 6/30: .44%

PART H - ADDITIONAL INFORMATION

PART I - PREPARER AND AUTHORIZED SIGNATURE

Kerry Shampine,Manager, Code Compliance
(Preparer's Name and Title)

(503) 226-4211
(Area Code and Telephone Number)

kerry.shampine@nwnatural.com
(Preparer's email address)

(Area Code and Facsimile Number)

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Distribution Integrity Management Program

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Appendix E-4. Hazardous Leaks Repaired, Categorized by Material, (HLR-M) Reports

Hazardous Leaks Repaired by Material		
2010	OR	WA
Coated Steel	39	1
Polyethylene	38	4
Bare Steel	5	0
ABS	0	0

Hazardous Leaks Repaired by Material		
2011	OR	WA
Coated Steel	80	3
Polyethylene	240	40
Bare Steel	2	0
ABS	0	0

Hazardous Leaks Repaired by Material		
2012	OR	WA
Coated Steel	70	1
Polyethylene	215	56
Bare Steel	4	0
ABS	0	0

Hazardous Leaks Repaired by Material		
2013	OR	WA
Coated Steel	67	9
Polyethylene	303	59
Bare Steel	3	0
ABS	0	0

Hazardous Leaks Repaired by Material		
2014	OR	WA
Coated Steel	79	1
Polyethylene	312	60
Bare Steel	5	0
ABS	0	0

Hazardous Leaks Repaired by Material		
2015	OR	WA
Coated Steel	80	6
Polyethylene	384	69
Bare Steel	5	0
ABS	0	0

Hazardous Leaks Repaired by Material		
2016	OR	WA
Coated Steel	91	3
Polyethylene	261	41
Bare Steel	5	0
ABS	138	16

Hazardous Leaks Repaired by Material		
2017	OR	WA
Coated Steel	82	6
Polyethylene	325	69
Bare Steel	2	0
ABS	0	0

Hazardous Leaks Repaired by Material		
2018	OR	WA
Coated Steel	71	1
Polyethylene	342	68
Bare Steel	1	0
ABS	0	0

Hazardous Leaks Repaired by Material		
2019	OR	WA
Coated Steel	75	0
Polyethylene	283	70
Bare Steel	0	0
ABS	0	0

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Hazardous Leaks Repaired by Material		
2020	OR	WA
Coated Steel	74	5
Polyethylene	323	56
Bare Steel	1	0
ABS	0	0

Hazardous Leaks Repaired by Material		
2021	OR	WA
Coated Steel	94	3
Polyethylene	338	49
Bare Steel	2	0
ABS	0	0

Hazardous Leaks Repaired by Material		
2022	OR	WA
Coated Steel	81	1
Polyethylene	313	20
Bare Steel	0	0
ABS	0	0

Hazardous Leaks Repaired by Material		
2023	OR	WA
Coated Steel	73	3
Polyethylene	311	19
Bare Steel	0	0
ABS	0	0

Hazardous Leaks Repaired by Material		
2024	OR	WA
Coated Steel	82	2
Polyethylene	269	22
Bare Steel	1	0
ABS	0	0

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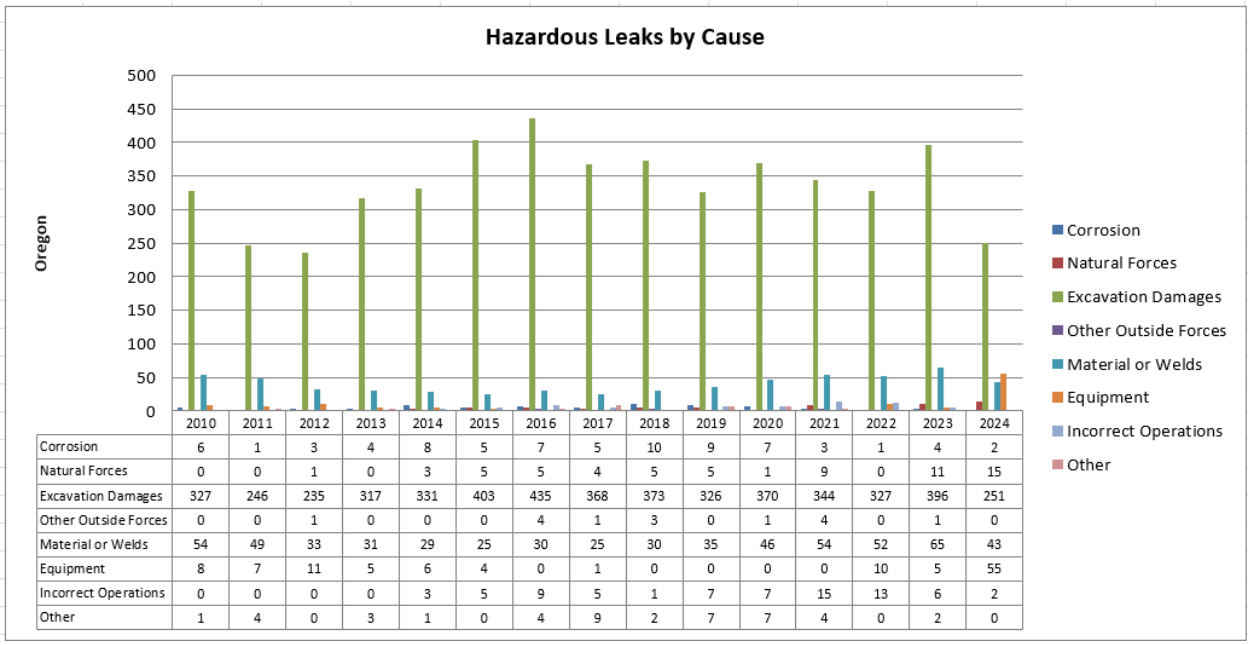
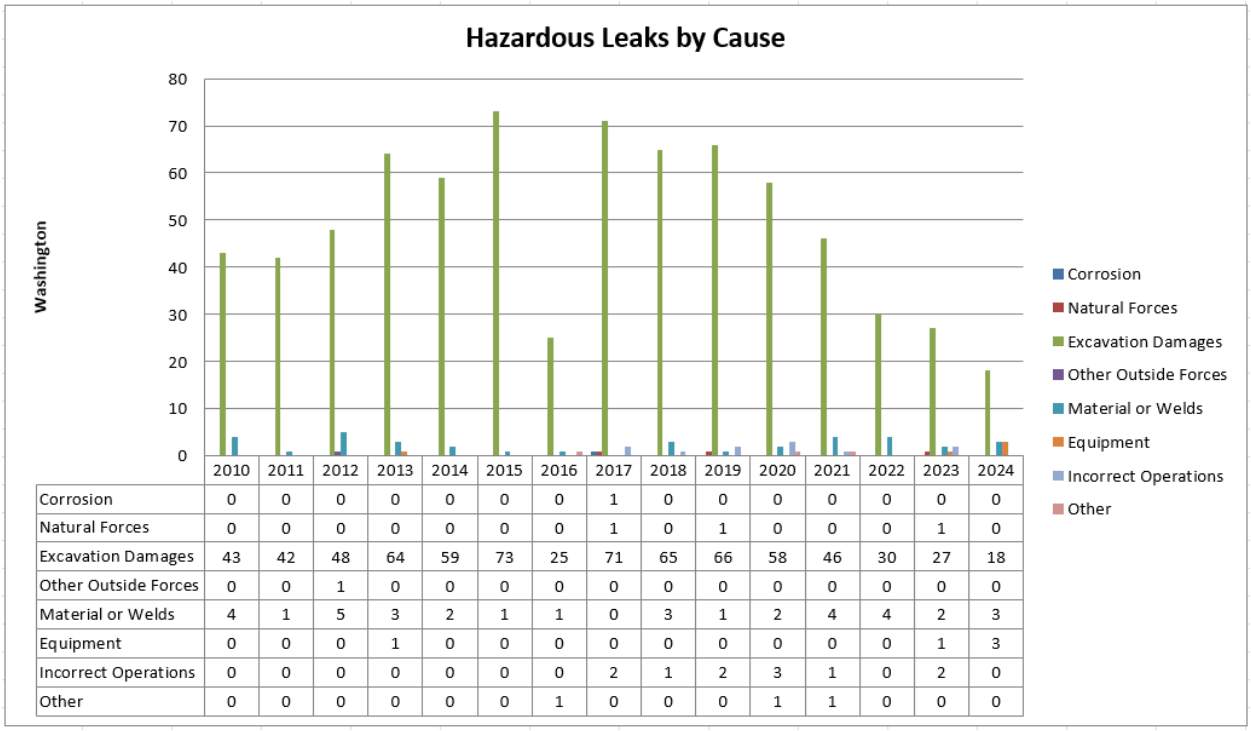
Appendix E-5. Hazardous Leaks by Cause



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Corrosion	6	1	3	4	8	5	7	5	10	9	7	3	1	4	2
Natural Forces	0	0	1	0	3	5	5	4	5	5	1	9	0	11	15
Excavation Damages	327	246	235	317	331	403	435	368	373	326	370	344	327	396	251
Other Outside Forces	0	0	1	0	0	0	4	1	3	0	1	4	0	1	0
Material or Welds	54	49	33	31	29	25	30	25	30	35	46	54	52	65	43
Equipment	8	7	11	5	6	4	0	1	0	0	0	0	10	5	55
Incorrect Operations	0	0	0	0	3	5	9	5	1	7	7	15	13	6	2
Other	1	4	0	3	1	0	4	9	2	7	7	4	0	2	0



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Corrosion	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0
Natural Forces	0	0	0	0	0	0	0	1	0	1	0	0	0	1	0
Excavation Damages	43	42	48	64	59	73	25	71	65	66	58	46	30	27	18
Other Outside Forces	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
Material or Welds	4	1	5	3	2	1	1	0	3	1	2	4	4	2	3
Equipment	0	0	0	1	0	0	0	0	0	0	0	0	0	1	3
Incorrect Operations	0	0	0	0	0	0	0	2	1	2	3	1	0	2	0
Other	0	0	0	0	0	0	1	0	0	0	1	1	0	0	0

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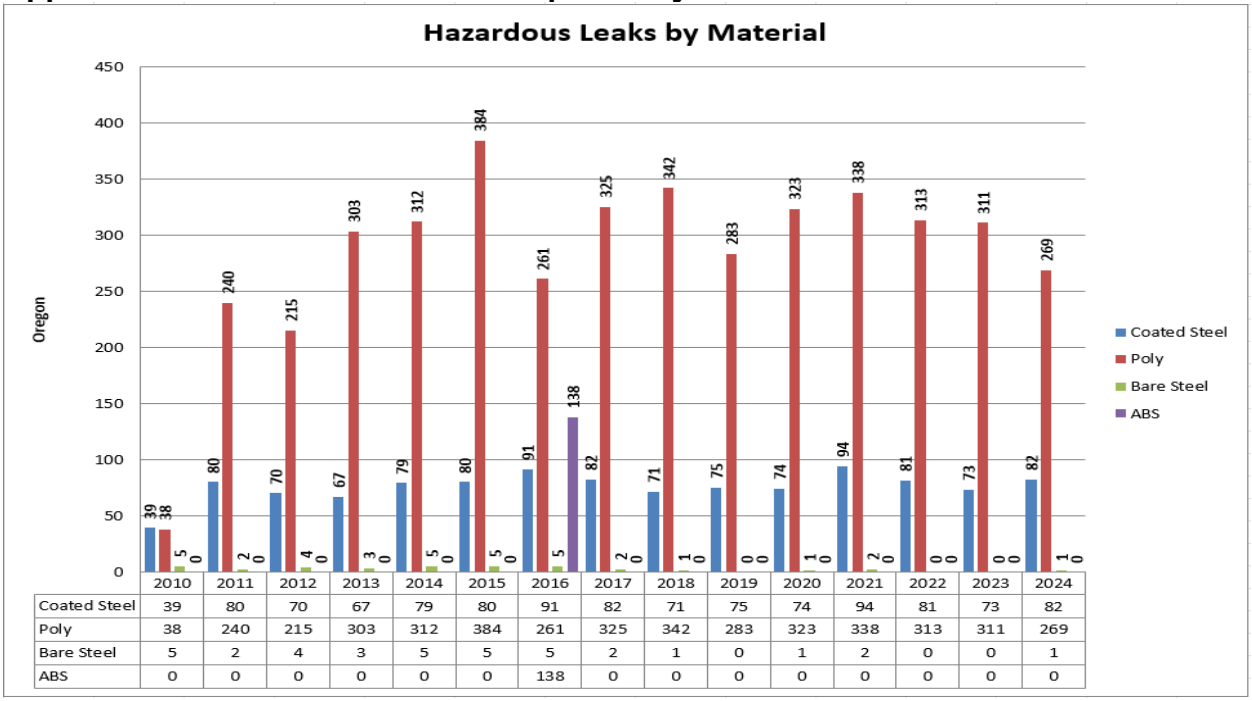
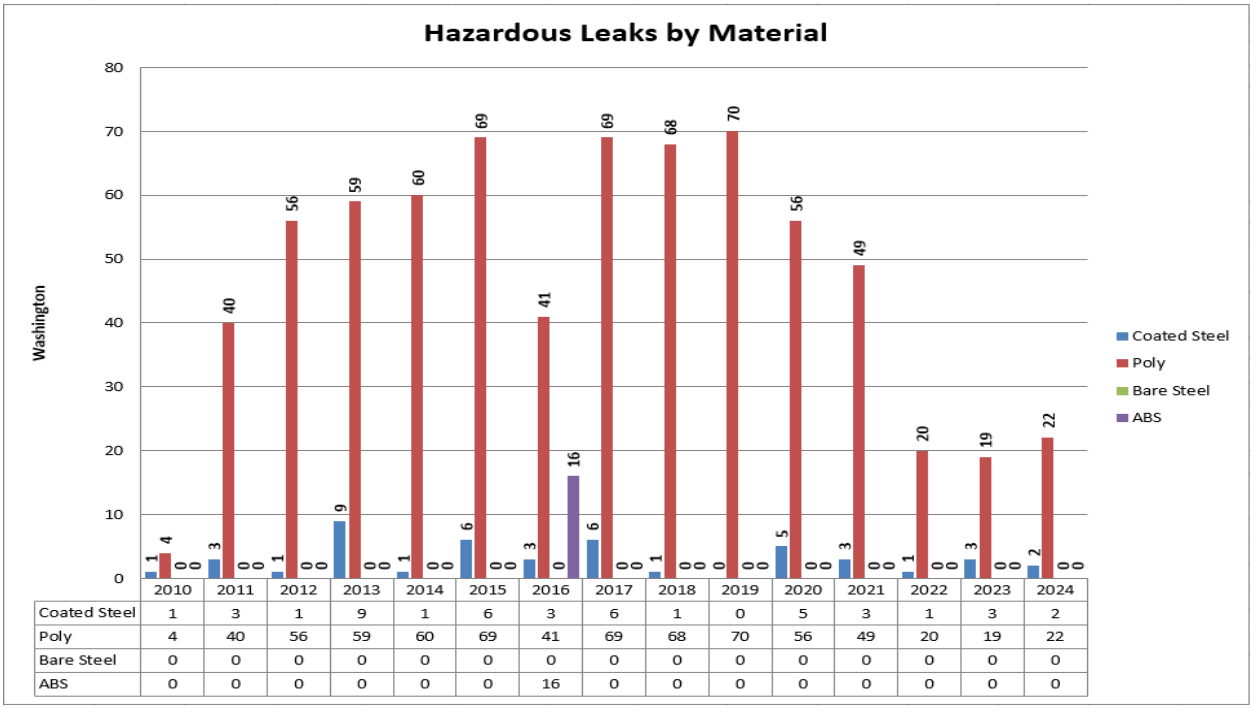
Appendix E-6. Hazardous Leaks Repaired by Material



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Coated Steel	39	80	70	67	79	80	91	82	71	75	74	94	81	73	82
Poly	38	240	215	303	312	384	261	325	342	283	323	338	313	311	269
Bare Steel	5	2	4	3	5	5	5	2	1	0	1	2	0	0	1
ABS	0	0	0	0	0	0	138	0	0	0	0	0	0	0	0



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Coated Steel	1	3	1	9	1	6	3	6	1	0	5	3	1	3	2
Poly	4	40	56	59	60	69	41	69	68	70	56	49	20	19	22
Bare Steel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ABS	0	0	0	0	0	0	16	0	0	0	0	0	0	0	0

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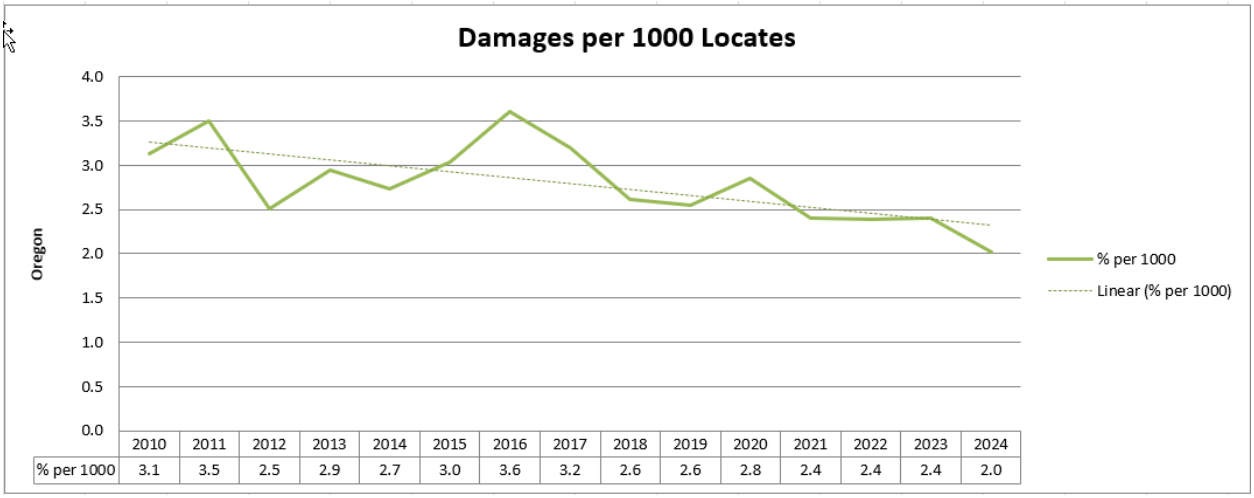
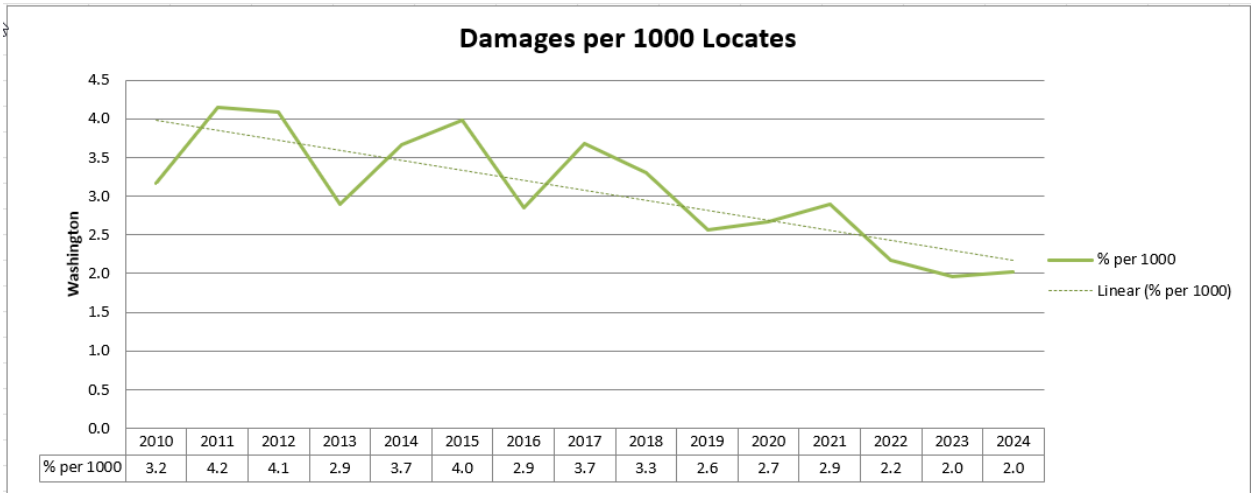
Appendix E-7 Damages per 1000 Locates



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
% per 1000	3.1	3.5	2.5	2.9	2.7	3.0	3.6	3.2	2.6	2.6	2.8	2.4	2.4	2.4	2.0



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
% per 1000	3.2	4.2	4.1	2.9	3.7	4.0	2.9	3.7	3.3	2.6	2.7	2.9	2.2	2.0	2.0

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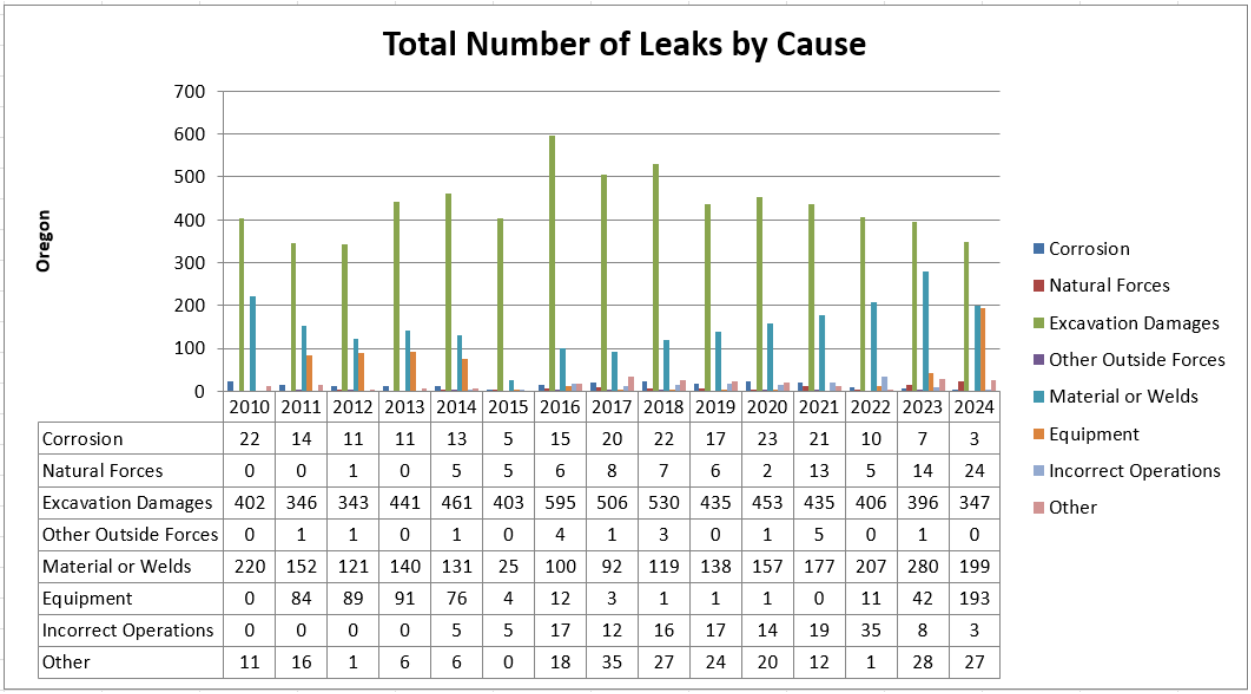
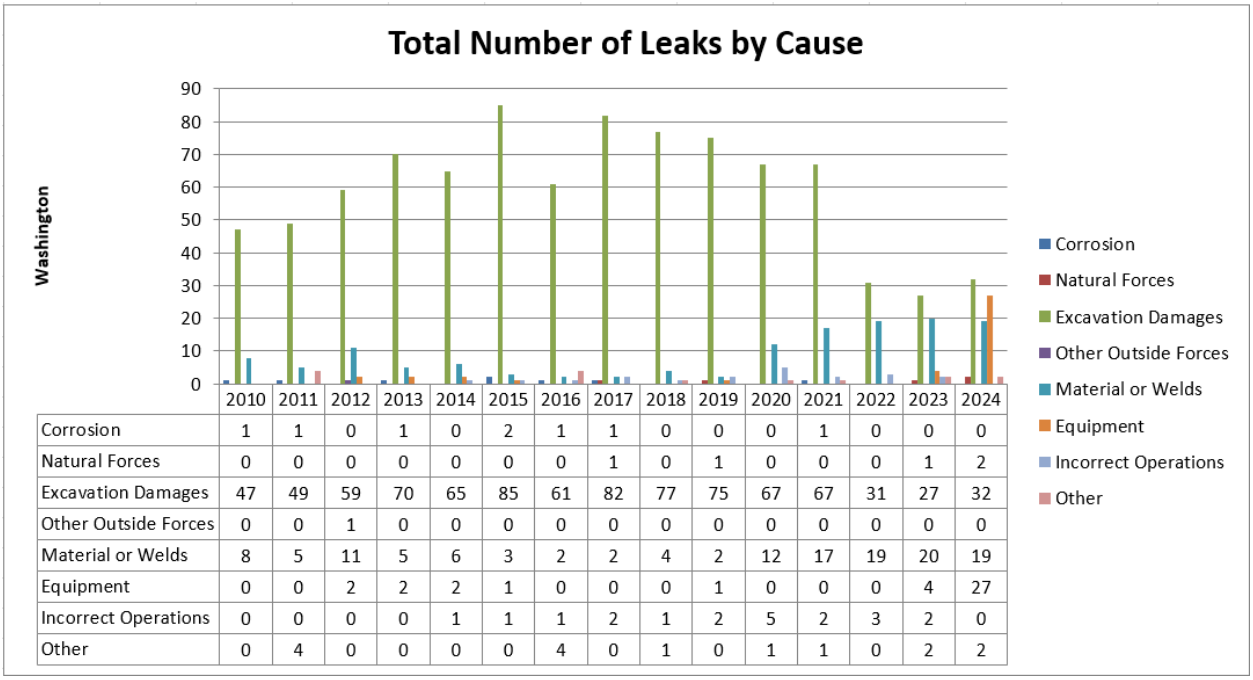
Appendix E-8. Total Leaks by Cause



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Corrosion	22	14	11	11	13	5	15	20	22	17	23	21	10	7	3
Natural Forces	0	0	1	0	5	5	6	8	7	6	2	13	5	14	24
Excavation Damages	402	346	343	441	461	403	595	506	530	435	453	435	406	396	347
Other Outside Forces	0	1	1	0	1	0	4	1	3	0	1	5	0	1	0
Material or Welds	220	152	121	140	131	25	100	92	119	138	157	177	207	280	199
Equipment	0	84	89	91	76	4	12	3	1	1	1	0	11	42	193
Incorrect Operations	0	0	0	0	5	5	17	12	16	17	14	19	35	8	3
Other	11	16	1	6	6	0	18	35	27	24	20	12	1	28	27



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Corrosion	1	1	0	1	0	2	1	1	0	0	0	1	0	0	0
Natural Forces	0	0	0	0	0	0	0	1	0	1	0	0	0	1	2
Excavation Damages	47	49	59	70	65	85	61	82	77	75	67	67	31	27	32
Other Outside Forces	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
Material or Welds	8	5	11	5	6	3	2	2	4	2	12	17	19	20	19
Equipment	0	0	2	2	2	1	0	0	0	1	0	0	0	4	27
Incorrect Operations	0	0	0	0	1	1	1	2	1	2	5	2	3	2	0
Other	0	4	0	0	0	0	4	0	1	0	1	1	0	2	2

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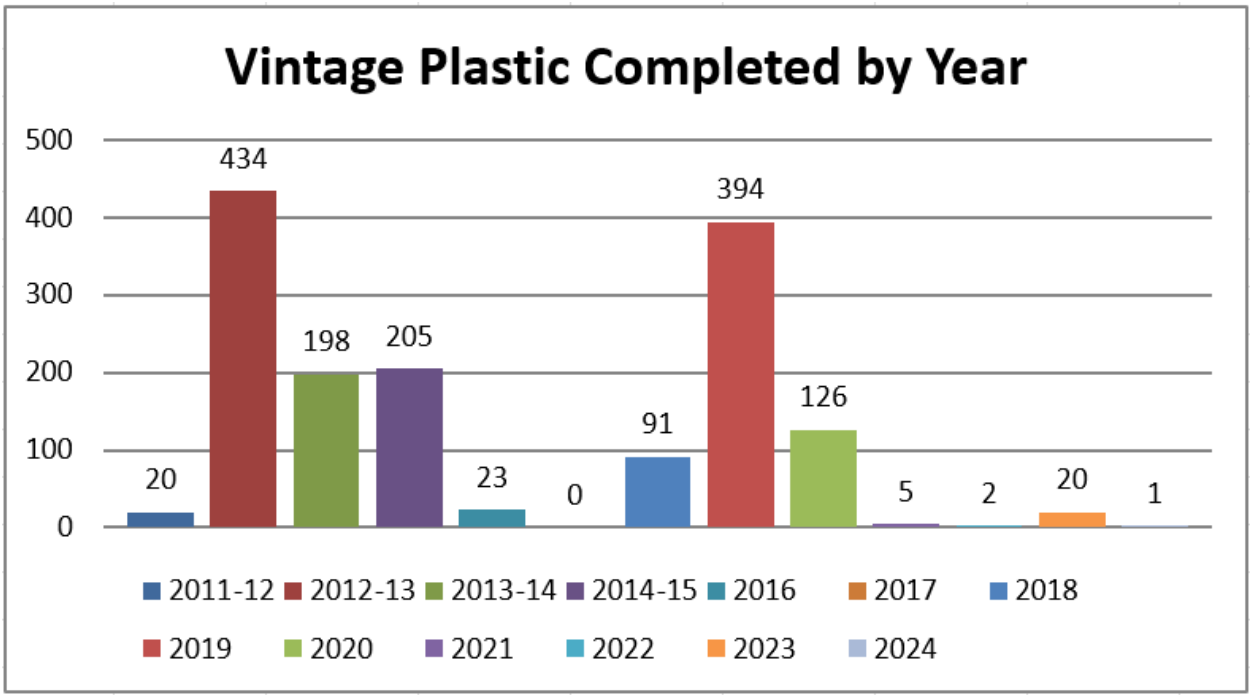
Appendix E-9. Vintage Plastic count completed by year (Tracker year Nov-Oct)



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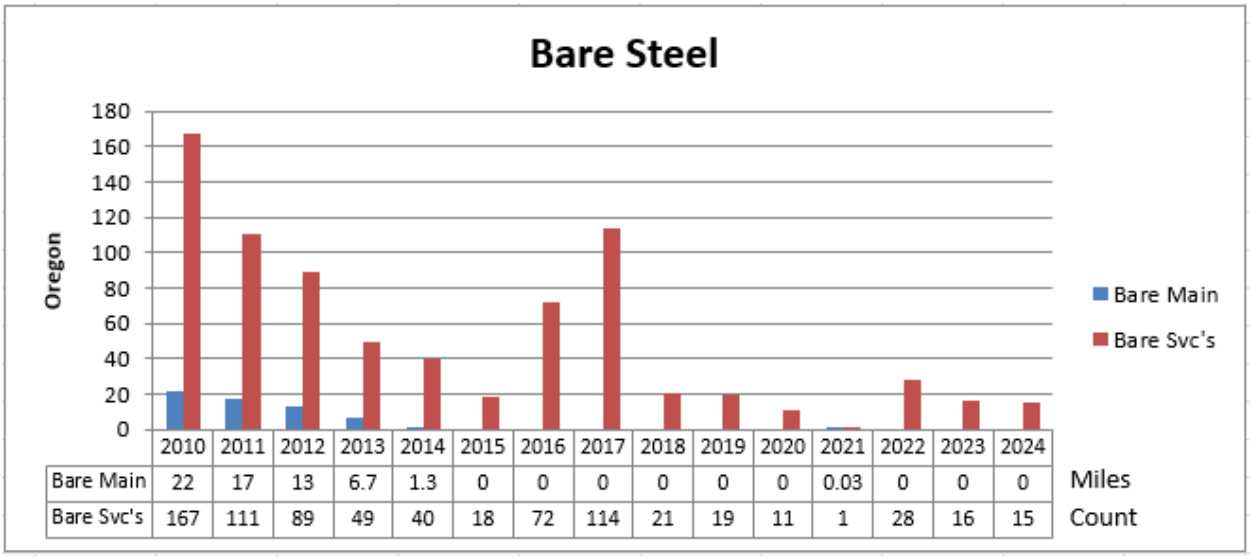
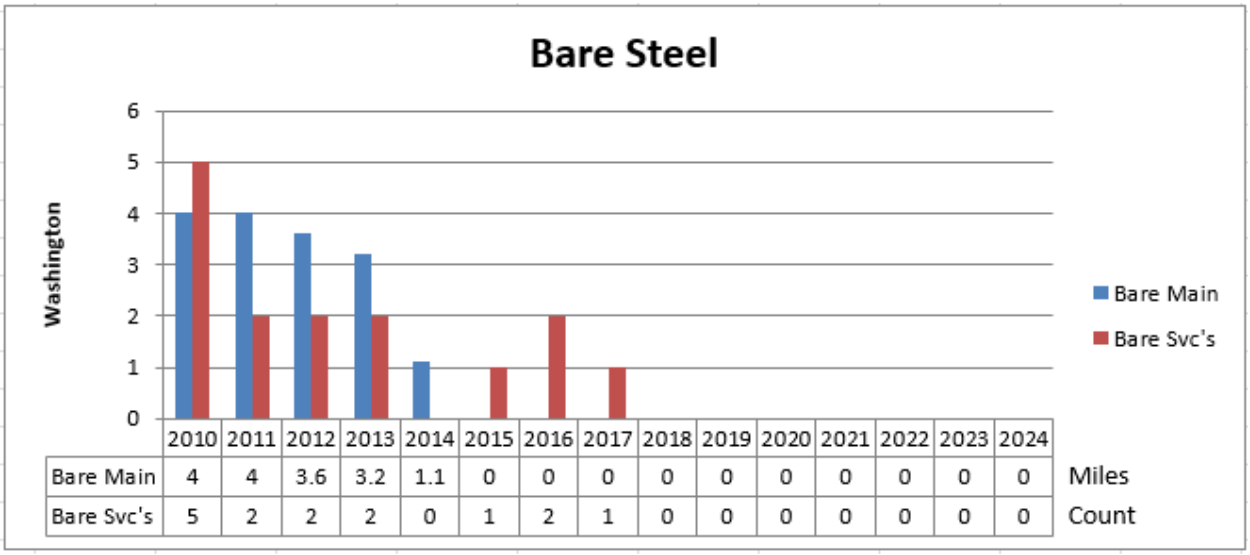
Appendix E-10. Bare Steel Main and Services



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	
Bare Main	22	17	13	6.7	1.3	0	0	0	0	0	0	0.03	0	0	0	Miles
Bare Svc's	167	111	89	49	40	18	72	114	21	19	11	1	28	16	15	Count



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	
Bare Main	4	4	3.6	3.2	1.1	0	0	0	0	0	0	0	0	0	0	Miles
Bare Svc's	5	2	2	2	0	1	2	1	0	0	0	0	0	0	0	Count

APPENDIX F

Chapter 10.0

Periodic Evaluation and Improvement

Appendix F-1. Revision Log Distribution Integrity Management Program Plan

Date	Section	Rev	Primary Change	Approved
8/1/2011		**0**	Initial Document	JSK
9/5/2012	2.1	**1**	Changed Field Construction and Maintenance Manual to Field Operations Manual	JSK
9/5/2012	3.1	**1**	Updated IMP org chart	JSK
9/5/2012	4	**1**	Updated definition of SME	JSK
9/5/2012	5.0, Fig 5-0	**1**	Updated flowchart for clarity	JSK
9/5/2012	New section 5.2	**1**	Added new section 5.2 titled Missing Data	JSK
9/5/2012	Old section 5.2	**1**	Old Section “5.2 Review” renamed “5.3 Review” and flowchart moved to Chapter 10 with other plan review language.	JSK
9/5/2012	Old section 5.3	**1**	Renumbered section 5.4. Updated CFM reference to new FOM reference.	JSK
9/5/2012	6.0, Figure 6-0	**1**	Updated flow chart to correct errors and clarify process.	JSK
9/5/2012	6.6.3	**1**	Clarified language regarding ABS services	JSK
9/5/2012	8.0, Figure 8-0	**1**	Corrected errors in flow chart.	JSK
9/5/2012	8.1.3	**1**	Added A/A action Investigate condition of marker posts on HP dist. Pipe in Class 1 and 2 locations.	JSK
9/5/2012	8.1.6	**1**	Added A/A action to replace riser valves in coastal locations	JSK
9/5/2012	8.1.8	**1**	Added new section 8.1.8 A/A action documentation.	JSK
9/5/2012	9	**1**	Added reference to SPO/SPW 003 pertaining to the Annual Report	JSK
9/5/2012	9.7	**1**	Added new section 9.7 for monitoring performance measures and effectiveness review. Moved some language from old section 10.2 to new section 9.7.	JSK
9/5/2012	10.1	**1**	Updated section to include all components mentioned in FAQ C.4.f.2. Updated flowchart (old chart 5-1) to match.	JSK

9/5/2012	Old section 10.2	**1**	Section removed. Pertinent components moved to new section 9.7	JSK
9/5/2012	New section 10.2	**1**	New section 10.2 added “Notification of plan Changes”	JSK
9/5/2012	New section 11.2	**1**	Added new section 11.2 to outline procedure for collecting and submitting data for Mechanical Fitting Failure Report.	JSK
9/5/2012	Appendix D-1	**1**	Added A/A action to investigate and remediate marker posts on HP Dist. Pipelines	JSK
9/5/2012	Appendix D-1	**1**	Added A/A action to investigate and replace problematic riser valves installed in coastal locations	JSK
9/5/2012	New Appendix D-2	**1**	Added new A/A Action documentation form	JSK
9/5/2012	Old Appendix D-2	**1**	Renamed former Appendix D-2 to Appendix D-3. Added information from 2011 Annual Report.	JSK
9/5/2012	Appendix E-1	**1**	Added 2011 Distribution Annual Report - Oregon	JSK
9/5/2012	Appendix E-2	**1**	Added 2011 Distribution Annual Report - Washington	JSK
9/5/2012	Appendix E-3	**1**	Updated table	JSK
10/8/2012	3.1	**2**	Updated Org Chart	JSK
10/8/2012	5	**2**	Updated plan revision timing to once per calendar year	JSK
10/8/2012	5.2	**2**	Updated language to mention initial review of pipe data and reference Appendix A-3	JSK
10/8/2012	5.2	**2**	Updated language to mention no need to actively research missing or insufficient data	JSK
10/8/2012	5.2	**2**	Added reference to Mapframe help document for plat corrections.	JSK
10/8/2012	5.4	**2**	Added language about using paper as-built’s for large projects.	JSK
10/8/2012	Figure 6-0	**2**	Updated flowchart for clarity	JSK
10/8/2012	6.3.1	**2**	Updated language concerning seismic risk to system	JSK

10/8/2012	6.3.4	**2**	Updated language about Natural forces not considered a threat.	JSK
10/8/2012	6.8.1	**2**	Added section 6.8.1 Build-overs	JSK
10/8/2012	7.5	**2**	Changed Risk model review to annual	JSK
10/8/2012	8.1.5/8.1.6	**2**	Moved Service Tee Cap A/A action to Material, Weld or Joint Failure from Equipment Failure	JSK
10/8/2012	9	**2**	Updated list of Performance measures listed	JSK
10/8/2012	9.5	**2**	Updated language on tracking Hazardous leaks by material	JSK
10/8/2012	New 9.6	**2**	Added Known system leaks at end of year scheduled for repair as a performance measurement	JSK
10/8/2012	New 9.7	**2**	Added Number of ABS services in system at end of year as a performance measure	JSK
10/8/2012	New 9.9	**2**	Added section 9.9 Effectiveness Measures to define how the performance measures are evaluated	JSK
10/8/2012	9.1	**2**	Changed effectiveness review from periodic to annual	JSK
10/8/2012	10.1	**2**	Updated plan review language and changed review timeline from periodic to once per calendar year. Updated bullets to match flowchart 10-0	JSK
10/8/2012	Appendix A-2	**2**	Added new appendix A-2 that lists all the attributes that are collected on newly constructed facilities in GIS	JSK
10/8/2012	Appendix A-3	**2**	Added new appendix A-3 that evaluates the amount of missing data in the GIS system	JSK
10/8/2012	Appendix C-3	**2**	Updated for clarity	JSK
10/8/2012	Appendix D-1	**2**	Renamed Performance Measure to Effectiveness Measure	JSK
10/8/2012	Appendix E-1	**2**	Added new Appendix E-1 to record baseline for all performance measures	JSK
10/8/2012	Appendix E	**2**	Renumbered remaining appendices in E to account for the new E-1	JSK

10/8/2012	Appendix E-4	**2**	Renamed to report hazardous leaks by material	JSK
10/24/2012	New 9.6	**3**	Added Number of Miles of Bare Steel Main in the System at End of Year as a Performance Measure	JSK
10/24/2012	New 9.7	**3**	Added Number of Bare Steel Services in the System at End of Year as a Performance Measure	JSK
11/1/2012	3.1 Table 1	**3**	Updated IMP Org Chart	JSK
11/1/2012	6.7.3	**3**	Modified language of Mechanical fitting failures to remove frost heave as a failure mechanism. Added language that icing from pressure cut may cause a failure. Also added language that mechanical fitting failure may be classified as Natural Forces or Excavation Damage depending on root cause of failure.	JSK
11/1/2012	5.4	**3**	Added language that newly installed pipe must meet the requirements of Engineering Standard 27-001, and Engineering Specification 003 and 004.	JSK
11/5/2012	7.4	**3**	Added validation process for DIMP Risk Model	JSK
4/1/2013	Entire Document	**4**	Revision Date to 3.1 and updated documents date. Spelling and other minor corrections are not individually noted.	RRT
4/1/2013	5.2	**4**	Changed reference from Mapframe help document to Fieldsmart User's Guide	RRT
4/1/2013	6.1.1	**4**	Updated reference from 6.3 to 6.1.2 regarding SME approach to threat identification.	RRT
4/1/2013	6.1.3	**4**	Simplified reference to NTSB website. Web links in the DIMP plan were broken. "Reports may be found at: http://www.ntsb.gov/Publictn/P_Acc.htm; Recommendation Letters may be found at: http://www.ntsb.gov/recs/letters/". Changed to read…	RRT

			"Reports and recommendation letters may be found at: http://www.ntsb.gov"	
4/1/2013	6.6.6	**4**	Removed reference to Aldyl-A from this section	RRT
4/1/2013	6.6.7	**4**	Added section to reference to Aldyl-A	RRT
4/1/2013	8.1.5	**4**	Added "Vintage Plastic Replacement" and "Aldyl-A" to material replacement list.	RRT
4/1/2013	8.1.8	**4**	Added Section 8.1.8 to address Build-Over's as an A/A.	RRT
4/1/2013	8.1.8	**4**	Renumbered 8.1.8 to 8.1.9 to accommodate "Other" threats after Build-Overs were added as an A/A.	RRT
4/1/2013	9	**4**	Changed "ABS services" to "Vintage Plastic" per change to section 8.1.5	RRT
4/1/2013	Appendix D Table D-1	**4**	Added Build-Over's to list of DIMP A/A.	RRT
4/1/2014	Entire document	**5**	Miscellaneous spelling and grammar	RRT
4/1/2014	1	**5**	Updated customer count 600,000 to 695,000	RRT
4/1/2014	Table 1	**5**	Updated Org Chart	RRT
4/1/2014	5.1.2	**5**	Updated vendor name "GL" to "DNV GL"	RRT
4/1/2014	5.1.2	**5**	Change "imported" to "referenced" to reflect actual practice.	RRT
4/1/2014	5.1.3	**5**	Added information regarding implementation of ERV (Engineering Records Viewer)	RRT
4/1/2014	5.1.5	**5**	Re-worded to clarify PragmaCAD's role	RRT
4/1/2014	5.4	**5**	Changed reference to Engineering Specifications "004" to MTS-003" and "003" to MTS-001"	RRT
4/1/2014	6.2.2	**5**	Changed "NW Natural is aware of one area where…" to "NW Natural is aware of areas where…"	RRT
4/1/2014	6.2.3	**5**	Changed "(paint)" to "(epoxy/paint)" in the 3rd paragraph.	RRT

4/1/2014	6.6.7	**5**	Added sentence “All know Aldyl A services were removed from NW Natural’s system in 2013.” To the end of the paragraph.	RRT
4/1/2014	8.2.4	**5**	Changed “Advantica” to “DNV-GL Essentials” to reflect proper name of product.	RRT
4/1/2014	Appendix D-3	**5**	Updated performance metrics with 2012 and 2013 data.	RRT
3/31/2015	All sections	**6**	Updated dates and footer information to reflect annual review	RRT
3/31/2015	1	**6**	Updated customer count to 700,000	RRT
3/31/2015	3.1.2	**6**	Changed “Integrity Management Supervisor” to “ Manager of System Integrity” to reflect current organizational structure.	RRT
3/31/2015	Table 1	**6**	Changed titles in IMP Organizational Chart to reflect organizational structure and retirement of Bruce Paskett	RRT
3/31/2015	Section 5.1.2	**6**	Updated name of vendor “(Essentials by Advantica/DNV-GL)” modified to “(Essentials by DNV-GL)”	RRT
3/31/2015	Section 5.1.3	**6**	Replaced references to “FileNet” with “ERV”.	RRT
3/31/2015	Section 5.1.3	**6**	Removed “a digital record database”. Currently records are stored in a shared drive and ERV is used to retrieve information using meta-data.	RRT
3/31/2015	Section 6.8.2	**6**	Last sentence of this section was added to describe the implementation of the sewer cross bore program in 2013.	RRT
3/31/2015	Section 8.1.7	**6**	Removed “and develop a plan” from first bullet point. The plan was developed in 2013.	RRT
3/31/2015	Table D-1	**6**	In the row pertaining to “Corrosion” the completion date of bare steel replacement was changed from 2021 to 2015 to reflect revised agreement with OPUC to accelerate bare steel replacement.	RRT

3/23/2016	All sections	**7**	Updated dates and footer information to reflect annual review	CAW
3/23/2016	1	**7**	Changed over 700k to approximately	CAW
3/23/2016	Table 1	**7**	Removed Andrea Kuehnel from Chart	CAW
3/23/2016	Table 1	**7**	Changed Compliance Mgr. to Joe Karney	CAW
3/23/2016	4	**7**	Added ERV to definitions	CAW
3/23/2016	6	**7**	Added order # to threat list	CAW
3/23/2016	All 6	**7**	changed order/% of threats and from date to range to present	CAW
3/23/2016	6.2.1	**7**	Removed 1% bare and non-catholically protected steel. Add completion of bare	CAW
3/23/2016	6.2.3	**7**	Removed high humidity and atmospheric pollutants	CAW
3/23/2016	6.2.3	**7**	Revised SP 465 to 480	CAW
3/23/2016	8.1	**7**	Revised to show A/A's in chart Appendix D instead of here	CAW
3/23/2016	8.1.9	**7**	Re-numbered to 8.1.1 after removing A/A's	CAW
3/23/2016	9.6	**7**	Added completed 2015 to bare	CAW
3/23/2016	9.7	**7**	Added completed 2015 to bare with ongoing research to validate.	CAW
3/23/2016	9.8	**7**	Added see chart in Appendix D-3	CAW
3/23/2016	9.12	**7**	Added - with charts and or data to last sentence	CAW
3/23/2016	10	**7**	Added the word <u>of</u> to the first sentence	CAW
3/23/2016	Appendix A-3	**7**	Updated date to GIS query missing data chart	CAW
3/23/2016	Appendix D-3	**7**	Updated Key Program Key to 2015	CAW
3/23/2016	Appendix E-5 to E9	**7**	Added trend charts	CAW
3/23/2016	Appendix E	**7**	Added Bare Chart	CAW
3/23/2016	Contents	**7**	re-numbered to reflect page changes	CAW
3/17/2017	Cover	**8**	Changed Cover Date	CAW
3/17/2017	All Pages Footer	**8**	Changed Rev and date	CAW
3/17/2017	1	**8**	Updated customer count	CAW
3/17/2017	3.1 Table 1	**8**	Updated Org Chart	CAW

3/17/2017	Appendix A-3	**8**	Distribution query change date for data	CAW
3/17/2017	Appendix E-2	**8**	Dist Annual Report show years of reports	CAW
3/17/2017	Appendix E-4 to E10	**8**	Update to show up to current year	CAW
4/4/2018	Page 1 (cover)	**9**	Changed Date	CAW
4/4/2018	Page 12 Table	**9**	Formatted and updated ORG.	CAW
4/4/2018	Page 27	**9**	Re-ordered Risk	CAW
4/4/2018	Page 101	**9**	Entered System MAOP DIMP 57-60	CAW
4/4/2018	Charts in back	**9**	added 2017 data	CAW
4/4/2018	Bottom of pages	**9**	updated REV and Date	CAW
4/4/2019	Bottom of pages	**10**	updated REV and Date	CAW
4/4/2019	Charts in back	**10**	Added 2018 data	
3/30/2020	Page 1 (cover)	**11**	Updated Company Address	SRL
3/30/2020	Page 1 (cover)	**11**	Changed Cover date	SRL
3/30/2020	All Pages	**11**	Changed Rev and date	SRL
3/30/2020	1.0	**11**	Updated customer count	SRL
3/30/2020	3.1 Table 1	**11**	Updated Org Chart	SRL
3/30/2020	4.0	**11**	Updated Definitions to include Standard Practice acronyms	SRL
3/30/2020	All Sections	**11**	Added Washington Standard Practice (SPW) where appropriate	SRL
3/30/2020	5.4	**11**	Added Engineering Standard for Poly Pipe	SRL
3/30/2020	All of Section 6	**11**	Updated date range to 2010 to 2019 and reflect latest data	SRL
3/30/2020	6.7.3	**11**	Revised classification of mechanical coupling failure	SRL
3/30/2020	Appendix E-4 to E-10	**11**	Updated with 2019 data	SRL
4/2/2021	Page 1 (Cover)	**12**	Changed Cover Date	SRL
4/2/2021	All Pages	**12**	Changed revision and date	SRL
4/2/2021	1.0	**12**	Updated customer count	SRL
4/2/2021	2.1	**12**	Updated Standard Practice definition	SRL
4/2/2021	3.1 Table 1	**12**	Updated Org Chart	SRL
4/2/2021	4	**12**	Clarified definition of “damage”	SRL
4/2/2021	5.1.4	**12**	Updated to show that Damage Prevention data is stored on Sharepoint.	SRL

4/2/2021	5.1.6	**12**	Updated headings of Annual Report to reflect current PHMSA Annual Report	SRL
4/2/2021	5.2	**12**	Updated location of Pipe Inspection Report to P-Cad	SRL
4/2/2021	Section 6	**12**	Updated years and ranking of threats	SRL
4/2/2021	8.2	**12**	Updated Leak Management FOM reference	SRL
4/2/2021	11.1	**12**	Added EFVs and Service line valves as an Annual Reporting requirement.	SRL
4/2/2021	Appendix D-1	**12**	Added Class A services and Enhanced EFV program as new A/As	SRL
4/2/2021	Appendix E-1	**12**	Noted that Bare Steel is a completed A/A and will no longer be tracked due to no known bare steel in the NW Natural system	SRL
4/2/2021	Appendix E-4 to E-6	**12**	Updated with 2020 data	RVP
4/2/2021	Appendix E-8	**12**	Updated with 2020 data	RVP
4/2/2021	Appendix E-7 & E-9	**12**	Updated with 2020 data	RVP
4/1/2022	Page 1 (Cover)	**13**	Changed Cover Date	SRL
4/1/2022	All Pages	**13**	Changed revision and date	SRL
4/1/2022	1.0	**13**	Updated customer count	SRL
4/1/2022	2.0	**13**	Added that NW Natural does not own nor operate Gathering Lines	SRL
4/1/2022	3.1 Table 1	**13**	Updated Org Chart	SRL
4/1/2022	5.4	**13**	Added that abandoned or out of service facilities will be part of as build	SRL
4/1/2022	6.2.2	**13**	Updated percentages of poly and steel in the distribution system.	SRL
4/1/2022	Appendix A-2	**13**	Noted that pressure tests for high pressure distribution services are verified, but not an attribute in GIS	SRL
4/1/2022	Appendix D-3	**13**	Updated with 2021 data	LMG
4/1/2022	Appendix E-1	**13**	Added Performance measures Sunshields and Proactive EFVs as AAs	SRL
4/1/2022	Appendix E-4 to E-6	**13**	Updated with 2021 data	LMG
4/1/2022	Appendix E-8	**13**	Updated with 2021 data	LMG
4/1/2022	Appendix E-7 to E-10	**13**	Updated with 2021 data	LMG
4/3/2023	Page 1 (Cover)	**14**	Changed Cover Date	SRL
4/3/2023	All Pages	**14**	Changed revision and date	SRL

NW Natural

Distribution Integrity Management Program

Program Plan

4/3/2023	All Pages	**14**	Various format changes to make document more consistent and improve navigations within the document	SRL
4/3/2023	Table 1	**14**	Changed organization chart to add Joe Karney as VP of Engineering and Operations, added Willy Durig as Integrity Analyst and added Laurel Garrett as GIS Specialist	SRL
4/3/2023	3.1	**14**	Updated title of Vice President to include “Engineering”	SRL
4/3/2023	5.1.2	**14**	Removed reference of Asset Register and replaced with SAP due to implementation of new Asset Management system	SRL
4/3/2023	5.1.5	**14**	Replaced Pragma CAD and P-CAD with Clevest due to implementation of new Asset Management System	SRL
4/3/2023	5.1.6	**14**	Modified data in Annual report to reflect that Mechanical Fitting failure report is no longer submitted and that the number of mechanical fitting failures are listed in the Annual report	SRL
4/3/2023	6.6.3	**14**	Noted that all known ABS services have been removed	SRL
4/3/2023	11.3	**14**	Removed reference to Mechanical Fitting Failure report which is no longer required by PHMSA	SRL
4/3/2023	Table D-1	**14**	Updated year to complete Inside Services AA to 2025	SRL
4/3/2023	Table D-1	**14**	Updated completion date for service tee caps to “Upon Discovery”	SRL
4/3/2023	Table D-1	**14**	Updated completion date for Ineffective Coating to “Upon Discovery”	SRL
4/3/2023	Table D-1	**14**	Update completion date for Steel in Steel services to 2025	SRL
4/3/2023	Table D-1	**14**	Updated completion date for Difficult to Turn Valves to “Upon Discovery”	SRL
4/3/2023	Table D-1	**14**	Updated completion date for Wayne Manufactured Risers to “Upon Discovery"	SRL
4/3/2023	Table D-1	**14**	Updated completion date for Sewer Cross Bores to “On going”	SRL
4/3/2023	Table D-1	**14**	Updated completion date for Buildovers to “Upon Discovery”	SRL
4/3/2023	Table D-1	**14**	Updated completion data for Records and SIP video as “Completed”	SRL

4/3/2023	Table D-1	**14**	Updated completion date for MAOP to 2025	SRL
4/3/2023	Appendix D-3	**14**	Updated with 2022 data	SRL
4/3/2023	Appendix E-4 to E-10	**14**	Updated with 2022 data	SRL
4/1/2024	Page 1 (Cover)	**15**	Changed Cover Date	SRL
4/1/2024	All Pages	**15**	Changed revision and date	SRL
4/1/2024	Section 1.0	**15**	Updated Customer Count	SRL
4/1/2024	Section 3.0	**15**	Replaced Code references to cover the entire Subpart P	SRL
4/1/2024	Section 5.1.6	**15**	Reflected change in PHMSA Annual report where number of EFVs is no longer a required field	SRL
4/1/2024	Section 6.2.1	**15**	Updated percentages of poly and steel based on Annual Report data	SRL
4/1/2024	Section 11	**15**	Removed the EFV requirement due to updated PHMSA annual report	SRL
4/1/2023	Appendix D-3	**15**	Updated with 2023 data	SRL
4/1/2023	Appendix E-4 to E-10	**15**	Updated with 2023 data	SRL
3/31/2025	Page 1 (Cover)	**16**	Changed Cover Date	SRL
3/31/2024	All Pages	**16**	Changed Revision and date	SRL
3/31/2025	Section 2.1	**16**	Added Engineering Specifications, Standards and Procedures as other documents referenced in this plan	SRL
3/31/2025	Section 3.1, Table 1	**16**	Updated NW Natural IMP Organization charts to reflect new personnel and NW Natural holdings company	SRL
3/31/2025	Section 4	**16**	Updated definition of D.I.R.T.	SRL
3/31/2025	Section 5.1.1	**16**	Included definition of IQGeo	SRL
3/31/2025	Section 5.2	**16**	Revised process to implement map corrections using IQGeo	SRL
3/31/2025	Section 5.4	**16**	Removed MapFrame reference as that system has been retired	SRL
3/31/2025	Section 6.1.3	**16**	Removed outdated link to PHMSA and NTSB site	SRL
3/31/2025	Section 6.4.5	**16**	Included IQGeo as the process to implement mapping changes	SRL
3/31/2025	Table D-1	**16**	Added Dithiazine as an Accelerated Action	SRL
3/31/2025	Table D-1	**16**	Added Idle Risers as an Accelerated Action	SRL
3/31/2025	Table D-1	**16**	Added valves between MAOPs as an Accelerated Action	SRL

3/31/2025	Appendix D-3	**16**	Updated with 2024 data	SRL
3/31/2025	Appendix E-4 to E-10	**16**	Updated with 2024 data	SRL

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Direct Testimony of Wayne K. Pipes

FACILITIES

Exh. WKP-1T

August 29, 2025

DIRECT TESTIMONY OF WAYNE K. PIPES

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position at Northwest Natural Gas Company ("NW Natural" or "the Company").

A. My name is Wayne K. Pipes. I am the Director of Facilities, Security and Emergency Management for NW Natural. I am responsible for facilities, real estate, security and emergency management activities for NW Natural, which includes planning and management of real estate, construction, capital projects, maintenance, and security and emergency management for NW Natural's facilities.

Q. Please summarize your educational background and business experience.

A. I have over 38 years of facilities management and construction experience. I have been employed at NW Natural since 2014. Before assuming my current position at NW Natural in 2014, I worked for New Seasons for a year as Director of Design, Construction, and Facilities Management. I also worked for Knowledge Universe for 15 years as Vice President of Facilities and Development, and for Red Lion Hotels for 17 years as Senior Director of Facilities Management.

Q. What is the purpose of your testimony?

A. The primary purpose of my testimony is to describe major facilities projects that are included in this rate case. Specifically, I will discuss The Dalles Resource Center ("The Dalles RC") and physical security upgrades the Company is undertaking at various sites.

Q. Please provide a summary of your testimony.

A. I will discuss the major facilities projects included in this rate case. These projects will enhance security and improve The Dalles RC, which will increase functionality and

support ongoing safe and efficient operations. A summary of the projects is below:

- The Dalles Resource Center – As part of the Company's on-going facilities strategy, NW Natural will be relocating The Dalles RC to a new location in The Dalles, Oregon. I give an overview of The Dalles RC Project and why the Company is replacing the current facility (i.e., the current facility/site is too small and does not include the NW Natural standard equipment and functionality that is required for efficient and safe operations). I also discuss the purchase of a new piece of land to build the new facility. The land purchase will occur in 2025, and The Dalles RC Project will be complete in October 2026.
- Security Enhancements - NW Natural is making physical security enhancements at its facilities and field infrastructure through a multi-year effort. Enhanced physical security is necessary in response to increasing threats to facilities and direction from the United States Department of Homeland Security's Transportation Security Administration ("TSA") about those threats. These annual enhancements will continue and should be completed in 2028.

Q. Have you prepared exhibits to accompany your testimony?

A. Yes. The exhibits to my testimony are:

- Exh. WKP-2 – KPFF Report – The Dalles Resource Center
- Exh. WKP-3 – The Dalles Resource Center Alternatives Analysis
- Exh. WKP-4 – Cushman & Wakefield Report
- Exh. WKP-5 – Physical Security Enhancements Alternatives Analysis
- Exh. WKP-6C – 2022 RFP Site Security Upgrades Summary

- Exh. WKP-7 – 2018 Pipeline Security Guidelines
- Exh. WKP-8 – TSA Directives 2021-01E and 2021-02F

II. DISCUSSION OF PROJECTS INCLUDED IN THIS CASE

A. The Dalles Resource Center Project

Q. Please provide an overview of the existing resource center in The Dalles and the operations there.

A. NW Natural operates a resource center in The Dalles, Oregon, which is essential for supporting the delivery of safe and reliable service across Klickitat and Skamania Counties in Washington as well as Hood River and Wasco Counties in Oregon. NW Natural currently leases this property, and the lease expires at the end of 2026. The leased area is one-half acre and includes a prefabricated steel building. The building consists of a single-story 65-foot by 40-foot garage, a 19-foot by 40-foot ground-floor office, and a 19-foot by 40-foot mezzanine office above the ground floor, totaling about 4,100 square feet. The site also features a microwave tower. Ten employees work from this site, representing Customer Field Services, Construction, Emergency Response, and Community Affairs.

The services provided out of this location include customer field services, construction, transmission maintenance, leakage inspection, system operations, and field engineering. The facility also provides materials and equipment storage.

Q. Why is The Dalles Resource Center Project necessary?

A. The Dalles RC Project is necessary for several reasons. First, as mentioned above, the lease is expiring in December 2026. NW Natural's standard procedure in these situations is to evaluate whether the Company could potentially extend the lease or if

other alternatives, such as relocation, should be considered. This evaluation occurred during the period 2018-2020, at the end of which the best path forward identified was relocation. The current site (half acre) has become wholly inadequate and the daily operations at this location have simply outgrown the site. The evaluation determined that approximately 2.5 acres are needed for efficient ongoing and future operational functionality.

Second, the office building lacks current standard NW Natural functionality. It does not have a conference room, a write-up room, a drying room, or changing room and showers, and the kitchen is inadequate. The existing site is too small to support current operational needs like a vehicle fueling system, pipe storage, truck scale, truck and equipment wash system and a decant system. The site also lacks and cannot accommodate sufficient indoor covered storage for Company tools and materials, or enclosed parking for specialty equipment, to protect it from the environment. The site also lacks space to accommodate adequately sized storage bins for rocks and sand. The absence of a decant system means employees must drive 23 miles one way (1.5-hour round trip) to dispose of wet spoils. Similarly, the lack of a covered spoils bin requires employees to drive five miles one way (20-minute round trip) to dispose of dry spoils. NW Natural must relocate to a new site because it cannot overcome size constraints in the existing facility to adequately provide for these functional operational improvements.

Third, a seismic assessment of the metal building was completed in 2016 by KPFF Engineering (Exh. WKP-2) and concluded that the building does not meet current life-safety building codes, raising concerns about employee safety and the

ability to operate after a seismic event. Additionally, the lack of onsite fueling could hinder NW Natural's response capabilities during a major natural disaster.

In sum, The Dalles RC Project is necessary because the current lease is expiring, the existing site lacked seismic resiliency, and the buildings and site are too small to accommodate required operations functionality and to enhance efficiency and employee safety.

Q. What alternatives did the Company consider before selecting The Dalles Resource Center land?

A. The Company considered several alternatives as summarized in Exh. WKP-3. The Company's broker, Cushman & Wakefield, conducted an extensive two-year search and evaluated several properties, and the site of the new The Dalles RC was the only available property that met the Company's requirements for an adequately sized space in an appropriately zoned area. The new property is large enough to accommodate the Company's new purpose-built building and necessary equipment and vehicle storage. The property was also desirable because it was the lowest cost and carried lower risk for zoning approval. The Cushman and Wakefield Report is provided as Exh. WKP-4.

Q. What steps did the Company take after selecting The Dalles site?

A. The Company enlisted the help of various consultants to conduct due diligence on the potential new site that included site design; civil and geotechnical engineering; environmental evaluation; construction estimating; planning, zoning, and construction evaluation; and engagement with The Dalles Planning Department. The Company

determined based on its due diligence that the new site would meet current requirements for a resource center.

Q. How is The Dalles Resource Center Project important to the Company's business continuity planning?

A. The Dalles RC is the Company's only facility in the Columbia Gorge. The resource center is essential to the Company's ability to perform basic utility functions and serves as a center for Company regional emergency response. The Dalles RC project will increase Company emergency response readiness by providing a new facility that will be operational following a major seismic event. Additionally, NW Natural will install a fueling station that will be available for Company use during emergencies that could impact retail fueling stations.

Q. Please describe the scope of The Dalles Resource Center Project.

A. The Company will construct and move into a new facility on the newly purchased site. The new facility will include an office building and warehouse that will be designed to be operational following a significant seismic event. The new facility will also provide various yard support infrastructure, including a covered pipe storage shed, enclosed specialty equipment storage garage attached to the pipe storage building, a spoils and decant system shed, a fuel tank within a fueling canopy, and a truck wash room that includes a Landa unit for separating oil from water.

The project will also include basic general site improvements like landscaping, yard lighting, parking area striping and bollard installation, fencing, and motorized driveway gates, and the Company will construct the building with necessary features like HVAC, plumbing, and mechanical systems and furniture.

Q. Please describe the office building and warehouse the Company will construct at The Dalles Resource Center.

A. The Company will construct both an office building and a warehouse designed to be operational following a significant seismic event. The office building will include offices, a write-up room, a non-commercial galley, locker rooms with showers, a drying room, and a data room. The Company will utilize the warehouse to store the various tools and equipment necessary to support operations at The Dalles RC.

Q. Please explain why the Company needs the various outbuildings and equipment at The Dalles Resource Center.

A. The functionality of The Dalles RC aligns with the functionality of NW Natural's resource centers across its service territory to support Company operations, safety, and resiliency objectives. I also explained the need for each of these structures, systems, and pieces of equipment in my testimony in docket UG-200994 (Exh. WKP-1CT, page 5, lines 11-15) for the updated and retrofitted Vancouver Resource Center where I state that NW Natural:

> " . . . will address improvements to the yard, including construction of outbuildings to provide for needed storage, covered spoils bins, specialty equipment garage, decant system, vehicle fueling station, truck wash booth and equipment, and site work, including paving, lighting and fencing."

I provide the following additional detail for each of the site features described above.

Q. Why is the covered pipe storage needed?

A. There is no existing covered storage space at The Dalles Resource Center for pipes and special equipment. Because the Company's pipes require protection from ultraviolet ("UV") light, the Company has had to use tarps to provide UV protection, which may

increase the risk of injury to NW Natural personnel when removing and tarping polyethylene pipe.

Q. How will the Company use the specialty equipment garage?

A. During freezing weather, critical equipment has been stored in the mechanic garage area at night and then removed in the morning to allow mechanics to utilize the garage. The specialty equipment garage will provide heated storage space and a permanent home for temperature sensitive equipment such as the vacuum truck and vapor extraction unit.

Q. Why did NW Natural decide to install a fueling station?

A. The fueling station will improve productivity by allowing employees to fuel their vehicles and equipment while on site at the beginning and end of their shifts, without having to rely on driving to retail gas stations. Additionally, as I discussed above, the fueling station will support the Company's business continuity objectives by providing an independent on-site fuel source in the event of a major disaster limiting access to retail fueling sources.

Q. What is the decant system and why is it important to NW Natural's The Dalles operations?

A. The decant system is used to remove liquids from soils removed during excavation work (also called "spoils") completed by utility operations. The liquids are removed by placing the soil in the decant system, which is a sloped containment bin that enables liquids to separate from the soil by allowing settling of the heavier solid materials and evaporation and draining of the liquids.

The decant system is important to NW Natural's The Dalles field operations because disposal of spoils is required to support the Company's construction projects—including large capital projects, system reinforcement projects, main extensions, new service installations, customer relocates, and cut and abandons—that involve vacuum excavation and horizontal directional drilling operations. Environmental compliance requirements are continuing to reduce the availability for disposal sites, and as a result, sites accepting spoils are overcrowded with vehicles and pose safety concerns for the Company's employees when entering sites, during spoil disposal, and exiting sites. Additionally, due to the limited availability of sites accepting spoils, NW Natural has often needed to haul spoils to far away alternate locations, which is an inefficient use of resources in terms of both fuel and employee time. Due to the above issues, NW Natural is planning to install these systems at all resource centers over the next several years.

Q. How are the spoils bins used in the Company's operations?

A. The spoils bins are used for storage of sand and gravel, which is used for fill material in construction, and are also used for storage of material removed during excavation activities, which may include soils, asphalt, and other materials. These materials are stored on site in the spoils bins on an ongoing basis and then hauled off to a disposal site in larger quantities for efficiency.

Q. Why is the truck scale needed?

A. The truck scale is a safety measure to ensure that NW Natural's trucks and trailers meet applicable weight limitations to avoid overloading with equipment and materials.

Q. Why is the truck wash needed?

A. The truck wash system is used for cleaning all vehicles and equipment used at The Dalles Resource Center, which includes dump trucks, backhoes, trailers, specialty equipment, pickup trucks, and service vans. Keeping this equipment clean improves safety by ensuring equipment can be inspected properly prior to use, and helps maintain the equipment and extends its life expectancy.

Q. What is the timing associated with The Dalles Resource Center Project?

A. The Company expects to purchase the new property in September 2025. The Company is in the early stages of designing the new facility and expects to complete The Dalles RC and place it into service in October 2026, in Rate Year 1.

Q. What will the Company do to maintain service between the time it vacates the existing facility and when it starts utilizing the new The Dalles Resource Center?

A. The Company will continue to occupy its existing facilities until the new The Dalles RC is completed. The lease at the existing property expires on December 31, 2026.

Q. Please describe the Company's proposal for cost recovery for The Dalles Resource Center Project.

A. The Company is seeking to include $17.6 million as an addition to rate base, or $4.4 million on a Washington-allocated basis. The allocation is based on the number of customers served by The Dalles Resource Center in Washington versus Oregon.

B. Security Upgrades

Q. Please summarize the security upgrades NW Natural is undertaking.

A. In response to increasing threats and new direction from TSA, NW Natural is undertaking a comprehensive, multi-year effort to enhance the physical security at the

Company's facilities and field infrastructure. The initial phase of this effort included a pilot program to complete upgrades at five high-priority sites in 2023.

After the pilot concluded, NW Natural began implementing security upgrades more broadly in 2024. The Company anticipates completing multiple sites per year over the next three or four years. I have included Exh. WKP-5, the alternative analysis for the Physical Security Upgrades completed in December 2024. Currently, NW Natural anticipates that all security upgrades will be completed by 2028.

Q. How did NW Natural determine that security upgrades are necessary?

A. A variety of emerging threats and new requirements over the last six years have led NW Natural to evaluate and prioritize physical security upgrades. The Company began working on a physical security strategy and roadmap in 2017 to address issues of employee and public safety posed by potential security breaches. The first step in this process was to document all physical security apparatuses associated with Company facilities and identify potential risks. To aid in this effort, NW Natural engaged a consulting firm, CH2M, in 2017 to develop a criticality ranking and asset protection recommendations. With input from NW Natural subject matter experts, CH2M completed the criticality ranking of the Company's facilities and field infrastructure in early 2018.

In March 2018, TSA—the federal agency that oversees pipeline safety—issued pipeline security guidelines that contained recommendations regarding assessing the risks of and implementing site-specific security measures at both critical and non-

critical facilities.[1] See Exh. WKP-7. The TSA updated these guidelines in 2021, creating a mechanism for designating "critical" facilities to ensure these sites have sufficient security to avoid service disruptions to important infrastructure and to the public at large.

Following the May 2021 ransomware attack on the Colonial Pipeline, TSA issued several directives mandating cybersecurity measures. See Exh. WKP-8. One way that these directives enhance cybersecurity is by addressing physical security, because TSA recognized that unauthorized access to physical facilities could enable a bad actor to obtain access to cyber systems. Along with the pipeline security guidelines, the cybersecurity directives related to physical security highlighted the importance of NW Natural's ongoing efforts to strengthen physical security and the need to accelerate and expand those efforts.

In June 2022, TSA conducted an audit of several NW Natural sites classified as "critical" infrastructure, and the TSA audit recommendations also informed the Company's planned upgrades during the pilot and at other sites.

Finally, the United States in general has seen a recent uptick in attacks on the energy system, including intentional destruction of critical infrastructure, and the Company has experienced a number of break-ins and theft at the Company's resource centers. For all these reasons, NW Natural decided to address physical security upgrades in a comprehensive way—first by pursuing the pilot and then the broader program.

[1] Transportation Security Administration, *Pipeline Security Guidelines* (March 2018; updated April 2021), *available at* https://www.tsa.gov/sites/default/files/pipeline_security_guidelines.pdf.

Q. Please provide additional detail regarding the pilot program.

A. NW Natural designed the pilot program to help the Company refine its choice of technology/equipment, procurement strategy, quality assurance, risk management, cost estimates, and efficient execution of security upgrades. In particular, the pilot was designed so the Company could improve its knowledge of costs, supply chain issues, and equipment that may need long lead time; test various price breaks for purchasing materials needed in bulk; and identify efficiencies from conducting upgrades at multiple sites or along with unrelated projects at specific sites.

The Company's facilities and field infrastructure include more than 1,200 sites, and because security upgrades can be costly, it is not feasible to complete every recommended upgrade at each site. Instead, the pilot included more limited upgrades at each site—for example, installing an anti-climb attachment to an existing fence rather than installing an entirely new anti-climb fence; using automated fence monitoring that can sense human movement; employing uncuttable fencing materials; and using key cards along with security codes for access to sensitive information. Following the pilot, NW Natural evaluated the general contractor, Essex Construction, that implemented the pilot and overall project implementation to determine the most efficient and effective approach to security upgrades more broadly. The Company's post-pilot focus is on choosing durable materials and mechanisms that result in stronger physical and cyber security.

Q. Who is the general contractor for the broader security upgrade program, and how did NW Natural select them?

A. The general contractor is Essex Construction, and NW Natural selected them through a request for proposals process in which they achieved the highest score and were the lowest cost. Essex Construction has experience working with other utilities in this type of work. A summary of the Request for Proposals is included as confidential Exh. WKP-6C.

Q. Please provide specific examples of the types of security upgrades that will be undertaken at program sites.

A. The scope varies from site to site and can include one or more of the following: New fencing, anti-climb fencing, lighting, video surveillance systems, intelligent intrusion detection systems, enhanced gates, gate alarms, and/or radar stations and signage. The list of NW Natural sites requiring physical security upgrades in Washington comprises primarily of telemetry sites, district regulator stations, and gate stations.

Q. How will the security upgrades provide benefits?

A. Security upgrades provide several benefits: They improve customer and employee safety; protect property, plant and equipment; and improve cyber security at locations that are connected to the Company's gas control system. They also ensure NW Natural is compliant with requirements from regulators—specifically the TSA. And, they help ensure the Company's system can continue providing safe and reliable service to customers without interruption.

Q. What is the Company's current forecasted cost for the security upgrades?

A. The Company estimates it will complete an additional $2.5 million in upgrades annually from 2025 through 2028. This equates to approximately $375 thousand annually on a Washington-allocated basis.

Q. What is the Company's anticipated timing for these projects?

A. Various sites are completed each year, and the Company is anticipating the work to be completed in 2028.

Q. Does this conclude your Direct Testimony?

A. Yes.

II. LIST OF EXHIBITS

Exh. WKP-2	KPFF Report-The Dalles Resource Center
Exh. WKP-3	The Dalles Resource Center Alternatives Analysis
Exh. WKP-4	Cushman & Wakefield Report
Exh. WKP-5	Physical Security Enhancements Alternatives Analysis
Exh. WKP-6C	2022 RFP Site Security Upgrades Summary (Confidential and Redacted)
Exh. WKP-7	2018 Pipeline Security Guidelines
Exh. WKP-8	TSA Directives 2021-01E and 2021-02F

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Wayne K. Pipes

FACILITIES

Exh. WKP-2

August 29, 2025

ASCE 41-13 Tier 1 Seismic Evaluation of

NW Natural – The Dalles Service Center

1125 Bargeway Road
The Dalles, OR 97058

August 5, 2016
KPFF Project No. 1600122

NW Natural – The Dalles Service Center
ASCE 41-13 Tier 1 Seismic Evaluation

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Appendix ASCE 41-13 Summary Data Sheet & Checklists

Introduction

This report is to summarize the findings of our seismic evaluation of the NW Natural The Dalles Service Center located at 1125 Bargeway Road, The Dalles, OR. The evaluation was performed using the procedures of ASCE 41-13 "Seismic Evaluation and Retrofit of Existing Buildings." Please note that this evaluation only relates to the seismic performance of the structure. It does not address issues related to gravity framing.

Scope and Intent

KPFF Consulting Engineers was contracted to perform a Tier 1 seismic evaluation of the NW Natural The Dalles Service Center located in The Dalles, Oregon. This evaluation is based on a site visit that was completed on May 3, 2016, and upon the procedures of ASCE 41-13 "Seismic Evaluation and Retrofit of Existing Buildings." The intent of the evaluation is to determine if the structure meets the acceptance criteria of the Basic Performance Objective for Existing Buildings (BPOE). For this evaluation, the building was considered a Risk Category II building (i.e. a standard building occupancy) as defined by the International Building Code and the Oregon Structural Specialty Code. Therefore, the BPOE requires meeting the Life Safety Structural Performance level at the BSE-1E seismic hazard level, and the Life Safety Nonstructural Performance level also at the BSE-1E seismic hazard level. The City of Portland, chapter 24.85, stipulates that the BSE-1E seismic hazard level shall not be taken as less than 75 percent of the BSE-1N seismic hazard level. This City of Portland requirement is being applied to all NW Natural evaluations as to provide a consistent evaluation process across all locations. Life Safety, BSE-1E, and BSE-1N are defined as follows:

- Life Safety is a structural performance level in which a structure has significantly damaged components but retains a margin against the onset of partial or total collapse. It is possible that the structure will be damaged to the extent that it is not practical to repair and re-occupy the building.

- BSE-1E is a seismic hazard level that represents an earthquake that has a probability of exceedance of 20% in a 50 year period. This can also be thought of as an earthquake that is not expected to be exceeded in a 225 year return period.

- BSE-1N is two thirds of a seismic hazard level that represents an earthquake that has a probability of exceedance of 2% in a 50 year period multiplied by a risk coefficient. This can also be thought of as two thirds of the ground acceleration of an earthquake that is not expected to be exceeded in a 2,475 year return period.

Site and Building Data

The NW Natural The Dalles Service Center is an existing pre-engineered and prefabricated steel building, located at 1125 Bargeway Road, in The Dalles, Oregon. The original construction date is unknown. The overall building measures approximately 84 feet in the

northeast-southwest direction by 40 feet in the northwest-southeast direction. It consists of a single story 65-foot by 40-foot garage, a 19-foot by 40-foot ground floor office, and a 19-foot by 40-foot mezzanine office (above the ground floor office). The combined building is approximately 4,100 square feet.

The roof structure consists of corrugated metal roofing that spans between cold-formed metal joists. The joists span between transverse steel frames, and the frames are bolted to the slab/foundation. The lateral force resisting system in the northeast-southwest direction consists of metal roof decking and diagonal roof bracing, which transfer load to the transverse frames via bolted connections, and bolted connections transfer the load from the frames into wall diagonal bracing, and these diagonals are bolted to the base of the frames that are bolted to the slab/foundation. The lateral force resisting system in the northwest-southeast direction consists of metal roof decking and diagonal roof bracing, which transfer load to the transvers frames, and the frames are bolted to the slab/foundation.

List of Criteria Used for Analysis

A geotechnical investigation was not performed for this evaluation. It was assumed that classification of the soils at the site as Site Class D and the following ground motions were used for the analysis:

Parameter	Value	Comments
$S_{X1,\ BSE\text{-}1E}$	0.157 g	Design spectral response acceleration parameter at 1 second for the BSE-1E seismic hazard level.
$S_{XS,\ BSE\text{-}1N}$	0.458 g	Design short-period (0.2 seconds) spectral response acceleration parameter for the BSE-1N seismic hazard Level.
T	0.217 s	Building fundamental period, as defined in Section 4.5.2.4.
S_a	0.343 g	Response spectral acceleration parameter. S_a = minimum($S_{X1,\ BSE\text{-}1E}$ / T, 0.75$S_{XS,\ BSE\text{-}1N}$)

The Level of Seismicity for the structure is therefore considered to be “High” as defined by Section 2.5 of ASCE 41. Please reference the full summary of the evaluation assumptions listed in the appendix.

Findings

The building was evaluated using the Tier 1 checklists, including the “Life Safety Non-structural Checklist,” as required in Section 4.4 of ASCE 41-13. The building in its existing condition does not meet the requirements of the Basic Performance Objective for Existing Buildings (i.e. Life Safety structural performance at three-quarters of BSE-1N seismic hazard level, as amended by the City of Portland Chapter 24.85). The following table summarizes the deficiencies that were identified for the building per the Tier 1 checklists. Reference Appendix A for the summary data sheet and completed checklists.

Structural Deficiencies

No.	Item	Tier 1 Ref.	Comments
1	n/a	n/a	n/a

Note: There were no identified structural noncompliant items. However, the following list of structural unknowns may contain noncompliant items if evaluation was possible.

Structural Unknowns

No.	Item	Tier 1 Ref.	Comments
1	Load Path	A.2.1.1	It is unclear how the mezzanine attaches to the steel frames or if it is self-supported/braced. The metal building alone appears to have a complete load path.
2	Mezzanines	A.2.1.3	It is not clear how the mezzanine is laterally braced. The mezzanine connections to the main steel frame were not exposed to view, and the building structure drawings were not available for review.
3	Liquefaction	A.6.1.1	A geotechnical report was not available for review. However, the Oregon Department of Geology and Mineral Industries (DOGAMI) Statewide Geohazards Viewer does provide information on site hazards. Per DOGAMI's Hazard Viewer, this building site has a "low" earthquake liquefaction hazard.
4	Slope Failure	A.6.1.2	A geotechnical report was not available for review. However, the Oregon Department of Geology and Mineral Industries (DOGAMI) Statewide Geohazards Viewer does provide information on site hazards. Per DOGAMI's Hazard Viewer, this building site has a "high" landslide hazard.
5	Surface Fault Rupture	A.6.1.3	A geotechnical report was not available for review. However, the Oregon Department of Geology and Mineral Industries (DOGAMI) Statewide Geohazards Viewer does provide information on site hazards. Per DOGAMI's Hazard Viewer, there are no identified active faults located within several miles of the site.
6	Ties Between Foundation Elements	A.6.2.3	Without structural drawings, it is not known if foundation ties between columns are present.
7	Brace Axial Stress Check	A.3.3.1.2	Without structural drawings, and the lack of access inside the northern part of the exterior walls, the quantity of diagonal rod bracing bays is not known.
8	Moment-Resisting Connections	A.3.1.3.4	Without structural drawings that describe the frame details, it is not possible to perform this check.

No.	Item	Tier 1 Ref.	Comments
9	Compact Members	A.3.1.3.8	Without structural drawings that describe the frame details, it is not possible to determine the frame member section properties.

Nonstructural Deficiencies

No.	Item	Tier 1 Ref.	Comments
1	Shut-Off Valves	A.7.13.3	A natural gas shut-off valve was not identified.
2	Flexible Couplings	A.7.15.4	Hazardous material piping (natural gas) does not appear to have flexible couplings (all rigid steel).
3	Tall Narrow Contents	A.7.11.2	Not all cabinets/refrigerators/storage racks/etc. are anchored.
4	Fall-Prone Contents	A.7.11.3	Heavy items on storage racks do not appear to be braced to the racks.

Note: Not all nonstructural checklist items were able to be identified. The following list of nonstructural unknowns may contain noncompliant items if evaluation was possible.

Nonstructural Unknowns

No.	Item	Tier 1 Ref.	Comments
1	Suspended Gypsum Board	A.7.2.3	The ceiling attachments were not viewable.
2	Overhead Glazing	A.7.4.8	The type of glazing is not known.
3	Stair Details	A.7.10.2	The stair details were not accessible to view, and structural drawings were not available for review; therefore the condition is not known.

Conceptual Seismic Upgrade Work

No explicit structural deficiencies are identified in the Tier 1 Checklists as noted in the Structural Deficiencies table previously shown in this report. However, there are structural unknowns that may contain noncompliant items if evaluation was possible. These unknowns may be identified as compliant or noncompliant if more extensive investigation, beyond that of a Tier 1 checklist, was performed.

Nonstructural deficiencies are identified in the Tier 1 Checklists, and are listed in the Nonstructural Deficiencies table previously shown in this report. There are also nonstructural unknowns that may contain noncompliant items if evaluation was possible. These unknowns

may be identified as compliant or noncompliant if more extensive investigation, beyond that of a Tier 1 checklist, was performed. The following is a list of potential solutions to mitigate the identified deficiencies:

1. Shut-Off Valves: Identify the shut-off valves for natural gas. Add shut-off valve if one is not present.
2. Flexible Couplings: Add flexible couplings to natural gas piping.
3. Tall Narrow Contents: Anchor cabinets/refrigerators/storage racks/etc. that are taller than 6 feet and with a height-to-depth ratio greater than 3-to-1.

No explicit structural deficiencies are identified in the Tier 1 Checklists; however, as previously noted, several structural unknowns may contain noncompliant items if more extensive investigation was performed. Based on our experience with seismic upgrades of similar buildings, the probable cost of an upgrade of this type related to direct structural costs would be approximately $25 - $30 per square foot. This does not include costs associated with nonstructural deficiencies, soft costs, impacts to architectural or M/E/P systems, business interruption, geotechnical ground improvement, etc. It is assumed that an M/E/P designer or contractor would address costs associated with the identified nonstructural deficiencies.

Summary

This ASCE 41-13 Tier 1 seismic evaluation was prepared for the NW Natural – The Dalles Service Center. It was found that the aforementioned building, in its current state, does not achieve the desired seismic performance objective for Life Safety Structural Performance at the BSE-1E seismic hazard or 0.75 x BSE-1N seismic hazard as amended by the City of Portland's Chapter 24.85. It also does not achieve the desired seismic performance objective for Life Safety Nonstructural Performance at the same seismic hazard as stated above.

Since there are no identified structural deficiencies, yet several unknowns, further investigation should be completed to determine compliance of the identified unknowns. If the unknowns were to identify structural deficiencies, in the event of a significant seismic event, it is expected that the building will be damaged, possibly to the point where repair and re-occupancy of the building is not possible. The threat to the life safety of the building occupants, under the seismic hazards and performance objectives mentioned in this report, is higher than it would be compared to a building constructed to modern building codes. Most of the nonstructural seismic upgrade work would relate to bracing and/or restraint of nonstructural components and contents. The nonstructural unknowns should also be further investigated. It is our opinion that conventional seismic upgrade work could be employed to reduce/mitigate this seismic risk.

Appendix

ASCE 41-13 Summary Data Sheet and Checklists

Appendix C: Summary Data Sheet

BUILDING DATA

Building Name: NW Natural - The Dalles Service Center Date: May 3, 2016

Building Address: 1125 Bargeway Road, The Dalles, OR 97058

Latitude: 45.610616 Longitude: -121.19476 By: IKE

Year Built: Unknown Year(s) Remodeled: Unknown Original Design Code: Unknown

Area (sf): 4,100 Length (ft): 84 (NE-SW) Width (ft): 40 (NW-SE)

No. of Stories: 1 (plus mezzanine) Story Height: 24 ft Total Height: 24 ft

USE ☐ Industrial ☑ Office ☐ Warehouse ☐ Hospital ☐ Residential ☐ Educational ☑ Other: Service Center/Garage

CONSTRUCTION DATA

Gravity Load Structural System: Structural steel

Exterior Transverse Walls: Corrugated metal panels Openings? Yes

Exterior Longitudinal Walls: Corrugated metal panels Openings? Yes

Roof Materials/Framing: Corrugated metals panels over light gauge metal joists supported by structural steel frames

Intermediate Floors/Framing: Mezzanine - plywood sheathing over wood framing

Ground Floor: Concrete slab on grade

Columns: Structural steel Foundation: Spread footings

General Condition of Structure: Good (structural steel appears to be in good condition)

Levels Below Grade? No

Special Features and Comments: None

LATERAL-FORCE-RESISTING SYSTEM

	Longitudinal	Transverse
System:	Rod bracing	Rod bracing
Vertical Elements:	Steel columns	Steel columns
Diaphragms:	Rod bracing	Rod bracing
Connections:	Rod bracing bolted to steel columns at top and bottom	Rod bracing bolted to steel columns at top and bottom

EVALUATION DATA

BSE-1N Spectral Response Accelerations: S_{Ds}= 0.458 S_{D1}= 0.290

Soil Factors: Class= Site Class D

BSE-1E Spectral Response Accelerations: S_{XS}= 0.258 S_{X1}= 0.157

Level of Seismicity: High Performance Level: Life Safety

Building Period: T= 0.217 seconds

Spectral Acceleration: S_a= min($S_{X1,\ BSE\text{-}1E}$ / T = 0.724, $S_{X1,\ BSE\text{-}1N}$ = 0.343) = 0.343

Modification Factor: $C_mC_1C_2$= 1.0 (1-story S3) Building Weight: W= 107 kips

Pseudo Lateral Force: $V = C_mC_1C_2S_aW$= 37 kips

BUILDING CLASSIFICATION: S3

REQUIRED TIER 1 CHECKLISTS

	Yes	No
Basic Configuration Checklist	☑	☐
Building Type **S3** Structural Checklist	☑	☐
Nonstructural Component Checklist	☑	☐

FURTHER EVALUATION REQUIREMENT: n/a

Project Name NW Natural - The Dalles Service Center
Project Number 1600122

ASCE 41-13 Tier 1 Checklists

FIRM:	KPFF Consulting Engineers
PROJECT NAME:	NW Natural - The Dalles Service Center
SEISMICITY LEVEL:	High
PROJECT NUMBER:	1600122
COMPLETED BY:	IKE
DATE COMPLETED:	May 3, 2016
REVIEWED BY:	IKE
REVIEW DATE:	August 5, 2016

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

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Project Name NW Natural - The Dalles Service Center
Project Number 1600122

16.1 Basic Checklist

Very Low Seismicity

Structural Components

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☐	U ☒	LOAD PATH: The structure shall contain a complete, well-defined load path, including structural elements and connections, that serves to transfer the inertial forces associated with the mass of all elements of the building to the foundation. (Commentary: Sec. A.2.1.1. Tier 2: Sec. 5.4.1.1)	Unclear how the mezzanine attaches to the steel frames. The metal building alone appears to have a complete load path: metal roof decking and roof diagonal rod bracing, diagonal rod bracing in the N-S direction and moment frames in the E-W direction.
C ☐	NC ☐	N/A ☒	U ☐	WALL ANCHORAGE: Exterior concrete or masonry walls that are dependent on the diaphragm for lateral support are anchored for out-of-plane forces at each diaphragm level with steel anchors, reinforcing dowels, or straps that are developed into the diaphragm. Connections shall have adequate strength to resist the connection force calculated in the Quick Check procedure of Section 4.5.3.7. (Commentary: Sec. A.5.1.1. Tier 2: Sec. 5.7.1.1)	There are no concrete or masonry walls.

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Project Name NW Natural - The Dalles Service Center
Project Number 1600122

16.1.2LS Life Safety Basic Configuration Checklist

Low Seismicity

Building System

General

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☐	U ☒	LOAD PATH: The structure shall contain a complete, well-defined load path, including structural elements and connections, that serves to transfer the inertial forces associated with the mass of all elements of the building to the foundation. (Commentary: Sec. A.2.1.1. Tier 2: Sec. 5.4.1.1)	Unclear how the mezzanine attaches to the steel frames. The metal building alone appears to have a complete load path: metal roof decking and roof diagonal rod bracing, diagonal rod bracing in the N-S direction and moment frames in the E-W direction.
C ☐	NC ☐	N/A ☒	U ☐	ADJACENT BUILDINGS: The clear distance between the building being evaluated and any adjacent building is greater than 4% of the height of the shorter building. This statement need not apply for the following building types: W1, W1A, and W2. (Commentary: Sec. A.2.1.2. Tier 2: Sec. 5.4.1.2)	There are no immediately adjacent buildings.
C ☐	NC ☐	N/A ☐	U ☒	MEZZANINES: Interior mezzanine levels are braced independently from the main structure or are anchored to the seismic-force-resisting elements of the main structure. (Commentary: Sec. A.2.1.3. Tier 2: Sec. 5.4.1.3)	The mezzanine connections to the main steel frame were not exposed to view, and building structure drawings were not available for review. It is not clear how the mezzanine is laterally braced.

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Project Number 1600122

Building Configuration

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☒	☐	WEAK STORY: The sum of the shear strengths of the seismic-force-resisting system in any story in each direction is not less than 80% of the strength in the adjacent story above. (Commentary: Sec. A2.2.2. Tier 2: Sec. 5.4.2.1)	This is a one-story building (with the exception of the mezzanine).
C	NC	N/A	U		
☐	☐	☒	☐	SOFT STORY: The stiffness of the seismic-force-resisting system in any story is not less than 70% of the seismic-force-resisting system stiffness in an adjacent story above or less than 80% of the average seismic-force-resisting system stiffness of the three stories above. (Commentary: Sec. A.2.2.3. Tier 2: Sec. 5.4.2.2)	This is a one-story building (with the exception of the mezzanine).
C	NC	N/A	U		
☒	☐	☐	☐	VERTICAL IRREGULARITIES: All vertical elements in the seismic-force-resisting system are continuous to the foundation. (Commentary: Sec. A.2.2.4. Tier 2: Sec. 5.4.2.3)	The steel frames are continuous to the foundation.
C	NC	N/A	U		
☒	☐	☐	☐	GEOMETRY: There are no changes in the net horizontal dimension of the seismic-force-resisting system of more than 30% in a story relative to adjacent stories, excluding one-story penthouses and mezzanines. (Commentary: Sec. A.2.2.5. Tier 2: Sec. 5.4.2.4)	This is a one-story building, and the steel frames appear to be symmetric.

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C	NC	N/A	U		
☐	☐	☒	☐	MASS: There is no change in effective mass more than 50% from one story to the next. Light roofs, penthouses, and mezzanines need not be considered. (Commentary: Sec. A.2.2.6. Tier 2: Sec. 5.4.2.5)	This is a one-story building (with the exception of the mezzanine).
☒	☐	☐	☐	TORSION: The estimated distance between the story center of mass and the story center of rigidity is less than 20% of the building width in either plan dimension. (Commentary: Sec. A.2.2.7. Tier 2: Sec. 5.4.2.6)	

Moderate Seismicity

Geologic Site Hazards

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☐	☒	LIQUEFACTION: Liquefaction-susceptible, saturated, loose granular soils that could jeopardize the building's seismic performance shall not exist in the foundation soils at depths within 50 ft under the building. (Commentary: Sec. A.6.1.1. Tier 2: 5.4.3.1)	A geotechnical report was not available for review.
☐	☐	☐	☒	SLOPE FAILURE: The building site is sufficiently remote from potential earthquake-induced slope failures or rockfalls to be unaffected by such failures or is capable of accommodating any predicted movements without failure. (Commentary: Sec. A.6.1.2. Tier 2: 5.4.3.1)	A geotechnical report was not available for review.

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C	NC	N/A	U		
☐	☐	☐	☒	SURFACE FAULT RUPTURE: Surface fault rupture and surface displacement at the building site are not anticipated. (Commentary: Sec. A.6.1.3. Tier 2: 5.4.3.1)	A geotechnical report was not available for report.

High Seismicity

Foundation Configuration

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☒	☐	☐	☐	OVERTURNING: The ratio of the least horizontal dimension of the seismic-force-resisting system at the foundation level to the building height (base/height) is greater than $0.6S_a$. (Commentary: Sec. A.6.2.1. Tier 2: Sec. 5.4.3.3)	
C	NC	N/A	U		
☐	☐	☐	☒	TIES BETWEEN FOUNDATION ELEMENTS: The foundation has ties adequate to resist seismic forces where footings, piles, and piers are not restrained by beams, slabs, or soils classified as Site Class A, B, or C. (Commentary: Sec. A.6.2.2. Tier 2: Sec. 5.4.3.4)	Without structural drawings, it is not known if foundation ties are present between column footings.

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Project Number 1600122

ASCE 41-13 Tier 1 Checklists

FIRM:	KPFF Consulting Engineers
PROJECT NAME:	NW Natural - The Dalles Service Center
SEISMICITY LEVEL:	High
PROJECT NUMBER:	1600122
COMPLETED BY:	IKE
DATE COMPLETED:	May 3, 2016
REVIEWED BY:	IKE
REVIEW DATE:	August 5, 2016

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Project Name NW Natural - The Dalles Service Center
Project Number 1600122

16.6LS Life Safety Structural Checklist for Building Type S3: Steel Light Frames

Low and Moderate Seismicity

Seismic-Force-Resisting System

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☐	☒	BRACE AXIAL STRESS CHECK: The axial stress in the diagonals, calculated using the Quick Check procedure of Section 4.5.3.4, is less than $0.50F_y$. (Commentary: Sec. A.3.3.1.2. Tier 2: Sec. 5.5.4.1)	Without structural drawings and visible access to the north end of the building, the quantity of diagonal rod bracing bays is not known. The steel grade for the rod bracing is also unknown.

Connections

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☒	☐	☐	☐	TRANSFER TO STEEL FRAMES: Diaphragms are connected for transfer of seismic forces to the steel frames. (Commentary: Sec. A.5.2.2. Tier 2: Sec. 5.7.2)	Roof diaphragm rod bracing is connected to the frame columns.
☒	☐	☐	☐	STEEL COLUMNS: The columns in seismic-force-resisting frames are anchored to the building foundation. (Commentary: Sec. A.5.3.1. Tier 2: Sec. 5.7.3.1)	The columns are bolted to the concrete slab/foundation.

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Project Name NW Natural - The Dalles Service Center
Project Number 1600122

High Seismicity

Seismic-Force-Resisting System

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☐	☒	MOMENT-RESISTING CONNECTIONS: All moment connections are able to develop the elastic moment (F_yS) of the adjoining members. (Commentary: Sec. A.3.1.3.4. Tier 2: Sec. 5.5.2.2.1)	Without structural drawings that describe the frame details, it is not possible to perform this calculation.
C	NC	N/A	U		
☐	☐	☐	☒	COMPACT MEMBERS: All frame elements shall meet compact section requirements set forth by AISC 360, Table B4.1. (Commentary: Sec. A.3.1.3.8. Tier 2: Sec. 5.5.2.2.4)	Without structural drawings that describe the frame details, it is not possible to determine section properties.
C	NC	N/A	U		
☒	☐	☐	☐	OTHER DIAPHRAGMS: The diaphragm does not consist of a system other than wood, metal deck, concrete, or horizontal bracing. (Commentary: Sec. A.4.7.1. Tier 2: Sec. 5.6.5)	The roof diaphragm has horizontal/diagonal bracing.

Connections

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☒	☐	☐	☐	ROOF PANELS: Metal, plastic, or cementitious roof panels are positively attached to the roof framing to resist seismic forces. (Commentary: Sec. A.5.5.1. Tier 2: Sec. 5.7.5)	The roof panels appear to be fastened to the roof framing.

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C	NC	N/A	U		
☒	☐	☐	☐	WALL PANELS: Metal, fiberglass, or cementitious wall panels are positively attached to the framing and foundation to resist seismic forces. (Commentary: Sec. A.5.5.2. Tier 2: Sec. 5.7.5)	The wall panels are fastened to the wall framing, the framing to the main moment frames, and the main frames to the foundation.

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Project Number 1600122

ASCE 41-13 Tier 1 Checklists

FIRM:	KPFF Consulting Engineers
PROJECT NAME:	NW Natural - The Dalles Service Center
SEISMICITY LEVEL:	High
PROJECT NUMBER:	1600122
COMPLETED BY:	IKE
DATE COMPLETED:	May 3, 2016
REVIEWED BY:	IKE
REVIEW DATE:	August 5, 2016

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16.17 Nonstructural Checklist

The Performance Level is designated LS for Life Safety or PR for Position Retention. The level of seismicity is designated as "not required" or by L, M, or H, for Low, Moderate, and High.

All Seismicity Levels

Life Safety Systems

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☒	U ☐	LS-LMH; PR-LMH. FIRE SUPPRESSION PIPING: Fire suppression piping is anchored and braced in accordance with NFPA-13. (Commentary: Sec. A.7.13.1. Tier 2: Sec. 13.7.4)	The building does not contain fire sprinklers.
C ☐	NC ☐	N/A ☒	U ☐	LS-LMH; PR-LMH. FLEXIBLE COUPLINGS: Fire suppression piping has flexible couplings in accordance with NFPA-13. (Commentary: Sec. A.7.13.2. Tier 2: Sec. 13.7.4)	The building does not contain fire sprinklers.
C ☒	NC ☐	N/A ☐	U ☐	LS-LMH; PR-LMH. EMERGENCY POWER: Equipment used to power or control life safety systems is anchored or braced. (Commentary: Sec. A.7.12.1. Tier 2: Sec. 13.7.7)	The generator is anchored to a concrete slab.
C ☐	NC ☐	N/A ☒	U ☐	LS-LMH; PR-LMH. STAIR AND SMOKE DUCTS: Stair pressurization and smoke control ducts are braced and have flexible connections at seismic joints. (Commentary: Sec. A.7.14.1. Tier 2: Sec. 13.7.6)	The building does not contain seismic joints.

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C	NC	N/A	U		
☐	☐	☒	☐	LS-MH; PR-MH. SPRINKLER CEILING CLEARANCE: Penetrations through panelized ceilings for fire suppression devices provide clearances in accordance with NFPA-13. (Commentary: Sec. A.7.13.3. Tier 2: Sec. 13.7.4)	The building does not contain fire sprinklers.
☐	☐	☒	☐	LS-not required; PR-LMH. EMERGENCY LIGHTING: Emergency and egress lighting equipment is anchored or braced. (Commentary: Sec. A.7.3.1. Tier 2: Sec. 13.7.9)	This check is not required for the Life Safety Performance Level.

Hazardous Materials

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☒	☐	LS-LMH; PR-LMH. HAZARDOUS MATERIAL EQUIPMENT: Equipment mounted on vibration isolators and containing hazardous material is equipped with restraints or snubbers. (Commentary: Sec. A.7.12.2. Tier 2: 13.7.1)	This type of equipment, mounted on isolators, does not appear to occur in this building.
☐	☐	☒	☐	LS-LMH; PR-LMH. HAZARDOUS MATERIAL STORAGE: Breakable containers that hold hazardous material, including gas cylinders, are restrained by latched doors, shelf lips, wires, or other methods. (Commentary: Sec. A.7.15.1. Tier 2: Sec. 13.8.4)	There do not appear to be "breakable" containers that hold hazardous materials.

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C	NC	N/A	U		
☒	☐	☐	☐	LS-MH; PR-MH. HAZARDOUS MATERIAL DISTRIBUTION: Piping or ductwork conveying hazardous materials is braced or otherwise protected from damage that would allow hazardous material release. (Commentary: Sec. A.7.13.4. Tier 2: Sec. 13.7.3 and 13.7.5)	Gas piping appears to be braced to the building.
☐	☒	☐	☐	LS-MH; PR-MH. SHUT-OFF VALVES: Piping containing hazardous material, including natural gas, has shut-off valves or other devices to limit spills or leaks. (Commentary: Sec. A.7.13.3. Tier 2: Sec. 13.7.3 and 13.7.5)	A natural shut-off valve was not identified.
☐	☒	☐	☐	LS-LMH; PR-LMH. FLEXIBLE COUPLINGS: Hazardous material ductwork and piping, including natural gas piping, has flexible couplings. (Commentary: Sec. A.7.15.4, Tier 2: Sec.13.7.3 and 13.7.5)	Couplings all appear to be rigid steel.
☐	☐	☒	☐	LS-MH; PR-MH. PIPING OR DUCTS CROSSING SEISMIC JOINTS: Piping or ductwork carrying hazardous material that either crosses seismic joints or isolation planes or is connected to independent structures has couplings or other details to accommodate the relative seismic displacements. (Commentary: Sec. A.7.13.6. Tier 2: Sec.13.7.3, 13.7.5, and 13.7.6)	There are no seismic joints.

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Partitions

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☒	U ☐	LS-LMH; PR-LMH. UNREINFORCED MASONRY: Unreinforced masonry or hollow-clay tile partitions are braced at a spacing of at most 10 ft in Low or Moderate Seismicity, or at most 6 ft in High Seismicity. (Commentary: Sec. A.7.1.1. Tier 2: Sec. 13.6.2)	There are no masonry walls.
C ☐	NC ☐	N/A ☒	U ☐	LS-LMH; PR-LMH. HEAVY PARTITIONS SUPPORTED BY CEILINGS: The tops of masonry or hollow-clay tile partitions are not laterally supported by an integrated ceiling system. (Commentary: Sec. A.7.2.1. Tier 2: Sec. 13.6.2)	There are no heavy partitions supported by ceilings.
C ☐	NC ☐	N/A ☒	U ☐	LS-MH; PR-MH. DRIFT: Rigid cementitious partitions are detailed to accommodate the following drift ratios: in steel moment frame, concrete moment frame, and wood frame buildings, 0.02; in other buildings, 0.005. (Commentary A.7.1.2 Tier 2: Sec. 13.6.2)	There are no rigid cementitious partitions.
C ☐	NC ☐	N/A ☒	U ☐	LS-not required; PR-MH. LIGHT PARTITIONS SUPPORTED BY CEILINGS: The tops of gypsum board partitions are not laterally supported by an integrated ceiling system. (Commentary: Sec. A.7.2.1. Tier 2: Sec. 13.6.2)	This check is not required for the Life Safety Performance Level.

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C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-MH. STRUCTURAL SEPARATIONS: Partitions that cross structural separations have seismic or control joints. (Commentary: Sec. A.7.1.3. Tier 2. Sec. 13.6.2)	This check is not required for the Life Safety Performance Level.
C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-MH. TOPS: The tops of ceiling-high framed or panelized partitions have lateral bracing to the structure at a spacing equal to or less than 6 ft. (Commentary: Sec. A.7.1.4. Tier 2. Sec. 13.6.2)	This check is not required for the Life Safety Performance Level.

Ceilings

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☒	☐	LS-MH; PR-LMH. SUSPENDED LATH AND PLASTER: Suspended lath and plaster ceilings have attachments that resist seismic forces for every 12 ft^2 of area. (Commentary: Sec. A.7.2.3. Tier 2: Sec. 13.6.4)	There are no lath and plaster ceilings.
C	NC	N/A	U		
☐	☐	☐	☒	LS-MH; PR-LMH. SUSPENDED GYPSUM BOARD: Suspended gypsum board ceilings have attachments that resist seismic forces for every 12 ft^2 of area. (Commentary: Sec. A.7.2.3. Tier 2: Sec. 13.6.4)	This was not viewable for gypsum board ceilings.

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C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-MH. INTEGRATED CEILINGS: Integrated suspended ceilings with continuous areas greater than 144 ft^2, and ceilings of smaller areas that are not surrounded by restraining partitions, are laterally restrained at a spacing no greater than 12 ft with members attached to the structure above. Each restraint location has a minimum of four diagonal wires and compression struts, or diagonal members capable of resisting compression. (Commentary: Sec. A.7.2.2. Tier 2: Sec. 13.6.4)	This check is not required for the Life Safety Performance Level.
C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-MH. EDGE CLEARANCE: The free edges of integrated suspended ceilings with continuous areas greater than 144 ft^2 have clearances from the enclosing wall or partition of at least the following: in Moderate Seismicity, 1/2 in.; in High Seismicity, 3/4 in. (Commentary: Sec. A.7.2.4. Tier 2: Sec. 13.6.4)	This check is not required for the Life Safety Performance Level.
C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-MH. CONTINUITY ACROSS STRUCTURE JOINTS: The ceiling system does not cross any seismic joint and is not attached to multiple independent structures. (Commentary: Sec. A.7.2.5. Tier 2: Sec. 13.6.4)	This check is not required for the Life Safety Performance Level.
C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-H. EDGE SUPPORT: The free edges of integrated suspended ceilings with continuous areas greater than 144 ft^2 are supported by closure angles or channels not less than 2 in. wide. (Commentary: Sec. A.7.2.6. Tier 2: Sec. 13.6.4)	This check is not required for the Life Safety Performance Level.

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C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-H. SEISMIC JOINTS: Acoustical tile or lay-in panel ceilings have seismic separation joints such that each continuous portion of the ceiling is no more than 2500 ft^2 and has a ratio of long-to-short dimension no more than 4-to-1. (Commentary: Sec. A.7.2.7. Tier 2: 13.6.4)	This check is not required for the Life Safety Performance Level.

Light Fixtures

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☒	☐	LS-MH; PR-MH. INDEPENDENT SUPPORT: Light fixtures that weigh more per square foot than the ceiling they penetrate are supported independent of the grid ceiling suspension system by a minimum of two wires at diagonally opposite corners of each fixture. (Commentary: Sec. A.7.3.2. Tier 2: Sec. 13.6.4 and 13.7.9)	Grid ceilings do not occur. Light fixtures are connected directly to the gypsum board ceilings.
C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-H. PENDANT SUPPORTS: Light fixtures on pendant supports are attached at a spacing equal to or less than 6 ft and, if rigidly supported, are free to move with the structure to which they are attached without damaging adjoining components. (Commentary: A.7.3.3. Tier 2: Sec. 13.7.9)	This check is not required for the Life Safety Performance Level.
C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-H. LENS COVERS: Lens covers on light fixtures are attached with safety devices. (Commentary: Sec. A.7.3.4. Tier 2: Sec. 13.7.9)	This check is not required for the Life Safety Performance Level.

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Cladding and Glazing

RATING				DESCRIPTION	COMMENTS
C ☐	NC ☐	N/A ☒	U ☐	LS-MH; PR-MH. CLADDING ANCHORS: Cladding components weighing more than 10 lb/ft^2 are mechanically anchored to the structure at a spacing equal to or less than the following: for Life Safety in Moderate Seismicity, 6 ft; for Life Safety in High Seismicity and for Position Retention in any seismicity, 4 ft. (Commentary: Sec. A.7.4.1. Tier 2: Sec. 13.6.1)	The building does not have this type of cladding.
C ☐	NC ☐	N/A ☒	U ☐	LS-MH; PR-MH. CLADDING ISOLATION: For steel or concrete moment frame buildings, panel connections are detailed to accommodate a story drift ratio of at least the following: for Life Safety in Moderate Seismicity, 0.01; for Life Safety in High Seismicity and for Position Retention in any seismicity, 0.02. (Commentary: Sec. A.7.4.3. Tier 2: Section 13.6.1)	All walls are metal siding and are "hard-fastened" directly to the structural frame.
C ☐	NC ☐	N/A ☒	U ☐	LS-MH; PR-MH. MULTI-STORY PANELS: For multi-story panels attached at more than one floor level, panel connections are detailed to accommodate a story drift ratio of at least the following: for Life Safety in Moderate Seismicity, 0.01; for Life Safety in High Seismicity and for Position Retention in any seismicty, 0.02. (Commentary: Sec. A.7.4.4. Tier 2: Sec. 13.6.1)	There are no multi-story panels.
C ☐	NC ☐	N/A ☒	U ☐	LS-MH; PR-MH. PANEL CONNECTIONS: Cladding panels are anchored out-of-plane with a minimum number of connections for each wall panel, as follows: for Life Safety in Moderate Seismicity, 2 connections; for Life Safety in High Seismicity and for Position Retention in any seismicity, 4 connections. (Commentary: Sec. A.7.4.5. Tier 2: Sec. 13.6.1.4)	There are no cladding panels.

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C	NC	N/A	U		
☒	☐	☐	☐	LS-MH; PR-MH. BEARING CONNECTIONS: Where bearing connections are used, there is a minimum of two bearing connections for each cladding panel. (Commentary: Sec. A.7.4.6. Tier 2: Sec. 13.6.1.4)	The metal siding are fastened directly to the wall framing at several locations.
☐	☐	☒	☐	LS-MH; PR-MH. INSERTS: Where concrete cladding components use inserts, the inserts have positive anchorage or are anchored to reinforcing steel. (Commentary: Sec. A.7.4.7. Tier 2: Sec. 13.6.1.4)	There are no concrete cladding components.
☐	☐	☐	☒	LS-MH; PR-MH. OVERHEAD GLAZING: Glazing panes of any size in curtain walls and individual interior or exterior panes over 16 ft^2 in area are laminated annealed or laminated heat-strengthened glass and are detailed to remain in the frame when cracked. (Commentary: Sec. A.7.4.8: Tier 2: Sec. 13.6.1.5)	The type of glazing is not known.

Masonry Veneer

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☒	☐	LS-LMH; PR-LMH. TIES: Masonry veneer is connected to the backup with corrosion-resistant ties. There is a minimum of one tie for every 2-2/3 ft^2, and the ties have spacing no greater than the following: for Life Safety in Low or Moderate Seismicity, 36 in.; for Life Safety in High Seismicity and for Position Retention in any seismicity, 24 in. (Commentary: Sec. A.7.5.1. Tier 2: Sec. 13.6.1.2)	There is no masonry veneer.

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C	NC	N/A	U		
☐	☐	☒	☐	LS-LMH; PR-LMH. SHELF ANGLES: Masonry veneer is supported by shelf angles or other elements at each floor above the ground floor. (Commentary: Sec. A.7.5.2. Tier 2: Sec. 13.6.1.2)	There is no masonry veneer.
☐	☐	☒	☐	LS-LMH; PR-LMH. WEAKENED PLANES: Masonry veneer is anchored to the backup adjacent to weakened planes, such as at the locations of flashing. (Commentary: Sec. A.7.5.3. Tier 2: Sec. 13.6.1.2)	There is no masonry veneer.
☐	☐	☒	☐	LS-LMH; PR-LMH. UNREINFORCED MASONRY BACKUP: There is no unreinforced masonry backup. (Commentary: Sec. A.7.7.2. Tier 2: Section 13.6.1.1 and 13.6.1.2)	There is no unreinforced masonry.
☐	☐	☒	☐	LS-MH; PR-MH. STUD TRACKS: For veneer with metal stud backup, stud tracks are fastened to the structure at a spacing equal to or less than 24 in. on center. (Commentary: Sec. A.7.6.1. Tier 2: Section 13.6.1.1 and 13.6.1.2)	There is no masonry veneer.

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C	NC	N/A	U		
☐	☐	☒	☐	LS-MH; PR-MH. ANCHORAGE: For veneer with concrete block or masonry backup, the backup is positively anchored to the structure at a horizontal spacing equal to or less than 4 ft along the floors and roof. (Commentary: Sec. A.7.7.1. Tier 2: Section 13.6.1.1 and 13.6.1.2)	There is no masonry veneer.
C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-MH. WEEP HOLES: In veneer anchored to stud walls, the veneer has functioning weep holes and base flashing. (Commentary: Sec. A.7.5.6. Tier 2: Section 13.6.1.2)	This check is not required for the Life Safety Performance Level.
C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-MH. OPENINGS: For veneer with metal stud backup, steel studs frame window and door openings. (Commentary: Sec. A.7.6.2. Tier 2: Sec. 13.6.1.1 and 13.6.1.2)	This check is not required for the Life Safety Performance Level.

Parapets, Cornices, Ornamentation, and Appendages

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☒	☐	LS-LMH; PR-LMH. URM PARAPETS OR CORNICES: Laterally unsupported unreinforced masonry parapets or cornices have height-to-thickness ratios no greater than the following: for Life Safety in Low or Moderate Seismicity, 2.5; for Life Safety in High Seismicity and for Position Retention in any seismicity, 1.5. (Commentary: Sec. A.7.8.1. Tier 2: Sec. 13.6.5)	There are no URM parapets.

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C	NC	N/A	U		
☐	☐	☒	☐	LS-LMH; PR-LMH. CANOPIES: Canopies at building exits are anchored to the structure at a spacing no greater than the following: for Life Safety in Low or Moderate Seismicity, 10 ft; for Life Safety in High Seismicity and for Position Retention in any seismicity, 6 ft. (Commentary: Sec. A.7.8.2. Tier 2: Sec. 13.6.6)	There are no canopies.
☐	☐	☒	☐	LS-MH; PR-LMH. CONCRETE PARAPETS: Concrete parapets with height-to-thickness ratios greater than 2.5 have vertical reinforcement. (Commentary: Sec. A.7.8.3. Tier 2: Sec. 13.6.5)	There are no concrete parapets.
☒	☐	☐	☐	LS-MH; PR-LMH. APPENDAGES: Cornices, parapets, signs, and other ornamentation or appendages that extend above the highest point of anchorage to the structure or cantilever from components are reinforced and anchored to the structural system at a spacing equal to or less than 6 ft. This checklist item does not apply to parapets or cornices covered by other checklist items. (Commentary: Sec. A.7.8.4. Tier 2: Sec. 13.6.6)	Where these items occur, they are anchored.

Masonry Chimneys

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☒	☐	LS-LMH; PR-LMH. URM CHIMNEYS: Unreinforced masonry chimneys extend above the roof surface no more than the following: for Life Safety in Low or Moderate Seismicity, 3 times the least dimension of the chimney; for Life Safety in High Seismicity and for Position Retention in any seismicity, 2 times the least dimension of the chimney. (Commentary: Sec. A.7.9.1. Tier 2: 13.6.7)	There are no URM chimneys.

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C	NC	N/A	U		
☐	☐	☒	☐	LS-LMH; PR-LMH. ANCHORAGE: Masonry chimneys are anchored at each floor level, at the topmost ceiling level, and at the roof. (Commentary: Sec. A.7.9.2. Tier 2: 13.6.7)	There are no masonry chimneys.

Stairs

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☒	☐	LS-LMH; PR-LMH. STAIR ENCLOSURES: Hollow-clay tile or unreinforced masonry walls around stair enclosures are restrained out-of-plane and have height-to-thickness ratios not greater than the following: for Life Safety in Low or Moderate Seismicity, 15-to-1; for Life Safety in High Seismicity and for Position Retention in any seismicity, 12-to-1. (Commentary: Sec. A.7.10.1. Tier 2: Sec. 13.6.2 and 13.6.8)	These types of stair enclosures do not occur in this building.
C	NC	N/A	U		
☐	☐	☐	☒	LS-LMH; PR-LMH. STAIR DETAILS: In moment frame structures, the connection between the stairs and the structure does not rely on shallow anchors in concrete. Alternatively, the stair details are capable of accommodating the drift calculated using the Quick Check procedure of Section 4.5.3.1 without including any lateral stiffness contribution from the stairs. (Commentary: Sec. A.7.10.2. Tier 2: 13.6.8)	The stair details were not accessible to view, and structural drawings were not available for review; therefore, the condition is not known.

Contents and Furnishings

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☒	☐	LS-MH; PR-MH. INDUSTRIAL STORAGE RACKS: Industrial storage racks or pallet racks more than 12 ft high meet the requirements of ANSI/MH 16.1 as modified by ASCE 7 Chapter 15. (Commentary: Sec. A.7.11.1. Tier 2: Sec. 13.8.1)	There did not appear to be any storage racks more than 12 feet tall.

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C	NC	N/A	U		
☐	☒	☐	☐	LS-H; PR-MH. TALL NARROW CONTENTS: Contents more than 6 ft high with a height-to-depth or height-to-width ratio greater than 3-to-1 are anchored to the structure or to each other. (Commentary: Sec. A.7.11.2. Tier 2: Sec. 13.8.2)	Not all cabinets/refrigerators/storage racks/etc. are anchored.
C	NC	N/A	U		
☐	☒	☐	☐	LS-H; PR-H. FALL-PRONE CONTENTS: Equipment, stored items, or other contents weighing more than 20 lb whose center of mass is more than 4 ft above the adjacent floor level are braced or otherwise restrained. (Commentary: Sec. A.7.11.3. Tier 2: Sec. 13.8.2)	Heavy items on storage racks do not appear to be braced or anchored to the racks.
C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-MH. ACCESS FLOORS: Access floors more than 9 in. high are braced. (Commentary: Sec. A.7.11.4. Tier 2: Sec. 13.8.3)	This check is not required for the Life Safety Performance Level.
C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-MH. EQUIPMENT ON ACCESS FLOORS: Equipment and other contents supported by access floor systems are anchored or braced to the structure independent of the access floor. (Commentary: Sec. A.7.11.5. Tier 2: Sec. 13.7.7 and 13.8.3)	This check is not required for the Life Safety Performance Level.

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C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-H. SUSPENDED CONTENTS: Items suspended without lateral bracing are free to swing from or move with the structure from which they are suspended without damaging themselves or adjoining components. (Commentary. A.7.11.6. Tier 2: Sec. 13.8.2)	This check is not required for the Life Safety Performance Level.

Mechanical and Electrical Equipment

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☒	☐	☐	☐	LS-H; PR-H. FALL-PRONE EQUIPMENT: Equipment weighing more than 20 lb whose center of mass is more than 4 ft above the adjacent floor level, and which is not in-line equipment, is braced. (Commentary: A.7.12.4. Tier 2: 13.7.1 and 13.7.7)	Suspended equipment appears to be braced.
C	NC	N/A	U		
☒	☐	☐	☐	LS-H; PR-H. IN-LINE EQUIPMENT: Equipment installed in-line with a duct or piping system, with an operating weight more than 75 lb, is supported and laterally braced independent of the duct or piping system. (Commentary: Sec. A.7.12.5. Tier 2: Sec. 13.7.1)	Suspended equipment appears to be braced.
C	NC	N/A	U		
☒	☐	☐	☐	LS-H; PR-MH. TALL NARROW EQUIPMENT: Equipment more than 6 ft high with a height-to-depth or height-to-width ratio greater than 3-to-1 is anchored to the floor slab or adjacent structural walls. (Commentary: Sec. A.7.12.6. Tier 2: Sec. 13.7.1 and 13.7.7)	Tall narrow equipment appears to be anchored.

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C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-MH. MECHANICAL DOORS: Mechanically operated doors are detailed to operate at a story drift ratio of 0.01. (Commentary: Sec. A.7.12.7. Tier 2: Sec. 13.6.9)	This check is not required for the Life Safety Performance Level.
C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-H. SUSPENDED EQUIPMENT: Equipment suspended without lateral bracing is free to swing from or move with the structure from which it is suspended without damaging itself or adjoining components. (Commentary: Sec. A.7.12.8. Tier 2: Sec. 13.7.1 and 13.7.7)	This check is not required for the Life Safety Performance Level.
C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-H. VIBRATION ISOLATORS: Equipment mounted on vibration isolators is equipped with horizontal restraints or snubbers and with vertical restraints to resist overturning. (Commentary: Sec. A.7.12.9. Tier 2: Sec. 13.7.1)	This check is not required for the Life Safety Performance Level.
C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-H. HEAVY EQUIPMENT: Floor-supported or platform-supported equipment weighing more than 400 lb is anchored to the structure. (Commentary: Sec. A.7.12.10. Tier 2: 13.7.1 and 13.7.7)	This check is not required for the Life Safety Performance Level.

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C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-H. ELECTRICAL EQUIPMENT: Electrical equipment is laterally braced to the structure. (Commentary: Sec. A.7.12.11. Tier 2: 13.7.7)	This check is not required for the Life Safety Performance Level.
☐	☐	☒	☐	LS-not required; PR-H. CONDUIT COUPLINGS: Conduit greater than 2.5 in. trade size that is attached to panels, cabinets, or other equipment and is subject to relative seismic displacement has flexible couplings or connections. (Commentary: Sec. A.7.12.12. Tier 2: 13.7.8)	This check is not required for the Life Safety Performance Level.

Piping

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-H. FLEXIBLE COUPLINGS: Fluid and gas piping has flexible couplings. (Commentary: Sec. A.7.13.2. Tier 2: Sec. 13.7.3 and 13.7.5)	This check is not required for the Life Safety Performance Level.
☐	☐	☒	☐	LS-not required; PR-H. FLUID AND GAS PIPING: Fluid and gas piping is anchored and braced to the structure to limit spills or leaks. (Commentary: Sec. A.7.13.4. Tier 2: Sec. 13.7.3 and 13.7.5)	This check is not required for the Life Safety Performance Level.

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

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C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-H. C-CLAMPS: One-sided C-clamps that support piping larger than 2.5 in. in diameter are restrained. (Commentary: Sec. A.7.13.5. Tier 2: Sec. 13.7.3 and 13.7.5)	This check is not required for the Life Safety Performance Level.
☐	☐	☒	☐	LS-not required; PR-H. PIPING CROSSING SEISMIC JOINTS: Piping that crosses seismic joints or isolation planes or is connected to independent structures has couplings or other details to accommodate the relative seismic displacements. (Commentary: Sec. A7.13.6. Tier 2: Sec.13.7.3 and Sec. 13.7.5)	This check is not required for the Life Safety Performance Level.

Ducts

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-H. DUCT BRACING: Rectangular ductwork larger than 6 ft^2 in cross-sectional area and round ducts larger than 28 in. in diameter are braced. The maximum spacing of transverse bracing does not exceed 30 ft. The maximum spacing of longitudinal bracing does not exceed 60 ft. (Commentary: Sec. A.7.14.2. Tier 2: Sec. 13.7.6)	This check is not required for the Life Safety Performance Level.
☐	☐	☒	☐	LS-not required; PR-H. DUCT SUPPORT: Ducts are not supported by piping or electrical conduit. (Commentary: Sec. A.7.14.3. Tier 2: Sec. 13.7.6)	This check is not required for the Life Safety Performance Level.

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C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-H. DUCTS CROSSING SEISMIC JOINTS: Ducts that cross seismic joints or isolation planes or are connected to independent structures have couplings or other details to accommodate the relative seismic displacements. (Commentary: Sec. A.7.14.5. Tier 2: Sec. 13.7.6)	This check is not required for the Life Safety Performance Level.

Elevators

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☒	☐	LS-H; PR-H. RETAINER GUARDS: Sheaves and drums have cable retainer guards. (Commentary: Sec. A.7.16.1. Tier 2: 13.8.6)	There are no elevators.
C	NC	N/A	U		
☐	☐	☒	☐	LS-H; PR-H. RETAINER PLATE: A retainer plate is present at the top and bottom of both car and counterweight. (Commentary: Sec. A.7.16.2. Tier 2: 13.8.6)	There are no elevators.
C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-H. ELEVATOR EQUIPMENT: Equipment, piping, and other components that are part of the elevator system are anchored. (Commentary: Sec. A.7.16.3. Tier 2: 13.8.6)	This check is not required for the Life Safety Performance Level.

Legend: C = Compliant, NC = Noncompliant, N/A = Not Applicable, U = Unknown

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Project Name NW Natural - The Dalles Service Center
Project Number 1600122

C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-H. SEISMIC SWITCH: Elevators capable of operating at speeds of 150 ft/min or faster are equipped with seismic switches that meet the requirements of ASME A17.1 or have trigger levels set to 20% of the acceleration of gravity at the base of the structure and 50% of the acceleration of gravity in other locations. (Commentary: Sec. A.7.16.4. Tier 2: 13.8.6)	This check is not required for the Life Safety Performance Level.
☐	☐	☒	☐	LS-not required; PR-H. SHAFT WALLS: Elevator shaft walls are anchored and reinforced to prevent toppling into the shaft during strong shaking. (Commentary: Sec. A.7.16.5. Tier 2: 13.8.6)	This check is not required for the Life Safety Performance Level.
☐	☐	☒	☐	LS-not required; PR-H. COUNTERWEIGHT RAILS: All counterweight rails and divider beams are sized in accordance with ASME A17.1. (Commentary: Sec. A.7.16.6. Tier 2: 13.8.6)	This check is not required for the Life Safety Performance Level.
☐	☐	☒	☐	LS-not required; PR-H. BRACKETS: The brackets that tie the car rails and the counterweight rail to the structure are sized in accordance with ASME A17.1. (Commentary: Sec. A.7.16.7. Tier 2: 13.8.6)	This check is not required for the Life Safety Performance Level.

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Project Name NW Natural - The Dalles Service Center
Project Number 1600122

C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-H. SPREADER BRACKET: Spreader brackets are not used to resist seismic forces. (Commentary: Sec. A.7.16.8. Tier 2: 13.8.6)	This check is not required for the Life Safety Performance Level.
C	NC	N/A	U		
☐	☐	☒	☐	LS-not required; PR-H. GO-SLOW ELEVATORS: The building has a go-slow elevator system. (Commentary: Sec. A.7.16.9. Tier 2: 13.8.6)	This check is not required for the Life Safety Performance Level.

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BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Wayne K. Pipes

FACILITIES

Exh. WKP-3

August 29, 2025

NW Natural
PROJECT ALTERNATIVES NARRATIVE

Program/Project Name: The Dalles
Date: 12/11/2024
Project Sponsor: Wayne Pipes
Executive Sponsor: Mardi Saathoff
Project Manager: Philip Zlatnik
Preparer: Philip Zlatnik

SECTION 1: BUSINESS CASE

This section should be solution-agnostic, and about the overarching problem we're trying to solve no matter which route we end up taking.

OBJECTIVES *Why are we tackling this project?*	
Current State What is happening now? Where are we starting?	NW Natural operates a resource center in The Dalles, Oregon (the Company's only facility in the Columbia River Gorge), which is essential for supporting the delivery of safe and reliable service and serving as a center for the Company's regional emergency response across northern Hood River and Wasco Counties in Oregon, as well as Klickitat and Skamania Counties in Washington. The facility is small, leased, and the lease expires at the end of 2026. The leased area is ½ acre and includes a prefabricated steel building. The building consists of a single-story 65-foot by 40-foot garage, a 19-foot by 40-foot ground-floor office, and a 19-foot by 40-foot mezzanine office above the ground floor, totaling about 4,100 square feet. The site also features a microwave tower. Ten employees work from this site, representing Customer Field Services, Construction, Emergency Response, and Community Affairs. KPFF Engineering completed a seismic assessment of the metal building in 2016 and concluded that the building does not meet current life-safety building codes, raising concerns about employee safety. Additionally, the lack of onsite fueling could hinder NW Natural's response capabilities during a major natural disaster. The office building lacks standard NW Natural functionality. It does not have a conference room, a write-up room (where the crews meet each morning to get their assignments for the day and close out their day), a drying room, or changing room or showers, and the kitchen is inadequate. In addition, the existing site is too small to support current operational needs like a vehicle fueling system, pipe storage, and a decant system. The site lacks and cannot accommodate sufficient indoor covered storage for Company tools and materials, or enclosed parking for specialty equipment, to protect it from the environment. The site also lack space to accommodate adequately sized storage bins for rocks and sand. The absence of a decant system means employees must drive 23 miles one way (1.5-hour round trip) to dispose of wet spoils. Similarly, the lack of a covered spoils bin requires employees to drive 5 miles one way (20-minute round trip) to dispose of dry spoils.
Problem Statement In simple terms, what are we trying to solve? What is the business need this is tackling? Why is this a problem worth solving (e.g. why is the current state not working)?	The lease on the current facility expires at the end of 2026. We need to find a new site that provides adequate and safe facilities to support our evolving business operations while upholding the values of the Company.

Desired Deliverables What high level output / scope / deliverables are core to this project?	The goal of the project is to provide an office building with standard NW Natural functionality, a warehouse, and the necessary outbuildings and yard functionality, including paving.

SECTION 2: ALTERNATIVES SUMMARY

OVERVIEW *How did we review these options?*	
Review Process Summarize how options were chosen, who was involved in the choice and how options were evaluated. If some criteria were considered more important based on the type of project, please explain here.	**How options were chosen:** • The options being evaluated are the available properties for sale in The Dalles. **Who was involved in the choice?** • Project team, Environmental team, Operations, and the Facilities Steering Committee. **How options were evaluated:** • Fit, accessibility, cost and risk. **Were any criteria considered more important?** • Fit and cost.
DECISION CRITERIA *Describe the criteria used to determine the selection from the various alternatives considered. For example, is this a program/project where the least cost option should be selected? Are there other factors, such as safety or quality that come into play? Include both quantitative and qualitative factors as appropriate.*	
Criteria: Fit, Accessibility and Costs	The project team considered the required functionality and how well the functionality could be accommodated at the various parcels of land for sale, the accessibility, and the cost of the parcels.

SECTION 3: ALTERNATIVES DETAIL

RECOMMENDED OPTION *Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option. If positive /neutral/negative observations do not exist, enter N/A*	
Description	Purchase two adjacent parcels of land (lots 4 & 5) from the Port of The Dalles and build a new resource center spanning both sites. After the Company completes the purchase of a new two-parcel site, the Company will construct and move into a new facility on the new site. The new property will be used for materials and equipment storage once it is purchased and for construction materials and activities as the new facility is being constructed. The new facility will include an office building and warehouse (both designed to be functional following a seismic event) and various yard support infrastructure. The other structures include a covered pipe storage shed, enclosed specialty equipment storage garage attached to the pipe storage building, a spoils bin and decant system shed, a fuel tank within a fueling canopy, and a truck washroom that includes a Landa unit for separating oil from water. The scope will also include a truck and heavy equipment scale. The Company will also make general site improvements like landscaping, yard lighting, paving, striping and bollard installation, fencing, and motorized driveway gates.
In brief, why is this the	The Company's real estate brokers and the project team evaluated fourteen sites over the last year and a half. The team evaluated five sites more closely with test fits and zoning reviews. From these evaluations, the team is recommending the adjacent parcels of land (Lots 4 & 5) in the Port of The

recommended option?	Dalles as they will best meet the operational and corporate real estate needs of the Company based on cost, usable land and accessibility for vehicles and associated risks.	
Assessment	**Analysis Against Criteria:** Costs, Usable land, and Approach	**Pros:** • Least expensive property available for purchase. • Has the largest amount of usable space of the two finalist sites being considered. • There is strong support from employees and operations management for this approach. • Creating a new resource center at this location would create no or little disruption to Operations. • Recent experience with architect, consultants, and general contractor on similar projects (new build at Lincoln City and Warrenton). **Cons:** • Not applicable
	Analysis Against Criteria: Accessibility and Risks	**Pros:** • The lots 4 & 5 being recommended have excellent vehicle access which is critical for emergency response. • The two lots to be used are zoned industrial, which is appropriate for the intended purpose. • The two lots avoid the potential development risk associated with the Columbia Cinema property since other property is not zoned for our use and would require a conditional use approval. • The project team has met with the permitting agencies in The Dalles and Agencies Having Jurisdiction (AHJ's) appear supportive of the Company's plans for the combined sites. **Cons:** • Not applicable
	Analysis Against Criteria: Timing	**Pros:** • Time required to acquire, design, and permit fits within the Company's desired timeline including completing the project by the time the lease for the current facility in The Dalles expires at the end of 2026. **Cons:** • Completing the due diligence and securing approvals and permits can take time. It is conceivable that there would be significant delays to any of these, then this represents a risk to the schedule.
	Additional Risks	Building a new facility on new site does involve unknown geo-technical conditions, and securing approvals and permits can take time.
	Additional Benefits	**Financial Benefits:** • Bid review process, including competitively bidding scopes over $25,000, results in a lower overall cost. • Structural upgrades to minimize impact from seismic event. **Operational Benefits:** • Multiple design review approach to ensure design meets requirements. • Efficiency: Eliminating need to drive to external locations to dispose of spoils. • Reduced risk: safety (seismic upgrades to office/warehouse, and ability to weigh trucks to ensure not overweighting). • Environmental: Reducing truck drive time to dispose of spoils. **Customer Benefits:** • Benefit of improved availability of employees to carry out evolving day-to-day operations by eliminating unnecessary driving to dispose of wet spoils. Improved efficiency and productivity.

		Employee Benefits: • Improved employee morale from improved functionality (decant tank onsite, exercise room). • Improved efficiency (reduced driving time to dispose of spoils). • Reduced risk: safety (seismic, driving overweighted vehicles). **Other Benefits:** • Bid review process, including competitively bidding scopes over $25,000, results in a lower overall cost. • Complying with ODOT requirement for ensuring vehicles are not over weighted. • Benefit of improved reliability because of addressing the seismic resiliency issue.

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$ 14.8 m	$ 1.63 m (11%)	$ 16.4 m
O&M Range	**Program/Project**		**Ongoing Maintenance & Support**
	$ 0		$ 0
Source/ Method of Cost Data	Bremik (General contractor), LRS (Architect), URI (Owners Representative), project team, Cushman & Wakefield, commercial real estate broker		

ALTERNATIVE 1 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*		
Description	Purchase a new site and build new resource center where the Columbia Cinema is located.	
In brief, why is this option not recommended?	This alternative is not recommended because it would be more expensive and carries a higher risk than the recommended option.	
Assessment	**Analysis Against Criteria:** Costs, Usable land, and approach	**Pros:** • N/A **Cons:** More expensive than Lots 4 & 5
	Analysis Against Criteria: Risks	**Pros:** • N/A **Cons:** • There are zoning issues with this location. It is not zoned industrial. • There is significantly more public relations risk associated with this option given that it is currently the only functioning movie cinema in The Dalles.
	Analysis Against Criteria: Timing	**Pros:** • N/A **Cons:** • The cinema is not approved for the intended usage. It is currently zoned commercial, and this would need to be changed to industrial, which would require a permitting variance and additional time.
	Additional Risks	The permit variance process is complicated and there is no guarantee that it would be approved.
	Additional Benefits	**Financial Benefits:** • N/A **Operational Benefits:** • N/A **Customer Benefits:**

		• N/A **Employee Benefits:** • N/A

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$ 15.8 m	$ 1.7 m (11%)	$ 17.5 m
O&M Range	**Program/Project**		**Ongoing Maintenance & Support**
	N/A		N/A
Source/ Method of Cost Data	Bremik (General contractor), LRS (Architect), URI (Owners Representative), project team, Cushman & Wakefield, commercial real estate broker		

ALTERNATIVE 2 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*		
Description	Purchase a new site and build new resource center at either 215 Terminal Avenue, 208 Webber Street or Ward Road.	
In brief, why is this option not recommended?	The team is not recommending any of these sites as having reviewed them they were determined to be not suitable for our operational and corporate real estate purposes.	
Assessment	**Analysis Against Criteria:** Costs, Usable land, and approach	**Pros:** • N/A **Cons:** • The sites are deemed unsuitable for the following reasons: ○ **Terminal Ave:** The parcel size is insufficient for our needs, and the sloping topography would limit its usability. ○ **Ward Rd:** The property size does not meet the required functionality. ○ **Webber St:** Proximity to the railroad line would likely impede site access.
	Analysis Against Criteria: Risks	**Pros:** • N/A **Cons:** • The sites are considered unsuitable for the following reasons: ○ **Terminal Ave:** The sloping topography would limit its usability. ○ **Webber St:** Proximity to the railroad line would likely impede site access.
	Analysis Against Criteria: Timing	**Pros:** • N/A **Cons:** • N/A
	Additional Risks	N/A
	Additional Benefits	**Financial Benefits:** • N/A **Operational Benefits:** • N/A **Customer Benefits:** • N/A **Employee Benefits:** • N/A
POTENTIAL COST (EXCLUDING CONTINGENCY)		

Capital Range	Direct	CURRENT COH	Total
	$ n/a	$ n/a	n/a
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	N/A	N/A	
Source/ Method of Cost Data	Bremik (General contractor), LRS (Architect), URI (Owners Representative), project team, Cushman & Wakefield, commercial real estate broker		

ALTERNATIVES CONSIDERED NOT VIABLE *Provide a description of any additional alternatives that were considered but rejected up front as not viable, and explain why*		
	Description	**Why the Alternative is not viable**
Alternative 3	Purchase the current site and retrofit the existing building and yard	• Site too small • Not for sale
Alternative 4	Move employees, equipment, materials, and vehicles to the Parkrose Resource Center	• The Parkrose Resource Center is 75 + miles away and moving this far away would severely impact the Company's ability to respond to emergency calls in the Hood River, Wasco, Klickitat and Skamania Counties. • Parkrose is not large enough to accommodate the employees, equipment, materials, and vehicles from The Dalles. • Additionally, Parkrose does not have a decant system or a truck scale.
Alternative 5	Move employees, equipment, materials, and vehicles to the Vancouver Resource Center	• The Vancouver Resource Center is 82+ miles away and moving this far away would severely impact the Company's ability to respond to emergency calls in the Hood River, Wasco, Klickitat and Skamania Counties. • Vancouver is not large enough to accommodate the employees, equipment, materials, and vehicles from The Dalles.
Alternative 6	Do nothing	• Does not address the issue of the current lease expiring on 12/31/2026. • Does not address the lack of functionality at the existing leased facility. • Does not address the need for a local means of disposing of wet spoils. • Does not address safety and health needs of employees. • Does not address regulatory (ODOT) requirements.

SUPPLEMENTARY INFORMATION

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Wayne K. Pipes

FACILITIES

Exh. WKP-4

August 29, 2025

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NW Natural Land Acquisition and Negotiation Summary – The Dalles, OR

Objective: Cushman & Wakefield was engaged to identify and secure a land site or existing structure for purchase. The ideal site needed to be a strategically located, approximately (2) two to four (4) acre parcel of commercially or industrially zoned land with easy access to transportation links, ensuring both optimal value and cost efficiency. We completed this search over a period of multiple years, unable to find a structure which (1) existed and (2) was financially feasible to develop into the building NW Natural needed.

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1. Site Selection Process:

Our team followed our typical site selection process below; however, what was unique about this requirement was the limited availability of inventory, both in existing structures that could be converted and available land.

- *Defining Requirements*: Established key criteria, including site size, zoning, accessibility, infrastructure availability, and future expansion potential.
- *Market Research*: Assessed available properties, market conditions, recent sales, and comparable transactions to determine the best options. In this particular instance there were so few options being marketed that we actively called all sites that we felt could potentially meet NW Natural's need to identify off-market opportunities.
- *Property Shortlisting*: Identified top candidates based on cost, location, entitlement feasibility, and development readiness. There were very few sites, and most were non-conforming uses, or sites that use to be alternative uses. For example, we evaluated converting a movie theater for this use and it proved to be problematic and cost prohibitive. Suffice to say all rocks were uncovered.
- *Due Diligence*: Conducted site visits, environmental assessments, and legal compliance reviews to mitigate risks before advancing negotiations. Additionally, evaluated construction costs of reconfigurations versus the cost of new construction.

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2. Negotiation Strategy & Execution:

After a five year search for an existing facility that could be converted, we identified land at the Port of The Dalles which met the needs of NW Natural most efficiently; however, we initially began negotiating on sites 8 & 9, which contained attributes provided them a higher value for other users. Additionally, after our due diligence, it was determined that a significant amount of the lots was not developable, due to both slope as well as wetlands.

As a result, our negotiation strategy to pay only for the portion of the lots that NW Natural could develop and build on. Additionally, the Port preferred to have NW natural relocate to lots 4 & 5. NW Natural fit well on lots 4 & 5, and the attributes that made lots 8 & 9 a higher value for the Port did not impact NW Natural. However, lots 4 & 5 were larger so our team negotiated that we would pay for only the size of developable land we would have purchased on lots 8 & 9.

No warranty or representation, expressed or implied, is made as to the accuracy of the information contained herein, and same is submitted subject to errors, omissions.

3. Cost Savings Summary:

Our team's negotiation strategy was implemented to achieve optimal results and used two primary strategies:

1: Only pay on the useable land, not the land in entirety

2: Develop on the most cost affordable land (size and price) that fit NW Natural's need.

Originally, the Port placed NW Natural on lots 8 and 9, which had an asking price of $1,276,691.33. However, the Port later determined that these sites, despite their excellent views of the Columbia River Gorge, were not well-suited for industrial use. As a result, they instead offered lots 4, 5, and 6, stating that lots 8 and 9 were no longer an option.

Lots 4 and 5 were significantly larger (6.4 acres compared to 2.7 acres), with a combined asking price of $2,310,000—substantially more than the original lots. Despite this, we successfully negotiated for NW Natural to pay only for the usable area of lots 4 and 5.

After evaluating these lots, NW Natural not only secured the agreement to pay only for the usable portion but also negotiated an additional $75,000 credit from the Port. This resulted in a final purchase price of $999,999.00, making it the most cost-effective land option.

It is important to note that after evaluating multiple existing buildings and other sites in the area over a period of five (5) years, these were the only sites that would be suitable for this facility. The concern from the community was that NW Natural would have to look outside the Dalles, which from a business perspective did not serve customers as well, and from a real estate perspective would have been more costly.

Summary: Through a multi-year site selection process we were able to find multiple land and sites to be evaluated. However, after due diligence on multiple sites all sites were ruled out because they were either cost prohibitive (a reconfiguration far exceeded new construction costs) or they did not meet the needs of NW Natural (zoning, soils, etc). After we identified sites that could work we negotiated only to pay for land that could be developed and through due diligence and test fits identified the most cost effective solution for NW Natural that best meet their needs.

If you have any questions, we would be happy to provide additional information or have a discussion.

Thank you,

Matt Johnson
Executive Managing Director

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BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Wayne K. Pipes

FACILITIES

Exh. WKP-5

August 29, 2025

NW Natural
PROJECT ALTERNATIVES NARRATIVE

Program/Project Name: 2025 Physical Security Enhancement - Oregon
Date: 12/3/2024
Project Sponsor: Wayne Pipes
Executive Sponsor: MardiLyn Saathoff
Project Manager: Mackenzie Hopkins
Preparers: Philip Zlatnik, Mackenzie Hopkins

SECTION 1: BUSINESS CASE

This section should be solution-agnostic, and about the overarching problem we're trying to solve no matter which route we end up taking.

OBJECTIVES *Why are we tackling this project?*	
Current State What is happening now? Where are we starting?	The initial phase of a multi-year initiative concluded early in 2024 with a pilot project focused on enhancing security. This phase successfully upgraded security at five high-priority locations and updated the Corporate Security Standards document, specifically the Tiers of Protection. Additionally, it reduced incidents of theft and break-ins at a local resource center and provided crucial insights for the broader security enhancement program. After the first year of the project concluded, the project team and key stakeholders identified the next group of priority sites for upgrades in 2025.
Problem Statement In simple terms, what are we trying to solve? What is the business need this is tackling? Why is this a problem worth solving (e.g. why is the current state not working)?	In response to increasing threats, changing trends in the security industry, and ongoing direction from TSA, NW Natural is undertaking a comprehensive, multi-year effort to enhance the physical security at the Company's facilities and field infrastructure.

Desired Deliverables
What high level output / scope / deliverables are core to this project?
	Continue with the security upgrade program that started with the pilot in 2023.
	• Enhance physical security at critical facilities, as identified by the TSA Pipeline Guidelines and assessments conducted by Corporate Security.
	• Complete security upgrades at the sites approved for 2025. The upgrades will include a combination of the following:
	  ○ 7' Anti-Climb or 8' Chain Link Fence with three strands of barbed wire and outward barbed wire arms.
	  ○ Panel Filler and rock as needed.
	  ○ Black industrial fencing slats.
	  ○ Emergency egress for every pedestrian gate with mesh screening and pick plates installed.
	  ○ Protected padlock enclosure for all pedestrian and vehicle gates with padlocks.
	  ○ Reinforced vehicle gate with full metal shrouds.
	  ○ NW Natural "No Trespassing" signage every 50 feet and at every pedestrian/vehicle gate.
	  ○ Perforated metal installed over existing or infilled/secured exterior building windows.
	  ○ Reinforced exterior building doors with no windows and 6" exterior door pick plates.
	  ○ Storefront design locks for exterior building doors with no interior locking tumbler.
	  ○ LED lighting to sufficiently illuminate all interior and exterior areas.

	○ CCTV cameras to provide sufficient coverage of exterior areas. ○ Clear vegetation zone several feet from the exterior fence line. ○ Bollards, Jersey barriers, or other traffic control devices. • Update the Tiers of Protection and hardware specifications as required. • Continue to execute and evolve the program to manage security upgrades at the high-priority sites annually over the next three years.

SECTION 2: ALTERNATIVES SUMMARY

OVERVIEW *How did we review these options?*	
Review Process Summarize how options were chosen, who was involved in the choice and how options were evaluated. If some criteria were considered more important based on the type of project, please explain here.	The review process concentrated on evaluating the remaining NW Natural sites based on their criticality, as well as the equipment and materials required to enhance physical security in the most cost-effective way, rather than adopting entirely different security measures like deploying guards. Building on the security pilot conducted in 2023, the method for prioritizing sites has evolved to include critical facilities as outlined in the TSA Pipeline Guidelines, sites identified as Critical Cybersecurity Assets (CCSA), and recommendations from Corporate Security. The approach has been shared with the Physical Security Steering Committee.
DECISION CRITERIA *Describe the criteria used to determine the selection from the various alternatives considered. For example, is this a program/project where the least cost option should be selected? Are there other factors, such as safety or quality that come into play? Include both quantitative and qualitative factors as appropriate.*	
Criteria: Implementation Approach and Costs	The decision-making criteria encompass approaches for addressing both short-term and long-term security risks at the different sites, compliance with TSA regulations, and the overall costs.
Criteria: Risks	The decision criteria focus on the criticality and risk profile of each site (including any recent/recurring security incidents) and the urgency of compliance with TSA requirements.
Criteria: Timing	• Urgency to address security gaps. • Safety considerations, such as avoiding hot work (like welding) during summer at remote locations.

SECTION 3: ALTERNATIVES DETAIL

RECOMMENDED OPTION *Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option. If positive /neutral/negative observations do not exist, enter N/A*	
Description	Proceed with the third year of the multi-year program to implement physical security upgrades.
In brief, why is this the recommended option?	• Leverages the approach endorsed by industry leader CH2M. • Implements design specifications and tiers of protection as recommended by Corporate Security. • Builds upon the successful pilot project completed in early 2024. • Reduces risk to employees and customers in a methodical, risk-based manner, prioritizing according to site criticality.

	• Offers the most effective strategy to address security vulnerabilities at the Company's sites and ensure compliance with TSA regulations. • Continuously informs and guides the ongoing multi-year program to address the Company's security needs. • Helps ensure the Company's system can continue providing safe and reliable service to customers without interruption.	
Assessment	**Analysis Against Criteria:** Implementation Approach and Costs	**Pros:** • Most cost-effective method for enhancing security across the Company's service territory. • The implementation approach is refined through updates made to the Tiers of Protection and the development of hardware specifications during the pilot, including unit pricing. • Continuation of security upgrades reinforces the Company's commitment to complying with TSA regulations. • Enhances physical security at facilities and increases accountability for access by personnel and visitors. **Cons:** • May still require the deployment of guards or other forms of deterrents at certain sites for specific tasks that necessitate human presence.
	Analysis Against Criteria: Risks	**Pros:** • The risk mitigation strategy benefits from insights derived from the successful completion of the pilot project, including the use of gas and Radio Frequency detection equipment at pipeline and telemetry sites (where microwave equipment is present). **Cons:** • None identified.
	Analysis Against Criteria: Timing	**Pros:** • The implementation plan is refined by insights gained from completing the pilot project, which include detailed hardware specifications, understanding product lead times, and better understanding of installation timeframes. **Cons:** • None identified.
	Additional Risks	• Potential delays in the supply chain could impact the timely completion of security upgrades. • Changes in regulatory requirements or updates to TSA guidelines may require adjustments to planned security measures, potentially increasing costs and implementation time. • Unforeseen technical challenges could arise with new security technologies or hardware being integrated into existing systems.
	Additional Benefits	• **Incident Analysis:** Provides the capability for video review at some sites, enhancing security and safety incident responses. • **Data Utilization:** Employs analytics and technology to analyze data and video, aiding in investigations and operational assessments.

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$2.5M	$0.25M (10%)	$2.75M
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	N/A	N/A	
Source/ Method of Cost Data	Essex (General contractor), URI (Owners Representative), project team.		

ALTERNATIVE 1 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*		
Description	Enhance site security by deploying contract guards at select locations in addition to reinforcing physical barriers and controls. This includes installing upgraded fencing, enhanced lighting, more robust access control systems, and improving clearance from vegetation to reduce concealment opportunities.	
In brief, why is this option not recommended?	Given NW Natural's 1200+ geographically diverse and often remote sites, deploying security guard services extensively would be cost prohibitive. While deploying guards at select locations is possible, for 2025, there is only one site where this approach makes sense. This strategy is not sustainable or recommended for most sites.	
Assessment	**Analysis Against Criteria:** Implementation Approach and Costs	**Pros:** • Provides real-time security response to break-ins. **Cons:** • Incurs additional Operations and Maintenance (O&M) costs on top of the expenses for implementing physical security enhancements at each site. • Not feasible to deploy guards at all sites, especially in remote locations.
	Analysis Against Criteria: Risks	**Pros:** • Provides for more immediate security response to break-ins. **Cons:** • Limited capability to deploy guards at all sites, especially those in remote areas.
	Analysis Against Criteria: Timing	**Pros:** • Provides for more immediate security response to break-ins. • Guards can potentially be deployed more quickly at select sites compared to implementing full security upgrades. **Cons:** • Not sustainable as a long-term security solution. • Full security upgrades are still necessary at sites, even with guard deployment.
	Additional Risks	N/A
	Additional Benefits	N/A

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$2.5M	$0.25M (10%)	$2.75M
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
		$ 73K*	
Source/ Method of Cost Data	Essex (General contractor), URI (Owners Representative), project team, current PO with Compass Security for unarmed security services. *Annual cost for deploying guards at the noted one site (8x5).		

ALTERNATIVE 2 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*	
Description	Establish a Security Operations Center (SOC) and employ 5-6 full-time employees to monitor camera feeds and manage alarm systems across multiple sites. This setup will enable centralized surveillance and rapid response coordination.

In brief, why is this option not recommended?	While establishing a Security Operations Center (SOC) and hiring 5-6 full-time employees offers a more integrated long-term security solution compared to deploying contract guards, it is not recommended at this time due to the higher O&M costs involved. Additionally, this option would still necessitate upgrading fencing, lighting, and access control at resource centers and remote sites, further increasing the overall cost.	
Assessment	**Analysis Against Criteria:** Implementation Approach and Costs	**Pros:** • Provides more immediate security response to break-ins. **Cons:** • Incurs significant operational and maintenance costs and implementing physical security enhancements at each site. • Limited feasibility of deploying guards at all sites, particularly in remote locations.
	Analysis Against Criteria: Risks	**Pros:** • Provides for more immediate security response to break-ins. **Cons:** • Limited capability to deploy guards at all sites, especially those in remote areas.
	Analysis Against Criteria: Timing	**Pros:** • Provides for more immediate security response to break-ins. **Cons:** • Establishing the SOC would entail additional time but potentially could be done in parallel with implementing physical security enhancements at each site.
	Additional Risks	N/A
	Additional Benefits	N/A

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$2.5M	$0.25M (10%)	$2.75M
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
		$ 800-960K*	
Source/ Method of Cost Data	Essex (General contractor), URI (Owners Representative), project team. * Assumption: Fully loaded Security Consultant FTE is $160K/year		

ALTERNATIVES CONSIDERED NOT VIABLE

Provide a description of any additional alternatives that were considered but rejected up front as not viable, and explain why

	Description	**Why the Alternative is not viable**
Alternative 3	Take no action	The current risk level, as determined by CH2M's security assessment, is unacceptable. Additionally, Corporate Security has indicated that there is still work to be done to ensure compliance with TSA guidelines.
Alternative 4		
Alternative 5		

SUPPLEMENTARY INFORMATION

As needed, you may include any useful information gathered during the assessment phase including analysis like cost benefit / risk analysis / sensitivity analysis, etc.

Approved AA for the 2024 Physical Security Enhancement Project

2024 Phys Sec Enhancement AA.doc›

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Wayne K. Pipes

FACILITIES

Exh. WKP-6C

REDACTED VERSION

August 29, 2025

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY (PAGES 1-2) UNDER WAC 480-07-160 AND HAS BEEN REDACTED.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

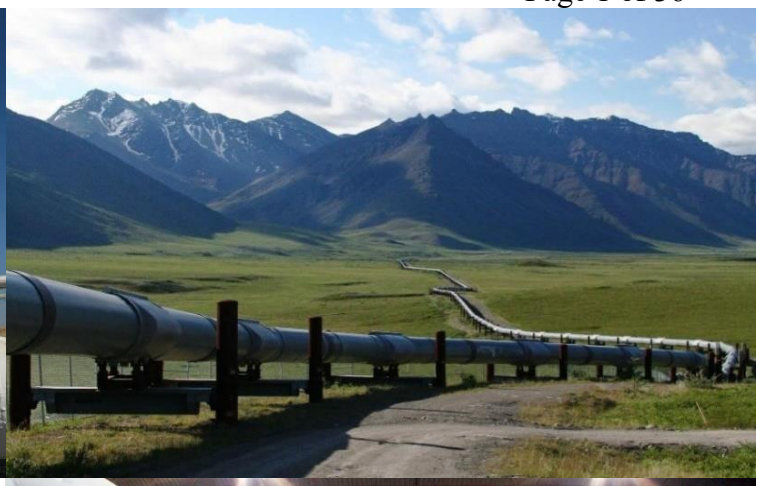
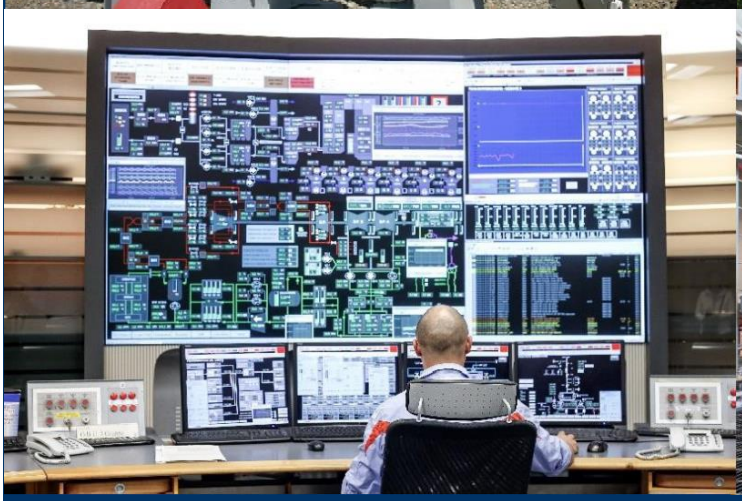
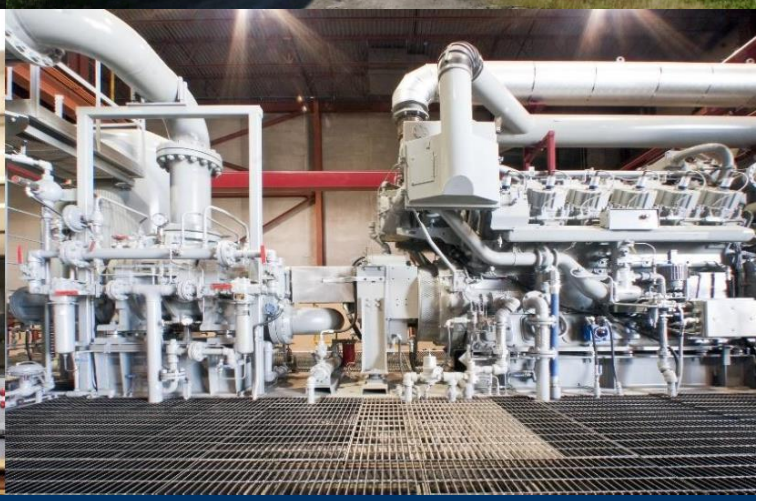
NORTHWEST NATURAL GAS COMPANY

Exhibit of Wayne K. Pipes

FACILITIES

Exh. WKP-7

August 29, 2025

Pipeline Security Guidelines

March 2018 (with Change 1 (April 2021))

Transportation Security Administration

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Record of Changes

Change Number	Date	Comment
1	April 2021	Replaced Section 5 (Criticality)

1 INTRODUCTION

Under the provisions of the Aviation and Transportation Security Act (Public Law 107-71), the Transportation Security Administration (TSA) was established on November 19, 2001 with responsibility for civil aviation security and "security responsibilities over other modes of transportation that are exercised by the Department of Transportation." On September 8, 2002, TSA initiated its pipeline security efforts. Those responsibilities now reside within the Office of Security Policy and Industry Engagement's Surface Division.

1.1 Background and Purpose

In executing its responsibility for national pipeline security, TSA originally utilized the Pipeline Security Information Circular, issued on September 5, 2002, by the Department of Transportation's (DOT) Office of Pipeline Safety as the primary Federal guideline for industry security. Complementing this document, and also adopted by TSA, was the DOT-issued Pipeline Security Contingency Planning Guidance of June 2002.

Recognizing that the Security Circular required updating, TSA initiated a process to amend the Federal security guidance. The 2010 Pipeline Security Guidelines were developed with the assistance of industry and government members of the Pipeline Sector and Government Coordinating Councils, industry association representatives, and other interested parties. This document was soon revised resulting in the 2011 Pipeline Security Guidelines.

The advancement of security practices to meet the ever changing threat environment in both the physical and cyber security realms required that the guidelines be updated again. Utilizing a similar industry and government collaborative approach, TSA developed this document, which supersedes the 2011 version of the Pipeline Security Guidelines.

The security measures in this guidance provide the basis for TSA's Pipeline Security Program Corporate Security Reviews and Critical Facility Security Reviews. This document is guidance and does not impose requirements on any person or company. The term "should" means that TSA recommends the actions described. Nothing in this document shall supersede Federal statutory or regulatory requirements.

1.2 Scope

These guidelines are applicable to operational natural gas and hazardous liquid transmission pipeline systems, natural gas distribution pipeline systems, and liquefied natural gas facility operators. Additionally, they apply to operational pipeline systems that transport materials categorized as toxic inhalation hazards (TIH). TIH materials are gases or liquids that are known or presumed on the basis of tests to be so toxic to humans as to pose a health hazard in the event of a release during transportation. (See the Hazardous Materials Regulations: 49 CFR parts 171-180.)

Operators of pipeline systems not included in the descriptions above are encouraged to implement the security measures contained herein to the extent appropriate to their particular system.

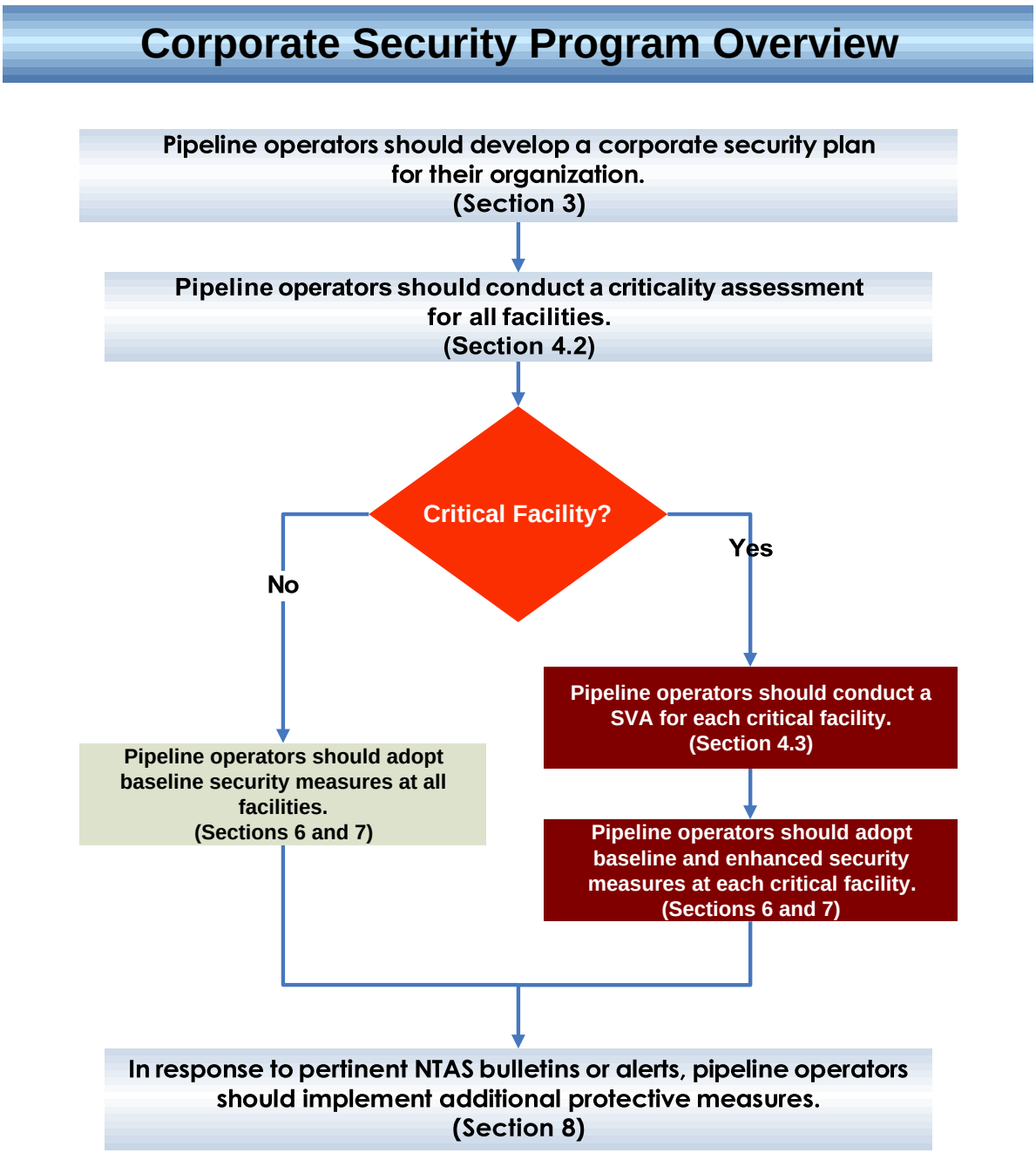
2 CORPORATE SECURITY PROGRAM

A risk-based corporate security program should be established and implemented by each pipeline operator to address and document the organization's policies and procedures for managing security related threats, incidents, and responses. In addition, each operator should:

- Develop a corporate security plan as described in Section 3;
- Ensure sufficient resources, to include trained staff and equipment, are provided to effectively execute the corporate security program;
- Ensure identified security deficiencies have appropriate financial resources allocated in the corporate budgeting and purchasing processes;
- Assign a qualified primary and alternate staff member to manage the corporate security program;
- Develop and maintain a cyber/Supervisory Control and Data Acquisition (SCADA) security plan, or incorporate cyber/SCADA security measures in the corporate security plan;
- Develop and maintain security elements within the corporate incident response and recovery plan;
- Implement appropriate threat level protective measures upon receipt of a pertinent National Terrorism Advisory System (NTAS) Bulletin or Alert; and
- Notify TSA of security incidents meeting the criteria provided in Appendix B by phone or email as soon as possible.

Figure 1 identifies the major steps that each pipeline operator should take in creating and implementing a corporate security program and the relevant sections in the guidelines where specific details are provided.

Figure 1: Corporate Security Program Overview



3 CORPORATE SECURITY PLAN

3.1 Introduction

Operators should develop and implement a security plan customized to the needs of the company. The corporate security plan should be comprehensive in scope, systematic in its development, and risk-based reflecting the security environment. At a minimum, the plan should:

- Identify the primary and alternate security manager or officer responsible for executing and maintaining the plan;
- Document the company's security-related policies and procedures, to include, but not limited to, methodologies used and timelines established for conducting criticality assessments, risk assessments, and security vulnerability assessments (SVAs), if applicable;
- Reference other company plans, policies and procedures such as insider threat, business continuity, incident response and recovery plans;
- Be reviewed on an annual basis, and updated as required based on findings from assessments, major modifications to the system or any of its facilities, substantial changes to the environment in which it operates, or other significant changes;
- Be protected from unauthorized access based on company policy; and,
- Be provided to TSA for review upon request.

3.2 Security Plan Elements

This section identifies and provides a brief description of the recommended elements of a corporate security plan. In developing their plan, operators should incorporate these elements in a format that is most suitable to their organization.

- **System(s) Description** - Identify the pipeline system(s) to which the plan applies.
- **Security Administration and Management Structure** - Identify the person(s) primarily responsible for the corporate security program, and describe the responsibilities and duties of personnel assigned to security functions.
- **Risk Analysis and Assessments** - Describe the methodology used to conduct security risk analysis to include criticality assessments and SVAs.
- **Physical Security and Access Control Measures** - Describe the corporate policies and procedures employed to reduce security risks throughout the company.
- **Equipment Maintenance and Testing** - Discuss policies and procedures for ensuring security systems and equipment are maintained and function properly.

- **Personnel Screening** - Describe policies and procedures for conducting employee background checks, including criteria for disqualification and process for appeal, in compliance with Federal and state laws. Describe company policies for contractor personnel background checks.
- **Communications** - Describe the policies and procedures employed to ensure effective communication is maintained on both a routine and emergency basis. The description should include, but not be limited to, types of equipment used, communication methods between personnel, facilities, off-site responders, and procedures for notification of government and law enforcement agencies.
- **Personnel Training** - Describe security training requirements, to include training in security equipment operation, security awareness, and security incident recognition and reporting procedures for company personnel and contractors.
- **Drills and Exercises** - Describe company policies and procedures for conducting security drills and exercises. Establish requirements for after-action reports, communication of lessons learned, and implementation of security improvement efforts based on exercise results.
- **Security Incident Procedures** - Describe procedures for responding to security incidents and emergencies. Define the types of events that constitute a breach of security, describe the procedures for investigating security incidents, and who should be notified. In addition, the emergency response plan may be referenced in this section.
- **NTAS Response Procedures** - Describe the operator's additional protective measures for periods of heightened threat corresponding to the duration of Department of Homeland Security (DHS) NTAS Bulletins or Alerts.
- **Plan Reviews** - Describe policies and procedures for the review, validation, and updating of the corporate security plan.
- **Recordkeeping** - Describe security-related recordkeeping requirements, such as for criticality assessments, SVAs, and other company sensitive security information, as well as measures to prevent unauthorized disclosure.
- **Cyber/SCADA System Security Measures** - Describe the corporate policies and procedures employed to reduce security risks to cyber/SCADA systems and assets throughout the company. If a separate cyber/SCADA security plan is maintained, it should be incorporated by reference.
- **Essential Security Contact Listings** - List internal and external emergency contact information for reporting and responding to a security incident or suspicious activity.
- **Security Testing and Audits** - Describe policies and procedures for auditing and testing of the effectiveness of the company's security plan and procedures, to include documentation of results.
- **Outreach** - Describe policies and procedures for company security awareness outreach efforts to neighbors, law enforcement, media, and the public.

4 RISK ANALYSIS

4.1 Introduction

The intent of these guidelines is to bring a risk-based approach to the application of the security measures throughout the pipeline industry. As stated in the National Infrastructure Protection Plan, DHS assesses risk as a function of threats, vulnerabilities, and consequences. With this in mind, the most effective security programs employ a risk management process that facilitates planning and decision making to mitigate risks for pipeline assets. General elements include:

- Assessments used to determine facility criticality;
- Threat assessments identifying known or potential adversaries;
- Vulnerability assessments identifying security weaknesses;
- Risk assessments (based on threat, vulnerability, and consequence, considering facility criticality assessment findings);
- Risk mitigation to determine and implement appropriate risk reduction countermeasures; and
- Ongoing risk management to monitor, reassess, and modify the program.

Recognizing that there are multiple risk assessment methodologies, each operator should determine the process and methodology most appropriate for implementation of the corporate security plan at the facilities comprising their pipeline system. TSA may ask to review the operator's risk assessment methodology.

4.2 Criticality Assessment

Determining facility criticality is an essential first step in the security risk management process. Information and findings gathered in the criticality assessment assist operators with prioritizing assets and implementing risk reduction countermeasures. Operators should evaluate each operating facility within their system using the criteria outlined in Section 5.2 to determine or validate criticality. Operators should:

- Conduct facility criticality assessments on a periodic basis, not to exceed 18 months, for all facilities;
- Document the methodology used, and retain the criticality assessment until no longer valid;
- Conduct an SVA or the equivalent as outlined in Section 4.3 of this document for facilities determined to be critical; and
- Maintain and secure the company's list of critical facilities.

The operator's list of critical facilities is subject to review and evaluation by TSA. Operators and TSA will work together towards concurrence on the facilities listed.

4.3 Security Vulnerability Assessment

A security vulnerability assessment (SVA) is one of the risk assessment methodologies pipeline operators may choose. The SVA serves as a planning and decision support tool to assist security managers with identifying, evaluating, and prioritizing risks and determining effective security measures to mitigate threats and vulnerabilities to their critical facilities. Common steps performed while conducting an SVA include:

- Asset Characterization - identification of hazards and consequences of concern for the facility, its surroundings, and its supporting infrastructure; and identification of existing layers of protection;
- Threats Assessment - description of possible internal and external threats;
- Security Vulnerability Analysis - identification of potential security vulnerabilities and existing countermeasures and their level of effectiveness in reducing identified vulnerabilities;
- Risk Assessment - determination of the relative degree of risk to the facility in terms of the expected effect on each asset and the likelihood of success of an attack; and
- Countermeasures Analysis – comparison of strategies that reduce the probability of a successful attack or reduce the possible degree of success, strategies that enhance the degree of risk reduction, the capabilities and effectiveness of mitigation options, and the feasibility of the options.

Operators of critical pipeline facilities should:

- Conduct an SVA or the equivalent on a periodic basis, not to exceed 36 months, and within 12 months after completion of a significant enhancement or modification to the facility;
- Conduct an SVA or the equivalent for newly identified or constructed critical facilities within 12 months of designation or after achieving operational status.
- Document findings from each assessment and retain them until no longer valid;
- Implement appropriate findings from the SVA in a timely fashion but no later than 24 months after SVA completion; and
- Document the assessment methodology used and make the documentation available for TSA review upon request.

5 CRITICALITY

5.1 Introduction

The objective in determining which pipeline facilities are critical is to ensure that reasonable appropriate security risk reduction measures are implemented thereby reducing the impact of service disruptions to critical infrastructure and the public.

5.2 Facility Criticality

The designation of critical pipeline facilities is a challenging task considering the diverse operational and market environments spanning the pipeline industry. Pipeline operators are uniquely positioned to understand the criticality of their operations and the infrastructure necessary to serve those functions. Pipeline companies should develop a written policy and procedure to identify critical facilities in accordance with their enterprise risk management process and the TSA guidance below.

To aid operators in applying the guidance, the criteria are differentiated for each of the three major pipeline subsectors:

- natural gas distribution
- natural gas transmission (to include LNG peak shaving and satellite plants)
- hazardous liquid transmission

Determination of pipeline critical facilities:

- TSA is responsible for notifying pipeline operators of TSA-designated critical pipeline systems. Operators should pay particular attention to identifying critical facilities on these systems.
- A pipeline facility is considered critical if it provides primary service to designated critical infrastructure and is determined by the operator to be a "single point of failure" (i.e., does not have redundancy or systematic backup). TSA defines a single point of failure as a facility that if rendered inoperable would degrade service to critical infrastructure to the point that the infrastructure would not be able to satisfactorily perform its critical mission.
- Operators are responsible for conducting an operational assessment and identifying specific pipeline facilities that are necessary for critical pipeline systems (as designated by TSA) to function.
- System redundancies, contingency plans and available mitigations may be considered when evaluating the criticality of a facility. If requested, operators should provide TSA documentation including how identified redundancies are evaluated. This documentation is protected from unauthorized disclosure as sensitive security information. As external mutual aid is not under the control of the operator, it should not be considered as a contingency or mitigation factor when identifying critical facilities.
- Operators should coordinate with the appropriate internal company business functions, (e.g., sales, marketing, and rates (tariffs)) to identify pipeline feeds to potentially critical

infrastructure, including large volume customers such as natural gas-fired power generation plants, military bases and defense industrial base manufacturers.

- Operators may take into consideration whether firm or interruptible contracts are in place. In general, contracts for interruptible service may indicate the dependency on a fuel source is not vital to that critical infrastructure; however, this assumption should be validated with owners of said critical infrastructure.
- Operators may consider adjustments based on the severity of consequences as a result of the loss of a facility or disruption in service (e.g., climate conditions, restart capability and life-safety).
- Operators may consider their ability to continue operations (e.g., product free flow or alternate or redundant prime-mover capacity) as an adequate facility backup as long as they demonstrate no impact to deliverability.
- TSA, in consultation with pipeline operators, may designate specific pipeline facilities as critical in accordance with this guidance.
- Operators may set more stringent criteria and designate facilities as critical in addition to those meeting the guidance below.

A pipeline facility is defined as new and existing pipelines, rights of way, and any equipment, facility, or building used in the transportation of gas or hazardous liquids or in the treatment of gas or hazardous liquids during the course of transportation.[1] Critical facilities may include, but are not limited to:

- pipeline interconnections
- metering and/or regulating stations
- pump stations
- compressor stations
- operational control facilities
- main line valves
- tank farms, terminals

If damage or destruction of a facility has the potential to meet at least one of the following criteria, the facility or facilities should be designated as critical.

[1] Consistent with definitions in 49 CFR § 192.3, 193.2007 and 195.2.

Table 1: Critical Facility Criteria

Criteria	Subsector	Guidance
1. Disrupt or significantly reduce required service or deliverability to installations identified as critical to national defense.		TSA will notify pipeline operators who directly serve installations or defense industrial base (DIB) manufacturers deemed critical to national defense and who rely on the pipeline commodity to perform a critical mission at that location.
	Natural Gas Distribution	Natural gas distribution operators should designate as critical those facilities that must function to provide service to critical defense installations or DIB manufacturers with a firm contract.
	Natural Gas Transmission	Natural gas transmission operators should designate as critical those facilities that must function to provide service to critical defense installations or DIB manufacturers with a firm contract.
	Hazardous Liquid Transmission	Hazardous liquid transmission operators should designate as critical those facilities that must function to provide service to critical defense installations or DIB manufacturers.
2. Disrupt or significantly reduce required service or deliverability to key infrastructure (such as power plants or major airports) resulting in major operational disruption.		TSA will notify pipeline operators of key infrastructure they serve (e.g., "black start" electric power generation plants, Category X airports and service to the Strategic Petroleum Reserve).
	Natural Gas Distribution	Service to Natural Gas-Fired Power Generation Plants Natural gas distribution operators should designate as critical those facilities that must function to provide service to power generation facilities that: • Directly serve as Defense Critical Electric Infrastructure as identified by Department of Energy (DOE) and with firm contract • Receive natural gas in excess of 30,000 MMcf annually per a firm contract as listed on Energy Information Administration (EIA) Form 923 (Power Plant Operations Report (Annual)) • Serve as a "black start" electric generation plant with firm contract
	Natural Gas Transmission	Service to Natural Gas-Fired Power Generation Plants Natural gas transmission operators should designate as critical those facilities that must function to provide service to power generation facilities that: • Directly serve as Defense Critical Electric Infrastructure as identified by DOE and with firm contract

Criteria	Subsector	Guidance
2. Disrupt or significantly reduce required service or deliverability to key infrastructure (such as power plants or major airports) resulting in major operational disruption. (Cont.)	Natural Gas Transmission (Cont.)	• Receive natural gas in excess of 30,000 MMcf annually per a firm contract as listed on EIA Form 923 (Power Plant Operations Report (Annual)) • Serve as a "black start" electric generation plant with firm contract
	Hazardous Liquid Transmission	Service to Category X Airports Hazardous liquid transmission operators should designate as critical those facilities that must function to provide service to TSA designated Category X airports. Service to the Strategic Petroleum Reserve (SPR) Hazardous liquid transmission operators should designate as critical those facilities that must function to provide service to or within the SPR sites.
3. Cause mass injuries, casualties or significant health or environmental effects.[2]	Natural Gas Distribution	Operator-Generated Methodology In addition to guidance below, natural gas distribution operators should use their own methodology to designate additional critical facilities which may cause mass casualty or significant health effects. Operators should consider variation in service territory and facility siting, differences in regional weather extremes and distinctions among risk profiles. Facilities Operating Near Occupied Buildings or Areas Natural gas operators should evaluate their facilities through their Distribution Integrity Management Program (DIMP)[3] or comparable risk methodology and designate as critical those facilities that: • Operate at pressures above 125 PSIG • Operate in a Class 4 location (regardless of operating pressure) as defined in the Dept. of Transportation (DOT) 49 Code of Federal Regulations [4] • Operate in a Class 3 location (regardless of operating pressure) and do not have service regulators installed or redundant overpressure protection systems

[2] For these guidelines, a mass casualty incident is defined as an event that overwhelms the local healthcare system, where the number of casualties vastly exceeds the local resources and capabilities in a short period of time.
[3] 49 CFR, Part 192 Subpart P, Gas Distribution Pipeline Integrity Management (IM).
[4] 49 CFR § 192.5.

Criteria	Subsector	Guidance
3. Cause mass injuries, casualties or significant health or environmental effects. (Cont.)	Natural Gas Distribution (Cont.)	High Risk (Tiered) Facilities under DHS CFATS Natural gas distribution operators should review and consider as critical all facilities designated as high risk under the DHS Chemical Facility Anti-Terrorism Standards (CFATS) program.
	Natural Gas Transmission	Facilities Operating in HCAs Natural gas transmission operators should designate as critical all facilities operating in High Consequence Areas (HCAs) as defined in Dept. of Transportation (DOT) 49 Code of Federal Regulations.[5] HCAs could include designated human health-safety, structure or human occupancy impact zones from a release of natural gas. High Risk (Tiered) Facilities under DHS CFATS Natural gas transmission operators should review and consider as critical all facilities designated as high risk under the DHS Chemical Facility Anti-Terrorism Standards (CFATS) program.
	Hazardous Liquid Transmission	Facilities Operating in HCAs Hazardous liquid transmission operators should designate as critical all facilities operating in High Consequence Areas (HCAs) as defined in Dept. of Transportation (DOT) 49 Code of Federal Regulations.[6] HCAs can include commercially navigable waterways, high population areas, other populated areas, or unusually sensitive areas. High Risk (Tiered) Facilities under DHS CFATS Hazardous liquid transmission operators should review and consider as critical all facilities designated as high risk under the DHS Chemical Facility Anti-Terrorism Standards (CFATS) program.
4. Disrupt or significantly reduce required service or deliverability resulting in a state or local government's inability to provide essential public services and emergency response for an	Natural Gas Distribution	Natural gas distribution operators should designate as critical those facilities that directly support essential public services and emergency response and which rely on natural gas to perform their critical mission. Consideration should be given to: • government complexes or hubs that function as a state's primary government facility, including executive, legislative and judicial complexes • state emergency response headquarters

[5] 49 CFR § 192.903 and Appendix E to Part 192: Guidance on Determining High Consequence Areas and on Carrying Out Requirements in the Integrity Management Rule.
[6] 49 CFR § 195.450, 195.452 and Appendix C to Part 195: Guidance for Implementation of an Integrity Management Plan.

Criteria	Subsector	Guidance
extended period of time.	Natural Gas Distribution (Cont.)	• complexes that provide essential public service or emergency response capability[7] Operators should coordinate with the appropriate state office (e.g., State Office of Emergency Management) to identify essential public service and emergency response facilities. In the case that state offices are nonresponsive to operator requests, TSA will work with DHS to facilitate this coordination. For this criterion, an extended period of time is defined as the inability to provide essential public services and emergency response for seven or more consecutive days due to a disruption of natural gas distribution service.
	Natural Gas Transmission	Not applicable
	Hazardous Liquid Transmission	Hazardous liquid transmission operators should designate as critical those facilities that directly support essential public services and emergency response and which rely on hazardous liquids to perform their critical mission. Consideration should be given to: • government complexes or hubs that function as a state's primary government facility, including executive, legislative and judicial complexes • state emergency response headquarters • complexes that provide essential public service or emergency response capability[8] Operators should coordinate with the appropriate state office (e.g., State Office of Emergency Management) to identify essential public service and emergency response facilities. In the case that state offices are nonresponsive to operator requests, TSA will work with DHS to facilitate this coordination. For this criterion, an extended period of time is defined as the inability to provide essential public services and emergency response for seven or more consecutive days due to a disruption of hazardous liquid transmission service.

[7] See FEMA *Continuity Guidance Circular* (February 2018) and particularly National Essential Functions 6 – Provide Emergency Services, 7 – Maintain Economic Stability, and 8 – Provide Basic Essential Services.
[8] See FEMA *Continuity Guidance Circular* (February 2018) and particularly National Essential Functions 6 – Provide Emergency Services, 7 – Maintain Economic Stability, and 8 – Provide Basic Essential Services.

Criteria	Subsector	Guidance
5. Disrupt or significantly reduce the intended usage of major rivers, lakes, or waterways (for example, public drinking water for large populations or disruption of major commerce or public transportation routes).	Natural Gas Distribution	Not applicable
	Natural Gas Transmission	Not applicable
	Hazardous Liquid Transmission	Hazardous liquid transmission operators should designate as critical all pipeline facilities that could significantly impact public drinking water sources if state or local advisories are issued. Hazardous liquid transmission operators should designate as critical all pipeline facilities subject to Oil Pipeline Response Plans[9] impacting a PHMSA-defined Major River-High Volume Area or Other Navigable Waters.[10] Hazardous liquid transmission operators are encouraged to consult with environmental/risk specialists with expertise in this area.
6. Disrupt or significantly reduce required service or deliverability to a significant number of customers or individuals for an extended period of time.	Natural Gas Distribution	Natural gas distribution operators should designate as critical all facilities that if disrupted for more than seven consecutive days would experience reduced service or deliverability to 100,000 or more meters.
	Natural Gas Transmission	Not applicable
	Hazardous Liquid Transmission	Not applicable
7. Significantly disrupt pipeline system operations for an extended period of time.	Natural Gas Distribution	Natural gas distribution operators should designate as critical all pipeline facilities where the loss or disruption of facility operations lasting more than seven days would significantly impact overall deliverability and system safety. Factors to consider in determining criticality of a facility include: • whether a facility contains components not readily available to the operator due to long lead times or limited geographic sourcing • if a facility contains critical pipeline cyber assets[11] Natural gas distribution operators should identify as critical operational control rooms without a hot site backup (i.e., a backup control room that is continuously running and where all hardware and software are run concurrently with the primary site).

[9] 49 CFR, Part 194 – Response Plans for Onshore Oil Pipelines.
[10] 49 CFR, Part 194 – Response Plans for Onshore Oil Pipelines, Appendix B.
[11] Section 7.2, TSA *Pipeline Security Guidelines* (March 2018).

Criteria	Subsector	Guidance
7. Significantly disrupt pipeline system operations for an extended period of time. (Cont.)	Natural Gas Transmission	Natural gas transmission operators should designate as critical all pipeline facilities where the loss or disruption of facility operations lasting more than 14 days would significantly impact overall deliverability and system safety. Factors to consider in determining criticality of a facility include: • whether a facility contains components not readily available to the operator due to long lead times or limited geographic sourcing • if a facility contains critical pipeline cyber assets[12] Natural gas transmission operators should identify as critical operational control rooms without a hot site backup (i.e., a backup control room that is continuously running and where all hardware and software are run concurrently with the primary site).
	Hazardous Liquid Transmission	Hazardous liquid transmission operators should designate as critical all pipeline facilities where the loss or disruption of facility operations lasting more than seven days would significantly impact overall deliverability and system safety. Factors to consider in determining criticality of a facility include: • whether a facility contains components not readily available to the operator due to long lead times or limited geographic sourcing • if a facility contains critical pipeline cyber assets[13] Hazardous liquid transmission operators should identify as critical operational control rooms without a hot site backup (i.e., a backup control room that continuously running and where all hardware and software are run concurrently with the primary site).

[12] Section 7.2, TSA *Pipeline Security Guidelines* (March 2018).
[13] Section 7.2, TSA *Pipeline Security Guidelines* (March 2018).

6 FACILITY SECURITY MEASURES

6.1 Introduction

Upon completion of the risk analysis process, operators should determine the appropriate mitigation measures for both critical and non-critical facilities.

6.2 Baseline and Enhanced Security Measures

Pipeline operators should develop and implement baseline security measures at all of their facilities.

Operators should develop and implement **both** baseline and enhanced security measures at each of their critical facilities.

Table 2 identifies the baseline and enhanced security measures for operators to implement at appropriate pipeline facilities. Recurring actions are summarized in Appendix A.

6.3 Site-Specific Security Measures

Operators should develop, document, and implement site-specific security measures for each of their critical facilities. These measures should be tailored explicitly for each facility and address specific actions to be taken in response to pertinent NTAS Bulletins or Alerts. On a periodic basis, not to exceed 18 months, these site-specific security measures should be reviewed and updated as necessary.

Table 2: Baseline and Enhanced Security Measures

	BASELINE SECURITY MEASURES	ENHANCED SECURITY MEASURES
Physical Security and Access Control	**Fencing / Barriers**	
	Employ measures to impede unauthorized access to facilities.	Create a security perimeter that impedes unauthorized vehicles from entering the facility perimeter or critical areas by installing and maintaining barriers (e.g., fences, bollards, jersey barriers, or equivalent.)
	Maintain fences, if used, without gaps around gates or underneath the fence line.	
	Ensure that there is a clear zone for several feet on either side of the fence, free of obstructions, vegetation, or objects that could be used for concealment or to scale the fence.	
	Access Controls	
	Employ measures to impede unauthorized persons from gaining access to a facility and restricted areas within a facility.	Implement procedures (such as manual or electronic sign in/out) for controlling access to the facility and restricted buildings or areas within the facility.
	Close and secure perimeter gates or entrances when not in use.	Monitor and escort visitors at critical facilities.
	Post “No Trespassing” or “Authorized Personnel Only” signs at intervals that are visible from any point of potential entry.	
	Gates	
		Install and maintain gates of an equivalent quality to the barrier to which they are attached.
	Locks and Key Control	
		Establish and document key control procedures for key issuance, tracking, collection, loss, and unauthorized duplication.
		Use patent keys to prevent unauthorized duplication.
		Conduct key inventories every 24 months.

Table 2: Baseline and Enhanced Security Measures

	BASELINE SECURITY MEASURES	ENHANCED SECURITY MEASURES
Physical Security and Access Control	**Facility Lighting**	
		Provide sufficient illumination for human or technological recognition of intrusion into the facility perimeter or critical areas.
	Intrusion Detection & Monitoring	
		Provide critical facilities or critical areas within a facility with security measures to monitor, detect, and assess unauthorized access 24 hours a day, 7 days a week.
Personnel Security	**Personnel Identification and Badging**	
	Develop identification and badging policies and procedures for personnel who have access to secure areas or sensitive information. These policies should address: • Lost or stolen identification cards or badges; • Temporary badges; and • Personnel termination.	Ensure that company or vendor identification is available for examination by being visibly displayed or carried by personnel while on-site.
		Ensure personnel identification cards or badges are secure from tampering and contain the individual's photograph and name.
	Background Investigation	
	Establish policies and procedures for applicant pre-employment screening and behavioral criteria for disqualification of applicants and employees.	Conduct pre-employment background investigations of applicants for positions that are: • Authorized regular unescorted access to control systems or sensitive areas; • Authorized access to sensitive information; • Assigned security roles; • Assigned to work at or granted access rights to critical facilities. At a minimum, investigations should: • Verify and validate identity; • Check criminal history*; and • Verify and validate legal authorization to work. * NOTE: Operators should consider using the Federally-established list of disqualifying crimes (see 49 CFR 1572.103) to assess the suitability of their personnel for these positions.

Table 2: Baseline and Enhanced Security Measures

	BASELINE SECURITY MEASURES	ENHANCED SECURITY MEASURES
Personnel Security		Verify that contractors have background investigation policies and procedures at least as rigorous as the pipeline operator's.
		Conduct recurring background investigations on a regular basis (as labor laws or bargaining unit contracts allow), not to exceed 10 years, for employees occupying security positions or who have access to sensitive information or areas.
Equipment Maintenance and Testing	**Equipment Maintenance and Testing**	
	Develop and implement a maintenance program to ensure security systems are in good working order.	Through routine use or quarterly examination, verify the proper operation and/or condition of all security equipment.
	Identify and respond to security equipment malfunctions or failures in a timely manner.	
		Provide an equivalent level of protective security measures to mitigate risk during power outages, security equipment failure, or extended repair of security systems.
Design & Construction	**Design and Construction**	
	Integrate security risk mitigation measures during the design, construction, or renovation of a facility.	Conduct an SVA for newly identified or constructed critical facilities within 12 months of designation or after achieving operational status.
		Update the facility SVA within 12 months following significant modifications.
Communication	**Communication**	
	Develop internal and external notification requirements and procedures for security events.	Ensure primary and alternate communication capabilities exist for internal and external reporting of appropriate security events and information.
	Document and periodically update contact (who) and communication (how) information for Federal, state, and local homeland security/law enforcement agencies. (See Appendix B for TSA contact information.)	Establish a defined process for receiving, handling, disseminating, and storing security and threat information.

Table 2: Baseline and Enhanced Security Measures

	BASELINE SECURITY MEASURES	ENHANCED SECURITY MEASURES
Personnel Training	**Personnel Training**	
	Provide security awareness briefings, to include security incident recognition and reporting procedures, for personnel with unescorted access upon hiring and every 3 years thereafter.	Provide security training, to include incident response training, to personnel assigned security duties upon hiring and annually thereafter.
	Document security training and maintain records in accordance with company record retention policy.	
Drills and Exercises	**Drills and Exercises**	
	Conduct periodic security drills or exercises, to include announced or unannounced tests of security and incident plans. These can be conducted in conjunction with other required drills or exercises. * NOTE: Response to an actual security incident can satisfy this measure.	Conduct or participate in an annual security drill or exercise. Multiple facilities may participate in a common drill or exercise.
		Develop and implement a written post-event report assessing security drills or exercises and documenting corrective actions.
Security Incident Procedures	**Security Incident Procedures**	
	Implement procedures for responding to security incidents or emergencies and to pertinent National Terrorism Advisory System (NTAS) Bulletins or Alerts. These procedures should include the appropriate reporting requirements.	
	Post bomb threat checklists by telephones at staffed facilities.	

Table 2: Baseline and Enhanced Security Measures

	BASELINE SECURITY MEASURES	ENHANCED SECURITY MEASURES
Recordkeeping	**Recordkeeping**	
	Develop and document recordkeeping policies and procedures for security information. Protection of SSI in accordance with the provisions of 49 CFR Parts 15 and 1520 should be specifically addressed.	
	The following documents, as appropriate, should be retained until superseded or replaced: • Corporate Security Plan; • Criticality assessment(s); • Training records; • Security drill or exercise reports; • Incident response plan(s); • Security testing and audits. Make security information records available to TSA upon request.	In addition to the documents specified for non-critical facilities, the following documents, applicable to critical facilities, should be retained until superseded or replaced: • SVA(s); • Site-specific measures. Make security information records available to TSA upon request.
Outreach	**Outreach**	
		Conduct outreach to nearby law enforcement agencies to ensure awareness of the facility's functions and significance.
		Conduct outreach to neighboring businesses to coordinate security efforts. Also conduct outreach to neighboring residences to provide facility security awareness.

7 PIPELINE CYBER ASSET SECURITY MEASURES

7.1 Introduction

The operational technology used by the operators to manage their infrastructure and products are vital to the pipeline system's safe and efficient operation. "Operational technologies" (OT) are the systems that detect or cause a change through the direct monitoring and/or control of physical devices, processes and events in the pipelines. OT systems include control systems (SCADA, process control systems (PCS), distributed control systems (DCS)), measurement systems and telemetry systems, which are collectively referred to as "pipeline cyber assets."

The National Institute of Standards and Technology (NIST) has developed the *Framework for Improving Critical Infrastructure Cybersecurity,* a set of standards and best practices to assist organizations in managing cybersecurity risks and to promote the protection of critical infrastructure. To implement an effective cybersecurity strategy, pipeline operators should consider the approach outlined in the NIST Framework and the guidance issued by DHS and the Department of Energy along with industry-specific or other established methodologies, standards, and best practices (see Section 7.4).

7.2 Pipeline Cyber Assets Classification

Operators should evaluate pipeline cyber assets and classify them using the following criteria:

- Critical pipeline cyber assets are OT systems that can control operations on the pipeline. Baseline and enhanced security measures should be applied to these assets.
- Non-critical pipeline cyber assets are OT systems that monitor operations on the pipeline. Baseline security measures should be applied to these assets.

7.3 Security Measures for Pipeline Cyber Assets

Table 3 shows the baseline and enhanced cybersecurity measures that pipeline operators should apply to pipeline cyber assets based on their criticality designation. These measures incorporate updates to the previous TSA Pipeline Security Guidelines as well as recommendations and practices from the government and industry documents listed in Section 7.4. The cybersecurity guidelines that follow are organized according to the relevant functions and categories presented in the NIST Framework.

Table 3: Baseline and Enhanced Cyber Security Measures

	Baseline Security Measures	Enhanced Security Measures
Identify	**Asset Management**	
	Establish and document policies and procedures for assessing and maintaining configuration information, for tracking changes made to the pipeline cyber assets, and for patching/upgrading operating systems and applications. Ensure that the changes do not adversely impact existing cybersecurity controls.	Employ mechanisms to maintain accurate inventory and to detect unauthorized components.
	Develop and maintain a comprehensive set of network/system architecture diagrams or other documentation, including nodes, interfaces, remote and third party connections, and information flows.	Review network connections periodically, including remote and third party connections. Develop a detailed inventory for every endpoint.
	Review and assess pipeline cyber asset classification as critical or non-critical at least every 12 months.	
	Business Environment	
	Ensure that any change that adds control operations to a non-critical pipeline cyber asset results in the system being recognized as a critical pipeline cyber asset and enhanced security measures being applied.	
	Governance	
	Establish and distribute cybersecurity policies, plans, processes and supporting procedures commensurate with the current regulatory, risk, legal and operational environment.	
	Review and assess all cybersecurity policies, plans, processes, and supporting procedures regularly, not to exceed 36 months, or when there is a significant organizational or technological change. Update as necessary.	Review and assess all cybersecurity policies, plans, processes, and supporting procedures regularly, not to exceed 12 months, or when there is a significant organizational change. Update as necessary.
	Risk Management Strategy	
	Develop an operational framework to ensure coordination, communication and accountability for information security on and between the control systems and enterprise networks.	

Table 3: Baseline and Enhanced Cyber Security Measures

	Baseline Security Measures	Enhanced Security Measures
Identify	**Risk Assessment**	
	Establish a process to identify and evaluate vulnerabilities and compensating security controls.	Ensure threat and vulnerability information received from information sharing forums and sources are made available to those responsible for assessing and determining the appropriate course of action.
Protect	**Access Control**	
	Establish and enforce unique accounts for each individual user and administrator, establish security requirements for certain types of privileged accounts, and prohibit the sharing of these accounts. In instances where systems do not support unique user accounts, then implement appropriate compensating security controls (e.g., physical controls).	Restrict user physical access to control systems and control networks through the use of appropriate controls. Employ more stringent identity and access management practices (e.g., authenticators, password-construct, access control).
	Ensure that user accounts are modified, deleted, or de-activated expeditiously for personnel who no longer require access or are no longer employed by the company.	
	Establish and enforce access control policies for local and remote users. Procedures and controls should be in place for approving and enforcing policy for remote and third-party connections.	Monitor physical and remote user access to critical pipeline cyber assets.
	Ensure appropriate segregation of duties is in place. In instances where this is not feasible, apply appropriate compensating security controls.	
	Change all default passwords for new software, hardware, etc., upon installation. In instances where changing default passwords is not technically feasible (e.g., a control system with a hard-coded password), implement appropriate compensating security controls (e.g., administrative controls).	Employ mechanisms to support the management of accounts.

Table 3: Baseline and Enhanced Cyber Security Measures

	Baseline Security Measures	Enhanced Security Measures
Protect	**Awareness and Training**	
	Ensure that all persons requiring access to the organization's pipeline cyber assets receive cybersecurity awareness training.	Provide role-based security training on recognizing and reporting potential indicators of system compromise prior to obtaining access to the critical pipeline cyber assets.
	Establish and execute a cyber-threat awareness program for employees. This program should include practical exercises/testing.	
	Data Security & Information Protection	
	Establish and implement policies and procedures to ensure data protection measures are in place, including identifying critical data and establishing classification of different types of data, establishing specific handling procedures, and protections and disposal.	
	Protective Technology	
	Segregate and protect the pipeline cyber assets from enterprise networks and the internet using physical separation, firewalls and other protections.	
	Regularly validate that technical controls comply with the organization's cybersecurity policies, plans and procedures, and report results to senior management.	
	Implement technical or procedural controls to restrict the use of pipeline cyber assets for only approved activities.	
Detect	**Anomalies and Events**	
	Implement processes to generate alerts and log cybersecurity events in response to anomalous activity. Review the logs and respond to alerts in a timely manner.	
	Security Continuous Monitoring	
	Monitor for unauthorized access or the introduction of malicious code or communications.	
	Conduct cyber vulnerability assessments as described in your risk assessment process	Utilize independent assessors to conduct pipeline cyber security assessments.

Table 3: Baseline and Enhanced Cyber Security Measures

	Baseline Security Measures	Enhanced Security Measures
Detect	**Detection Processes**	
	Establish technical or procedural controls for cyber intrusion monitoring and detection.	
	Perform regular testing of intrusion and malware detection processes and procedures.	
Respond	**Response Planning**	
	Establish policies and procedures for cybersecurity incident handling, analysis and reporting, including assignment of the specific roles/tasks to individuals and teams.	Conduct cybersecurity incident response exercises periodically.
	Establish and maintain a cyber-incident response capability.	Establish and maintain a process that supports 24 hours a day cyber incident response.
	Communications	
	Report significant cyber incidents to senior management; appropriate federal, state, local, tribal, and territorial (SLTT) entities; and applicable ISAC(s).	Pipeline operators should follow the notification criteria in Appendix B
	Mitigation	
	Ensure the organization's response plans and procedures include mitigation measures to help prevent further impacts.	
Recover	**Recovery Planning**	
	Establish a plan for the recovery and reconstitution of pipeline cyber assets within a timeframe to align with the organization's safety and business continuity objectives.	
	Improvements	
	Review the organization's cyber recovery plan annually. Update as necessary.	

7.4 Cyber Security Planning and Implementation Guidance

The following is a list of planning and implementation guidance developed by industry or Federal government entities. Operators should consult the current edition of these and other cyber security references on a frequent basis in developing and reviewing their company's cyber security program.

- American Chemistry Council, *Guidance for Addressing Cyber Security in the Chemical Industry*
- American Gas Association (AGA) Report Number 12, *Cryptographic Protection of SCADA Communications, Part 1: Background, Policies and Test Plan*
- American National Standards Institute (ANSI)/International Society of Automation (ISA) – 99.00.01 – 2007, *Security for Industrial Automation and Control Systems: Terminology, Concepts, and Models*
- ANSI/ISA – 99.02.01 – 2009, *Security for Industrial Automation and Control Systems: Establishing an Industrial Automation and Control System Security Program*
- American Petroleum Institute (API) Standard 1164 *Pipeline SCADA Security*
- ANSI/API Standard 780, *Security Risk Assessment Methodology for the Petroleum and Petrochemical Industries*
- U.S. Department of Commerce, National Institute of Standards and Technology (NIST), *Framework for Improving Critical Infrastructure Cybersecurity*
- U.S. Department of Commerce, NIST, Special Publication 800-82, *Guide to Industrial Control Systems (ICS) Security*
- U.S. Department of Homeland Security, Office of Infrastructure Protection, Risk-*Based Performance Standards Guidance: Chemical Facility Anti-Terrorism Standards,* May 2009
- U.S Department of Energy, Office of Electricity Delivery and Energy Reliability, *Energy Sector Cybersecurity Framework Implementation Guidance,* January 2015
- U.S Department of Homeland Security, Transportation *Systems Sector Cybersecurity Framework Implementation Guidance,* June 2015

8 PROTECTIVE MEASURES FOR NATIONAL TERRORISM ADVISORY SYSTEM (NTAS) ALERTS

The Department of Homeland Security's NTAS provides a framework to disseminate information via Bulletins or Alerts regarding the threat of terrorist acts to the nation.

TSA has developed a supplement to this document containing recommended security measures to reduce vulnerabilities to pipeline systems and facilities during periods of heightened threat and to establish a consistent security posture within the pipeline industry. This supplement is unclassified but sensitive and is marked as Sensitive Security Information (SSI). The password- protected document may be obtained by email request to pipelinesecurity@dhs.gov.

APPENDIX A – RECURRING ACTIONS

	RECURRING ACTIONS				
	12 Months	**18 Months**	**24 Months**	**36 Months**	**Other**
Baseline	Perform an annual review of the corporate security plan and update as required. (Section 3.1)	Conduct facility criticality assessments on a periodic basis, not to exceed 18 months. (Section 4.2)			Periodically update contact and communications information for government agencies. (Table 2 Communication)
					Conduct security drills or exercises on a periodic basis. (Table 2 Drills and Exercises)
	Review and assess pipeline cyber asset classification as critical or non-critical at least every 12 months. (Table 3 Cyber Asset Management)			Review and assess all cybersecurity policies, plans, processes, and supporting procedures regularly, not to exceed 36 months. (Table 3 Cyber Governance)	Perform regular testing of intrusion and malware detection processes and procedures. (Table 3 Cyber Detection Processes)
	Review the organization's cyber recovery plan annually. (Table 3 Cyber Improvements)				Conduct cybersecurity incident response exercises periodically. (Table 3 Cyber Response Planning)
					Periodically review facility staffing requirements for implementing additional security measures. (NTAS Supplement, p.1)
					Provide notification of a pipeline incident in accordance with Appendix B.

RECURRING ACTIONS					
	12 Months	**18 Months**	**24 Months**	**36 Months**	**Other**
Enhanced	Conduct a SVA within 12 months of significant modification to a critical facility, a newly identified critical facility or a newly constructed facility identified as critical. (Section 4.3)		Implement appropriate findings NLT 24 months after SVA completion. (Section 4.3)	Conduct periodic SVAs, not to exceed 36 months. (Section 4.3)	
		Review site-specific security measures periodically, not to exceed 18 months. (Section 6.3)	Conduct key inventories every 24 months. (Table 2 Locks and Key Control)		Verify the proper operation and/or condition of all security equipment through routine use or quarterly examination. (Table 2 Equipment Maintenance and Testing)
	Conduct or participate in an annual security drill or exercise. (Table 2 Exercises and Drills)				Conduct recurring background investigations, not to exceed 10 years, for employees occupying security positions or in sensitive positions. (Table 2 Background Investigation)
	Provide security training to personnel assigned security duties upon hiring and annually thereafter. (Table 2 Personnel Training)			Provide security awareness briefings for personnel with unescorted access upon hiring and every 3 years thereafter. (Table 2 Personnel Training)	
	Review and assess all cybersecurity policies, plans, processes, and supporting procedures regularly, not to exceed 12 months. (Table 3 Cyber Governance)				

Note: 1. Baseline measures apply to all pipeline operators. Enhanced measures apply to operators' critical facilities.
2. All baseline and enhanced security measures are detailed in Section 6 of this document.

APPENDIX B - TSA NOTIFICATION CRITERIA

As the lead Federal agency for pipeline security, TSA requests to be notified of security incidents that are indicative of a deliberate attempt to disrupt pipeline operations or activities that could be considered precursors to such an attempt. Pipeline operators should notify the Transportation Security Operations Center (TSOC) via phone at 866-615-5150 or email at TSOC.ST@dhs.gov as soon as possible if any of the following incidents occurs or if there is other reason to believe that a terrorist incident may be planned or may have occurred:

- Explosions or fires of a suspicious nature affecting pipeline systems, facilities, or assets;
- Actual or suspected attacks on pipeline systems, facilities, or assets;
- Bomb threats or weapons of mass destruction (WMD) threats to pipeline systems, facilities, or assets;
- Theft of pipeline company vehicles, uniforms, or employee credentials;
- Suspicious persons or vehicles around pipeline systems, facilities, assets, or right-of-way;
- Suspicious photography or possible surveillance of pipeline systems, facilities, or assets;
- Suspicious inquiries from people asking about pipeline system, facility, or asset operations, vulnerabilities, or security practices;
- Suspicious individuals applying for security-sensitive positions in the pipeline company;
- Theft or loss of sensitive security information (detailed pipeline maps, security plans, etc.).

When contacting the TSOC, provide as much of the following information as possible:

- Name and contact information;
- The time and location of the incident, as specifically as possible;
- A description of the incident or activity involved;
- Which entities have been notified and what actions have been taken;
- The names and/or descriptions of persons involved or suspicious parties and license plates as appropriate.

Actual or suspected cyber-attacks that could impact pipeline industrial control systems (SCADA, PCS, DCS), measurement systems and telemetry systems or enterprise associated IT systems should be reported to the National Cybersecurity and Communications Integration Center (NCCIC) at 888-282-0870.

For questions or concerns, email the TSA Pipeline Security staff at pipelinesecurity@dhs.gov

APPENDIX C – LIST OF ACRONYMS

AGA	American Gas Association
ANSI	American National Standards Institute
APGA	American Public Gas Association
API	American Petroleum Institute
CFR	Code of Federal Regulations
DCS	Distributed Control System
DHS	U.S. Department of Homeland Security
DOT	U.S. Department of Transportation
FEMA	Federal Emergency Management Agency
HSEEP	Homeland Security Exercise and Evaluation Program
HSIN	Homeland Security Information Network
ICS	Industrial Control System
INGAA	Interstate Natural Gas Association of America
ISA	International Society of Automation
IT	Information Technology
NIST	National Institute of Standards and Technology
NTAS	National Terrorism Advisory System
PCS	Process Control System
SCADA	Supervisory Control and Data Acquisition
SSI	Sensitive Security Information
SVA	Security Vulnerability Assessment
TIH	Toxic Inhalation Hazard
TSA	Transportation Security Administration
TSOC	Transportation Security Operations Center
WMD	Weapons of Mass Destruction

APPENDIX D – REFERENCE DOCUMENTS

Operators should consult the current edition of these and other security references on a frequent basis in developing and reviewing their company's security program. Cyber planning and implementation guidance appears in Section 7.4.

American Gas Association (AGA), Interstate Natural Gas Association of America (INGAA) & American Public Gas Association (APGA), *Security Guidelines: Natural Gas Industry, Transmission and Distribution*

American Petroleum Institute (API) & National Petrochemical & Refiners Association (NPRA), *Security Vulnerability Assessment Methodology for the Petroleum and Petrochemical Industries*

API, *Security Guidelines for the Petroleum Industry*

Homeland Security Presidential Directive 7: *Critical Infrastructure Identification, Prioritization, and Protection*.

Presidential Policy Directive 7: *National Terrorism Advisory System (NTAS)*

U.S. Department of Homeland Security, Federal Emergency Management Agency (FEMA), *Homeland Security Exercise and Evaluation Program (HSEEP) Vols. 1 - 4*

U.S. Department of Homeland Security, *National Infrastructure Protection Plan*

U.S. Department of Homeland Security, National Cyber Security Division, *Catalog of Control Systems Security: Recommendations for Standards Developers*

U.S. Department of Homeland Security, Transportation Security Administration (TSA), *Pipeline Security Smart Practices*

U.S. Department of Homeland Security, TSA, *Transportation Systems Sector-Specific Plan: Pipeline Modal Annex*

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Wayne K. Pipes

FACILITIES

Exh. WKP-8

August 29, 2025

U.S. Department of Homeland Security
Transportation Security Administration
6595 Springfield Center Drive
Springfield, Virginia 20598

MEMORANDUM

To: Covered Pipeline Owner/Operators

Date: May 1, 2025

Subject: Renewal of the Security Directive Pipeline-2021-01 Series: *Enhancing Pipeline Cybersecurity*

Attached to this memorandum is Security Directive (SD) Pipeline-2021-01E: *Enhancing Pipeline Cybersecurity*. This SD is a continuation of the SD Pipeline-2021-01 series and cancels and supersedes SD Pipeline-2021-01D. SD Pipeline-2021-01E is effective on May 3, 2025, and expires May 2, 2026. Revisions to the text of the SD are highlighted in **bold**.

This SD applies to Owner/Operators of TSA-designated hazardous liquid and natural gas pipelines or liquefied natural gas facilities. All Owner/Operators subject to these requirements have been previously notified by TSA. If TSA identifies additional Owner/Operators with critical pipeline systems or facilities who were not previously subject to the SD Pipeline-2021-01 series, TSA will notify these Owner/Operators and provide specific compliance deadlines for the requirements in this SD.

The renewal of this SD continues to require covered Owner/Operators to take crucial measures to enhance pipeline cybersecurity, which were first issued in May 2021. There are no substantive revisions to the SD Pipeline-2021-01 series through this renewal, i.e., changes are limited to the effective date, expiration date, and series letter designation.

Consistent with TSA's previous determination, this SD is not marked as Sensitive Security Information (SSI). While SDs generally are categorically deemed SSI under TSA's regulations (49 CFR part 1520), TSA previously determined that the contents of this SD would not be detrimental to transportation security if publicly disclosed. No revisions to the Information Collection Request previously approved by the Office of Management and Budget are necessary to accommodate any information collected under the revision.

The SD requires that Owner/Operators provide written confirmation of receipt of this SD via email to SurfOps-SD@tsa.dhs.gov. All queries concerning the attached SD should be submitted to TSA at TSA-Surface@tsa.dhs.gov.

Ha Nguyen McNeill
Acting Administrator
Transportation Security Administration

Attachment: SD Pipeline-2021-01E

U.S. Department of Homeland Security
Transportation Security Administration
6595 Springfield Center Drive
Springfield, Virginia 20598

May 1, 2025

SECURITY DIRECTIVE

NUMBER	Security Directive Pipeline-2021-01**E**
SUBJECT	Enhancing Pipeline Cybersecurity
EFFECTIVE DATE	**May 3, 2025**
EXPIRATION DATE	**May 2, 2026**
CANCELS AND SUPERSEDES	Security Directive Pipeline-2021-01D
APPLICABILITY	Owners and operators of a hazardous liquid and natural gas pipeline or a liquefied natural gas facility notified by TSA that their pipeline system or facility is critical
AUTHORITY	49 U.S.C. 114(d), (f), (*l*) and (m)
LOCATION	All locations within the United States

I. PURPOSE AND GENERAL INFORMATION

Due to the ongoing cybersecurity threat to pipeline systems and associated infrastructure, the Transportation Security Administration (TSA) is issuing this Security Directive.[1] All revisions to this Security Directive series from the previous version, Security Directive Pipeline-2021-01**D**, are highlighted in bold.

This Security Directive continues to require three critical actions. First, it requires TSA-specified Owner/Operators to report cybersecurity incidents to the Department of Homeland Security's Cybersecurity and Infrastructure Security Agency (CISA). Second, it requires Owner/Operators to designate a Cybersecurity Coordinator and alternate(s) sufficient to ensure either the primary or alternate Cybersecurity Coordinator is available to TSA and CISA at all times (24 hours per day, seven days per week) to coordinate cybersecurity practices and address any incidents that arise. Third, it requires Owner/Operators to review their current activities against TSA's recommendations for pipeline cybersecurity to assess

[1] TSA is issuing **t**his Security Directive under the authority of 49 U.S.C. 114(*l*)(2)(A), which states: "Notwithstanding any other provision of law or executive order (including an executive order requiring a cost-benefit analysis), if the Administrator determines that a regulation or Security Directive must be issued immediately in order to protect transportation security, the Administrator shall issue the regulation or Security Directive without providing notice or an opportunity for comment and without prior approval of the Secretary."

cyber risks, identify any gaps, develop remediation measures, and report the results to TSA and CISA.

To avoid duplicate reporting, information provided to CISA pursuant to this Security Directive will be shared with TSA and may also be shared with the National Response Center and other agencies as appropriate. Similarly, information provided to TSA pursuant to this Security Directive will be shared with CISA and may also be shared with the National Response Center and other agencies as appropriate.[2] All information that must be reported to TSA or CISA pursuant to this Security Directive is sensitive security information subject to the protections of 49 CFR part 1520.

TSA may use the information, with company-specific data redacted, for TSA's intelligence-derived reports. TSA and CISA also may use information submitted for vulnerability identification, trend analysis, or to generate anonymized indicators of compromise or other cybersecurity products to prevent other cybersecurity incidents.[3]

II. ACTIONS REQUIRED

A. Applicability and Deadlines for Compliance

1. *Applicability:* The provisions of this Security Directive apply to Owners and operators of a hazardous liquid and natural gas pipeline or a liquefied natural gas facility notified by TSA that their pipeline system or facility is critical.[4]

2. *Additional Critical Pipeline Systems or Facilities:* In the event that TSA identifies additional Owner/Operators with critical pipeline systems or facilities who are not currently subject to the Security Directive Pipeline-2021-01 series, TSA will notify the Owner/Operator and provide specific compliance deadlines for the requirements in this Security Directive.

B. Owner/Operators must designate and use a primary and at least one alternate Cybersecurity Coordinator at the corporate level.

1. Owner/Operators must provide in writing to TSA, at SurfOps-SD@tsa.dhs.gov, the names, titles, phone number(s), and email address(es) of the Cybersecurity Coordinator and alternate Cybersecurity Coordinator(s) within seven days of the commencement of new operations or change in any of the information required by this section.

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[2] Presidential Policy Directive (PPD) 41 calls for Federal cyber incident response agencies to share incident information with each other to achieve unity of governmental effort. *See* PPD-41 § III.D.

[3] *See* Information Collection Request, OMB No. 1652-0050 for TSA's identification of the Most Critical Pipelines, as required by sec. 1557(b) of the 9/11 Act and OMB No. 1652-0055 for assessment data.

[4] *See* section 1557(b) of the *Implementing Recommendations of the 9/11 Commission Act of 2007,* Pub. L. 110-53 (121 Stat. 266; Aug. 3, 2007) (9/11 Act) (codified at 6 U.S.C. § 1207). Section 1557(b) requires TSA to review pipeline security plans and inspect critical facilities of the 100 most critical pipeline operators. In general, criticality is determined based on factors such as the volume of product transported, service to other critical sectors, *etc*.

2. The Cybersecurity Coordinator and alternate(s) must—

   a. Be a U.S. citizen who is eligible for a security clearance;

   b. Serve as the primary contact for cyber-related intelligence information and cybersecurity-related activities and communications with TSA and CISA;

   c. Ensure the primary or an alternate Cybersecurity Coordinator is accessible to TSA and CISA 24 hours a day, seven days a week;

   d. Coordinate cyber and related security practices and procedures internally; and

   e. Work with appropriate law enforcement and emergency response agencies.

C. Owner/Operators must report cybersecurity incidents to CISA involving systems that the Owner/Operator has responsibility to operate and/or maintain including:

   1. Unauthorized access of an Information or Operational Technology system;

   2. Discovery of malicious software on an Information or Operational Technology system;

   3. Activity resulting in a denial of service to any Information or Operational Technology system;

   4. A physical attack against the Owner/Operator's network infrastructure, such as deliberate damage to communication lines; and

   5. Any other cybersecurity incident that results in operational disruption to the Owner/Operator's Information or Operational Technology systems or other aspects of the Owner/Operator's pipeline systems or facilities, or otherwise has the potential to cause operational disruption that adversely affects the safe and efficient transportation of liquids and gases including, but not limited to impacts to a large number of customers, critical infrastructure or core government functions, or impacts national security, economic security or public health and safety.

D. Owner/Operators must report the information required by Section II.C., as soon as practicable, but no later than 24 hours after a cybersecurity incident is identified. Reports required by this section must be made to CISA Central using CISA's Reporting System form at: **https://www.cisa.gov/forms/report** or by calling (888) 282-0870.[5] If the required information is not available at the time of reporting, Owner/Operators must submit an initial report within the specified timeframe and provide supplemental information within 24 hours of it becoming available. All reported information will be protected in a manner appropriate for the sensitivity and criticality of the information.

[5] CISA's Incident Reporting System provides a secure web-enabled means of reporting computer security incidents to CISA. This system assists analysts in providing timely handling of the security incidents Owner/Operators must report pursuant to this Security Directive as well as the ability to conduct improved analysis.

E. The report to CISA required by Section II.C. must include the following information, as available to the reporting Owner/Operator at the time of the report:

1. The name of the reporting individual and contact information, including a telephone number or email address. The report must also explicitly specify that the information is being reported in order to satisfy the reporting requirements in this Security Directive.

2. The affected hazardous liquid and natural gas pipeline(s) and/or facilities, including identifying information and location.

3. Description of the threat, incident, or activity, to include:

   a. Information about who has been notified and what action has been taken;

   b. Any relevant information observed or collected by the Owner/Operator, such as malicious IP addresses, malicious domains, malware hashes and/or samples, or the abuse of legitimate software or accounts; and

   c. Any known threat information, to include information about the source of the threat or attack, if available.

4. A description of the incident's impact or potential impact on Information or Operational Technology systems and operations. This information must also include an assessment of actual, imminent or potential service operations, operational delays, and/or data theft that have or are likely to be incurred, as well as any other information that would be informative in understanding the impact or potential impact of the cybersecurity incident.

5. A description of all responses that are planned or under consideration, to include, for example, a reversion to manual backups, if applicable.

6. Any additional relevant information.

F. Cybersecurity Vulnerability Assessment

1. Owner/Operators must review Section 7 of TSA's 2018 Pipeline Security Guidelines (with Change 1 (April 2021)),[6] and—

   a. Assess whether current practices and activities to address cyber risks to Owner/Operators Information and Operational Technology systems align with the Guidelines;

   b. Identify any gaps; and

   c. Identify remediation measures that will be taken to fill those gaps and a timeline

[6] Available at https://www.tsa.gov/sites/default/files/pipeline_security_guidelines.pdf.

for implementing these remediation measures.

2. The assessment and identification of gaps must be completed using the form provided by TSA.[7]

3. The completed vulnerability assessment report containing all information required by this section must be submitted to TSA. Owner/Operators who have previously submitted a vulnerability assessment to TSA are not required to update and submit a revised assessment.

III. PROCEDURES FOR SECURITY DIRECTIVES

A. Owner/Operators must:

1. Immediately provide written confirmation of receipt of this Security Directive via email to TSA at SurfOps-SD@tsa.dhs.gov.

2. Immediately disseminate the information and measures in this Security Directive to corporate senior management, security management representatives, and any personnel having responsibilities in implementing the provisions in this Security Directive. The Owner/Operator also should share this Security Directive with anyone subject to the provisions of this Security Directive to include, but not limited to, Federal, state, and local government personnel, tenants, and contractors.

3. Brief all individuals responsible for implementing this Security Directive.

B. Owner/Operators may comment on this Security Directive by submitting data, views, or arguments in writing to TSA via email at TSA-Surface@tsa.dhs.gov. TSA may amend the Security Directive based on comments received. Submission of a comment does not delay the effective date of the Security Directive.

IV. DEFINITIONS

A. *Business critical functions* means the Owner/Operator's determination of capacity or capabilities to support functions necessary to meet operational needs and supply chain expectations.

B. *Cybersecurity incident* means an occurrence that, without lawful authority, jeopardizes or is reasonably likely to jeopardize the integrity, confidentiality, or availability of computers, information or communications systems or networks, physical or virtual infrastructure controlled by computers or information systems, or information resident on the system. This definition includes an event that is under investigation or evaluation by the Owner/Operator as a possible cybersecurity incident without final determination of the event's root cause or nature (such as malicious, suspicious, or benign).

[7] The assessment form is not Sensitive Security Information before it is completed. Once any question is answered on the form, however, it becomes Sensitive Security Information subject to the protections of 49 CFR part 1520.

C. *Days* means calendar days unless otherwise indicated. As used for compliance deadlines, if a requirement must be met on a date that is a federal holiday, the compliance deadline will be the next federal business day after the holiday.

D. *Information Technology system* means any services, equipment, or interconnected systems or subsystems of equipment that are used in the automatic acquisition, storage, analysis, evaluation, manipulation, management, movement, control, display, switching, interchange, transmission, or reception of data or information that fall within the responsibility of an Owner/Operator subject to TSA's Cybersecurity Requirements to operate and/or maintain.

E. *Operational disruption* means a deviation from or interruption of business critical functions that results from a compromise or loss of data, system availability, system reliability, or control of systems.

F. *Operational Technology system* is a general term that encompasses several types of control systems, including industrial control systems, supervisory control and data acquisition systems, distributed control systems, and other control system configurations, such as programmable logic controllers, fire control systems, and physical access control systems, often found in the industrial sector and critical infrastructure. Such systems consist of combinations of programmable electrical, mechanical, hydraulic, pneumatic devices or systems that interact with the physical environment or manage devices that interact with the physical environment.

G. *Owner/Operator* means a person who owns or maintains operational control over pipeline facilities or engages in the transportation of hazardous liquids or natural gases and who has been identified by TSA as one of the most critical interstate and intrastate natural gas and hazardous liquid transmission pipeline infrastructure and operations.

H. *Unauthorized access* means access of an Information Technology or Operational Technology system from an unknown source; access by a third party or former employee; an employee accessing systems for which he or she is not authorized. This term may include a non-malicious policy violation such as the use of shared credentials by an employee otherwise authorized to access it.

V. APPROVAL OF ALTERNATIVE MEASURES

Owner/Operators must immediately notify TSA via email at TSA-Surface@tsa.dhs.gov if unable to implement any of the measures in this Security Directive. Owner/Operators may submit proposed alternative measures and the basis for submitting the alternative measures to TSA for approval to the email address above.

Ha Nguyen McNeill
Acting Administrator
Transportation Security Administration

U.S. Department of Homeland Security
Transportation Security Administration
6595 Springfield Center Drive
Springfield, Virginia 20598

MEMORANDUM

To: Covered Pipeline Owner/Operators

Date: May 1, 2025

Subject: Renewal of the Security Directive Pipeline-2021-02 Series: *Pipeline Cybersecurity Mitigation Actions, Contingency Planning, and Testing*

Attached to this memorandum is Security Directive (SD) Pipeline-2021-02F: *Pipeline Cybersecurity Mitigation Actions, Contingency Planning, and Testing*. This SD is a continuation of the SD Pipeline-2021-02 series and cancels and supersedes SD Pipeline-2021-02E. SD Pipeline-2021-02F is effective on May 3, 2025, and expires on May 2, 2026. Revisions to the text of the SD are highlighted in **bold**.

This SD series applies to Owner/Operators of TSA-designated hazardous liquid and natural gas pipelines or liquefied natural gas facilities. All Owner/Operators subject to these requirements have been previously notified by TSA. If TSA identifies additional Owner/Operators with critical pipeline systems or facilities who were not previously subject to the SD Pipeline-2021-02 series, TSA will notify these Owner/Operators and provide specific compliance deadlines for the requirements in this SD.

The renewal of this SD maintains TSA's performance-based cybersecurity requirements, which were first issued in July 2021. There are no substantive revisions to the SD Pipeline-2021-02 series through this renewal, i.e., changes are limited to the effective date, expiration date, and series letter designation.

Consistent with TSA's previous determination, this SD is not marked as Sensitive Security Information (SSI). While SDs generally are categorically deemed SSI under TSA's regulations (49 CFR part 1520), TSA previously determined that the contents of this SD would not be detrimental to transportation security if publicly disclosed. No revisions to the Information Collection Request previously approved by the Office of Management and Budget are necessary to accommodate any information collected under the revision.

The SD requires that Owner/Operators provide written confirmation of receipt via email to SurfOps-SD@tsa.dhs.gov. All queries concerning the attached SD should be submitted to TSA at TSA-Surface@tsa.dhs.gov.

Ha Nguyen McNeill
Acting Administrator
Transportation Security Administration

Attachment: SD Pipeline-2021-02F

U.S. Department of Homeland Security
Transportation Security Administration
6595 Springfield Center Drive
Springfield, Virginia 20598

May 1, 2025

SECURITY DIRECTIVE

NUMBER	Security Directive Pipeline-2021-02**F**
SUBJECT	Pipeline Cybersecurity Mitigation Actions, Contingency Planning, and Testing
EFFECTIVE DATE	**May 3, 2025**
EXPIRATION DATE	**May 2, 2026**
CANCELS AND SUPERSEDES	Security Directive Pipeline-2021-02E
APPLICABILITY	Owners and Operators of a hazardous liquid and natural gas pipeline or a liquefied natural gas facility notified by TSA that their pipeline system or facility is critical
AUTHORITY	49 U.S.C. 114(d), (f), (*l*) and (m)
LOCATION	All locations within the United States

I. PURPOSE AND GENERAL INFORMATION

The Transportation Security Administration (TSA) is issuing this Security Directive due to the ongoing cybersecurity threat to pipeline systems, under the authority of 49 U.S.C. 114(*l*)(2)(A).[1] This Security Directive continues to require performance-based regulatory cybersecurity measures first issued by TSA on July 26, 2021 under the Security Directive Pipeline-2021-02 series.[2] In general, this Security Directive is applicable to the same pipeline and liquefied natural gas facilities subject to the requirements of the Security Directive Pipeline-2021-01 series, which first went into effect on May 28, 2021.[3] All

[1] This Security Directive series is issued under the authority of 49 U.S.C. 114(*l*)(2)(A), which states: "Notwithstanding any other provision of law or executive order (including an executive order requiring a cost-benefit analysis), if the Administrator determines that a regulation or security directive must be issued immediately in order to protect transportation security, the Administrator shall issue the regulation or security directive without providing notice or an opportunity for comment and without prior approval of the Secretary."
[2] As noted in the Office of Management and Budget's Unified Agenda, TSA intends to more permanently codify these requirements through notice-and-comment rulemaking.
[3] *See* Section II.A. for applicability.

revisions to this Security Directive series from the most recent version, SD Pipeline-2021-02**E**, are highlighted in **bold**.

The actions required by TSA continue to be necessary to protect the national security, economy, and public health and safety of the United States and its citizens from the impact of malicious cyber intrusions affecting the nation's most critical gas and liquid pipelines. Even minor disruptions in critical pipeline systems may result in temporary product shortages that can cause significant harm to national security. Prolonged disruptions in the flow of commodities could lead to widespread energy shortfalls, with ripple effects across the economy. Disruptions and delays may affect other domestic critical infrastructure and industries that depend on the commodities transported by the nation's pipeline systems.

The goal of this Security Directive is to reduce the risk that cybersecurity threats pose to critical pipeline systems and facilities by implementing layered cybersecurity measures that demonstrate a defense-in-depth approach against such threats. Recent and evolving intelligence emphasizes the growing sophistication of nefarious persons, organizations, and governments, highlights vulnerabilities, and intensifies the urgency of implementing and sustaining the requirements in this Security Directive series.[4]

To protect against the ongoing threat to the United States' national and economic security, this Security Directive mandates that TSA-specified Owners/Operators of pipeline and liquefied natural gas facilities implement the following cybersecurity measures to prevent disruption to, and degradation of, this critical infrastructure. Specifically, Owner/Operators must do the following:

1. Establish and implement a TSA-approved Cybersecurity Implementation Plan that describes the specific cybersecurity measures employed and the schedule for achieving the outcomes described in Section III.A. through III.E.

2. Develop and maintain an up-to-date Cybersecurity Incident Response Plan to reduce the risk of operational disruption, or the risk of other significant impacts on business critical functions, as defined in this Security Directive, should the Information and/or Operational Technology systems of a gas or liquid pipeline be affected by a cybersecurity incident. *See* Section III.F.

3. Develop a Cybersecurity Assessment Plan and submit (a) an annual update, for approval, that describes how the Owner/Operator will proactively and regularly assess the effectiveness of cybersecurity measures and identify and resolve device,

[4] *See, e.g.*, Joint Cybersecurity Advisory (AA22-110A), *Russian State-Sponsored and Criminal Cyber Threats to Critical Infrastructure* (dated April 20, 2022), available at *https://www.cisa.gov/uscert/sites/default/files/publications/AA22-110A_Joint_CSA_Russian_State-Sponsored_and_Criminal_Cyber_Threats_to_Critical_Infrastructure_4_20_22_Final.pdf*. *See also* additional information regarding current threats posted at *https://www.cisa.gov/shields-up*. *See also* Office of the Director of National Intelligence (ODNI), *Annual Threat Assessment of The U.S. Intelligence Community* (dated **March 2025**), available at **2025** Annual Threat Assessment of the U.S. Intelligence Community; and CISA Joint Cybersecurity Advisory: *People's Republic of China State-Sponsored Cyber Actor Living off the Land to Evade Detection* (AA23-144a) (dated May 24, 2023), available at https://www.cisa.gov/news-events/cybersecurity-advisories/aa23-144a.

network, and/or system vulnerabilities, and (b) an annual report that provides Cybersecurity Assessment Plan results from the previous year. *See* Section III.G.

TSA significantly revised the Security Directive Pipeline 2021-02 series**,** initially issued in July 2021**,** to provide Owner/Operators with more flexibility to meet the intended security outcomes while ensuring sustainment of the cybersecurity enhancements accomplished through this Security Directive series. Cybersecurity experts from TSA and the Cybersecurity and Infrastructure Security Agency (CISA) contributed to the development of the measures in this Security Directive series to ensure the efficacy of the requirements in mitigating system vulnerabilities.

This revision retains the transition to a more flexible, performance-based approach requiring all Owner/Operators to submit a Cybersecurity Implementation Plan for TSA approval. All currently identified critical Owner/Operators have a TSA-approved Cybersecurity Implementation Plan in place. This plan sets the security measures and requirements against which TSA inspects for compliance.[5] *See* Section II.B. Pursuant to 49 U.S.C. 114(f), the TSA Administrator is authorized to "enforce security-related regulations and requirements"; "inspect, maintain, and test security facilities, equipment, and systems"; and "oversee the implementation, and ensure the adequacy of security measures at … transportation facilities." Given this authority, TSA may require Owner/Operators to provide specific documentation and access to TSA as necessary to establish compliance. *See* Section IV of this Security Directive for examples of the type of records to which TSA may require access.

Although TSA has determined that this document is not sensitive security information, all information that must be reported or submitted to TSA pursuant to this Security Directive is sensitive security information subject to the protections of part 1520 of title 49, Code of Federal Regulations (CFR). DHS may use the information, with company-specific data redacted, for DHS's intelligence-derived reports. DHS also may use information submitted for vulnerability identification, trend analysis, or to generate anonymized indicators of compromise or other cybersecurity products to prevent other cybersecurity incidents.[6] Information provided to DHS pursuant to this Security Directive may also be shared with other agencies as appropriate.[7] The distribution, disclosure, and availability of information will be restricted to persons with a need to know, and safeguarding, protecting, and marking methods for sensitive/critical information will be utilized.[8] The Office of Management and Budget has approved this collection under OMB Control No. 1652-0056.

The Transportation Security Oversight Board (TSOB) is statutorily required to "review and ratify or disapprove" emergency regulations and security directives issued by TSA under 49 U.S.C. 114(*l*)(2). *See* 49 U.S.C. 114(*l*)(2)(B) and 115(c)(1). The TSOB previously

[5] *See also* 49 U.S.C. 114(f); 49 CFR part 1503.
[6] *See* OMB Control No. 1652-0056.
[7] Presidential Policy Directive (PPD) 41 requires Federal agencies to rapidly share incident information with each other to achieve unity of governmental effort. *See* PPD-41 § III.D ("Whichever Federal agency first becomes aware of a cyber incident will rapidly notify other relevant Federal agencies in order to facilitate a unified Federal response and ensure that the right combination of agencies responds to a particular incident"). Furthermore, for purposes of information shared with DHS pursuant to this directive, cyber incident responders with responsibilities under PPD-41 are "covered" persons with a "need to know," as provided by 49 CFR 1520.7 and 1520.11, respectively.
[8] *See* 49 CFR 1520.5(b)(5) and *https://www.tsa.gov/for-industry/sensitive-security-information*.

determined that TSA may renew this security directive without additional review by the TSOB if no changes are made to the requirements. If the TSOB decides not to ratify any section or subsection of this Security Directive, or deems any section or subsection inapplicable, the remainder of this Security Directive shall not be affected unless otherwise specified by the TSOB.

II. ACTIONS REQUIRED

A. Applicability, Deadlines for Compliance, and Scope

1. *Covered Pipeline Owner/Operators:* This Security Directive applies to Owner/Operators of TSA-designated critical pipeline systems or facilities notified before July 26, 2022, that they are required to comply with the Security Directive Pipeline-2021-02 series.[9]

2. *Additional Critical Pipeline Systems or Facilities:* If TSA identifies additional Owner/Operators with critical pipeline systems or facilities who were not already subject to the Security Directive Pipeline-2021-02 series, TSA will notify the Owner/Operator and provide specific compliance deadlines for the requirements in this Security Directive.

3. *Managed Security Service Providers:* If an Owner/Operator has delegated to, or shared responsibility with, a Managed Security Service Provider, wholly or in part, for specific security measures in the Owner/Operator's Cybersecurity Implementation Plan, the Owner/Operator retains sole responsibility under this Security Directive for ensuring compliance with the Owner/Operator's TSA-approved Cybersecurity Implementation Plan and this Security Directive.

4. *Authorized Representative:* Authorized Representatives are empowered by the Owner/Operator to coordinate and/or conduct activities required by this Security Directive and/or contained within the Owner/Operator's TSA-approved Cybersecurity Implementation Plan. Both Owner/Operators and Authorized Representatives are liable for non-compliance on the part of the Authorized Representative with the applicable requirements of the Owner/Operator's TSA-approved Cybersecurity Implementation Plan and this Security Directive.

5. *Scope:* The requirements in this Security Directive apply to the covered Owner/Operators' Critical Cyber Systems.

   Note: If an Owner/Operator determines they have no Critical Cyber Systems, as defined in Section VII., they must notify TSA in writing within 60 days of the effective date of this Security Directive. TSA will notify the Owner/Operator if the agency disagrees with the Owner/Operator's determination and may require the Owner/Operator to provide additional information regarding the methodologies or

[9] *See* § 1557(b) of the *Implementing Recommendations of the 9/11 Commission Act of 2007*, (Pub. L. 110-53; 121 Stat. 266; Aug. 3, 2007) (9/11 Act) (codified at 6 U.S.C. 1207(b) (requiring TSA to review pipeline security plans and inspect critical facilities of the 100 most critical pipeline operators). Applicability for this Security Directive is the same as the Security Directive Pipeline-2021-01 series and the Security Directive Pipeline-2021-02 series.

rationale used to identify Critical Cyber Systems. In the event that an Owner/Operator who does not have Critical Cyber Systems changes its method of operations, they must reevaluate whether they have a Critical Cyber System, and if so, notify TSA within 60 days of the change in operations to determine the schedule for complying with the requirements of this Security Directive.

B. Cybersecurity Implementation Plan

1. The Cybersecurity Implementation Plan must provide the information required by Sections III.A. through III.E. of this Security Directive and describe in detail the Owner/Operator's defense-in-depth plan, including physical and logical security controls, for meeting each of the requirements in Sections III.A. through III.E.

2. Once approved by TSA, the Owner/Operator must implement and maintain all measures in the TSA-approved Cybersecurity Implementation Plan and meet any schedule stipulated in the plan.

III. CYBERSECURITY MEASURES

The Owner/Operator must:

A. Identify the Owner/Operator's Critical Cyber Systems as defined in Section VII. of this Security Directive. TSA will notify the Owner/Operator if the agency disagrees with the Owner/Operator's determination and may require the Owner/Operator to provide additional information regarding the methodologies or rationale used to identify Critical Cyber Systems. After consultation with Owner/Operators, TSA may notify an Owner/Operator that it must include additional Critical Cyber Systems identified by TSA not previously identified by the Owner/Operator in its Cybersecurity Implementation Plan.

B. Implement network segmentation policies and controls designed to prevent operational disruption to the Operational Technology system if the Information Technology system is compromised or vice versa. As applied to Critical Cyber Systems, these policies and controls must include:

1. A list and description of —

a. Information Technology and Operational Technology system interdependencies;

b. All external connections to the Operational Technology system; and

c. Zone boundaries, including a description of how Information Technology and Operational Technology systems are defined and organized into logical zones based on criticality, consequence, and operational necessity.

2. An identification and description of measures for securing and defending zone boundaries, that includes security controls—

a. To prevent unauthorized communications between zones; and

b. To prohibit Operational Technology system services from traversing the Information Technology system, unless the content of the Operational Technology system is encrypted while in transit.

C. Implement access control measures, including for local and remote access, to secure and prevent unauthorized access to Critical Cyber Systems. These measures must incorporate the following policies, procedures, and controls:

1. Identification and authentication policies and procedures designed to prevent unauthorized access to Critical Cyber Systems that include—

a. A schedule for memorized secret authenticator resets; and

b. Documented and defined mitigation measures for components of Critical Cyber Systems that will not have passwords reset in accordance with the schedule required by the preceding subparagraph (III.C.1.a.) and a timeframe to complete these mitigations.

2. Multi-factor authentication, or other logical and physical security controls that supplement password authentication to provide risk mitigation commensurate to multi-factor authentication. If an Owner/Operator does not apply multi-factor authentication for access to industrial control workstations in control rooms regulated under 49 CFR parts 192 or 195, the Owner/Operator shall specify what compensating controls are used to manage access.

3. Policies and procedures to manage access rights based on the principles of least privilege and separation of duties. Where not technically feasible to apply these principles, the policies and procedures must describe the compensating controls that the Owner/Operator will apply.

4. Enforcement of standards that limit availability and use of shared accounts to those that are critical for operations, and then only if absolutely necessary. When the Owner/Operator uses shared accounts for operational purposes, the policies and procedures must ensure—

a. Access to shared accounts is limited through account management that uses principles of least privilege and separation of duties; and

b. Individuals who no longer need access do not have knowledge of the password necessary to access the shared account.

5. Schedule for review of existing domain trust relationships to ensure their necessity and policies to manage domain trusts.

D. Implement continuous monitoring and detection policies and procedures that are designed to prevent, detect, and respond to cybersecurity threats and anomalies affecting Critical Cyber Systems. These measures must include:

1. Capabilities to—

a. Prevent malicious email, such as spam and phishing emails, from adversely impacting operations;

b. Prohibit ingress and egress communications with known or suspected malicious Internet Protocol addresses;

c. Control impact of known or suspected malicious web domains or web applications, such as by preventing users and devices from accessing malicious websites;

d. Block and prevent unauthorized code, including macro scripts, from executing; and

e. Monitor and/or block connections from known or suspected malicious command and control servers (such as Tor exit nodes, and other anonymization services).

2. Procedures to—

a. Audit unauthorized access to internet domains and addresses;

b. Document and audit any communications between the Operational Technology system and an external system that deviates from the Owner/Operator's identified baseline of communications;

c. Identify and respond to execution of unauthorized code, including macro scripts; and

d. Implement capabilities (such as Security, Orchestration, Automation, and Response) to define, prioritize, and drive standardized incident response activities.

3. Logging policies that—

a. Require continuous collection and analyzing of data for potential intrusions and anomalous behavior; and

b. Ensure data is maintained for sufficient periods to allow for effective investigation of cybersecurity incidents.

4. Mitigation measures or manual controls to ensure industrial control systems can be isolated when a cybersecurity incident in the Information Technology system creates risk to the safety and reliability of the Operational Technology system.

E. Reduce the risk of exploitation of unpatched systems through the application of security patches and updates for operating systems, applications, drivers, and firmware on Critical Cyber Systems consistent with the Owner/Operator's risk-based methodology. These measures must include—

1. A patch management strategy that ensures all critical security patches and updates on Critical Cyber Systems are current.

2. This strategy required by Section III.E.1. must include:

    a. The risk methodology for categorizing and determining criticality of patches and updates, and an implementation timeline based on categorization and criticality; and

    b. Prioritization of all security patches and updates on CISA's Known Exploited Vulnerabilities Catalog.[10]

3. If the Owner/Operator cannot apply patches and updates on specific Operational Technology systems without causing a severe degradation of operational capability to meet business critical functions, the patch management strategy must include a description and timeline of additional mitigations that address the risk created by not installing the patch or update.

F. Develop and maintain a Cybersecurity Incident Response Plan.

1. Owner/Operators must have an up-to-date Cybersecurity Incident Response Plan for the Critical Cyber Systems that include measures to reduce the risk of operational disruption, or the risk of other significant impacts on business critical functions should the covered pipeline or facility experience a cybersecurity incident. The Cybersecurity Incident Response Plan must provide specific measures sufficient to ensure the following objectives, as applicable:

    a. Prompt containment of the infected server or device.

    b. Segregation of the infected network (or devices) to ensure malicious code does not spread by, as necessary —

        i. Segregating (removing from the network) the infected device(s);

        ii. Segregating any other devices that shared a network with the infected device(s);

        iii. Preserving volatile memory by collecting a forensic memory image of affected device(s) before powering off or moving; and

        iv. Isolating and securing all infected and potentially infected devices, making sure to clearly label any equipment that has been affected by malicious code.

    c. Security and integrity of backed-up data, including measures to secure backups, store backup data separate from the system, and procedures to ensure that the backup data is free of known malicious code when the backup is made and when tested for restoral.

[10] Available at*: https://www.cisa.gov/known-exploited-vulnerabilities-catalog*.

d. Established capability and governance for isolating the Information and Operational Technology systems in the event of a cybersecurity incident that results or could result in operational disruption.

e. Exercises to test the effectiveness of procedures, and personnel responsible for implementing measures, in this Cybersecurity Incident Response Plan, no less than annually. These exercises must—

i. Test at least two objectives of the Owner/Operator's Cybersecurity Incident Response Plan required by subparagraphs F.1.a. through F.1.d. of this section, no less than annually; and

ii. Include the employees identified (by position) in paragraph F.2 of this section as active participants in the exercises.

2. The Cybersecurity Incident Response Plan must identify who (by position) is responsible for implementing the specific measures in the Incident Response Plan and any necessary resources needed to implement the measures.

G. Develop a Cybersecurity Assessment Plan for proactively assessing and auditing cybersecurity measures.

1. The Owner/Operator must develop a Cybersecurity Assessment Plan for proactively assessing Critical Cyber Systems to ascertain the effectiveness of cybersecurity measures and to identify and resolve device, network, and/or system vulnerabilities.

2. The Cybersecurity Assessment Plan required by Section III.G.1. must –

a. Assess the effectiveness of the Owner/Operator's TSA-approved Cybersecurity Implementation Plan;

b. Include a cybersecurity architecture design review at least once every two years that includes verification and validation of network traffic and system log review and analysis to identify cybersecurity vulnerabilities related to network design, configuration, and inter-connectivity to internal and external systems;

c. Incorporate other assessment capabilities, such as penetration testing of Information Technology systems and the use of "red" and "purple" team (adversarial perspective) testing;

d. Include a schedule for assessing and auditing specific cybersecurity measures and/or actions required by subparagraphs G.2.a. through G.2.c. The schedule must ensure at least one-third (1/3) of the policies, procedures, measures, and capabilities in the TSA-approved Cybersecurity Implementation Plan are assessed each year, with 100 percent assessed over any three-year period; and

e. Ensure a Cybersecurity Assessment Plan annual report of the results of assessments conducted in accordance with the Plan is submitted to TSA as described in paragraph G.4. of this section. The required report must indicate—

i. For the previous 12 months, which assessment method(s) were used to determine whether the policies, procedures, and capabilities described by the Owner/Operator in its Cybersecurity Implementation Plan are effective; and

ii. Results of the individual assessments conducted in the previous 12 months.

3. The Owner/Operator must submit its Cybersecurity Assessment Plan on an annual basis to TSA for approval. The Cybersecurity Assessment Plan must be submitted to TSA no later than 12 months from the date of TSA's approval of the Owner/Operator's previous Cybersecurity Assessment Plan.

4. The Owner/Operator must submit the Cybersecurity Assessment Plan report required by section G.2.e. to TSA no later than 12 months from the date of TSA's approval of the most recent Cybersecurity Assessment Plan.

IV. RECORDS

A. *Use of previous plans, assessments, tests, and evaluations.* As applicable, Owner/Operators may use previously developed plans, assessments, tests, and evaluations to meet the requirements of this Security Directive. If the Owner/Operator relies on these materials, they must include an index of the records and their location organized in the same sequence as the requirements in this Security Directive. In addition, these materials must be explicitly incorporated by reference into the Cybersecurity Implementation Plan and made available to TSA upon request.

B. *Protection of sensitive security information.* The Owner/Operator must, at a minimum, store and transmit the following information required by this Security Directive consistent with the requirements in 49 CFR part 1520:[11]

1. Plans and reports; and

2. Audit, testing, or assessment results.

C. *Documentation to Establish Compliance*

1. The Owner/Operator must make records necessary to establish compliance with the requirements of this Security Directive available to TSA upon request for inspection and/or copying.

2. TSA may request to inspect or copy the following documents to establish compliance with this Security Directive:

a. Hardware/software asset inventory, including supervisory control, and data acquisition systems.

b. Firewall rules.

[11] Owner/Operators may contact SSI@tsa.dhs.gov for more information on how to comply with requirements for the protection of Sensitive Security Information.

c. Network diagrams, switch and router configurations, architecture diagrams, publicly routable internet protocol addresses, and Virtual Local Area Networks.

d. Policy, procedural, and other documents that informed the development, and documented implementation of, the Owner/Operator's Cybersecurity Implementation Plan, Cybersecurity Incident Response Plan, Cybersecurity Assessment Plan, and assessment or audit results.

e. Data providing a "snapshot" of activity on and between Information and Operational Technology systems, such as—

i. Log files;

ii. A capture of network traffic (i.e., packet capture (PCAPs)), not to exceed a period of twenty-four hours, as identified and directed by TSA;

iii. "East-West Traffic" of Operational Technology systems/sites/environments within the scope of this Security Directive's requirements; and

iv. "North-South Traffic" between Information and Operational Technology systems, and the perimeter boundaries between them.

f. Any other records or documents necessary to establish compliance with this Security Directive.

V. PROCEDURES FOR SECURITY DIRECTIVES

A. General Procedures

1. *Confirm Receipt.* Immediately provide written confirmation of receipt of this Security Directive via e-mail to TSA at SurfOps-SD@tsa.dhs.gov;

2. *Dissemination.* Immediately disseminate the information and measures in this Security Directive to corporate senior management and security management representatives. The Owner/Operator must provide the applicable security measures in this Security Directive to the Owner/Operator's direct employees and authorized representatives responsible for implementing applicable security measures as necessary to ensure compliance.

B. *Comments.* Owner/Operators may comment on this Security Directive by submitting data, views, or arguments in writing to TSA via e-mail at TSA-Surface@tsa.dhs.gov. Any comments referring to specific measures in this Security Directive must be protected in accordance with the requirements in 49 CFR part 1520. TSA may amend the Security Directive based on comments received. Submission of a comment does not delay the effective date of the Security Directive or requirement to comply with the provisions of the Security Directive.

C. *Submission of Documentation to TSA.* Owner/Operators are required to submit documents in a manner prescribed by TSA. TSA will provide Owner/Operators specific instructions for submission of required documents.

VI. AMENDMENTS TO CYBERSECURITY IMPLEMENTATION PLAN

A. *Changes to ownership or control of operations.* An Owner/Operator required to submit a Cybersecurity Implementation Plan under Section II.B. of this Security Directive must submit a request to amend its Cybersecurity Implementation Plan if, after approval, there are any changes to the ownership or control of the operation.

B. *Changes to conditions affecting security*. An Owner/Operator required to submit a Cybersecurity Implementation Plan under Section II.B. of this Security Directive must submit a request to amend its Cybersecurity Implementation Plan if, after approval, the Owner/Operator makes, or intends to make, permanent changes to the policies, procedures, or measures approved by TSA, including, but not limited to, changes to address:

1. Determinations that a specific policy, procedure, or measure in the Cybersecurity Implementation Plan is ineffective based on results of the audits and assessments required under Section III.G. of this Security Directive; or

2. The Owner/Operator has identified or obtained new or additional capabilities for meeting the requirements in the Security Directive that have not been previously approved by TSA.

C. *Permanent change*. For purposes of this section, a "permanent change" is one intended to be in effect for 45 or more calendar days.

D. *Schedule for requesting amendment*. The Owner/Operator must file the request for an amendment to its Cybersecurity Implementation Plan with TSA no later than 50 calendar days after the permanent change takes effect, unless TSA allows a longer time period.

E. *TSA approval*.

1. TSA may approve a requested amendment to a Cybersecurity Implementation Plan if TSA determines that it is in the interest of the public and transportation security and the proposed amendment provides the level of security required under this Security Directive.

2. TSA may request additional information from the Owner/Operator before rendering a decision.

F. *Petition for reconsideration*. No later than 30 calendar days after receiving a denial of an amendment to a Cybersecurity Implementation Plan, the Owner/Operator may file a petition for reconsideration following the procedures in 49 CFR 1570.119.

VII. DEFINITIONS

In addition to the terms defined in 49 CFR 1500.3, the following terms apply to this Security Directive:

A. *Authorized Representative* means, for the purpose of this Security Directive, a person who is not a direct employee of the Owner/Operator, but is authorized to act on the Owner/Operator's behalf to perform measures required by the Security Directive and/or contained within the Owner/Operator's TSA-approved Cybersecurity Implementation Plan. The term authorized representative may include agents, contractors, and subcontractors. This term does not include Managed Security Service Providers.

B. *Business critical functions* means the Owner/Operator's determination of capacity or capabilities to support functions necessary to meet operational needs and supply chain expectations.

C. *Critical Cyber System* means any Information or Operational Technology system or data that, if compromised or exploited, could result in operational disruption. Critical Cyber Systems include business services that, if compromised or exploited, could result in operational disruption.

D. *Cybersecurity architecture design review* means a technical assessment based on government and industry-recognized standards, guidelines, and best practices that evaluates systems, networks, and security services to determine if they are designed, built, and operated in a reliable and resilient manner. These reviews must be designed to be applicable to the Owner/Operator's Information and Operational Technology systems.

E. *Cybersecurity incident* means an event that, without lawful authority, jeopardizes, disrupts or otherwise impacts, or is reasonably likely to jeopardize, disrupt or otherwise impact, the integrity, confidentiality, or availability of computers, information or communications systems or networks, physical or virtual infrastructure controlled by computers or information systems, or information resident on the system. This definition includes an event that is under investigation or evaluation by the Owner/Operator as a possible cybersecurity incident without final determination of the event's root cause or nature (such as malicious, suspicious, benign).

F. *Days* means calendar days unless otherwise indicated. As used for compliance deadlines, if a requirement must be met on a date that is a federal holiday, the compliance deadline will be the next federal business day after the holiday.

G. *Demilitarized Zone (DMZ)* or *perimeter network*, means a network area (a subnetwork) that sits between an internal network and an external network. The security demilitarized zone is used for providing external controlled access to services used by external personnel to the control system network to ensure secure application of system updates and upgrades. For someone on the external network who does not have authorization to connect to the internal network, the demilitarized zone is a dead end.

H. *East-West Traffic* means, in a networking context, the lateral movement of network traffic within a trust zone or local area network.

I. *Information Technology **s**ystem* means any services, equipment, or interconnected systems or subsystems of equipment that are used in the automatic acquisition, storage, analysis, evaluation, manipulation, management, movement, control, display, switching, interchange, transmission, or reception of data or information that fall within the responsibility of the Owner/Operator to operate and/or maintain.

J. *Interdependencies* means relationships of reliance within and among Information and Operational Technology systems that must be maintained for those systems to operate and provide services.

K. *Managed Security Service Providers* means for the purposes of this Security Directive, a person who is not a direct employee of the Owner/Operator, but who provides one or more services or capabilities that the Owner/Operator is using to perform measures required by the Security Directive and/or contained within the Owner/Operator's TSA-approved Cybersecurity Implementation Plan. Managed Security Service Providers generally provide a logical service or capability. Managed Security Service Providers are not Authorized Representatives.

L. *Memorized secret authenticator* means a type of authenticator comprised of a character string intended to be memorized by, or memorable to, the subscriber, permitting the subscriber to demonstrate something they know as part of an authentication process.

M. *North-South Traffic* means network traffic that moves through a perimeter boundary into another trust level.

N. *Operational disruption,* for purposes of this Security Directive, means a deviation from or interruption of business critical functions that results from a compromise or loss of data, system availability, system reliability, or control of system**s**.

O. *Operational Technology **s**ystem* is a general term that encompasses several types of control systems, including industrial control systems, supervisory control and data acquisition systems, distributed control systems, and other control system configurations, such as programmable logic controllers, fire control systems, and physical access control systems, often found in the industrial sector and critical infrastructure. Such systems consist of combinations of programmable electrical, mechanical, hydraulic, pneumatic devices or systems that interact with the physical environment or manage devices that interact with the physical environment.

P. *Owner/Operator* means a person who owns or maintains operational control over pipeline facilities or engages in the transportation of hazardous liquids or natural gases and who has been identified by TSA as one of the most critical interstate and intrastate natural gas and hazardous liquid transmission pipeline infrastructure and operations.

Q. *Phishing* means tricking individuals into disclosing sensitive personal information through deceptive computer-based means (such as internet web sites or e-mails using social engineering or counterfeit identifying information).

R. *Security, Orchestration, Automation, and Response* means capabilities that enable Owner/Operators to collect inputs monitored by the security operations team. For example, alerts from the security information and event management system and other security technologies – where incident analysis and triage can be performed by leveraging a combination of human and machine power – help define, prioritize and drive standardized incident response activities. These capabilities allow an Owner/Operator to define incident analysis and response procedures in a digital workflow format.

S. *Shared Account* means an account that is used by multiple users with a common authenticator to access systems or data. A shared account is distinct from a group account, which is a collection of user accounts that allows administrators to group similar user accounts together in order to grant them the same rights and permissions. Group accounts do not have common authenticators.

T. *Spam* means electronic junk mail or the abuse of electronic messaging systems to indiscriminately send unsolicited bulk messages.

U. *Tor,* also known as *The Onion Router,* means software that allows users to browse the web anonymously by encrypting and routing requests through multiple relay layers or nodes. Tor software obfuscates a user's identity from anyone seeking to monitor online activity (such as nation states, surveillance organizations, information security tools). This deception is possible because the online activity of someone using Tor software appears to originate from the Internet Protocol address of a Tor exit node, as opposed to the address of the user's computer.

V. *Trust relationship* means an agreed-upon relationship between two or more system elements that is governed by criteria for secure interaction, behavior, and outcomes relative to the protection of assets. This term refers to trust relationships between system elements implemented by hardware, firmware, and software.

W. *Unauthorized Access of an Information Technology or Operational Technology System* means access from an unknown source, access by a third party or former employee; an employee accessing systems for which he or she is not authorized; and may include a non-malicious Owner/Operator's policy violation such as the use of shared credential by an employee otherwise authorized to access it.

Ha Nguyen McNeill
Acting Administrator
Transportation Security Administration

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Direct Testimony of Brian E. Fellon

INFORMATION TECHNOLOGY & SERVICES

Exh. BEF-1CT

REDACTED VERSION

August 29, 2025

DIRECT TESTIMONY OF BRIAN E. FELLON

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position at Northwest Natural Gas Company dba NW Natural ("NW Natural" or "Company").

A. My name is Brian E. Fellon. My title is Vice President, Chief Information Officer & Chief Information Security Officer. I am responsible for NW Natural's information technology and services ("IT&S"), including cybersecurity, information technology ("IT"), operational technology ("OT"), service desk, and other technology-related architecture, infrastructure, network, and applications—which together enable NW Natural to support its customers and operate successfully.

Q. Please describe your education and employment background.

A. I hold a Bachelor's degree in business administration from the University of Washington and a Master of Business Administration from Seattle University. I have more than 25 years of experience in IT, and nearly 20 years of IT leadership in management and executive levels. I joined NW Natural in my current role in 2024. Prior to joining NW Natural, I was Director of Information Technology, Application Services, at Puget Sound Energy in Bellevue, Washington for eight years. Prior to that, I held a variety of technical and technology leadership roles in consulting, aerospace, and retail sectors.

Q. What is the purpose of your testimony?

A. The primary purpose of my testimony is to introduce and describe the IT&S projects and programs for which the Company is seeking recovery in this case. I will therefore provide an overview of NW Natural's strategic vision, explain major IT&S planning

areas, and provide details regarding the major IT&S projects and programs for which recovery is sought in this rate case.

Q. Please summarize your testimony.

A. First, I provide an overview of NW Natural's IT&S environment, including the ongoing need to migrate to cloud-based software and associated cost-recovery concerns. Second, I provide an update on the Company's Horizon Program. Third, I describe the IT&S projects that will be included in each year of the proposed multi-year rate plan ("MYRP"), including preexisting and pro forma projects. Finally, I detail two programmatic IT&S efforts for which the Company seeks cost recovery in this proceeding: (1) the EDP Data Reporting and Analytics Program and (2) the Telemetry Refresh Program.

Q. Please explain how the Company's major IT&S projects are organized.

A. The Company's major IT&S projects are organized into the following categories:

1. **Horizon Program:**[1] The Horizon Program is a multi-year, two-phase IT&S initiative to upgrade NW Natural's central technology architecture. While the second phase of this project will not be placed in service until after the MYRP in this case, several smaller prerequisite projects will enter service during the MYRP. I discuss this Program and the constituent prerequisite projects in more detail in Section III (Horizon Program Update).

[1] NW Natural uses the term "program" internally to refer to large, multi-project initiatives. This use is distinct from the Commission's use of "programmatic investments" to mean investments made according to a schedule or plan, where investment is forecast using "historical trends." *See* Used and Useful Policy Statement ¶¶ 11n.19, 35.

2. **Field and Web Mapping:** Field and Web Mapping refers to the systems and tools that allow NW Natural to view its infrastructure and other assets in a geospatial format and for collecting various types of data related to these assets. These tools also provide field and office personnel with visual representations of NW Natural facilities and assets, which they use for a range of business purposes including inspection and compliance programs. Currently, NW Natural is in the midst of a multi-year initiative to update the Company's field and web mapping solutions by phasing out end-of-life software and transitioning to a consolidated set of modern software solutions.
3. **Field Workforce Management:** Field Workforce Management involves the tools necessary to schedule, dispatch, and route NW Natural personnel in the field. Successful field workforce management relies on accurate and efficient field and web mapping for visibility into NW Natural's system and physical assets, and then uses this foundation to optimize the management of field personnel.
4. **Identity Governance and Administration ("IGA"):** IGA is the process of granting, updating, reviewing, and revoking access to technology systems for NW Natural employees and contractors, based on job changes or other Company needs, and forms an important component of the Company's security controls. The Company's IGA work effort includes several projects necessary to transition to an automated IGA software solution, and thus ensure consistent, secure monitoring and control of access and permissions.

5. **Customer Self-Service:** The Customer Self-Service enhancements initiative provides customers with new features and efficiencies to improve communication and accessibility, helping customers manage their accounts more easily through the web-based and phone systems. Customer Self-Service projects also equip customer service representatives with tools to resolve complex issues faster and serve customers more efficiently.
6. **Technology Refresh:** Technology Refresh focuses on physical infrastructure necessary to enable the Company's IT&S. This category of work includes microwave towers, voice radio, and telemetry equipment—all of which is necessary to monitor and maintain to ensure the safe and reliable provision of service.
7. **Gas Control Daily Operations Platform ("GCDOP"):** The GCDOP is a strategic initiative to replace the company's aging, custom-built Supervisory Control and Data Acquisition ("SCADA") platform with a modern, modular, and secure SCADA platform to control and monitor the Company's distributed pipeline infrastructure.
8. **Application Lifecycle Management ("ALM"):** ALM refers to work needed to update and maintain critical IT&S applications and platforms. These maintenance-related investments are necessary to ensure IT&S systems' security and reliability. By keeping software and equipment at supported levels, NW Natural can continue to receive critical system and security patches, take advantage of the latest technology features, and maintain license compliance as defined by support agreements. While ALM can overlap with other categories

of IT&S work, the Company uses ALM to refer to work that is exclusively lifecycle-related.

9. **Back-Office Functions:** Back-office Functions represent the underlying administrative infrastructure needed to ensure that NW Natural, as a utility company, operates safely, reliably, and effectively. In the Company's IT&S space, this includes financial reporting software, billing systems, risk analytic tools, and report generation functions.

Q. How are the Company's IT&S investments allocated to Washington customers?

A. The Company's IT&S investments are allocated to Washington and Oregon customers using the allocation factor of total customers. The Washington allocation factor for total customers in this case is 12.17 percent. The Direct Testimony of Kyle T. Walker (Exh. KTW-1T) addresses the topic of allocation factors and their associated methodology.

II. OVERVIEW OF THE IT&S ENVIRONMENT

Q. Please describe NW Natural's current IT&S environment.

A. IT&S continues to play a critical and ever-evolving role in serving customers, utility operations, and cybersecurity. In this dynamic environment, NW Natural strives to modernize its systems while prudently preserving and extending the useful life of the systems in place. The Company will continue to prioritize IT&S cybersecurity, ensuring that both the new and existing IT&S platforms are safeguarded against potential threats.

Q. Does the Company's IT&S environment continue to include the adoption of cloud-based solutions?

A. Yes. Cloud-based solutions have become industry standard for large enterprises. Utilities often transition to cloud-based solutions when legacy systems reach end-of-life because these solutions have become the standard offering in the industry, if not the only available offering for a given system. Legacy systems are increasingly difficult and costly to maintain, lack compatibility with modern technologies, and pose significant cybersecurity risks. Cloud-based platforms provide enhanced scalability with resource demands, real-time data accessibility, and robust support and real-time cybersecurity updates from developers. With on-premises options being phased out, cloud-based solutions are now the primary avenue for utilities to maintain their operations and ensure reliable service delivery in an evolving energy landscape. Over the last several years, the Company has successfully migrated an array of IT&S solutions and platforms to Microsoft's Azure cloud platform as part of NW Natural's overarching goal of simplifying IT&S solutions.

Q. Is NW Natural continuing to experience financial pressures associated with the cloud-based solutions?

A. Yes. While cloud-based solutions are the prudent (and sometimes only) choice for the Company and our customers, the accounting rules associated with these solutions create new financial pressures for several reasons. **First**, unlike on-premises solutions, the utility can capitalize only the implementation costs of cloud-based assets, with the depreciable life of this asset tied to the duration of the contract for the software service. Typically, in the IT&S field, these contracts are relatively short—between one and five

years. As such, the depreciable life of the asset is very fast compared to most of the utilities' long-lived assets. With a five-year asset life, if the utility does not recover a single year of the asset, the utility is foregoing 20 percent of the recovery of that asset.

Second, cloud-based assets are a relatively new technology. NW Natural did not have any cloud-based assets prior to 2020. As such, this asset class is a growing asset class, which creates a more urgent financial need to ensure that the Company is routinely recovering this new asset class.

Third, because cloud-based solutions entail ongoing subscriptions, the accounting rules require that these subscription costs be accounted for as operations and maintenance ("O&M") expense. As noted above, with the system-wide migration to cloud-based solutions, NW Natural is continuing to experience increases in the Company's annual incremental O&M expense as the Company moves to more cloud-based tools.

Q. How does the rapidly changing IT&S environment impact project forecasting in a MYRP?

A. The rapid evolution of IT&S systems makes these projects particularly challenging to forecast with specificity in the more remote years of a MYRP. As I note above, IT&S projects frequently operate on shorter time horizons. Thus, particularly for projects in Rate Years 2 and 3, the Company bases its cost estimates and forecast need on the reasonably expected lifecycles of certain critical IT&S infrastructure.

For instance, the Company currently anticipates needing to update or replatform its website as part of the Website Technology Project in 2027 (Rate Year 2). This timeline reflects a typical planning lifecycle for website technologies. However, since

software tools evolve rapidly, the Company will not be able to finalize its evaluation and confirm specific options until closer to the project kick-off date in 2026. Thus, certain projects in the later years of the MYRP will involve additional documented analysis concerning project scope, cost, and alternatives, to support prudent and timely decision-making.

Q. How does the rapid evolution of IT&S systems impact the Company's application lifecycle management?

A. The rapid evolution of IT&S systems means that the Company must plan for routine system updates. For IT&S systems, the application lifecycle is usually 2-3 years, at which point the Company must update to current software. If updates are not made, then the Company risks exposing these crucial systems to cybersecurity threats or facing reliability challenges due to lack of vendor support. In adopting new software versions, the Company seeks to balance longevity and reliability. While adopting the most recent version would ensure that vendor support would be available for the longest period of time, the latest software versions often experience the most "bugs" or technical issues. Thus, the Company seeks to prudently balance maintaining existing, vendor-supported software versions while ensuring that applications remain secure and reliable.

Q. Is there a particular area of the Company's IT&S environment that is undergoing the most transformative change during this MYRP?

A. Yes. The Company's field and web mapping program is undergoing a particularly transformative change. This multi-year initiative involves upgrading and replacing the systems used to manage and view NW Natural's geospatial and physical asset data.

The geographic information system ("GIS") team uses geospatial data to maintain NW Natural's gas asset records and to model the Company's gas facilities and operations. This detailed network model allows the Company to control how gas moves through the system and to highlight potential system gaps. The following simplified Table 1 summarizes the Company's roadmap for the field and web mapping product suite relevant to this MYRP, which consolidates significant functionality onto the Company's new IQGeo platform:

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Table 1. Company's Roadmap for the Field and Web Mapping Product Suite

Application	Status	Uses	Users
IQGeo	• 2020: Implementation • 2023: Lifecycle management (version update to 6.5) • 2027: Lifecycle management (version update to latest major release, currently forecasted as 8.x)	View geospatial data and maps, complete surveys, report leaks	Field and Back Office
MapFrame	Replaced by IQGeo (2024)	View and correct maps	Field and Back Office
ArcMap (Esri)	Will be replaced by ArcGIS Pro (2026)	Create, edit, and analyze GIS data and connectivity model	GIS, Environmental Management, Pipeline Integrity
ArcGIS Pro (Esri)	Will replace ArcMap (2026)	Create, edit, and analyze GIS data and connectivity model	GIS, Environmental Management, Pipeline Integrity
Geometric Network (Esri)	Will be replaced by Utility Network (2026)	Model network connectivity of gas infrastructure	GIS, Pipeline Integrity, others for valve isolation and cathodic protection tracing
Utility Network (Esri)	Will replace the Geometric Network (Esri) (2026)	Model network connectivity of gas infrastructure	GIS, Pipeline Integrity, others for valve isolation and cathodic protection tracing
ArcFM Viewer	Will be replaced by Esri product (2026)	Trace cathodic protection network	Corrosion Team
Visual Fusion	Will be replaced by IQGeo and Esri (2027)	View valve isolation tracing maps for emergency response	Back Office, Gas Control
Capture (IQGeo)	Will be replaced by IQGeo Network Manager (2027)	Field drawing tool for newly constructed assets	Field and Back Office

Q. How do the projects you detail in your testimony align with the Company's overarching strategic goals?

A. Each of the projects I detail in my testimony supports the Company's goal of serving customers through a secure and compliant system. These projects ensure the reliability and resilience of NW Natural's operations, enhance operational security, and leverage opportunities to streamline NW Natural's IT&S portfolio using off-the-shelf tools that are effective and vendor-supported. NW Natural has worked closely with software vendors to identify competitive and effective solutions that prioritize quality customer service and reliable business operations. As the Company implements its overarching strategic IT&S transition to cloud-based platforms, NW Natural will continue to prudently maximize the useful life of existing IT&S systems for the benefit of customers.

III. HORIZON PROGRAM UPDATE

Q. Please briefly describe the Horizon Program.

A. As described in UG-200994, the Horizon Program is a multi-year, two-phase IT&S initiative to upgrade NW Natural's central technology architecture. Each phase, referred to as Horizon 1 and Horizon 2: Vista ("H2: Vista"), is driven by a significant keystone project to upgrade a major piece of software using modern, industry-standard software tools. NW Natural successfully completed the first phase of the transformational effort ("Horizon 1") in 2022, by upgrading the Company's backbone enterprise resource planning ("ERP") software. The costs for this phase of the project were included in year two of the UG-200994 Multi-Year Rate Plan. Horizon 1 was implemented on time and within reasonable budget parameters, providing valuable

lessons learned for the Horizon Program's second major phase: H2: Vista. This second phase will comprehensively update the Company's outdated customer information system ("CIS") and other customer-facing functions and related services, and is currently in development.

Q. What is the status of the Horizon Program?

A. In 2024, the Company completed the initial planning stage of H2: Vista, which involved a comprehensive framing study to confirm the sequence and scope of various prerequisite and component projects. This careful preliminary analysis was crucial to minimize risk in the larger implementation components of H2: Vista. NW Natural is moving forward with the prerequisite projects identified in the study to prepare for its CIS replacement. These prerequisite activities will ensure that NW Natural has the right foundational technologies in place to support its CIS replacement and will ensure that the Company's legacy CIS is able to provide reliable service to NW Natural customers during the transition.

Q. Please summarize the CIS study approach.

A. The Company completed the six-month study with third-party consultant support from Ernst & Young ("EY"). EY was selected through a competitive procurement process, which included several vendors that are leaders in implementations of this type. EY brought extensive experience in completing recent similar work with other utilities around the country. The study followed a structured approach, starting with a current state assessment, followed by the identification of the strategic alternatives, and concluding with a development of the recommendation and a roadmap for the program.

The December 2024 NW Natural Executive Update of the CIS study is included in confidential Exh. BEF-2C.

Q. Please summarize the study recommendation.

A. The study recommended initiating implementation of the new CIS in 2030, while dedicating the next five years to completing the prerequisite work. This approach mitigates the risks associated with the upcoming CIS replacement project and establishes a more balanced and steady expenditure pattern in the years leading up to the CIS implementation. This recommendation is based on several compelling reasons:

- **Financial Impacts:** Financial management is a cornerstone of this recommendation, focusing on reducing near-term costs. This plan prioritizes NW Natural's mission of providing affordable service by minimizing the immediate impact on customer rates.
- **Service Impacts:** By extending the timeline for completing peripheral and prerequisite projects, NW Natural can address more pressing customer needs sooner.
- **Strategy & Alignment:** This strategy enables steady investment in the existing technology and the completion of vital prerequisite projects, while deferring major capital expenditures and synchronizing them with the completion of other large capital programs.
- **Implementation Logistics:** This plan acknowledges the current personnel limitations within NW Natural's IT&S and business teams, which are not presently staffed to manage such a large-scale project. There is too great a risk of unknown complexities to move forward with prerequisites and CIS project launch in a single

workstream. CIS is a critical business function and a longer timeframe for completion is needed to adequately reduce project risk.

- **Technology Considerations:** Delaying the CIS replacement allows NW Natural to continue using its existing CIS asset, thereby obtaining additional value from the investment. While the current system meets business needs today, its flexibility and scalability to accommodate growth and evolving customer needs are limited.

Additionally, the study categorized CIS Replacement projects into three groups:

1. **Evolve & Sustain projects:** These are essential to maintain business as usual while preparing for the CIS replacement, including the cutover and stabilization phases.
2. **Prerequisite projects:** These projects are necessary to meet core business needs and mitigate risks associated with the CIS Replacement, while aligning with the customer lifecycle management roadmap.
3. **CIS Replacement projects:** These are directly related to the replacement efforts, such as the CIS implementation itself.

Q. What alternatives did the Company consider?

A. NW Natural evaluated three alternatives for CIS replacement to determine which one best aligns with the Company's desired outcomes and objectives. The evaluation involved a thorough examination of each alternative's advantages, disadvantages, and potential impacts:

1. **Near-Term CIS Replacement:** This alternative involves replacing the existing CIS with SAP within the next five years. This approach would require

significant financial investment in the next few years and the simultaneous execution of prerequisite and peripheral projects.

2. **Long-Term CIS Replacement:** This alternative is a gradual approach to replacing the existing CIS in the early 2030s, one that balances expenditure and resources utilization over time. It allows for the completion of necessary peripheral projects before transitioning to the new CIS.

3. **Defer CIS Replacement Decision:** This alternative involves improving and strengthening the existing CIS through regular hardware and software refreshes. It also includes redesigning the user interface and reducing its scope to primarily billing functions. The decision on replacing the existing CIS would be deferred indefinitely.

Q. How did NW Natural consider each of these alternatives?

A. Each alternative was developed with a proposed timeline, along with a sequence of activities, which allowed the Company to better understand the broader impact of the sequencing of work outlined in the alternatives. Each of the three CIS alternatives was then scored across a set of criteria and business objectives. These criteria were categorized into key areas of impact, including Strategy and Alignment, Service Impact, Financial Impact, Implementation Logistics, and Technology considerations. For each area, specific criteria such as strategic fit, regulatory compliance, benefits versus risks, customer expectations, and operational excellence were evaluated.

Q. What alternative did NW Natural choose for its CIS system?

A. After completing its formal evaluation process, the Company chose long-term replacement (option 2), while also incorporating some stabilization work for the

existing CIS. A CIS replacement is among the most complex projects a utility can undertake, and because of this NW Natural intends to complete all peripheral and prerequisite work at a manageable pace to account for staffing level dynamics. This work will put the Company on track to replace the CIS on a specific timeline, currently estimated to be 2032. By adopting this deliberate, structured approach to replacing its CIS, NW Natural can ensure a seamless transition to a new system while maintaining customer service quality.

Q. What other considerations were a factor in NW Natural's decision to postpone the replacement of the CIS system?

A. NW Natural needs to complete several prerequisite and peripheral projects in advance of replacing the CIS system. Completing this work along with preparing to launch a new CIS would be extremely challenging due to the limited size of NW Natural's current CIS support team. The existing CIS system is maintained by a small, experienced team within NW Natural, which includes key employees eligible for retirement over the next 3-5 years. These individuals possess detailed working knowledge of the CIS's architecture, operation, customizations, and integrations. Regulatory requirements and business enhancements involving changes to the CIS flow through a very narrow funnel of design and development capacity. By extending the time needed before starting the new CIS implementation from two years to five years, NW Natural can build up its CIS staffing, execute the necessary peripheral projects, and implement certain prerequisite projects.

Q. Were there external factors in the market affecting the decision to not pursue replacing the CIS in the near-term?

A. Yes. System integrator demand is outpacing supply for utilities looking to replace their CIS in the next two years. According to EY, many similarly sized or larger utilities are pursuing CIS replacement projects. There is a finite capacity of quality CIS system integrators, and the current competition for these resources would result in higher costs or lower quality resources for NW Natural.

Q. Were there other factors considered in the decision to not pursue the third alternative of maintaining the current CIS and deferring the CIS replacement decision indefinitely?

A. Yes. The Company determined that making significant investments in the existing CIS would not be a viable long-term solution. Long-term support (e.g., over 10 years) of the current CIS and its associated hardware will become increasingly difficult, risky, and costly. While NW Natural plans to take steps over the next several years to evolve and sustain the existing CIS as needed, the underlying CIS technologies (e.g., iSeries hardware and report program generator, or "RPG," code) are moving toward obsolescence.

Q. How is NW Natural planning to manage risks associated with the current CIS given the replacement date of 2032?

A. NW Natural is implementing a series of "Evolve & Sustain CIS" projects to ensure the continued stability and performance of the existing CIS leading up to and through its replacement. These projects include activities necessary to maintain business as usual while preparing for the replacement of the CIS and through the cutover and stabilization

phases. This work encompasses several key upgrade projects, including (a) enhancing the integration of the CIS with the Clevest field work management system to enhance operational efficiency, (b) upgrading the CIS graphical user interface to better support customer service representatives, and (c) performing lifecycle upgrades scheduled between 2028 and 2030. These projects are strategically planned to keep the CIS components up-to-date and secure, ensuring consistent service reliability for customers within a well-managed budget. The projects are grouped to address different operational needs, including vendor selection and third-party integrations, ensuring that each aspect of the CIS is optimized for performance and security.

Q. Is the Company seeking cost recovery of projects associated with H2: Vista in this rate case?

A. Yes. NW Natural is seeking cost recovery associated with completing several projects that are part of the CIS replacement roadmap. These projects are essential to maintain business as usual while preparing for the CIS replacement. Although these projects are part of the CIS roadmap, they are also necessary as part of ongoing investment to ensure continued availability, stability, and security of our existing CIS. The projects are:

- **CIS to Clevest Integration Hardening and Upgrade Project:** This project will ensure a robust and efficient connection between the current CIS and the Clevest field work management system, which is critical for ensuring stable transfer of work orders between the two systems. This project involves $612 thousand in proforma system investment, with a Washington allocation of $74 thousand. This project is expected to be in service in August 2025.

- **Application Lifecycle Management - LegaSuite Project:** This project is required to update to CIS graphical user interface (GUI) to maintain system technical currency. This project involves $56 thousand in total system investment, with a Washington allocation of $7 thousand.
- **CIS Data Quality Cleansing:** This initiative mitigates CIS replacement risk by migrating CIS data to the Enterprise Data Platform ("EDP"), conducting data quality analysis, and implementing data governance measures. By transferring historical CIS data to the EDP and retaining only the current data necessary for billing within the CIS, the scope and risk of the CIS replacement will be significantly reduced. This project involves $4.5 million in total system investment, with a Washington allocation of $545 thousand. I discuss this project in more detail below, along with other Rate Year 3 projects (Section VIII).

IV. IN-SERVICE PROJECTS
(through March 31, 2025)

A. Genesys Replatform Project

Q. As an initial matter, can you please provide some background on Genesys' role within NW Natural?

A. Genesys is the Company's advanced call routing software provider. Previously, NW Natural used Genesys PureConnect, an on-premises solution, to serve 7 groups and 300 combined agents across NW Natural, including Customer Support and the Customer Contact Center. Due to the centrality of Genesys' role in NW Natural's communications operations, the Genesys PureConnect software was a critical infrastructure system that needed to be available 24 hours a day, 365 days a year. As a

result, reliability issues with this system were unacceptable for public health and safety.

Q. Please describe the Genesys Replatform Project.

A. The Genesys Replatform Project transitioned the Genesys call routing solution to a cloud environment, in response to the impending termination of support for the on-premise PureConnect platform by the software provider.

Q. Why was the Genesys Replatform Project necessary?

A. The Genesys Replatform Project was necessary to maintain the integrity and reliability of the Company's communications with customers. Fundamentally, this project was driven by the sunset of the Genesys PureConnect on-premises software. Genesys was phasing out the availability of and support for the PureConnect system, first by ceasing to offer new support agreements in January 2024, and then by fully ceasing support and operation of the system on July 31, 2025. Thus, while Genesys PureConnect had been an integral part of handling NW Natural's customer interactions and support experience, the Company needed to transition to a different call routing solution.

Q. What are the benefits of the Genesys Replatform Project?

A. In addition to preventing outages on this critical part of NW Natural's communications infrastructure, the Genesys Replatform Project reduced the risk of product downtime and supported integration with other software solutions. A cloud-hosted call-routing software can greatly minimize outages compared to on-premises options, which can be subject to location-specific service interruptions. Similarly, Genesys Cloud supports integrations with a wide range of other software solutions, which can facilitate future integrations across other technologies and platforms.

Q. Did NW Natural consider alternatives to replatforming the Genesys software?

A. Yes. NW Natural explored deploying a new contact center solution, but doing so would have been more costly, more labor-intensive, and would not have provided assurance of superior service. Moreover, integrating a new software solution with the Company's other software systems would have introduced additional reliability risks.

Q. What is the status of the Genesys Replatform Project?

A. The Genesys Replatform Project was placed in service in September 2024. The alternatives analysis for this project is attached as Exh. BEF-3.

Q. What cost recovery is NW Natural requesting for the Genesys Replatform Project in this case?

A. NW Natural seeks to recover its capital investment of approximately $3.1 million on a system basis, or $0.4 million on a Washington-allocated basis.

B. Utilities International Planner Replatform Project

Q. Please describe the Utilities International ("UI") Planner Replatform Project.

A. The UI Planner Replatform Project migrated the Company's UI planning system into the cloud. UI Planner is NW Natural's corporate financial and regulatory finance planning system and is also used by most of the Company's utility peers to perform complex, iterative forecasts and problem-solving. The Company's legacy version of UI Planner was first implemented in 2014 and was no longer supported by the software provider after 2023. In order to continue using the UI Planner software, the system needed to be replatformed to the modern cloud-based environment—which also required integrating UI Planner's new cloud-based software product.

Q. What alternatives did NW Natural consider to replatforming the UI Planner software?

A. The only available alternative to UI Planner was Excel's manual spreadsheet functionality, which the Company used prior to UI Planner. Thus, the Company considered foregoing the UI Planner replatform and reverting to Excel. However, this option was not considered to be reasonably viable for several reasons. **First,** Excel does not have the functionality to run complex models, meaning that any forecasting analysis would require sequenced and interrelated model runs that take significantly longer and yield less reliable results. **Second,** Excel requires laborious manual entry that is both error-prone and costly. **Third,** Excel models must still be built, requiring significant up-front and ongoing maintenance labor.

Q. Are there other benefits of replatforming UI Planner besides maintaining existing functionality?

A. Yes. The new UI product comes with additional benefits not available in the legacy, on-premises model, including significantly faster model run times, greater modeling transparency, and alternative financial statement methods—which are important for Generally Accepted Accounting Principles ("GAAP") forecasting.

Q. What is the current status of the UI Planner Replatform Project?

A. The UI Planner Replatform Project entered service in September 2024. The alternatives analysis for this project is attached as Exh. BEF-4.

Q. What cost recovery is NW Natural requesting for the UI Planner Replatform project in this case?

A. NW Natural seeks to recover its capital investment of approximately $2.1 million on a system basis, or $0.3 million on a Washington-allocated basis.

C. IQGeo Upgrade Project

Q. Please provide some context on how the IQGeo Upgrade Project fits into the Company's field and web mapping program.

A. The IQGeo Upgrade Project is part of a multi-year program to replace the Company's field and web mapping solutions by phasing out end-of-life software tools and transitioning to a consolidated set of modern software solutions. NW Natural relies on its field and web mapping tools to view its infrastructure and other assets in a geospatial format and to collect various types of data related to these assets. These field and web mapping tools provide field and office personnel with visual online and offline representations of NW Natural facilities and assets, which they use for a range of business purposes, including inspection compliance programs.

IQGeo is a key piece of this consolidation and transition project and serves as the Company's new field and web mapping operations hub. IQGeo is a user-friendly, map-based tool that provides field and office personnel with the information they need to improve data accuracy and safety. IQGeo was first licensed in 2019, was implemented in 2020, and is gradually being supplemented with additional functionalities (known as "use cases") over time.

Q. Please describe the IQGeo Upgrade Project.

A. The IQGeo Upgrade Project (a) upgraded to a newer, fully supported version of IQGeo, (b) replatformed IQGeo to Azure's enterprise-wide cloud environment, and (c) established automated testing for the IQGeo application.

Q. Why was it necessary to upgrade IQGeo?

A. It was necessary to upgrade IQGeo to mitigate risks of technical failures for the Company's essential field and web mapping system. As with other software products, IQGeo requires periodic upgrades to address bug fixes, incorporate product improvements, and maintain support services from the software vendor. In this case, the software vendor had discontinued full support for the existing product version. Additionally, NW Natural is in the process of upgrading and replacing other legacy mapping applications that rely on or integrate with IQGeo (such as, for example, those included in the Field and Web Maps Enablement Phase II Project). The previous version 6.1 of IQGeo was not compatible with these other projects, further supporting the need to undertake the upgrade.

Q. What is the current status of the IQGeo Upgrade Project?

A. This project entered service in December 2023. The alternatives analysis for this project is attached as Exh. BEF-5.

Q. What cost recovery is NW Natural requesting for the IQGeo Upgrade Project in this case?

A. NW Natural seeks to recover its capital investment of $1.8 million on a system basis, or $0.2 million on a Washington-allocated basis.

D. MapFrame Replacement Project

Q. Please provide some background on the MapFrame Replacement Project and how this Project fits into the Company's field and web mapping program.

A. The MapFrame Replacement Project continues the Company's field and web mapping goals by transitioning away from an end-of-life software tool and consolidating features in a modern system. MapFrame was previously used as a general map viewer and map correction tool, allowing the field and back-office users to:

- View gas facility location and asset information;
- Document changes to field conditions and mapping errors; and
- Create personal map notes for users to document information.

None of the above functionalities were available in NW Natural's other field and web mapping software tools. This Project allowed the Company to consolidate software tools by replacing MapFrame with IQGeo, which provides an up-to-date visual interface with NW Natural's operational assets.

Q. Please describe the MapFrame Replacement Project.

A. The MapFrame Replacement Project transitioned the Company away from an existing end-of-life software system (MapFrame) and developed equivalent functionality in the Company's IQGeo platform. This Project involved developing CIS integration to view customer information, creating location widgets to display locational information, implementing a design interface to allow for map corrections, enabling users to generate personal notes tied to maps, and facilitating map printing from mobile devices. All of these features were part of developing a new set of "use cases" in IQGeo, consistent with the goal for IQGeo's development as a central operations hub.

Q. Why was the MapFrame Replacement Project necessary?

A. The MapFrame Replacement Project was necessary because the previous MapFrame software was end-of-life, and indeed had not received a software update from its developer since 2015. As a result, transitioning away from this product was important to ensure continuity of NW Natural's operations. Transitioning MapFrame's functions to IQGeo was also a prerequisite for other field and web mapping transition efforts, which are designed to integrate with IQGeo's more modern system.

Q. Are there any additional benefits of the MapFrame Replacement Project?

A. Yes. By transitioning MapFrame's current map viewing and map correction functions into IQGeo, the Company was able to streamline the Company's IT&S product suite. This consolidation is consistent with NW Natural's broader strategy of simplifying its IT&S portfolio to benefit customers.

Q. Did NW Natural consider alternatives to the MapFrame Replacement Project?

A. Yes, NW Natural considered two alternatives to the MapFrame Replacement Project. **First,** the Company considered implementing an alternative mapping solution to replace MapFrame. This option was not selected because it would involve implementing a new—non-IQGeo—mapping solution, which would complicate the Company's IT&S environment, delay implementation of a new solution, and increase licensing, implementation, and maintenance costs.

Second, the Company considered maintaining the existing MapFrame solution. This option was not selected because it would undermine reliability of the Company's mapping functions in the short-term, would require NW Natural to pay to maintain two software systems instead of one, and would merely delay identifying a replacement

option in the long-term because the current MapFrame tool is already end-of-life. In addition, delaying a transition away from MapFrame would delay the other geospatial projects that depend on IQGeo taking on MapFrame's current map-viewing functionalities.

Q. What is the status of the MapFrame Replacement Project?

A. The MapFrame Replacement Project was placed in service in July 2024. The alternatives analysis for this project is attached as Exh. BEF-6.

Q. What cost recovery is NW Natural requesting for the MapFrame Replacement Project in this case?

A. NW Natural seeks to recover its capital investment of $3.0 million on a system basis, or $0.4 million on a Washington-allocated basis.

E. Clevest Optimization Project

Q. Please provide some background on the Clevest Optimization Project.

A. Clevest is NW Natural's new mobile workforce management software used to schedule, dispatch, and complete all work in the field—ranging from emergency response to routine maintenance work. Clevest replaced NW Natural's previous end-of-life application, PragmaCad ("P-CAD"), and was developed and implemented as part of the Horizon 1 Program. Clevest was fully deployed in 2022 and has since served as NW Natural's mobile workforce management tool.

Q. Please describe the Company's Clevest Optimization Project.

A. The Clevest Optimization Project was an incremental new effort to optimize and improve the Clevest mobile work management system, including (1) resolving post-deployment issues identified in the product's performance ("stabilization") and

(2) adding new functionalities that were initially not included but, following the product's launch, turned out to be critical ("optimization"). By expeditiously stabilizing and optimizing the Clevest software, the Company ensured that the tool continues to provide the best value for the Company and its customers.

Q. Why was post-deployment stabilization necessary?

A. While effective in a testing environment, Clevest proved to have difficulty accommodating the complexity of NW Natural's operations. As a result, when the platform was deployed and used, the Company encountered issues such as slowed response times. For instance, system input requests would have long lag times, often ranging from 3-5 minutes, and even up to 30 minutes. While the system was operable, these significant lag times created delays in work order processing and customer response times. A new dedicated workstream was necessary to address the post-deployment project performance issues.

Q. Why was post-deployment optimization necessary?

A. As part of streamlining NW Natural's IT&S infrastructure, NW Natural initially determined that certain features and functions of the Clevest platform were non-essential and could be deprioritized. For instance, while work orders could be viewed in sequence, the platform did not allow users to view all work orders tied to a certain location. In practice, the absence of these features and functions resulted in dissatisfaction for both field employees and customers. For instance, without the ability to alert a field worker that multiple work requests were scheduled at the same location, multiple visits would be scheduled—resulting in an ineffective allocation of employee time and confusing customers. Based on this feedback from Clevest users,

NW Natural identified a list of mission-critical and high-priority functionalities necessary to optimize Clevest's performance.

Q. Did NW Natural attempt to avoid and mitigate post-deployment problems in the initial Clevest procurement process?

A. Yes. NW Natural sought to avoid and minimize any development and deployment issues with Clevest by bringing in an implementation expert, Accenture, to help manage the implementation process. NW Natural coordinated meetings with Accenture and the Clevest vendor, including regular meetings with senior leaders and executives at each company. NW Natural also committed a dedicated business lead and project manager to focus on Clevest work, with twice-daily status updates to maintain progress and momentum.

Q. What alternatives did NW Natural consider before proceeding with the Clevest Optimization Project?

A. NW Natural considered four main alternatives before deciding to proceed with the Clevest Optimization Project: (1) addressing only basic stabilization issues (such as lagging response times), without pursuing further optimizations or enhancements; (2) addressing stabilization issues and a subset of new functionalities deemed mission-critical, but not addressing other priority features; (3) addressing stabilization issues as well as mission-critical and high-priority functionalities and features; and (4) addressing stabilization issues and the full list of all functionalities and features identified by Clevest users. Of these, NW Natural selected the third option.

Q. Why did the Company decide not to restrict its efforts to basic stabilization issues?

A. The Company decided not to restrict the project to minimal stabilization issues for two reasons. **First,** declining to proactively address known gaps in performance would result in ongoing technical debt as known issues accrued over time. **Second,** failing to address the functional issues experienced by Clevest users would have undermined the value of the overall Clevest investment. Addressing mission-critical functionality gaps was essential to ensure NW Natural's successful provision of service and to avoid significant customer dissatisfaction. For instance, due to Clevest's inconsistent performance in assigning fieldwork out into the future, work assignments needed to be manually reviewed each morning to ensure that pre-work had been correctly assigned. By optimizing this functionality, the Company could ensure proper distribution of work among field resources and better meet scheduling commitments to customers.

Q. Why did the Company decide not to pursue only stabilization and mission-critical functionality improvements?

A. The Company decided not to pursue only stabilization and mission-critical functionality improvements because addressing the high-priority issues did not significantly impact the overall project cost. These additional functionality improvements are relatively high-impact, low-effort new features. For instance, as originally implemented, Clevest displayed phone numbers, but did not allow these numbers to be copied or clicked to trigger a call. A simple improvement now displays phone numbers as hyperlinks, thus allowing the number to be clicked to trigger an outbound call. Similarly, construction crews interfacing with Clevest need to select the type of equipment (e.g., pipe size) required for various projects. However, as deployed,

Clevest did not display products in a clearly discernible order and did not allow products to be filtered. New functionality added in the Clevest Optimization Project presents equipment in a more logical order and allows for type-ahead functionality, which quickly highlights the needed equipment for selection. By incorporating these kinds of low-investment features, the Company can facilitate more accurate recordkeeping and enable construction crews to spend less time interacting with the Clevest platform and more time serving customers.

Q. Why did the Company decide not to pursue the full suite of functionality improvements?

A. The Company decided not to pursue the full suite of functionality improvements to include medium- and low-priority features for two reasons. **First,** expanding the project to include medium- and low-priority features would have substantially increased the overall project costs. **Second,** the medium- and low-priority features required additional upgrades to the Clevest software in order to enable the new features. However, such upgrades are not yet available, and would thus have significantly delayed optimizing the Clevest product. Due to these combined cost and delay factors, the Company decided to focus on the mission-critical and high-priority features instead.

Q. Were there additional alternatives that were rejected as not viable at this stage?

A. Yes. NW Natural identified three alternatives to the Clevest Optimization Project but determined they were not viable under the circumstances: (1) accepting the Clevest product without modification or improvement; (2) implementing a new mobile work management option; and (3) reverting to the original P-CAD tool.

Q. Why was it not viable to simply continue to use Clevest as it was deployed?

A. Continuing to rely on Clevest as deployed without any stabilization or optimization was deemed unacceptable due to the significant delays associated with the tool, which made it challenging for field employees and caused delays in processing orders. As deployed, the product also encountered unexpected data access restrictions, extensive user interface demands, and other functionality issues. The Company's mobile work management tool is a key aspect of the Company's day-to-day operations and customer engagement. Declining to address key issues in the product's performance was not an acceptable option.

Q. Why did NW Natural not consider switching to an entirely different mobile work management platform?

A. Following Clevest's deployment, NW Natural did not consider switching to a wholly new mobile work management platform due to concerns regarding cost, delay, lack of clearly preferable alternative tools, and ongoing strengths with Clevest:

- **Cost:** Any mobile work management platform requires considerable expense to design, develop, deploy, and integrate. Even significant investment in optimizing/enhancing an existing system cannot reasonably compare to the cost of starting the process from scratch with a whole new mobile work management tool.
- **Delay:** Implementing a new product option would take years to complete. NW Natural was already using Clevest as the Company's mobile work management tool and required prompt improvements to the tool's functionality. Identifying and deploying a brand-new tool would have required significantly more time without alleviating the immediate need for tool enhancements.

- **Alternative Tools**: Available market offerings for mobile work management tools were limited. As a result, even if NW Natural sought to identify and implement an alternate vendor's tool, other deployment issues could arise.
- **Clevest Usefulness:** As designed, Clevest remained a used and useful product and continued to offer the potential for substantially improved user experience over the previous P-CAD tool.

Q. Given the post-deployment issues, why did NW Natural not consider reverting, even temporarily, to the P-CAD tool?

A. Reverting to the previous P-CAD tool was not possible as that tool was already end-of-life. While P-CAD has rolled out a new mobile workforce management system offering, this new system is a wholly new software platform—and its use would thus require the same comprehensive deployment effort described above.

Q. What is the current status of the Clevest Optimization Project?

A. The Clevest Optimization Project was placed in service in July 2024. The alternatives analysis for this project is attached as Exh. BEF-7.

Q. What cost recovery is NW Natural requesting for the Clevest Optimization Project in this case?

A. NW Natural seeks to recover its capital investment of approximately $7.6 million on a system basis, or $0.9 million on a Washington-allocated basis.

F. Identity Governance and Automation Phase 1 Project

Q. Please provide some context for the Identity Governance and Automation (IGA) Program as a whole.

A. The IGA Program is a multi-year, multi-phase effort to identify, implement, and integrate a new IGA software system to establish robust security access and privilege management. Robust security access and privilege management is essential to ensure that critical information is protected and that no single individual has end-to-end access for key decision-making pathways. Indeed, secure access controls are a key part of complying with the Sarbanes-Oxley Act of 2002. This legislation requires NW Natural and other public companies to implement, among a range of other security-related controls, mechanisms to ensure that unauthorized individuals cannot access sensitive financial information.[2]

Previously, security access and other privileges were handled manually, with no centralized control point. As a result, there was no mechanism to certify that an individual's access to security and other functions had been removed following offboarding or other role changes. By implementing a new IGA system, NW Natural increased security of both customer and Company data while streamlining the staff management process.

[2] Sarbanes-Oxley Sections 302.2, 404.

Q. Please describe the IGA Phase 1 Project and how this relates to the other IGA Program phases.

A. The IGA Phase 1 Project focused on selecting, installing, and configuring a modern IGA solution, integrating the solution with the Company's workforce-management systems, and establishing core product functionality that ensures departing workers are automatically removed from network access and related services. Phase 2 and Phase 3 build on this foundation by integrating with additional IT&S systems, consolidating account visibility for centralized monitoring and reporting, and establishing automated access with those systems. Each of these subsequent phases are described in more detail below. Phase 2 is projected in to be in service in rate year 2, and Phase 3 in rate year 3.

Q. Why is a dedicated IGA software solution necessary?

A. A dedicated IGA software solution is necessary to ensure consistent, secure monitoring and control of access and permissions across the Company. To be clear, monitoring and controlling security access and permissions is more complicated than merely turning a switch on or off. **First,** since there are a range of applications with different access points, there is currently no one centralized mechanism to remove security access for a given individual. **Second,** updated access and permissions may also be triggered by changed positions and roles, meaning that maintaining accurate and up-to-date security controls requires nuanced control. **Third,** an individual's access to any given system or piece of information cannot be viewed in isolation, but rather as a complete picture of that individual's security access and permissions across the

Company. This visibility is important to ensure that individuals do not have too much access to sensitive information.

Q. Why had the Company not previously implemented an IGA software tool?

A. NW Natural had not previously implemented an automated IGA tool because the Company was endeavoring to maximize the utility of the existing, less costly manual system. Historically, NW Natural had manually removed security and permissions access for departing personnel as part of the offboarding process and had attempted to improve and strengthen this system over time. However, even an enhanced manual system carries greater risk of failure and security gaps than an automated system. NW Natural therefore determined to move forward with identifying and implementing a centralized IGA software tool.

Q. What software system did NW Natural select for the IGA system and how was this tool selected?

A. NW Natural selected a software system called IdentityNow, developed by a third-party vendor, SailPoint. NW Natural selected SailPoint's IdentityNow tool through a multi-step, multi-factor evaluation process. **First,** the Company collaborated with an independent consultant, Forrester, to establish initial parameters for IGA software and system needs. Forrester also provided a list of possible system integrators, which are third parties with deep subject matter expertise that can help guide the selection and implementation of specific software tools. **Second,** NW Natural conducted a competitive request for proposal ("RFP") process to select a system integrator, evaluating each for cost-competitiveness and industry experience. This process resulted in NW Natural selecting Integral Partners as the system integrator. **Third,**

Integral Partners worked with NW Natural to develop a detailed picture of minimum system requirements for an IGA solution. Integral Partners used this assessment to prepare a scoring system for different IGA solutions, allowing a side-by-side comparison of each option's technical environment, useability, integration capabilities, auditing functions, types of security controls provided, and other key factors. **Fourth,** Integral Partners then scored IGA tools from 18 different vendors to identify a subset of reasonable options for more detailed consideration. This process yielded three software options that the system integrator considered to be reasonably in line with NW Natural's system requirements and operational needs: SailPoint's IdentityNow, SailPoint's IdentityIQ ("IIQ"), and [redacted] For each of these options, Integral Partners also provided cost estimates. **Fifth,** NW Natural assessed each of the three options and conducted its own assessment of available alternatives.

Q. Why did NW Natural select SailPoint's IdentityNow?

A. NW Natural selected SailPoint's IdentityNow software tool because it offered the best, most cost-effective solution to serve long-term customer needs. SailPoint's IdentityNow scored the highest in Integral Partners' scoring system, and offers a comprehensive, user-friendly, and secure IGA solution. SailPoint also has a strong vendor reputation and industry recognition, readily integrates with NW Natural's other IT&S systems, and provides good long-term cost-effectiveness.

Q. Was the IdentityNow solution the least-cost long-term option overall?

A. Yes. IdentityNow's annual subscription costs of $250,000 per year were similar to the other IGA options—which ranged from an estimated $225,000 (for [redacted]) to

$300,000 (for SailPoint's IIQ) per year—while also providing substantially greater alignment with NW Natural's system. The slightly less expensive annual subscription option, [redacted], lacked built-in integrations with other applications in NW Natural's IT&S environment, and would therefore have required substantially more investment to integrate and maintain. As a result, accounting for the implementation and maintenance costs, SailPoint's IdentityNow solution presented the most cost-effective long-term option to provide these important security protections for customers.

Q. How did NW Natural identify the scope of work that would be included in the different phases of the IGA Program?

A. NW Natural identified the scope of work for each phase of the IGA Program in collaboration with Forrester and Integral Partners. In developing this roadmap, NW Natural identified three basic work streams: (1) initial product selection, implementation, and activation; (2) integration with the highest priority systems (specifically, workforce management systems); and (3) expansion of additional automated access controls throughout the Company's IT&S systems. Subsequent IGA phases then prioritize the additional IT&S systems for integration according to (i) the degree of security and compliance risks; (ii) the size of the user base affected; and (iii) complexity (and associated cost) of the integration effort. I discuss the specific components of the IGA Phase 2 and IGA Phase 3 Projects in more detail below.

Q. What is the current status of the IGA Phase 1 Project?

A. The Company placed this project in service in October 2024. The alternatives analysis for this project is attached as confidential Exh. BEF-8C.

Q. What cost recovery is NW Natural requesting for the IGA Phase 1 Project in this case?

A. NW Natural seeks to recover its investment of $3.5 million on a system basis, or $0.4 million on a Washington-allocated basis.

G. Start-Stop-Transfer Project

Q. Please describe the Start-Stop-Transfer Project and explain how this Project fits into the broader Customer Service Program.

A. The Start-Stop-Transfer Project is part of the Company's broader effort to modernize customer service functions, including by enabling self-service online features. The Start-Stop-Transfer Project created a new self-service tool that allows customers to initiate, terminate, or relocate their service with NW Natural using the Company's website. This project replaced and expanded on the existing manual entry forms previously found on the Company's website.

Q. Why was the Start-Stop-Transfer Project necessary?

A. The Start-Stop-Transfer Project was necessary to address customer dissatisfaction with the existing web-based interface for modifying their service with NW Natural. Based on the Company's web tracking, in 2022, only 29 percent of initiated forms to start, stop, or transfer service were successfully completed—resulting in approximately 100,000 customers who were unable to complete their service request online. This pattern corresponded to the prevalence of calls into the Company's Customer Care Center ("CCC"), where requests to start, stop, or transfer service constituted the single most common reason for customer calls in 2022. Based on feedback from the CCC team, the Company understood that customers struggled to complete the online forms

for a range of reasons, including (a) difficulty locating relevant account information; (b) confusion regarding which form to use for which circumstance; (c) the need for precise address information to complete a service request; and (d) lack of customer understanding regarding the importance of required information. The new Start-Stop-Transfer Project addressed all of these concerns through a new web-based tool, which also integrated with the Company's back-end CIS.

Q. What are the benefits of the Start-Stop-Transfer Project?

A. The central benefit of the Start-Stop-Transfer Project is that it enables customers to seamlessly initiate, terminate, and relocate their service with NW Natural, at their convenience and without the need to seek assistance by phone during business hours. The project improves the customer experience by implementing a user-friendly interface, which includes:

- A simplified road map for customers, along with easy navigation markers;
- Clear indicators of required form fields using accessible color coding;
- Explanatory "question mark" features to help customers understand the need for required information;
- Existing account validation and automatic provision of customer-specific information, such as accounts numbers, when starting a service request;
- A modernized address entry field with assisted entry to reduce customer input errors; and
- Increased access to self-service controls for customers renting properties.

Taken together, these new features help customers control their service at times that are most convenient for them—including when the CCC may not be available.

Q. Were there viable alternatives to Start-Stop-Transfer Project?

A. Yes, NW Natural considered two alternatives to the Start-Stop-Transfer Project described above. **First,** NW Natural considered pursuing an incremental approach, whereby the Company would improve only the address entry field portion of the feature. Based on CCC staff feedback, inaccurate address information was one barrier to customers successfully using NW Natural's online start-stop-transfer forms, because the previous tool did not auto-propose correct addresses and could not process a request if the address included errors. NW Natural therefore evaluated whether to modify only this aspect of the online forms as an incremental improvement. However, the Company concluded that this option was not preferable because (1) it would be more costly in the long term, as each new incremental improvement would require re-engaging an outside vendor, with associated start-up costs, and (2) there was no assurance that the address input improvement alone would significantly improve the customer experience. Given the range of issues described with the existing online forms and the need to bring in outside vendor support, the Company concluded that resolving the other prominent customer complaints simultaneously would best serve customers and would be most cost-effective.

Second, the Company considered automating the start-stop-transfer service forms into the Company's CIS, rather than maintaining a separate web-based system. While this option would have improved integration of the feature with the Company's back-end systems and improved allocation of staff time, it would not have addressed customer concerns with the online, self-service experience.

Q. What is the status of the Start-Stop-Transfer Project?

A. This project was placed in service in August 2024. The alternatives analysis for this project is attached as Exh. BEF-9.

Q. What cost recovery is NW Natural requesting for the Start-Stop-Transfer Project in this case?

A. NW Natural seeks to recover its capital investment of $2.7 million on a system basis, or $0.3 million on a Washington-allocated basis.

H. Composition 2.0 Project

Q. Please describe the Composition 2.0 Project and how this project fits into the Company's back-office functions.

A. The Composition 2.0 Project modernized the Company's electronic and printed documents for customers, including bills, notices, letters, welcome packages, and refund checks. Composition 2.0 was the second phase in the Composition overhaul project. In phase one ("Composition 1.0"), the Company implemented the OpenText platform that is the basis for the Company's broader document modernization effort. Prior to the Composition 2.0 Project, Composition software was used to produce digital bill PDFs, which were then used by NW Natural's third-party online payment processor to display customers' digital bills. These PDFs were also archived for record-keeping. With the implementation of the OpenText software as part of Composition 1.0, NW Natural was able to fully modernize additional customer-facing documents, as well as more comprehensively redesign and standardize document presentation in Composition 2.0. This redesign was the first time that NW Natural had comprehensively updated its bill presentation for customers in more than 26 years.

Q. What are the benefits of the Composition 2.0 Project for customers?

A. The Composition 2.0 Project provides a range of important benefits for customers, by allowing the Company to:

- Improve customers' ability to locate key information by enabling NW Natural to highlight important aspects of a customer's bill;
- Include answers to frequently asked questions on customer-facing documents;
- Develop multi-language documents;
- Include useful context for customers regarding their bills, such as comparing a customer's gas usage to the same month in prior years;
- Explain potential monthly bill fluctuations by providing information on factors that may be driving a month-to-month difference, such as the number of days in the billing cycle and average temperature variances from normal;
- Emphasize online payment and self-service account options accessible with a QR code;
- Highlight contact information for any remaining customer questions;
- Enable geographically segmented information, thus allowing Oregon customers to see only Oregon-specific information; and
- Provide greater clarity concerning customer payment plans.

Q. What are the benefits of the Composition 2.0 Project for the Company's internal operations?

A. In addition to creating more modern and user-friendly electronic and printed documents, Composition 2.0 provides three important benefits for the Company's

internal operations: **First,** Composition 2.0 allowed the Company to eliminate residual reliance on a legacy print generation function known as Advanced Function Printing, which was no longer supported by the vendor, IBM. **Second,** the project reduced risk associated with H2: Vista. By removing aspects of document presentment from the CIS now, the Company has fewer issues to resolve in H2: Vista. **Third,** the project standardized document sizes. Historically, NW Natural's documents were printed on smaller-than-standard paper. Switching to standard sizes substantially improved the printing and delivery process by:

- Reducing supply chain issues with procuring specialty paper products;
- Improving efficiency of the print-and-mail vendor by avoiding the daily need to set up custom settings to handle custom sizes; and
- Enabling automated process controls, which can detect bill insertion issues when papers are standard sizes.

Q. How did the Company develop its redesigned customer-facing documents?

A. The Company developed the redesigned documents through both a qualitative and quantitative information gathering process. On a qualitative level, the Company solicited feedback from 39 employees in customer-facing teams, including the Contact Center, Rates and Regulatory, Customer Lifecycle Management, and Account Services. These teams were able to identify key customer concerns that could be effectively and proactively addressed through revisions to customer documents.

From a quantitative perspective, NW Natural then distributed an online survey to over two thousand customers across the Company's service territory to validate the new design direction and to expand on identified questions or concerns. This survey

yielded 736 responses and over 500 narrative responses. These responses indicated strong support for the proposed redesign, with 86 percent of respondents liking the redesigned documents. Based on this data and the extensive customer feedback, NW Natural developed a list of "frequently asked questions" and responsive answers to include on customer-facing documents.

Q. What is the status of the Composition 2.0 Project?

A. NW Natural placed the Composition 2.0 Project in service in September 2024. The alternatives analysis for this project is attached as Exh. BEF-10.

Q. What cost recovery is NW Natural requesting for the Composition 2.0 Project in this case?

A. NW Natural seeks to recover its capital investment of approximately $6.3 million on a system basis, or $0.8 million on a Washington-allocated basis.

I. PowerPlan Project

Q. Please describe the PowerPlan Project and how this project fits into the Company's back-office functions.

A. The PowerPlan Project transitioned a key accounting function, known as the capital settlement process, from the Company's existing PowerPlan tool and into the broader SAP ERP system. The capital settlement process tracks costs accumulated under work orders and projects and allocates those costs to various accounts in PowerPlan.

Q. Why was the PowerPlan Project necessary?

A. The PowerPlan Project was necessary to correct a lack of visibility of information between PowerPlan and SAP. SAP could not distinguish the settlement charges in PowerPlan from other charges, meaning that SAP's automated reports indicated that

total charges on any given capital project netted to $0.00—because charges incurred were offset by the returning settlement charge. Additionally, by performing the capital settlement process outside of SAP in PowerPlan, project managers and others had less visibility into the capital settlement process. Without this visibility, project managers and others had less opportunity to detect and correct errors, which had caused delays in issuing reports. NW Natural had therefore been relying on manual overrides to accurately track the capital settlements process, which was an unsustainably labor-intensive process.

Q. What are the benefits of the PowerPlan Project?

A. By transitioning the Company's capital settlements process to SAP, the PowerPlan Project was able to improve the accuracy of the Company's capital projects tracking and reporting data, enable effective allocation of Company accounting staff time, and provide project managers and others with visibility into the capital settlements process and with detailed cost-allocation information.

Q. Were there viable alternatives to the PowerPlan Project?

A. No. The only other alternative was to continue to use PowerPlan—which, as I have explained, required cumbersome workarounds and increased the potential of reporting errors for capital project tracking. As a result, maintaining the status quo did not address the Company's core need for a more reliable, transparent capital settlements process, and there were no other viable alternative means of providing this function.

Q. What is the status of the PowerPlan Project?

A. The PowerPlan Project was placed in service in March 2024. The alternatives analysis for this project is attached as Exh. BEF-11.

Q. What cost recovery is NW Natural requesting for the PowerPlan Project in this case?

A. NW Natural seeks to recover its capital investment of $1.4 million on a system-wide basis, or $0.2 million on a Washington-allocated basis.

J. SAP Treasury Project

Q. Please describe the SAP Treasury Project and how this project fits into the Company's back-office functions.

A. The SAP Treasury Project implemented an industry-standard software tool to automate and manage the Company's treasury functions—such as financial tracking and payment approval systems. The new tool provides consolidated and comprehensive visibility into the Company's financial risk management using the necessary subset of SAP's "Treasury Track" software functionalities.

Q. Why was the SAP Treasury Project necessary?

A. The SAP Treasury Project was necessary to address the risks and inefficiencies of the Company's existing manual processes. Previously, the Company relied on predominantly manual, Excel-based tools for its treasury processes, including cash-flow tracking (e.g., daily cash position report generation), bank account tracking, and analyzing liquidity needs. These functions are essential for managing financial risk and ensuring the successful functioning of the utility as a whole.

Q. Why was it important to transition away from manual tools for the Company's treasury processes?

A. It was important to transition away from manual tools for two reasons: (1) because they entail significant employee time that could be more effectively allocated; and

(2) because manual entry yields less reliable and accurate data. As a result, most peer utilities had already automated treasury functions, such as by using SAP's Treasury Track software.

Q. Did NW Natural consider any alternatives to the SAP Treasury Project for automating the Company's treasury processes?

A. Yes. NW Natural considered two alternatives to the chosen SAP Treasury Project: (1) exploring a non-SAP software solution; and (2) incorporating the full SAP Treasury Track software suite—rather than the selected limited functionalities.

Q. Why did NW Natural choose SAP as the software provider?

A. NW Natural chose to rely on SAP as the software provider because NW Natural's treasury processes must integrate smoothly with the Company's broader enterprise platform and data systems. Since NW Natural recently transitioned to SAP's S/4 HANA platform to provide this underlying enterprise platform, utilizing SAP's Treasury Track software enables smooth integration with NW Natural's data systems and other departments. Additionally, consolidating and streamlining the number of applications and vendors in the Company's portfolio is consistent with NW Natural's broader strategy of simplifying its IT&S portfolio for the benefit of customers.

Q. Why did NW Natural choose not to incorporate the full SAP Treasury Track software suite?

A. NW Natural chose not to take on the full SAP Treasury Track software suite because this comprehensive software bundle provides functions beyond the minimum viable product needed to meet NW Natural's treasury process needs, while increasing overall costs. The full SAP Treasury Track bundle would have included functions such as

multi-bank connectivity, market and credit risk modules, and reporting tools that are either unnecessary or already incorporated in other software tools. Given the higher incremental license and implementation costs, NW Natural selected a subset of the SAP Treasury Track functionality instead.

Q. What are the other benefits of the SAP Treasury Project?

A. In addition to addressing risk and non-optimal use of employee time, the SAP Treasury Project provides a wide array of additional benefits, including: (1) granular visibility into the Company's payment processing; (2) automated bank account tracking; (3) real-time visibility into market interest rate data; and (4) automated development of amortization and interest rate schedules.

Q. What is the current status of the SAP Treasury Project?

A. The SAP Treasury Project entered service in November 2023. The alternatives analysis for this project is attached as Exh. BEF-12.

Q. What cost recovery is NW Natural requesting for the SAP Treasury Project in this case?

A. NW Natural seeks to recover its capital investment of approximately $2.9 million on a system basis, or $0.4 million on a Washington-allocated basis.

V. PRO FORMA PROJECTS
(April 1, 2025 – July 31, 2026)

A. Resource Scheduling Optimization Project

Q. Please describe the Resource Scheduling Optimization Project and how this project fits into NW Natural's workforce management program.

A. The Resource Scheduling Optimization Project will improve the software used by NW Natural's Resource Management Center ("RMC") to manage field worker schedules and timesheets, thus allowing the Company to better track and assign work. The Company's workforce management software, known as "Workforce," is part of the Company's SAP ERP backbone, and is used to enter and track time worked, time off, and other scheduling details (such as coordinating on-call shifts), while incorporating relevant bargained-for pay terms. The Resource Scheduling Optimization Project will resolve issues with the Workforce software that currently require several manual workarounds and will implement functionality improvements, described in more detail below.

Q. Why is the Resource Scheduling Optimization Project necessary?

A. The Resource Scheduling Optimization Project is necessary to allow the Workforce software to accurately and efficiently support project workflow. Currently, manual workarounds are required to ensure that work is assigned to individuals who are available and qualified, and to ensure that individuals with capacity are assigned adequate work. By optimizing the Workforce software, the Company will be better able to see and deploy its available field workforce.

Q. Did NW Natural consider alternatives to the project?

A. Yes. NW Natural considered three alternatives before deciding to proceed with the Resource Scheduling Optimization Project:

1. **Address only mission-critical items**. Mission-critical items are those needed to automate manual processes or to eliminate interference with current business processes. For example, mission-critical items include (a) adjusting extraneous exception messages that distract from genuinely critical exceptions; and (b) establishing standard shift patterns, including rotation and on-call shifts, to reduce the rework needed to allow the system to accurately reflect scheduled shifts. NW Natural would not pursue further optimization and enhancements with this alternative. This alternative was estimated to cost between $1.21 million and $1.31 million, not including construction overhead ("COH").
2. **Address both mission-critical and high-priority items.** This alternative would include additional work on high-priority changes that address integration between the Workforce software and other systems, such as Clevest and SuccessFactors (the Company's human resources software). For instance, reducing the volume of discreet blocks of time from Clevest by aggregating adjacent and identical slices reduces the time needed to audit timesheets. Similarly, incorporating accurate personnel qualifications data from SuccessFactors into Workforce allows scheduling to ensure that appropriately qualified personnel are assigned to needed work, rather than requiring manual verification processes. This alternative was estimated to cost between $1.43 million and $1.53 million, not including COH.

3. **Address mission-critical, high-priority and fully optimized items.** This alternative would include fully optimizing items that improve user experience, such as on the NW Natural mobile application. These optimizations are relatively minor, low-effort enhancements, such as enabling mobile features. This alternative was estimated to cost between $1.55 million and $1.65 million, not including COH.

Of these alternatives, NW Natural selected the third option, which included all three categories of improvements.

Q. Why did NW Natural choose to include high-priority optimizations in addition to mission-critical improvements?

A. The Company chose to include high-priority optimizations because restricting the project scope to only mission-critical improvements would not have resolved important process gaps and would have left several manual workarounds in place, while still entailing approximately $1.2 million to $1.3 million in capital investment. For instance, without incorporating an individual's qualifications from SuccessFactors, the Company would continue to rely on manual workarounds to ensure that work is assigned to individuals who are qualified to perform the assigned work.

Q. Why did NW Natural also choose to include fully optimized items?

A. The Company chose to include fully optimized items because these optimizations required relatively little development or configuration resources and, in some cases, simply involve enabling a feature. Thus, fully optimizing the functionality improvements results in high-impact new features without substantial additional cost.

Q. What is the status of the project?

A. The Company placed the project into service in March 2025. The operational efficiencies caused by the Workforce updates reduced the number of labor hours needed for RMC staff to perform manual workarounds, which enabled RMC staff to handle ancillary tasks that were previously assigned to contractors. The Company was able to remove two contractor roles by the end of May 2025, resulting in savings of approximately $88 thousand of O&M expense and $234 thousand of capital costs. Company witness Kyle T. Walker reflects these savings in the updated revenue requirement in his Direct Testimony.[3] The alternatives analysis for this project is attached as Exh. BEF-13.

Q. What cost recovery is NW Natural requesting for the Resource Scheduling Optimization Project in this case?

A. NW Natural seeks to recover its capital investment of $1.7 million on a system-wide basis, or $0.2 on a Washington-allocated basis.

B. Esri Utility Network Replatform Project

Q. Please provide some context for the Esri Utility Network ("UN") Replatform Project and how this project fits into the Company's field and web mapping program.

A. The Esri UN Replatform Project is part of the Company's ongoing effort to consolidate and update the field and web mapping systems. This Esri UN Replatform Project transitions several interrelated, end-of-life applications involved in managing the

[3] Exh. KTW-1T.

Company's detailed geospatial data to modern, supported platforms. As context, geospatial data is used to model the Company's pipeline infrastructure and support a range of Company operations, such as ensuring system integrity, modeling gas flows, tracking customer assets, and assigning field workers. While the geospatial data is used directly by certain NW Natural teams (such as Pipeline Integrity and GIS teams), the data is also integrated into other applications to allow non-GIS personnel to see NW Natural's pipeline infrastructure and apply map-based updates.

Currently, NW Natural uses software from Esri, a global provider of geospatial software, to manage the Company's geospatial data. This software includes both Esri's ArcMap, which allows NW Natural to create, edit, and analyze geospatial data, as well as Esri's Geometric Network, which models the Company's geospatial network. Together, this system serves as a digital twin of the NW Natural gas infrastructure, representing the location, status, material, and other characteristics of assets to support the safe operation and maintenance of the system. This network models how gas moves through the system, which not only allows the Company to reliably identify and locate assets, but also enhances operational integrity by identifying potential gaps and risks in the system's operations. Additionally, the network supports emergency response procedures, such as by identifying valves to isolate an area in case of system damage (also known as valve isolation tracing).

Q. Please describe the Esri UN Replatform Project.

A. The Esri UN Replatform Project involves four related product transitions: **First,** this project will replace the outdated Esri ArcMap software, which handles viewing, editing, analyzing, sharing, and managing geospatial data, with new Esri software

called ArcGIS Pro. **Second,** this project will migrate the geospatial data model from Esri's Geometric Network to Esri's new geospatial modeling tool, known as the Utility Network (UN). **Third,** this project will replace Schneider Electric's ArcFM software with equivalent functionality in the new Esri software—eliminating ArcFM from the Company's product suite. NW Natural's Corrosion Protection team currently uses Schneider Electric's ArcFM Viewer to trace cathodic protection needs. With the transition to the new Esri system, the Company will no longer need to maintain the separate ArcFM software. **Fourth,** this project will update the Esri server backbone, known as "ArcGIS Enterprise," to allow the geospatial data in Esri UN to integrate with the Company's other IT&S systems, such as Customer Order Management and Pipeline Locating.

Q. Why is the Esri UN Replatform Project necessary?

A. The ESRI UN Replatform Project is necessary because NW Natural's current geospatial data systems, including Esri Geometric Network, Esri ArcMap, and the underlying ArcGIS Enterprise server, are all nearing end-of-life and must be replaced or updated. The ArcGIS Enterprise server reaches end of support in August 2026. ArcMap is currently in a "mature support" phase, without patches or updates being provided, and even this support ends on March 1, 2028 for utility customers (other customers' support terminates March 1, 2026). Transitioning to ArcGIS Pro impacts the modeling network as well, as Esri's Geometric Network is not compatible with ArcGIS Pro. This consolidated Esri UN Replatform Project is therefore designed to allow NW Natural to migrate this integrated set of field and web mapping applications by July 2026.

Q. Did NW Natural consider alternatives to the Esri UN Replatform Project?

A. Yes, NW Natural considered two primary alternatives to the Esri UN Replatform Project. **First,** NW Natural considered a two-phase approach, whereby the Company would postpone the ArcMap-to-ArcGIS Pro replacement until closer to the 2028 end-of-service deadline, while proceeding with transitioning the network connectivity model to Esri's UN platform. This alternative was not selected because it would (a) result in higher overall project costs by requiring two different workstreams; and (b) complicate implementation because the data migrated to the UN platform would need to be kept as "read-only" to avoid data incompatibilities between the ArcMap and UN systems.

Second, NW Natural considered postponing both the ArcMap and Esri Geometric Network transitions until closer to the 2028 end-of-service deadline. This alternative was not selected because (a) NW Natural would still need to pursue a separate ArcGIS Enterprise update and (b) without the updates to the other Esri software, NW Natural would not be able to migrate and terminate Schneider Electric's ArcFM software—necessitating further updates to maintain that software, which is end-of-life. Updating ArcFM independently would likely cost between $750,000 and $1.3 million, depending on the available system integrators—further increasing overall project costs. Given the inevitability of transitioning the Esri products and the current limited support for these software systems, NW Natural determined not to further delay replatforming to the Esri UN and ArcGIS Pro systems.

Q. Are there any other factors that contribute to the timing of the Esri UN Replatform Project?

A. Yes. The timing of this project is also impacted by the broader market for system integrators. Esri is the dominant player in the field and web mapping space for utilities. All utilities will need to have transitioned away from Esri's Geometric Network by March 1, 2028. Competition for quality, affordable system integrators will become increasingly challenging the longer the Company waits to put this project in service. Thus, delaying this project would undermine NW Natural's ability to retain a high-quality and cost-effective system integrator.

Moreover, retaining a reliable system integrator is particularly important for a project with this degree of operational consequence. NW Natural geospatial data is both highly technical and foundational to the Company's safety, security, and emergency response functions. It is therefore particularly important that the Company accomplishes this transition in a timely, deliberate manner with quality support.

Q. Were there other alternatives that NW Natural rejected as not viable?

A. Yes. The Company determined that adopting an alternative geospatial data network solution from IQGeo, an existing NW Natural technology provider, was not viable. IQGeo's network offering is new to the market and unproven in the gas utility industry. While IQGeo works effectively as a data-viewer application, editing, managing, and maintaining detailed geospatial and network data is a far more complex task with crucial safety and reliability implications. Thus, NW Natural determined that adopting IQGeo's network option was too great an operational risk to be a viable alternative at this time.

Q. In addition to ensuring the reliability of the Company's geospatial data systems, are there other benefits to the Esri UN Replatform Project?

A. Yes. In addition to offering a more reliable system through required lifecycle management, the ESRI UN project will allow the Company to securely publish and share up-to-date geospatial information internally and externally, such as with local jurisdictions that use this information for project planning purposes. This tool replaces previously static, PDF maps that could not be readily updated to reflect the Company's dynamic system.

Q. What is the status of the Esri UN Replatform Project?

A. NW Natural conducted an RFP and selected a System Integrator, known as SSP Innovations, to facilitate this work in April 2025. The Esri UN Replatform project is in the Execution phase, and the Company plans to place this project in service in July 2026. The alternatives analysis for this project is attached as Exh. BEF-14.

Q. What cost recovery is NW Natural requesting for the Esri UN Replatform Project in this case?

A. NW Natural seeks to recover its capital investment of $14.1 million on a system-wide basis, or $1.7 million on a Washington-allocated basis.

C. Field and Web Maps Enablement Phase I Project

Q. Please describe the Field and Web Maps Enablement Phase I Project.

A. The Field and Web Maps Enablement Phase I Project is part of the Company's broader Field and Web Mapping multi-year initiative to update the Company's field and web mapping solutions by phasing out end-of-life software and transitioning to a

consolidated set of modern software solutions.[4] This Field and Web Maps Enablement Phase I Project transitioned the Company's valve isolation tracing functionality from Visual Fusion, an existing end-of-life software system, to the Company's IQGeo platform using a custom user interface. A valve isolation trace is performed when there is an emergency, such as pipeline damage, to create a map identifying the valves to be closed to isolate a specific area. The process also generates an impacted customer list for outage notifications. Valve isolation traces are run by members of the GIS support team, Engineering, Gas Control, and the RMC teams. The results are also used by the Emergency Contact Center team through Clevest, to create work orders to relight gas that was shut off during an emergency response.

Q. Why is the Field and Web Maps Enablement Phase I Project necessary?

A. The Field and Web Maps Enablement Phase I Project is necessary because the current Visual Fusion software has been in an end-of-life stage with Microsoft since 2021, which prompted NW Natural to undertake a careful product replacement assessment. The basic support that NW Natural receives does not include application enhancements or break fixes. As a result, transitioning away from this product is important to ensure continuity of NW Natural's operations as well as to mitigate cybersecurity concerns. While there are other uses of Visual Fusion, valve isolation tracing is its most critical functionality, so enabling another application to perform tracing is the highest priority Visual Fusion feature to transition. This project is a necessary step that will allow NW

[4] For a breakdown of the field and web mapping software transitions, please refer to Table 1 in Section II.

Natural to eventually decommission the Visual Fusion platform and reduce technical architectural complexity through platform consolidation.

Transitioning the remaining Visual Fusion functionalities is addressed in the Field and Web Maps Enablement Phase II Project, which I describe below.

Q. Did NW Natural consider alternatives to the Field and Web Maps Enablement Phase I Project?

A. Yes. NW Natural conducted a careful assessment to identify the replacement options for this functionality, which is critical to emergency response procedures. While replacement was necessary, the Company did not wish to over-invest in customization if an off-the-shelf option was available. As a result, NW Natural considered one primary alternative to the Field and Web Maps Enablement Phase I Project: implementing IQGeo's existing tracing module instead of creating a custom user interface. While the Company carefully considered this option, IQGeo's off-the-shelf tracing module requires users to rely on IQGeo's geospatial data network manager—as compared to the Esri UN tool, described above. In order to use IQGeo's tracing module, NW Natural would have needed to maintain one data model for Esri geospatial data and a second data model for IQGeo. This alternative was not selected because maintaining two geospatial data models presents too great a risk of error, in that running a trace in each system may provide different results—an unacceptable result for a tool specifically designed to address emergency situations. Since, as I explain above, the Company did not consider adopting IQGeo's back-end geospatial data network to be a viable alternative to Esri UN, the Company also determined not to use IQGeo's existing tracing module.

In addition, NW Natural considered maintaining the existing Visual Fusion software. However, the Company determined that this option was not viable because it would undermine the reliability of the Company's mapping functions due to reliance on the software that is end-of-life.

Based on this assessment, NW Natural determined that transitioning the Company's valve isolation tracing functionality to a custom interface in IQGeo was the best available alternative to meet customer needs.

Q. What is the status of the Field and Web Maps Enablement Phase I Project?

A. The Field and Web Maps Enablement Phase I Project was placed in service in June 2025. The alternatives analysis for this project is included in Exh. BEF-15.

Q. What cost recovery is NW Natural requesting for the Field and Web Maps Enablement Phase I Project in this case?

A. NW Natural seeks to recover its capital investment of $1.3 million on a system-wide basis, or $0.2 million on a Washington-allocated basis.

D. IGA Phase 2 Project

Q. Please describe the IGA Phase 2 Project and how it relates to the IGA Phase 1 Project.

A. The IGA Phase 2 Project builds on the foundation established in the IGA Phase 1 Project by controlling access to technology systems and integrating with physical security devices. While IGA Phase 1 implemented the foundational IGA software system and provides visibility into the scope and roles of individual users, IGA Phase 2 focuses on expanding application integration, automating access provisioning (as opposed to solely access removal), and adding new security and control mechanisms.

Additionally, this project will create access certifications, which can audit and report on access permissions to ensure that employees and contractors have access to only what they need. This functionality is particularly important so that offboarded employees or other unauthorized individuals cannot access sensitive information.

Q. Why is the IGA Phase 2 Project necessary?

A. The IGA Phase 2 Project is a necessary step to build expertise and improve security by centralizing control of user access permissions and building out these integrated control systems through the Company's other applications. As described above, Phase 2 builds on the foundation established in Phase 1 to expand the reach and functionality of the base automation, and refine access management processes.

Q. How did NW Natural consider alternatives to the IGA Phase 2 Project?

A. At a high level, the Company considered alternatives to IGA as a whole, as part of the broader IGA planning effort to determine the relevant factors that drive integration priority. Now, for the IGA Phase 2 Project, the Company is applying those criteria to determine the priority of specific application integrations. Prioritized applications include critical IT&S infrastructure systems like IQGeo that have high user volumes, and thus automatic access controls can save significant manual effort. The alternatives analysis for this project is attached as Exh. BEF-16.

Q. What is the status of the IGA Phase 2 Project?

A. The IGA Phase 2 Project is in the Execution phase, and is the project is expected to be completed by October 2025. The alternatives analysis for this project is attached as Exh. BEF-16.

Q. What cost recovery is NW Natural requesting for the IGA Phase 2 Project in this case?

A. NW Natural seeks to recover its capital investment of approximately $2.8 million on a system-wide basis, or $0.3 million on a Washington-allocated basis.

E. JANA Project

Q. Please describe the JANA Project and how this project fits into the Company's back-office functions.

A. The JANA[5] Probabilistic Risk Model (a) refreshes the risk modeling used by NW Natural's Distribution Integrity Management Program ("DIMP"), and (b) transitions the Company's modeling from a relative risk assessment to a probabilistic model. Risk models are required by the Code of Federal Regulations ("CFR"), CFR 49 Part 192[6], and are used to assess risks associated with gas distribution system threats. Currently, NW Natural relies on a relative risk model, which measures the likelihood of failure associated with a threat, as compared to other risks. In contrast, a probabilistic risk model will allow the Company to quantitatively assess the probability of failure in any given system component and estimate the expected consequences, independent of that risk's relationship to other risks within the Company.

[5] "JANA" is JANA Corporation, a provider of risk modeling and software. *See* *Who We Are - Helping you predict risk in your pipeline systems | JANA*.

[6] I understand that 49 CFR Part 192 requires that an operator "evaluate the risks associated with its distribution pipeline" and "determine the relative importance of each threat and estimate and rank the risks posed to its pipeline[,]" including "each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure." 49 CFR 192.1007(c). After the evaluation of risks, the operator must "identify and implement measures to address" the ranked risks. 49 CFR 192.1007(d).

Q. Why is the JANA Project necessary?

A. The JANA Project is necessary because a probabilistic risk assessment tool more accurately measures the risks relevant to customer safety, allows the Company to more effectively prioritize risks on a cost-optimized basis, and represents a crucial improvement to the Company's risk assessment process. Indeed, in a 2020 report titled "Pipeline Risk Modeling – Overview of Methods and Tools for Improved Implementation" ("2020 Report") the US Pipeline and Hazardous Materials Safety Administration ("PHMSA") identified the important benefits of a probabilistic risk management program for industries such as gas utilities. As this 2020 Report explained, a probabilistic risk model allows utilities to assess, not merely the qualitative degree of risk compared to other risks, but the quantitative degree of actual risk to pipeline safety. This probabilistic approach is particularly important for safety-critical functions like gas utility infrastructure, where the Company has an obligation, not merely to prioritize among system risks, but to ensure an overall safety of the system. A copy of the 2020 Report is included in Exh. BEF-17.

Q. Has PHMSA specifically commented on the importance of transitioning away from relative risk models?

A. Yes. In the 2020 Report, PHMSA emphasized the need for continuous improvement of risk modeling practices, and the importance that pipeline operators transition from relative risk modeling to probabilistic risk modeling:

> The [Integrity Management ("IM")] regulations also require operators to continuously improve their IM programs, and overall industry integrity performance has shown general improvement over time. However the continuing occurrence of significant pipeline incidents points to a continuing need for operators to upgrade their tools for risk assessment and risk management. *Upgrades to risk assessment processes using quantitative or probabilistic risk models is a prudent step for operators to take* to improve IM programs, allowing better definition of the risks on pipeline systems and better support for risk management practices.[7]

Q. Following PHMSA's 2020 Report, did NW Natural conduct additional analysis to determine whether a probabilistic risk model was necessary and appropriate for the Company?

A. Yes. Once PHMSA's 2020 Report was released, NW Natural performed an internal review of the existing relative risk model for the NW Natural distribution system. Based on this analysis, the Company determined that a probabilistic risk model was appropriate to ensure that the Company is remediating risk on a risk-cost optimized basis for a given risk—rather than based on the degree of difference between one risk and another.

Q. What is the difference between a relative risk model and a probabilistic risk model?

A. In a relative risk model, a score is developed for 50 foot x 50 foot raster sections throughout the system by multiplying the likelihood of failure by the consequence of failure to determine a risk score. The numerical components of this scoring system were developed by NW Natural based on industry and subject-matter-expert (SME) data in 2011 and are documented in the NW Natural DIMP Plan. A probabilistic risk

[7] Exh. BEF-17 at 19 (emphasis added).

model incorporates the probability of failure in the risk calculation along with quantifying the consequence of failure. By incorporating the probability of failure along with quantifying the consequence of failure, a more quantitative assessment of risk is developed for a specific asset in the NW Natural distribution system. This quantitative approach allows the Company to not only accurately rank risks based on the probability of risk, but also to quantify risk reduction achieved per threat mitigated, and thus to identify the most cost-efficient risk mitigation actions.

Q. Did NW Natural consider retaining its relative risk model?

A. Yes. However, based on PHMSA's 2020 Report and internal discussions, NW Natural determined that its current model should no longer be used, for several reasons:

1. **Compounding Uncertainty in Scale Assessments.** Relative risk models use what is known as an ordinal scale, where the values have relationships relative to each other (e.g., 4 is worse than 2), but where the intervals on the scale do not have a precise value (e.g., 4 is not necessarily twice 2). When these numerical values are then used within other calculations, the results of relative risk assessments are inconsistent and compound the more they are used.
2. **Range Compression Risk Distortion.** Relative risk models used bounded scales, despite the fact that the probability of failure and the associated potential consequences can vary by several orders of magnitude. Forcing these values onto a bounded scale compresses and potentially distorts the perceived risk and can result in inconsistent risk rankings.
3. **Cognitive Bias.** Relative risk models rely on subject matter expert assessments, as opposed to the statistical analysis of historical failure data used in

probabilistic risk models. Relying on subject matter expert assessments exposes the model to unconscious cognitive biases and can result in inconsistent risk assessments.

4. **Inability to Verify Accuracy.** Since relative risk models do not provide quantitative risk outputs, the model's assessments cannot be compared to actual events in order to verify the model's accuracy.

Based on this assessment, NW Natural concluded that it would be prudent to transition to a probabilistic risk model for the DIMP.

Q. Once NW Natural identified the need to transition to a probabilistic risk model, how did the Company select its preferred solution?

A. NW Natural selected its preferred probabilistic risk model solution by conducting demonstration sessions with the two vendors that implement risk models to support the natural gas industry: [redacted] and JANA. For the [redacted] demonstration session, the input data that NW Natural needed to use for the risk model were in a legacy format that could not be used by the vendor. The vendor presented options to resolve this issue, but such an option would have required a separate configuration of the GIS distribution system to be created. There were also concerns if legacy compliance data could be used in the risk model. Legacy compliance data is important as it provides a historical trend to threats to system. In contrast, the JANA demonstration provided an interface that was much more adaptable to all formats of legacy information that NW Natural had for inputs into the risk model. Additionally, the JANA risk model is more user-friendly for employees.

Q. What is the status of the JANA Project?

A. The JANA Project is in the Execute phase and will be placed in service in August 2025. The project alternatives analysis is included in confidential Exh. BEF-18C.

Q. What cost recovery is NW Natural requesting for the JANA Project in this case?

A. The Company seeks to recover its capital investment of $1.3 million on a system basis, or $0.2 million on a Washington-allocated basis.

F. Application Lifecycle Management - SAP Update Project

Q. Please describe the Application Lifecycle Management - SAP Update ("ALM-SAP") Project.

A. The ALM-SAP Project involved updating NW Natural's SAP S4 platform from S/4 HANA 2020 to the current version, S/4 HANA 2023. SAP S4 is the Company's key enterprise application used to support its field operations, engineering functions, financial operations, and ability to pay suppliers and vendors. As with other critical system software updates, updating SAP S4 involves multiple steps to ensure that NW Natural's operations are not disrupted. A system update therefore includes rigorous testing, training, updates to quality assurance, staging, and production environments, as well as post-deployment "hyper care" to quickly resolve any user-identified issues. Testing is particularly crucial for critical systems, as the updated software can impact integrated applications. These issues must then be addressed before the update can be successfully deployed. For the Company's SAP S4 platform, for instance, the Company depends on the system to comply with Sarbanes-Oxley requirements, meaning that both rigorous testing and rigorous documentation of those testing results are required.

Q. Why was it necessary to update SAP S4?

A. It was necessary to update SAP S4 as part of the standard application maintenance lifecycle, in order to mitigate risks of technical failures of the Company's essential enterprise operating system. As with other software products, SAP requires periodic updates to address bug fixes, incorporate product improvements, and maintain support services. In this case, NW Natural's current 2020 SAP S4 version will no longer be fully supported by SAP at the end of 2025. An unsupported platform would put the Company's operations at risk, as any security patches or other system issues could not be resolved without SAP's assistance. Therefore, updating SAP S4 to the latest version is critical in ensuring the essential functionality of NW Natural's SAP system. SAP has indicated that the new version will be supported through 2030.

Q. Were there viable alternatives to the ALM-SAP Project?

A. No. The only alternative to an update was remaining on the current SAP S4 version. This alternative would have placed NW Natural at significant risk as it results in limited vendor support for its critical enterprise application. The reduction in support would prevent the delivery of legal and regulatory changes, support for integrations, and functional enhancements. Also, there is no guarantee of technical updates including support of new operating systems and database versions. Lastly, even if updates were available, such updates may include additional fees for problem resolution.

Q. What is the status of the ALM-SAP Project?

A. The project was placed in service in June 2025. The alternatives analysis for this project is attached as Exh. BEF-19.

Q. What cost recovery is NW Natural requesting for the ALM-SAP Project in this case?

A. NW Natural seeks to recover its capital investment of $2.6 million on a system-wide basis, or $0.3 million on a Washington-allocated basis.

G. Clevest Update Project

Q. Please describe the Clevest Update Project and how this project fits into the Company's broader application lifecycle management program.

A. The Clevest Update Project involves updating NW Natural's mobile workforce management software from version 7.3 to version 8.3. The Clevest software is essential for scheduling, dispatching, and completing the majority of the Company's fieldwork, which ranges from emergency response to routine maintenance tasks. This project is part of the Company's broader application lifecycle management program, in that it seeks to implement a routine platform update as part of ensuring the security and reliability of the Company's IT&S software systems.

Q. Why is the Clevest Update Project necessary?

A. Updating Clevest is essential to mitigate the risks of technical failures in NW Natural's critical system used for scheduling, dispatching, and completing fieldwork. Like other software products, Clevest requires periodic updates from the vendor to address bug fixes, incorporate product improvements, and maintain support services. The standard support for the Company's current version of Clevest ended on December 31, 2024; extended support, which includes fixing security vulnerabilities or errors, will end on December 31, 2026. Operating on an unsupported platform could jeopardize NW Natural's operations if a software defect arises that requires vendor support for

resolution or the application of critical fixes, including security updates. Therefore, updating Clevest now is crucial to ensure the efficient and secure operation of this vital system. Additionally, the Clevest Update Project will allow for better coordination among resources, including a new calendar view for more efficient work scheduling. This improvement is particularly beneficial for managing tasks for work groups that currently rely on spreadsheets and multiple SharePoint sites for their work forecast and capacity management. Specific improvements include:

- Enhanced nearby order functionality and filtering will provide work groups with increased visibility of tasks that need to be completed and their locations.
- The "Targeted Nearby Orders" search will allow preconfigured search criteria to be created for different scenarios when the field is looking for specific types of work. For work groups that self-assign their work, these features will enable faster identification and assignment of work.
- Adding the "Special Indicators" functionality to Clevest will provide a crucial pipe inspection job code that allows field personnel and dispatchers a way to quickly identify high-priority work.
- Mobile platform enhancements will allow employees to self-assign work from the mobile platform, and to more efficiently complete time tickets at the end of shifts. These enhancements will also enable automatic resending of system messages that initially fail to send, reducing the number of queued work orders and preventing potential delays in information flow between systems.

Q. Were there viable alternatives to the Clevest Update Project?

A. No. The only alternative to updating Clevest to the latest version is to remain on the current Clevest version. Maintaining supported application is an integral part of the Company's cyber-security. Moreover, disruption to the Company's field workforce platform would substantially interfere with the Company's ability to ensure safe and reliable operations.

Q. What is the status of the Clevest Update project?

A. The Clevest Update Project planning phase is starting in the third quarter of 2025 and the project will be placed in service in the second quarter of 2026.

Q. What cost recovery is NW Natural requesting for the project in this case?

A. NW Natural seeks to recover its capital investment of $2.3 million on a system-wide basis, or $0.3 million on a Washington-allocated basis.

VI. RATE YEAR 1 PROJECTS
(August 1, 2026 – July 31, 2027)

A. Microwave Stability Project

Q. Please provide context for the Microwave Stability Project.

A. NW Natural relies on microwave towers to transmit information over long distances, and has employed this technology for decades as a reliable, non-wires information transmission alternative. This information is used as part of the Company's SCADA and Emergency Voice Radio systems, among other functions. NW Natural currently has 24 microwave towers, most of which were built decades ago—the oldest was installed in 1957. Many of these towers are in remote locations, and the Company has not previously conducted a comprehensive microwave assets site assessment.

Q. Please describe the Microwave Stability Project.

A. The Microwave Stability Project involves (a) conducting a detailed site assessment of the Company's microwave towers; (b) addressing identified operational challenges, interference issues, and safety hazards; and (c) replacing or expanding existing towers and addressing any residual safety issues. Each of these phases proceeds as follows:

- **2025 (Assessment Phase)**: NW Natural has engaged GP&A Telecommunications Engineers to conduct on-site surveys, maps, and health assessments of the existing 24 microwave towers. This work will produce detailed analysis and recommendations for each site, which will then be used to create a multi-year microwave stability strategy. This assessment phase is expected to be complete in August 2025.
- **2026 (Critical Fixes & Vendor Selection for Additional Work)**: Once the assessment is complete, NW Natural will address the urgent tower fixes and restore any downed microwave links that are identified as necessary. At the same time, the Company will conduct a vendor qualification and RFP selection process to perform any additional remedial work.
- **2027-2031 (Replace/Expand Towers & Safety Enhancements)**: Based on the final assessment, the Company will replace, relocate, and/or expand existing towers to address any gaps in transmission coverage.

Q. Why is the Microwave Stability Project necessary?

A. The Microwave Stability Project is necessary because ensuring the reliability of the microwave information transmission network is crucial to system reliability and emergency preparedness. Non-wires information transmission is particularly crucial

in emergency situations, such as "man down" scenarios, cellular communications outages, and other emergency response demands. These towers also host the antennae for the Company's voice radio communications system. However, the health, state, and operability of many of NW Natural's 24 microwave tower sites are unknown, posing potential safety hazards. Indeed, the Company is aware of five towers with degraded functionality due to tree and vegetation growth, meaning that those areas currently lack reliable voice radio functionality, telemetry data reporting, and back-up SCADA transmission. Restoring full communications and information transmission in these areas is critical.

Q. Is NW Natural considering alternatives to the Microwave Stability Project?

A. Yes. In addition to the ongoing analysis regarding project details and scope, NW Natural is considering converting to traditional wires-based network carrier transport, such as fiber optic cable, instead of microwave transport. However, there are disadvantages with traditional network carrier transport and, in some cases, this alternative is not feasible due to the remote location of some NW Natural sites. Where traditional network carriers are physically feasible, their disadvantages can include:

- **Cost:** Traditional network carrier transport, such as fiber optic or leased lines, can be more expensive due to installation, maintenance, and leasing fees.
- **Deployment Time**: Installing wired infrastructure often takes longer compared to deploying microwave links, which can be set up relatively quickly. Even where NW Natural seeks to lease existing lines, the Company must typically build the "last mile" segment, which can entail considerable cost and delay.

- **Flexibility:** Microwave transport offers greater flexibility in reaching remote or hard-to-access areas where laying cables might be impractical or impossible.
- **Interference and Maintenance**: While microwave networks can face interference issues, traditional networks are more susceptible to physical damage (e.g., from construction or natural disasters), which can lead to longer downtimes and higher repair costs.

Whether wires-based solutions are appropriate for individual sites will be assessed in the site-specific survey.

Q. What is the status of the Microwave Stability Project?

A. The Company plans to complete the initial assessment phase of this project in the third quarter of 2025. Near-term projects identified by this assessment (phase 2) will then be placed in service in the third quarter of 2026. Additional microwave tower replacements, relocations, and/or expansions, as well as any residual safety work (phase 3) will be placed in service incrementally thereafter, with the full Microwave Stability Project expected to be complete by the end of 2031.

Q. What cost recovery is NW Natural requesting for the Microwave Stability Project in this case?

A. NW Natural seeks to recover its capital investment for those portions of this project that will be placed in service before July 31, 2029, which consists of $25.2 million on a system-wide basis, or $3.1 million on a Washington-allocated basis. This amount includes a system projected $6.9 million being placed in service through Rate Year 1 ($0.8 million on a Washington-allocated basis), $7.0 million through Rate Year 2 ($0.9 million on a Washington-allocated basis) and $6.7 million through Rate Year 3 ($0.8

million on a Washington-allocated basis), subject to further specification following the detailed site assessment described above.

B. Customer Field Service Scheduling and Route Optimization Project

Q. Please provide some context for how the Customer Field Service Scheduling and Route Optimization Project fits into the Company's broader workforce management program.

A. The Customer Field Service Scheduling and Route Optimization Project builds on the work from the Resource Scheduling Optimization Project (discussed above). While the Resource Scheduling Optimization Project ensures that the Company has a clear picture of which resources are available when, the Customer Field Service Scheduling and Route Optimization Project allocates work and establishes the most efficient routes for that work to be performed by the Customer Field Services group. This Project focuses on service technician work, which is the highest volume customer-facing work, and optimizes how that work is assigned to the field workforce (including route optimization). This project prioritizes and sequences high-volume service technician work on a day-to-day level and ensures that customer-facing work is performed efficiently.

Q. Please describe the Customer Field Service Scheduling and Route Optimization Project.

A. This project will implement a new scheduling and optimization tool for customer field service work and integrate it with NW Natural's existing field work management solution. The updated field service scheduling tool will incorporate resource capacity, qualifications, service level agreements and work orders, and will optimize routes for

the associated technicians automatically. The tool will also re-optimize the route at a specified frequency or if manually triggered after an emergency order is placed. The primary objective of the project is to optimize and prioritize work for field operations, ensuring efficient and effective resource utilization.

Q. Why is the Customer Field Service Scheduling and Route Optimization Project necessary?

A. The Customer Field Service Scheduling and Route Optimization Project is necessary to address important shortfalls in the current work scheduling and routing system. Currently, the Company's scheduling cannot account for real-time traffic or filter project assignments based on work order priority. Additionally, when one work-assignment area is particularly busy, there is currently no mechanism to split that assignment area in order to increase the volume of field workers available to respond to system needs.

Q. What are the benefits of the Customer Field Service Scheduling and Route Optimization Project?

A. Benefits of this Project include:

- Automating the manual task of scheduling and assignment activities;
- Maximizing field work performed by ensuring tasks are properly distributed to the right resources, taking into account various factors such as traffic, skill sets, order aging, and strategic goals; and
- Enabling efficient responses and necessary adjustments throughout the day in response to disruptions caused by emergent tasks.

These improvements collectively enhance customer service and satisfaction by ensuring schedule adherence and quicker response times through automation.

Q. Is NW Natural considering alternatives to the Customer Field Service Scheduling and Route Optimization Project?

A. Yes. NW Natural is still in the process of considering available alternatives, and plans to complete a full alternatives analysis by January 2026. Possible alternatives include (a) sustaining the existing "Advanced Scheduler" system and (b) incorporating an alternate external solution.

Q. What is the status of the project?

A. This project is in the Initiate phase. It will begin the planning phase in the third quarter of 2025 and will complete a detailed alternatives analysis in January 2026. Pending the results of that assessment, NW Natural anticipates that this project will be placed in service in April 2027.

Q. What cost recovery is NW Natural requesting for the Customer Field Service Scheduling and Route Optimization Project in this case?

A. NW Natural seeks to recover its capital costs of approximately $2.7 million on a system basis, or $0.3 million on a Washington-allocated basis, which will be included in rates in Rate Year 2.

C. Compliance Data Management Optimization Project

Q. Please describe the Compliance Data Management ("CDM") Optimization Project.

A. The CDM Optimization Project will establish a clear technological and procedural system for tracking and managing compliance-related work by the CDM team. The

CDM team is responsible for managing legally mandated compliance work to ensure the integrity of the gas system. The CDM team's current processes are heavily manual, resource-intensive, and susceptible to human error, leading to delays in work order creation and reduced capacity for timely regulatory compliance in the field. With existing headcount, meeting operational demands is becoming unsustainable. The CDM Optimization Project will modernize NW Natural's compliance operations by introducing automation, enhancing system integration, and improving data capture in the field. These updates will align the Company's practices with industry standards, improve data integrity, and free up staff to focus on strategic compliance oversight—ultimately driving efficiency, reducing risk, and supporting regulatory excellence.

Q. Why is the Compliance Data Management Optimization Project necessary?

A. The CDM Optimization Project is necessary to address gaps in the Company's management of compliance work. Based on a gap analysis, gaps include system automation, automated compliance reporting and notification, and system integrations. This CDM Optimization Project addresses these gaps by creating automated reports, notifications, and work orders associated with necessary compliance-related work.

For instance, when a field worker submits a referral for repair work that is needed, there is currently no way to link the repair order with the inspection or original work order that initiated the referral. This disconnect creates a gap in reporting and requires the CDM team to spend significant time searching through the system to try to locate the repair order to prove the repair work was complete. The CDM Optimization Project automatically links the repair work referral with the original

inspection or initiating work order, thus ensuring continuity in tracking remedial and compliance-related work.

Similarly, the new project automates manual data entry tasks regarding equipment location and relative functions, preventing data entry errors. By addressing these gaps, the Company minimizes exposure to safety and compliance risks and better enables its CDM team to focus on the important task of managing compliance without having to navigate significant manual and inefficient processes.

Q. Is NW Natural considering alternatives to the Compliance Data Management Optimization Project?

A. Yes. NW Natural considered two alternatives for the CDM Optimization Project. **First,** NW Natural evaluated the option of maintaining current CDM tools and processes without addressing identified gaps. This approach would not equip the CDM team to effectively manage compliance or field operations and would fail to improve visibility, oversight, or public safety outcomes. The team would remain reactive—focused on transactional tasks and responding to compliance breaches—rather than proactively managing risk. Continuing with manual processes instead of implementing automated, controlled IT solutions increases the likelihood of missed critical referrals and compliance orders, posing operational and regulatory risks.

Second, the Company considered addressing a small number of items via an initiative in 2025 and not pursuing resolution for remaining gaps, such as providing automated notifications to field groups regarding new compliance obligations. This option was not selected due to the continued reliance on both manual processing and

ongoing contractor support. This option was also comparable from a cost perspective, and so did not provide commensurate benefits given the cost.

Q. What is the status of the CDM Optimization Project?

A. The CDM Optimization Project will begin in January 2026. The Company expects to place the project into service in October 2026. Further documentation supporting this project is included in Exh. BEF-20. The Company is currently working on an alternatives analysis for the CDM Optimization Project.

Q. What cost recovery is NW Natural requesting for the CDM Optimization Project in this case?

A. NW Natural seeks to recover its capital investment of $2.1 million on a system-wide basis, or $0.3 million on a Washington-allocated basis.

D. Field and Web Maps Enablement Phase II Project

Q. Please describe the Field and Web Maps Enablement Phase II Project.

A. The Field Web Maps Enablement Phase II Project will continue the broader effort to phase out end-of-life software tools and transition to a consolidated set of modern systems by (a) transitioning remaining Visual Fusion functionalities to IQGeo and Esri UN; (b) updating IQGeo to a supported version; and (c) transitioning the "as-built" data reconciliation process from the IQGeo Capture application to a new IQGeo tool, which will provide an up-to-date visual interface with NW Natural's operational assets. This Project will allow the Company to discontinue use of the Visual Fusion software.

Q. Why is the Field and Web Maps Enablement Phase II Project necessary?

A. The Field and Web Maps Enablement Phase II Project is necessary to both consolidate the Company's suite of field and web mapping tools and to ensure that the existing tools remain reliable, as follows:

- Visual Fusion software is end-of-life and has not received a software update since 2016. Web maps in Visual Fusion need to be moved to a different mapping solution. By transitioning Visual Fusion's map viewing and map functions into IQGeo, the Company streamlines the IT&S product suite. Transitioning these functions will require an updated version of IQGeo.
- The Company's current version of the IQGeo platform (6.5) is out of official support, and will need to be updated to a supported version. It is necessary to update IQGeo to mitigate risks of technical failures for the Company's essential field and web mapping system. As with other software products, IQGeo requires periodic updates to address bug fixes, incorporate product improvements, and maintain support services from the software vendor.
- IQGeo's Capture application will no longer be supported after equivalent functionality is incorporated into the base IQGeo platform in late 2026. Capture currently provides critical functionality, such as reconciling geospatial data with as-built equipment details. As a result, NW Natural will need to determine whether to replace this functionality with third-party software, or adopt IQGeo's replacement solution, Network Manager Gas. If NW Natural adopts IQGeo's Network Manager Gas, then a more current version of IQGeo's software will also be required.

Q. Is NW Natural considering alternatives to the Field and Web Maps Enablement Phase II Project?

A. Yes, though a full alternatives analysis will be completed in 2026 before beginning project work. At this time, the Company has conducted an initial assessment of a "no action" alternative and has concluded that some action is necessary for two reasons. **First,** maintaining the existing Visual Fusion software over the long-term will undermine the reliability of the Company's mapping functions, as Visual Fusion is already end-of-life. **Second,** maintaining IQGeo version 6.5 indefinitely is not viable because continued reliance on unsupported versions undermines the reliability of the Company's mapping functions and introduces risk to fixing product issues and maintaining product security. **Third**, the Company's Capture application is being phased out in 2026, and thus some replacement application will be required.

A detailed alternatives analysis will evaluate IQGeo's Network Manager application as a replacement for Capture. Other non-IQGeo solutions will also be considered, such as an Esri-solution or a solution from an Esri partner.

Q. What is the status of this Project?

A. This Project is currently in Intake phase, and NW Natural anticipates completing its analysis of alternatives in 2026, prior to starting work. This project is expected to be placed in service in July 2027.

Q. What cost recovery is NW Natural requesting for the Field and Web Maps Enablement Phase II Project in this case?

A. NW Natural seeks to recover its capital investment of approximately $1.3 million on a system basis, or $0.2 million on a Washington-allocated basis.

E. Customer Self-Service Enhancements Project

Q. Please describe the Customer Self-Service Enhancements Project.

A. The Customer Self-Service Enhancements Project will develop several new features to make it easier for customers to conduct business with NW Natural online (through the Company's website) and over the phone (through the Interactive Voice Response ("IVR") system). While the precise contours of this project are still being developed, potential workstreams include:

- Create Landlord-Between-Tenant service functionality that will allow property managers the ability to start, stop, or transfer gas service for tenants through the Company's website when the tenant is unable to complete the transaction. Currently, landlords must call customer service in these circumstances, resulting in over 11,000 unnecessary calls annually. This new feature will allow property managers to manage gas services at their convenience, reducing the need for customer service calls.
- Automate back-office processing for residential start and transfer service. This feature will eliminate the up to three-day processing time required to complete start or transfer service requests made on the Company's website—made possible by the Start-Stop-Transfer Project, described above. Adoption and completion of the online start, stop, and transfer service request have increased from 29 percent to 60 percent since the new online tool launched. However, customers continue to contact customer service due to delays in back-office processing. This feature will remove the delay and enhance the customer experience.

- Enable Contact Center Co-Browsing (also known as "collaborative browsing"), allows customer service agents to simultaneously view and interact with the same web page that customers are seeing in real-time, thus allowing the customer service agent to more efficiently guide customers through challenges. This tool is particularly valuable for resolving issues concerning log-in and password issues, and is important to reduce customer time and frustration.
- Provide an HTML view of the customer bill to enhance mobile accessibility. Currently, the Company offers only a PDF view of the bill, which is not optimized for mobile devices. More than 50 percent of customers access the Company's website on a mobile device.
- Incorporate artificial intelligence ("AI") assistance technology into the IVR, such as Agent Assistant, Quality Management, After Call Summarization, Knowledge Article Generation, Virtual Agent (Chatbot), AI Rep Checklist, Predictive Routing, and Analytics. AI for NW Natural customer service agents will provide faster service and enable customers to self-serve via the IVR more efficiently.
- Enhance the Company's customer notification capabilities by integrating text messaging and enterprise-wide email capabilities for all customers. Offering text messaging for common customer communication is a much-desired feature asked for by customers in customer satisfaction surveys.
- Introduce the ability for customers to select the language they prefer for the website. The Company will begin with Spanish and phase in the other top languages in NW Natural's service territory.

- Incorporate several enhancements to the IVR that will improve current call-flows, increase the service order types available, and streamline integration with the payment processing provider—thus enabling more seamless interactions for customers that pay their bills over the phone. These improvements will also incorporate after-call surveys for better analytics to guide future improvements, after-hours callback scheduling capability, and the ability to modify and cancel service orders.

Q. Why are these self-service enhancements necessary?

A. These self-service enhancements are necessary to effectively serve customers and to reduce the volume of Customer Care Center (CCC) calls. The identified improvements will save customers time and offer more convenient methods to conduct business with the Company. Moreover, the improvements provide the type of responsive and clear service that customers expect from their service providers, as indicated from customer satisfaction surveys and comments to customer service agents. These improvements also accommodate more language options and enhance efficiency through increased automation. Together, these website and IVR self-service enhancements aim to eliminate barriers to customers getting the service they need.

Q. Will NW Natural consider alternatives to the Customer Self-Service Enhancements Project?

A. Yes, and NW Natural is continuing to consider project alternatives. NW Natural will complete an alternatives assessment for this project, including identifying the appropriate priority order for these enhancements, in the first quarter of 2026. In addition to evaluating the overall costs and self-service benefits of different aspects of

this project, the Company intends to evaluate alternatives according to their equity impacts. Specifically, the Company will continue to assess whether and to what extent various self-service enhancements address barriers to service for disproportionately impacted customers.

For instance, facilitating landlord service requests can help avoid service disruptions to tenants who may face language barriers or lack adequate digital access. Similarly, HTML bills are readily compatible with assistive technologies like screen readers, increasing accessibility for vision-impaired customers. In addition, improving phone-based actions can better support customers with rigid work schedules and limited computer access, while co-browsing functions with customer service can support customers with technology literacy barriers. Finally, providing a website with language translation options can expand the self-service opportunities for non-English readers. NW Natural will continue to evaluate these and other equity implications as part of its comprehensive alternatives assessment.

Q. What is the status of the Customer Self-Service Enhancements Project and when is it expected to be placed in service?

A. This Project will begin in early 2026, and is expected to place the identified series of enhancements in service incrementally over the following several years, beginning in the second half of 2026. NW Natural will be able to provide a clear roadmap and timeline for these enhancements after the alternatives analysis and project roadmap is completed in early 2026.

Q. What cost recovery is NW Natural requesting for the Customer Self-Service Enhancements Project in this case?

A. NW Natural currently estimates that this project will entail $11.1 million in capital investment over the life of the project (through 2029), including $2.5 million placed in service in Rate Year 1, $5.7 million in Rate Year 2, and $2.3 million in Rate Year 3.

F. Website Technology Project

Q. Please describe the Website Technology Project.

A. The Website Technology Project will update and potentially replatform the Company's website in order to enhance security and maintain the stability of the Company's website architecture. This project will start with an initial assessment phase (Phase Zero) to evaluate current functionalities, support, security gaps, and to identify a path forward that meets both technical and functional challenges. The primary goals of this project will be to enhance the security and stability of the Company's website, while identifying opportunities to improve the customer experience and to simplify the Company's digital architecture. The results of Phase Zero will guide cost-effective decision-making and result in a recommendation for a specific implementation path.

Q. What are the possible implementation paths for the Website Technology Project that NW Natural is currently considering?

A. NW Natural is currently considering two main implementation paths for the Website Technology Project. The first option would be to update the current website's underlying software components to fully supported versions and implement security improvements to the existing platform. Security improvements would include mechanisms such as single sign-on, advanced monitoring for malicious activity, cloud

security enhancements, and enhanced Payment Card Industry ("PCI") security to meet the latest security standards and requirements.

The second option would involve identifying and transitioning to a new platform for the website that incorporates the needed security improvements. Based on a preliminary analysis, this new platform would improve customer experience with additional self-service feature enhancements, simplify the website's architecture, and avoid the need to update the complex technology stack underlying the current website platform.

Q. Why is the Website Technology Project necessary?

A. The Website Technology Project is crucial to ensure that this customer-facing system, which handles over three million sessions annually, remains stable and secure. Similar to other software systems, the website software and platform require regular updates to address bug fixes, product software and technical system improvements, enhanced functionality, and vendor support. This project aims to update several overdue components and implement necessary security enhancements.

Q. Did NW Natural consider alternatives to the Website Technology Project?

A. As I explain above, NW Natural is in the process of evaluating alternatives for this project. A full alternatives analysis is expected to be completed in the third quarter of 2025, which will allow the Company to confirm the appropriate course of action.

Q. What is the status of the Website Technology Project?

A. The Website Technology Project is currently in the Planning phase. The Company currently anticipates beginning the Website Technology Project in 2026 and placing it in service in July 2027. The project charter is included in Exh. BEF-21.

Q. What cost recovery is NW Natural requesting for the Website Technology Project in this case?

A. NW Natural seeks to recover its capital investment for this project, currently estimated at $14.3 million on a system basis, or $1.7 million on a Washington-allocated basis.

VII. RATE YEAR 2 PROJECTS
(August 1, 2027 – July 31, 2028)

A. Gas Control Daily Operations Platform (GCDOP) Implementation Project

Q. Please describe the GCDOP Program as a whole.

A. The GCDOP Program is a strategic initiative to replace the Company's aging, custom-built SCADA platform with a modern, modular, and secure SCADA platform. This program includes separate efforts to first plan for and implement the new SCADA platform (the "GCDOP Implementation Project"), which will enter service in Rate Year 2, and then to subsequently implement additional gas system data capabilities (the "GCDOP Consolidated Reporting Project"), which will enter service in Rate Year 3.

Q. What is the role of the SCADA platform in NW Natural's operations?

A. The SCADA platform is real-time software that provides monitoring and control capabilities for NW Natural's Gas Control team managing the gas distribution pipeline system. This capability allows the Company to deliver gas to our customers in a safe and reliable manner, and is necessary to maintain pipeline situational awareness.

Q. What is NW Natural's current software solution for the SCADA platform?

A. NW Natural's current SCADA software platform was installed in 2005, and relies on a customized system that integrates with software called iFIX, developed and

maintained by GE Vernova ("GE"). Thus, the Company relies on a combination of in-house software developers and GE support to maintain the hybrid system operations.

Q. Why did NW Natural develop a hybrid SCADA solution?

A. A hybrid SCADA solution was developed in order to allow the iFIX software to meet the operational requirements for a gas distribution pipeline control room. Foundationally, the iFIX system is based on a human-machine interface (HMI) server that is designed to manage plant operations, rather than a gas distribution pipeline system for an enterprise control room. When the platform was installed in 2005, this type of HMI-server based software was commonly used because it was (a) cost-effective, (b) readily transitioned between the preexisting hardware systems to networking with field telemetry devices, and (c) allowed development of custom applications to address gaps in functionality required for an enterprise control room. However, this type of platform did not provide enterprise solutions and integrations—or the level of compliance functionalities—required for gas distribution system operations. As a result, NW Natural substantially modified the iFIX platform over time with custom gas management and compliance services that are now offered "off-the-shelf" by SCADA vendors.

Q. Why is the GCDOP Program needed?

A. The GCDOP Program is needed to address several deficiencies and risks with the Company's current hybrid system. **First,** the current customized system was developed over 20 years ago and is now difficult to maintain and support. By the time NW Natural's new SCADA platform is installed in 2027, the custom system will have been in service for 22 years, well beyond the normal useful life for this type of system.

Second, the current platform has become increasingly unstable and unreliable. As the existing software was modified over time to accommodate NW Natural's gas distribution pipeline system, the system architecture started experiencing more frequent system disconnects and manual restarts. In 2024, for instance, the system required 39 manual restarts. While NW Natural has a back-up server to respond to such outages, transitioning to this back-up is a manual process, which can take between 30 minutes and 2 hours.

Third, the Company lacks peer gas distribution company users to help encourage appropriate maintenance of iFIX as a gas control SCADA platform. Today, NW Natural is the only known gas distribution company using iFIX as a SCADA solution. Without a critical mass of gas distribution companies pressing for maintenance, major system deficiencies have gone unaddressed for years, resulting in recurring outages.

Fourth, the existing software system lacks robust and reliable reporting functionality. Forecasting and reporting are essential tools for the Gas Control and Gas Supply teams. The current system's data capture and reporting mechanisms do not readily integrate with the Company's other software solutions, such as Power BI, undermining the reliability and efficiency of these reporting functions.

Q. When did NW Natural initiate the current GCDOP Program?

A. NW Natural began planning for the current GCDOP Program in 2023. That year, NW Natural retained Accenture to conduct an initial system assessment and explore potential replacement or update options.

Q. What were the results of Accenture's initial system assessment?

A. The main result of Accenture's assessment was to recommend replacing—rather than updating—the existing iFIX platform. Accenture determined that updating the existing system would require the Company to first remove all the existing layers of custom integrations from iFIX and return the software to its baseline configuration, before attempting to update the system and redevelop the custom integration side of the platform. NW Natural estimates that this reversal and updating process would cost approximately $10.1 million. Given that this approach would continue to rely on extensive customization and would forego better-suited off-the-shelf options for modern gas control systems, Accenture recommended identifying a replacement option rather than reinvesting in the existing hybrid system.

Q. How did NW Natural identify and evaluate options for replacing the existing platform?

A. In 2024, NW Natural retained IBM to identify the requirements for a new SCADA platform and to conduct a gap analysis, which the Company then used as the basis for approaching potential vendors. IBM approached eight vendors with potentially compatible offerings—including GE, which offers other SCADA products in addition to iFIX. NW Natural received responses from two potential vendors: AspenTech ("Aspen") and [redacted]

NW Natural conducted substantial due diligence into both responsive bids, and selected Aspen as the lower-cost and better service option to provide a new SCADA software platform. Aspen is a reputable and reliable company that supports

approximately 70 percent of the electric utility market with targeted strategic growth in the gas utility industry.

Q. In addition to being lower-cost, does the Aspen software solution provide other benefits for the Company's new SCADA platform?

A. Yes. Aspen's software approach is modular, which means it is comprised of multiple services with separate software components. While somewhat more complex from a software perspective, this approach is appropriate when an outside software expert is maintaining the code. A modular system is helpful in several respects:

- First, modular software allows for incremental installation, whereby the Company can transition to the new platform in one step, and subsequently take on additional available capabilities (such as through the GCDOP Consolidated Reporting Project) in future steps.
- Second, modular software enables less disruptive updates as the system ages. When one portion of the system needs to be updated for maintenance, this portion of the system can be updated without impacting the full software stack.
- Third, a modular system is not only more easily installed, but is also more easily uninstalled, thus supporting streamlined eventual replacement as part of NW Natural's long-term, multi-decade lifecycle system planning.

Q. Following this RFP process, did NW Natural nonetheless reconsider updating the current system as an alternative to replacement?

A. Yes. In June 2025, GE issued a patch that addressed a major cause of the SCADA system's crashes over the past five years. This patch has substantially reduced the need for manual restarts. As a result, the Company reevaluated whether to update and

maintain the existing hybrid iFIX SCADA platform solution as an alternative to replacement. Based on this analysis, the Company ultimately determined that replacement was still appropriate for three reasons:

First, retaining a hybrid system remains too precarious for this essential gas control system function. As the Company has experienced, hybrid systems combine the risks of both inadequate third-party vendor support and limitations of in-house custom systems support. Here, GE has already demonstrated intermittent and delayed support for issues that have interfered with basic SCADA operations. Even following the recent update, NW Natural gas control operators must still carefully manage how they use the system to avoid triggering system freezes and restarts. Similarly, relying on in-house custom-built solutions adds substantial development risk and potential points of failure. Thus, while the immediate reliability concerns were largely addressed by GE's latest patch, a hybrid system built on GE's iFIX software remains unreliable long-term.

Second, reinvesting in a hybrid solution would be inconsistent with the Company's broader IT&S strategy to move away from custom in-house software and towards stable, off-the-shelf solutions. In 2005, there were limited options for SCADA software companies focused on the needs of gas distribution companies. With the development of off-the-shelf, modular SCADA software solutions for gas control systems, the Company has quality, modern options that are comprehensively designed for NW Natural's long-term needs.

Third, updating the Company's existing hybrid SCADA system would not address the data and reporting deficiencies in the iFIX platform. Even updated, the

iFIX platform would continue to rely on a data format that does not readily integrate with the Company's other software solutions, and would thus continue to rely on manual workarounds to ensure accurate reporting.

Based on this analysis, NW Natural concluded that replacing the existing platform remained the best long-term alternative to safely and reliably serve customers.

Q. Are there other benefits of the GCDOP Program beyond addressing issues with the existing SCADA software platform?

A. Yes. This program will provide a stable, industry-standard platform for NW Natural's central gas system operations and management system, while improving reliability and ensuring accurate, consistent reporting. In addition, the new system will feature:

- A secure modern architecture,
- Centralized management of display maintenance and distribution,
- Streamlined product and patch releases through vendor-managed source code,
- State-of-the-art cybersecurity aligned with ISO-27001 standards,
- Simplified database administration and improved system release efficiency,
- Enhanced system administration and operational resiliency, and
- Enhanced user experience.

Q. What is the status of the GCDOP Implementation Project?

A. The GCDOP Implementation Project is currently in the Assess phase. The alternative analysis is included as confidential Exh. BEF-22C.

Q. What cost recovery is NW Natural requesting for the GCDOP Implement Project in this case?

A. NW Natural is requesting to recover its capital investment of approximately $19.0 million on a system basis, or $2.3 million on a Washington-allocated basis.

B. Customer Order Management Replatform Project

Q. Please describe the Customer Order Management ("COM") Replatform Project.

A. The COM Replatform Project will transition the Company's crucial order management system to a new platform to replace the end-of-life on-premises platform. The COM application is integral to the Company's customer service functions, as it manages complex customer order processes, including pricing and quoting, order management, fulfillment, reporting, and compliance. Additionally, the COM application supports all builder and contractor partner order management processes through an integrated portal on the NW Natural website.

Q. Why is the COM Replatform Project necessary?

A. The COM Replatform Project is necessary because NW Natural's legacy COM solution, first launched in 2019, is approaching end-of-life. The existing COM application is based on Microsoft's Dynamics 365 software. Microsoft has announced the end-of-life for NW Natural's on-premises implementation, meaning no additional functional software updates will be released. Even this limited, security-only support will end in January 2029.

Q. In addition to the end-of-life service schedule, are there additional factors driving the timing of this Project?

A. Yes. The COM Replatform Project is an integral part of the CIS replacement effort (H2:Vista), and is necessary to meet H2:Vista's prerequisite timeline milestones. This Project is therefore being developed to enter service in March 2028, both to ensure that basic security support is still available, and to avoid overlap with the CIS replacement work.

Q. Did NW Natural consider alternatives to the COM Replatform Project?

A. NW Natural will explore and evaluate available alternatives for this project before work begins to ensure the appropriate solution is selected and implemented.

Q. What is the status of the COM Replatform Project?

A. The project was identified in the Company's CIS study[8] and is currently in the Intake phase. The project is expected to be placed in service in March 2028.

Q. What cost recovery is NW Natural requesting for the COM Replatform Project in this case?

A. NW Natural seeks to recover capital investment of approximately $4.8 million on a system basis, or $0.6 million on a Washington-allocated basis.

[8] Confidential Exh. BEF-2C.

C. IGA Phase 3 Project

Q. Please describe the IGA Phase 3 Project and how this Project relates to the broader IGA effort.

A. The IGA Phase 3 Project expands on the foundational work in IGA Phase 1 and the application integration work in IGA Phase 2 by expanding integration with additional applications, enabling periodic access certifications, and piloting role-based access control.

Q. How does role-based access control differ from the Company's existing user-access control systems?

A. Currently, access permissions are tied to specific individuals as they enter specific roles and are granted access, or leave the Company and are removed from access. Where an individual may stay with the Company—sometimes for decades—and take on a variety of different roles, it is important to update that individual's access permissions to avoid accruing access permissions that are no longer necessary for the individual's latest role. Thus, role-based access permissions allow access to be assigned based not on an individual's specific new access permissions, but on the full scope of appropriate access based on the individual's current role.

Q. Is the Company considering alternatives for the IGA Phase 3 Project?

A. Yes. The Company will continue to consider the appropriate scope of application integrations for this phase of the IGA Program. While the Company's decision to allocate application integration and a role-based access pilot to Phase 3 was considered as part of the broader IGA program evaluation, this ongoing application-specific evaluation allows the Company to pragmatically build on the foundation established in

Phases 1 and 2 within realistic resource, budget, and timeline constraints. Application integration is prioritized based on system risk, the number of users impacted, and the complexity of the integration required.

Q. What is the status of the IGA Phase 3 Project?

A. The Project is expected to be placed in service in October 2027.

Q. What cost recovery is NW Natural requesting for the IGA Phase 3 Project in this case?

A. NW Natural seeks to recover its capital investment of $2.4 million on a system basis, or $0.3 million on a Washington-allocated basis.

D. Customer Engagement Platform Project

Q. Please describe the Customer Engagement Platform Project.

A. The Customer Engagement Platform Project will provide a tool for the Company to efficiently and effectively communicate with customers beyond bulk-correspondence communications. This new system will serve an important role in enabling adoption of high efficiency equipment, ensuring compliance with managed curtailments, and facilitating targeted safety communications. In contrast to a CIS, which records transactions and customer information, the Customer Engagement Platform Project will allow the Company to track communications to and from customers, and to target communications to different types of customers with different needs.

Q. Why is the Customer Engagement Platform Project necessary?

A. The Customer Engagement Platform Project is necessary because the Company currently relies on a cumbersome, and frequently manual approach to managing customer engagement. In the absence of a Customer Engagement Platform, the

Company can segment customer communications based on customer class, or by manually parsing specific customer variables. As a result, the Company's current customer communications primarily involve broad, general messages to all customers. The Company lacks the tools to configure, manage, and track individual customer engagement and communications. This means the Company cannot ensure that only relevant communications are sent based on specific criteria such as preferred language, participation in payment or arrearage management plans, gas usage, bill payment method, dwelling type (e.g., apartment vs. home), and responses to previous communications.

A Customer Engagement Platform will allow the Company to efficiently tailor communications strategies to provide customers with the most useful information. For instance, the Company currently cannot automate communications to customers that have particularly high consumption rates who might benefit from information regarding more efficient heat systems. As another example, the Company currently must manually manage communications with customers who have repeatedly contacted customer service regarding bill levels, and who might benefit from participation in bill discount programs. This Project would better facilitate these tailored communications.

Q. What are the benefits of the Customer Engagement Platform Project?

A. The Customer Engagement Platform Project will benefit customers by ensuring that they receive important safety, cost-saving, and account information in the manner that works for them, while—just as importantly—avoiding providing unnecessary and irrelevant information that may be distracting or burdensome. This flexible

functionality will benefit all NW Natural customers, but also carries important equity benefits. For instance, the new platform will allow NW Natural to:

- Follow up with participants in programs like the Arrearage Management Program, payment plans, and bill discount programs, with consideration for language preferences, to ensure that customers have information relevant to their program participation;
- Personalize communications at an individual level, such as identifying program eligibility and relevant account status, to focus messaging and increase effectiveness of the communication;
- Direct public safety communications to customers in specific areas that will be affected by service disruptions through multiple communication methods, such as text, email, and phone calls, allowing time for disproportionately impacted customers to prepare and to communicate with Company representatives;
- Facilitate customers' migration to lower-cost payment methods, such as automated clearing house electronic payments, while avoiding communicating to customers who have already adopted such methods; and
- Ensure compliance during curtailments, with automated and faster follow-ups for non-responsive customers, while avoiding excessive communications to responsive customers.

Q. Will NW Natural consider alternatives to the Customer Engagement Platform Project?

A. Yes, and NW Natural is still evaluating alternatives for project implementation. A crucial component of the project will be conducting a study to thoroughly outline the

specific functionality requirements and explore various alternatives to address those needs.

Q. What is the status of the Customer Engagement Platform Project?

A. The project is slated to begin in 2026 with a needs study and alternatives analysis. Pending the outcome of that assessment, development would begin in late 2026 and the project is scheduled to enter service in October 2027.

Q. What cost recovery is NW Natural requesting for the Customer Engagement Platform Project in this case?

A. The Company seeks to recover its capital investment of $3.4 million on a system basis, or $0.4 million on a Washington-allocated basis, which would be provisional capital in Rate Year 2.

E. Project Continuation

Q. You indicated that certain projects previously described will include assets to be placed in service in Rate Year 2. Please identify these projects.

A. The following projects described above include assets to be placed in service in Rate Year 2:

- **Microwave Stability Project**: NW Natural expects to place $7.0 million of this $25.2 million project in service in Rate Year 2, reflecting the incremental replacement/expansion of microwave transmission towers (see detailed project discussion in Section VI.A).
- **Customer Self-Service Enhancements Project**: NW Natural expects to place $5.7 million of this $11.1 million project in service in Rate Year 2, reflecting the

incremental deployment of customer self-service functions (see detailed project discussion in Section VI.E).

VIII. RATE YEAR 3 PROJECTS
(August 1, 2028 – July 31, 2029)

A. H2:Vista - CIS Data Quality Cleansing Project

Q. Please describe the CIS Data Quality Cleansing Project.

A. This Project is a prerequisite the H2:Vista CIS replacement project to migrate and improve the Company's consolidated customer information data, enabling future seamless migration to a new CIS platform. Data migration is frequently one of the more complex and time-intensive aspects of a platform replacement, due to the number of constituent variables. This project will ensure that the Company can operate consistently while transitioning the integral CIS backbone architecture, and aligns with the Company's broader strategic goals of customer focus, operational excellence, and regulatory compliance. This project's timeline was designed to ensure completion before the Company initiates the H2:Vista project work, to minimize internal resource constraints.

Q. Why is the CIS Data Quality Cleansing Project needed?

A. The CIS Data Quality Cleansing Project is needed to ensure that customer data is accurate and consistent through the CIS replacement effort. Accurate and consistent data is necessary to maintain operational continuity, quality customer service, and regulatory compliance during system transitions, particularly when high volumes of existing data are incorporated into a new software solution.

Moreover, this project is not only a prerequisite for H2:Vista, but serves to make this data more accessible to current users. For instance, CIS data is frequently needed by the Data, Reporting, and Analytics team to prepare reports, but accessing this data currently depends on technical resources in CIS development.

Q. Did NW Natural consider alternatives to the CIS Data Quality Cleansing Project?

A. Yes. Alternatives for this project were considered as part of the comprehensive CIS replacement planning process, and NW Natural will complete an updated alternatives analysis in the Assess phase of the project. Any CIS replacement requires data migration, and the Company evaluated whether to conduct this data clean-up and migration as an initial step or simultaneously with the CIS replacement in H2:Vista. NW Natural determined that it was appropriate to sequence this work effort prior to H2:Vista in order to ensure access to adequate internal resources and avoid any operational breakdowns in the CIS transition process.

Q. What is the status of the CIS Data Quality Cleansing Project?

A. This project will begin in 2026. The project is expected to be complete and placed in service in October 2028.

Q. What cost recovery is NW Natural requesting for the CIS Data Quality Cleansing Project in this case?

A. NW Natural seeks to recover its expected investment of $4.5 million on a system basis, or $0.5 million on a Washington-allocated basis.

B. GCDOP Consolidated Reporting Project

Q. Please describe the GCDOP Consolidated Reporting Project.

A. The GCDOP Consolidated Reporting Project is the second phase of the GCDOP Program, discussed above. This project will ensure that the data collected by the new GCDOP is used effectively by incorporating the resulting data into NW Natural's enterprise data "warehouse"—the cloud Enterprise Data Platform (EDP). This project will also prepare specific use cases designed to provide effective and streamlined reporting, such as identifying areas to optimize gas quality and flow, analyzing lost and unaccounted for gas (LUAF), and tracking and managing underground storage.

Q. Has the Company already determined precisely which capabilities will be included in the second phase of the GCDOP Program?

A. No. The Company will be best positioned to determine the precise scope of the additional capabilities once the GCDOP is placed in service in fall of 2027.

Q. What is the status of the GCDOP Consolidated Reporting Project?

A. The project will begin in 2027 with the expectation that an alternatives analysis will be completed for this project after the GCDOP is placed in service in fall of 2027. After the project scope is finalized, the GCDOP Consolidated Reporting Project is expected to be placed in service in June 2029.

Q. What cost recovery is NW Natural requesting for the GCDOP Consolidated Reporting Project in this case?

A. NW Natural seeks to recover its capital investment of approximately $3.8 million on a system basis, or $0.5 million on a Washington-allocated basis.

C. Voice Radio Tech Refresh Project

Q. Please provide some context for the Voice Radio Tech Refresh Project and how it fits into the Company's broader Technology Refresh Program.

A. Voice radio communications have been an integral part of NW Natural's day-to-day operations and emergency response strategy since the 1970's, and provide the core communications network across the Company's service territory. As with other Technology Refresh projects, this Voice Radio Tech Refresh Project focuses on updating the technology infrastructure necessary to support the Company's IT&S systems—here, the Company's voice radio system.

Q. Please describe the Voice Radio Tech Refresh Project.

A. The Voice Radio Tech Refresh Project updates the Company's digital mobile radio ("DMR") system from the current DMR-2 system to DMR-3. This project will be developed in three phases:

- **2027 (RFP, Design, System Purchase)**: NW Natural will conduct an RFP process, select a vendor, complete the detailed design of the DMR-3 system, obtain the necessary radio frequency, and purchase the system hardware (such as antennas, repeaters, and controllers).
- **2028 (System Installation, Radio Purchase, Initial Rollout)**: NW Natural will then configure, install, and test the system hardware, update training and support processes, and perform initial truck radio rollout.
- **2029 (Integration, Rollout)**: NW Natural will expand the Omnicore Digital Console and integrate the system with Emergency Services, including conducting training and performing the mobile handheld radio rollout.

Q. Why is the Voice Radio Tech Refresh Project necessary?

A. The Voice Radio Tech Refresh Project is necessary to strengthen the reliability of the Company's communications network and improve personnel safety, both in day-to-day operations and during emergencies. The current DMR-2 system does not include critical safety components such as GPS location tracking, "Technician Down Alerting," or data transmission capabilities. Technician Down Alerting functions using an accelerometer in the portable radio, and detects if the technician falls and is unable to call for help. DMR-3 also allows the system to dynamically select radio frequencies, which improves the system's reliability.

In addition to these important features, transitioning to DMR-3 is also important to enable collaboration with Emergency Services, such as police and fire departments. Emergency services providers have asked that the Company be able to communicate via radio during emergency situations to enable prompt and secure emergency coordination. Currently, DMR-2 allows the Company to receive radio communications, but not to respond, whereas DMR-3 will enable two-way communication and establish end-to-end message encryption.

Q. Will the Company consider alternatives to the Voice Radio Tech Refresh (DMR-3) Project?

A. Yes. In the Assess phase of the project, NW Natural will finalize an alternatives analysis for this project. NW Natural expects to consider three alternatives. **First**, NW Natural will consider the status quo of not transitioning to DMR-3 and instead retaining the DMR-2 system. As noted above, the lack of critical safety features in the

existing system and the inability to effectively communicate with Emergency Services in a crisis situation are key concerns.

Second, the Company will consider expediting the DMR-3 project and performing both the truck radio and handheld radio rollouts in 2027. The Company expects that a phased approach will be preferable because it (a) smooths cost impacts for customers, (b) avoids straining internal implementation resources, and (c) minimizes operational disruptions.

Third, NW Natural will consider using cell phones instead of voice radios, but this alternative is not likely to be viable because cell phones rely on telecommunications carriers which are prone to outages or blocked calls due to system failures and increased traffic during emergencies. One recent example of this occurred during the Los Angeles fires in the fall of 2024. A team of NW Natural Emergency Field Technicians were deployed to assist, and they could not communicate via their cell phones. However, the handheld voice radios worked, enabling the Field Technicians to communicate in real time during the emergency.

Q. What is the status of the Voice Radio Tech Refresh (DMR-3) Project?

A. This project is currently in the planning stage and the Company expects to finalize the project roadmap in Q3 of 2026. Based on preliminary planning, NW Natural expects to complete phase one of the project in the fourth quarter of 2027, place phase two into service by the fourth quarter of 2028 and place phase three into service by the fourth quarter of 2029.

Q. What cost recovery is NW Natural requesting for the Voice Radio Tech Refresh (DMR-3) Project in this case?

A. NW Natural seeks to recover its capital investment of approximately $6.7 million on a system basis, or $0.8 million on a Washington-allocated basis, over the MYRP. The Company is seeking recovery of Washington-allocated amounts of $0.3 million, $0.3 million, and $0.2 million for Rate Year 1, Rate Year 2, and Rate Year 3, respectively.

D. Project Continuation

Q. You indicated that certain projects previously described will include assets to be placed in service in Rate Year 3. Please identify these projects.

A. The following projects described above include assets to be placed in service in Rate Year 3:

- **Microwave Stability Project**: NW Natural expects to place $6.7 million of this $25.2 million project in service in Rate Year 3, reflecting the incremental replacement/expansion of microwave transmission towers (see detailed project discussion in Section VI.A). The Rate Year 3 amount on a Washington-allocated basis is $0.8 million.
- **Customer Self-Service Enhancements Project**: NW Natural expects to place $2.3 million of this $11.1 million project in service in Rate Year 3, reflecting the incremental deployment of customer self-service functions (see detailed project discussion in Section VI.E). The Rate Year 3 amount on a Washington-allocated basis is $0.3 million.
- **Voice Radio Tech Refresh Project**: NW Natural expects to place $1.9 million of this $6.7 million project in service in Rate Year 3, reflecting the new DMR system's

integration with Emergency Services and the rollout of mobile handheld radios (see detailed project discussion in Section VII.E). The Rate Year 3 amount on a Washington-allocated basis is $0.2 million.

IX. PROGRAMMATIC INVESTMENTS

Q. Please briefly distinguish between discrete projects or programs and "programmatic investments."

A. The Company uses the term "programmatic investments" to refer to those investments made according to a schedule or plan, where the investment is often forecast using historical trends, as opposed to discrete projects or programs that are not tied to trended forecasts or predictable schedules.[9]

A. Data, Reporting and Analytics Program

Q. Please describe the Data, Reporting and Analytics ("DRA") Program.

A. The DRA Program is an ongoing initiative to support the Company's data-driven decision-making. This Program builds on the Company's implementation of Microsoft's Power BI software stack, previously addressed in Docket UG-200994.[10] This set of tools allows the Company to develop analytics and publish reports for a range of critical business purposes, including safety, compliance, damage prevention, valve maintenance, and emergency tracking. Developing analytics and producing reports relies on carefully assessing the specific requirements, identifying the underlying data, structuring the associated reporting, testing the reporting and analysis

[9] The Company relies on the Commission's distinction between projects and programmatic investments. *See* Used and Useful Policy Statement ¶¶ 11n.19, 35.

[10] *In the Matter of Washington Utilities and Transportation Commission v. Northwest Natural Gas, d/b/a/ NW Natural*, Docket UG-200994, Direct Testimony of Jim R. Downing, Exh. JRD-1T at 38-39 (Dec. 18, 2020).

process, and then producing the reports and any required visualizations for the end users. End users range from internal departments to government entities. Taken together, this DRA process requires developing and testing connections between different parts of the Company's systems to provide useful, clear, and reliable reports and analysis.

Q. How does the DRA Program relate to the Company's essential operations and provision of service?

A. The DRA Program is central to the Company's operations and effective decision-making, as it is the means by which NW Natural understands and manages its overall operations and performance. For instance, effective data analytics allow the Company to track and report on emergency response times, call volumes, and areas affected, thereby allowing the Company to allocate resources more effectively. Similarly, data analytics are necessary to provide comprehensive damage prevention reports to state regulators, identify risk areas, and guide future investments. Effective decision-making, analysis, and reporting needs are met through individual use cases, which are developed and placed in service separately as each is completed.

Q. What categories of use cases are most commonly required for data-driven decision-making and reporting?

A. The DRA Program focuses on several key categories of use case development:

- **Safety and Incident Management**: This category includes reports that track safety incidents, including vehicle collisions, employee injuries, and pipeline damage, as well as the incidents' underlying causes. This type of report allows the Company

to effectively design interventions to prevent future incidents and protect customer, employee, and public safety.

- **Gas Operations and Maintenance**: This category of reports includes tracking gas leaks, outages, storage, and consumption. For example, reports can use historical data regarding consumption and storage, along with up-to-date weather forecasts, to better predict total supply needs and ensure that the Company has adequate supplies to reliably serve customers. This category of report also includes comprehensive pipeline maintenance histories, patterns of maintenance issues, and timelines for responsive maintenance activities.
- **Customer Service**: This category of reports includes customer service response times, patterns of customer feedback and satisfaction, and categories of concerns reported. These reports are crucial to effectively designing customer service support systems and to ensuring that customer field services are available when and where they are needed.
- **Regulatory and Compliance**: These reports are used to provide information to regulatory and governmental organizations, such as PHMSA, local governmental entities, and state regulators. For instance, the Company prepares substantial reports on pipeline code compliance, atmospheric corrosion, heat detection patterns, and a wide array of asset inspections. These reports are an important part of ensuring that the Company is meeting its safety and environmental responsibilities and legal obligations.
- **Financial and Billing**: This category of reports allows the Company to effectively track and manage Company spending by department and manager, including

identifying and explaining variance between budgets and actual spend levels. Reports also analyze customer billing and consumption patterns, such as arrearage overviews, late payments, and qualification for bill discount programs.

Q. How does NW Natural determine which use cases, reports, and analytics to pursue within the DRA Program?

A. The Company determines which use cases, reports, and analytics to pursue through use case intake forms, which allow for consistent evaluation of use case requests. This process includes oversight and approval of use case requests by NW Natural officers to ensure the appropriate reports and use cases are prioritized.

Q. Are there viable alternatives to the DRA Program?

A. No. To be clear, reporting and analytics play a critical role across the Company, including regulatory compliance, operational efficiency, financial management, customer service, safety, and emergency response. In the absence of the DRA Program and its ability to leverage the Company's consolidated data warehouse through the Power BI software, NW Natural would have to rely on labor-intensive, ad-hoc, Excel-based reporting to meet regulatory reporting requirements and data analysis needs. This alternative is not viable because a manual alternative is both more error-prone and too slow to meet compliance deadlines.

Q. Are there other benefits of the DRA Program's centralized data and analytics approach?

A. Yes. A centralized DRA Program provides a consistent and scalable approach to reporting. Unlike decentralized methods, which often rely on siloed data sources and manual processes, a centralized DRA Program ensures data integrity, avoids duplicated

efforts, and enables faster, more reliable insights from Company data. A centralized data warehouse also supports governance, security, and compliance by maintaining a single source of truth across the organization.

Q. What is the status of the DRA Program?

A. The DRA Program is active and ongoing, and will continue throughout the MYRP. New reports and use cases are placed in service as they are produced, tracked quarterly. Based on the Company's historical need for rigorous, data-driven reporting and analytics, there is a clear and predictable future need for further such capabilities. Table 2, below, is the Company's historical and forecast investment in the DRA Program, based on calendar years.

Table 2. Investment in DRA Program

Sum of Annual Forecasts - Capital Spend *Forecast does not include AFUDC, Tax or COH					
2023 - Actuals	2024 - Actuals	2025 – Actuals + Forecast	2026 - Forecast	2027 - Forecast	2028 - Forecast
$7,755,777	$6,580,103	$5,104,599	$ 4,500,300	$4,500,300	$4,500,300

Q. Has the Company's DRA Program investment changed over time?

A. Yes. As shown in Table 2 above, the Company has effectively reduced its annual DRA investment by optimizing report creation and improving data quality over time. These improvements have allowed the Company to reduce the annual estimated investment need to approximately $4.5 million. Forecast years are based on reasonable extrapolations from historical spend and projected DRA needs. With a stable data warehouse and clear ongoing reporting and analytic needs, the Company's future DRA investment is predictable, stable, and sustainable.

Q. What cost recovery is NW Natural requesting for the DRA Program in this case?

A. NW Natural seeks to recover, on a system-wide basis, its historical capital investment of $17 million, pro forma investment of $8.0 million, and ongoing forecast investments of approximately $4.5 million per Rate Year. On a Washington-allocated basis, these amounts are $2.1 million in historical investment, $1.0 million in pro forma investment, and $0.6 million in ongoing forecast investment per Rate Year.

B. Telemetry Lifecycle Management Program

Q. As an initial matter, what do you mean by "telemetry"?

A. Telemetry refers to the physical systems and equipment that allow NW Natural to manage its natural gas pipeline through the active, central monitoring and control system, known as Supervisory Control and Data Acquisition (SCADA). SCADA systems collect, transmit, and measure data from remote sources, using sensors and other devices to collect data through remote communications systems, known as telemetry. These telemetry systems include a range of equipment, such as SCADA Remote Terminal Units/Programmable Logic Controllers, pressure transmitters, flow meters, line heaters, actuators, and communications equipment.

Q. Please describe the Telemetry Lifecycle Management Program.

A. The Telemetry Lifecycle Management Program is an on-going effort to replace outdated physical SCADA equipment with modern technology to comply with new security and safety standards. The projects involve surveying, permitting, and deploying new equipment to the Company's remote monitoring and control sites. NW Natural targets 20 sites for updates each year.

Q. Why is the Telemetry Lifecycle Management Program necessary?

A. The Telemetry Lifecycle Management Program is crucial to ensure accurate and reliable telemetry regarding the condition and control of NW Natural's pipeline systems. These projects manage the lifecycle of the remote telemetry sites to ensure accurate data for the SCADA system, thus maintaining the Company's safe and reliable operation of its gas pipeline system.

The specific nature of the telemetry equipment varies by location, depending in part on the site's accessibility, and has historically included radio, network circuits, cellular, and satellite connections, and other transmission technologies. Over time, each site's telemetry equipment ages and reaches end-of-life and is no longer reliable. As a site reaches end of life, NW Natural must update the site with current technology to maintain system, regulatory, security, and safety requirements. By developing a systematic program for maintaining the Company's telemetry systems, NW Natural can support the critical functionality of its telemetry systems while avoiding unnecessary cost spikes.

Q. What is the schedule or plan for implementing the Telemetry Lifecycle Management Program?

A. The Telemetry Lifecycle Management Program is designed to allow for systematic maintenance across the Company's telemetry locations. As of June 2025, NW Natural has 283 telemetry sites, and periodically adds new telemetry sites to support changing SCADA monitoring needs and ensure adequate system coverage. The Telemetry Lifecycle Management Program targets approximately 20 sites per year, allowing the Company to maintain and update sites on approximately a 15-year rotating cycle. Since

the Telemetry Lifecycle Management Program was initiated in 2020, the Company has gradually established its sustainable maintenance program levels, which are expected to remain level, adjusted for inflation, going forward. This ongoing Telemetry Lifecycle Management Program entails predictable spending levels, as shown in Table 3 below.

Table 3. Telemetry Lifecycle Management Program Spending Levels

Calendar Year	Investment[11]
2020	$1.702 million
2021	$1.690 million
2022	$2.206 million
2023	$3.136 million
2024	$3.415 million
2025	$3.880 million
2026	$3.400 million
2027	$3.400 million
2028	$3.400 million
2029	$3.400 million

This consistent, programmatic investment level allows the Company to maintain the reliability of this important technological infrastructure.

Q. Why does the Company plan for a 15-year cycle for the Telemetry Lifecycle Management Program?

A. A 15-year cycle for telemetry maintenance and refresh is appropriate to allow the Company to account for the shorter life expectancies of the electronic equipment at these telemetry sites. When conducting the 15-year refresh, the Company evaluates each site and identifies those assets in need of replacement.

[11] Investment forecasts, beginning July 2025, are direct costs only.

Q. What is the status of the Telemetry Lifecycle Management Program?

A. The Telemetry Lifecycle Management Program is active and ongoing, and remains on-track to implement the planned site updates each year. For the 20 sites identified for the 2025 cycle, the Company has completed 9 sites to date.

Q. What cost recovery is NW Natural requesting for the Telemetry Lifecycle Management Program in this case?

A. The Company is requesting recovery of its historical investment through March 31, 2025, of $4.5 million on a system basis, or $0.5 million on a Washington-allocated basis. On a forward-looking basis through the MYRP, the Company expects to place this capital in-service, as shown in Table 4 below.

Table 4. Telemetry Lifecycle Management Program Investment in MYRP

MYRP Period	Investment
Pro-Forma (April 1, 2025 – July 31, 2026)	$4.5 million[12]
Rate Year 1 August 1, 2026 – July 31, 2027	$2.6 million
Rate Year 2 August 1, 2027 – July 31, 2028	$3.8 million
Rate Year 3 August 1, 2028 – July 31, 2029	$3.9 million

These amounts differ from the calendar year view, shown above, based on the timing of the Company's telemetry investments and the time period captured by the MYRP's respective Rate Years.

[12] The Pro Forma Period is slightly higher because it reflects 15 months of investment.

X. CONCLUSION

Q. What are your recommendations regarding the IT&S projects described in your testimony?

A. I propose the Commission approve cost recovery for these projects. As described in my testimony above, these projects are necessary for NW Natural to continue to provide safe and reliable service and will provide an improved and secure customer experience.

Q. Does this conclude your Direct Testimony?

A. Yes.

XI. LIST OF EXHIBITS

Exh. BEF-2C	NW Natural Executive Update of CIS Study (Confidential and Redacted)
Exh. BEF-3	Genesys Replatform Project Alternatives Analysis
Exh. BEF-4	Utilities International Planner Replatform Project Alternatives Analysis
Exh. BEF-5	IQGeo Upgrade Project Alternatives Analysis
Exh. BEF-6	MapFrame Replacement Project Alternatives Analysis
Exh. BEF-7	Clevest Optimization Project Alternatives Analysis
Exh. BEF-8C	Identity Governance Automation Phase 1 Project Alternatives Analysis (Confidential and Redacted)
Exh. BEF-9	Start-Stop-Transfer Project Alternatives Analysis
Exh. BEF-10	Composition 2.0 Project Alternatives Analysis
Exh. BEF-11	PowerPlan Project Alternatives Analysis

Exh. BEF-12	SAP Treasury Project Alternatives Analysis
Exh. BEF-13	Resource Scheduling Optimization Project Alternatives Analysis
Exh. BEF-14	Esri UN Replatform Project Alternatives Analysis
Exh. BEF-15	Field and Web Maps Enablement Phase I Project Alternatives Analysis
Exh. BEF-16	IGA Phase 2 Project Alternatives Analysis
Exh. BEF-17	2020 Report: Pipeline Risk Modeling – Overview of Methods and Tools for Improved Implementation
Exh. BEF-18C	JANA Project Charter (Confidential and Redacted)
Exh. BEF-19	Application Lifecycle Management - SAP Update Project Alternatives Analysis
Exh. BEF-20	Compliance Data Management Optimization Project Options
Exh. BEF-21	Website Technology Project Charter
Exh. BEF-22C	GCDOP Implementation Alternatives Analysis (Confidential and Redacted)

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Brian E. Fellon

INFORMATION TECHNOLOGY & SERVICES

Exh. BEF-2C

REDACTED VERSION

August 29, 2025

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY (PAGES 1-13)
UNDER WAC 480-07-160 AND HAS BEEN REDACTED.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Brian E. Fellon

INFORMATION TECHNOLOGY & SERVICES

Exh. BEF-3

August 29, 2025

NW Natural
PROJECT ALTERNATIVES NARRATIVE

Program/Project Name: Genesys Replatform
Date:9/20/2023
Project Sponsor: Dina Thompson
Executive Sponsor: Jim Downing
Project Manager: Christopher Long
Preparer: Christopher Long / Lisa Delaney
Was this project part of IRP: NO (enter "Yes, included", "Yes, Acknowledged" or "No")

SECTION 1: BUSINESS CASE

This section should be solution-agnostic, and about the overarching problem we're trying to solve no matter which route we end up taking.

OBJECTIVES *Why are we tackling this project?*	
Current State What is happening now? Where are we starting?	Genesys PureConnect is the Company's existing on-premises, advanced call routing software, which serves 7 groups and approximately 300 combined agents across NW Natural, including Customer Acquisitions, Customer Support, Engineering Support, IT, Marketing, Resource Management, Customer Contact Center, and Major Account Service Team(s). This platform also hosts functions within the Integrated Voice Response application to request service orders and interfaces with Paymentus to enable telephone access to billing accounts. "Genesys PureConnect is a "Tier 0" critical infrastructure system as defined in the NWN Application Availability Tiers standard. Outages will result in public Health and Safety concerns and immediate cessation of primary function(s). Tier 0 services are required to be available 24x7x365 and have clear resiliency requirements to ensure uptime." The initiative is in response to the upcoming end-of-life for the PureConnect product in early 2025.
Problem Statement In simple terms, what are we trying to solve? What is the business need this is tackling? Why is this a problem worth solving (e.g., why is the current state not working)?	**Problem Statement**: Starting in January 2024, Genesys will *cease to offer new support* agreements and license modifications for PureConnect limiting change to features, or capacity of the existing platform, with software support ending on July 31st, 2025, marking the system's end of life. ***On July 31st, 2025 the system will cease to operate.*** To secure our contact center operations, maintain system uptime, and ensure ongoing functional requirements are met, it is imperative to address the forthcoming end-of-life support for Genesys PureConnect and strategize a solution that aligns with our operational requirements. **Business Need:** Genesys PureConnect has been integral in handling our customer interactions. With the termination of official support, NWN faces potential risks, including: 1. **Operational Stability**: Without continued software lifecycle support, software glitches, malfunctions, or other unexpected issues that may disrupt our service delivery. 2. **Security Vulnerability:** As no new security patches will be released post support date, our system may become susceptible to potential security breaches or data compromises. 3. **Integration Challenges:** Over time, compatibility with other evolving systems or third-party software like Paymentus might be compromised, leading to integration issues and impact to end customers.

	Why is this problem worth Solving? 1. **Customer Satisfaction:** Maintaining the integrity and reliability of the contact center platform is paramount to ensuring customer satisfaction. Disruptions can lead to decreased customer satisfaction. 2. **Business Continuity:** To ensure that there is no disruption in our daily operations, we need a solution before support ends, allowing for ample time to transition as required. 3. **Cost Implications:** Proactively addressing this issue can prevent potential financial losses from disrupted operations, security breaches or emergency migrations. 4. **Improved Experience:** Staying updated with software solutions will not only prevent potential issues but can provide enhanced features, performance improvements, and better integration capabilities, ensuring a good user and customer experience. Additionally, new technology will bring customer self service functions to the platform further optimizing the customer's interaction.
Desired Deliverables What high level output / scope / deliverables are core to this project?	Ensure that NW Natural can continue to provide reliable contact center operations and maintain high-quality customer contact services. Ensure long-term, effective integration with other Company software solutions. Limit disruption to customers and NW Natural operations.

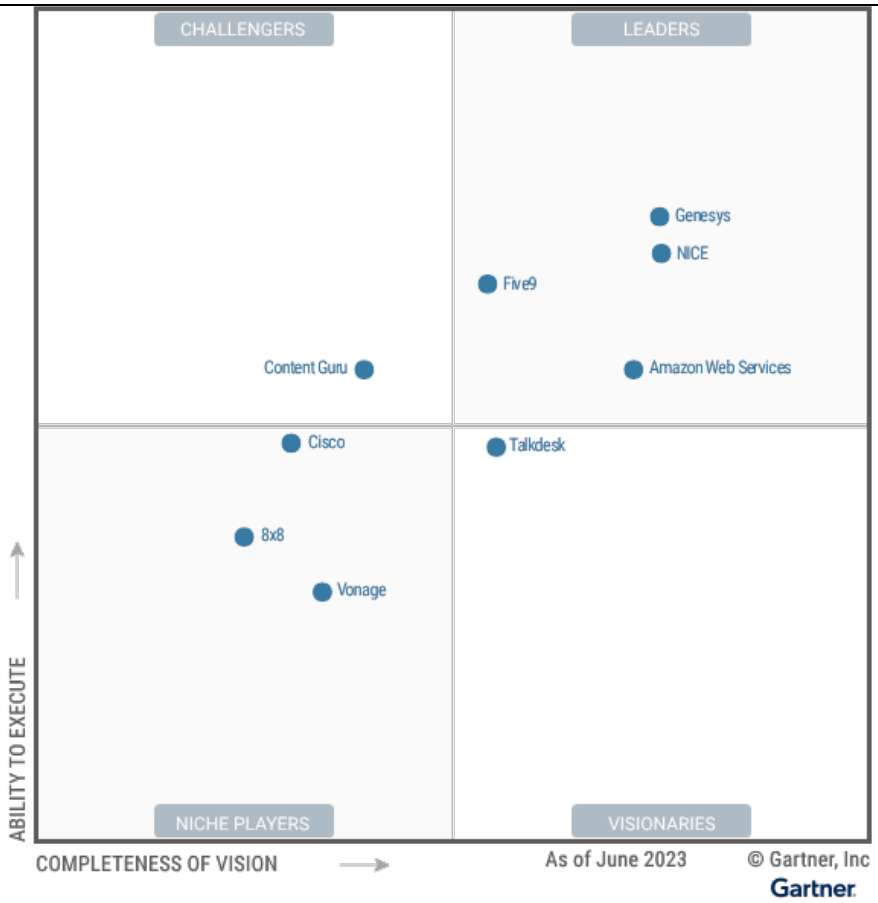
SECTION 2: ALTERNATIVES SUMMARY

OVERVIEW *How did we review these options?*	
Review Process Summarize how options were chosen, who was involved in the choice and how options were evaluated. If some criteria were considered more important based on the type of project, please explain here.	Driven by the sunset of the Genesys PureConnect on-premises software lifecycle, a critical evaluation has been initiated to evaluate the sustainability and efficiency of the existing Genesys platform. The options under consideration are straightforward: either upgrade to the next-generation product from Genesys, explore solutions from a different vendor or maintain the status quo with the current on-premises Genesys system. Core requirements, such as basic features, agent and supervisor functionalities, integration capabilities, and workforce management functions, are anticipated to be comparable between both the upgrade and new solution exploration options. The leading alternatives, predominantly cloud-based, are expected to adhere to similar industry benchmarks regarding architecture and cybersecurity compliance. Given that these foundational elements are presumed consistent across provider choices, they won't form the crux of our analysis. Instead, our focus is on deployment efforts, user implications, and overarching cost considerations. The alternatives assessment process included: • **Current System Analysis**: Detailed documentation of the existing environment setup, including configurations, integrations, customizations, and roles

	• **Stakeholder and Business Feedback:** Compilation of feedback and requirements from executives, key stakeholders, and users of Genesys regarding features, capabilities, and constraints of the current solution.
DECISION CRITERIA *Describe the criteria used to determine the selection from the various alternatives considered. For example, is this a program/project where the least cost option should be selected? Are there other factors, such as safety or quality that come into play? Include both quantitative and qualitative factors as appropriate.*	
Criteria: Level of effort to deploy	a. Complexity • How intricate or straightforward is each option to implement, irrespective of the nature of the change (upgrade, new solution or maintaining existing system) b. Resource Allocation • What people, technical, and financial resources are required for each option? • Does the option require new expertise, or can it be handled by the current resources on staff? c. Timeline • How long is the expected duration from the mobilization of the vendor to completion of each option? • Are there any anticipated delays or hurdles specific to an option?
Criteria: User Impact	a. Learning Curve • How quickly can users adapt to the changes or upgrades presented by each option? • Does a particular option require users to unlearn certain processes or habits? b. Training Needs: • How quickly can users adapt to the changes or upgrades presented by each option? • Does a particular option require users to unlearn certain processes or habits? c. Productivity • Is there expected downtime or a potential drop in productivity during or post-implementation for each option? • How soon can normalcy or improved performance be expected post-transition?
Criteria: Overall Cost Implications	a. Initial Expenditure • What are the upfront costs associated with each option, including licensing, hardware, and setup? b. Ongoing Costs: • Are there recurrent expenses, such as maintenance fees, subscription costs, or additional licenses?

SECTION 3: ALTERNATIVES DETAIL

RECOMMENDED OPTION *Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option. If positive /neutral/negative observations do not exist, enter N/A*	
Description	Replatform to Genesys Cloud
In brief, why is this the recommended option?	○ Seamless transition: As it's within the Genesys ecosystem, migration will be more straightforward with fewer compatibility issues and less possibility of user impact. ○ Opting for Genesys Cloud mitigates the risk of user disruption and training needs, given users' familiarity with the existing Genesys interface and terminology. This choice directly impacts a smoother transition and faster user adoption. ○ Gartner, an independent technology advisory firm, has recognized Genesys as a market leader in the Contact Center as a Service (CCaaS) sector, noting the following strengths: ▪ Genesys has an extensive operational and channel presence in multiple regions. This wide geographic reach makes it a strong contender for consideration by organizations interested in contact center platform consolidation. ▪ Genesys offers strong tools and processes to migrate customers either from other Genesys offerings or from competitors' premises-based platforms to Genesys Cloud CX. ▪ Genesys offers strong tools and processes to migrate customers either from other Genesys offerings or from competitors' premises-based platforms to Genesys Cloud CX. ▪ **Gartner Magic Quadrant for Contact Contact Center as a Service (CCaaS)**



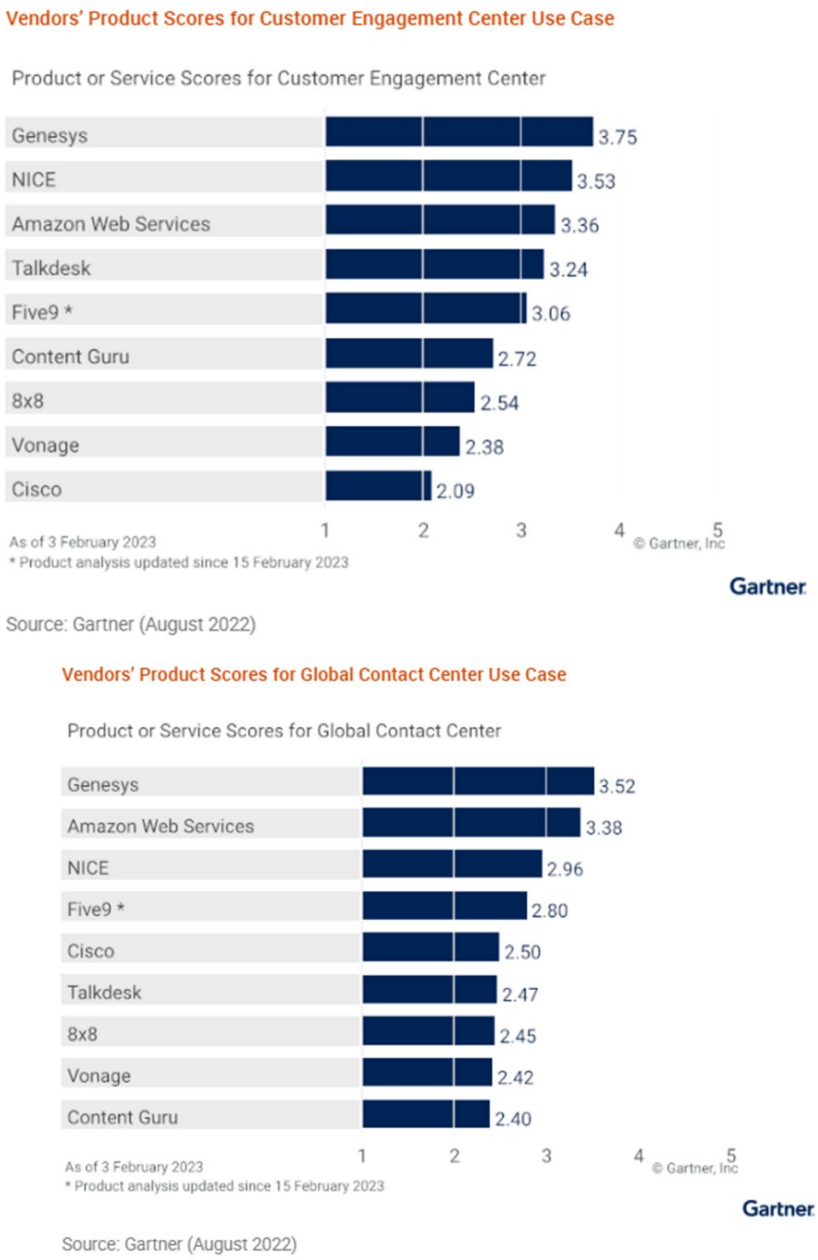
- Genesys achieves the top Product or Service Scores by Gartner across several critical use cases in the Contact Center sector:

Analysis

Critical Capabilities Use-Case Graphics

Vendors' Product Scores for High-Volume Customer Call Center Use Case

Source: Gartner (August 2022)

<table>
<tr><td></td><td colspan="2"> 

Source: Gartner (August 2022)

Source: Gartner (August 2022)</td></tr>
<tr><td rowspan="3">Assessment</td><td>Analysis Against Criteria: Level of effort to deploy</td><td>As the migration remains within the Genesys ecosystem, a more streamlined transition process is expected with fewer compatibility challenges. Migrating data and training users for the new environment is still necessary.</td></tr>
<tr><td>Analysis Against Criteria: User Impact</td><td>Users familiar with Genesys PureConnect will find the Cloud variant somewhat familiar, thus reducing the learning curve. They would also benefit from enhanced and newly integrated features.</td></tr>
<tr><td>Analysis Against Criteria: Overall Cost Implications</td><td>Costs for transitioning to Genesys Cloud encompass licensing, potential infrastructure adjustments, and migration or training expenses. Manufacturer discounts for upgrading and long-term savings from scalability, and fewer infrastructure costs will help offset these initial outlays. Licensing costs are similar to other service providers in this space.</td></tr>
</table>

	Additional Benefits	**Reduced Risk of Downtime:** • Switching to a cloud solution can greatly minimize or prevent outages from significant failures in the virtual applications hosted in-house. The cloud solution primarily aims to maintain the uptime of a Contact Center application. **Integration and Futureproofing:** • Genesys Cloud supports easy integrations with other software solutions, like Paymentus "out of the box" using standard REST APIs

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$2,000,299 - $2,202,299	6%	$2,120,316 - $2,334,436
O&M Range	**Program/Project**		**Ongoing Maintenance & Support**
	$60,000 - $70,000		Y2/Y3 recurring Genesys Cloud license subscription $373,678.33/year
Source/ Method of Cost Data	Bidder quote as a response to RFP process in progress. Project/Program O&M is forecasted for training requirements		

ALTERNATIVES CONSIDERED NOT VIABLE

Provide a description of any additional alternatives that were considered but rejected up front as not viable, and explain why

	Description	**Why the Alternative is not viable**
Alternative 1	Deploy a new contact center solution.	Deploying a new contact center solution would be more costly, more labor-intensive, and take significantly more time, without any assurance of superior service. Moreover, switching to a wholly new service provider would carry additional integration risks, as the service has not demonstrated compatibility with the Company's other software systems. Furthermore, implementing a fully new alternative is not cost-effective as any new product would require the full design, development, and deployment process that the Company undertook when first implementing Genesys. In short, this option would carry significant potential for delay, performance degradation, and disruption of this critical service.
Alternative 2	Do nothing.	Opting to "do nothing" and retaining the existing Genesys on-premises presents unacceptable risks to both the public from a safety perspective and general business operations. Unchanged systems become more susceptible to security vulnerabilities and compatibility issues with evolving tools and 3rd party solutions in production at NWN. This not only exposes the organization to potential breaches if the infrastructure is not secure. Inaction would exacerbate vulnerabilities, potential for outages, and downtime due to lack of software support.

**Add rows for any additional alternatives considered not viable*

SUPPLEMENTARY INFORMATION

As needed, you may include any useful information gathered during the assessment phase including analysis like cost benefit / risk analysis / sensitivity analysis, etc.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Brian E. Fellon

INFORMATION TECHNOLOGY & SERVICES

Exh. BEF-4

August 29, 2025

NW Natural
PROJECT ALTERNATIVES NARRATIVE

Program/Project Name: UI Planner Re-platform
Date: 5/22/23
Project Sponsor: Tobin Davilla/Jorge Moncayo
Executive Sponsor: Brody Wilson
Project Manager: SMichael Crotty
Preparer: Tobin Davilla
Was this project part of IRP: No

SECTION 1: BUSINESS CASE

This section should be solution-agnostic, and about the overarching problem we're trying to solve no matter which route we end up taking

OBJECTIVES *Why are we tackling this project?*	
Current State What is happening now? Where are we starting?	We are currently using the Utilities International (UI) legacy model for our financial planning solution. This solution will no longer be supported after this year. We need to either find a new solution or move to the new UI planner financial model.
Problem Statement In simple terms, what are we trying to solve? What is the business need this is tackling? Why is this a problem worth solving (e.g. why is the current state not working)?	The existing version of NWN long range financial and regulatory tool (UI Planner) is reaching the end of life and will no longer be supported by UI at the end of 2023. The current version was implemented in 2014. To continue using this tool, it will need to be re-platformed.
Desired Deliverables What high level output / scope / deliverables are core to this project?	A financial forecasting solution that interfaces with our other existing financial systems and provides us with utility industry leading robust modeling capabilities that provides fast, accurate and complex financial, regulatory, and business development planning.

SECTION 2: ALTERNATIVES SUMMARY

OVERVIEW *How did we review these options?*	
Review Process Summarize how options were chosen, who was involved in the choice and how options were evaluated. If some criteria were considered more important based on the type of project, please explain here.	Options were assessed by the Financial Planning and Analysis team. UI planner is our current tool used for utility and regulatory financial planning. It is the solution our utility peers use as well, and we are not aware of any other utility specific solution. The other alternative is to develop a model in Excel. Due to the above, two alternatives were discussed: 1) re-platforming UI planner from legacy model to their new system or 2) reverting back to Excel.
DECISION CRITERIA *Describe the criteria used to determine the selection from the various alternatives considered. For example, is this a program/project where the least cost option should be selected? Are there other factors, such as safety or quality that come into play? Include both quantitative and qualitative factors as appropriate.*	
Criteria: Alignment to NW Natural's IT Strategy	Ability to leverage this for future needs rather than a point solution.
Criteria: Cost-Benefit Analysis	Should a solution be built or bought.
Criteria: Timing	Ability to complete a project in time to meet a regulatory, business, product lifecycle, or safety requirement.

SECTION 3: ALTERNATIVES DETAIL

RECOMMENDED OPTION: UI PLANNER *Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option. If positive /neutral/negative observations do not exist, enter N/A*		
Description	UI planner new solution	
In brief, why is this the recommended option?	UI planner is the utility industry leader in financial planning solutions used by most of our utility peers including PGE, PacifiCorp, Avista, Puget Sound, PG&E, and Southwest Gas to name a few. This solution performs highly complex iterative solving and allows us to work on multiple scenarios at the same time. This solution provides high confidence reports eliminating errors in the modeling. This solution also interfaces with our existing platforms such as SAP and PowerPlant.	
Assessment	**Analysis Against Criteria:** Alignment to NW Natural's IT Strategy	This solution will be a SaaS solution and the plan is for UI planner to provide SaaS managed services. This managed services contract will provide backups, disaster recovery, penetration and exception monitoring, annual upgrades, and security patches.
	Analysis Against Criteria: Cost Benefit Analysis	The new UI product comes with additional benefits not seen in the existing legacy model. Benefits include, but not limited to, faster run times of at least 10x speed which is critical as this could save significant time during peak period modeling; greater drill down transparency which is important to support regulatory data requests, and alternative financial statements which is important for GAAP forecasting. Re-platforming from legacy model to new system will enable us to continue support until new system is completed.
	Analysis Against Criteria: Timeline	This project can kick off in Q3 2023 and would be planned to be completed prior to fall 2024. By beginning the project in 2023, UI will continue to support our existing legacy model until project completion.
	Additional Risks	None that we can identify at this point
	Additional Benefits	Data integration with source systems, eliminating side excel spreadsheets, managed service supports backups, security patches, and upgrades. UI is a utility-specific company that includes best practice calculations into their models informed from peer utilities (continual improvements to reporting/calculations based on utility feedback.)

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$1.5M - $2.0M	$150K - $200K	$1.65M - $2.20M
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$0 - $0	$235K - $280K	
Source/ Method of Cost Data	Preliminary project pricing with Utilities International		

ALTERNATIVE 1: MICROSOFT EXCEL *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*		
Description	Utilize Microsoft Excel	
In brief, why is this option not recommended?	Excel does not have the functionality to run a complex model that is now necessary for more accurate financial planning. The complexity of analysis and scenarios does not make it feasible. In addition, running multiple scenarios is not possible in Excel so the planning process is greatly lengthened making it not possible to complete in timely manner. Human error is also greatly increased when performing in a non-fixed model such as excel.	
Assessment	**Analysis Against Criteria:** Alignment to NW Natural's IT Strategy	This solution doesn't meet scope requirements and agility needed by the business plus introduces a high likelihood of human error and traceability.

	Analysis Against Criteria: Cost Benefit Analysis	It would initially require a great deal of time and resources to attempt to get a model built in excel. However, it would utilize a product that we have which would require no incremental on-going maintenance costs. It could be built in-house or could be contracted to be built by a third party. Existing solutions would not be supported after this year during buildout of excel model.
	Analysis Against Criteria: Timeline	Timeline would be pressed due to the need to get a model finalized by end of 2023 since UI planner would no longer be supported.
	Additional Risks	There are many risks to building this in Excel. Not easily auditable with drill down functionality to assumptions, greater risk for human error, prone to adding quick shortcuts or workarounds & hardcoding, and version control to name a few. An extremely complex system that would need to be built from the ground up. Greater risk for human error in modeling.
	Additional Benefits	Excel is widely used so training future employees on how to use a model in excel or change logic is much easier than a specialized software solution such as UI planner.

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$0	$0	$0
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$0	$0	
Source/ Method of Cost Data	Assumed built in house and done by the team. No incremental cost, large time commitment.		

ALTERNATIVES CONSIDERED NOT VIABLE

Provide a description of any additional alternatives that were considered but rejected up front as not viable, and explain why

	Description	**Why the Alternative is not viable**
Alternative 2	Do Nothing	Current solution will no longer be supported in 2024
Alternative 3	N/A	
Alternative 4	N/A	

SUPPLEMENTARY INFORMATION

As needed, you may include any useful information gathered during the assessment phase including analysis like cost benefit / risk analysis / sensitivity analysis, etc.

None needed at this time.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Brian E. Fellon

INFORMATION TECHNOLOGY & SERVICES

Exh. BEF-5

August 29, 2025

NW Natural
PROJECT ALTERNATIVES NARRATIVE

Program/Project Name: IQGeo Upgrade
Date: 5/11/2023
Project Sponsor: Dina Thompson / Dan Kizer
Executive Sponsor: Jim Downing / Joe Karney
Project Manager: Joe Harrison
Preparer: Joe Harrison
Was this project part of IRP: No

SECTION 1: BUSINESS CASE

This section should be solution-agnostic, and about the overarching problem we're trying to solve no matter which route we end up taking

OBJECTIVES *Why are we tackling this project?*	
Current State What is happening now? Where are we starting?	The IQGeo version that NWN uses for field mapping of assets is currently on version 6.1.
Problem Statement In simple terms, what are we trying to solve? What is the business need this is tackling? Why is this a problem worth solving (e.g. why is the current state not working)?	Our current software IQGEO 6.1 has been out of support since June 2022. While partial support continues through June 2024, this support does not include fixes for issues already addressed by subsequent updates (such as 6.5). IQGEO was initially implemented in 2020 and, consistent with other comparable software products, requires periodic upgrades to address bug fixes, product improvements, etc.
Desired Deliverables What high level output / scope / deliverables are core to this project?	• Upgrade IQGeo from version 6.1 to 6.5 • Migrate IQGeo installation from legacy Azure subscription to modern Enterprise Azure subscription • Create a software regression testing suite for IQGeo that is automated instead of manual

SECTION 2: ALTERNATIVES SUMMARY

OVERVIEW *How did we review these options?*	
Review Process Summarize how options were chosen, who was involved in the choice and how options were evaluated. If some criteria were considered more important based on the type of project, please explain here.	• Analysis conducted by the project team and external vendors to identify options, pros, cons, and potential risks and issues. • Project team agreed to a recommendation on implementation approach • Presented to the Steering Committee to gain approval to move forward with recommendation • Followed the Projects Governance Process for decision making.
DECISION CRITERIA *Describe the criteria used to determine the selection from the various alternatives considered. For example, is this a program/project where the least cost option should be selected? Are there other factors, such as safety or quality that come into play? Include both quantitative and qualitative factors as appropriate.*	
Criteria: Alignment to NW Natural's IT Strategy	Ability to leverage this for future needs, rather than a point solution
Criteria: Cost-Benefit Analysis	Whether a solution should be built or bought
Criteria: Timing	Ability to complete a project in time to meet a regulatory requirement

SECTION 3: ALTERNATIVES DETAIL

RECOMMENDED OPTION: UPGRADE + AZURE REPLATFORM + TEST AUTOMATION *Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option. If positive /neutral/negative observations do not exist, enter N/A*		
Description	**Upgrade to 6.5 + Azure + Test Automation**: Upgrade IQGeo to version 6.5, and create testing automation and re-platform to new Azure cloud environment.	
In brief, why is this the recommended option?	• The decision to upgrade to version 6.5 was due to 6.5 being a supported version of IQGeo software that has all the capabilities NWN relies on to complete current workflows. • Since the IQGeo software needed to be upgraded anyway, it made sense to move it to the modern Azure cloud environment so the new installation could take advantage of new capabilities and security features present only in the new Azure environment. • IQGeo software is expected to be updated every 12 to 24 months. Since the software was going to be upgraded as part of this project, it made sense to build a suite of automated regression test tools now to support this upgrade and future upgrades.	
Assessment	**Analysis Against Criteria:** Alignment to NW Natural's IT Strategy	• Reduce technical debt • Microsoft Azure subscription to comply NW Natural's security and architectural standards • Aligns with NWN GIS Roadmap
	Analysis Against Criteria: Cost Benefit Analysis	• Reduce risk associated with unsupported software for field operations • Reduces person hours and human element of testing future IQGeo software updates (every 12 – 24 mos.)
	Analysis Against Criteria: Timeline	• Upgrade of IQGeo is a necessary dependency for future projects such as ESRI UN, Network Gas Manager and Replacement of ArcFM, Visual Fusion and Mapframe (latter two are both end of life software)
	Additional Risks	• No current staff have experience configuring the IQGeo system, so there is reliance on the vendor's expertise
	Additional Benefits	• By working these three workstreams together instead of individually we can take advantage of reducing execution time and person hours by not duplicating efforts.

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$500K - $1.75M	$50K - $175K	$550K - $1.9M
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$50K - $150K	$0	
Source/ Method of Cost Data	Internal estimates of future project costs and vendor quotes.		

ALTERNATIVE 1: DO NOTHING *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*		
Description	**Do Nothing**: Do not perform the upgrade, continue business as usual.	
In brief, why is this option not recommended?	While a grace period for support is offered by the vendor through June 2024, the software platform needs to be updated prior to that date. Given the compliance reporting requirements for field of assets it was deemed too risky to continue to run on software that is not fully supported by the vendor. IQGeo version 6.5 also provides features that will enhance NWN user experience.	
Assessment	**Analysis Against Criteria:** Alignment to NW Natural's IT Strategy	• Lack of supported software introduces unnecessary risk. • Not upgrading would halt GIS Roadmap • Updated software capability from IQGEO version 6.5 wouldn't be available to the field.

	Analysis Against Criteria: Cost Benefit Analysis	• Zero spend today would likely cause increased costs later either in terms of emergent conditions leading to inability to report compliance or delay of future GIS projects.
	Analysis Against Criteria: Timeline	• Delay of future GIS projects.
	Additional Risks	• None
	Additional Benefits	• None

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$0	$0	$0
O&M Range	**Program/Project**	**Incremental Ongoing Maintenance & Support**	
	$0	$0	
Source/ Method of Cost Data	No costs incurred.		

ALTERNATIVE 2: UPGRADE ONLY *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*		
Description	**Upgrade Only:** Upgrade to 6.5 only (No test automation or re-platform)	
In brief, why is this option not recommended?	Without test automation of the regression testing suite, this upgrade and future upgrades would still require significant person hours for testing phases, and without re-platforming to the new Azure subscription, IQGeo cannot benefit from the following: • Aligning with best practices. • Standardization (e.g., structure, naming convention) will normalize and simplify support. • Align with security policies • Current network access and control policies	
Assessment	**Analysis Against Criteria:** Alignment to NW Natural's IT Strategy	• Keeping software up-to-date and in a state of being supported by the vendor.
	Analysis Against Criteria: Cost Benefit Analysis	• Least costly in the short term.
	Analysis Against Criteria: Timeline	• Upgrade of IQGeo is a necessary dependency for future projects such as ESRI UN and Network Gas Manager for the Legacy Mapping Replacement project
	Additional Risks	• No current staff has experience configuring the system, so our reliance on the vendor's expertise increases.
	Additional Benefits	• None

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$400K - $1M	$40K - $100K	$440K - $1.1M
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$40K - $100K	$xx - $xx	
Source/ Method of Cost Data	Internal estimates of future project costs and vendor quotes.		

**Copy/Add table for any additional alternatives*

ALTERNATIVES CONSIDERED NOT VIABLE *Provide a description of any additional alternatives that were considered but rejected up front as not viable, and explain why*

	Description	Why the Alternative is not viable
Alternative 3	Upgrade to IQGeo 7.1	Version 7.1 not available until June 2023 and Inspection module capability required and currently used by NWN not available until June 2024. The timeline did not align with the project's desired timeline.
Alternative 4	Upgrade + Azure resubscription only	Including test automation work within the current project allows NWN to leverage existing project resources instead of a standalone project which would require incremental PMO resources to manage.
Alternative 5		

**Add rows for any additional alternatives considered not viable*

SUPPLEMENTARY INFORMATION

As needed, you may include any useful information gathered during the assessment phase including analysis like cost benefit / risk analysis / sensitivity analysis, etc.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Brian E. Fellon

INFORMATION TECHNOLOGY & SERVICES

Exh. BEF-6

August 29, 2025

NW Natural
MAPFRAME REPLACEMENT ALTERNATIVES NARRATIVE

Program/Project Name: FieldSmart View (aka MapFrame) Replacement
Date: October 30, 2023
Project Sponsor: Dina Thompson / Dan Kizer
Executive Sponsor: Jim Downing / Joe Karney
Project Manager: Deirdre O'Donnell
Preparer: Shivon Van Allen, Deirdre O'Donnell
Was this project part of IRP: No

SECTION 1: BUSINESS CASE

This section should be solution-agnostic, and about the overarching problem we're trying to solve no matter which routes we end up taking

OBJECTIVES
Why are we tackling this project?

Current State
What is happening now? Where are we starting?

NW Natural (NWN) relies on FieldSmart View (commonly known as MapFrame) to support operations, including:

- Viewing gas facility location and asset information,
- Documenting changes to field conditions and mapping errors,
- Creating personal map notes for users to document information.

FieldSmart View does not have equivalent functionality in other parts of the NWN infrastructure. A single user may need to use FieldSmart View in addition to other mapping applications (IQGeo, Visual Fusion, Clevest, and/or ArcFM Viewer) in order to complete their work.

Fieldsmart View is one of five field and web mapping applications that NWN uses today. The applications, statuses, uses, and users are outlined below.

Application/Tool	Status	Uses	Users
Fieldsmart View (MapFrame)	End of Life	General map viewer, map correction creation	Field and back office
ArcFM Viewer	Near End of Life (2028)	Tracing cathodic protection network, limited feature editing	Corrosion Team
Visual Fusion	End of Life	Custom maps for different business groups, critical functionality is the valve isolation tracing map for emergency response	Back office, including Gas Control that relies on valve isolation tracing
Clevest	Implemented in 2022	Limited view of asset information, crew and work locations	Primarily used by field users and RMC
IQGeo	Implemented in 2020	Viewing GIS and SAP assets, completing surveys, reporting leaks, creating as-builts. Intended to be the application to replace FieldSmart View for field users.	Field and back office

Notably, the mapping data displayed in the above applications is created and maintained in Esri's ArcGIS Desktop Suite, specifically in the ArcMap application. Esri's ArcMap is the application where edits are made daily to GIS data based on as-builts and other changes

	made in the field. After the GIS data is edited in Esri, the mapping data can be viewed by the field and back-office users in the integrated application listed above, allowing employees and contractors to perform their work. Like FieldSmart View, Visual Fusion and ArcFM Viewer are at or near end-of-life, meaning that NWN will need to find replacement solutions for these tools in the future.
Problem Statement In simple terms, what are we trying to solve? What is the business need to tackle this? Why is this a problem worth solving (e.g., why is the current state not working)?	FieldSmart View is an old application that increases risk within NW Natural from a support & stability level and blocks other NWN IT&S modernization efforts (such as the Esri Utility Network migration, described below). • FieldSmart View is an end-of-life application, meaning the application no longer receives security updates or defect fixes from the software provider. The last S/W update from GE vendor was Oct 15 of 2015. No new enhancements or support for new operating systems are offered. This creates risk of service interruption and possible breakage for end users who rely on this application. It also creates additional workloads for NW Natural resources to maintain this application in its end-of-life state. • FieldSmart View cannot support data schema changes, reducing its ability to provide a complete look at NWN's assets. MapFrame backend processing uses an SDE service that reads the ESRI data but the service in not compatible with later versions of ESRI. • NWN's GIS data is migrating to a new data model (from Esri's Geometric Network (GN) to Esri's Utility Network (UN)). This migration is necessary because the tool NWN uses today for editing and analyzing GIS data (ArcMap) is near end of life, and the new tool we will migrate to (ArcGIS Pro) does not support our current data model (GN). ArcMap reaches end of life in 2028, meaning at that point Esri will not provide support, patching, or critical fixes. Therefore, by March 2028, NWN needs to transform our GIS data to the UN and switch to managing our GIS data in ArcGIS Pro. Because Fieldsmart View cannot support data schema changes, the application will not be able to display GIS data post-UN migration. Transitioning away from FieldSmart View is a dependency for the UN project.
Desired Deliverables What high level output / scope / deliverables are core to this project?	• Provide functionality equivalent or superior to FieldSmart View on a robust, fully supported platform. • Reduce the number of mapping applications necessary for the field to complete work. Enable most field users to have a single mobile device (iPad) to complete map-related work.

SECTION 2: ALTERNATIVES SUMMARY

OVERVIEW *How did we review these options?*	
Review Process Summarize how options were chosen, who was involved in the choice and how options were evaluated. If some criteria were considered more important based on the type of project, please explain here.	• IQGeo was selected by NWN in 2018 as the product to replace FieldSmart View, Visual Fusion, and ArcFM Viewer. NWN began the work to replace these applications with IQGeo solutions in 2019 with some use cases being transitioned from these applications to IQGeo, including a general map viewing application, survey and inspection functionality, and integration with the asset management system. The work to transition the remaining use cases was put on hold to accommodate a higher priority project, Horizon1. • The MapFrame Replacement project's goal is to replace remaining like-for-like functionality in FieldSmart View with functionality in IQGeo. • Analysis conducted by the project team and vendors (TGG and IQGeo) identified options, pros, cons, and potential risks and issues associated with this project.
DECISION CRITERIA *Provide like for like functionality in IQGeo that is available in FieldSmart View today.*	

Criteria: Alignment to NW Natural's IT Strategy	• Ability to leverage IQGeo for future needs, rather than a point-in-time (i.e. temporary) solution • Solution provides end users with a single mapping solution available on one device (either mobile or laptop/PC)
Criteria: Cost-Benefit Analysis	• Whether a solution should be built or bought • Level of customization needed to provide and maintain essential functionality
Criteria: Timing	• Provide mapping solution before end of life of ArcMap and mandatory migration to Esri's Utility Network
Criteria: Product Familiarity	• The mapping tool will be used throughout the organization by field users and back officer personnel, on iPads and on laptops or desktops. Training and adoption considerations should be evaluated for mapping solution selected, including ease of use, level of support needed, and amount of training required.

SECTION 3: ALTERNATIVES DETAIL

RECOMMENDED OPTION *Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option. If positive /neutral/negative observations do not exist, enter N/A*		
Description (Full scope of project)	Transfer key FieldSmart View functionality into IQGeo, including creation of map corrections, CIS integration to view customer information, location widget to display locational information, main design palette for designing work, a "lite" asset map viewer for contractors, ability for users to generate personal notes, and ability to print maps from mobile devices.	
In brief, why is this option recommended?	This option ensures business continuity and removes the risk of NWN critical operations running on an end-of-life platform. It allows NWN to expand platform functionality that will help technical growth in the future. This option aligns with NWN's geospatial strategy to work towards a single, consolidated field and web mapping application for end users and provide field users with a more streamlined method for their mapping needs. It also allows the Esri UN migration to continue uninterrupted.	
Assessment	**Analysis Against Criteria:** Alignment to NW Natural's IT Strategy	• The operational and security risk of running an unsupported application and infrastructure will be remediated. • This work is a prerequisite for a critical platform upgrade of our Esri GIS solutions. • IQGeo added functionality will be available to the field and back-office users and allow IT&S to replace field laptops with mobile devices since many field users' work could be completed on an iPad. • Replacing FieldSmart View with IQGeo will reduce the organization's risk profile by eliminating one of the old, depreciated mapping applications in the portfolio without adding to the number of supported applications. Providing FieldSmart View-like functionalities in IQGeo will allow the majority of field users a more streamlined method for their mapping needs within a single application.
	Analysis Against Criteria: Cost-Benefit Analysis	• Zero spend today would likely cause increased costs later in terms of emergent conditions leading to inability to report compliance or delay of future GIS projects. • This approach allows us to transfer one of NW Natural's mapping applications, meaning slightly lower licensing costs since this application will no longer be needed.
	Analysis Against Criteria: Timing	• Delay of future projects, namely the Esri UN Migration. Completing the UN migration is dependent on transitioning away from FieldSmart View. • All projects with a geospatial impact at NWN share critical resources, so planning and early execution tasks will compete for NWN and vendor resources.
	Criteria: Product Familiarity	• IQGeo is available to all NWN employees today. Even if a team was not part of the Horizon 1, IQGeo rollout, teams have been exploring and using IQGeo for the past year.

		• Field users are already familiar with IQGeo and perform some of their work there today (the iPad and Windows application). • Training will include some users that are new to IQGeo, but for users already using IQGeo, training will consist of new functionality, not core product use.
	Additional Risks	• Enabling NWN's desired functionality in IQGeo will require custom development, which IT&S prefers to avoid as it adds risk and complexity over the lifespan of the application.
	Additional Benefits	• The Esri UN Migration continue planning activities with the best information and earliest timeframe known. Once FieldSmart functionality has been transferred to IQGeo, The Esri UN Migration can advance to critical execute steps • Business continuity ensured for this application

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$3.4M - $3.6M	$342k - $364k	$3.8M - $4M
O&M Range	**Program/Project**		**Ongoing Maintenance & Support**
	$113k - $125k		$60k for 2024 2023-2025 Total = $266k
Source/ Method of Cost Data	Capital range was estimated using a 10% accuracy for Assess Phase. So, range shows 90% to 110% Costs were created using a planned resource sheet with utilization expectations and team member expertise and estimates on two vendor costs (I.e., IQGeo and TGG). • Hardware: 20k estimation • Software: ○ Fieldsmart (GE) - $60K/year (w. estimate of 3% annual increase) ○ No additional IQGeo licensing costs expected due to already existing enterprise license that covers all employees and contractors ○ 2024 Total = $89k ○ 2025 Total = $91k ○ 2023-2025 Total = $266k Capital range based on a previous IT&S consolidated view with multiple applications. Therefore, capital range above weights FieldSmart migration as 45% of overall capital range.		

ALTERNATIVE 1 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*		
Description	Do nothing and leave the current legacy applications in place.	
In brief, why is this option not recommended?	• NWN would continue to use multiple mapping applications on multiple devices. • FieldSmart View would continue to be at end of life and present significant risk. • Work on other projects, like the Esri UN Migration, would be significantly impacted, if not halted.	
Assessment	**Analysis Against Criteria:** Alignment to NW Natural's IT Strategy	• This alternative would not allow NWN to move away from an application that is end of life. FieldSmart View cannot support data schema changes, reducing its ability to provide a complete look at NWN's assets. • Continuing to use this application places a burden on the NWN IT&S Application and GIS teams to maintain. • The Esri UN Migration would keep the legacy applications as dependencies. Technical debt would be incurred to ensure Esri migration incorporates the applications. This technical debt would incur

		cost at the time of implementation as well as create complexity & additional cost when Esri UN Migration expands. It would limit future projects ability to tap into NWN budgets and resource utilization • Additional functionality would not be available in IQGeo for field users.
	Analysis Against Criteria: Cost-Benefit Analysis	• By not transitioning away from FieldSmart View, NWN would continue the maintenance spend today and will still need to replace this application in the future. The project costs will be pushed into the future, since ultimately a solution is needed to replace FieldSmart View. • Esri UN Migration costs would increase tech debt by requiring development of additional, complex integrations and workarounds to enable the legacy applications to consume UN data, if that is even possible.
	Analysis Against Criteria: Timing	• Delay of future GIS projects, namely the Esri UN Migration. • Introduce increased complexity to the Esri UN Migration project in order to retool integrations to UN data.
	Additional Risks	• NWN has only one or two resources that have experience in FieldSmart View configuration. This provides a potential point of failure for NWN. • There is not adequate redundancy across field and web mapping applications, so if additional functionality is not added to IQGeo and an issue causes FieldSmart View to be unavailable, the organization would risk being unable to perform certain tasks, such as reporting mapping errors via Plat Corrections.
	Additional Benefits	• Change management not needed.

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	NA	NA	NA
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$30k	$266k	
Source/ Method of Cost Data	• Hardware: 20k estimation (unknown currently) • Software: ○ Fieldsmart (GE) - $60K/year (w. estimate of 3% annual increase) ○ No additional IQGeo licensing costs expected due to already existing enterprise license that covers all employees and contractors ○ 2024 Total = $89k ○ 2025 Total = $91k 2023-2025 Total = $266k		

ALTERNATIVE 2 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*		
Description	Implement an alternative mapping solution, like Esri's ArcGIS Field Maps, to replace FieldSmart View. Field Maps is a mobile application for viewing data, data capture and editing, and locating assets and information.	
In brief, why is this option not recommended?	The Esri UN Migration project is dependent on moving away from FieldSmart View before NWN can migrate to the UN. Implementing a new mapping solution could take longer and be more expensive than continuing to develop IQGeo. A new application would require additional planning and significant change management and training for NWN employees. These efforts would impact Esri UN Migration timeline as well as introduce a new (fifth) mapping solution for end users further complicating their ability to complete work.	
Assessment	**Analysis Against Criteria:** Alignment to NW Natural's IT Strategy	• Field users would need to leverage two different mapping solutions (IQGeo and Field Maps) in the field which may increase confusion and increase training costs. • Would not be able to implement the Esri UN work before the FieldSmart View has been migrated

		• Technical/business overview and maintenance until Esri launch would need to support FieldSmart, an aging application, which would drain resource utilization. Any work done before the Esri UN launch would incur tech debt.
	Analysis Against Criteria: Cost-Benefit Analysis	• Increased licensing costs to enable Esri Field Maps for named users to access applications. • Increased costs later to maintain an additional field and web mapping application. • UN Migration costs would expand due to including an additional application to integrate. • Changes would require engaging with new external contractor support. This would add additional time and money to the project to get a new implementation vendor up to speed on NWN infrastructure and business.
	Analysis Against Criteria: Timing	• Delay of future GIS projects. • Potential delay of UN Migration. • Additional time spent to select application and vendor and to integrate and configure.
	Additional Risks	• Introduce another field mapping application, creating an additional application for IT&S to support and increased confusion and complexity for end users
	Additional Benefits	• Significant training and change management needed for end users

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$2.6M - $6.9M	$260k-$693k	$2.9M - $7.6M
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$86k - $230k	$89k for 2024 2023-2025 Total = $266k	
Source/ Method of Cost Data	Take the recommended costs and then increase by 20%. Reasoning includes the fact that this would be a new system, new integration paths Ongoing maintenance unchanged		

**Add rows for any additional alternatives considered not viable*

SUPPLEMENTARY INFORMATION

As needed, you may include any useful information gathered during the assessment phase including analysis like cost benefit / risk analysis / sensitivity analysis, etc.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Brian E. Fellon

INFORMATION TECHNOLOGY & SERVICES

Exh. BEF-7

August 29, 2025

NW Natural
PROJECT ALTERNATIVES NARRATIVE

Program/Project Name: Clevest Optimization & Stabilization
Date: 11/16/2023
Project Sponsor: Dina Thompson / Jaime Ulestad / Dan Kizer/Cari Colton/Jim Hart
Executive Sponsor: Jim Downing / Joe Karney / Dave Weber
Project Manager: Graham Hulbert
Preparer: Jennifer Chiaratti
Was this project part of IRP: No

SECTION 1: BUSINESS CASE

This section should be solution-agnostic, and about the overarching problem we're trying to solve no matter which route we end up taking.

OBJECTIVES *Why are we tackling this project?*	
Current State What is happening now? Where are we starting?	Clevest is the new mobile workforce management software used by NWN to schedule, dispatch, and complete all work in the field (from emergency and compliance to routine). This platform is also used to support plant and fleet maintenance and compliance work. Clevest was deployed and became NWN's mobile workforce management tool in 2022. Following deployment of Clevest and as the product was being used, NWN identified certain issues with the product's performance requiring additional follow-up work and refinement. Based on a prior Alternatives Analysis, NWN concluded that essential product stabilization efforts were required, and that further analysis was necessary to determine whether and how to pursue further platform optimizations. As a result, NWN determined to: • Develop a clear road map of possible improvements to further optimize the Clevest product. • Develop a prioritized list of recommendations and a plan to standardize, simplify, and optimize work order related screens and workflows in NWN mobile work management system to improve field efficiency and effectiveness. NWN has recently completed an additional step in this analysis and must now decide whether, and to what extent, to pursue the prioritized list of recommendations.
Problem Statement In simple terms, what are we trying to solve? What is the business need this is tackling? Why is this a problem worth solving (e.g. why is the current state not working)?	Prior to Clevest's deployment, some features were initially deprioritized but, following deployment and in the course of product use, were found to be critical. In the absence of these refinements and additional functionalities, NWN has been relying on inefficient workarounds that need to be ameliorated.
Desired Deliverables What high level output / scope / deliverables are core to this project?	Ensure that NWN's work management software interface can properly manage demands on employee time and ensure clear and user-friendly functionality, while meeting all relevant business and performance needs.

SECTION 2: ALTERNATIVES SUMMARY

OVERVIEW *How did we review these options?*	
Review Process Summarize how options were chosen, who was involved in the choice and how options were evaluated.	• Conducted analysis with the project team and external vendors to identify options, pros, cons, and potential risks and issues. Team included: NW Natural field users, Enterprise Asset Management team (EAM), Information Technology and Services team (IT&S), and software vendor IFS, which owns the Clevest Platform

If some criteria were considered more important based on the type of project, please explain here.	• Project team and Project Sponsors agreed to a recommendation on implementation approach • Reviewed with Executive Sponsors to gain approval to move forward with recommendation • Reviewed with IT&S Alignment Team
DECISION CRITERIA *Describe the criteria used to determine the selection from the various alternatives considered. For example, is this a program/project where the least cost option should be selected? Are there other factors, such as safety or quality that come into play? Include both quantitative and qualitative factors as appropriate.*	
Criteria: Alignment to NW Natural's IT Strategy	Ability to leverage this for future needs rather than a point solution.
Criteria: Cost-Benefit Analysis	Near-term and long-term costs compared to functional benefits for system users.
Criteria: Timing	Ability to complete the project in time to meet a regulatory, business, product lifecycle, or safety requirement.

SECTION 3: ALTERNATIVES DETAIL

RECOMMENDED OPTION: Partial Optimization + High Priority Items *Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option. If positive /neutral/negative observations do not exist, enter N/A*	
Description	During the review process, identified areas of improvement were compartmentalized based on degrees of urgency, into distinct buckets: (1) mission-critical, (2) high priority, (3) medium/low priority. Mission-critical items address functionalities that drive essential aspects of NW Natural's successful provision of service to our customers, and the lack of which may drive negative financial consequences, increased operational or safety risk, or significant customer dissatisfaction. For example, one functional improvement in the "mission-critical" scope addresses "Future Date Assignments," which allows the system to effectively assign fieldwork out into the future. Currently, the Clevest system's functionality for future date assignments works inconsistently, meaning that, each morning, work assignments need to be manually reviewed to ensure that pre-work has been correctly assigned. By optimizing this functionality, we can ensure proper distribution of work among our field resources and better guarantee that we can make our scheduling commitments with our customers. As an additional example, there is no way to alert a scheduler or a fieldworker that there are multiple work requests at the same premise/location. This results in multiple visits from field techs and unsatisfied and confused customers. Thus, optimizing the workforce management software to allow for visibility into all fieldwork by location will enable better allocation of staff time and increase customer satisfaction. High priority items maximize functional impacts of the software and the overall utility of the investment. A simple example of a high priority item is to enable direct dialing functionality to a field resource assigned to a work order when monitoring work from the resource center. While individual phone numbers are visible in Clevest, they are not directly actionable and cannot be copied. A simple improvement would present the number as a hyperlink and allow a supporting back-office resource to trigger an outbound call with a simple click. The ability to quickly contact field crews enables safer operations and higher customer satisfaction. For field workers, most high priority items represent changes required to ensure that they have visibility to all information needed to perform work effectively and safely as well as the means to efficiently close out work. As an example, construction workers today are presented with a very long dropdown list in which they must choose the pipe size representative of what they have put into the ground. This list is not presented in any logical order which requires inefficient scrolling to select the applicable value. The high priority item that would remediate this inefficiency would be to simply present the pipe size in a logical order and allow supplemental type-ahead type of functionality to quickly bubble up the desired value. This is a low investment change that

	in aggregate will result in more accurate records and allow construction crews to spend more time serving our customers and less time inefficiently interacting with a form. The Partial Optimization + High Priority items option addresses both above buckets of mission-critical and high-priority items but does not include medium/low-priority items.	
In brief, why is this the recommended option?	This option allows NWN to not only remove the majority of significant workarounds in place due to system constraints, but also to optimize Clevest's performance, and thus to improve field efficiency by simplifying and standardizing completion of work steps in the system across various work order types. By expeditiously optimizing the Clevest software, the Company can ensure that the tool continues to provide the best value for the Company and its customers.	
Assessment	**Analysis Against Criteria:** Alignment to NW Natural's IT Strategy	• By resolving technical issues with the in-use program, this approach reduces technical debt. • By executing a long-term plan for Clevest optimizations, the Company can clearly and deliberately plan for optimal efficiency rather than having to fix additional technical inefficiencies in a reactive manner in the future.
	Analysis Against Criteria: Cost Benefit Analysis	• A cohesive approach to address these constraints holistically is more cost effective and will result in better adoption than addressing each constraint individually. • Executing a prioritized plan for optimization ensures the cost-effective allocation of resources for maximum user benefit.
	Analysis Against Criteria: Timeline	• Targeting high-priority fixes and key functionalities for mission-critical items enables rapid improvements to product performance, while allowing for successful and efficient implementation of the high priority optimizations. • Limiting scope to high-priority items allows immediate implementation of key features, while also allowing team to reevaluate possible additional features after future Clevest product upgrades are implemented.
	Additional Risks	• Implementing optimizations/enhancements may identify interactions with previously pursued fixes, which would then need to be reconciled.
	Additional Benefits	• Significantly improves user experience. • Stabilizes the performance of the Clevest product. • Ensures that the platform will maintain functionality through future architecture enhancements.

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$6.5M - $7.5M (Stabilization + Optimization)	$650k - $750k (Stabilization + Optimization)	$7.15M - $8.25M (Stabilization + Optimization)
O&M Range	**Program/Project**		**Ongoing Maintenance & Support**
	$300k - $310k (Stabilization + Optimization)		N/A
Source/ Method of Cost Data	Internal and external estimates of project costs.		

<table>
<tr><th colspan="4">ALTERNATIVE 1: Nothing above Stabilization
Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.</th></tr>
<tr><td>Description</td><td colspan="3">Address base functionality issues.
Design, build, test, and deploy solutions to address mission-critical issues in product performance identified during final stage of initial product deployment and following implementation. Accept, and complete the current stabilization work efforts and go no further with the proposed optimizations.
Take up Clevest software upgrades as recommended by product vendor to address software related issues.
Develop and deliver training required for any changes to processes.</td></tr>
<tr><td>In brief, why is this option not recommended?</td><td colspan="3">Stabilization alone will not result in optimal use of the platform, does not address substantial with the current platform’s functionality, and will actually be more expensive because the lack of these optimizations creates further stability problems – driving up the costs of stabilizing the platform.
This option will not allow for a full assessment of further improvements to optimize Clevest performance.
It does not position the platform for future growth with expanding/changing system architecture.</td></tr>
<tr><td rowspan="5">Assessment</td><td>Analysis Against Criteria: Alignment to NW Natural’s IT Strategy</td><td colspan="2">Failing to implement needed improvements increases technical debt.
Responding reactively to critical concerns while declining to proactively plan for optimal performance does not align with NWN’s IT strategy.</td></tr>
<tr><td>Analysis Against Criteria: Cost Benefit Analysis</td><td colspan="2">Foregoing executing a road map to maximize Clevest’s efficacy and efficiency is actually more costly because issues that are not addressed in the optimization efforts would create stability issues requiring increased work in the stabilization phase of the project.
Enables continued essential use of the platform, but without allowing for thoughtful long-term planning.</td></tr>
<tr><td>Analysis Against Criteria: Timeline</td><td colspan="2">Delays full implementation of process optimization to realize more efficiencies.</td></tr>
<tr><td>Additional Risks</td><td colspan="2">End user experience impacted by continuing to tweak or adjust existing processes that are not efficient.
Process complexities may still exist with workarounds.</td></tr>
<tr><td>Additional Benefits</td><td colspan="2">None</td></tr>
<tr><td colspan="4">POTENTIAL COST (EXCLUDING CONTINGENCY)</td></tr>
<tr><td rowspan="2">Capital Range</td><td>Direct</td><td>CURRENT COH</td><td>Total</td></tr>
<tr><td>$4.0M - $5.0M
(Stabilization)</td><td>$400k - $500k
(Stabilization)</td><td>$4.4M - $5.5M
(Stabilization)</td></tr>
<tr><td rowspan="2">O&M Range</td><td colspan="2">Program/Project</td><td>Ongoing Maintenance & Support</td></tr>
<tr><td colspan="2">$30k - $40k
(Stabilization)</td><td>N/A</td></tr>
<tr><td>Source/ Method of Cost Data</td><td colspan="3">Internal and external estimates of project costs.</td></tr>
</table>

ALTERNATIVE 2: Partial Optimization *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*		
Description	• Develop mission critical optimizations to address most essential user deficiencies. • Deliver "mission-critical" optimization items, described above, but not the "high priority" items. • Develop and deliver training required for any changes to processes.	
In brief, why is this option not recommended?	• Partial optimization will not address important issues identified by system users, while costing roughly the same amount as full optimization. • It does not position the platform for future evolution with expanding/changing system architecture. • The incremental costs of including high priority items in the project are marginal compared to this partially optimized solution. This would not be an efficient way to invest in the platform.	
Assessment	**Analysis Against Criteria:** Alignment to NW Natural's IT Strategy	• Failing to implement needed improvements increases technical debt. • Will result in responding reactively to unaddressed concerns while declining to proactively plan for optimal performance. This does not align with NWN's IT strategy.
	Analysis Against Criteria: Cost Benefit Analysis	• Foregoing executing a full road map to maximize Clevest's efficacy and efficiency is slightly less costly in the short term but ignores possible significant functionality improvements that also leverage the existing Clevest investment. • Enables continued essential use of the platform, but without allowing for thoughtful long-term planning.
	Analysis Against Criteria: Timeline	• Delays full implementation of process optimization to realize more effective use of employee time.
	Additional Risks	• End user experience impacted by continuing to tweak or adjust existing processes that are not efficient. • Process complexities may still exist with workarounds.
	Additional Benefits	None

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$6.0M - $7.0M (Stabilization + Optimization)	$600k - $700k (Stabilization + Optimization)	$6.6M - $7.4M (Stabilization + Optimization)
O&M Range	**Program/Project**		**Ongoing Maintenance & Support**
	$300k - $310k (Stabilization + Optimization)		N/A
Source/ Method of Cost Data	Internal and external estimates of project costs.		

ALTERNATIVE 3: Full Optimization *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*		
Description	• Develop and deliver full optimization to address all user deficiencies, including mission-critical, high-priority, and medium/low priority. • Develop and deliver training required for any changes to processes.	
In brief, why is this option not recommended?	• Options identified were dependent on service pack (i.e., minor product upgrades) and/or major upgrades that would create a longer delay, additional technology support, and further training to be developed and delivered. • Limits the ability to continue the progress of other enhancements and defect resolutions when a service pack and/or upgrade is in process.	
Assessment	**Analysis Against Criteria:** Alignment to NW Natural's IT Strategy	• By resolving technical issues with the in-use program, this approach would reduce technical debt. • Medium/low-priority items require additional upgrades to Clevest software in order to enable implementation; these upgrades are not yet available.
	Analysis Against Criteria: Cost Benefit Analysis	• Highest cost of all alternatives
	Analysis Against Criteria: Timeline	• Extended timeline to deliver the improvements to product performance • Dependent on vendor product improvements for when their product upgrades will be released
	Additional Risks	• Implementing optimizations/enhancements may identify interactions with previously pursued fixes, which would then need to be reconciled. • Introduces upgrade-related risk for known mission-critical and high-priority fixes
	Additional Benefits	• Significantly improves user experience. • Stabilizes the performance of the Clevest product. Ensures that the platform will maintain functionality through future architecture enhancements.

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$7.5M - $8.5M (Stabilization + Optimization)	$750k - $850k (Stabilization + Optimization)	$8.25M - $9.35M (Stabilization + Optimization)
O&M Range	**Program/Project**		**Ongoing Maintenance & Support**
	$300k - $320k (Stabilization + Optimization)		N/A
Source/ Method of Cost Data	Internal and external estimates of project costs.		

ALTERNATIVES CONSIDERED NOT VIABLE *Provide a description of any additional alternatives that were considered but rejected up front as not viable, and explain why*		
	Description	**Why the Alternative is not viable**
Alternative 3	Do Nothing	As deployed, the new Clevest work management system encountered significant challenges for users, necessitating multiple manual workarounds and other unacceptable inefficiencies. Based on user feedback, failing to perform basic product stabilization work is not viable.
Alternative 4	Implement an alternative mobile workforce management system and vendor to replace Clevest.	• Implementing a fully new alternative is not cost effective as any new product would require the full design, development, and deployment process that Clevest required. • Implementing a new product option would take multiple years to complete, while stabilization of the current product remains necessary. • Current offerings on the market for systems that support these functions are limited, and any such alternative solution could face similar constraints. • As designed, Clevest remains a useable and useful product and retains the potential to substantially improve user experience over the previous P-CAD tool.
Alternative 5	Revert to P-CAD tool.	Reverting to the previous P-CAD tool is not possible as that tool was already end-of-life when NWN transitioned to Clevest. While P-CAD offers a new workforce management system, this would entail the same issues as Alternative 4.

**Add rows for any additional alternatives considered not viable*

SUPPLEMENTARY INFORMATION

As needed, you may include any useful information gathered during the assessment phase including analysis like cost benefit / risk analysis / sensitivity analysis, etc.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Brian E. Fellon

INFORMATION TECHNOLOGY & SERVICES

Exh. BEF-8C

REDACTED VERSION

August 29, 2025

NW Natural
PROJECT ALTERNATIVES NARRATIVE

Program/Project Name: Identity Governance and Administration
Date:
Project Sponsor: Matthew Carlson
Executive Sponsor: Jim Downing
Project Manager: Keaton Beyer
Preparer:
Was this project part of IRP: No

SECTION 1: BUSINESS CASE

This section should be solution-agnostic, and about the overarching problem we're trying to solve no matter which route we end up taking

OBJECTIVES *Why are we tackling this project?*	
Current State What is happening now? Where are we starting?	Northwest Natural (NWN) does not have an Identity Governance Administration (IGA) tool. Currently, employee access is controlled in various systems with manual processes and no centralized control point.
Problem Statement In simple terms, what are we trying to solve? What is the business need this is tackling? Why is this a problem worth solving (e.g. why is the current state not working)?	When an employee or contractor is offboarded from NWN, there is no way to certify their access has been completely removed from all systems because there is no centralized controller. The Sarbanes-Oxley Act (SOX) requires consistent, reliable removal of access permissions for offboarded employees as part of ensuring that unauthorized individuals cannot access sensitive financial information. Unfortunately, even with efforts to optimize and enhance NWN's manual processes, this manual method has been unable to sustain consistent compliance due to the scale and complexity of NWN's systems. As a result, NWN needs to implement an automated identity and access management tool and associated processes to control onboarding and offboarding.
Desired Deliverables What high level output / scope / deliverables are core to this project?	Installation of an IGA tool along with associated processes and integration with core systems.

SECTION 2: ALTERNATIVES SUMMARY

OVERVIEW *How did we review these options?*	
Review Process Summarize how options were chosen, who was involved in the choice and how options were evaluated. If some criteria were considered more important based on the type of project, please explain here.	NWN hired Integral Partners, a company specializing in identity solution architecture and installation, who worked with NWN to gather requirements for an IGA tool, and then used these requirements to score potential IGA tools based on best fit for NWN. The main functional categories on which tools were evaluated are: • User Provisioning • Role-based Access Control (RBAC) • Access Request and Approval • Access Certification • Identity Analytics • Password Management • Segregation of Duties (SoD) • Reporting and Audit Trail • Compliance Management • Third-party Integrations with Leading Toolsets • Workflow Automation

	These are industry standard functions of an IGA tool which were scored based on the tools ability to meet NWN's 160 prioritized requirements and 26 use cases. This analysis yielded three strong contenders, which were then evaluated based on relative cost. The project team then evaluated the analysis and recommended the tool which best fit NWN's needs.
DECISION CRITERIA *Describe the criteria used to determine the selection from the various alternatives considered. For example, is this a program/project where the least cost option should be selected? Are there other factors, such as safety or quality that come into play? Include both quantitative and qualitative factors as appropriate.*	
Criteria: Alignment to NW Natural's IT Strategy	Comprehensive features and functionality paired with scalability, flexibility, user-friendly interface, integration capabilities, security and compliance, and vendor support.
Criteria: Cost-Benefit Analysis	Should a solution be built or bought and which bought solution is the most cost effective while still achieving the project's goal.
Criteria: Timing	Ability to complete a project in time to meet a regulatory, business, product lifecycle, or safety requirement.

SECTION 3: ALTERNATIVES DETAIL

RECOMMENDED OPTION *Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option. If positive /neutral/negative observations do not exist, enter N/A*		
Description	SailPoint IdentityNow (IDN)	
In brief, why is this the recommended option?	**SailPoint IdentityNow** best aligns with Northwest Natural's needs for a comprehensive, scalable, user-friendly, and secure IGA solution. SailPoint IdentityNow offers a robust feature set, scalability, usability, integration capabilities, security, and cost-effectiveness. This tool also has a strong vendor reputation and industry recognition, as supported by evidence from vendor documentation, case studies, and references.	
Assessment	**Analysis Against Criteria:** Alignment to NW Natural's IT Strategy	SailPoint IdentityNow is an easy to maintain system due to its configurability and user friendliness. It is a Solution as a Service (SaaS) meaning it is cloud hosted with yearly licenses rather than a bought solution, which is consistent with NWN's broader move towards implementing cloud-based, hosted tools.
	Analysis Against Criteria: Cost Benefit Analysis	SailPoint is the industry leader and one of the strongest offerings in this space. While SailPoint's subscription costs are somewhat higher than the other options considered, it presents the least-cost long-term solution because it requires less in-house customization and has demonstrated integration with other major tools, thus requiring less implementation cost and less ongoing maintenance.
	Analysis Against Criteria: Timeline	SailPoint IDN is highly configurable, meaning it does not require much custom coding to implement. This makes it one of the fastest tools to implement, though some change processes to replace existing manual processes and accommodate the tool will be required.
	Additional Risks	SailPoint IDN will require NWN to change their processes which means this project will have to consider the people change aspect of the implementation.
	Additional Benefits	• Comprehensive Features and Functionality: ○ **Rationale**: SailPoint IdentityNow presents a robust suite of Identity Governance and Administration (IGA) functionalities, catering to the specific needs of energy companies. This includes comprehensive identity lifecycle management, streamlined access request and certification processes, efficient role management, and advanced analytics. These features are strategically aligned with Northwest

		Natural's objective of fortifying identity governance within the energy sector, where security and regulatory compliance are paramount. ○ **Evidence**: Extensive review of vendor documentation and live product demonstrations demonstrate the tool's extensive array of capabilities. These features are well-suited to address the intricate identity management requirements of Northwest Natural, ensuring a seamless and secure user access experience while facilitating compliance with regulations and security standards. • <u>Scalability and Flexibility:</u> ○ **Rationale**: SailPoint IdentityNow offers flexibility to meet the needs of a large energy company and adapt to evolving needs, without compromising on the security-related benchmarks and requirements needed to ensure appropriate identity and governance protections. ○ **Evidence**: Examining case studies and seeking references from companies with similar needs that have successfully implemented SailPoint IdentityNow at scale provides concrete evidence of its capacity to adapt and expand, making it a well-suited solution for Northwest Natural's evolving and diverse user landscape. • <u>User-Friendly Interface:</u> ○ **Rationale**: Usability is a key factor, especially where administrators and managers interact with the system. An intuitive and user-friendly interface can streamline operations, reducing time spent on administration. ○ **Evidence**: User feedback or usability studies conducted by the vendor have provided evidence of "SailPoint IdentityNow's" user-friendliness. • <u>Integration Capabilities:</u> ○ **Rationale:** Seamless integration with existing systems and applications is essential for efficient identity management. SailPoint IdentityNow offers connectors and APIs that facilitate integration with various platforms, including HR systems, Active Directory, and cloud applications. ○ **Evidence:** Vendor-provided documentation on the availability and ease of use of integration connectors and APIs demonstrate its integration capabilities. • <u>Security and Compliance:</u> ○ **Rationale**: Security and compliance take precedence within the energy sector due to its critical infrastructure and regulatory framework. For Northwest Natural, safeguarding identity data is of utmost importance because identities have become a key target for nation states and criminals. SailPoint IdentityNow is adept at fortifying security, providing stringent controls, comprehensive audit trails, and robust compliance reporting mechanisms. These features are tailor-made to protect sensitive identity information and to ensure that Northwest Natural remains fully compliant with applicable regulations. ○ **Evidence**: The credibility of SailPoint IdentityNow in meeting the security and compliance needs of energy companies is substantiated through vendor whitepapers, detailed security documentation, and a host of recognized compliance certifications such as SOC 2 and ISO 27001. These certifications and documents underscore the tool's ability to uphold security and regulatory requirements. • <u>Vendor Reputation and Support:</u>

		○ **Rationale**: The reputation of the vendor and the quality of their support services are critical factors in ensuring a successful implementation and long-term partnership. ○ **Evidence**: References and testimonials from other organizations that have had positive experiences with SailPoint IdentityNow and its vendor can attest to its reliability and support quality. • <u>Industry Recognition:</u> ○ **Rationale**: Recognition and awards within the IAM industry can indicate the excellence of a particular IGA toolset. Awards and acknowledgments from reputable organizations or analysts can provide validation of its capabilities. ○ **Evidence**: Reports and assessments from industry analysts like Gartner, Forrester, or KuppingerCole recognize SailPoint IdentityNow as a leader in the IGA market.

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$3,100,000 - $3,400,000	$310,000 - $340,000	$3,100,000- $3,400,000
O&M Range	**Program/Project**		**Ongoing Maintenance & Support**
	$250,000 - $275,000		$250,000 - $315,000
Source/ Method of Cost Data	Integral Partners. Sailpoint IDN licenses are $250,000 per year with the installation cost being the base, $400,000 for their work and the remaining $2,450,000 for internal labor. We can capitalize the first year of licenses as part of the total capital range. Ongoing maintenance and support figures are for licenses only. The system support will be done by existing FTE and therefore is not incremental.		

ALTERNATIVE 1 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*		
Description	SailPoint IdentityIQ (IIQ)	
In brief, why is this option not recommended?	SailPoint IIQ is SailPoint's on-premises IGA tool. It is highly customizable meaning it will accommodate NWN's processes. However, the extent of this tool's flexibility is the reason why it is not recommended. Highly custom systems take more time, money, and expertise to maintain, which increase the likelihood for bugs and downtime. Additionally, an overly customized system will allow automation of inefficient or relatively insecure processes, perpetuating existing problems rather than fixing the root cause.	
Assessment	**Analysis Against Criteria:** Alignment to NW Natural's IT Strategy	SailPoint is not investing as heavily into IIQ as they attempt to transition their customers to IDN, their SaaS cloud offering. This means it is lacking the robust features and functions of IDN which are required by NWN, causing IIQ to score lower in the analysis.
	Analysis Against Criteria: Cost Benefit Analysis	Similar up-front cost to the cloud offering recommended option, but with higher implementation and support costs including additional charges for upgrades estimated at $10,000 per custom module per upgrade.
	Analysis Against Criteria: Timeline	Increased customization means a longer implementation schedule.
	Additional Risks	
	Additional Benefits	

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$3,615,000 – $3,960,000	$361,500 - $396,000	$3,615,000 – $3,960,000
O&M Range	**Program/Project**		**Ongoing Maintenance & Support**
	$315,000 - $345,000		$325,000 - $410,000
Source/ Method of Cost Data	Integral Partners. SailPoint IIQ licenses are $300,000 per year plus 25% higher in effort than SailPoint IdentityNow to maintain per year due to maintaining customized processes and on prem upgrades.		

	Ongoing Maintenance and Support includes licenses and estimated yearly upgrade costs for on-premises software.

ALTERNATIVE 2 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*		
Description	[redacted]	
In brief, why is this option not recommended?	[redacted] is an alternate software vendor that provides a similar tool, but with fewer established connections and integrations with third-party applications, which NWN will need to implement the tool in the broader IT&S environment. Ultimately, these shortcomings would make [redacted] more expensive to implement and maintain.	
Assessment	**Analysis Against Criteria:** Alignment to NW Natural's IT Strategy	[redacted] is in the top three recommended tools for NWN. It could work well for NWN but the issue is supportability and ease of maintenance which will result in higher near-term implementation and higher long-term upkeep costs.
	Analysis Against Criteria: Cost Benefit Analysis	[redacted] is customizable, but with customization comes maintenance cost. The tool will be harder to maintain requiring a larger team and higher operating expense.
	Analysis Against Criteria: Timeline	The implementation timeline for [redacted] is expected to be 20% longer due to higher customization required.
	Additional Risks	
	Additional Benefits	[redacted] does have all the necessary capabilities and is highly customizable which are two of its main benefits.

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$3,800,000 - $4,175,000	$380,000 - $417,500	$3,800,000 - $4,175,000
O&M Range	**Program/Project**		**Ongoing Maintenance & Support**
	$315,000 - $345,000		$250,000 - $315,000
Source/ Method of Cost Data	Integral Partners. [redacted] licenses are $225,000 per year plus 15% higher in effort than SailPoint IdentityNow to maintain per year due to customized processes. Ongoing Maintenance and Support includes licenses and estimated yearly upgrade costs for on-premises software.		

**Copy/Add table for any additional alternatives*

ALTERNATIVES CONSIDERED NOT VIABLE *Provide a description of any additional alternatives that were considered but rejected up front as not viable, and explain why*		
	Description	**Why the Alternative is not viable**
Alternative 3	**One Identity**	Minimally met criteria and would require higher effort to implement and maintain with tool costs being similar to other options.
Alternative 4	**Omada**	Difficult maintainability and scalability. Omada has a low USA presence and is mainly in the EU posing potential support issues.
Alternative 5	**Microsoft**	Missing access certifications and Segregation of duties capabilities.
Alternative 6	**Do Nothing**	Does not meet the basis for the project to remediate SOX compliance issues or security needs.

**Add rows for any additional alternatives considered not viable*

SUPPLEMENTARY INFORMATION

As needed, you may include any useful information gathered during the assessment phase including analysis like cost benefit / risk analysis / sensitivity analysis, etc.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Brian E. Fellon

INFORMATION TECHNOLOGY & SERVICES

Exh. BEF-9

August 29, 2025

NW Natural
PROJECT ALTERNATIVES NARRATIVE

Program/Project Name: Web Portals: Start, Stop, Transfer
Date: 10.30.2023
Project Sponsor: Cory Beck
Executive Sponsor: Kim Rush
Project Manager: Carolyn Jane Campbell
Preparer: Carolyn Jane Campbell
Was this project part of IRP: No

SECTION 1: BUSINESS CASE

This section should be solution-agnostic, and about the overarching problem we're trying to solve no matter which route we end up taking.

OBJECTIVES *Why are we tackling this project?*	
Current State What is happening now? Where are we starting?	The Customer Lifecycle Management (CLM) Team has initiated the Web Portals Start, Stop, Transfer project to improve the start, stop, and transfer service functionality on the current NW Natural website for residential customers. • All residential customers start or stop service during their relationship with NW Natural. • Start, stop, and transfer service requests are among the top reasons for inbound calls to the Customer Contact Center (CCC) and was the top reason for calls to the CCC in 2022. Higher call volume can, in turn, lead to long wait times. • In 2022, approximately 140,000 customers attempted to use start, stop, or transfer service forms online. Only 28% of those forms were completed, leaving approximately 100,000 customers that did not complete the online form. • Over 7,000 customers renting properties were unable to use start service forms online due to their landlord's agreement with NW Natural. These agreements are not visible to tenants and limits their ability to self-serve through the website.
Problem Statement In simple terms, what are we trying to solve? What is the business need this is tackling? Why is this a problem worth solving (e.g., why is the current state not working)?	The CLM Team has identified issues with the existing start, stop, and transfer service functionality that have contributed to customer dissatisfaction and inability to complete these processes online: • Customers do not receive their account number, or status of their request through the website portal, and therefore, are unable to immediately access their account details via self-service portals upon completing their start service request. • Customers are calling the CCC to receive assistance with their service due to a lack of available account information online. • Customers are unable to successfully start, or transfer their gas service and/or account online at their convenience because of inadequate features on the current NW Natural website. • Customers often find themselves in the wrong online form because the current website lacks explicit instructions, clear indicators of required form fields, and what required information is used for.
Desired Deliverables What high level output / scope / deliverables are core to this project?	The ability to support the customer journey through start, stop, and transfer service on the NW Natural website and updated integration with Customer Information System (CIS). These are the highest priority web portals improvements due to the high volume of customers that utilize this service monthly.

SECTION 2: ALTERNATIVES SUMMARY

OVERVIEW *How did we review these options?*	
Review Process Summarize how options were chosen, who was involved in the choice and how options were evaluated. If some criteria were considered more important based on the type of project, please explain here.	Project criteria were reviewed based on providing the greatest benefit to residential customers wanting to self-serve online through the NWN website. Through direct customer surveys and interviews the team gathered customer data and insights to understand why customers do not use the self-service portal to the current interface's full extent. Simultaneously, NW Natural Customer Service Agents of varying tenure were interviewed. These interviews identified the most impactful features that would improve the existing online start, stop, and transfer user experience.
DECISION CRITERIA *Describe the criteria used to determine the selection from the various alternatives considered. For example, is this a program/project where the least cost option should be selected? Are there other factors, such as safety or quality that come into play? Include both quantitative and qualitative factors as appropriate.*	
Criteria: Customer Experience	The quality of the customer experience is the leading criterion used to identify the recommended option. The recommended option must include updates to existing processes and functionality, aimed at improving the customer experience both online and when contacting the CCC.
Criteria: New Features	New features must be associated with existing Start, Stop, and Transfer forms on the NW Natural website. New features must allow customers to reduce their need to call the CCC and self-serve through the online portal.
Criteria: Feasibility	The likelihood of this project being accomplished within a project timeline, maintains project scope, and accounts for the constraint on NW Natural resources. Since this project will rely heavily on CIS resources, the feasibility of this project must account for the availability of these resources.

SECTION 3: ALTERNATIVES DETAIL

<table>
<tr><th colspan="4">RECOMMENDED OPTION
Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option. If positive /neutral/negative observations do not exist, enter N/A</th></tr>
<tr><td>Description</td><td colspan="3">Implement Start, Stop, Transfer website functionality, with partial CIS integration, including:

• Develop, implement, and test a new user-friendly web-based service management tool, including simplified road map, easy navigation, evident indicators of required form fields using accessible color coding, and text changes for to create clarity around required information.
• Digitally match customers to their current account and provide existing customer account validation and immediately provide customers with their account number start service requests.
• Modernize the address entry field to be a single line with assisted entry to reduce customer input errors.
• Upgrade the landing page with FAQs and new features to help customers determine what form to complete.
• Incorporate increased accessibility for additional information “Question Mark” features to add understanding to specific form field and the reason why they are required.
• Reduce limitations for access to self-service features, including removing the limitation for residential customers renting properties.</td></tr>
<tr><td>In brief, why is this the recommended option?</td><td colspan="3">Executing on the desired deliverables will provide customers with their account information immediately upon their start service request, expedite customer’s service orders, and reduce customer’s need to call the CCC for assistance on their start, stop, or transfer service request.

In addition, the recommended option includes essential integration with CIS providing internal system process upgrades to better manage eligible start, stop, and transfer service requests.

With better self-service options and focusing on direct customer requests, the recommended option will streamline processes that impact all residential customers in a meaningful way.</td></tr>
<tr><td rowspan="5">Assessment</td><td>Analysis Against Criteria: Customer Experience</td><td colspan="2">Incorporating additional functionality on the NW Natural website enhances how customers can proactively use self-service options to complete start, stop, and transfer service tasks via the online portal. When customers can self-serve, they are able to complete tasks at a time that is most convenient for them (e.g., in the evening when the CCC may not be available) and lessens their need to call the CCC for assistance. Fewer calls to the CCC reduces customer wait times when engaging with Customer Service Representants (CSR) and increases customer satisfaction with NW Natural.</td></tr>
<tr><td>Analysis Against Criteria: New Features</td><td colspan="2">The proposed functionality will reduce customer frustration by providing an intuitive and improved process online so customers can complete start, stop, or transfer service.</td></tr>
<tr><td>Analysis Against Criteria: Feasibility</td><td colspan="2">By targeting this project on the specific need to enable start-stop-transfer service online, NW Natural will have the resources necessary to support this project.</td></tr>
<tr><td>Additional Risks</td><td colspan="2">• Due to resource constraints on IT&S staff, there is some risk that this project may encounter delays due to competing project resource needs. While the outside vendor will perform the core development work, in-house staff are required for effective testing and integration.</td></tr>
<tr><td>Additional Benefits</td><td colspan="2">• Fewer calls into the CCC related to start, stop, or transfer of services increases the availability of CSRs to support customers calling with other service requests.
• Customer experience enhancements include low-effort high-impact updates for start, stop, transfer via self-service process already being heavily utilized.</td></tr>
<tr><td colspan="4">POTENTIAL COST (EXCLUDING CONTINGENCY)</td></tr>
<tr><td rowspan="2">Capital Range</td><td>Direct</td><td>CURRENT COH</td><td>Total</td></tr>
<tr><td>$1,593,750 - $2,987,500</td><td>10%</td><td>$1,753,125 – 3,306,250</td></tr>
</table>

O&M Range	Program/Project	Ongoing Maintenance & Support
	$38,135 - $76,240	$37,350 – 75,000
Source/ Method of Cost Data	Project scope was translated to a project schedule with estimates for Labor and Services costs. Labor was allocated based on estimated utilization % multiplied by the labor rate. Services were estimated based on anticipated work to be done and estimates provided by potential vendors. The total cost range for the project currently follows the PMO cone of uncertainty range for the current phase the project is in (-25% to +50%).	

ALTERNATIVE 1 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*		
Description	Full automation of the Start, Stop, and Transfer Service forms within the CIS. This alternative requires development to occur within CIS (not the website) which requires further and more complex development to CIS, including upgrades to CIS functionality.	
In brief, why is this option not recommended?	This alternative would result in higher costs, longer project timeline, and prioritizes NW Natural operational benefits over customer value add.	
Assessment	**Analysis Against Criteria: Customer Experience**	Automation of the Start, Stop, and Transfer Service forms within the CIS would not prioritize the customer's online self-service experience.
	Analysis Against Criteria: New Features	The features associated with full CIS automation would prioritize internal improvements over the customer experience. Negating this option because it does not fulfill the leading decision criteria.
	Analysis Against Criteria: Feasibility	This alternative would require an estimated additional six months to automate the back-office transactions. NW Natural cannot immediately support the amount of CIS resources required for this effort. The lack of available CIS resources will delay the implementation of essential self-service website improvements. Making this option not feasible based on time to completion and available NW Natural resources.
	Additional Risks	Risk would include the possible breakage of the current online system, making it even more challenging for customers to use the online self-service portal.
	Additional Benefits	More efficient back-office labor for NW Natural.

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$3,506,250 – $5,259,375	10%	$3,856,875 - $5,785,323
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$38,135 - $76,240	$75,000 – $100,000	
Source/ Method of Cost Data	Estimate provided by potential vendor in conjunction with NWN Tech lead and CIS team input.		

ALTERNATIVE 2 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*		
Description	Reduce scope to solely include updating the address entry field. Based on CCC feedback, the address entry field is one barrier to successfully using NW Natural's online start-stop-transfer form because it fails to auto-propose correct address solutions and will fail to process a request if the address includes any errors. A narrow upgrade focused on improving the address entry field would address this customer concern. NW Natural therefore considered modifying only this aspect of the web portal.	
In brief, why is this option not recommended?	This is not a complete alternative; exclusively updating the address entry field will not significantly improve the customer experience. While incremental improvements might be an option to test which fix is most impactful, the relative cost of pursuing these upgrades incrementally is substantially more costly.	
Assessment	**Analysis Against Criteria: Customer Experience**	This limited improvement would not resolve other prominent customer complaints received during interviews.
	Analysis Against Criteria: New Features	Updating the address entry field as a standalone effort would require more overhead than the benefit the limited update would provide customers.
	Analysis Against Criteria: Feasibility	Addressing customer complaints by improving the website in small increments, as this alternative suggests, will increase the cost of this project over time. External contractors are needed to complete the website redevelopment. The continual effort associated with onboarding and offboarding external contractors makes the work associated with implementing this limited update to the outcome less impactful. Therefore, it is more cost-effective to complete the updating of the address entry field as part of a larger inclusive scope.
	Additional Risks	This limited update will not have a high enough impact on customers currently able to complete the form to justify costs. Putting the availability of future funds for self-service website improvements at risk.
	Additional Benefits	One of the most common complaints from Customer Service Representatives (CSR) is related to address entry fields. Updating the address entry field would reduce the number of complaints from CSRs.

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$201,840 - $403,680	10%	$222,024 - $444,048
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$10,00 – $15,000	$5,000	
Source/ Method of Cost Data	Services were estimated based on anticipated work to be done and a rough estimate provided by one vendor.		

**Copy/Add table for any additional alternatives*

ALTERNATIVES CONSIDERED NOT VIABLE *Provide a description of any additional alternatives that were considered but rejected up front as not viable, and explain why*			
		Description	**Why the Alternative is not viable**
Alternative 3	Additional Interactive Voice Response (IVR) changes	Incorporation of IVR changes cannot be made due to a concurrent IVR Genesys cloud migration project. The Genesys project is updating the IVR system, making it inefficient to do both projects at the same time.	
Alternative 4		Do nothing	Customer feedback clearly indicates that the status quo is unacceptably difficult. Online engagement is an expected part of customer service, and updated functionality is thus an important part of providing adequate service to NW Natural's customers.

**Add rows for any additional alternatives considered not viable*

SUPPLEMENTARY INFORMATION

As needed, you may include any useful information gathered during the assessment phase including analysis like cost benefit / risk analysis / sensitivity analysis, etc.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Brian E. Fellon

INFORMATION TECHNOLOGY & SERVICES

Exh. BEF-10

August 29, 2025

NW Natural
PROJECT ALTERNATIVES NARRATIVE

Program/Project Name: Composition 2
Date: 05/22/2023
Project Sponsor: Alan Garcia / Dina Thompson
Executive Sponsor: Kim Rush / Jim Downing
Project Manager: April Johnson
Preparer: April Johnson
Was this project part of IRP: No

SECTION 1: BUSINESS CASE

This section should be solution-agnostic, and about the overarching problem we're trying to solve no matter which route we end up taking

OBJECTIVES *Why are we tackling this project?*	
Current State What is happening now? Where are we starting?	Composition 2.0 is the second of two phases in the Composition project. The objective of this Composition project is to produce modern, user-friendly electronic and printed documents for customers, including bills, notices, letters, and refund checks, and to ensure that documents are presented the same whether in paper or digital form. Composition 1.0 implemented the OpenText platform that is the basis for this document modernization effort. Currently, Composition software is used to produce digital bill PDFs, which are then used by Paymentus to produce customers' digital bills. These PDFs are also archived for recordkeeping. For additional context on the Composition project as a whole and Composition 1.0, please see the 2018 Composition Software Alternatives Analysis.
Problem Statement In simple terms, what are we trying to solve? What is the business need this is tackling? Why is this a problem worth solving (e.g. why is the current state not working)?	With the implementation of the Composition software, NWN is now in a position to fully modernize additional customer-facing documents, as well as more comprehensively redesign and standardize document presentation in Composition 2.0. Further extending the OpenText solution would also dispose of any remaining reliance on Advanced Function Printing (AFP) generation, which is no longer supported by IBM and is end-of-life.
Desired Deliverables What high level output / scope / deliverables are core to this project?	Improve performance and stability by implementing up-to-date software upgrades. Modernize customer-facing documents and improve customer experience. Standardize document scales and reduce supply chain issues.

SECTION 2: ALTERNATIVES SUMMARY

OVERVIEW *How did we review these options?*	
Review Process Summarize how options were chosen, who was involved in the choice and how options were evaluated.	Initial Alternative Analysis was conducted in 2018 and underwent standard review process. Please reference the 2018 Composition Software Alternatives Analysis. Options have been reviewed by project team and project sponsors

If some criteria were considered more important based on the type of project, please explain here.	
DECISION CRITERIA *Describe the criteria used to determine the selection from the various alternatives considered. For example, is this a program/project where the least cost option should be selected? Are there other factors, such as safety or quality that come into play? Include both quantitative and qualitative factors as appropriate.*	
Criteria: Alignment to NW Natural's IT Strategy	Ability to leverage this for future needs rather than a point solution.
Criteria: Cost-Benefit Analysis	Should a solution be built or bought.
Criteria: Timing	Ability to complete a project in time to meet a regulatory, business, product lifecycle, or safety requirement.

SECTION 3: ALTERNATIVES DETAIL

RECOMMENDED OPTION *Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option. If positive /neutral/negative observations do not exist, enter N/A*	
Description	OpenText Expansion/Upgrade & Document Redesign
In brief, why is this the recommended option?	Expanding the existing OpenText solutions (Document Presentment and Extended Enterprise Content Management (xECM)) allows NWN to modernize customer-facing documents including bills, letters, notices, and refund checks. The full extension of the OpenText software also eliminates the need to convert legacy CIS print file formats (AFP & TIFF) to PDF. The legacy CIS AFP generation currently being converted is unsupported/end of life from IBM. Redesigning customer-facing documents will modernize customer communication and clarity by highlighting key information, such as customer action items. Enabling customers to more easily find the most important information on their bills can save them time and effort, reduce customer frustration, and potentially reduce customer support calls. Modernized bills and other documents could also facilitate communication of potential energy efficiency measures and related opportunities for customers. The expanded and upgraded OpenText utilization further improve the customer experience by: • Opening the capability for multi-language documents. • Allowing for segmented information so OR customers will only see OR information and the same for WA customers seeing only WA information (the prior solution had both states combined). Providing only one state's info improves clarity and reduces customer confusion. • Providing increased clarity around payment plans • Prioritizing important customer communications to call attention to important customer issues and possible action items. By upgrading existing software and hardware to the latest versions of OpenText Document Presentment and Extended Enterprise Content Management (xECM), this approach also provides improved performance and stability. Lastly, the redesign portion of this project also includes standardizing document sizes and types. The custom size of our bill can cause supply chain issues. Sourcing non-standard size envelopes has the potential to cause billing delays. Standardizing document sizes would help ensure adequate access to print materials.

Assessment	**Analysis Against Criteria:** Alignment to NW Natural's IT Strategy	NW Natural's IT&S strategy seeks to maintain a product suite of integrated, out-of-the-box products to minimize maintenance and support costs.
	Analysis Against Criteria: Cost Benefit Analysis	Reduced administrative costs around local printing
	Analysis Against Criteria: Timeline	January 2023 – May 2024
	Additional Risks	• Finalization of template design • SME availability • Software training for end users and internal NW Natural team • Long turnaround time with SAP customer support - accepted risk
	Additional Benefits	• Consistent design/brand communications across printed materials • Efficiency in on-going maintenance of upgrade software and decoupled form versions • New CIS functionality to support CCC team in customer communication/generating forms

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$2.9M - $3.1M	$290,000 - $310,000	$3.2M - $3.4M
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$0 - $50k	$0 - $10K	
Source/ Method of Cost Data	Resource forecasting, SOW's, Change Requests, all documented in Planview		

ALTERNATIVE 1 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*		
Description	Remain in current state	
In brief, why is this option not recommended?	Expanding the Composition software allows NWN to leverage the existing software platform to substantially improve customer experience in customer-facing documents. Failing to proceed with the expansion and upgrade would not allow for modernization or standardization of document presentation and design, or ensure the ongoing reliability and stability of the software platform.	
Assessment	**Analysis Against Criteria:** Alignment to NW Natural's IT Strategy	Does not ensure ongoing stability of product suite Fails to maximize customer benefits of Composition project as a whole
	Analysis Against Criteria: Cost Benefit Analysis	Least cost option in the near term
	Analysis Against Criteria: Timeline	Proceeding now enables timely replacement of end-of-life programs.
	Additional Risks	Delaying or foregoing this project places pressure on other end-of-life programs currently supporting the document presentation workflow.
	Additional Benefits	None

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**

	$0	$0	$0
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$0	$0	
Source/ Method of Cost Data	No change, current state.		

**Copy/Add table for any additional alternatives*

ALTERNATIVES CONSIDERED NOT VIABLE *Provide a description of any additional alternatives that were considered but rejected up front as not viable, and explain why*		
	Description	**Why the Alternative is not viable**
Alternative 3	Upgrading OpenText but not redesigning customer-facing documents	A significant motivating factor of the Composition project is to improve customer experience. While proceeding with the upgrade alone would address the product stability issues, it would not address the project's central customer-service purpose.
Alternative 4		
Alternative 5		

**Add rows for any additional alternatives considered not viable*

SUPPLEMENTARY INFORMATION

As needed, you may include any useful information gathered during the assessment phase including analysis like cost benefit / risk analysis / sensitivity analysis, etc.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Brian E. Fellon

INFORMATION TECHNOLOGY & SERVICES

Exh. BEF-11

August 29, 2025

NW Natural
PROJECT ALTERNATIVES NARRATIVE

Program/Project Name: PowerPlan Optimization
Date: 9/15/23
Project Sponsor: Amanda Faulk / Cristan Kelley / Dina Thompson
Executive Sponsor: Brody Wilson / Jim Downing
Project Manager: Michael Crotty
Preparer: Jennifer Chiaratti
Was this project part of IRP: No

SECTION 1: BUSINESS CASE

This section should be solution-agnostic, and about the overarching problem we're trying to solve no matter which route we end up taking

OBJECTIVES *Why are we tackling this project?*	
Current State What is happening now? Where are we starting?	Costs accumulated under work orders and projects are tracked and allocated to various accounts in PowerPlan. For capital costs, this process, known as the "capital settlement process," currently occurs in a software product called PowerPlan.
Problem Statement In simple terms, what are we trying to solve? What is the business need this is tackling? Why is this a problem worth solving (e.g. why is the current state not working)?	. There has been a lack of visibility of information between PowerPlan and SAP, which has proven to be quite problematic. SAP cannot distinguish the settlement charges in PowerPlan from other charges. Consequently, the reporting within SAP reflects total charges on a project netting to $0.00 because the charges incurred are offset by the returning settlement charges. Additionally, by performing the capital settlement process outside of SAP in PowerPlan, project managers and others have less visibility into the capital settlement process. Without this visibility, project managers and others have less opportunity to detect and correct errors, which has sometimes caused delays in issuing reports.
Desired Deliverables What high level output / scope / deliverables are core to this project?	• Configure and implement changes to the capital settlement process to ensure appropriate system integration and necessary visibility by project managers and others. • Provide business and technical documentation supporting configuration and implementation. •

SECTION 2: ALTERNATIVES SUMMARY

OVERVIEW *How did we review these options?*	
Review Process Summarize how options were chosen, who was involved in the choice and how options were evaluated. If some criteria were considered more important based on the type of project, please explain here.	• Conducted analysis with the project team and external vendors to identify options, pros, cons, and potential risks and issues. Team included: NWN Accounting, IT&S, Accenture, PowerPlan • Project team and Project Sponsors agreed to a recommendation on implementation approach. • Reviewed with Executive Sponsors to gain approval to move forward with recommendation.
DECISION CRITERIA *Describe the criteria used to determine the selection from the various alternatives considered. For example, is this a program/project where the least cost option should be selected? Are there other factors, such as safety or quality that come into play? Include both quantitative and qualitative factors as appropriate.*	
Criteria: Process Standardization	Ability to leverage out of the box functionality in an efficient manner

Criteria: Reporting	Ability to produce accurate reporting and analyze data
Criteria: Timing	Ability to conduct the process in a timely manner

SECTION 3: ALTERNATIVES DETAIL

RECOMMENDED OPTION: Implement Capital Settlement Process in SAP *Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option. If positive /neutral/negative observations do not exist, enter N/A*		
Description	Transition the capital settlement process from PowerPlan to SAP	
In brief, why is this the recommended option?	Allows for use of standard cost reporting including transparency into the types of costs incurred.	
Assessment	**Analysis Against Criteria:** Process Standardization	• Utilizes standard out-of-the-box functionality which is more easily supportable during minor upgrades • Eliminates the need to implement and maintain workarounds (e.g., manual processes) in reports
	Analysis Against Criteria: Reporting	• Better cost reporting inside of SAP, aligned to standard. • Cost transparency will allow users to review, understand, and explain cost drivers
	Analysis Against Criteria: Timing	• Improve the timing of the settlement process as all costs are settled in the same system (SAP) • Reduces the effort to manually evaluate projects due to indecipherable cost information
	Additional Risks	• The extent to which the solution will improve information previously transferred between PowerPlan and SAP is still being assessed. • If the solution is implemented mid-year, rather than at the end of a full calendar year, then the transition between the two systems will need to be reconciled.
	Additional Benefits	

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$1.5M - $2.0M	$150K - $200K	$1.65M - $2.20M
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$25k - $50k		
Source/ Method of Cost Data	Statements of work from external vendors.		

ALTERNATIVE 1: Maintain Current State *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*		
Description	Capital settlement continues to be performed in PowerPlan with a post back to SAP (maintain current state).	
In brief, why is this option not recommended?	Does not address the current problem statement.	
Assessment	**Analysis Against Criteria:** Process Standardization	• Continue to implement reporting workarounds to provide necessary cost reporting from SAP • This would not achieve process standardization, but rather requires each report to be adjusted. This pattern would continue for new reports used by the business. • This does not address the root cause of cost transparency, but rather mitigates the impact of the current issue.
	Analysis Against Criteria: Reporting	• Lack of transparency in reporting could make it more difficult to obtain detailed project data to support data requests • Continued challenges to identify and reconcile adjustments amongst thousands of lines of settlement records during monthly financial close • This approach would not prevent potential risk of erroneous cost reporting
	Analysis Against Criteria: Timing	• Overall elongated delays in the close and reporting processes as data must flow between systems.
	Additional Risks	• Challenge to deep dive on the cost drivers • Challenge to drive down to the actual costs associated with a project and O&M cost receivers
	Additional Benefits	• Sustains existing financial posting process

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	N/A	N/A	N/A
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	N/A	see below	
Source/ Method of Cost Data	Unable to estimate the ongoing maintenance and quantify the sustained risk of workarounds. The investment would continue in perpetuity as additional reporting capabilities of SAP are delivered through new versions and upgrades.		

ALTERNATIVES CONSIDERED NOT VIABLE *Provide a description of any additional alternatives that were considered but rejected up front as not viable, and explain why*		
	Description	**Why the Alternative is not viable**
Alternative 2	N/A	
Alternative 3	N/A	
Alternative 4	N/A	

SUPPLEMENTARY INFORMATION

As needed, you may include any useful information gathered during the assessment phase including analysis like cost benefit / risk analysis / sensitivity analysis, etc.

None needed at this time.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Brian E. Fellon

INFORMATION TECHNOLOGY & SERVICES

Exh. BEF-12

August 29, 2025

Natural
PROJECT ALTERNATIVES NARRATIVE

Program/Project Name: SAP Treasury
Date: 06/01/2023
Project Sponsor: Nikki Sparley / Dina Thompson
Executive Sponsor: Brody Wilson / Jim Downing
Project Manager: Ashwini Prasad
Preparer: Jennifer Chiaratti
Was this project part of IRP: No

SECTION 1: BUSINESS CASE

This section should be solution-agnostic, and about the overarching problem we're trying to solve no matter which route we end up taking

OBJECTIVES *Why are we tackling this project?*	
Current State What is happening now? Where are we starting?	Treasury processes are predominantly manual and performed in Excel, with the exception of electronic bank statements and payment monitoring/approval functions.
Problem Statement In simple terms, what are we trying to solve? What is the business need this is tackling? Why is this a problem worth solving (e.g. why is the current state not working)?	Currently, the Treasury processes are predominantly manual, and performed in Excel. They are not housed in an integrated system such as SAP. This results in high manual effort, several resource hours for data entry (e.g., daily cash position report generation), as well as ongoing review and approval. There is also a level of risk associated with data entry. The project allows for automation of these processes for consistently accurate data, which will result in better reporting, significantly faster data entry processing, and allow for better use employee time. Automating these processes would be consistent with industry-standard practices of peer utilities, many of which have already automated basic Treasury functions. NWN is behind the curve in automating Treasury functions.
Desired Deliverables What high level output / scope / deliverables are core to this project?	The functionality that would enhance and increase efficiency in our processes are: • Providing granular visibility into payment processing • Automated bank account tracking • Incorporating industry-standard bank statements • Automating cash flow tracking to support day-to-day liquidity needs • Automating interest rate data instrument tracking, including developing amortization and interest rate schedules • Providing real-time visibility into market interest rate data • Ensuring successful integration with NWN systems and platforms

SECTION 2: ALTERNATIVES SUMMARY

OVERVIEW *How did we review these options?*	
Review Process Summarize how options were chosen, who was involved in the choice and how options were evaluated. If some criteria were considered more important based on the type of project, please explain here.	• Analysis conducted by the project team and external vendors to identify options, pros, cons, and potential risks and issues. • Project team agreed to a recommendation on implementation approach • Presented to the Steering Committee to gain approval to move forward with recommendation • Followed the Projects Governance Process for decision making

DECISION CRITERIA *Describe the criteria used to determine the selection from the various alternatives considered. For example, is this a program/project where the least cost option should be selected? Are there other factors, such as safety or quality that come into play? Include both quantitative and qualitative factors as appropriate.*	
Criteria: Alignment to NW Natural's IT Strategy	Ability to leverage this for future needs rather than a point solution.
Criteria: Cost-Benefit Analysis	Most cost-effective option for the business
Criteria: Timing	Ability to complete a project in time to meet a regulatory, business, product lifecycle, or safety requirement.

SECTION 3: ALTERNATIVES DETAIL

RECOMMENDED OPTION – SAP TREASURY TRACK SELECTED FUNCTIONALITY *Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option. If positive /neutral/negative observations do not exist, enter N/A*		
Description	Implement SAP Treasury Track, with minimum essential functionality: • Payment Monitoring and Approvals • Bank Relationship Management • Electronic Bank Statements Cash Application • Cash Position • Cash Flow Forecasting & Liquidity Management • Debt & Investments • Market Data Integration • Treasury Accounting • Treasury Reporting	
In brief, why is this the recommended option?	The above modules will address the basic Treasury automation needs and support a more integrated and automated system. These modules and associated functionalities represent the minimum set needed to support the core Treasury business functions. Many of these functions are also mutually dependent (such as cash position and cash flow), meaning that automating one aspect of Treasury functions necessitates automating related processes as well.	
Assessment	**Analysis Against Criteria:** Alignment to NW Natural's IT Strategy	An initial portion of the SAP Treasury Track was implemented during Horizon 1, continuing with optimizing the Treasury Tracks is aligned to the IT Strategy.
	Analysis Against Criteria: Cost Benefit Analysis	Least costly option.
	Analysis Against Criteria: Timeline	Allows for implementation by year end, starting 2024 with a clean break for year end.
	Additional Risks	• Reconciliation work required during cutover. • Forecasting functionality is relatively near-term and not the solution for a long-term strategic solution.
	Additional Benefits	• Data integration with source systems, eliminating side excel spreadsheets, managed service supports backups, security patches, and upgrades.

		• Allow Treasury bank transfers and payments performed outside of SAP (primarily in WFB CEO) to be done in the system. Minimize month-end journal entries and streamline Treasury transactions. • Automation of daily cash positioning and more visibility into the short-term cash requirements. • Master sheet of bank accounts is currently maintained in an Excel spreadsheet. Implementing this module will allow a central repository of all bank information and authorized signer in SAP. It will help keep track of the different changes for SOX compliance. • Streamline the debt creation to amortization/interest schedule. We have different processes for handling different debt instruments, so it would be beneficial to have a standard repository for these transactions in SAP. • Automation will reduce the manual work currently done and free up time for other project work. • Systems integration allows for KPI reporting and Executive reporting. • Integration is a steppingstone to integrate Water into SAP. • The integration establishes infrastructure for growth.

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$1.7M - $2.5M	$170k - $250k	$1.8M - $2.75M
O&M Range	**Program/Project**		**Ongoing Maintenance & Support**
	$100K - $200K		$xx - $xx
Source/ Method of Cost Data	Internal estimates of future project costs and vendor quotes.		

ALTERNATIVE 1: SAP TREASURY TRACK – FULL FUNCTIONALITY *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*		
Description	Implement SAP Treasury Track, with full functionality Everything included in Recommended Alternative, plus: • Advanced Payment Management • Multi bank connectivity • Market and Credit Risk • In House Bank and Payment Factory • Statutory & regulatory reporting • FX Hedging	
In brief, why is this option not recommended?	This is not the recommended option because it provides above and beyond the minimum viable product required to meet the Treasury business needs. This alternative would require additional product licensing, functionality in FX hedging and record keeping not necessary because NWN currently utilizes Horizon Allegro with no issues, and required reporting is provided in standard "can" reports. In sum, these modules are either unnecessary at this time or duplicative of other IT&S programs. Additionally, it is important to ensure that the core SAP Treasury functions are successfully implemented before considering whether to incorporate more sophisticated and complex modules.	
Assessment	**Analysis Against Criteria:** Alignment to NW Natural's IT Strategy	An initial portion of the SAP Treasury Track was implemented during Horizon 1, continuing with optimizing the Treasury Tracks is aligned to the IT Strategy.
	Analysis Against Criteria: Cost Benefit Analysis	• Higher implementation costs overall • Incremental license costs would be incurred

	Analysis Against Criteria: Timeline	• Project would have been extended by a duration of approx. 3 months to accommodate the additional scope. • Does not allow for implementation by year end.
	Additional Risks	
	Additional Benefits	

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$2.1M - $3.0M	$210k - $300k	$2.31M - $3.3M
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$150K - $250K	$xx - $xx	
Source/ Method of Cost Data	Internal estimates of future project costs and vendor quotes.		

ALTERNATIVES CONSIDERED NOT VIABLE

Provide a description of any additional alternatives that were considered but rejected up front as not viable, and explain why

	Description	**Why the Alternative is not viable**
Alternative 3	Do Nothing	Maintains manual process risks does not solve for current state problem.
Alternative 4	Implement non-SAP solution	Inconsistent with consolidated IT&S strategy to streamline and implement focused suite of technology platforms. Other applications would not integrate with NWN data systems and other departments.
Alternative 5		

**Add rows for any additional alternatives considered not viable*

SUPPLEMENTARY INFORMATION

As needed, you may include any useful information gathered during the assessment phase including analysis like cost benefit / risk analysis / sensitivity analysis, etc.

BEFORE THE

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INFORMATION TECHNOLOGY & SERVICES

Exh. BEF-13

August 29, 2025

NW Natural
PROJECT ALTERNATIVES NARRATIVE

Program/Project Name: Resource Scheduling Optimization
Date: 3/21/2024
Project Sponsor: Dina Thompson / Jaime Ulestad /Cari Colton
Executive Sponsor: Jim Downing / Joe Karney / Dave Weber
Project Manager: Cal Gosla
Preparer: Jennifer Chiaratti
Was this project part of IRP: No

SECTION 1: BUSINESS CASE

This section should be solution-agnostic, and about the overarching problem we're trying to solve no matter which route we end up taking.

OBJECTIVES *Why are we tackling this project?*	
Current State What is happening now? Where are we starting?	Workforce is the scheduling and timesheet tracking software used by NWN to manage field worker schedules and timesheets. Note: Workforce is used for timesheets by NWN a whole, but the Resource Management Center uses Workforce for both scheduling and timekeeping processes. Following deployment of Workforce and as the product was being used, NWN identified certain issues with the product's performance requiring additional follow-up work and refinement. These issues have resulted in the creation of several manual workarounds to enable critical processes: • Tracking field worker qualifications • Anticipating worker center/position changes • Facilitating field PTO auctions • Tracking and managing field shift vacancies • Managing On Call shifts • Tracking rest periods • Communicating worker schedules and availability to planners • Tracking timesheets needing auditing These manual workarounds are time consuming and have resulted in long RMC worker hours to ensure quality work and the hiring of additional contractors to handle the workload. NWN concluded that an optimization effort was needed to ensure the tool supports business processes to its capability. As a result, NWN developed a prioritized list of recommendations and a plan to improve WFS and related integrations for the RMC. NWN has recently completed an assessment and received recommendations and must now decide whether, and to what extent, to pursue the prioritized list of recommendations.
Problem Statement In simple terms, what are we trying to solve? What is the business need this is tackling? Why is this a problem worth solving (e.g. why is the current state not working)?	The manual workarounds have resulted in excess labor hours (including the need for contractors) to execute key RMC processes.
Desired Deliverables What high level output / scope / deliverables are core to this project?	Improvements to Workforce and associated integrations, systems, and processes to increase the efficiency and effectiveness of RMC schedulers, planners, and timekeepers. Improvements will result in decreased workload through the automation of now manual workarounds. The key indicators of success are estimates of weekly hours spent on various process activities.

SECTION 2: ALTERNATIVES SUMMARY

OVERVIEW *How did we review these options?*	
Review Process Summarize how options were chosen, who was involved in the choice and how options were evaluated. If some criteria were considered more important based on the type of project, please explain here.	• Conducted analysis with the project team and external vendor to identify options, pros, cons, and potential risks and issues. Team included: NW Natural field users, Enterprise Asset Management team (EAM), Information Technology and Services team (IT&S), and system integrator Rizing, which has expertise in Workforce • Project team and Project Sponsors agreed to a recommendation on implementation approach • Reviewed with Executive Sponsors and gained approval to move forward with recommendation
DECISION CRITERIA *Describe the criteria used to determine the selection from the various alternatives considered. For example, is this a program/project where the least cost option should be selected? Are there other factors, such as safety or quality that come into play? Include both quantitative and qualitative factors as appropriate.*	
Criteria: Alignment to NW Natural's IT Strategy	Ability to leverage this for future needs rather than a point solution.
Criteria: Cost-Benefit Analysis	Near-term and long-term costs compared to functional benefits for system users.
Criteria: Timing	Ability to complete the project in time to meet a regulatory, business, product lifecycle, or safety requirement.

SECTION 3: ALTERNATIVES DETAIL

RECOMMENDED OPTION: All Recommended Items (Mission Critical, High Priority, Fully Optimized) *Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option. If positive /neutral/negative observations do not exist, enter N/A*	
Description	During the review process, identified areas of improvement were compartmentalized based on degrees of urgency, into distinct buckets: (1) mission-critical, (2) high priority, (3) fully optimized. **Mission Critical** items address functions of Workforce that are core to business processes. This includes the following: • **System Cleanup**: Adjust features that drive manual behavior or interfere with business processes. For example, adjustment of exception messages that are not needed and distract from critical exceptions. This is expected to ease use of the system and make day-to-day processes more efficient. • **Enable Standard Features to Enhance Current Business Processes**: For example, color coding schedule boxes for quicker view, automations to vacate shifts when PTO is approved, scripts to automate some employee onboarding processes, and drag and drop functionality. These features will improve day-to-day use and enable the RMC to bring manual vacancy management processes into Workforce in an automated way to reduce workloads. • **Custom Reports**: Develop reports for payroll and for the RMC to enable faster communication between schedulers and planners and enable more efficient timesheet audits. • **Configure System to Decrease Manual Processes**: Standard shift patterns (rotation patterns), on-call shifts, and rest period calculations will be configured to better align with business processes. This will reduce the amount of rework needed to ensure the system accurately reflects scheduled shifts. In particular this will enable the management of on call shifts in-system, rather than on spreadsheets.

<table>
<tr><td></td><td colspan="2">

- **Training**: Foundations training and feature specific training to ensure RMC users understand how to use Workforce effectively.

High Priority items address connection points between Workforce and other systems. This includes the following:

- **Improving the Clevest to WFS Integration**: Reducing the volume of time slices from Clevest by aggregating adjacent and identical slices will reduce the time needed to audit timesheets.
- **Improving the SuccessFactors to WFS Integration**: Ensuring that adequate qualifications data is fed to WFS. This will increase the efficiency of scheduling processes, especially when performing callouts, as the schedulers and planners will be able to rely on information in the system, rather than on external spreadsheets. Additionally, this will enable schedulers to rely on in-system information for qualifications and future employee changes rather than tracking those manually outside the system.
- **Improving the WFS to Clevest Integration**: Ensuring accurate and timely schedule data is available for planners in Clevest. This will reduce the effort needed by the planners to confirm worker availability in Workforce.
- **Other improvements**: Restructuring the field hierarchy to better align with business processes, bringing manual spreadsheet creation processes into the system (around the forecasting spreadsheet), enabling vacation bidding (to automate a now manual process), training.

Fully Optimized items address opportunities for improvement that not critical but are expected to add value. This includes the following:

- **Implement new mobile features**: Shift bidding and swapping, time off requests, timesheet views. These features will reduce the email and phone call burden on RMC staff by using existing features in Workforce.
- **Custom reporting training**: NWN resources will be trained to customize reports. Significant time is spent pulling multiple reports to get needed information from Workforce. Additional training in this area is expected to reduce the burden on RMC staff for gathering information.

The chosen option includes all three buckets of work

</td></tr>
<tr><td>In brief, why is this the recommended option?</td><td colspan="2">This option allows NWN to not only improve core functionality, but also to optimize Workforce connection points, and add features useful for field resources.</td></tr>
<tr><td rowspan="5">Assessment</td><td>Analysis Against Criteria: Alignment to NW Natural's IT Strategy</td><td>• By resolving technical issues with the in-use program, this approach reduces technical debt and enables efficiency
• By engaging in a concerted, focused effort, enhancements can be delivered quickly to ensure the RMC has the tools it needs to manage field worker time.</td></tr>
<tr><td>Analysis Against Criteria: Cost Benefit Analysis</td><td>• A cohesive approach to address these improvements holistically is more cost effective and will result in better adoption than addressing each constraint individually.
• Executing a prioritized plan for optimization ensures the cost-effective allocation of resources for maximum user benefit.</td></tr>
<tr><td>Analysis Against Criteria: Timeline</td><td>• Targeting high-priority improvements for mission-critical items enables rapid improvements to product performance, while allowing for successful and efficient implementation of the high priority optimizations.
• Including all items in scope enables faster value realization than would be had if lower priority items were handled in a separate, later effort.</td></tr>
<tr><td>Additional Risks</td><td>• Implementing large collections of improvements at once limits the ability for incremental learning that may reveal further opportunities.</td></tr>
<tr><td>Additional Benefits</td><td>• Significantly improves user experience.
• Ensures that the platform will maintain functionality through future architecture enhancements.</td></tr>
</table>

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$1.4M to 1.5M	$150K	$1.55M to $1.65M
O&M Range	**Program/Project**		**Ongoing Maintenance & Support**
	$60k - $65k		N/A
Source/ Method of Cost Data	Internal and external estimates of project costs.		

<table>
<tr><th colspan="4">ALTERNATIVE 1: Only Mission Critical
Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.</th></tr>
<tr><td>Description</td><td colspan="3">• Deliver only the Mission Critical items described above</td></tr>
<tr><td>In brief, why is this option not recommended?</td><td colspan="3">• This alone will not result in optimal use of the platform, does not address needed improvements to integrations, and does not include important re-configurations. Multiple manual workarounds will remain:
o Tracking field worker qualifications
o Facilitating field PTO auctions
o Tracking rest periods
o Communicating worker schedules and availability to planners
o Tracking timesheets needing auditing</td></tr>
<tr><td rowspan="5">Assessment</td><td>Analysis Against Criteria: Alignment to NW Natural’s IT Strategy</td><td colspan="2">• Failing to implement needed improvements increases technical debt.
• Responding reactively to critical concerns while declining to proactively plan for optimal performance does not align with NWN’s IT strategy.</td></tr>
<tr><td>Analysis Against Criteria: Cost Benefit Analysis</td><td colspan="2">• Foregoing other improvements is actually more costly because issues that are not addressed in the efforts would continue to degrade RMC performance</td></tr>
<tr><td>Analysis Against Criteria: Timeline</td><td colspan="2">• Delays full implementation of process optimization to realize improved efficiencies.</td></tr>
<tr><td>Additional Risks</td><td colspan="2">• Negative end user experience impacted by continuing to rely on workarounds that are not efficient.</td></tr>
<tr><td>Additional Benefits</td><td colspan="2"></td></tr>
<tr><th colspan="4">POTENTIAL COST (EXCLUDING CONTINGENCY)</th></tr>
<tr><td rowspan="2">Capital Range</td><th>Direct</th><th>CURRENT COH</th><th>Total</th></tr>
<tr><td>$1.1M to 1.2M</td><td>$110K</td><td>$1.21M to $1.31M</td></tr>
<tr><td rowspan="2">O&M Range</td><th colspan="2">Program/Project</th><th>Ongoing Maintenance & Support</th></tr>
<tr><td colspan="2">$50k - $55k</td><td>N/A</td></tr>
<tr><td>Source/ Method of Cost Data</td><td colspan="3">Internal and external estimates of project costs.</td></tr>
</table>

<table>
<tr><th colspan="4">ALTERNATIVE 2: Only Mission Critical and High Importance
Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.</th></tr>
<tr><td>Description</td><td colspan="3">• Deliver only the Mission Critical and High Importance items listed above.</td></tr>
<tr><td>In brief, why is this option not recommended?</td><td colspan="3">• This option leaves out the Fully Optimized bucket of work, the benefit of which exceeds the incremental cost. Specific value left unrealized:
o Improvements to the WFS mobile experience
o Reporting training to enable NWN resources to extract needed data from WFS.</td></tr>
<tr><td rowspan="5">Assessment</td><td>Analysis Against Criteria: Alignment to NW Natural's IT Strategy</td><td colspan="2">• Failing to implement needed improvements increases technical debt.
• Neglecting useful features reduces efficiency</td></tr>
<tr><td>Analysis Against Criteria: Cost Benefit Analysis</td><td colspan="2">• The fully optimized features are relatively inexpensive to implement given the value they'll bring</td></tr>
<tr><td>Analysis Against Criteria: Timeline</td><td colspan="2">• Delays full implementation of process optimization to realize more effective use of employee time.</td></tr>
<tr><td>Additional Risks</td><td colspan="2">• End user experience impacted by continuing to rely on existing processes and features that are not as efficient as they could be</td></tr>
<tr><td>Additional Benefits</td><td colspan="2">None</td></tr>
<tr><th colspan="4">POTENTIAL COST (EXCLUDING CONTINGENCY)</th></tr>
<tr><td rowspan="2">Capital Range</td><th>Direct</th><th>CURRENT COH</th><th>Total</th></tr>
<tr><td>$1.3M to 1.4M</td><td>$130K</td><td>$1.43M to $1.53M</td></tr>
<tr><td rowspan="2">O&M Range</td><th colspan="2">Program/Project</th><th>Ongoing Maintenance & Support</th></tr>
<tr><td colspan="2">$55k - $60k</td><td>N/A</td></tr>
<tr><td>Source/ Method of Cost Data</td><td colspan="3">Internal and external estimates of project costs.</td></tr>
</table>

ALTERNATIVES CONSIDERED NOT VIABLE *Provide a description of any additional alternatives that were considered but rejected up front as not viable, and explain why*		
	Description	**Why the Alternative is not viable**
Alternative 3	Do Nothing	The RMC is in need of improvements to their scheduling tool and related integrations to improve efficiencies and effectiveness. Existing workloads and the continued staffing of contractors is not sustainable over the long term.
Alternative 4	Implement an alternative scheduling system and vendor to replace Workforce.	• Implementing a fully new alternative is not cost effective as any new product would require the full design, development, and deployment process that Workforce required. • Implementing a new product option would take multiple years to complete, while improvement of the current product remains necessary. • A new alternative would affect all employees of the company, as the RMC is not the only user group for Workforce. • As designed, Workforce remains a useable and useful product and retains the potential to effectively enable business processes.

**Add rows for any additional alternatives considered not viable*

SUPPLEMENTARY INFORMATION

As needed, you may include any useful information gathered during the assessment phase including analysis like cost benefit / risk analysis / sensitivity analysis, etc.

BEFORE THE

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INFORMATION TECHNOLOGY & SERVICES

Exh. BEF-14

August 29, 2025

NW Natural
PROJECT ALTERNATIVES NARRATIVE

Program/Project Name: Esri UN Migration
Date: 9/27/2023
Project Sponsor: Dan Kizer, Dina Thompson
Executive Sponsor: Joe Karney, Jim Downing
Project Manager: Kristin Powers
Preparer: Kristin Powers
Was this project part of IRP: No

SECTION 1: BUSINESS CASE

This section should be solution-agnostic, and about the overarching problem we're trying to solve no matter which route we end up taking

OBJECTIVES
Why are we tackling this project?

Current State
What is happening now? Where are we starting?

Esri builds the mapping and spatial analytics software (ArcMap, part of the ArcGIS Suite) used at NW Natural (NWN) for viewing, editing, analyzing, and managing geospatial data. The GIS (geographic information system) team uses ArcMap to maintain NW Natural's gas asset records and connectivity model for our gas system. The connectivity model, or network, allows NWN to model how the gas facilities operate. The network controls how gas moves through our system and enhances operational integrity by highlighting potential gaps in the system. The underlying network model is what drives valve isolation, cathode protection, and pressure tracing, which are all critical to asset management and emergency response. We currently use Esri's geometric network (GN) for modeling gas connectivity.

There are several tools and products we use to interact with our GIS data at NWN. Below is a simplified table to provide more context and to show how the Esri products are related to other pieces. The driver for this project is based on the Esri tools, although there are other projects in flight to update/change/replace other tools in the ecosystem.

Items in green are Esri tools impacted by this project. All other tools are out of scope for this effort.

Application/Tool	Status	Uses	Users
ArcMap (Esri)	Near End-of-Life (2028)	Create, edit, and analyze GIS data and connectivity model.	GIS Team, Environmental Management, Pipeline Integrity
ArcGIS Pro (Esri)	Plan to implement as part of this project	Create, edit, and analyze GIS data and connectivity model – replaces ArcMap.	GIS Team, Environmental Management, Pipeline Integrity
Geometric Network, GN (Esri)	Not compatible with ArcGIS Pro, must transition from this model	Model network connectivity of NWN's gas infrastructure.	GIS Team, Pipeline Integrity, Visual Fusion users for Valve Isolation Tracing
Utility Network, UN (Esri)	Plan to implement as part of this project	Model network connectivity of NWN's gas	GIS Team, Pipeline Integrity, potentially other users for Valve Isolation and

		infrastructure – replaces GN.	Cathodic Protection Traces
ArcFM Viewer	Near End-of-Life (2028) – replacement is part of another project	Tracing cathodic protection network, limited feature editing	Corrosion Team
Visual Fusion	End-of-Life – replacement is part of another project	Custom maps for different business groups, critical functionality is the valve isolation tracing map for emergency response	Backoffice, including Gas Control that relies on valve isolation tracing
Fieldsmart View (MapFrame)	End-of-Life – replacement is part of another project	General map viewer, map correction creation	Field and back office
Clevest	Implemented in 2022	Limited view of asset information, crew and work locations	Primarily used by field users and RMC
IQGeo	Implemented in 2020	Viewing GIS and SAP assets, completing surveys, reporting leaks, creating as-builts	Field and back office

Notably, the mapping data displayed in the above applications is created and maintained in Esri's ArcGIS Desktop Suite (primarily ArcMap). These applications are where edits are made daily to GIS data based on as-builts and other changes made in the field. After the GIS data is edited in Esri, the mapping data can be viewed by the field and back office users in other connected tools like IQGeo or Clevest to allow employees to do their work.

Problem Statement
In simple terms, what are we trying to solve? What is the business need this is tackling? Why is this a problem worth solving (e.g. why is the current state not working)?

At a high level, we have a product nearing end-of-life (ArcMap) and a data model (GN) that we need to transition. Esri is requiring customers to move from ArcMap to ArcGIS Pro and will discontinue support for ArcMap on 3/1/2028. The GN is not compatible with ArcGIS Pro, so utilities using Esri need to simultaneously transition to the Utility Network (UN) to continue modeling gas connectivity in the GIS. Esri committed to providing only security patches and critical fixes for utility customers during Mature Support, 3/2024 – 2/2028, while utilities complete the transformation. Given that moving to a new tool suite is expected to take 18-24 months, planning for this transition now is particularly crucial.

Once transitioned, Esri products will receive software updates, patches, and hotfixes. We must make this, or some, transition eventually, because we need to manage our geospatial data on a tool that can be improved, patched, and made secure.

In addition, NWN's GIS systems are interdependent, meaning that upgrades to one section require us to ensure that other related systems are compatible. In this case, for instance, the Legacy Mapping Replacement (LMR) project cannot fully remove Mapframe or ArcFM Viewer without us transitioning to UN. As a result, careful coordination among the GIS suite is critical.

Desired Deliverables
What high level output / scope / deliverables are core to this project?

- Implement and transition to a replacement GIS solution
- Migrate identified data from the GN to the new solution and eventually turn off editing in the GN
- Implement a new data model and map old data to the new model for the solution
- Ensure all GIS processes and tools either work in the solution or are replaced with like-for-like tools (for example, replacing ArcMap with another tool, like ArcGIS Pro, to manage GIS data)
- Perform change management activities for all impacted stakeholders

	• Set up new architecture to support the solution • Review processes and update/streamline, if possible

SECTION 2: ALTERNATIVES SUMMARY

OVERVIEW *How did we review these options?*	
Review Process Summarize how options were chosen, who was involved in the choice and how options were evaluated. If some criteria were considered more important based on the type of project, please explain here.	• Conducted analysis with the project team and external vendors to identify options, pros, cons, and potential risks and issues. Project team agreed to a recommendation on implementation approach • Presented to the Steering Committee and the IT&S Alignment Team to gain approval to move forward with recommendation We evaluated options based on: • Gartner feedback on tools in the space • Use of tools at other utilities • Fit with the NWN IT&S landscape • Tool ease of use • Difficulty of migration efforts • Cost
DECISION CRITERIA *Describe the criteria used to determine the selection from the various alternatives considered. For example, is this a program/project where the least cost option should be selected? Are there other factors, such as safety or quality that come into play? Include both quantitative and qualitative factors as appropriate.*	
Criteria: Cost of implementing solution	What are the costs associated with the different options?
Criteria: Familiarity with product	Since the GIS team will use this tool to maintain NW Natural's gas asset records and generate the connectivity model for our gas system, it is important to take into account how much training will be required to use the recommended solution – is it difficult to use, is this similar to what they do already, how complex is it for new users to learn, what resources are already available to support users?
Criteria: Existing place in NWN's IT&S landscape	How many IT&S applications will this solution touch? If we completely replace it with something new, what is the level of effort to keep connected systems functioning? If we use the new version of the existing tool, what impact does that have on integrations?
Criteria: New or improved solution functionality	While our main goal is a like-for-like transfer, does the solution considered provide any new or improved functionality? Will we be able to improve things like reporting outputs? Can we retire other third-party tools used prior to the implementation of the solution?

SECTION 3: ALTERNATIVES DETAIL

RECOMMENDED OPTION *Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option. If positive /neutral/negative observations do not exist, enter N/A*	
Description	Transition fully to the UN and retire the GN and related tools – ArcMap, ArcFM Desktop (extension), and ArcFM Viewer.
In brief, why is this the	Why stay on Esri and move to the UN:

<table>
<tr><td>recommended option?</td><td colspan="2">

Gartner confirmed that Esri is dominant in GIS space, and they were not seeing many other utilities moving off Esri despite the required transformation.
Esri has a good ecosystem of partners and 3rd party tools.
Esri UN is the most mature system of the modern, commercially available options.
It is already present in the NWN IT&S landscape, so while we will need to update integrations, it’s a much smaller lift than putting in an entirely new solution.
The team is familiar with using Esri products.
Other utilities have made this transition, so we are not the first to attempt it and we can use lessons learned from their migrations.

We recommend starting this immediately because:

We have a project team in place that is familiar with the assessment work and what needs to be done. If we postpone, we will need to spin up the project later and re-acclimate potentially different resources to the tasks at hand.
If we do this now, it allows for some time before current solution reaches end-of-life.
Cost are likely to go up over time if we wait, due to inflation and competition pressures.
If we wat, we will likely experience greater internal resource competition for other big projects like H2; by moving through the planning stage sooner and engaging third-party external vendors to aid the transition, we can avoid overlapping with the most resource-intensive efforts for H2 deployment.
If we wait, we will run into greater external competition for vendor resources as more utilities, now encountering the solid end-of-life deadline, undertake this work as well.

</td></tr>
<tr><td rowspan="6">Assessment</td><td>Analysis Against Criteria: Cost</td><td>The assessment project with the UN SME resulted in scope reductions for the UN migration, resulting in a less expensive overall project – no need to implement parts of the solution we will not use. Making this transition also allows us to retire some 3rd party apps like ArcFM. Staying with Esri is cheaper than moving to an entirely new application and data model.</td></tr>
<tr><td>Analysis Against Criteria: Familiarity</td><td>Our GIS users are familiar with Esri’s ArcGIS Suite, so the general look and feel will be similar and reduce time to learn the new tools. However, this move will necessitate usage of a new professional desktop solution, ArcGIS Pro, in favor of the current ArcMap solution. Training will be required. However, our newly-graduated GIS analysts are actually trained on ArcGIS Pro in school currently, so some of the team already has the necessary skills.</td></tr>
<tr><td>Analysis Against Criteria: Existing Place in landscape</td><td>This move will require all integrations to be refactored to leverage real-time services rather than direct database connections and exports. This transition also presents an opportunity to reevaluate our architecture (cloud vs. on prem decision to be made during the Plan phase) to support the new tooling. However, this is better than bringing in a new tool and building entirely new integrations from scratch with everything.</td></tr>
<tr><td>Analysis Against Criteria: New or improved solution functionality</td><td>By moving to ArcGIS Pro and the UN, we are gaining access to more tools and new functionality that will allow us to better manage our gas system.

This move will improve our ability to report on PHMSA-required data because UN provides more accurate pipeline footage calculations.
This will improve the accuracy of our GIS data and system modeling.
As part of the transition to the UN, NWN must adopt a gas industry standard data model. Adoption of an industry standard data model aids in more efficient data management and enhanced data quality.

</td></tr>
<tr><td>Additional Risks</td><td>

There are other projects underway impacting the GIS landscape at NWN, so we propose to sequence the project work to balancing interlocking needs, and internal capacity availability while we execute these transitions (e.g., Legacy Mapping Tool replacement will remove 3 applications this is currently integrated with – MapFrame, Visual Fusion, and ArcFM Viewer).

</td></tr>
<tr><td>Additional Benefits</td><td>Financial benefits:

This will allow us to stop using and paying for UN-incompatible 3rd party tools and switch to using tools within Esri.

Operational benefits:</td></tr>
</table>

		• Once transitioned, Esri products will be in full support and receive not merely basic security patches and critical fixes, but software updates, functional patches, and hotfixes, as well as full tech support. This will reduce the security risk of using the tool.
		• This will provide us an opportunity to clean up data and only transition information that is important to NWN.
		• This will allow us to review current processes and potentially streamline them where possible.
		• The ability to update and maintain our GIS data is integral to providing safe and reliable service to our customers. The GIS data is the system of record for the location of our gas facilities. The maps that display the GIS data to our end users provide location information for responding to emergencies, aid in locating infrastructure in the real world, and inform business planning and decision making.
		  ○ Implementing the Esri UN and service-based infrastructure would allow changes made in the GIS to be reflected in mapping applications, like IQGeo, more quickly. This will provide field users with the most current GIS data sooner than our current state, which can take more than 24 hours to reflect in field mapping applications.
		  ○ This project also implements linear pipeline referencing, which will enable NWN to model elevation changes and record events on our transmission assets. They will show as 3D instead of 2D, leading to more accurate asset management and reporting. Documenting events (changes) on 3D models of transmission pipelines will offer more accurate location and stationing information for field users.
		  ○ Access to higher accuracy pipeline inspection data with the ability to leverage better analytics will improve how we asses and manage pipeline risk.

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$11.8M – $16M	$1.2M – 1.6M	$13M – 17.6M
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$210K – 280K	$100K – $150K	
Source/ Method of Cost Data	• During the Assess phase, we worked with a UN migration SME to create an implementation plan with a detailed timeline to understand expected length of the project. • Internal labor and direct support contractors (PM, CM, etc.) were estimated based on this timeline. • The UN SME said many SI vendors are coming in between $7M-$15M for migration alone, but our project should be smaller based on completed pre-work, less complex data relative to other companies, the fact that we are a gas company and not electric, and other factors. • We reviewed license costs for the new Esri UN with our Esri rep for an initial estimate on ongoing costs.		

ALTERNATIVE 1 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*	
Description	A hybrid approach could be implemented - keeping ArcMap for editing short term but pushing data to a read-only version of the UN that could be integrated with other apps. So, we would start transitioning now and finish at a later date.

In brief, why is this option not recommended?	• This does not solve the long-term issue that ArcMap is reaching end-of-life, but it potentially buys time to get NWN GIS users transitioned to ArcGIS Pro and new editing workflows. • We would have to run a second project to move off ArcMap. The second project would need to conclude before March 2028 when ArcMap reaches end-of-life. This will extend the project timeline and increase costs in the long run.	
Assessment	**Analysis Against Criteria: Cost**	This would create additional costs when we spun up a second phase of the project later to finish the transition instead of doing it all at once. We would have to re-onboard a team of potentially different resources, which takes additional time and money.
	Analysis Against Criteria: Familiarity	Our GIS users already use ArcMap, so there would be no immediate change. However, by 2028, we will have to transition to ArcGIS Pro, so there would have to be a follow-up project for that. That would require training and change management efforts.
	Analysis Against Criteria: Existing Place in landscape	This move will still require all integrations to be refactored to leverage real-time services rather than direct database connections and exports. Same analysis as the recommended approach.
	Analysis Against Criteria: New or improved solution functionality	We will not have access to the improved tooling described in the recommended option until we move off ArcFM, so short term, it would be a like-for-like change, and long term, we would have improved functionality.
	Additional Risks	• If we segment this into two projects, we complicate resource commitment between the UN implementation and the Horizon 2 project commitments. • If we pick up the migration at a later date, external project resources familiar with the implementation may no longer be available. • The cost of the work and licenses may go up. • This scenario would involve significantly more complexity to transform the data between data models while also ensuring that third-party applications work correctly.
	Additional Benefits	Same as recommended option. Other benefits include: • Users could continue using ArcMap longer, so they would not need training immediately while we focused on connecting the UN to our integrated systems and stabilizing. • Users would have a longer time to get comfortable using ArcGIS Pro.

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$12.3M – $16.5M	$1.2M – 1.7M	$13.5M – 18.2M
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$210K – 280K	$100K – $150K	
Source/ Method of Cost Data	• Same as the recommended option, but with two months of time added on for restarting and ending the second phase of the project. • Software cost of maintaining ArcFM longer ($50k/yr) included.		

ALTERNATIVE 2 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*	
Description	Postpone the project until closer to the end-of-life date, then transition fully to the UN and retire the GN and related tools (ArcMap, ArcFM Desktop (extension), and ArcFM Viewer), completing everything before Mar 1, 2028.
In brief, why is this option not recommended?	• As we get closer to the end-of-life date of ArcMap, there will likely be an influx of companies trying to do the same thing, so there will be competition for vendors to support us. • With inflation and costs shifting, it will likely be more expensive a few years from now. • With Horizon 2 coming down the pipeline, we would be in competition for resources, money, and other IT&S assets. • The lead time to complete this work is 18-24 months, so we would not want to delay very long.

Assessment	**Analysis Against Criteria: Cost**	Cost of the entire effort will likely go up due to inflation and competition for resources. It appears there are no additional benefits gained from the increased cost.
	Analysis Against Criteria: Familiarity	No additional information relative to the recommended option.
	Analysis Against Criteria: Existing Place in landscape	No additional information relative to the recommended option.
	Analysis Against Criteria: New or improved solution functionality	No additional information relative to the recommended option.
	Additional Risks	• If we wait too long, we will likely experience greater internal resource competition for other big projects like H2; we could be at risk for overlapping with the most resource-intensive efforts for H2 deployment. • If we are close to ArcMap's true end-of-life, we will be competing for SI vendor resources with many other companies. • With that competition, the cost of experienced contractors could increase. • If we cannot get experienced contractors because they are on other projects for other companies, we will have to work with less experienced folks and that could cause project delays or poor implementation quality. • If something minor goes wrong with the ArcMap, Esri will not fix it. • If we need new functionality in the ArcMap, Esri will not build it, so we'll need to find a 3rd party tool for it. • If we add a new application to the NWN IT&S landscape that uses GIS information, we will need to update more integrations when we migrate (rework).
	Additional Benefits	• We have several years to transition to the UN before ArcMap is out of support, so there is no imminent threat of end-of-life. • If we wait, we may decommission more IT&S integrated tools so there could be less work to update existing integrations. • If vendors complete more migrations with other clients, they can bring that additional experience and those lessons learned to our migration to improve it.

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$13M – $18M	$1.3M – 1.8M	$14.3M – 19.8M
O&M Range	**Program/Project**		**Ongoing Maintenance & Support**
	$235K – 300K		$110K – $165K
Source/ Method of Cost Data	Same as recommended option, but with roughly 4% inflation added for two years assuming we start in 2025, plus an increase for expected resource costs.		

**Copy/Add table for any additional alternatives*

ALTERNATIVES CONSIDERED NOT VIABLE *Provide a description of any additional alternatives that were considered but rejected up front as not viable, and explain why*		
	Description	**Why the Alternative is not viable**
Alternative 3	Do not transition from ArcMap and do not replace the tool.	We would be keeping some of NWN's most important information on an application that was no longer receiving security patches, hotfixes, or any level of customer support. This is not acceptable and not viable.
Alternative 4	Build a custom, in-house solution.	We do not have the in-house development resources to do this, so it would require hiring developers, then keeping FTEs to maintain,

		update, patch, etc. the tool. There would be no external support, we would not be able to ask other utilities how they were handing tasks in the tool, there would be no how-to resources already available online to check out, there would be not 3rd party compatible tools. We would have to re-write all our integrations.
Alternative 5	Transition away from Esri entirely to another commercial GIS solution, like GE Smallworld.	Gartner confirmed Esri is dominant in the space, and they are not seeing many other utilities moving away from Esri despite the required data transformation. Esri has a good ecosystem of partners and 3rd party tools that work with them. Additionally: • If we rooted Esri out of our IT&S landscape, we would have to create new integrations to many critical systems (SAP, Clevest, CIS, IQGeo) which puts them at risk. • We would need to train all our GIS users and technical support personnel on how to use the new tools, so this would be a much larger change management effort. • Data may be stored differently and might not migrate as easily, requiring more data cleanup. • All of our annual reporting has models set up that process Esri data and provide reports on that data. We would have to recreate those models, which requires substantial investments of time and resources. • All of these changes would likely require external contractor support, so this would add millions of dollars more to the project and slow down the timeline of delivery.
Alternative 6	Transition to IQGeo Network Manager (specifically)	Per the explanation above in the document, we have implemented IQGeo mostly as a data-viewer application, but editing and managing network data is a much different, far more complex task. Therefore, we don't think this would be a good idea for all the reasons above, and: • IQGeo is unproven as a system-of-record so far within utilities. • Additional planning activities would be required before implementation could be executed with confidence • Network Manager *Gas* is significantly less developed compared to the Network Manager *Electric* product and it would present additional risks that we would be the first gas utility to implement that solution • This would solve the network modeling/data piece, but we would need a backend solution for editors and analysts, so there would still need to be some software solution (e.g., keep using Esri) to fully meet NWN needs.

**Add rows for any additional alternatives considered not viable*

SUPPLEMENTARY INFORMATION

As needed, you may include any useful information gathered during the assessment phase including analysis like cost benefit / risk analysis / sensitivity analysis, etc.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Brian E. Fellon

INFORMATION TECHNOLOGY & SERVICES

Exh. BEF-15

August 29, 2025

NW Natural
Field Web Maps Phase 1 ALTERNATIVES NARRATIVE

Program/Project Name: Field Web Maps Phase 1
Date: October 31, 2024
Project Sponsor: Dina Thompson, Dan Kizer, Jaime Ulestad
Executive Sponsor: Brian Fellon, Joe Karney, Dave Weber
Project Manager: Kristin Powers
Preparer: Shivon Van Allen, Kristin Powers
Was this project part of IRP: No

SECTION 1: BUSINESS CASE

This section should be solution-agnostic, and about the overarching problem we're trying to solve no matter which routes we end up taking.

OBJECTIVES
Why are we tackling this project?

Current State
What is happening now? Where are we starting?

High Level Overview of Current State

NW Natural (NWN) is in the process of a multi-year program to replace its field and web mapping solutions by phasing out end-of-life software tools and transitioning to a consolidated set of modern software solutions. NWN relies on its field and web mapping tools to view its infrastructure and other assets in a geospatial format and for collecting various types of data related to these assets. These mapping tools provide field and office personnel with online and offline visual representations of NW Natural facilities and assets, which they use for various business purposes, including inspection compliance programs. Below is a table of the applications, their statuses, uses, and users. Tools directly related to this project effort are in green.

Application/Tool	Status	Uses	Users
Visual Fusion	Past End-of-Life (no longer supported by vendor) – this Phase 1 project will transition out Valve Isolation Tracing functionality, and Phase 2 will move custom web maps and decommission the tool.	Custom web maps for different business groups, and the relevant project functionality for this AA is the valve isolation tracing map for emergency response	Back office, including Gas Control, Engineering, Resource Management Center, and GIS teams
ArcMap (Esri)	Near End-of-Life (2028) – replacement is part of another project	Create, edit, and analyze GIS data and connectivity model.	GIS Team, Environmental Management, Pipeline Integrity
ArcFM (Schnieder Electric)	Near End-of-Support (2026) – replacement is part of another project	Model gas network connectivity, productivity tools for editing GIS data	GIS Team, Pipeline Integrity
ArcFM Viewer (Schnieder Electric)	Near End-of-Support (2026) – replacement is part of another project	Create and edit data and run cathodic protection traces	Corrosion, GIS Team
Clevest	Implemented in 2022	Limited view of asset information, crew, and work locations	Primarily field users and RMC
IQGeo	Implemented in 2019	View GIS and SAP assets, complete surveys, report	Field and back office

		leaks, create as-builts. Intended to be the application to replace Visual Fusion for tracing users	

Notably, the mapping data displayed in the above applications is created and maintained in Esri's ArcGIS Desktop Suite, specifically in the ArcMap application. Esri's ArcMap is the application where edits are made daily to GIS data based on as-builts and other changes made in the field. After the GIS data is edited in Esri, the mapping data is viewable by the field and back office users in the integrated applications listed above, allowing employees and contractors to perform their work.

NWN will migrate Esri tools starting in 2025, so anything that uses data from these tools needs to be updated and have its integrations reworked as part of that project. If NWN can decommission any legacy applications before then, that will prevent rework that will ultimately be thrown out once decommissioning is complete.

Project-Specific Overview

The Field Web Mapping Phase I Project begins the company transition away from an existing end-of-life software system, Visual Fusion, by moving its most critical functionality elsewhere. Specifically, this project is focused on migrating Valve Isolation Tracing capabilities.

In the event of an emergency, NWN uses Valve Isolation Tracing to determine what valves need to be shut off to isolate an area of the gas system in order to repair a damage or perform a new gas main tie-in procedure. NWN currently completes tracing in Visual Fusion, a legacy tool that is no longer supported by its vendor (Everbridge) and uses products that are no longer supported by Microsoft (SharePoint 2010, SQL Server 2012, Internet Explorer, and Microsoft Silverlight). NWN installed Visual Fusion in 2014 and enabled tracing functionality through customization shortly after that. The last update deployed to SharePoint was in 2016.

A Valve Isolation Trace is performed when there is an emergency, like damage to a pipe, to create a map identifying the valves that need to be turned off to isolate an area and to generate an impacted customer list for outage notification and relight order creation. To provide a sense of scale, in roughly 10 years, NWN has run about 4,000 valve isolation traces.

Valve Isolation Traces are run by members of the GIS (geographic information system), Engineering, Gas Control, and Resource Management Center teams. There are about 75 users who trace in Visual Fusion and more stakeholders who consume the information the application produces (for example, the Emergency Contact Center uses trace results and creates work orders to relight gas that had been shut off during an emergency response).

In addition to being out-of-support, the performance in Visual Fusion has degraded over time. For example, multiple users attempting to run a trace simultaneously causes application errors, and the time to execute traces has increased over time and can be unresponsive for some users. Both of these issues present risk to performing traces and responding swiftly during emergency situations.

GIS Analysts are also able to run Valve Isolation Traces using ArcFM tools in ArcMap if there is a problem with Visual Fusion, but user access is limited to the GIS team because of the complexity of the software. A trace in ArcMap currently yields the same valve isolation result as a trace in Visual Fusion, and it is critical that results in any future tool also match ArcMap. This allows NWN to accurately and efficiently respond to emergency events regardless of who is running a trace (the GIS Team

	uses ArcMap, while all other users use Visual Fusion). If the systems produced different results, it introduces risk around selecting the correct plan to isolate events in the field. The Field Web Maps Phase 2 Project (dates TBD) would focus on removing any remaining functionality from Visual Fusion and decommissioning it completely.
Problem Statement In simple terms, what are we trying to solve? What is the business need to tackle this? Why is this a problem worth solving (e.g., why is the current state not working)?	Visual Fusion is an old application that increases risk within NWN from a security, support and stability perspective and impacts other NWN IT&S modernization efforts (such as the consolidation and retirement of mapping tools). • Visual Fusion is past end-of-life, meaning the application no longer receives security updates or defect fixes from its software provider. The last update deployed to SharePoint was in 2016. No new enhancements or support for operating systems are offered. This creates the risk of service interruption and possible breakage for end users who rely on this application in emergency situations. It also creates additional workload for NWN resources to maintain this application in its end-of-life state. • Visual Fusion runs on products that both Microsoft and NWN no longer support, including Internet Explorer, Microsoft Silverlight, SharePoint 2010, and SQL Server 2012. NWN must maintain a Silverlight extension for employees to download in the Company's intranet Software Center, and there are precise instructions end users have to follow so Visual Fusion will run. The detailed instructions that must be followed could result in end user errors since they do not use the tool often, which may lead to wasted time for incorrect IT help desk support tickets, and additional unnecessary requests to the GIS team for assistance. • ArcMap is a specialized tool for viewing, editing and analyzing GIS data used by only approximately a dozen geospatial professionals at NWN. A non-ArcMap tracing solution is necessary for office and field employees to quickly and intuitively perform a valve trace to support emergency events. • Visual Fusion consumes data from NWN's Esri tools to create traces, and the tracing service relies on a third-party geospatial tool (ArcFM) for modeling the connectivity of NWN's system and performing the trace. NWN's GIS data is migrating to a new data model (from Esri's Geometric Network (GN) to Esri's Utility Network (UN)). This migration is necessary because the tool NWN uses today for editing and analyzing GIS data (ArcMap) is near end of life, and the new tool we will migrate to (ArcGIS Pro) does not support our current data model (GN). ArcGIS Pro will also replace the third party ArcFM application NWN uses today for productivity tools and tracing. If NWN is still using Visual Fusion when the Esri UN implementation starts in 2025, NWN will need to rework the integration between NWN's GIS data, which will have a new connectivity model and tracing mechanism. Since Visual Fusion will eventually be decommissioned, this will be an ineffective use of resources.
Desired Deliverables What high level output / scope / deliverables are core to this project?	• Provide Valve Isolation Tracing functionality equivalent or superior to Visual Fusion on a modern platform that is still supported by its vendor • Produce Valve Isolation Traces on the new tool that also match the trace results produced by ArcMap/ArcFM • Set up new architecture to support the solution, as needed • Reduce the number of mapping applications used by employees at NWN • Review processes and update/streamline, if possible • Perform change management activities for all impacted stakeholders

SECTION 2: ALTERNATIVES SUMMARY

OVERVIEW *How did we review these options?*	
Review Process Summarize how options were chosen, who was involved in the choice and how options were evaluated. If some criteria were considered more important based on the type of project, please explain here.	• IQGeo was selected by NWN in 2018 as the product to replace FieldSmart (aka MapFrame), Visual Fusion, and ArcFM Viewer. NWN began the work to replace these applications with IQGeo solutions in 2019. To date, general map viewing, survey and inspection functionality, integration with the asset management system, as-builting and map correction functionality have been transitioned to IQGeo, allowing for the retirement of FieldSmart. • This project's goal is to replace like-for-like Valve Isolation Tracing functionality in Visual Fusion with functionality in IQGeo. • Analysis conducted by the project team and vendors (The Gartrell Group and IQGeo) identified options, pros, cons, and potential risks and issues associated with this project. • The project team presented to the Enterprise Asset Management (EAM) Steering Committee and the IT&S Alignment Team to gain approval to move forward with this recommendation. The project team evaluated options based on: • Assessment on tools in the space • Flexibility to consume future state UN-data and traces • Fit with the NWN IT&S landscape • Tool ease-of-use • Cost and licensing
DECISION CRITERIA	
Criteria: Alignment to NW Natural's IT Strategy	• Ability to leverage IQGeo for future needs, rather than a point-in-time (i.e. temporary) solution • Solution consolidates tools in the NWN mapping space • Solution aligns with known future GIS projects, including the Esri UN Migration
Criteria: Cost-Benefit Analysis	• Whether a solution should be built or bought • Level of customization needed to provide and maintain essential functionality • Whether a solution requires us to buy new tools or additional licenses • Cost of labor to support solution once delivered
Criteria: Timing	• Provide mapping solution before end of life of ArcMap and mandatory migration to Esri's Utility Network • Completing work before resources are pulled onto other higher priority projects in 2025
Criteria: Product Familiarity	• The mapping tool will be used by about 75 people on laptops or desktops. Training and adoption considerations should be evaluated for the solution selected, including ease-of-use, level of support needed, and amount of training required

SECTION 3: ALTERNATIVES DETAIL

RECOMMENDED OPTION *Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option. If positive /neutral/negative observations do not exist, enter N/A*	
Description (Full scope of project)	Transfer Visual Fusion's Valve Isolation Tracing functionality into IQGeo and wait to transfer any remaining Visual Fusion functionality into IQGeo until the Phase 2 project. Tracing will be performed using the existing ArcFM tracing web service and a custom user interface in IQGeo for running and viewing traces. Note: Phase 2 will include an upgrade to supported version of IQGeo, implementation of Network Manger Gas to replace the IQGeo Capture application (for as-builting, map corrections, and public

	notes), and creation of new maps for the Operations Department. At that point, we will decommission Visual Fusion.	
In brief, why is this option recommended?	This option ensures business continuity and removes the risk of NWN-critical operations running on an end-of-life platform that does not receive security patches. It allows NWN to expand platform functionality that will help technical growth in the future. This option aligns with NWN's geospatial strategy to work toward consolidating field and web mapping applications for end users and provides end users with a more streamlined and easy-to-use method for their tracing needs. It also aligns with timing for the Esri UN migration.	
Assessment	**Analysis Against Criteria:** Alignment to NW Natural's IT Strategy	• The operational and security risk of running critical emergency response functionality on an unsupported application and infrastructure will be remediated. • Replacing Visual Fusion with IQGeo will move this functionality out of an old, depreciated mapping application without adding to the number of supported applications. • Migrating functionality out of Visual Fusion puts NWN closer to the goal of being able to fully decommission it after Phase 2. It also moves the most critical functionality out of the product. • Providing tracing functionality in IQGeo will allow end users a more streamlined, user-friendly method for their mapping needs within a single application.
	Analysis Against Criteria: Cost-Benefit Analysis	• Zero spend today would likely cause increased costs later in terms of rising project team costs, internal costs for keep-the-lights-on support for Visual Fusion and end-of-life Microsoft products, rising license costs for Visual Fusion, and difficult onboarding/user experience for new employees. • All end users already have IQGeo licenses and access, so there is no need to buy new licenses for them. Familiarity with the product also means training should be a lighter lift. • If NWN completes the work before the Esri UN Migration project, this will build the framework to make the transition simpler and more cost effective while also avoiding throwaway work. Otherwise, it will take more money and effort to update the connections between systems and will need to be redone anyway.
	Analysis Against Criteria: Timing	• All projects with a geospatial impact at NWN share critical internal and external resources, so planning and early execution tasks will compete for NWN and vendor resources. The sooner NWN starts, the less competition the company will have for key resources (internal and external). • If NWN starts this now, the work will be done well before the Esri UN Migration project finishes, so future rework with an end-of-life tool is avoided.
	Criteria: Product Familiarity	• IQGeo is available to all NWN employees and contractors. Many teams have been exploring and using IQGeo for years. • Most tracing end users are familiar with IQGeo and perform some of their mapping work there today. • Training will consist of new functionality, not core product use, which saves time and effort. • IT&S support for IQGeo is already in place with internal resources and contractors, so NWN does not have to teach the Day 2 support team new technology for the handoff. • NWN has an existing relationship with IQGeo as a vendor, so they are familiar with NWN's technology landscape, project team, and stakeholders.
	Additional Risks	• Enabling NWN's desired functionality in IQGeo requires customization, which IT&S prefers to avoid as it adds risk and complexity over the lifespan of the application. • Some rework is required when NWN completes the Esri UN Migration project (e.g., if we keep this on-prem but move Esri to the cloud (no decision in place yet), NWN will then need to move the solution to the cloud). However, the work would be to connect IQGeo, a tool we expect to use for a long time, not Visual Fusion, which we are trying to decommission.

	Additional Benefits	• Business continuity is already ensured for IQGeo. • The NWN tech lead estimates NWN can use the existing integration pattern as a foundation for the new solution, so it should decrease the level of effort to set up middleware/keep the data flowing.

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$1.1M - $1.3M	$110K – $130K	$1.2M – $1.5M

	Program/Project	**Ongoing Maintenance & Support**
O&M Range	$15-$20K	• Support costs: Less than $10K annually • Licensing costs: No new licenses so no cost increase from this, but IQGeo currently costs NWN $202,955/year through 2025

Source/ Method of Cost Data	Capital range was estimated using a 10% accuracy for Assess Phase. So, range shows 90% to 110%. Costs were estimated using a planning resource sheet with utilization expectations and team member expertise and estimates on two vendor costs (IQGeo and The Gartrell Group (TGG)). • Hardware: If we stay on-prem, we will use the existing app server and there will be no cost. If we deploy to Azure, it will be around $2k/year. • Software: No additional IQGeo licensing costs expected due to an already existing enterprise license that covers all employees and contractors. That current cost is $202,955/yr as of 2025. • Support costs: Since this is not used frequently (less than 4000 traces in 10 years), NWN anticipates it is less than 100 hours of NWN internal support a year, so less than $10K. Project O&M is for Change Management activities.

ALTERNATIVE 1 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*		
Description	Do nothing and leave the current legacy application in place for the foreseeable future.	
In brief, why is this option not recommended?	• Visual Fusion would continue to be past end-of-life and present significant risk, including from a cybersecurity perspective. • If Visual Fusion is inoperable, only the GIS team (staffed with around 12 people) would be able to run traces, which is a risk in emergency situations, including after business hours. • The cost of maintaining Visual Fusion will not provide any long-term value. • Future costs for replacing Visual Fusion will likely be higher due to inflation, and the Company may not have the key resources at that time to implement a replacement product. • We will not make progress on our strategic goal to reduce mapping applications.	
Assessment	**Analysis Against Criteria:** Alignment to NW Natural's IT Strategy	• This alternative would not allow NWN to move away from an application and supporting technology that is past end-of-life and end-of-support which represents significant cybersecurity risk. • Continuing to use this application places a burden on the NWN IT&S and GIS teams to maintain. • NWN would not meet application consolidation goals. • Ends users would do most of their work in IQGeo and then just perform traces in Visual Fusion, which increases job complexity, creates confusion, and incurs training costs.

	Analysis Against Criteria: Cost-Benefit Analysis	• By not transitioning away from Visual Fusion, NWN would continue the maintenance spend and licensing costs we have today, and we would still need to replace this application in the future. The project costs will be pushed into the future, since ultimately a new solution is needed. • If NWN does not complete this work before the Esri UN Migration project, it will take more money and effort to update the connections between systems and will need to be redone eventually anyway. More technical debt would be incurred at the time of implementation as well as create complexity and additional cost if we extend use of Esri tools in the future.
	Analysis Against Criteria: Timing	• The current project team members (internal and external) are not guaranteed to be available when work is restarted. • There are several large projects in the pipeline that will tap the same resources, causing further constraints to the project.
	Additional Risks	• NWN has only one internal resource that supports Visual Fusion on the backend. This creates significant risk. Even NWN's production support vendor for GIS activities and IQGeo does not support Visual Fusion. • Using Visual Fusion is difficult because of all the obsolete technical requirements – Internet Explorer, Microsoft Silverlight – so it is not a desirable end user experience.
	Additional Benefits	• Change management not needed • No immediate new capital costs incurred • Project team freed up to work on other priorities

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	N/A	N/A	N/A
O&M Range	**Program/Project**		**Ongoing Maintenance & Support**
	N/A		• VF Annual License Fee: $56,407 • Internal support cost: $10,000
Source/ Method of Cost Data	• Software: Visual Fusion - $56,407/year as of 2025 Support costs: Since this is not used frequently (less than 4,000 traces in 10 years), NWN anticipates it is less than 100 hours of NWN internal support a year, so around $10K.		

ALTERNATIVE 2 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*	
Description	Instead of implementing the current Valve Isolation Tracing process in IQGeo, switch to IQGeo's tracing solution, Network Manager Gas.
In brief, why is this option not recommended?	Network Manager Gas is a new product, and no other gas utilities are using this solution. NWN does not want to be the first customer to use this solution and take on the risks associated with an unproven product. Additionally, NWN did not go forward with this solution because IQGeo requires customers to use their data model to accomplish tracing, meaning NWN would have to maintain one data model for Esri GIS data and a second data model for IQGeo Network Manager Gas. Having two different manually maintained versions of the same data invites errors into the systems and makes it likely that running a trace in each system would provide different results, which is unacceptable in an emergency. Furthermore, maintaining two models also requires data editing and maintenance, which would expand the mapping responsibilities of the GIS team and be redundant work. It would be a time consuming for the GIS team to set up a new IQGeo data model and also set up the new Esri data model in early 2025 as part of the Esri UN Migration project.

Assessment	**Analysis Against Criteria:** Alignment to NW Natural's IT Strategy	This would have the same positive outcomes as our recommended solution: • The operational and security risk of running critical emergency response functionality on an unsupported application and infrastructure will be remediated. • Replacing Visual Fusion with IQGeo will move this functionality out of one of the old, depreciated mapping applications in the portfolio without adding to the number of supported applications. • Migrating functionality out of Visual Fusion puts NWN closer to the goal of being able to fully decommission it after Phase 2. It also moves the most critical functionality out of the product. • Providing tracing functionality in IQGeo will allow the end users a more streamlined, user-friendly method for their mapping needs within a single application.
	Analysis Against Criteria: Cost-Benefit Analysis	This would have the same positive outcomes as our recommended solution: • Zero spend today would likely cause increased costs later in terms of rising project team costs, internal costs for keep-the-lights-on support for Visual Fusion and end-of-life Microsoft products, rising license costs for Visual Fusion, and difficult onboarding/user experience for new employees. • If we complete the work before the Esri UN Migration project, we will not waste money on rework updating connections between the systems. Unlike our recommended solution: • Our license agreement already covers use of Network Manager Gas as long as we don't use it as our system of record. However, there would be additional cost for time for the editing and maintenance activities required of the GIS team.
	Analysis Against Criteria: Timing	This would have the same positive outcomes as our recommended solution: • All projects with a geospatial impact at NWN share critical internal and external resources, so planning and early execution tasks will compete for NWN and vendor resources. The sooner NWN starts, the less competition. • If NWN starts this now, NWN will be done well before the Esri UN Migration project finishes, eliminating future rework with an end-of-life tool.
	Criteria: Product Familiarity	This would have the same positive outcomes as our recommended solution: • IQGeo is available to all NWN employees and contractors. Many teams have been exploring and using IQGeo for years. • Most tracing end users are familiar with IQGeo and perform some of their mapping work there today. • IT&S support for IQGeo is already in place with internal resources and contractors, so NWN does not have to teach our Day 2 support team new technology. • NWN has an existing relationship with IQGeo, so they are familiar with NWN's technology landscape, project team, and stakeholders. Unlike our recommended solution: • Training will consist of new functionality, not core product use, which saves time and effort. However, this would be more training effort than the recommended approach since it is a new module in IQGeo.
	Additional Risks	• Additional planning activities would be required before implementation could be executed with confidence. The timeline of the project would extend. • Enabling NWN's desired functionality in IQGeo will still require customization, which IT&S prefers to avoid as it adds risk and complexity over the lifespan of the application.

		• Maintaining two data models introduces opportunity for mistakes and data that is not in sync. • We would have to do extensive QA testing to make sure trace results were identical in both systems, and there is no guarantee we could reach a point where that was true every time. • There will be rework required when NWN completes the Esri UN Migration project. However, it would be work to connect IQGeo, a tool we expect to use for a long time, not Visual Fusion, which we are trying to decommission. • Other gas utilities of similar sizes are not using this tool currently, so we would be the first to adopt it. That means there's a lot of unknown risks that may be realized once we start using the tool.
	Additional Benefits	• Business continuity is already ensured for this application.

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$1.3 - $1.6	$130K – $160K	$1.4M – $1.8M

	Program/Project	**Ongoing Maintenance & Support**
O&M Range	$18K – $24K	• Additional GIS team support costs: $166K (Some of this is capital, since mapping work is largely capital work) • IT&S Support costs: Less than $10K annually • Licensing costs: No new licenses so no cost increase from this, but IQGeo costs NWN $202,955/year through 2025
Source/ Method of Cost Data	We took the recommended project costs and then increased them by 20% as an estimate because this would be a new module to set up, which is a little more complex. We would also be the first gas utility to do it, so our vendor partners would not come into this with a strong foundation on how to execute. Ongoing maintenance will increase since we would need to maintain two data models. GIS Techs would have to update Esri and then work in IQGeo to update the connectivity model there. We assumed a 20% increase in mapping activities for 8 techs, so that's about 4 extra hours a week, which is about $166K. Mapping work is largely capital, but some of this would be an O&M hit.	

ALTERNATIVES CONSIDERED NOT VIABLE *Provide a description of any additional alternatives that were considered but rejected up front as not viable, and explain why*		
	Description	**Why the Alternative is not viable**
Alternative 3	Do not transition from Visual Fusion and do not replace the tool ever.	NWN would be running a critical emergency response function on an application that was no longer receiving security patches, hotfixes, or any level of customer support. Performing valve isolation traces would be a GIS Team responsibility, and the business would need to adapt schedules and emergency planning and coordination efforts to include the GIS Team going forward. It would likely require additional

		headcount on the GIS Team to support. This is not acceptable and not viable. Traces can be necessary outside of business hours, so it would require an on-call model to support.
Alternative 4	Build a custom, in-house solution.	NWN does not have the in-house development resources to do this, so it would require hiring developers, then keeping FTEs to maintain, update, patch, etc. the tool. There would be no external support, NWN would not be able to ask other utilities how they were handing tasks in the tool, there would be no how-to resources already available online to check out, there would be not 3rd party compatible tools. NWN would have to re-write all our integrations. This is not acceptable and not viable.
Alternative 5	Transition away from IQGeo entirely to another commercial tracing solution, such as expanding NWN's use of ArcFM Viewer for valve tracing or building an Esri web application.	NWN wants to consolidate mapping tools, not bring new ones into the ecosystem. A new tool would require a new set of license fees, new training for both the foundational use of the tool as well as the tracing-specific functionality, and new training for IT&S resources to maintain it. If NWN brought in a new tool, the company would need to build many integrations from scratch. All of these changes would likely require external contractor support and a system integrator, so this would add significant cost to the project and slow down the timeline of delivery.

**Add rows for any additional alternatives considered not viable*

SUPPLEMENTARY INFORMATION

As needed, you may include any useful information gathered during the assessment phase including analysis like cost benefit / risk analysis / sensitivity analysis, etc.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Brian E. Fellon

INFORMATION TECHNOLOGY & SERVICES

Exh. BEF-16

August 29, 2025

NW Natural
PROJECT ALTERNATIVES NARRATIVE

Program/Project Name: Identity Governance and Administration (IGA) - Centralization of User Provisioning and Management (IGA 2.0)
Date: 2/12/2025
Project Sponsor: Matt Carlson
Executive Sponsor: Brian Fellon
Project Manager: Michael Castle
Preparer: Michael Castle
Was this project part of IRP: NO (enter "Yes, included", "Yes, Acknowledged" or "No")

SECTION 1: BUSINESS CASE

This section should be solution-agnostic, and about the overarching problem we're trying to solve no matter which route we end up taking.

OBJECTIVES *Why are we tackling this project?*	
Current State What is happening now? Where are we starting?	NW Natural (NWN) is in the process of improving its overall IT security posture. The need for improvement is driven by both regulatory requirements and the evolving nature of the IT landscape (e.g., on-premises focused to cloud-centric). One of the priority areas for improvement is identity governance and administration (IGA) that includes consistent identification and tracking of personnel identities and access permissions as well as access management processes. As a result, a multiple-phased implementation of an IGA solution started with Phase 1 in 2023 to select, install and configure a state-of-the-art IGA solution (SailPoint Identify Security Cloud (ISC) product), establish connections and data collection for priority identity sources and key systems and establish foundational functionality. Additional project phases are planned to build upon the core IGA solution delivered in Phase 1.
Problem Statement In simple terms, what are we trying to solve? What is the business need this is tackling? Why is this a problem worth solving (e.g., why is the current state not working)?	**Problem Statement**: After implementation of the foundational IGA solution in 2024, the next phase of the project is needed for NWN to begin realizing the benefits of an IGA solution. This project will focus on extending the base functional capabilities, expanding to additional systems/applications, preparing for and implementing a pilot of Role Based Access Controls (RBAC) and solidifying the foundation for the IGA systems and processes, including establishing baseline SOX controls and disaster recovery plans for SailPoint ISC and NERM. Phase 3, planned to start in 2025, is expected to further deploy RBAC within the NW Natural environment and further expand automation of IGA processes. **Business Need / Why is this problem worth Solving?** When an employee or contractor is offboarded from NWN, there is no way to certify their access has been completely removed from all systems/applications until the IGA solution has been integrated with those systems/applications. The Sarbanes-Oxley Act (SOX) requires consistent, reliable removal of access permissions for offboarded employees as part of ensuring that unauthorized individuals cannot access sensitive financial information. Unfortunately, even with efforts to optimize and enhance NWN's current manual processes, this manual method has been unable to sustain consistent compliance due to the scale and complexity of NWN's systems. As a result, NWN needs to continue integration of the IGA solution with additional systems/applications.
Desired Deliverables What high level output / scope / deliverables are core to this project?	The key objective and outcome for the entire IGA initiative is to elevate the core function of an IGA tool to govern the lifecycle of identities across the enterprise. Automation and exception routing enhances the ability to respond to requests and issues quickly and efficiently.

	Once fully implemented, the IGA tool will eliminate many manual processes that are performed today. IGA will allow for policies to be engineered into the system, simplifying review and policy conformance. Through the course of IGA implementation, role-based access control within NWN will support least privilege access and timely provisioning and deprovisioning of the proper levels of access to technology systems and equipment.

SECTION 2: ALTERNATIVES SUMMARY

OVERVIEW *How did we review these options?*	
Review Process Summarize how options were chosen, who was involved in the choice and how options were evaluated. If some criteria were considered more important based on the type of project, please explain here.	The options under consideration are straightforward: continue integration of the existing IGA solution with additional systems/applications, explore solutions from a different vendor, or maintain the status quo with the current manual processes. IGA is an evolutionary, multi-phased effort to build infrastructure, processes, tools and capabilities to improve IT identity and access management and overall NW Natural IT security, compliance and efficiency; therefore, Phase 2 has always been anticipated. The scope for Phase 2 has been established to pragmatically build on the foundation established in Phase 1 within realistic resource, budget, and timeline constraints, applying lessons learned from Phase 1 and anticipated activities within NW Natural that may pose challenges for resources. Generally, NW Natural expected to continue the evolution of IGA with a Phase 2 effort and evaluated alternatives around items to include in scope, size of budget/resources and what could realistically be delivered in the near-term given competing priorities and ability to absorb change.
DECISION CRITERIA *Describe the criteria used to determine the selection from the various alternatives considered. For example, is this a program/project where the least cost option should be selected? Are there other factors, such as safety or quality that come into play? Include both quantitative and qualitative factors as appropriate.*	
Criteria: Level of effort to deploy	a. Complexity • How intricate or straightforward is each option to implement, irrespective of the nature of the change (upgrade, new solution or maintaining existing system) b. Resource Allocation • What people, technical, and financial resources are required for each option? • Does the option require new expertise, or can it be handled by the current resources on staff? c. Timeline • How long is the expected duration from the mobilization of the vendor to completion of each option? • Are there any anticipated delays or hurdles specific to an option?
Criteria: User Impact	a. Learning Curve • How quickly can users adapt to the changes or upgrades presented by each option? • Does a particular option require users to unlearn certain processes or habits? b. Training Needs: • How quickly can users adapt to the changes or upgrades presented by each option?

	• Does a particular option require users to unlearn certain processes or habits? c. Productivity • Is there expected downtime or a potential drop in productivity during or post-implementation for each option? • How soon can normalcy or improved performance be expected post-transition?
Criteria: Overall Cost Implications	a. Initial Expenditure • What are the upfront costs associated with each option, including licensing, hardware, and setup? b. Ongoing Costs: • Are there recurrent expenses, such as maintenance fees, subscription costs, or additional licenses?

SECTION 3: ALTERNATIVES DETAIL

RECOMMENDED OPTION *Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option. If positive /neutral/negative observations do not exist, enter N/A*		
Description	Continue integration of the existing IGA solution with additional systems/applications	
In brief, why is this the recommended option?	NWN's IGA strategy is to roll out additional scope and functionality over multiple project phases. The current project is the second of at least three planned phases. Phase 1, which completed in 2024, established connections and data collection for priority identity sources and key systems and established foundational functionality. This option is recommended as it will focus on extending the base functional capabilities, expanding to additional systems/applications, preparing for and implementing a pilot of Role Based Access Controls (RBAC) and solidifying the foundation for the IGA systems and processes, including establishing baseline SOX controls and disaster recovery plans for the IGA solution.	
Assessment	**Analysis Against Criteria:** Alignment to NW Natural's IT Strategy	Comprehensive features and functionality paired with scalability, flexibility, user-friendly interface, integration capabilities, security and compliance, and vendor support.
	Analysis Against Criteria: Cost-Benefit Analysis	Should a solution be built or bought and which bought solution is the most cost effective while still achieving the project's goal.
	Analysis Against Criteria: Timing	Ability to complete a project in time to meet a regulatory, business, product lifecycle, or safety requirement.
	Additional Benefits	Overall, IGA benefits include: 1. Improved end-user experiences including faster access to applications and services, consistent data across application identities, and role creation allows for access consistency. 2. Security posture improvements will address our immediate need to handle personnel terminations in accordance with regulatory obligations. Long-term benefits include improving group membership discovery and facilitating adoption of zero-trust network architecture. 3. Compliance and regulatory needs continue to grow in all industries. IGA will help us provide auditors with timely evidence to demonstrate compliance with various rules and regulations.

		4. Reduced Administrative Overhead - reduction in manual processing will increase accuracy of IAM activities and frees up resources to perform more value-add work.

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$2,643,384 - $2,846,184	10%	$2,907,722 - $3,130,802
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$20,000 - $30,000	$250,000 - $315,000	
Source/ Method of Cost Data	SailPoint Identify Security Cloud licenses are $250,000 per year with installation occurring in 2024. Ongoing maintenance and support figures are for licenses only. The system support will be done by existing FTE and therefore is not incremental.		

ALTERNATIVES CONSIDERED NOT VIABLE

Provide a description of any additional alternatives that were considered but rejected up front as not viable, and explain why

	Description	**Why the Alternative is not viable**
Alternative 1	Deploy a new IGA solution.	Deploying a new IGA solution would be more costly, more labor-intensive, and take significantly more time, without any assurance of achieving a superior outcome beyond where we are today with the existing SaaS solution. NWN's IGA strategy is to roll out additional scope and functionality over multiple project phases. The current project is the second of at least three planned phases. Other software vendors were evaluated as alternatives as part of the previous IGA project. This evaluation was summarized in the Alternatives Analysis for that project.
Alternative 2	Do nothing.	Opting to "do nothing" and retaining the existing IGA solution functionality would minimize the benefit of the $3.3M investment of implementing the foundational platform in the IGA 1.0 project which completed in 2024. The manual processes would need to be retained with their inherent compliance risk and reduced level of security.

**Add rows for any additional alternatives considered not viable*

SUPPLEMENTARY INFORMATION

As needed, you may include any useful information gathered during the assessment phase including analysis like cost benefit / risk analysis / sensitivity analysis, etc.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Brian E. Fellon

INFORMATION TECHNOLOGY & SERVICES

Exh. BEF-17

August 29, 2025

February 1, 2020

Pipeline Risk Modeling

Overview of Methods and Tools for Improved Implementation

Pipeline and Hazardous Materials Safety Administration

February 1, 2020

February 1, 2020

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Executive Summary

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is issuing this report to highlight the strengths and limitations for pipeline risk models, and to support improvements in Gas Transmission and Hazardous Liquid pipeline risk models. Operators establish risk models to address risk and improve safety within their respective pipeline systems.

Pipeline risk models are a foundational part of the assessment of operational pipeline risk. Federal pipeline safety integrity management (IM) regulations require pipeline operators to use risk assessments.[1] Based on the results of pipeline inspections and failure investigation findings, both the Department of Transportation's PHMSA and the National Transportation Safety Board (NTSB) have identified general weaknesses in the risk models used by pipeline operators in performing risk assessments for their IM programs.

To help address this problem, PHMSA organized a Risk Modeling Work Group (RMWG) composed of representatives of state and federal pipeline regulators, pipeline operators, industry organizations, national laboratory personnel, and other stakeholders. The purpose of the RMWG was to gather information regarding state-of-the-art pipeline risk modeling methods and tools, the use of those methods and tools, and the resulting data in operator IM programs. This document provides an overview of methods and tools for improved implementation based on the results of the RMWG.[2]

This report considers the major types of pipeline risk models, and the effectiveness of each type in supporting risk assessments, as applied to pipeline operator decisions. The four major risk model types considered are: Qualitative, Relative Assessment/Index, Quantitative System, and Probabilistic. Each type is characterized by the model inputs, outputs, and algorithms, and was evaluated according to its ability to support pipeline risk management decisions and regulatory requirements.

This overview document focuses on the applicability of the different risk model types to various risk management decisions required by the Federal pipeline safety IM regulations, including:

1. Risk Priorities for Baseline Integrity Assessments
2. Identification of Preventive Measures and Mitigative Measures
3. Evaluation and Comparison of Preventive Measures and Mitigative Measures
4. Consideration of Threats and their Interactions in Risk Assessments
5. Benefit-Cost Analysis for Risk Reduction Options[3]
6. Integrity Assessment Interval Determination

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[1] 49 Code of Federal Regulations (CFR) Part 192, Subpart O (Gas Transmission Pipelines) and 49 CFR Part 195.452 (Hazardous Liquid Pipelines).

[2] Documentation of RMWG activities, including all technical presentations and meeting notes, can be viewed on PHMSA's Pipeline Technical Resources web site in tab RMWG at https://www.phmsa.dot.gov/pipeline/risk-modeling-work-group/risk-modeling-work-group-overview.

[3] The IM rules require operators to reduce risks to high consequence areas (HCAs) by implementing preventive and mitigative measures (risk reduction actions) beyond those measures specifically required elsewhere in the pipeline safety regulations (49 CFR Parts 192 and 195). If limited operator resources require prioritization of measures that could be effective in reducing risk, then benefit-cost analysis, supported by the operator's risk model, provides an effective method of promoting efficiency as well as risk reduction.

7. Support of Continual Evaluation of Integrity and General Risk Management Decision Making

Conclusions

This report details discussions and technical recommendations related to the various aspects of pipeline risk modeling. PHMSA has derived the following summary conclusions:

1. The overriding principle in employing any type of risk model/assessment is that it supports risk management decisions to reduce risks.

2. While different risk model types have different capabilities for evaluating risk reduction actions, Quantitative System models or Probabilistic models are more versatile and provide greater capabilities to provide risk insights and support decision making. Such models can be more complex; however, they do not necessarily require more data than other types of risk models.
    - Small pipeline operators with limited but highly knowledgeable personnel resources will likely continue to use Relative Assessment/Index models.
    - Pipeline operators who continue to use Relative Assessment/Index models should seek to supplement personnel judgment with as much physical data as can reasonably be acquired over time.
    - Adequate and accurate data is needed for the application of all risk model types.

3. Pipeline operators should take ongoing actions to improve and update data quality and completeness over time. However, the type of risk model to employ in pipeline risk analysis should not depend primarily on the perceived initial quality and completeness of input data because all of the models utilize the available data. Instead, operators should select the best model approach and then populate the model with the best information currently available on risk factors or threats for each pipeline segment, and improve that data over time.

4. It is important for risk models to include modeling of incorrect operations, which includes human interactions and human performance, that are significant to the likelihood of failure or have a significant effect on consequences of a failure (e.g., inappropriate controller restart of pumps, realistic emergency response time scenarios, design and construction human errors).

5. It is important for pipeline risk models to include the potential effects of threats to interact in ways that can increase risk. Therefore, when risk analysis involves multiple threats, the effect of “interactive threats” or dependencies on likelihood of failure should be clearly evaluated.

6. Varying levels of sophistication are possible in the analysis of the consequences of a failure. However, it is important to consider an applicable range of scenarios (even if they do not have a high probability of occurrence) to capture the appropriate spectrum of possible consequences.

7. The characteristics of pipeline facilities that affect risk may be significantly different than those of line pipe, but the same basic risk assessment principles apply, and the same types of models may be applied.

PHMSA recommends that pipeline operators develop and apply risk models considering these summary conclusions and the associated technical recommendations contained in this document. This should result in an improved understanding of the risks from pipeline systems and should improve critical safety information provided for the broader integrity and risk management processes.

RMWG Meeting Technical Presentations

The RMWG conducted several meetings during 2016 and 2017 to define, review, and document best practices in applying pipeline risk models. The presentations on technical topics from the RMWG meetings have been used to develop this document. Pipeline operators may wish to consider these presentations when developing their own risk models. The below technical topics were presented at RMWG meetings, and are available at: https://www.phmsa.dot.gov/pipeline/risk-modeling-work-group/risk-modeling-working-group-rd-documents-presentations.

Likelihood: August 9-11, 2016, Washington, DC

- USCAE Risk Assessment Methodologies
- Review of Technical Presentations
- Risk Analysis and Rare Events Data
- Bayesian Data Analysis
- Interactive Threats Discussion
- Probability Estimation
- ASMEB31.8S Risk Modeling Summary

Consequences & PHMSA R&D Projects: October 4-6, 2016, Houston, Texas

- Emergency Planning & Response Performance Modeling
- GT QRA
- Risk Tolerance R&D Presentation
- Preventing Catastrophic Events R&D Project
- Pipeline Risk Assessment
- HL Consequence Overview
- Critical Review of Pipeline Risk Models R&D Project

Facility Risk: November 30-December 1, 2016, Washington, DC

- Facilities Risk Approaches
- GT Facilities Risk Management
- Facility Piping Risk Assessment
- LNG Facility Risk Analysis Process

Data: March 7-9, 2017, Houston, Texas

- API Technical Report on Data Integration (TR 1178)
- Data Integration – Industry Practices and Opportunities
- Data Integration Using GIS Systems & Improved Risk Modeling
- Data Uncertainty in Risk Models
- HCA and Incident Statistics
- Overview of Partial Draft BSEE PRA Procedures Guide
- Performance Data Analysis for Nuclear Power Plants (Industry Data)
- PODS Data Management
- Relative Risk Model Applications at Southwest Gas
- Risk Acceptability Tolerance (Probabilistic Models)
- Using Data in Relative models with Respect to Decision Criteria

Index Models and Migration to Quantitative Models: June 15, 2017, Houston, Texas

- SME Input into Pipeline Risk Models
- Index Models and Applications (Vectren)
- Index Models and Applications (Dynamic Risk)
- Data Quality for Index Models and Migration to Quantitative Models
- Migration from Older Risk Analysis Methods to Quantitative Models

The RMWG and PHMSA thank the individuals and groups that supported this effort by presenting materials at our meetings.

PHMSA thanks the members of the RMWG for their efforts and time spent in attending meetings, presentations, discussion, and commenting during the development of this document.

I. Definitions & Acronyms

Definitions		
Term	**Definition**	**Source**
Terms Related to Defining Risk		
Consequence	Impact that a pipeline failure could have on the public, employees, property, the environment, or organizational objectives.	B31.8S-2004, ISO 31000:2009
Frequency	Number of events or outcomes per defined unit of time. Frequency can be applied to past events or to potential future events, where it can be used as a measure of likelihood/probability.	ISO 31000:2009
Hazard	Source of potential harm or potential consequences.	Muhlbauer, 2004 ISO Guide 73-2009
Likelihood	The chance of something happening, whether defined, measured, or determined objectively or subjectively, qualitatively or quantitatively, and described using general terms or mathematically (such as a probability or frequency over a given time period).	ISO 31000:2009
Probability	(1) Likelihood, or (2) Measure of the chance of occurrence expressed as a number between 0 and 1, where 0 is impossibility and 1 is absolute certainty.	(1) numerous sources use the terms likelihood and probability interchangeably (2) ISO 31000:2009
Risk	Measure of potential loss in terms of both the likelihood or frequency of occurrence of an event and the magnitude of the consequences from the event. [Note: In practice, "likelihood," "probability," and "frequency" are often used interchangeably. In each risk modeling approach, the associated units (e.g., events/year) for each variable must be carefully assigned/verified in order to assure proper usage.]	B31.8S-2004 CSA Z662 Annex B
Terms Related to Defining Risk Assessment and Risk Assessment Models		
Risk analysis	Process of using available information to comprehend the nature of risk and estimate the level of risk.	ISO 31000:2009
Risk assessment	Systematic process in which hazards from pipeline operation are identified and the probability and consequences of potential adverse events are analyzed and estimated.	B31.8S-2004
Risk assessment model (Risk Model)	A set of algorithms or rules that use available information and data relationships to perform risk assessment. A model is a simplified representation of a pipeline system and represents the relation of important risk factors.	Muhlbauer, 2004

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Definitions		
Term	**Definition**	**Source**
Risk management	Overall program consisting of identifying potential threats to a pipeline; assessing the risk associated with those threats in terms of incident likelihood and consequences; mitigating risk by reducing the likelihood, the consequences, or both; and measuring the risk reduction results achieved.	B31.8S-2004
Terms Related to Different Types of Risk Models		
Index model	Scoring rules or algorithms that define how a risk index is calculated from input information. The scoring rules do not attempt to consistently adhere to the laws of probability.	RMWG
Probabilistic model	Model with inputs that are quantities or probability distributions and with outputs that are probability distributions. Model logic attempts to adhere to laws of probability.	RMWG
Qualitative	Expressible in relative terms, but not quantitatively or numerically; measured as relational categories (e.g., high, medium, low), but not as numerical quantities or amounts.	RMWG
Qualitative model	Model with inputs and outputs that are verbal or ordinal categories. Model logic defines output categories from combinations of input categories.	RMWG
Quantitative	Expressible in terms of numerical quantity or involving the numerical measurement of quantity or amount.	Dictionary (Merriam-Webster.com)
Quantitative model	A model with input that is quantitative and output that is quantitative. Model logic may or may not conform to laws of probability or to represent physical and logical relationships of risk factors (see definition of quantitative system model).	RMWG
Quantitative system model	A quantitative risk model with an algorithm that models the physical and logical relationships of risk factors to estimate quantitative outputs for likelihood and consequences and represents the outputs in standard units such as frequency, probability, and expected loss. This modeling approach is in contrast to index models that score and weight individual model inputs and calculate a unit-less index score.	RMWG
Relative assessment model	Synonymous term as a risk index model (see separate risk index definition).	RMWG
Risk index	Unit-less measure of risk derived from input information using ordinal scales.	ISO/IEC-31010-2009 – Risk management – Risk assessment techniques
Other Terms		
Data structure	A specialized format for organizing and storing data. A data structure is designed to organize data to suit a specific purpose so that it can be accessed and worked with in appropriate ways.	RMWG

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Definitions		
Term	**Definition**	**Source**
Facility	Portions of a pipeline system other than line pipe: includes compressor units, metering stations, regulator stations, delivery stations, holders, fabricated assemblies, and underground storage facilities (gas); and pumping units, fabricated assemblies associated with pumping units, metering and delivery stations and fabricated assemblies therein, breakout tanks, and underground storage facilities (liquid).	49 CFR Part 192.3 49 CFR Part 195.2
Failure	(1) A part in service has become completely inoperable; is still operable but is incapable of satisfactorily performing its intended function; or has deteriorated seriously, to the point that is has become unreliable or unsafe for continued use. (2) A structure is subjected to stresses beyond its capabilities, resulting in its structural integrity being compromised. (3) Unintentional release of pipeline contents, loss of integrity, leak, or rupture.	B31.8S-2004 Muhlbauer, 2004 Muhlbauer, 2015
Gas pipeline	All parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.	49 CFR Part 192.3
Hazardous liquid pipeline	All parts of a pipeline facility through which a hazardous liquid or carbon dioxide moves in transportation, including, but not limited to, line pipe, valves and other appurtenances connected to line pipe, pumping units, fabricated assemblies associated with pumping units, metering and delivery stations and fabricated assemblies therein, and breakout tanks.	49 CFR Part 195.2
Line pipe	Cylindrical linear “mileage” portions of a pipeline system that transport commodities from one point to another; i.e., the part of a pipeline system outside of any facilities.	49 CFR Part 195.2
Linear reference system	A systematic method of associating pipeline characteristics or other risk factors to specific positions on the pipeline.	RMWG
Mitigative measure	Risk reduction action to reduce risk by modifying the consequences of failure.	RMWG
Preventive measure	Risk reduction action to reduce risk by modifying the probability of failure.	RMWG
Risk factor	Pipeline characteristic or other input that is used by the model algorithm to determine model outputs; can be a data attribute input to a risk model.	RMWG

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Definitions		
Term	**Definition**	**Source**
Risk Modeling Work Group (RMWG)	A PHMSA-organized group composed of representatives of state and federal pipeline regulators, pipeline operators, industry organizations, national laboratory personnel, and other stakeholders. The purpose of the RMWG was to characterize state-of-the-art pipeline risk modeling methods and tools. RMWG members individually provided recommendations to PHMSA regarding the use of those methods, tools, and the resulting data in operator IM programs.	RMWG
Scenario	Sequence of events that, when combined, result in a failure.	Muhlbauer, 2015
Segment	A contiguous length of pipeline or part of a pipeline in a specific geographic location.	RMWG
Threat	Potential cause of failure; failure mechanism.	B31.8S-2004 Muhlbauer, 2015
Time-dependent	Failure rate for threat tends to increase with time and is logically linked with an aging effect.	Muhlbauer, 2015
Time-independent	Failure rate for threat tends to vary only with a changing environment; failure rate should stay constant as long as environment stays constant.	Muhlbauer, 2015

Acronyms	
Term	**Definition**
ALARP	as low as reasonably practicable
CD	construction damage
CFR	Code of Federal Regulations
CIS	close interval survey
CON	Construction
CP	cathodic protection
CW	cold weather
DCVG	direct current voltage gradient
DEM	digital elevation model
DFW	defective fabrication weld
DGW	defective girth weld
DP	defective pipe
DPS	defective pipe seam
EC	external corrosion
EM	earth movement
ESD	emergency shut-down
EQ	equipment
GF	gasket failure
GIS	geographic information system
HCA	high consequence area

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Acronyms	
Term	**Definition**
HRF	heavy rains and floods
HVL	highly volatile liquid
IEC	International Electrotechnical Commission
IC	internal corrosion
IM	integrity management
IO	incorrect operations
ISO	International Organization for Standardization
LIGHT	lightning
LRS	linear reference system
MAOP	maximum allowable operating pressure
MCRE	malfunction of control or relief equipment
MFR	manufacturing
MOP	maximum operating pressure
NTSB	National Transportation Safety Board
P&ID	piping and instrument drawing
PDP	previously damaged pipe
PHMSA	Pipeline and Hazardous Materials Safety Administration
PODS	Pipeline Open Data Standard
QRA	quantitative risk assessment
RMWG	Risk Modeling Work Group
ROW	right-of-way
SCC	stress corrosion cracking
SME	subject matter expert
SPPF	seal or pump packing failure
TP	third party
TPD	third-party damage
TSBPC	stripped threads, broken pipe, or coupling failure
V	vandalism
VSL	Value of Statistical Life
WROF	weather related and outside force

II. Introduction

A. Purpose of Document

Risk models are a foundational part of the assessment of operational pipeline risk and an integral part of gas and hazardous liquid pipeline integrity and risk management. A risk model provides a representation of the risks throughout a pipeline system by combining inputs associated with both likelihood and consequence aspects of unintended pipeline releases. The model supports risk analysis and helps operators evaluate and quantify the effects of various risk mitigation activities and make risk management decisions.

This document provides an overview of methods and tools to be used in risk modeling in support of pipeline integrity and risk management of gas and hazardous liquid transmission pipelines. Broader topics such as integrity management systems, quality management systems, overall risk management, and safety management systems are not addressed within this document.

Federal gas and hazardous liquid pipeline safety integrity management (IM) regulations (see Appendix E) contain requirements for the uses of risk assessments by pipeline operators. Based on the results of pipeline inspections and failure investigation findings, both the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) and the National Transportation Safety Board (NTSB) have identified general weaknesses in the risk models used by pipeline operators in performing risk assessments for their IM programs. Generally, the models used have not enabled operators to systematically identify and effectively analyze risk reduction actions. PHMSA has previously communicated findings and concerns regarding risk models at past public meetings.[4]

B. NTSB Recommendations

In 2015, the NTSB published a safety study titled *Integrity Management of Gas Transmission Pipelines in High Consequence Areas* (https://www.ntsb.gov/safety/safety-studies/Pages/SS1501.aspx). The NTSB undertook this study because of concerns about deficiencies in the operators' integrity management programs and the oversight of these programs by PHMSA and state regulators. As a result of the study, the NTSB made three recommendations to PHMSA concerning the use of risk assessments:

- **Recommendation P-15-10**: Update guidance for gas transmission pipeline operators and inspectors on the evaluation of interactive threats. This guidance

[4] See meeting records for "Improving Pipeline Risk Assessments and Recordkeeping," Arlington, Virginia, July 21, 2011 (https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=70), and "PHMSA Pipeline Risk Modeling Methodologies Public Workshop," Arlington, Virginia, September 9, 2015, (https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=104).

should list all threat interactions that must be evaluated and acceptable methods to be used.

- This overview document discusses interactive threats in Section IV, Important Elements of Likelihood Modeling, Part E, Interactive Threat Modeling. The section lists different threats that can potentially interact as well as methods for incorporating threat interactions into risk models and provides discussions of the completed PHMSA-funded project DTPH56-14-H-00004 that provides tools and techniques for accounting for interacting threats in risk assessments (https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=557).
- Applicable RMWG Presentations:
  - Discussion of Interactive Threats (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65681/interactive-threats-discussionrmwg0816.pdf, August 9-11, 2016, Washington, DC)

- **Recommendation P-15-12**: Evaluate the safety benefits of the four risk assessment approaches currently allowed by the gas integrity management regulations; determine whether they produce a comparable safety benefit; and disseminate the results of your evaluation to the pipeline industry, inspectors, and the public.[5]
  - This overview document evaluates the four basic risk modeling approaches based on their suitability to support risk management decisions required by IM regulations in Section III, Overview Information for Use of Risk Model Types, Part A, Selecting an Appropriate Risk Model.
  - Applicable RMWG Presentations:
    - Risk Analysis and Rare Events Data (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65691/risk-analysis-and-rare-events-datarmwg0816.pdf, August 9-11, 2016, Washington, DC)
    - Probability Estimation (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65676/probability-estimationrmwg0816.pdf, August 9-11, 2016, Washington, DC)
    - USCAE Risk Assessment Methodologies (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/te

[5] See Section II.D for discussion relating the NTSB-referenced risk assessment categories to the categories discussed in this document.

chnical-resources/pipeline/risk-modeling-work-group/65701/uscaeriskassessmentmethodolgoiesrmwg0816.pdf, August 9-11, 2016, Washington, DC)

- ASMEB31.8S Risk Modeling Summary (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65671/asmeb31-8s-risk-modeling-summaryrmwg0816.pdf, August 9-11, 2016, Washington, DC)
- Critical Review of Pipeline Risk Models R&D Project (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65711/skow-dtph56-15-t00003-final-project-presentation-05-sept-2016-riskwo.pdf, October 4-6, 2016, Houston, Texas)

- **Recommendation P-15-13**: Update guidance for gas transmission pipeline operators and inspectors on critical components of risk assessment approaches. Include (1) methods for setting weighting factors, (2) factors that should be included in consequence of failure calculations, and (3) appropriate risk metrics and methods for aggregating risk along a pipeline.
  - This overview document discusses components of risk assessment approaches throughout, including weighting factors (Appendix A.D-8), factors for consequence failure calculations (Sections V.A.1 through V.A.5), and risk metrics/aggregation (Section VII, Appendix A.2, Appendix B.2).
  - Applicable RMWG Presentations:
    - Pipeline Risk Assessment (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65721/muhlbauer-phmsacommitteeoct2016.pdf, October 4-6, 2016, Houston, Texas)
    - HL Consequence Overview (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65716/cavendish-phmsarmwgliquidoperatorconsequencepresentation.pdf, October 4-6, 2016, Houston, Texas)
    - GT QRA (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65736/ng-qra-working-group-rev6.pdf, October 4-6, 2016, Houston, Texas)

- Emergency Planning & Response Performance Modeling (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65741/westrick-emergency-planning-and-response-performance-modeling.pdf, October 4-6, 2016, Houston, Texas)
- Relative Risk Model Applications at Southwest Gas (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65781/relativeriskmodelapplicationsatsouthwestgasrmwg0317.pdf, March 7-9, 2017, Houston, Texas)
- Using Data in Relative models with Respect to Decision Criteria (https://primis.phmsa.dot.gov/rmwg/docs/Using_Data_in_Relative_models_with_Respect_to_Decision_Criteria_RMWG0317.pdf, March 7-9, 2017, Houston, Texas)
- Index Models and Applications (Vectren) (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65841/indexmodelsandapplicationsdynamicriskrmwg0617.pdf, June 15, 2017, Houston, Texas)
- Index Models and Applications (Dynamic Risk) (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65841/indexmodelsandapplicationsdynamicriskrmwg0617.pdf, June 15, 2017, Houston, Texas)
- Migration from Older Risk Analysis Methods to Quantitative Models (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65826/migrationfromoldermethodstoquantitativemodelsrmwg0617.pdf, June 15, 2017, Houston, Texas)

To promote the development and application of improved pipeline risk models and to respond to these recommendations, PHMSA committed to organize and work with stakeholders in a Risk Modeling Work Group (RMWG) to help inform the development of this overview of methods and tools document.

The RMWG[6] was organized with representatives from state and federal pipeline regulators, pipeline operators and industry organizations, national laboratories, and other stakeholders.

[6] The mission statement of the RMWG that developed this document can be found at https://www.phmsa.dot.gov/pipeline/risk-modeling-work-group/risk-modeling-working-group-rd-documents-presentations along with other pertinent background information. See also Appendix F of this document for the RMWG mission statement.

This overview document incorporates information gathered from the presentations, meetings, and comments from members of the RMWG with respect to the state-of-the-art of pipeline risk modeling.

C. Definition of Risk

Risk is defined[7] as a measure of potential loss in terms of both the likelihood (or frequency of occurrence) of an event and the magnitude of the consequences from the event. A standard conceptual definition of risk used to structure risk assessment is given by the equation:

$$Risk = Likelihood\ x\ Consequence$$

For hazardous liquid and natural gas pipeline systems, the basic undesired event is the failure of a pipeline or pipeline system that results in a release of the gas or hazardous liquid. Likelihood is the probability or frequency of failure due to threats that affect the pipeline, and consequence is the severity of impacts to different receptor categories (e.g., human safety, environment, property) because of a pipeline failure.

A risk analysis considers the likelihood of failure from all potential and existing threats at each location along the pipeline. In addition, each receptor category may experience different consequence levels from a pipeline failure, depending on the failure mode (e.g., leak vs. rupture event) and location of the failure (e.g., proximity to receptors such as population and environmentally sensitive areas).

D. Background

Federal pipeline safety regulations have included requirements for risk assessment and risk analysis in the hazardous liquid and gas pipeline integrity management (IM) rules since their inception. Gas transmission IM requirements are found in 49 Code of Federal Regulations (CFR) Part 192, Subpart O. Hazardous Liquid IM requirements are found in 49 CFR Part 195.452.[8]

Initially, many pipeline operators implemented relative risk models to prioritize their performance of baseline integrity assessments and remediation of pipeline segment threats. However, the application of risk analysis required by Federal pipeline safety regulations goes well beyond the simple prioritization of pipeline segments for baseline integrity assessments. Additional applications include the following broad areas of performance requirements:

- Identification (§§ 195.452 (i)(1) and 192.935(a)) and evaluation (§§ 195.452 (i)(2), 192.911(c), and 192.917(c)) of preventive measures and mitigative measures;

[7] See definitions used in Section I of this document.

[8] See Appendix E of this document for excerpts from these requirements that relate to risk assessment and risk models. Regulatory references are those in effect as of the date of this document.

- Continual integrity evaluation process to identify the risks of integrity threats (§§ 195.452 (j)(2) and 192.937(b)); and
- Continual integrity assessment interval determination process ((§§ 195.452 (j)(3) and 192.939(a)(1)(i)).

PHMSA inspections of operator IM programs include operator risk assessment processes and the risk models employed in those processes; inspection experience indicates that operators' risk assessment approaches, primarily qualitative and relative risk models, have been lacking in many cases to meet all IM requirements and provide meaningful insight into the risks in an operator's unique operating environment.

The IM regulations also require operators to continuously improve their IM programs, and overall industry integrity performance has shown general improvement over time. However, the continuing occurrence of significant pipeline incidents points to a continuing need for operators to upgrade their tools for risk assessment and risk management. Upgrades to risk assessment processes using quantitative or probabilistic risk models is a prudent step for operators to take to improve IM programs, allowing better definition of the risks on pipeline systems and better support for risk management practices.

PHMSA has communicated its findings and concerns regarding risk models at past public meetings[9] and worked with the stakeholder participants in the RMWG to develop this overview document in support of improved pipeline risk models and their usage, as appropriate.

E. Risk Model Categories

Risk models employed in pipeline risk analysis can be categorized based on the nature of the model's inputs, outputs, and the nature of the algorithms used to convert the inputs to outputs. This overview document evaluates each category for its suitability to support pipeline operator decision making.

Table II-1 below gives the breakdown of risk model categories:

[9] See meeting records "Improving Pipeline Risk Assessments and Recordkeeping," Arlington, Virginia, July 21, 2011 (https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=70), and "PHMSA Pipeline Risk Modeling Methodologies Public Workshop," Arlington, Virginia, September 9, 2015 (https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=104).

Table II-1
Risk Model Categories

Model Category	Inputs	Outputs	Algorithms
Qualitative[10]	Qualitative and Quantitative	Qualitative	"Matrix" Mapping Inputs to Outputs
Relative Assessment/Index	Qualitative and Quantitative	Quantitative – unit-less	Risk Index Scoring
Quantitative System	Quantitative[11]	Quantitative – with units	Quantitative System Model
Probabilistic	Quantitative, including probability distributions	Probability distributions	Quantitative System Model

The **Qualitative** model uses qualitative inputs and outputs. The model translates any quantitative inputs into ranges or qualitative outputs (e.g., high, medium, low). The algorithm in this model is a direct mapping of inputs to outputs, often represented by a matrix.[12]

The **Relative Assessment** or **Index** model uses quantitative *or* qualitative inputs to derive quantitative outputs using a scoring algorithm.[13] Scores assigned to inputs are combined to obtain a unit-less quantitative output "index" score. The most common method of combining inputs and obtaining model outputs is to sum the individual and sometimes weighted risk factor scores.

The quantitative outputs are not expressed in risk assessment units like probability, frequency, or expected loss. Instead, they are unit-less index scores for likelihood, consequence, and risk. This method of combining risk factor inputs and producing outputs distinguishes this model from quantitative system or probabilistic models. Index models were used widely by pipeline operators to establish priorities for integrity assessments as part of the baseline integrity assessment requirements of the pipeline IM rules.

[10] Includes "SME" approaches.
[11] These models can use qualitative inputs that have been converted to numerical equivalents for evaluation.
[12] See Appendix A and ISO/IEC 31010:2009 – *Risk management – Risk assessment techniques* Annex B.29.
[13] See Appendix A and ISO/IEC 31010:2009 – *Risk management – Risk assessment techniques* Annex B.28.

- The term "semi-quantitative" risk model is not used in this document, in part due to RMWG technical discussions that indicated a wide variance in how this term can be interpreted. ASME B31.8S also does not use the term semi-quantitative, but in the description of the relative assessment model approach states "*Such relative or data-based methods use models that identify and quantitatively weigh the major threats and consequences relevant to past pipeline operations. These approaches are considered relative risk models, since the risk results are compared with results generated from the same model.*" Consistent with this treatment, risk models that have incorporated quantitative elements into their algorithms, but retain the underlying relative model structure, are included in the Table II-1 "Relative Assessment/Index" model category.

The **Quantitative System** model also has quantitative inputs and outputs. However, it is distinguished from Relative Assessment/Index models in significant ways, including:

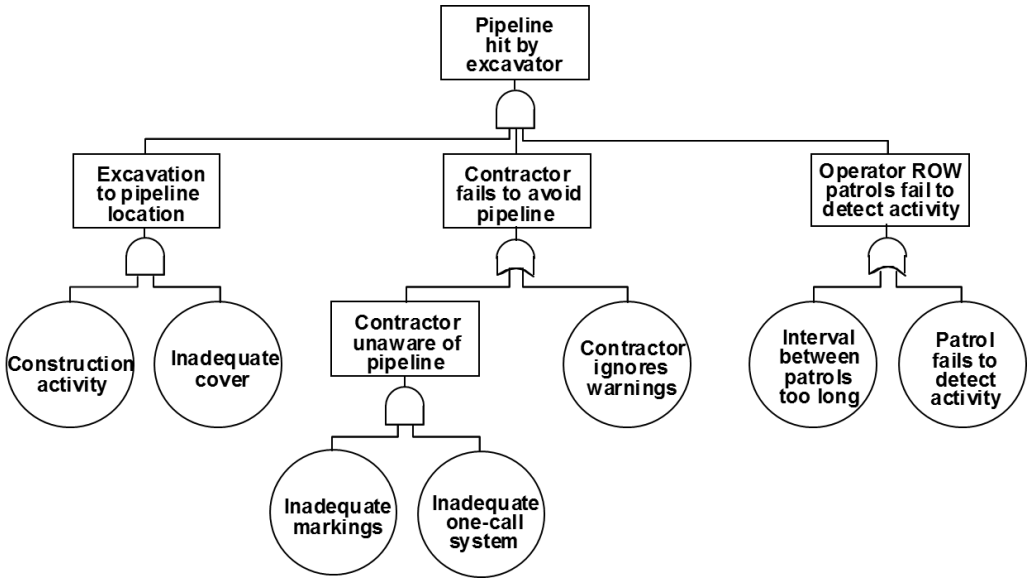
- Use of quantitative inputs and outputs that are expressed in risk assessment units like probability, frequency, expected loss, etc. Usage of risk assessment units is an important distinction from numerical/quantitative values used in Relative Assessment/Index models that are unit-less values, and only can be used to compare if they are higher/lower than other values within the model. For example:[14]
    - In a Relative/Index Model, a threat input value of "8" for coating condition on one pipeline segment versus a value of "4" on a different segment does not mean it is twice as likely to cause a failure due to poor coating, only that the segment with the higher value has relatively poorer coating than the segment with the lower value.
    - In a Relative/Index Model, a risk output value of "70" for a pipeline segment does not represent "twice" the risk of a different segment with an output value of "35"; only that the segment with the higher value has been determined to be of higher risk relative to the segment that has a lower score.
- Algorithms that model the physical and logical relationships of the pipeline system risk factors, the threats to system integrity, and the potential consequences of a product release from the system. This approach aims to combine risk factors in ways that more directly reflect physical reality (e.g., corrosion rates applied to effective wall thicknesses). The outputs from these models are likelihood, consequence, and risk measures expressed in recognizable units, such as probability or frequency of failure and expected loss.

  A minority of operators have employed models of this type in their IM programs.

[14] In these examples, higher values imply higher threat likelihood and higher risk.

As a simplified example of how Quantitative System models might model the relationship of risk factors in a pipeline system, consider part of a model of the probability of failure from third-party excavation damage. A failure from excavation damage may be modeled as the logical combination of factors such as the frequency of excavation activity in the area of the pipeline, one-call system probabilities, depth of cover, probability of an excavator hitting the pipeline, pipe resistance to a hit, and the effect of pipeline rights-of-way (ROW) patrolling. Figure II-1 (also shown in Appendix A.3) is an illustration of such a model for developing the probability of a pipeline hit by an excavator, using a fault tree to model the relationship of the relevant risk factors.[15] In this model, the probability of a hit is calculated by evaluating the likelihood of the individual risk factors (frequency of construction activity, probability of inadequate cover, probability of inadequate one-call, etc.) and combining these likelihoods according to the logical relationships in the model. The model's output likelihood is calculated in the units of frequency (per unit time) of a pipeline hit.[16]

Figure II-1
Simplified Example Fault Tree Model for Excavator to Hit Pipeline[17]



The **Probabilistic** model is a specific type of Quantitative System model. It is distinguished from other such models by using probability distributions to represent uncertainties in model inputs. Input distributions are propagated through the model to obtain probability distributions that represent uncertainty in the model outputs, such as failure probability, severity of consequences given a failure, or expected loss.

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[15] See ISO/IEC 31010:2009 – *Risk management – Risk assessment techniques*, Annex B.14.

[16] In contrast, an index model would have unit-less output values based on the (possibly weighted) sum of the individual risk factor scores.

[17] From Stephens, Mark, C-FER Technologies, *Methods for Probability Estimation* presentation to PHMSA Risk Modeling Work Group, 2016.

See Appendix A for examples of these model types.

E.1 ASME B31.8S Risk Assessment Method Categorization

In choosing risk assessment approaches to evaluate, PHMSA chose the risk model categories listed in above Table II-1, Risk Model Categories, as they are applicable for both hazardous liquid pipelines and gas transmission pipelines and represented basic methods of modeling.

ASME B31.8S-2004[18] presented four alternative approaches for gas transmission integrity management risk assessment:

1. Subject Matter Experts (SMEs)
2. Relative Assessment Models
3. Scenario-Based Models
4. Probabilistic Models

While there is overlap between these and PHMSA's four categories, the RMWG members noted that the ASME categories were not strictly risk models, but instead a mixture of both risk assessment tools and models.[19]

For example, Subject Matter Experts perform an important role in all types of pipeline risk modeling, and SME input is fundamental to both qualitative and quantitative model input. As a risk assessment method, the Table II-1 "Qualitative" category is comparable to the "Subject Matter Experts" B31.8S risk assessment approach category. To minimize potential confusion with the more general role of SMEs for all types of pipeline risk models, the term "Qualitative" risk model is used in this document instead of "Subject Matter Experts (SMEs)."

The RMWG members also noted that stand-alone scenario-based methods were utilized by some (mainly hazardous liquid) pipeline operators in the early phases of integrity management program development. These approaches look at specific failures and seek to identify events that could lead to that failure (e.g., HAZOP is a type of scenario model). In practice, this approach has proved to be difficult to apply to significant lengths of line pipe, and more recent applications have generally been limited to specialized cases (e.g., where a particular consequence is of concern).[20]

In addition, the B31.8S description of the "Scenario-Based" risk assessment method notes that "*This method usually includes construction of event trees, decision trees, and fault trees*." As noted previously in this section, these types of tools are often employed in both quantitative and probabilistic risk models as part of their model algorithms. For instance, fault trees[21] may be used to break down failure due to threats into more specific constituent events that can lead

[18] ASME B31.8S-2004 is incorporated by reference in the gas transmission IM rule, 49 CFR Part 192, Subpart O.
[19] Muhlbauer, *Pipeline Risk Assessment: The Definitive Approach and its Role in Risk Management*, 2015.
[20] PHMSA Risk Modeling Work Group, 08.09.16 Meeting Notes, Washington, DC (Likelihood).
[21] See ISO/IEC 31010:2009 – *Risk management – Risk assessment techniques*, Annex B.14.

to failure. Figure II-1 shows an example fault tree approach for excavation damage using a logical combination of contributing factors. The system can be modeled to the level of specificity where data and SME input can be applied to quantify the failure probability or frequency. Given that the application of this document is for both hazardous liquid pipelines and gas transmission pipelines, and that scenario-based tools can be used for various types of risk models, use of scenario-based tools were folded into the quantitative system and probabilistic risk model categories of this document.

III. Overview Information for Use of Risk Model Types

A. Selecting an Appropriate Risk Model

Pipeline operators should select risk models capable of supporting risk management decisions required as part of pipeline IM programs as well as more general risk management decisions that may be required. Table III-1 characterizes and compares the suitability of the different risk model categories defined in Section II.D to for each decision type.

Table III-1
Risk Model Types and Applicability to Decisions

Decision Type	Model Category			
	A. Qualitative Model	**B. Relative Assessment/ Index Model**	**C. Quantitative System Model**	**D. Probabilistic Model**
Risk Priorities for Baseline Integrity Assessment	A	A	A	BP
Preventive and Mitigative Measure Identification	A	A	A	BP
Preventive and Mitigative Measure Evaluation and Comparison	AI	AI	A	BP
Benefit-Cost Analysis for Risk Reduction Options	AI	AI	A	BP
Integrity Assessment Interval Determination	AI	AI	A	BP
General Risk Management Decision Making	AI	AI	A	BP

Key:

Can be Applicable with Additional Inputs to Risk Assessment Process	AI
Can be Applicable	A
Best Practice	BP

Qualitative Models and Relative/Index Models (Model Category A and Category B)

The initial application of risk models required by the hazardous liquid and gas transmission IM rules was to establish risk-based priorities for baseline integrity assessments. Relative assessment/index models, and to some extent qualitative-oriented models, were widely used by pipeline operators to support this requirement. This allowed large numbers of pipeline segments to be ranked based on risk factors. As indicated in Table III-1, the relative nature of assessment prioritization is an applicable application of these models. In the event a situation arises that would require the prioritization of a several new pipeline segments for a baseline assessment, relative/index models would still be applicable.

In addition to the broad scope of pipeline accident likelihood and consequence factors considered when using these type of risk models, Qualitative and Relative Assessment/Index models may be applied to support identification of preventive and mitigative measures, by considering model inputs and measures that change these inputs to values that are estimated to reduce risk. This application is essentially qualitative in nature, indicating the general effect proposed measures on the risk, so is appropriate for identifying P&M measures.

In general, application of Qualitative and Relative/Index models is more challenging for applications where the degree of difference between different scenarios, options, etc., or the risk as compared to a quantitative risk criterion is important, in addition to simply knowing which is a relatively higher or lower risk. Outputs from Qualitative and Relative Assessment/Index models may not be based on consistent units and cannot be assumed to be proportional to outputs like failure frequency, probability, or expected loss.

Qualitative or Relative Assessment/Index models do not produce this kind of output directly, so additional analysis or evaluation of the results is needed when these models are used to support comparison of alternative preventive or mitigative measures or benefit-cost analysis. Results from both Qualitative and Relative Assessment/Index models should be supplemented with additional analysis or data processing to be effective in supporting risk decisions.

Risk models that produce consistent quantitative output in standard risk units (probability of failure, expected loss, etc.) provide an easier format for evaluating and comparing risk alternatives, particularly for larger multi-regional pipeline systems. For applications, such as the comparison of alternative preventive or mitigative measures, or benefit-cost analysis, some form of a quantitative type of risk model output in standard risk units is generally needed.

In practice, continued use of qualitative and relative assessment/index models is best suited for small, less complex pipeline systems, where the effects of preventive and mitigative measures

on risk can be reasonably be understood via changes to the model inputs.[22] These systems can be characterized by limited geographic extent and lower mileage; simple system configuration; uniform risk factors throughout the system; affected HCAs limited in extent and similar in nature; and single, small operating organization.

Operators planning to continue the use of Qualitative and Relative Assessment/Index models should seek to supplement personnel judgment with as much pipeline physical attribute data as can reasonably be acquired over time. Operators should also ensure their risk model is capable of supporting risk management decisions required as part of pipeline IM programs, such as the selection of preventive and mitigative measures, and can be utilized for threat identification, risk analysis, and general risk management decisions.

Quantitative System Models (Model Category C)

Quantitative System models can be applicable for all decision types. The algorithms and outputs of quantitative system models produce quantitative estimates of overall risk, using consistent units. These models can be used to estimate the risk before and after risk reduction measures are implemented. Because a quantitative system model represents the physical and logical relationships of model inputs, the inputs can be varied to define alternatives and compare the risk reduction effects of each alternative. Candidate risk reduction measures at different locations along the pipeline can be compared via quantitative estimates using consistent input units. Quantified risk reduction benefits can be combined with data on implementation costs to perform benefit-cost analysis to further enhance decision making.

Probabilistic Models (Model Category D)

Probabilistic models are considered a best practice for supporting all decision types. Probabilistic models have the added feature of representing the uncertainty (i.e., realism) in model inputs by probability distributions, and the resulting ability to produce distributions for model outputs. This allows a systematic representation of uncertainty and unique risk insights for decision making not allowed by other model types. When utilizing the same data as a Relative model, the probability distribution outputs from the Probabilistic model inform the operator on the range of possible outcomes, regardless of data quality, which allows for more consistent decision making.

An example of the application of both Quantitative System and Probabilistic models is the incorporation of integrity assessment results and associated defect findings and remediation. In these models, the probability of failure and overall risk can be estimated using different integrity assessment intervals. Results can then be used to define optimal integrity assessment intervals consistent with the operator's risk tolerance. A Probabilistic model with input and output distributions is particularly effective for identifying integrity assessment intervals through its

[22] See ISO/IEC 31010:2009 – *Risk management – Risk assessment techniques*, Annex B, Section B.28, for additional discussion on the strengths and limitations of risk index models.

ability to support evaluation of the uncertainty in the predicted probability of failure given actual integrity assessment results. Also, uncertainties due to tool tolerances and other risk model inputs, such as corrosion growth rates, excavation damage statistics, and equipment reliability can be represented by input probability distributions, which may be propagated through the risk model along with other inputs to give an output distribution for probability of failure that more accurately portrays risk.

It should be noted that the IM rules require operators to reduce risks to high consequence areas (HCAs) by implementing preventive and mitigative measures beyond those measures required elsewhere in Parts 192 and 195 of the pipeline safety regulations. If limited operator resources require prioritization of risk reduction measures, then benefit-cost analysis, supported by the application of an effective risk model, can optimize the prioritization results. [Note: Risk analysis results should not be used to defer/delay the normal process of pipeline system remediation of known deficient conditions.]

A.1 Moving from Qualitative or Relative Assessment/Index Models to Quantitative System or Probabilistic Models

Quantitative System and Probabilistic models are considered more robust and capable of supporting all risk reduction decisions. Operators should consider moving to these risk modeling categories, as appropriate.

Developing and implementing Quantitative System models does not necessarily require more resources than Relative Assessment/Index models, despite some perceptions to the contrary. The structure of Quantitative System models can be more complex; however, they do not necessarily require more data than Index models and may be developed and implemented with common tools such as Microsoft Excel.

Many Relative Assessment/Index and Qualitative risk models include relatively large numbers of inputs representing pipeline characteristics and other risk factors. These inputs can serve as a starting point for development of a Quantitative System model that provides failure probability and risk in standard units. The inputs for Relative Assessment/Index models are often already quantified and can readily be incorporated in a Quantitative System model. PHMSA believes that operators using Relative Assessment/Index models should consider taking steps to develop Quantitative System models that utilize the inputs from their existing models. This would enhance the risk reduction decision making ability for those operators.

Probabilistic models are sometimes perceived as being excessively complex and requiring significant additional data. While it is true that quantifying a Probabilistic model involves more than a basic “spreadsheet” type of calculation, applying probabilistic analysis to basic Quantitative System models can be a more powerful use of available data. And while Probabilistic models are frequently believed to require more data, effective Probabilistic models can be developed with the same data used in Relative risk models. Effective Probabilistic model development is dependent upon appropriate use of data to accurately represent both the

certainty the data provides and the uncertainty the data implies. Modeling uncertainty in a Probabilistic model better informs the operator regarding the spectrums of the consequence and likelihood of failure that are possible, which, in turn, allows the operator to identify more effective risk reduction actions and improves assessment tool selection.

Probabilistic models include a more accurate representation of uncertainties than those provided by a Relative Assessment/Index risk model that uses point estimates of the same data as inputs.

A pragmatic approach is to evolve from the use of Relative Assessment/Index risk models to Quantitative or Probabilistic models over time. Organizational experience in developing and implementing quantitative system models for a limited number of threats can then be applied in a way that maximizes the benefits and optimizes the level of resources needed as the quantitative system model and probabilistic approaches are applied to an increasing number of threats.[23] Appendix D outlines one process for evolving Relative Index models to more of a Quantitative System modeling approach.

B. Understanding Uncertainty and Critical Model Parameters

The output of any risk model is an estimation of actual risk, so it is important to consider how much uncertainty may be involved with the model outputs. Variations in risk model inputs impact results, and different parameters have different influences on the results.

For Quantitative System models, input parameters can be represented by ranges of possible values, and the effect on the output of varying each input can be calculated. For Probabilistic models, the uncertainty in model inputs can be represented by probability distributions.

It is important to review the impact of input uncertainty to identify which uncertainties should be reduced by obtaining additional information. For example, the operator's SMEs may assign input variables a wide range of values given a lack of data or lack of SME agreement. If the range has a significant impact on the risk model results, efforts to obtain better data to reduce that uncertainty may be appropriate, particularly if the additional information could improve the evaluation of alternative risk reduction measures. In a probabilistic model, important model inputs (distributions) can be directly reviewed to help identify where there is significant uncertainty in the inputs (which ultimately impacts the confidence of model results). These inputs can be targeted for updating to reduce uncertainty and improve the fidelity of model results. [Appendix A Figure A-3 provides example distributions that represent uncertainties for model inputs as an illustration of this approach.]

Inputs that have the biggest impact on risk model output results are sometimes referred to as the "risk drivers." It is important when reviewing the risk drivers for a segment of line pipe or a

[23] Section IV.C addresses the potential for employing threat-specific risk models instead of a single modeling approach for all threats.

pipeline facility to determine if the model output results make basic technical sense. Examples are: risk model results are as expected by SMEs, no errors in the risk model or the inputs, or SME expectations are incorrect. (See Section III.C, Model Validation.)

Investigation of risk drivers can also suggest preventive and/or mitigative measures, by indicating the factors that could lead to the greatest reduction in risk if changed. Risk models should include the risk factors that change because of preventive measures and mitigative measures. If evaluated risk reduction measures do not result in differences in the model outputs, then analysts should ensure that this is not merely because the model does not include the applicable risk factors.

The relative importance of risk factors depends on the particular risk model output(s) of interest. Inputs may be important risk drivers over specific pipeline segments, but not significant system-wide or operator-wide. For example, the risk of failure due to a landslide might be negligible for the large majority of pipeline segments but could be the single most important risk factor for some segments with certain topography and soil conditions. The risk assessment model should accurately account for segment-specific parameters that are critical to the segment of pipeline being evaluated that experience similar threats and consequences.

C. Validating Risk Analysis Results

Risk model development requires the review of risk assessment results and validation of the model input and output data, both periodically and whenever significant changes are made to the model or its inputs (e.g., if operational experience demonstrates that data needs to be revised). Figure III-2 depicts typical risk model validation steps to ensure quality and the most accurate representation of pipeline risk.

Figure III-2
Model Validation

Validation of model **inputs** typically includes:

1. Model inputs should be validated against existing data/operational history and SME estimates, including inputs to both the likelihood and consequence analyses.
2. Model inputs need to represent the most accurate available information on each pipeline location. To accomplish this, input data should be reviewed and updated, as appropriate, by trained and qualified personnel. Management of risk model input

datasets should include clearly defined requirements, definitions, process owners, process maps, and governance structures to ensure compliance with ANSI/ASME B31.8S-2004 Section 5.7b. This clear definition of roles and responsibilities also applies if portions of the work are contracted to external organizations.

3. Consequence variables such as failure mode, response times, conditions affecting dispersion, and the locations of receptors need to cover the range of possibilities to ensure a representative selection of outcomes, particularly so that high-consequence outcomes are identified and can be selected for the application of risk reduction activities.
4. The structure of the risk model and algorithm(s) used to calculate risk measures should be checked to ensure the relationships of risk inputs are appropriately represented. The structure, analytical functions, analytical content, and technical computing structure detailed within the model should be continually reviewed and updated, as appropriate, by applicably trained and qualified personal.

Validation of model **outputs** typically includes:

1. Model outputs should be validated against SME review. The review includes operator-specific knowledge to ensure results are appropriate for operator-specific risks. The highest frequency sources of risk predicted by the model and risk drivers should be consistent with applicable historical data.
2. The results should be consistent with failure history data. If operating history of the analyzed pipeline or similar pipelines include failures or consequences that are not captured by the model, then changes to the model should be considered to include factors related to such historical events.
3. If model results vary sharply from SME expectations or operating history, the model and input values involved should be examined to identify the source(s) of the variance. It is possible that the discrepancy points to a need for data correction or modification to the model to accurately represent risk. It is also possible that the risk model results will yield new insights that are not consistent with SME expectations, so there may be variance in the operator's understanding of risk-important characteristics and what is produced by the model. These new insights into risk drivers are a valuable benefit of a risk model.

D. Configuration Control of Risk Models

Risk models are no different than other analytical tools supporting safe pipeline operation. They should be reviewed and updated on a regular, defined basis to assure they continue to accurately reflect the pipeline system's configuration and operation. A structured management of change process also applies to pipeline risk models. For example, data about the pipeline system is constantly being acquired, and updates to risk model inputs should be performed routinely to incorporate the latest information.

While the details of achieving management of change will vary for differing aspects of a risk model, the process for control and update of the model should assure that risk estimates provided to decision makers are accurate and incorporate the latest system information. For example, information on the population near the pipeline may change less frequently than cathodic protection information and may need less frequent updating in the model.

E. PHMSA Key Recommendations – Overview Information for Use of Risk Model Types

- The overriding principle in employing any type of model to support risk assessment is that it be capable of supporting risk management decisions.
    - A quantitative system or probabilistic model utilizes many of the same inputs as a relative assessment/index model. However, quantitative system and probabilistic models have algorithms that represent the physical relationships of model inputs, and model outputs that are risk measures in standard units. Consequently, the outputs from quantitative system models or probabilistic models are directly applicable to support evaluation and comparison of preventive measures. In general, a quantitative system or probabilistic model is more versatile for such an evaluation, with greater capabilities to provide risk insights and support decision making.
    - Outputs for qualitative and relative assessment/index models are not risk measures in standard units that are easily comparable for different segments or different preventive measures. Therefore, additional processing and interpretation of the results may be required to apply model risk evaluations to decision making by the operator. This additional processing and interpretation necessarily takes place outside of the risk model as part of the operator's overall risk assessment and risk evaluation process.
- Identification and evaluation of preventive measures is an important application of risk assessment, and required by IM regulations. This application can be supported by a risk model that has the following characteristics:
    - The model can indicate the change in risk from implementation of the risk reduction measure.
    - The model includes all threats to the pipeline segment that can be addressed by preventive measures.
    - Model inputs represent the pipeline characteristics and other risk factors affected by the preventive measures, so that the effect of each measure can be evaluated through changes in inputs or changes to the structure of the model.

IV. Likelihood Modeling for Line Pipe

This section[24] on line pipe covers important characteristics of the likelihood part of the risk definition and formula.[25] Likelihood represents the chance of an unwanted event occurring. In the context of pipeline risk modeling, the primary "unwanted event" for hazardous liquid and natural gas pipelines is the failure of a pipeline or pipeline system to contain the gas or hazardous liquid product. The likelihood part of a pipeline risk model encompasses the scenarios for failure and uses the model input variables in those scenarios and the interrelationships among inputs to estimate an overall likelihood of failure. To accomplish this, the model should specify:

1. Input variables representing characteristics of a pipeline segment and the environment around the segment, representing all factors important for estimating the likelihood of failure for the segment: They represent the prevalence of threats, the resistance of the pipeline system to threats, and the effectiveness of existing preventive measures. These variables may include pipe condition, coating condition, cathodic protection (CP) effectiveness, operating pressure, operating stress level, depth of cover, excavation activity around the pipeline, landslide potential, and product transported.
2. How to combine the model inputs in the overall evaluation of the likelihood of failure. The model should accurately represent threat interactions that could increase the likelihood of failure, and specify whether an input variable can cause failure on its own or must occur in combination with other factors.

Different model types have different output likelihood measures. Output likelihood measures from different model types[26] can be qualitative categories, relative indexes, or quantitative measures of probability or frequency in standard units. Output measures in standard units, such as failures per unit distance per unit time (e.g., failures per mile per year) are the most flexible and widely applicable model outputs, allowing a consistent measure of failure likelihood for a pipeline segment, specifying *time* and *distance* (length):

1. The likelihood of failure varies depending on the time interval being considered. For example, the likelihood of failure for a specific pipeline segment is higher over a 10-year period than during a single year. Consequently, likelihood measures are typically expressed as frequencies per unit time (e.g., failures per year).
2. The likelihood of failure also varies depending on which portion of a pipeline system is being evaluated. As a system that can extend over long linear distances, a pipeline has different likelihoods of failure for different portions, because risk

[24] Sections IV and V of this document consider modeling of likelihood and consequences primarily for line pipe segments. Risk modeling for pipeline facilities (e.g., pump and compressor stations, tank facilities) is considered in Section VII.

[25] See Section II.C of this document for definitions and formula.

[26] See Section II.D of this document.

factors vary at different locations. A pipeline risk model should be able to evaluate the likelihood of failure for specifically defined segments.

Sections IV.A through IV.H below provide additional information on risk model treatment of likelihood.

A. Pipeline Threats

The likelihood of pipeline failure is derived from the collective likelihood of all threats acting on the pipeline and leading to pipeline failure. Pipeline risk models break down broad threat categories into more specific inputs that can be quantified using data or judgment and combined by a model algorithm to obtain the likelihood estimate.

Pipeline IM regulations (see Appendix E) require identification and evaluation of preventive measures to reduce the likelihood of failure. Most preventive measures implemented by pipeline operators attempt to reduce the likelihood of failure due to a single threat or a subset of threats. To evaluate these potential preventive measures, the operator determines the impact of the potential measure on the likelihood of failure for each threat (also accounting for interacting or dependent threats) and sums all the threats to identify the final impact of the potential change to the likelihood of failure.

Historical pipeline failure experience has resulted in a generally consistent scheme for categorizing threats. Different sources employ similar categorization of threats that should be considered for a complete evaluation of pipeline failure likelihood. The Risk Modeling Work Group considered the threat categorization from four sources:

a. ASME Standard B31.8S-2004 identified threats[27]
b. Muhlbauer identified failure causes [28]
c. Canadian incident reporting failure causes[29]
d. U.S. DOT accident and incident report causes[30]

PHMSA compared and integrated the categories from these four sources to develop the following categories of threats recommended for the likelihood portion of risk models:

1. External Corrosion
2. Internal Corrosion
3. Environmental Cracking (including SCC)
4. Structural/Material Degradation (non-steel pipe)

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[27] ASME B31.8S-2004, *Managing System Integrity of Gas Pipelines*, 2005. Although developed specifically for application to gas pipelines, the threat categories in this document are applicable to hazardous liquid pipelines.
[28] Muhlbauer, *Pipeline Risk Assessment: The Definitive Approach and its Role in Risk Management*, 2015.
[29] CAN/CSA-Z-662-15, *Oil and Gas Pipeline Systems*, Annex H.
[30] PHMSA F 7000-1-Accident Report Form, F 7100.1-Incident Report Form, and F 7100.2-Incident Report Form can be accessed on PHMSA's web site at: https://www.phmsa.dot.gov/forms/operator-reports-submitted-phmsa-forms-and-instructions.

5. Manufacturing-related Defects (includes defective pipe and seam acted on by fatigue or other failure mechanisms)
6. Construction-, Installation-, or Fabrication-related Defects (includes defective girth weld, fabrication weld, wrinkle bend or buckle, stripped threads, broken pipe, coupling failure acted on by fatigue or other failure mechanisms)
7. Equipment Failure (includes failure of control/relief equipment, pump, compressor, seal/pump packing failure, threaded or non-threaded connection, tubing or fitting, gasket O-ring, equipment body)
8. Excavation Damage (includes damage by operator, contractor, or third party; includes immediate failure or damage that results in later failure)
9. Other Accidental Outside Force Damage (includes causes such as vehicle impacts, other fire or explosion, electric arcing)
10. Intentional Damage/Vandalism/Sabotage
11. Incorrect/Improper Operation (includes human errors such as tank overfull, valve misalignment, over-pressurization, improper equipment installation)
12. Geohazards/Weather/Natural Force Damage
13. Other/Uncategorized/Emerging Threat

Models should include all applicable threats, including any emerging threats found by pipeline operators that do not fit easily into the categories listed above. Even threats that have a low likelihood of causing a pipeline failure at a given location should be considered in the model (e.g., if the potential consequences due a failure from a low likelihood threat at the location could be high, the overall risk might be significant).

B. Selection of Approach for Representing Likelihood

The development of algorithms for assessing likelihood using a quantitative system model can employ a variety of approaches. The overall likelihood of failure is built threat by threat, by considering the factors affecting the likelihood of failure for each threat.[31] The structure and approach to estimating the likelihood of failure due to different threats can vary widely in Quantitative System models. The choice of approach may also differ for different threats within the same model, based on the available data and information. Some different likelihood modeling approaches include:[32]

1. **SME opinion** – SME opinion is converted into quantitative probabilities.
2. **Historical data** – Historical failure rates from available databases are used to estimate baseline failure rates, which are modified to reflect system specific attributes.

[31] Including accounting for threat interactions; see Section IV.E of this document.

[32] This list of approaches is taken from Skow, J., C-FER Technologies, Inc., *Critical Review of Candidate Pipeline Risk Models*, presentation at Pipeline Risk Modeling Methodologies Public Workshop, September 2015. See also Koduru, et al., C-FER Technologies, *Critical Review of Candidate Pipeline Risk Models*, 2016.

3. **Reliability Analysis Methods** – Detailed engineering models are used to estimate probability and consequence.

Another method for assessing the likelihood of failure for different threats is the "triad" approach recommended by Muhlbauer.[33] This approach envisions the modeling of pipeline failure mechanisms as assessing "exposure," "mitigation," and "resistance," defined as:

> *"…**Exposure (attack)** -…defined as an event which, in the absence of mitigation, can result in failure, if insufficient resistance exists…*
>
> ***Mitigation (defense)** -…type and effectiveness of every mitigation measure designed to block or reduce an exposure.*
>
> ***Resistance** – measure or estimate of the ability of the component to absorb the exposure force without failure, once the exposure reaches the component…"*

The application of relative assessment/index models in IM programs led to questions regarding "weights" for likelihood scores of individual and interacting threats and their relative contributions to failure likelihood. This issue arose because some models treated the likelihood contributions from all threats equally in the total risk estimates, and did not consider interacting threats. This is a distortion because, historically, different threats have caused failures with different frequency. [For example, past failure history indicates threats like corrosion, material cracking, and third-party damage have been the cause of failures with greater frequency and impact than other threats.]

To correct this distortion, some models apply fixed numerical weights as multipliers to each threat's likelihood score and add the weighted scores to obtain a total likelihood score. However, the weights are often based on risk model vendor's historical averages using data from diverse pipelines. Consequently, applying such averaged weights introduces additional distortion in the likelihood estimates intended to represent specific segments on specific pipelines with location-specific risk factors. To represent risk in the most accurate way possible, the risk assessment model should accurately account for segment-specific parameters of each segment of the pipeline being evaluated.

This is an issue affecting relative assessment/index models or qualitative models only, because Quantitative System models do not use fixed weights to normalize threat-specific likelihood of failure estimates for specific segments, although the quantitative estimates may use historical data as an input to the model.

[33] Muhlbauer, *Pipeline Risk Assessment: The Definitive Approach and its Role in Risk Management*, 2015. The reference includes examples of the modeling approach for different threats.

C. Single Approach or Threat-Specific Approach

When considering different modeling approaches, it is important to keep the overall purpose of risk modeling in mind – to understand the likelihood of threats to and consequences of a failure for a pipeline segment, and to identify measures to reduce and manage the risks. When a single approach is applied to all threats, the detail needed to model more complex threats adequately may be applied to other threats, even if a simpler approach is sufficient. Some operators may choose a threat-specific approach to risk modeling rather than a single approach for all threats to optimize available resources and reduce model complexity.

In practice, pipeline operators, particularly for smaller systems, often select approaches to risk modeling with the primary consideration of resource availability. Some modeling approaches are viewed as complex and costly, whereas other approaches may not be detailed enough to adequately model risk for specific threats. In addition, there can be a natural tendency for analysts to seek a single measure to characterize the overall risk for a pipeline segment. This can lead to the assumption that only a single approach should be taken to model pipeline risk.

A single risk value is of interest when evaluating the relative level of risk between different parts of a pipeline system, or when an absolute estimate of risk is needed. However, different threat-specific risk modeling approaches may be preferable, even if they do not result in a singular measure of likelihood or risk. For example, if one threat is thought to require a more detailed evaluation than others (e.g., stress corrosion cracking), operators should not feel like they must treat all threats with the same level of heightened sophistication if it is not needed. Less sophisticated models may be sufficient for the other threats.

Finding an appropriate balance of complexity, cost, and applicability of results is a challenge unique to each pipeline being analyzed. Figures IV-1 and IV-2 show the general outlines of these differing approaches (the multiple arrows in Figure IV-2 indicate threat-specific modeling approaches vs. the singular modeling approach shown in Figure IV-1).

One challenge to a threat-specific approach is the comparison of output results from the different approaches. The ability to compare results is important to evaluating which risks are the most important to address and promoting the efficient use of resources for implementing preventive measures across the pipeline operator's assets. One way to address this challenge is to extend the threat-specific analysis to include consequences, and then comparing threat-specific risk estimates, combining likelihood and consequences. Comparison of consequence estimates is generally more straightforward, as consequence estimates can be characterized by a common output such as expected loss.

Figure IV-1
Threat Category Modeling (Single Approach)

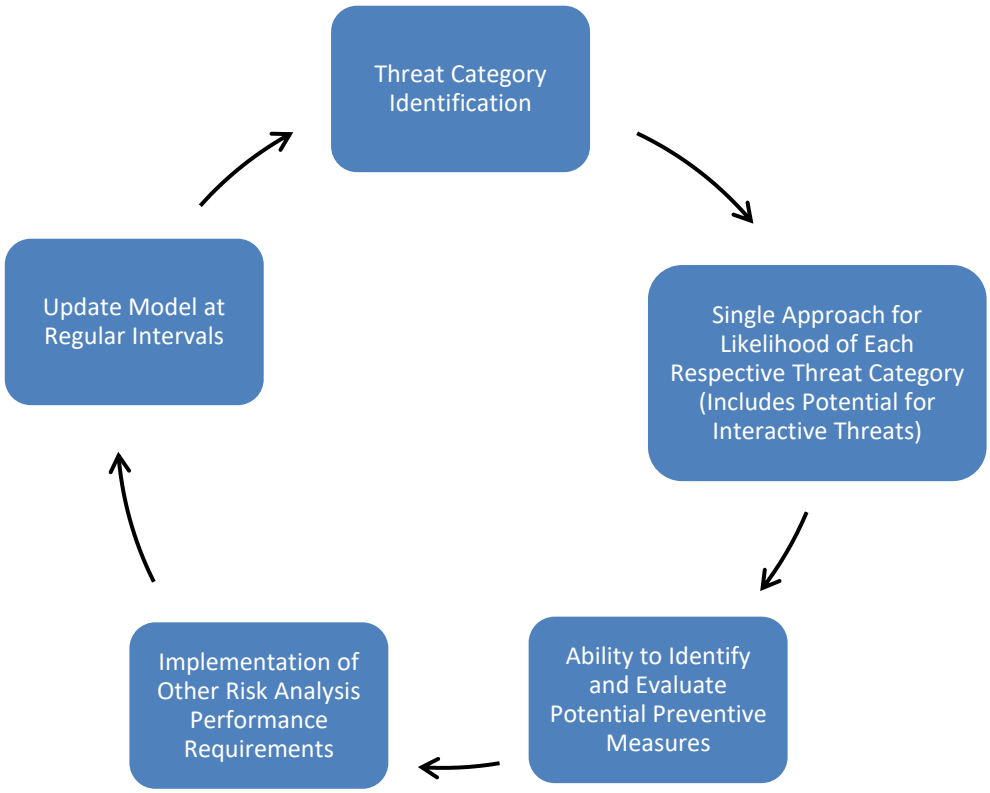
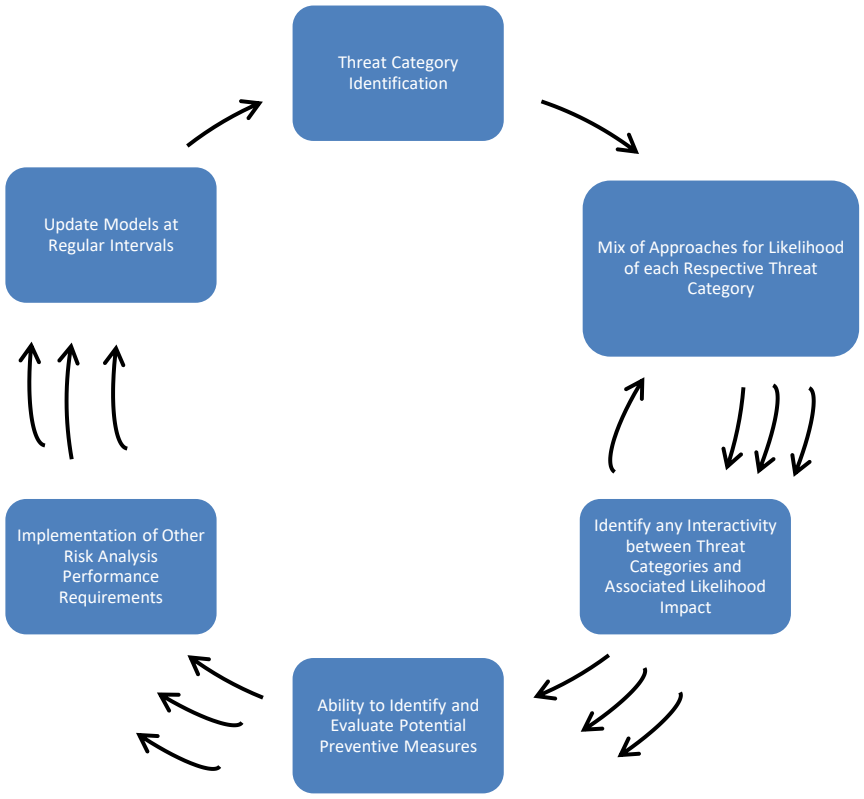


Figure IV-2
Threat Category Modeling (Threat-Specific Approach)



D. Human Performance Modeling

Historical failure experience shows that pipeline operator actions can have a significant effect on the likelihood of failure and the level of consequences following a pipeline failure. PHMSA has observed that these risk factors may be underrepresented in operator risk models. To fully represent the likelihood of failure, the risk model should include inputs related to human performance, and the model algorithms should include the relationship of these factors to other risk factors in the overall evaluation of risk. Risk modeling of human errors can be accounted for in various ways for likelihood estimates, including:

1. A threat category that represents operator actions that are the apparent cause of failures, e.g., "incorrect operation." While PHMSA incident and accident data often list "small" percentages for "incorrect operation" as an apparent cause,[34]

[34] https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-20-year-trends

probable and root cause analyses commonly find human performance as a leading contributory cause and cause of incidents and accidents as well as exacerbating the consequences of the failure.

2. Failures in other threat categories may stem from human errors. For example, "equipment failure" may result from maintenance, or design and construction human errors.
3. Consideration of interactive threats includes interactions between threats due to operator actions. For example, the threat category "incorrect operation" has potential interaction with threats in multiple categories. One example is a crack-like defect introduced during the manufacture of a seam weld along with failure of the operator to properly account for the effects of pressure-cycle-induced fatigue on potential seam defects.[35]
4. Potential human errors added to the uncertainty in the likelihood of failure given integrity assessment results, i.e., assessment results are subject to mischaracterization and misidentification of repair conditions.

Operator actions, or lack of actions, can often overlap between likelihood and consequence aspects of pipeline risk modeling. Actions taken in response to failures can affect the severity of consequences. They can also directly impact likelihood modeling when differing characteristic of pipeline releases is involved (e.g., likelihood of small vs. medium vs. large releases). Dependencies of potential release levels on operator actions should be considered in the model to correctly characterize risk.

E. Interactive Threat Modeling

The threats represented in a pipeline risk model may be interactive, because mechanisms that drive the likelihood of failure from one threat may be intensified by mechanisms driving the likelihood of failure from another threat. The interaction of the mechanisms driving both threats increases the total likelihood of failure from the combined threats. Multiple threats may also interact and result in an otherwise premature failure at a location on the pipeline. A study sponsored by PHMSA[36] uses a similar concept to define interacting threats as "two or more threats acting on a pipe or pipeline segment that increase the probability of failure to a level greater than the effects of the individual threats acting alone."

This study further points out that "…In order for threats to be interacting, they must act to cause a condition or situation that is more severe than that created by individual threats. It is important to note that threats are not necessarily interacting simply because they exist at the same location on a pipe or pipeline."

[35] See Section IV.E, Table IV-1 of this document.

[36] Munoz and Rosenthal, *Improving Models to Consider Complex Loadings, Operational Considerations, and Interactive Threats*, Kiefner and Associates, U.S. DOT / PHMSA DTPH56-14-H-00004, 2016.

To provide an appropriate likelihood of failure estimate, the risk model should account for the interaction of multiple threats. In addition, identification of effective preventive measures and evaluation of the effect of preventive measures on reducing the likelihood of failure should include consideration of interacting threats.

One example of threat interaction is external corrosion or cracking on pipe damaged by denting that has not yet failed. If the pipe damage caused external coating damage or coating shielding in an area of ineffective cathodic protection, then the pipe is more susceptible to external corrosion and cracking and the resulting likelihood of failure is increased. Another example is earth movement around a pipeline that exacerbates construction-related imperfections such as wrinkle-bends or certain vintages of girth welds.

The likelihood of failure from each threat includes a portion that involves that threat alone and a portion that involves interaction with other threats. To evaluate the likelihood of failure from multiple threats, the risk model should appropriately account for both portions. To illustrate, consider the following example of two threats. The likelihood of failure (probability) from the two threats can be expressed as:

$$P_T = P_1 + P_2 + P_i$$

Where P_1 = failure probability from threat 1 individual factors
P_2 = failure probability from threat 2 individual factors
P_i = failure probability from threat 1 and threat 2 interactions

P_i in this expression is evaluated by considering the increased conditional probability of failure from threat 2, given the interactive factors from threat 1. In this example, the increased likelihood of failure from external corrosion due to ineffective CP combined with the existing coating damage from previous pipe damage will be higher than the likelihood of failure from external corrosion if no coating damage is assumed. Accordingly, that will increase the probability P_i in the above expression[37] used to evaluate the probability of failure from either threat.

Defining the interactions between different threats is an important activity in pipeline risk model development. It enhances the accuracy of the model as a representation of the risk of the pipeline. Additionally, the process of investigating and defining potential threat interactions can uncover failure causes that may not be immediately apparent. For a complete risk analysis, the definition of risk factors and assignment of values to model inputs for a pipeline segment should involve consideration of threat interactions. Both historical data and SME input should be employed to define potential threat interactions. Analysis of historical failure data may point to failures resulting from interactive threats where pipe characteristics are similar to the

[37] The expression for the probability of failure from either threat is simplified by assuming the multiplied terms of the probability expression ($P_1 \times P_2$, $P_1 \times P_i$, $P_2 \times P_i$, etc., are small relative to the probabilities P_1, P_2, and P_i.

pipeline being modeled. SMEs with local knowledge can identify segments with characteristics that make them susceptible to interacting threats.

Munoz and Rosenthal[38] identified combinations of threat types that could potentially interact. The study, based on a literature search, SME surveys, and analysis of accident/incident historical data, identified 98 threat interactions considered "reasonably possible" and depicted these threat interactions in a matrix, shown below in Table IV-1.[39] Interacting threats are indicated by a "1" in the matrix entry for each pair of threats that interact. Footnotes to the table give conditions when the threats might interact.

Table IV-1
Interacting Threat Matrix

			Time-Dependent			Stable									Time-Independent							
			EC	IC	SCC	MFR		CON			EQ				IO	TPD			WROF			
			EC	IC	SCC	DP	DPS	DFW	DGW	CD	MCRE	TSBPC	GF	SPPF	IO	TP	PDP	V	EM	HRF	LIGHT	CW
	EC	EC			1	1	1		1	1[1]	1	1[3]	1		1	1	1		1	1		1
	IC	IC				1	1		1		1		1		1		1					
	SCC	SCC				1	1	1	1	1[4]	1				1		1		1	1		
	MFR	DP					1	1	1	1	1[2]					1[7]	1[7]	1[7]				
		DPS								1[5]	1[2]				1[6]	1[7]	1[7]	1[7]	1			
	CON	DFW										1			1	1			1	1		1
		DGW								1	1					1	1		1	1		1[8]
		CD									1[2]	1							1	1		
	EQ	MCRE										1	1	1	1	1	1			1	1	1
		TSBPC													1	1			1	1		1
		GF													1	1		1	1	1	1	
		SPPF													1							
	IO	IO														1	1	1	1	1		1
	TPD	TP															1		1	1		
		PDP																	1	1		
		V																				
	WROF	EM																		1		1
		HRF																				1
		LIGHT																				
		CW																				

Table IV-1 Footnotes:

1. A 1 applies unless the history of the segment indicates the construction damage has not contributed significantly to corrosion.
2. A 1 applies if the segment has not been subject to a pressure test to at least 1.25 times MAOP.
3. A 1 applies if the Dresser-coupled segment has no CP or has CP but no bonds across the Dresser couplings.
4. A 1 applies unless it can be shown either that little or no coating damage exists or that the segment is not susceptible to SCC.
5. A 1 applies if the pipe is seam-welded and was installed with wrinkle bends
6. A 1 applies if the pipe was manufactured with low-frequency welded ERW seam or flash welded seam.
7. A 1 applies unless it is known that the pipe material exhibits ductile fracture behavior under all operating circumstances.
8. A 1 applies only to pipe joined by acetylene girth welds or girth welds of known poor quality.

[38] Munoz and Rosenthal, *Improving Models to Consider Complex Loadings, Operational Considerations, and Interactive Threats*, Kiefner and Associates, U.S. DOT / PHMSA DTPH56-14-H-00004, 2016.

[39] Munoz and Rosenthal, *Improving Models to Consider Complex Loadings, Operational Considerations, and Interactive Threats*, Kiefner and Associates, U.S. DOT / PHMSA DTPH56-14-H-00004, 2016, Table 1.

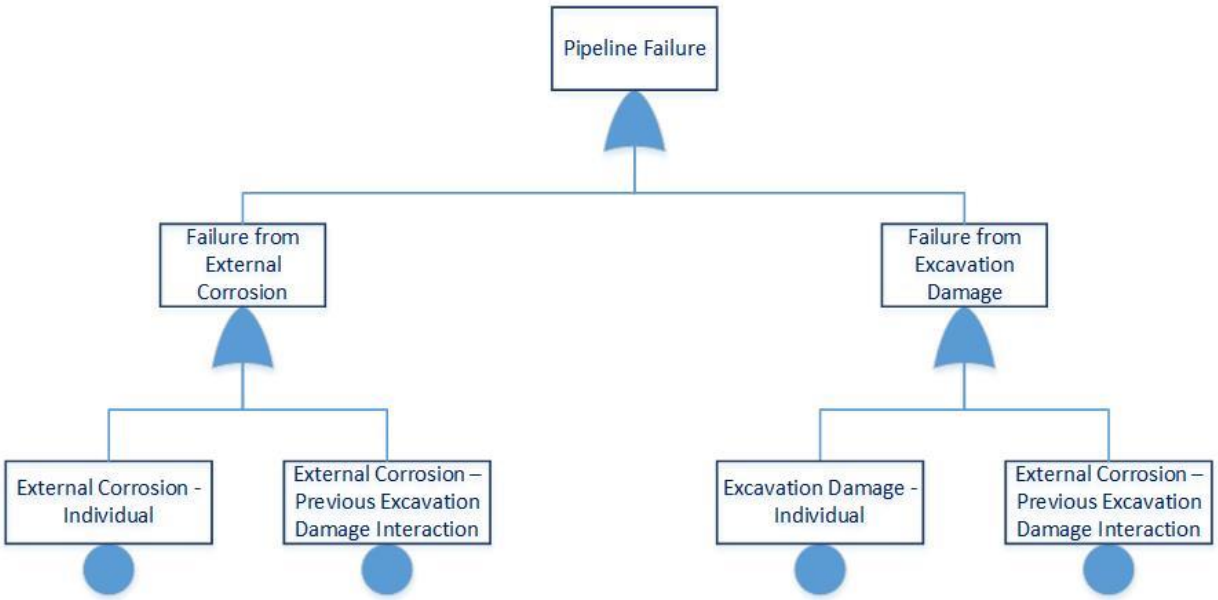
The codes used in the matrix to represent different threats are:

- External Corrosion (EC)
- Internal Corrosion (IC)
- Stress Corrosion Cracking (SCC)
- Manufacturing Related (MFR)
- Defective Pipe (DP)
- Defective Pipe Seam (DPS)
- Construction Related (CON)
- Defective Fabrication Weld (DFW)
- Defective Girth Weld (DGW)
- Construction Damage (CD)
- Equipment Related (EQ)
- Malfunction of Control or Relief Equipment (MCRE)
- Stripped Threads, Broken Pipe, or Coupling Failure (TSBPC)
- Gasket Failure (GF)
- Seal or Pump Packing Failure (SPPF)
- Incorrect Operations (IO)
- Third Party Damage (TPD)
- Third Party (includes First and Second Parties) (TP)
- Previously Damaged Pipe (PDP)
- Vandalism (V)
- Weather Related or Outside Force (WROF)
- Earth Movement (EM)
- Heavy Rains and Floods (HRF)
- Lightning (LIGHT)
- Cold Weather (CW)

Threat interactions such as shown in Table IV-1 should be incorporated in risk models at locations where they are found applicable.

Fault trees may be used to model interacting threats explicitly by representing shared failure mechanisms as the same basic event in the models for each of the interacting threats. When the likelihood of failure due to the interacting threats is quantified using the fault tree logic, then the combined likelihood of failure from the threats will correctly represent the contribution of the interactions. This is shown in Figure IV-3 below, using the example of external corrosion and excavation damage. Note that the threat interaction event under both external corrosion and excavation damage is identical.

Figure IV-3
Example Fault Tree Model of Interactive Threats



Threats that act on pipelines independently (e.g., external and internal corrosion) may also act simultaneously at the same location on a pipeline. If such conditions are identified, by integrity assessment methods or otherwise, then this would impact the evaluation of the likelihood of failure at the location where both threats are impacting the pipeline. For a valid estimate of likelihood of failure, the risk model should reflect the composite effect of both threats, based on the identified condition of the pipe.

Muhlbauer[40] states that some threat interactions may be considered in the "triad" approach to failure modeling (see Section IV.B of this document) by modeling varying "resistance" according to the mechanisms that define the interaction. In the external corrosion/excavation damage interaction example discussed previously, this would mean that modeling the resistance of the pipeline to the external corrosion threat is reduced in areas of excavation activity, by a factor that represents the likelihood that the excavation activity results in coating damage.

F. Threshold for Threat Consideration

Screening threats can have a distinct impact on risk analysis results. As part of IM rule requirements, operators must determine the applicability of specific threats to pipeline

[40] Muhlbauer, *Pipeline Risk Assessment: The Definitive Approach and its Role in Risk Management*, 2015.

segments for the purposes of conducting integrity assessments[41] and repairing anomalies. However, PHMSA has noted in pipeline inspections and failure investigations that operators are applying the threat screening criteria for integrity assessments to risk models, causing threats deemed insufficiently significant to require an integrity assessment to be inappropriately excluded from risk models.

IM regulations require pipeline integrity assessment and repairs of identified pipe anomalies for pipeline segments that could affect HCAs. Operators may also carry out integrity assessments beyond the HCA-affecting segments. Integrity assessment methods are employed for specific threats of concern (corrosion, cracking, mechanical damage). Operators base decisions on which integrity assessment methods to apply on an evaluation of the susceptibility of pipeline segments to specific threats. If a particular threat is not considered significant on a segment, then an integrity assessment method associated with that threat is not specifically required.

However, when a threat is eliminated from consideration for integrity assessment, the threat must not be eliminated from inclusion in a risk model used to evaluate other risk reducing measures. In other words, if a threat is not deemed significant enough to warrant application of a specific integrity assessment method, it does not necessarily mean that threat can be discarded from the likelihood analysis in the overall risk model nor can data stop being collected on that threat. To do so may lead to an incomplete risk evaluation and erroneous determinations of risk reduction measures. Many threats do not warrant that a unique integrity assessment technique be applied but are nonetheless valid for the consideration of risk reduction measures. The basis for screening out threats from consideration for integrity assessment must be documented and maintained for the useful life of the pipeline (in accordance with §§ 192.947 and 195.452(l)).

The pipeline risk model should represent all relevant threats. It is important that the threats included in the model are not limited only to those that have caused pipeline failure historically. Rather, the model should include other threats that have caused failures within the pipeline industry and could do so in the future because of pipe characteristics and changing conditions affecting the pipeline. On some segments, pipeline characteristics may result in the model estimating a negligible likelihood of failure for one or more threats (e.g., several orders of magnitude lower than higher likelihood threats). Such a result can be justification for reduced priority of additional measures to prevent failures from the negligible threats. However, such decisions must be made carefully to ensure a complete and accurate risk analysis. Additional considerations include:

[41] "Integrity assessment" refers to method(s) used to assess the integrity of the line pipe for identified threats. More than one method may be required to address all the threats to a pipeline segment (49 CFR Part 192, Subpart O). Current pipeline code sections can be accessed at the U.S. Government Printing Office web site at: https://www.ecfr.gov/cgi-bin/text-idx?SID=1d49a3b137cb1b6fc45251074e634b44&c=ecfr&tpl=/ecfrbrowse/Title49/49cfrv3_02.tpl.

1. Threat screening should consider the severity of consequences, as threats presenting a low likelihood of failure may be risk-significant if the failure modes could result in especially severe consequences.
2. If measures are taken to reduce the likelihood of failure from other threats, then the likelihood of failure from the screened-out threats should be reconsidered to determine if they are significant for a segment.
3. Interactions with other threats should be evaluated. Threats with low risk when considered individually may still interact with other threats and result in a significant risk.
4. Uncertainties in the assumptions and basis for model parameter values should be examined to determine if the likelihood of failure from a threat could be higher with small changes. If the uncertainties indicate that the likelihood of failure from the threat could be considerably higher, then evaluation of the threat should be included in the model. Understanding the shape of probability distributions for inputs can provide important insights into the effect of uncertainty and identify when actions to reduce uncertainty can impact decisions and yield significant risk reductions.

G. Application of Risk Models to Identify and Evaluate Preventive Measures

Integrity Management regulations require risk assessment to support identification of risk reduction measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area[42] and evaluation of the likelihood of a pipeline release occurring and how a release could affect the high consequence area.[43] Section 192.935(a) requires that an operator take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. Section 195.452(i) requires that an operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. "Preventive" measures reduce the likelihood of failure through additional protection against threats.

A risk model that supports an evaluation of the effect of implementing preventive measures has an output measuring likelihood of failure that is capable of reflecting changes due to preventive measures and estimating the differences in risk due to the changes. Changes can be represented in the model by changing the values assigned to variables or by making changes to the model structure (e.g., adding a variable to represent increased redundancy of measures combatting a threat).

The effectiveness of different types of models in supporting risk-based decisions, including decisions on preventive measures, was discussed in Section III.A. A risk model can support

[42] 49 CFR §§ 195.452 (i)(1) and 192.935(a).
[43] 49 CFR §§ 195.452 (i)(2), 192.911(c), and 192.917(c)).

identification and *evaluation* of preventive measures. To assist *identification*, sensitivity analysis can be conducted to help examine which threats and model inputs are driving the risk results. Preventive measures can be defined to address the most important risk drivers.

One method of performing such a sensitivity analysis is to reduce the value assigned to each model input variable one by one by a fixed percentage (e.g., 25-50 percent), leaving the other variables fixed at their best estimated values. The risk is then reevaluated using the revised input value. After this is repeated for all variables, the results can be compared. The variables that drive the biggest changes in the likelihood of failure could represent the risk factors with the best potential for risk reduction by preventive measures.

This evaluation can be performed on the entire pipeline or on specific pipeline segments. If considering the entire pipeline, the analysis results would show risk factors that have the greatest overall potential for risk reduction. If conducted separately for specific pipeline segments, the results indicate the factors that have greatest potential for risk reduction on those segments. If relatively few segments dominate the risk of the entire pipeline, then concentrating on the risk factors and potential preventive measures for the high-risk segments may present an efficient path to reducing risk.

Once risk drivers are identified, preventive measures may be defined to reduce the likelihood of failure. The risk reduction that may be achieved by implementing a measure is estimated by evaluating the baseline risk (i.e., *without* the preventive measure), evaluating the risk assuming the preventive measure is implemented, and calculating the difference as the estimated risk reduction. When this evaluation is performed for each preventive measure under consideration, the estimated effectiveness of all individual preventive measures is compared, necessary resources to complete each measure are calculated, and the most effective set of measures given available resources will be shown.

When estimating the significance of risk factors or the risk reduction achieved by preventive measures, the effects of interacting threats should be evaluated (see Section IV.E above). In addition, although the analysis may include *preventive* measures, the analysis to evaluate the potential benefit of a preventive measure should also include consequences to determine the overall risk reduction (versus just the reduction of likelihood). Any dependencies between likelihood and consequences should also be included, since these can affect the overall risk estimates.

For example, reducing the likelihood of failure from a particular threat may affect the distribution of failure modes (e.g., rupture vs. leak), which may then affect the distribution of release volume or the likelihood of different operator actions to limit a release. If a threat is reduced that has a higher than average proportion of failure by leak rather than rupture (e.g., corrosion), then the remaining distribution of failure modes will have a higher proportion of

failure by rupture, and the consequence and risk model outputs will need to be adjusted accordingly.[44]

H. PHMSA Key Recommendations – Likelihood Modeling

- The use of fixed numerical weights applied to risk factors and/or categories can introduce distortions in the likelihood of failure estimates from relative assessment/index models for specific pipeline segments. These distortions should be corrected as part of the necessary adjustments to apply the output from these models to the evaluation of risk reducing measures affecting specific segments.
- Uncertainties in the values of model variables can be important to the conclusions of a risk analysis and should be carefully evaluated. The likelihood of failure due to a threat should be evaluated in the context of uncertainties and the potential for consequences given the threat.
- Estimates of the likelihood of failure should be periodically validated, including evaluation of model inputs and outputs, to ensure the risk model accurately represents pipeline system risks.
- Identification of the most important model inputs or risk "drivers" is critical to understanding if the model outputs are technically valid. Risk model factors found to be important to the output risk levels should be reasonable when reviewed by SMEs or compared with historical data (both industry-wide and operator-specific).
- When risk analysis involves multiple threats, the effects of threat interactions or dependencies on the likelihood of failure should be evaluated. The threat interactions shown in Table IV-1 are recommend for inclusion where applicable. Other interactions found to be applicable at specific locations or in unique operating environments should be evaluated.
- The risk assessment should include modeling of human interactions that are significant to the likelihood of failure or have a significant effect on consequences following a failure.
- Different modeling methods may be applied to assessing the likelihood of failure due to different threats. Threat-specific modeling methods may necessarily vary and may not always be amenable to characterize risk as one composite risk value.

[44] While the leak to rupture threshold has been historically set at operating pressures of 30 percent SMYS (specified minimum yield strength), it is important to note that recent work by Kiefner and Associates and Kleinfelder has demonstrated that ruptures occur below 20 percent SMYS when interacting threats are present (see http://kiefner.com/wp-content/uploads/2013/05/Study_of_pipelines_-that_ruptured_at_stress_below_30pct_SMYS__PPIM_2013_paper.pdf). Operators should be aware of threat interactions when minimizing the consequence of a failure based on their assumption that the failure will only leak and not rupture.

V. Consequence Modeling

This section provides information on important characteristics of consequence, the second fundamental part of the risk definition and formula.[45] In the general risk definition, consequence represents and evaluates the severity and loss associated with an unwanted event. In pipeline risk modeling, the unwanted event is failure of a pipeline system or portion of a pipeline system. The consequence portion of a pipeline risk model encompasses the scenarios following a pipeline failure. The risk model uses the factors driving those scenarios and the interrelationships among risk factors to estimate the overall consequence of failure to potential receptors. Depending on the release characteristics, receptors may be at the point of failure of the segment or may be some distance away. To estimate consequences, the model should therefore include input variables representing important characteristics of a pipeline segment, including the product being transported and the location of the segment, and the potential paths of release dispersion between the segment and consequence receptors. These variables represent all factors needed to estimate the consequences of failure for all points along the segment.

The consequence analysis begins with consideration of a pipeline failure at a specific location and ends with estimates of the impacts that could occur from a release following the failure at that location. To evaluate the consequences of failure, the model includes and estimates the following dependent elements of a release:

1. **Product Hazard**: What kind of damage could the pipeline's transported product cause to receptors (e.g., flammability, toxicity)?
2. **Release rate and volume**: How much liquid or vapor could be released?
3. **Release dispersion characteristics**: Where, how, and when could the released product travel?
4. **Receptors**: Who or what could be impacted negatively by the release given the product hazard, volume, and dispersion?
5. **Expected Loss**: What is the estimated worth to the operator and other stakeholders of avoiding impacts to receptors and direct losses from a release?
    a. Receptors of a release may be diverse (e.g., the public, operator personnel, the environment, private and public property). Consequences can be measured individually for the different types of receptors, but optimal decision making can be facilitated if consequences can be translated into a single value equivalent that represents total loss from the consequences (e.g., dollars). If a unified measure of consequence is needed for risk assessment or decision-making, then a consistent and defensible method to measure the magnitude of consequences to different receptors is needed.

The first four[46] elements are estimated based on data and information on the objective characteristics of the pipeline and its location. However, "Expected Loss" is a more subjective measure that ultimately

[45] See sections I and II.B of the document above.
[46] Muhlbauer, *Pipeline Risk Assessment: The Definitive Approach and its Role in Risk Management*, 2015.

represents the realities, attitudes, and preferences of the operator organization and other stakeholders. For example, respective pipeline operators conduct operations in widely varying population densities, physical environments, regulatory environments, have varying levels of ability to cope with accident costs, etc., and have organization-specific levels of risk tolerance.

Conceptually, the evaluation of consequences is a function of these elements, with the estimates for each element dependent on previous elements:

$$Consequence\ of\ Pipeline\ Failure = f(H, Q, D, R, L(R))$$

Where:

$H = Product\ Hazard\ to\ Receptors$
$Q = Release\ Rate\ and\ Volume$
$D = Release\ Dispersion\ Characteristics$
$R = Receptors\ Impacted\ by\ the\ Release$
$L(R) = A\ Measure\ of\ the\ Loss\ given\ the\ Impacts\ to\ all\ Receptors$

Sections V.A through V.D of this document provide additional information on risk model treatment of consequence.

A. Selection of Approach

Consequences of pipeline failures can differ widely because of a variety of factors, including the differences in hazards and dispersion characteristics of different commodities. Table V-1 shows the names of commercially available consequence analysis models that have been used to estimate safety consequences for different commodities.[47] These models cover different elements of the consequence analysis described in Sections V.A.1 through V.A.4.

Table V-1
Safety Consequence Models for Different Commodities

Commodity	Hazard	Model Type	Models
Natural Gas	Jet Fire, Flash Fires, Blast Pressure, Thermal Radiation	Simplified Models	PIR calculation
		Detailed proprietary Models	PIPESAFE DNV PHAST
HVL		Hazard Area Estimate	API RP 581

[47] Presentation by J. Skow, C-FER Technologies to Risk Modeling Work Group, *Critical Review of Candidate Pipeline Risk Models*, October 5, 2016. This presentation can be accessed on the internet at: https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65711/skow-dtph56-15-t00003-final-project-presentation-05-sept-2016-riskwo.pdf

	Flash Fires, Jet Fires, Pool Fires, Fireballs, Toxic Effects, Blast Pressure	Proprietary Software	CANARY DNV PHAST EFECTS (TNO) TRACER (Safer Systems)
		CFD[48] Modelling	IOGP (2010) Norwegian Standard NORSOK Z-13 Annex F (NORSOK 2010)
Refined Product and Crude Oil	Pool Fires, Fireballs, Toxic Effects	Proprietary Software	
		CFD Modelling	

A consequence analysis approach should address all elements of a product release following a pipeline failure, including hazards of the released product, release rate and volume, dispersion characteristics, and receptor impacts. Exclusion of any element results in an incomplete analysis and unreliable results. Sections V.A.1 through V.A.5 below provide information on each of the consequence analysis elements, the inputs and outputs of each element, and the needs from risk models to support each element.

A.1 Hazard

Input: Pipeline commodity properties.

Output: Hazards to consequence receptors.

The analysis should consider acute hazards of the released products such as flammability, toxicity, and mechanical effects of a release, as well as chronic hazards such as environmental contamination. Acute thermal hazards can include effects from immediate or delayed ignition.

For a complete analysis, all hazards of all commodities that are transported in the pipeline should be included in the risk model. If multiple commodities are transported, then the hazards of all of them should be included. For example, a hazardous liquid pipeline could transport different types of HVLs, crude oil pipelines can carry sour crude and non-sour crude, refined products pipelines can carry jet-A fuel and high-octane gasolines, and natural gas pipelines can carry high BTU gas as well as lower BTU gas and some natural gas condensates. Each product that a pipeline transports comes with distinct hazards to humans and the environment and distinct dispersion characteristics over land, water, and air.

Even if the pipeline transports a single commodity type, release of the commodity could result in multiple hazards. Limiting the scope of the consequence analysis to only the most frequently transported commodity or the "most significant hazard" could result in

[48] "CFD" stands for "Computational Fluid Dynamics."

excluding risk-significant scenarios from the risk analysis. Often, the consequences of one hazard will dominate some locations, but for other locations, multiple hazards will each have an important contribution to risk.[49]

A.2 Volume

Input: Pipeline characteristics, location characteristics, failure modes, and commodity properties.

Output: Release volumes at each location following a failure.

For a complete risk assessment, the consequence analysis should include consideration of a wide range of scenarios to estimate the volume of commodity that might be released following a pipeline failure. Volume is an uncertain quantity, so a complete analysis may require consideration of multiple scenarios to estimate the range of volumes that could be released. Volume estimate scenarios are defined by input variables that affect release volumes, including the leak or rupture size, the flow rate through the pipe failure, the time required to detect the leak or rupture, the effect and timing of operator actions, the location of valves that could be used to isolate and limit the release, and the elevation profile of the pipeline. Considering of a range of possible scenarios, including both large and small failure sizes, better ensures that the highest risk scenarios are covered. Concentrating on only on one scenario (e.g., largest rupture) may not result in the highest release volume or the highest risk level.

At each potential release location, the range and distribution of failure sizes is dependent on the distribution of failure modes (leak vs. rupture). The distribution of failure modes is dependent on the distribution of the likelihood of failure from different threats, because threats have varying frequencies of failure in different modes. For example, corrosion failures on pipe with higher toughness properties tend to have a lower likelihood of rupture than seam and cracking failures or excavation damage. Therefore, the range of release volumes at each location is dependent of the distribution of threats at the location. For an accurate consequence estimate, the risk model algorithm should preserve this dependency.

To properly represent risk, the volume estimate should encompass the range of possibilities experienced in applicable historical releases. Historical data beyond the specific pipeline being analyzed should be included when considering the range of possible release volumes. If historical releases are considered inapplicable, the analysis should explain exclusion of these scenarios from consideration.

[49] For example, the 1999 Olympic Pipeline/Bellingham, Washington, accident caused three fatalities, two resulting from fire and one from fumes causing loss of consciousness. Document can be accessed at: https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR0202.pdf.

It may be useful for an operator to consider a fixed set of hole sizes based upon types of expected failures (e.g., pinhole, corrosion hole, small rupture, etc.) Release rates can then be calculated for each size and used as the basis for determine release volumes while incorporating other information, such as estimated response times.

A.3 Dispersion

Input: Release rate and volume, commodity properties, location and dispersion path characteristics, emergency response to spill.

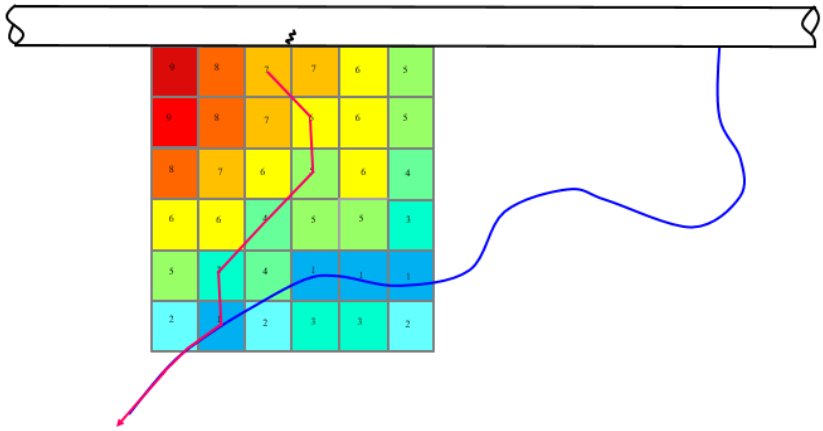
Output: Locations where receptors are subject to hazards from released commodities.

To support a complete consideration of potential consequences, the analysis should consider all dispersion methods and pathways that could result in adverse consequences to receptors, recognizing that pathways and magnitudes of dispersion are uncertain. The consequences of a pipeline release to impact potential receptors depend on the extent and direction of release dispersion. Dispersion depends on the product characteristics, volume released, geographic features around the pipeline, and environmental conditions. Depending on the released commodity and location characteristics, the release may disperse by air, soil, or water. Variable atmospheric and waterway conditions (e.g., wind direction and speed, water flow velocity) should be considered to include the full range of possible dispersion of the released commodity. Consideration of both high-likelihood and high-consequence dispersion scenarios is essential to a full evaluation of risk. It may also be that the most likely scenario is not the highest-risk scenario.

For released liquids, dispersion by land and water is frequently modeled using a digital elevation model (DEM) to trace potential spill flow paths, along with stream locations integrated in a GIS (see example in Figure V-1). Dispersion by water is particularly important to analyze, since waterways provide paths for the spill to reach more receptors further from the spill location. For very small spill volumes that occur away from waterbodies, detailed dispersion modeling may not be warranted, if the spill is unlikely to disperse beyond the immediate vicinity of its origin.

To initiate integrity management programs, pipeline operators were required to identify which of their pipeline segments could affect high consequence areas. Operators continue to update those analyses as an ongoing part of their IM programs. The analyses may involve use of elements of consequence models that include hazard identification, spill volume estimates, and dispersion estimates.

Figure V-1
Spill Plume Dispersion over Model of Relative Elevation Near Pipeline



A.4 Receptors

Input: Locations subject to hazards following release.

Output: Receptors in locations subject to hazard after release and dispersion.

The magnitude and direction of release dispersion defines the areas subject to release hazards, the potential receptors of release consequences in the hazard areas, and the severity of impacts. Depending on the hazards involved, potential receptors may be near the failure location on the pipeline, or they may be some distance away (particularly in scenarios where the released commodity may be transported by water). Potential receptors include:

- Persons occupying the hazard area (homes, workplaces, schools, hospitals, etc.) that could be injured or killed.
- Features of the natural environment (water resources, flora and fauna, etc.) that could be damaged or contaminated.
- Structures and other property that could be damaged or destroyed.

A.5 Expected Loss

Input: Consequences to receptors from a release.

Output: Expected loss due to consequences.

A measure of loss is needed to allow comparison of the expected loss from a pipeline failure to the resource expenditure of risk reduction measures, to help evaluate their relative effectiveness. Some consequences, such as the direct monetary costs of a release, including property damage, relocation costs, environmental cleanup costs, and paid civil and legal penalties, are directly comparable to the increased capital and operating costs required to implement risk reducing measures. However, release consequences could include additional impacts that are not readily measured by direct

monetary costs, including human casualties, ecological damage, damage to company reputation with regulators or the public, and product supply problems. If the analysis includes only monetary costs, it could understate the total loss from releases. Depending on the type of pipeline and the release, the societal impacts of such consequences could far exceed the direct monetary costs to the operator.

A common method for establishing a single-valued measure of the loss from diverse consequences is to convert all consequences to monetary equivalents. Operators are often reluctant to express losses due to fatalities and injuries in monetary terms. However, if human safety consequences are not included in the calculation of expected loss from failures, then the loss will be understated and the benefits of potential risk reducing measures will be undervalued. To fully characterize the loss from pipeline failure consequences, operators should include the cost of human casualties, along with other non-monetary costs, in the overall measure of consequences. The U.S. Department of Transportation has provided guidance[50] on the value of avoiding human casualties, prescribing a Value of Statistical Life (VSL) figure of $9.6 Million (2015 dollars) for DOT analyses.

In some applications, operators may choose one type of consequence, such as potential human casualties or environmental damage, and set decision criteria based on risk measures of this consequence only (e.g., expected fatalities per year). An example of this approach is given in Appendix B.1, which uses "FN" curves[51] as a guide for evaluating consequences based on human impacts. If a single consequence type is used to evaluate risk reduction measures, then the benefits of the risk reduction measures could be understated, because risks in other categories that are not included in the decision criteria may also be reduced by the risk reduction measures being considered.

Risk models may use an alternative to monetary equivalents to combine different types of consequences in a common measure of loss. If so, the method chosen should reflect the organization's relative valuation of the types of consequences involved. Scales used to measure loss for different receptors (e.g., human casualties, environmental damage, economic) should be internally consistent, so that the same values are assigned to loss levels that are valued equivalently for all receptors.

B. Operator and Emergency Responder Response

The responses of operator and emergency responders during an event are key factors in the severity of consequences from pipeline releases. Failure detection capability and the speed and

[50] U.S. DOT, *Guidance on Treatment of the Economic Value of a Statistical Life (VSL) in U.S. Department of Transportation Analyses – 2016 Adjustment*, 2016. Document can be accessed at: https://cms.dot.gov/sites/dot.gov/files/docs/2016%20Revised%20Value%20of%20a%20Statistical%20Life%20Guidance.pdf.

[51] See ISO/IEC 31010:2009 – *Risk management – Risk assessment techniques*, Section B.27.

efficacy of the emergency response can significantly impact the severity of the consequence of a release.

Consequence analysis should consider ability to detect leaks of various sizes as well as time to respond and shut down and isolate the pipeline. Overly optimistic expectations and assumptions about leak detection capabilities will likely lead to underestimating spill volumes and the associated consequences.

For hazardous liquid pipelines, operators have often used spill response plan assumptions in risk models to estimate spill volume and dispersion direction and distance as the basis for consequence estimates. Accident history indicates that although most pipeline accidents do not involve "maximum" or worst-case release estimates, in some cases, the anticipated level of consequences can be significantly underestimated. For a balanced assessment of consequences, operators should avoid non-conservative assumptions or estimates regarding spill response actions that impact release volumes or dispersion.

For example, the NTSB pipeline accident report for the July 25, 2010 Marshall, Michigan, crude oil pipeline rupture[52] stated "During interviews, first responders said that they were unaware of the scale of the oil release; this lack of knowledge contributed to their poor decision-making." In addition, NTSB concluded "that although Enbridge quickly isolated the ruptured segment of Line 6B after receiving a telephone call about the release, Enbridge's emergency response actions during the initial hours following the release were not sufficiently focused on source control and demonstrated a lack of awareness and training in the use of effective containment methods."

The NTSB pipeline accident report for the September 9, 2010, San Bruno, California, incident[53] concluded "…that the 95 minutes that PG&E took to stop the flow of gas by isolating the rupture site was excessive. This delay, which contributed to the severity and extent of property damage and increased risk to the residents and emergency responders, in combination with the failure of the SCADA center to expedite shutdown of the remote valves at the Martin Station, contributed to the severity of the accident."

While not typical, historical high-consequence releases such as the Marshall, Michigan, and San Bruno, California, incidents illustrate that variability in human actions in response to a failure can compound other factors to significantly affect the consequences of the failure. Emergency response time variation can depend on factors such a procedural complexity, logistical challenges, and the experience/training level of responders. Identification of the actual release location and the ability to isolate the release can vary widely depending on pipeline location and

[52] NTSB Accident Report NTSB/PAR-12/01 PB2012-916501, Enbridge Incorporated Hazardous Liquid Pipeline Rupture and Release, Marshall, Michigan, July 25, 2010. This document can be accessed on the internet at: https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1201.pdf.

[53] NTSB Accident Report NTSB/PAR-11/01 PB2011-916501, Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010. This document can be accessed on the internet at: https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1101.pdf.

configuration, and surrounding population density. Therefore, it is important for a complete and valid modeling of consequences that the model:

1. Identify and incorporate all key human actions or decision points that can have a substantial impact on the level of consequences following a failure. Even complex responses can generally be broken out into a relatively few major steps that should be accomplished to minimize the consequence of a release.
2. Estimate the range of time that may be required to perform the key actions. The estimate should include a sufficient range to cover the full uncertainty in response time. Using a single point estimate for potentially important parameters such as the time to stop stream flow spill migration is not appropriate without substantial justification and can potentially skew consequence calculations.
3. Estimate the key parameters that have a substantial impact on spill volume and dispersion given the range of possible response times and the effectiveness of the response.

Given the uncertainty in response times, it may be useful to develop best-estimate, minimum, and maximum estimates (or a probability distribution for key response times) to more fully define the range of expected consequences for the releases being analyzed. Consideration of a range or distribution of impacts from emergency response allows more insight on the range of risks than reliance on point estimates that might have originally been developed for other purposes.

C. Application to Identification of Mitigative Measures

Integrity management regulations require risk assessment to support identification[54] and evaluation[55] of risk reducing (preventive and mitigative) measures. Section 192.935(a) requires that an operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. Section 195.452(i) requires that an operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. "Mitigative" measures reduce the consequences of failure, through actions that reduce the product hazard, release volume, the dispersion of the release, or the exposure of receptors to the release.

Risk models can support *identification* and *evaluation* of mitigative measures. The effectiveness of different types of models in supporting decisions, including decisions on mitigative measures, was discussed in Section III.A. To assist *identification*, sensitivity analysis can be conducted to

[54] 49 CFR §§ 195.452 (i)(1) and 192.935(a). Current pipeline code sections can be accessed at the U.S. Government Printing Office web site at: https://www.ecfr.gov/cgi-bin/text-idx?SID=1d49a3b137cb1b6fc45251074e634b44&c=ecfr&tpl=/ecfrbrowse/Title49/49cfrv3_02.tpl.

[55] 49 CFR §§ 195.452 (i)(2), 192.911(c), and 192.917(c). Current pipeline code sections can be accessed at the U.S. Government Printing Office web site at: https://www.ecfr.gov/cgi-bin/text-idx?SID=1d49a3b137cb1b6fc45251074e634b44&c=ecfr&tpl=/ecfrbrowse/Title49/49cfrv3_02.tpl.

examine which consequence analysis inputs are driving the risk results. Risk reduction measures can then be defined to address the most important risk drivers and mitigate the consequences of failure. Consequences may be reduced by actions, such as:

1. Reducing potential release volumes by:
    a. Installing new emergency flow restriction devices, remote control valves, or automatic shutoff valves.
    b. Improving leak detection systems or operator response to rupture indications.
    c. Installing more SCADA measurement points to allow for more precise monitoring and quicker determinations of pressure, flow, or temperature data reflective of pipeline operating conditions at specific locations.
2. Reducing the potential for spill dispersion through such measures as secondary containment, positioning emergency equipment, or improving emergency response.
3. Relocating receptors or relocating the pipeline to lower the potential for receptor impacts.

These measures have varying levels of practicality and potential effectiveness.

For a risk model to adequately support an analysis of the effects of additional mitigative measures, the model's consequence evaluation should be capable of reflecting changes due to the projected mitigative measures and showing the differences in risk due to the changes, whether they be changes to the pipeline, operations, dispersion pathways, or location of potential receptors. Changes can be represented in the model by changing the values assigned to variables or by making changes to the model structure.

The potential risk reduction from implementing a measure is estimated by evaluating baseline risk (i.e., *without* the measure), evaluating risk assuming the measure is implemented, and calculating the difference as the estimated risk reduction. The results can then be fit into a benefit-cost analysis of the risk-reducing measures under consideration. When this evaluation is performed for each measure under consideration, the estimated effectiveness of all measures is compared, necessary resources to complete each measure are calculated, and the most effective set of measures given available resources will be shown.

D. PHMSA Key Recommendations – Consequence Modeling

- To support decision making and the identification and evaluation of mitigative measures, the consequence analysis should encompass the five elements of hazard, release volume, dispersion, receptors, and estimated loss. The impact of operator response actions and timing on these elements should be appropriately evaluated.
- Varying levels of sophistication are possible in the consequence analysis, while still allowing for useful results, but it is important to consider a range of scenarios, defined by a range of values for key consequence variables, to capture the full spectrum of possible consequences. Also, it is important to consider high-consequence scenarios, even if they have a low probability of occurrence.

- The quantitative information in the consequence analysis should represent the operator's best current understanding of important variables that affect estimates of hazards, release volume, and dispersion. Equally important is a consistent and complete measure of losses from estimated consequences. If index scores, monetary equivalents, or other measure are used to represent the cost of consequences to diverse receptors, then the relative values assigned to different consequence levels should be internally consistent and represent the values of the operator organization or values used in societal decision making.
- The risk analysis should include modeling of human interactions that have a significant effect on consequences following a failure.

VI. Facility Risk Modeling

Pipeline facility risk assessment is different from line pipe risk assessment, because facilities have different component types with different failure mechanisms and failure modes. Consequence assessment can also be different because facilities are most often located on property controlled by the pipeline operator and not on public rights-of-way (ROW). In general, facility risk models will measure the likelihood of failure for the facility location (or specific areas within a facility), rather than a likelihood per mile.

Gas Transmission Facilities include:

- Compressor stations
- Regulator and Metering Stations

Hazardous Liquid Transmission Facilities include:

- Tank Facilities
- Pump Stations
- Metering Stations

The liquid and gas IM regulations require HCA identification, risk assessment, and evaluation of preventive measures and mitigative measures for facilities as well as line pipe. The IM regulations require integrity assessments for line pipe only.

A. Comparison with Line Pipe Risk

The same basic principles apply for risk assessment of facilities as for risk assessment of line pipe. Risk assessment models for facilities should model likelihood and consequence. All threats to integrity at the facility should be considered in the likelihood assessment. All product hazards, dispersion paths, and receptors should be considered in the consequence assessment.

Risk assessment of facilities includes consideration of the failure modes considered for line pipe as well as additional failure modes introduced by the inclusion of other components, such as motive equipment (e.g., pumps, compressors).

Some important aspects of facility risk include:

- The concentration of complex equipment at facilities can result in a higher likelihood of failure due to threats like equipment failure and incorrect operation (as shown in historical incident data).
- Equipment failure can be a more significant threat for facilities. Factors such as vibration, excessive and varying temperatures, start-ups and shut-downs, wear, design and construction errors, and other aging/cycling effects affect motive equipment like compressors and pumps and can cause failures of equipment or associated piping.
- Because of the complexity of most pipeline facilities, their failures represent a higher likelihood of service interruption. Standard designs and regulations for facilities include alarms systems, emergency shut-down systems (ESD), site grading for control of lost product, and facility evacuation planning. Most operators employ reliability engineering practices and predictive maintenance schemes to manage facility risk. These factors should be included in the inputs of the facility risk model, as appropriate.
- Facilities that are above ground may be more susceptible than buried assets to some outside force damage threats.
- The operator's analysis should consider the difference between risks for manned and unmanned facilities.

Overall, facilities may have a smaller risk "footprint" than line pipe, and the geographic extent of consequences may not be as widespread. Many facility components are above ground and accessible for inspection and maintenance activities, in contrast to mainly underground line pipe.

To support improved facility operation, operators sometimes perform facility reliability analyses. The data and models for such analyses may be used as the basis for facility risk assessments, if they are augmented to include evaluation of consequences to receptors (e.g., human safety and environmental protection) both on and off the facility site. Operators may use tools often applied to analyze the failure of facilities, such as HAZOP, FMEAs, fault trees, LOPA, or "bow-tie" analysis,[56] as a starting point, expanding the analysis to consider failures that have offsite consequences and evaluating the risk of those failures. Operators may also be able to apply the data sets developed for risk assessment for those other tools and analyses.

[56] ISO/IEC 31010:2009 – *Risk management – Risk assessment techniques*, Sections B.13, B.14, B.18, B.21.

The following are other examples of threats and related risk factors for consideration in a facility risk assessment model:[57]

- Equipment Malfunction
  - Effect of Preventive Maintenance Program
  - Effect of Routine Inspections
  - Effect of Secondary Containment
  - Valve Releases
  - Pump Releases
  - Automation
- Pipe Corrosion
  - External Corrosion
    - External Corrosion Monitoring Program
    - Cathodic Protection Systems
    - Soil/air Interface
    - Historic Releases from External Corrosion
  - Internal Corrosion
    - Internal Corrosion Monitoring Program
    - Product Type
    - Low Flow/Dead Legs Piping
    - Historical Releases from Internal Corrosion
  - Atmospheric Corrosion
    - Facility Proximity to Coastal Area
    - Previous Atmospheric Corrosion Issues
    - Effect of Routine Inspections
- Pipe Outside Force Related failures
  - Existence of Underground Pipe Markings
  - Existence of Underground Pipe Maps
  - Effect of Monitoring of Excavations
  - Historic Outside Force Damage Failures
- Incorrect Operation[58]
  - Inadequate Procedures
  - Human Error
  - Quality of Station Documentation
  - Inadequate Training
  - Debris from Pigging and Hydrotesting
- Natural Force Damage

[57] Examples from RMWG presentation by M. LaMont, Integrity Plus, *Pipeline Facilities Risk Management*, November 30, 2016. This presentation can be accessed on the internet at: https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65766/facilitiesriskapproacheslamontrmwg1116.pdf.

[58] Incorrect Operation threat and related risk factors taken from the Appendix C facility risk example.

- Whether Located in Hurricane / Storm Prone Area
- Whether Located in Earthquake Prone Area
- Historic Natural Force Damage

Appendix C contains an example qualitative risk model used for facility risk assessment.

B. Application to Preventive Measures and Mitigative Measures

IM requirements for identification and evaluation of preventive measures and mitigative measures apply to facilities as well as line pipe. These regulations require operators take additional measures to prevent a pipeline failure and to mitigate the consequences of a failure that could affect a high consequence area.[59] The same model types (Section II.D) are available for facility risk assessment as line-pipe risk assessment, with the same capabilities to support decision making (Section III.A), although the threats and consequences evaluated using the models will be somewhat different for facilities.

For example, one hazardous liquid pipeline operator uses a relative assessment (index) model to assess risk at tank facilities. The model includes a likelihood index and leak impact factor (consequence) index. The likelihood index scores factors in the following categories:

- Design and Materials
- Incorrect Operations
- Corrosion
- External Forces

The design and materials category includes scores for such factors as:

- Material operating stress and cyclic stress
- Material vibration
- Safety systems predictive and preventive maintenance program
- Failure history of equipment like pumps, valves, tubing, and control and instrumentation

The leak impact factor index scores factors for product hazard, receptors, and spill size.

The design of many facilities includes telemetry, monitoring, and automatic shutdown and isolation systems. These instrument and control systems continuously monitor for leakage, explosive gas mixtures, fire, vibration, component temperature, intrusion, operating pressure, etc., and automatically isolate the system when alarm thresholds are exceeded. The required

[59] 49 CFR §§ 192.935 and 192.452(i)(1). Current pipeline code sections can be accessed at the U.S. Government Printing Office web site at: https://www.ecfr.gov/cgi-bin/text-idx?SID=1d49a3b137cb1b6fc45251074e634b44&c=ecfr&tpl=/ecfrbrowse/Title49/49cfrv3_02.tpl.

maintenance for these facilities often follows manufacturers' recommendations along with reliability engineering concepts to develop preventive actions to assure system availability, reducing the risk of failure. Risk models should support the evaluation of enhancements to equipment design, maintenance, inspection, and operation and the effects of such enhancements on risk.

With a risk model, changes in the likelihood of failure of different equipment can be made to represent reliability enhancements from changes to design, maintenance, testing, or operating practices. The risk model's algorithm can be altered to represent design changes that add redundancy or introduce automation. The risk model can be used to evaluate the likelihood of failure with and without the improvements to estimate the resulting changes in risk. The changes in risk values can be compared to the cost of implementing the enhancement if alternative risk reduction measures are being compared or benefit-cost analysis is being conducted to evaluate the measures.

C. PHMSA Key Recommendations – Facility Risk Modeling

- Facility characteristics that affect risk may be significantly different than those for line pipe. Different failure causes may be important and failures may have different consequences than nearby line pipe. However, the same basic principles apply for risk assessment of facilities as for risk assessment of line pipe and the same types of models may be applied.
- Incorrect operation, human error, and equipment failure can be important failure threats for facility risk and should be represented thoroughly in facility risk models.
- Existing operational approaches to assess facility reliability can often be adapted for evaluation of risk and off-site consequences and should be utilized where possible.

VII. Risk Modeling Data

Previous sections of this document concentrated on the structure of risk models and their use in supporting decisions on operator activities to control risks. This section discusses developing the values for input variables to risk models.

Model inputs should represent the best currently available information on risk factors for both the likelihood and consequences of pipeline failures. Inputs should draw data from both pipeline system records and the knowledgeable and informed opinion of subject matter experts (SMEs). Both data from records and SME input should be validated to ensure applicability as risk model inputs.

Using pipeline records to develop risk model inputs can be a large-scale effort, because of the wide variety of records involved and because pipeline characteristics can change considerably over the length of the pipeline. The operational and inspection history of pipeline segments can also vary significantly over the length of the pipeline. Other model inputs related to the environment in which the pipeline

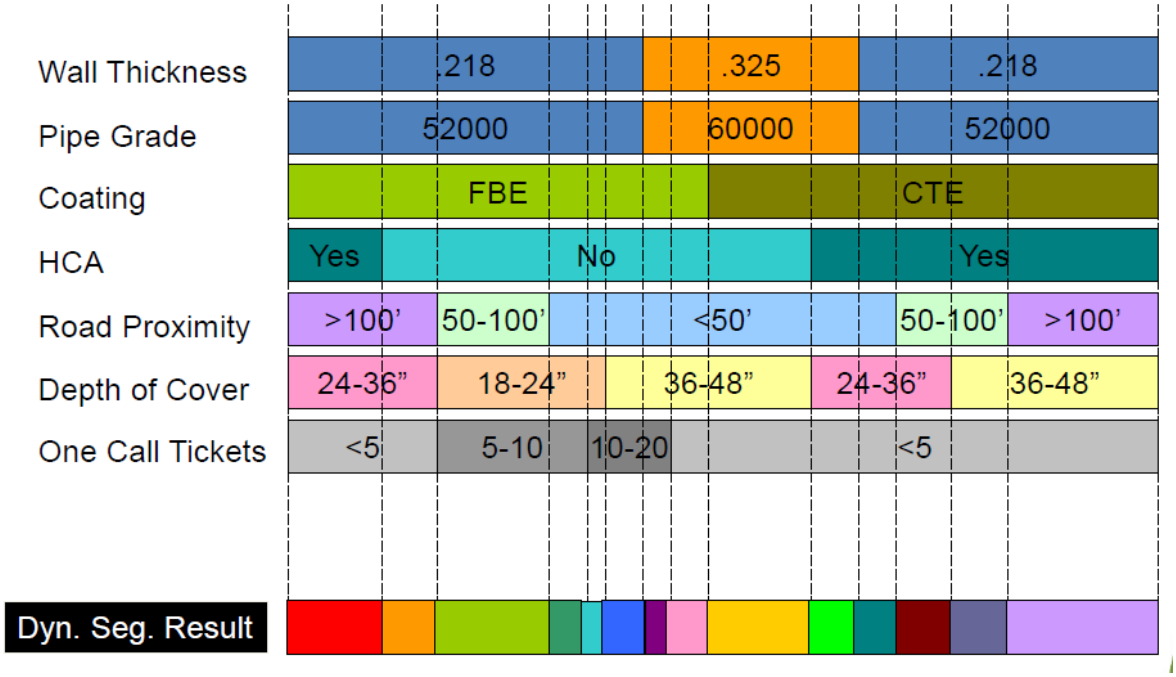
operates (e.g., terrain, soil types, and area characteristics around the pipeline) can also change significantly over the entire pipeline route. SME information should be used to fill gaps in information for model inputs as data from records is being assembled and validated and when inputs cannot be derived from any available records. Operators should revise field data acquisition forms to capture the data and information required to support their risk assessment and Geospatial Information Systems (GIS). Staff responsible for completing field data acquisition forms should be trained on the forms' requirements to meet the data quality expectations of the groups relying on this data to make decisions.

An important feature of input data for a pipeline risk model is a "Linear Reference System" (LRS) to tie risk factors to specific points or segments on the pipeline. Factors can be "linear" (e.g., pipe segments, HCA-affecting segments, class locations, inline inspection (ILI) ranges, MAOP/MOP, test pressure) or single "points" (e.g., facilities, valves, crossings, features or anomalies identified by ILI, girth welds). The reference system that specifies risk factor locations within the pipeline is integrated with a "geographical" location system to tie points and segments on the pipeline with the location of specific features around the pipeline (e.g., HCAs, buildings, bodies of water, elevation changes). In the context of risk models, this is necessary to align risk factors, affecting both the likelihood and consequences of a release, so that each location on the pipeline is appropriately represented by inputs to the risk model. This allows the risk model outputs to reflect the unique combination of risk factors representative at each location.

A GIS is useful to house data on the locations of pipeline characteristics and geographical features. If the operator does not use a GIS, then other methods should be used to accurately assign risk factors to the correct locations along the pipeline. SME knowledge on the relative location of pipeline-related factors and geographic features may be necessary to align these factors for input to the risk model.

In a risk model, sufficient distinction of model outputs at specific locations and insights about pipeline segment risks is enhanced by "dynamic segmentation," where separate risk model results are generated for pipe segments that have significantly different risk factors or significantly different levels of risk. Operators should define criteria for defining the segments with separate risk estimates. Under this approach, illustrated in Figure VII-1, a model would estimate risk separately for each segment where risk factors are distinct. In the figure, the distinct segments are indicated by the dashed vertical lines. For example, the first (leftmost) segment extends to where the "HCA" factor changes from "Yes" to "No"; the second segment extends from this point to where the "Road Proximity," "Depth of Cover," and "One-Call Ticket" factors all change value.

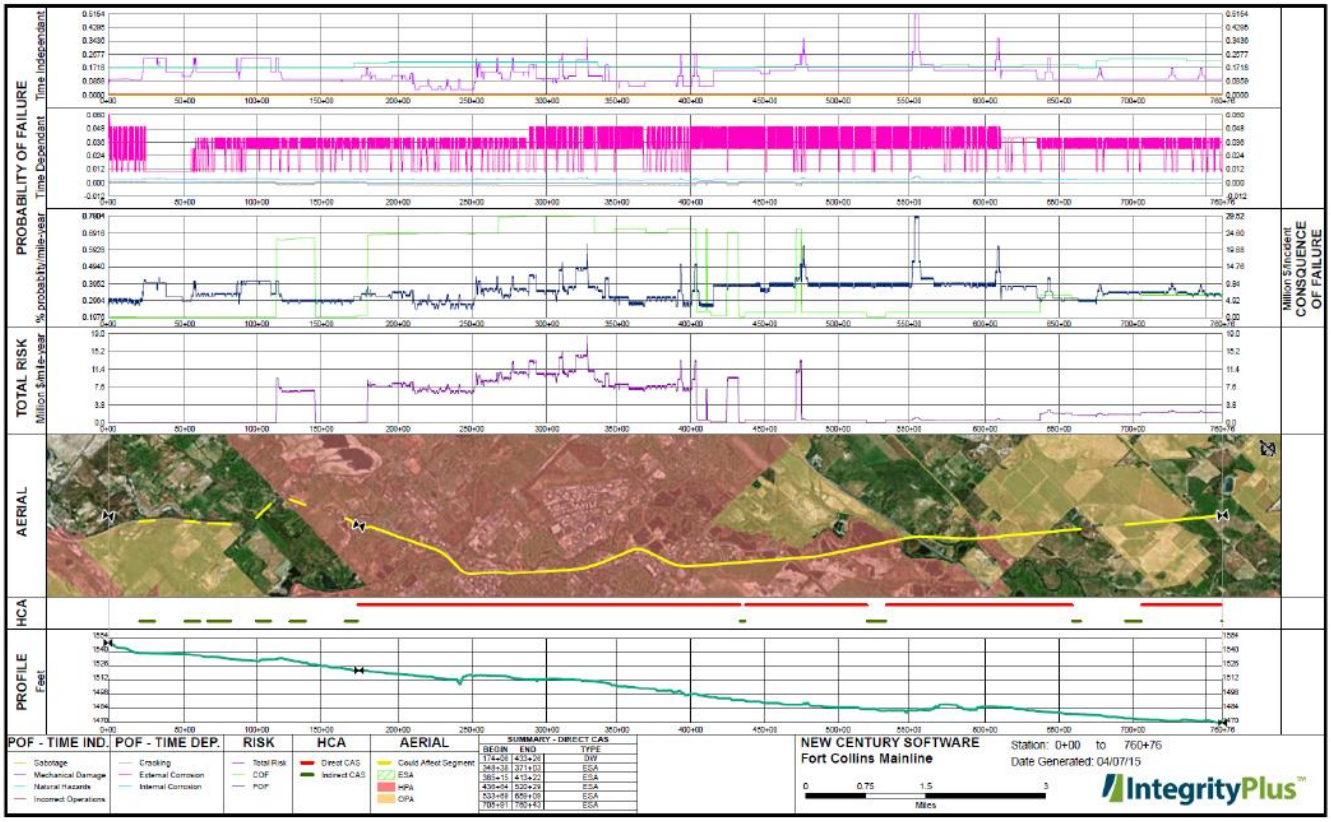
Figure VII-1
Dynamic Segmentation[60]



Observing the change in multiple risk factors along the pipeline route can suggest locations where preventive measures and mitigative measures to reduce risk could be most effective. Figure VII-2 depicts an example of a "risk alignment sheet," where changing risk model outputs along a pipeline route are shown in a visual form. As risk factor data changes and is used to generate estimates of likelihood, consequences, and risk, these outputs fluctuate.

[60] Both Figures VIII-1 and -2 are taken from a RMWG presentation by R. Brush, New Century Software, *PODS Data Management*, March 7, 2017. This presentation can be accessed on the internet at: https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65786/podsdatamanagementrmwg0317.pdf.

Figure VII-2
Sample "Risk Alignment Sheet"



A. Relation of Data to Risk Model Types

The most important reasons to choose specific risk model types include: 1) how the models relate to and represent the pipeline system, 2) the output risk measures provided by each model type, and 3) the capabilities of model types to support decision making (see section III.A). While the type and quality of data that are available as model inputs are discriminating factors for applying different types of models, they should not be the primary factor. All model types can employ a combination of location-specific data from records, industry or operator averages, and SME-sourced information. PHMSA does not believe that any specific model type is preferable simply based on the level of data quality available to support the model inputs. However, it should be acknowledged that the accuracy of a specific model is relative to data quality. All models are dependent on data quality and it is important that data quality be addressed consistent with improving the accuracy of model results.

A quantitative system model, if it represents the logical and physical combination of risk factors to produce likelihood and consequences, can produce useful results even if uncertainties exist in the input data. Although optimal results are obtained with a high degree of accurate location-specific data, system risk insights and support for decisions can be achieved with different levels

of data quality and completeness, including situations when significant reliance is placed on SME input or generic data.

B. Data Sources

Operator records of segment-specific characteristics are the primary source of data used for risk model inputs. Operators collect data from routine operating, maintenance, and inspection activities. For example, operating logs record pressures, indicative of stresses on the pipeline, and transients to which the pipeline may be subjected. Exposed pipe reports record data about the condition of the pipeline that is gathered whenever the pipeline is exposed by excavation for other reasons. Records of patrols and surveillance show nearby construction activities that could pose threats to the pipeline, and evidence of changes in local flora that may be indicative of changes in soil conditions. Data sets from in-line inspection integrity assessments also provide information about pipeline integrity.

Operators should ensure that their data acquisition forms are collecting the data needed for their risk model inputs. Construction, operations, maintenance, and inspection personnel responsible for completing data acquisition forms should be trained on requirements for completing forms with the needed data quality and completeness.

Table VII-1 lists typical data elements that apply to risk model inputs. Table VII-2 lists important sources for these data elements. Both tables were duplicated from ASME B31.8S (in some operating environments, operators may need to add additional data elements). Further information on data sources for risk model inputs may be found in ASME B31.8S, section 4.3.

February 1, 2020

Table VII-1
Data Elements[61]

CATEGORY	DATA
ATTRIBUTE DATA	Pipe wall thickness
	Diameter
	Seam type and joint factor
	Manufacturer
	Manufacturing date
	Material properties
	Equipment properties
CONSTRUCTION	Construction Year of installation
	Bending method
	Joining method, process and inspection results
	Depth of cover
	Crossings/casings
	Pressure test
	Field coating methods
	Soil, backfill
	Inspection reports
	Cathodic protection (CP) installed
	Coating type
OPERATIONAL	Gas quality
	Flow rate
	Normal maximum and minimum operating pressures
	Leak/failure history
	Coating condition
	CP system performance
	Pipe wall temperature
	Pipe inspection reports
	OD/ID corrosion monitoring
	Pressure fluctuations
	Regulator/relief performance
	Encroachments
	Repairs
	Vandalism
	External forces
INSPECTION	Pressure tests
	In-line inspections
	Geometry tool inspections
	Bell hole inspections
	CP inspections (CIS)
	Coating condition inspections (DCVG)
	Audits and reviews

[61] ASME B31.8S-2004, *Managing System Integrity of Gas Pipelines*, Table 1.

Table VII-2
Typical Data Sources[62]

Process and instrumentation drawings (P&ID)
Pipeline alignment drawings
Original construction inspector notes/records
Pipeline aerial photography
Facility drawings/maps
As-built drawings
Material certifications
Survey reports/drawings
Operator standards/specifications
Industry standards/specifications
O&M procedures
Emergency response plans
Inspection records
Test reports/records
Incident reports
Compliance records
Design/engineering reports
Technical evaluations
Manufacturer equipment data

Merging large amounts of data from diverse sources is facilitated by a consistent structure for storing and retrieving the data. As an example, the pipeline industry has developed the "Pipeline Open Data Standard" (PODS) database architecture as a structure for organizing pipeline data (see http://www.pods.org). Figure VII-3 depicts the top-level structure of PODS. Figure VIII-4[63] shows an example of the data structure for a PODS module, showing the structure for data items such as CP type, CP Criteria, Nominal Wall Thickness, Outside Diameter, Pipe Grade, and Pipe Long Seam. The full scope of PODS modules may be found at http://www.pods.org/wp-content/uploads/2015/06/PODS-6.0-Logical-Models1.pdf and a depiction of the full architecture showing relationships among modules may be found at http://www.pods.org/wp-content/uploads/2015/08/PODS-6.0-ERD1.pdf.

[62] ASME B31.8S-2004, *Managing System Integrity of Gas Pipelines*, Table 2.
[63] Figures VII-3 and -4 are taken from http://www.pods.org/pods-model/model-diagrams/.

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Figure VII-3
PODS Top-Level Module Organization

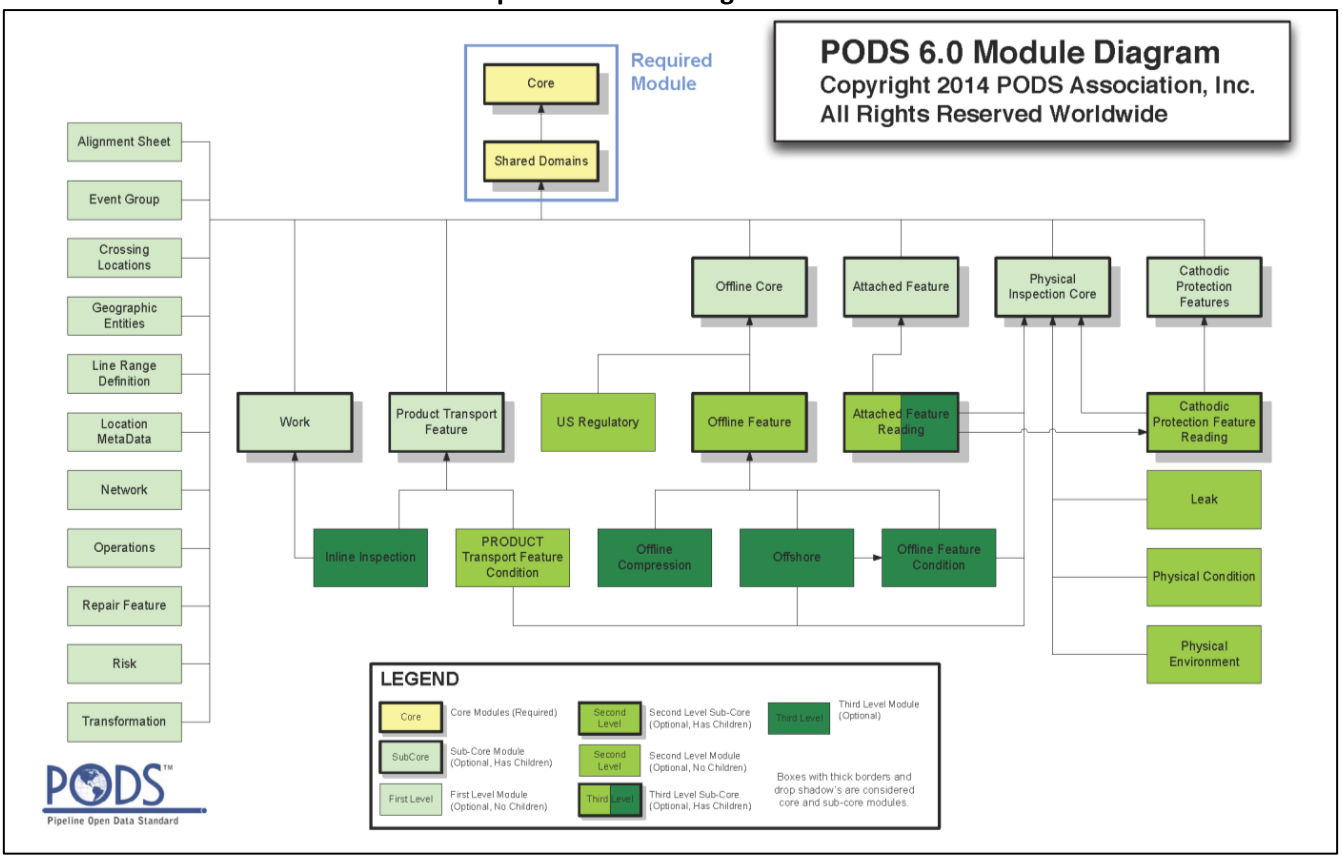
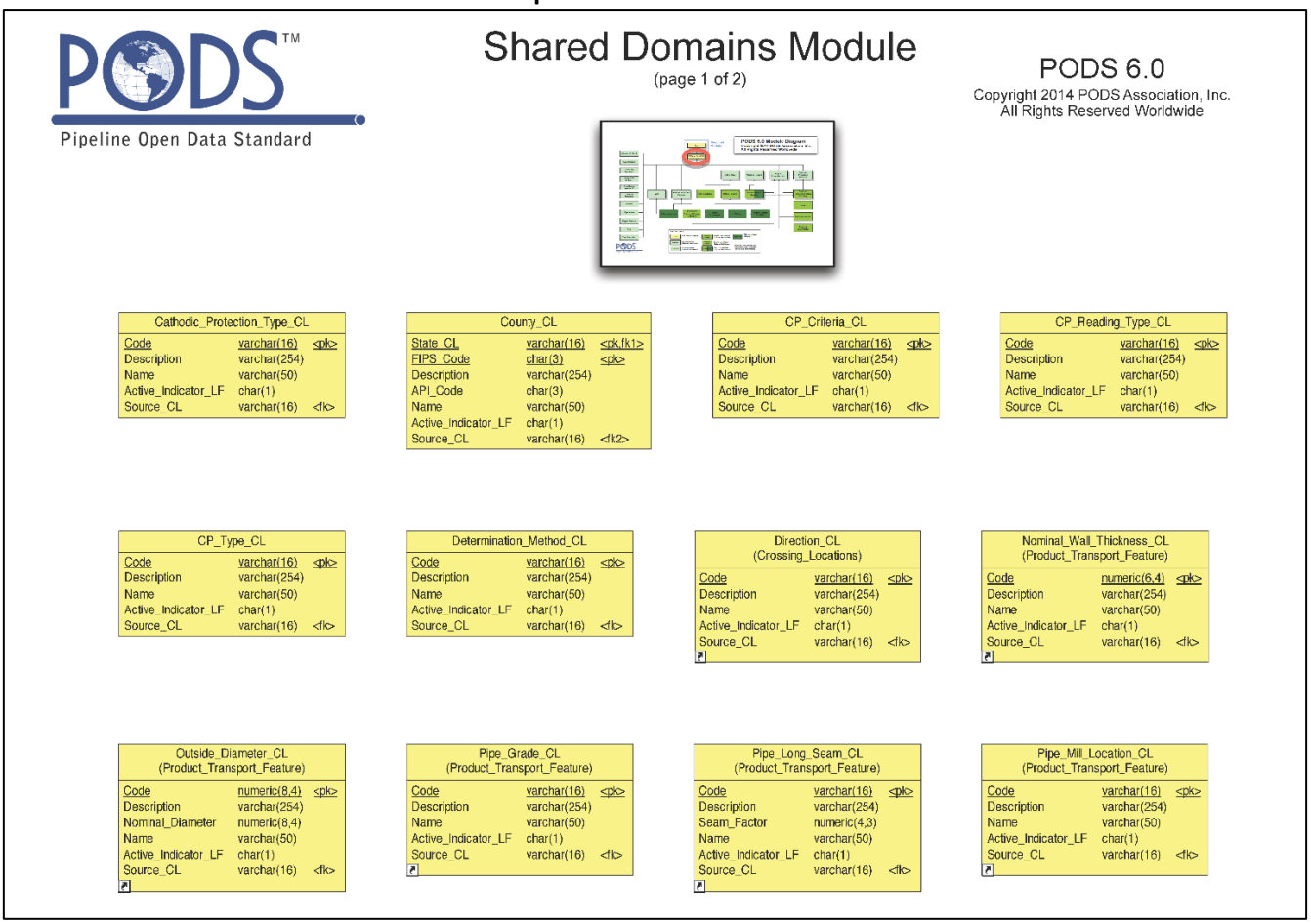


Figure VII-4
Example PODS Module



C. Data Quality and Uncertainty

It is important to evaluate the quality of the current data supplied to a risk model. For many pipeline risk models, improving the scope and quality of input data is a long-term process. The operator should understand the overall characteristics of the risk model data set and implement actions to ensure needed data quality and seek continuous improvement in the data gathered and input to the model. Risk model data quality issues can increase uncertainty in the results from the model. If the results are used to support decision making, then the results should be interpreted in light of those uncertainties.

There are many ways to measure data quality,[64] but, in the context of risk models, two central aspects can be identified:

1. Data Completeness
   For any model, there may be input variables that are not always known, or not verified to be accurate. Often in these cases, generic default values based on general industry information or SME knowledge and experience are applied. Accounting for this, a simple measure of data quality is the "unavailability" of pipeline-specific data in situations where default or generic average values are being used. This data quality measure can be further refined by considering the relative importance of the respective input data elements according to their impact on the risk model results.

   The lack of pipeline-specific data does not imply that certain model types should not be used and the results should not be applied to support decisions. If a model is thought to be a better representation of the pipeline system but input data is incomplete, then informed default inputs can be used as an interim step, and data needs can be prioritized as familiarity with the model, model results, and real-world application to pipeline integrity management develop.

   If a probabilistic model is being used, priorities for additional data collection may be developed systematically using a value-of-information analysis. This analysis estimates how additional data collection is expected to affect risk assessment results and thereby potentially change decisions on risk reducing measures. If the analysis finds that collecting specific additional information could change decisions significantly, then risk reduction could be significantly enhanced by collecting the additional information. To ensure complete and accurate data for risk model, operators should ensure that records are preserved and retrievable.

2. Data uncertainty
   In addition to data completeness, it is also important to understand the uncertainty in data inputs to a model, regardless of the modeling approach. It is straightforward to estimate the basic statistical attributes for each model input (e.g., mean, variance). Bayesian updating[65] (a technique where a set of existing information – e.g., industry level component failure rate – can be updated by additional pipeline-specific data) is one approach to providing updated statistical estimates as

[64] For example, see "Dimensions of Data Quality: *Toward Quality Data by Design"; Wang, Guarascio (1991)* (http://web.mit.edu/smadnick/www/wp2/1991-06.pdf), cited in presentation by P. Westrick, *Using Data in Relative models with Respect to Decision Criteria*, March 8, 2017.

[65] See *Probabilistic Risk Assessment Procedures Guide for Offshore Applications (DRAFT),* BSEE-2016-xxx (Draft), October 25, 2016, and presentation by R. Youngblood, Idaho National Laboratory, *Bayesian analysis approaches to risk modeling,* August 9, 2016 (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65686/bayesian-data-analysis-phmsarmwg0816.pdf).

additional data for a variable are obtained. Applying methods to estimate input variable uncertainty is especially important for risk models that apply only point estimates as input values rather than probability distributions. Applying a point estimate to represent a variable's underlying data is convenient, but if the data is spread over a wide range, this should be understood and handled in a deliberate manner (e.g., sensitivity analysis). This is particularly important for the input variables that have the largest effect on model results.

If SME input is used, then the uncertainty associated with this input should be understood, particularly for the most important input variables. Applying point values for SME-based input variables with little attention to the uncertainty in those inputs can introduce substantial bias into risk results.

A persistent issue often mentioned by pipeline operators is data loss during new construction and during asset acquisition. To ensure complete and accurate data for risk model, operators should ensure that records are preserved and retreivable after construction and acquistion events.

D. SME Input

Accurate records of pipeline characteristics (including operational, maintenance, and inspection history) and the geographic features in the pipeline vicinity should be the primary source of risk model inputs. However, complete and accurate records are not always available for every pipe segment, and some risk model inputs may not be obtainable from records. In some cases, operator or industry average values may be available as inputs where segment-specific data are not available. In other cases, operators are dependent on the knowledge and experience of personnel who are familiar with the pipeline and important risk factors. Although accurate data from records may be a preferable source, SMEs are a valuable source for significant portions of the information used as risk model inputs.

For greatest effectiveness, a structured process is needed to integrate and balance personnel knowledge on risk factors to ensure consistency and minimize bias. Steps in the process may resemble:[66]

1. Establish members of the SME group that will provide data estimates.

   Each SME should be an actual "expert," in that the individual has authoritative or unique knowledge on the risk factors being evaluated. Criteria for SME status include factors such as credentials demonstrating expertise (not just years in a job or longevity at a company), certificates and training records, industry recognition, professional/ongoing education, etc.

[66] The basic steps given here are adapted from Ayyub, B., *A Practical Guide on Conducting Expert Elicitation of Probabilities and Consequences for Corps Facilities*, U.S. Army Corps of Engineers, IWR Report 01-R-01, 2001.

2. Identify SME group facilitator and information integrator.

   The facilitator should be familiar with the risk model, know how to interpret and calibrate expert opinion accounting for individual biases, and know how to integrate the information to obtain useful inputs for the risk model.

3. Define each variable or model input that is being estimated by expert opinion.

   All quantities should be precisely defined so that the experts clearly understand the scope and boundaries of what is being estimated. All relevant records and maps should be available to the SME group to help clarify the variable definitions and guide the evaluations.

4. Define specific criteria for SME evaluation of variables.

   Specific rules should be established for how SMEs assign input values to ensure consistent application by different SMEs and consistent application across all pipeline segments covered by the risk model. For example, if "external coating condition" is being evaluated on a segment, then SMEs need specific criteria for what constitutes "good," "medium," "poor," "disbonded," or "shielding" coating conditions, so that the process can be consistently applied across the operator's pipeline assets. Quantitative criteria are preferable where practicable.

5. Elicit SME information to obtain values for variables.

   The process should involve a facilitated discussion to elicit risk factor inputs from the SME group. The facilitator should train the SMEs on the objectives of the evaluation, the process for eliciting SME input, and the evaluation criteria.

   Group discussion should be facilitated and opinions obtained and made available to the entire SME group for consideration before a conclusion is reached. Although knowledgeable, SMEs can still have biases that influence their estimates of variables. A discussion should endeavor to draw out any biases[67] and correct for them. Any available applicable data (including information on pipeline characteristics, operational history, or inspection history) that can be used for comparisons is useful for this purpose.

6. Aggregate and present results.

   The SME evaluations should be assessed for internal consistency and aggregated. The process should have documented rules for handling differences of opinion among SMEs[68] and methods for evaluating uncertainties in the inputs that are based

[67] Muhlbauer, W., *Pipeline Risk Management Manual*, 2004, Table 1.2, for a list of biases that can affect expert evaluations. See also Ayyub, 2001, Appendix C.

[68] Ayyub, B., A Practical Guide on Conducting Expert Elicitation of Probabilities and Consequences for Corps Facilities, U.S. Army Corps of Engineers, IWR Report 01-R-01, 2001. Different methods for combining expert opinions are summarized in Appendix C of Ayyub, 2001.

on SME information. SME input should always include measures of uncertainty that capture the range of possible values estimated by the expert for each variable and the relative weighting of the values in the range. Probability distributions are a convenient way to capture information on uncertainty and can be used as direct input to probabilistic risk models. One method for expert elicitation[69] involves assembling the evidence that each expert has used to formulate estimates, and deriving probability distributions for each variable consistent with that evidence.

7. Review and revise results.

   The aggregated results should be presented to the SMEs for review, additional discussion, and potential revision. SMEs should be given the opportunity to revise their assessments after presented with the aggregated evaluation results. Any revised estimates should be incorporated in the aggregated results and Step 6 repeated.

Further details on processes for obtaining information from SMEs may be found in the following references:

1. Ayyub, B., *Methods for Expert-Opinion Elicitation of Probabilities and Consequences for Corps Facilities*, U.S. Army Corps of Engineers, IWR Report -00-R-10, 2000.
2. Ayyub, B., *A Practical Guide on Conducting Expert Elicitation of Probabilities and Consequences for Corps Facilities*, U.S. Army Corps of Engineers, IWR Report 01-R-01, 2001.
3. Unal, R., Keating, C., Conway, B., and Chytka, T., *Development Of An Expert Judgement Elicitation Methodology Using Calibration And Aggregation For Risk Analysis In Conceptual Vehicle Design*, Old Dominion University, NASA, 2004.

E. PHMSA Key Recommendations – Risk Modeling Data

- An operator's choice for the type of risk model to employ in pipeline risk analysis should not primarily depend on factors related to quality and completeness of input data. Operators should take actions to improve data quality and completeness over time, but risk model inputs should represent the best currently available information on risk factors for each pipeline segment and operators should endeavor to employ segment-specific and location-specific data whenever possible to develop risk model inputs.
- Field data acquisition forms should be consistently checked against the data needs in the risk assessment and the GIS processes to assure the data that is needed to support these processes is being collected in the formats and quality expected. Personnel responsible for completing data acquisition forms should be trained on requirements for completing forms with the needed data quality and completeness.

[69] S. Kaplan, *'Expert information' versus 'expert opinions.' Another approach to the problem of eliciting/combining/using expert knowledge in PRA, Reliability Engineering and System Safety*, 35 (1992).

- Risk models that rely on generic estimates or SME information for a significant portion of input data can be useful to gain insight on risk issues and support decisions. This is especially so if the model algorithm reflects the physical and logical relationships of the input variables and the model output risk measures are expressed in standard units.
- Risk model results should be generated using dynamic segmentation to account for changes in characteristics of the pipeline and its operating environment along the pipeline route, so that the results best reflect the segment-specific and location-specific combinations of risk factors.
- SME input should be elicited carefully to best reflect expert knowledge on risk factors. A structured process should be employed to systematically obtain estimates from SMEs. All SME estimates should include a measure of the uncertainty in the estimates and effort should be made to minimize bias in the estimates.

Appendices

Appendix A – Likelihood Models

A.1 Qualitative Models

In qualitative models, inputs and outputs are developed as qualitative categories rather than numerical scores. In processes that use such models, the likelihood, consequence, and output risk levels are obtained by consideration of pipeline risk factors and assignment to a qualitative risk level. These models should have a defined logic for assigning risk levels.

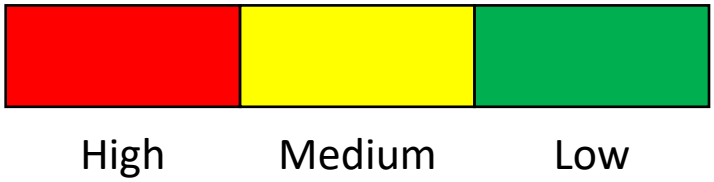
Risk levels may be assigned via an SME discussion. If so, a structured process is needed to integrate and balance the panel's knowledge on risk factors (see section VII.D).

A simplified example of the representation of qualitative results is given in Figure A-1. In the matrix shown, the different shaded regions represent areas of equivalent risk based on different combinations of likelihood and consequence.

Figure A-1
Example Qualitative Model

Consequence	Likelihood		
	High	Medium	Low
High			
Medium			
Low			

Qualitative Risk Scale



A.2 Relative Assessment (Index) Models

Relative Assessment (index) model inputs represent the major risk factors for failure of a pipeline segment, including characteristics of pipeline segments and the surrounding area. These inputs are assigned numeric scores that represent the relative effects on failure likelihood of a pipeline characteristic. Each input may also be assigned a numerical weight, which reflects a subjective assessment of the importance to the potential for a pipeline failure represented by the input. The weighted scores are then combined to calculate an index or score representing the risk presented by each segment. Weights are commonly applied to threat scores to account for the pipeline segment's or operator's failure cause history. Typically, a likelihood index score and consequence index score are calculated separately. They are then combined to obtain a total risk index score. The most common method of combining a likelihood and consequence index to calculate a risk score is by multiplying them.

The index model algorithms often combine likelihood factors according to categories representing major threats to pipeline integrity. For example, index model likelihood categories might include:

- External Corrosion
- Internal Corrosion
- Stress Corrosion Cracking
- Manufacturing Related Defects
    - Defective pipe seam
    - Defective pipe
- Welding/Fabrication Related
    - Defective pipe girth weld
    - Defective fabrication weld
    - Wrinkle bend or buckle
    - Stripped threads/broken pipe/coupling
    - Failure
- Equipment
    - Gasket O-ring failure
    - Control/Relief equipment malfunction
    - Seal/pump packing failure
    - Miscellaneous
- Third Party/Mechanical Damage
    - Damage inflicted by first, second, or third parties (instantaneous/immediate failure)
    - Previously damaged pipe (delayed failure mode)
    - Vandalism
- Incorrect Operations

    - Incorrect operational procedure
- Weather Related and Outside Force
    - Cold weather
    - Lightning
    - Heavy rains or floods
    - Earth Movements

The models typically include several inputs in each threat category. As noted above, each input is assigned a numerical score based on the characteristics or "attributes" of the pipeline segment or the area surrounding the section and is weighted according to its importance. The attribute information is stored in a pipeline risk database. Individual likelihood and consequence indexes can be calculated for each threat, using only the scores and weights of inputs included for the threat category.

For example, a risk index algorithm used by one pipeline operator includes the input "Construction Activity" under the category of "Third-Party Damage." This input has four possible levels, or "attributes," corresponding to different levels of construction activity along a pipeline segment. A numerical score is associated with each attribute so that the variable can be assessed on a consistent basis from pipeline segment to pipeline segment. The attributes and their associated scores for "Construction Activity" are as follows:

Construction Activity	
Attribute	Score
High	10
Medium	7
Low ("typical")	5
Very Low or None	1

Specific rules should be established for assigning attributes to ensure consistent application of the process across different SME groups. SMEs need specific guidance on what constitutes "high," "medium," "low," and "very low," so that the process can be consistently applied across the operator's pipeline assets.

Continuing the example, the weight for "Construction Activity" within the third-party damage threat category would be assigned a value (e.g., perhaps "13%"). In this algorithm, the attribute score for the "Construction Activity" variable is multiplied by this weight and summed with the weighted attribute scores for all other inputs in the third-party damage category to calculate a likelihood index score for the relative probability of pipeline damage due to third-party damage. This threat-specific index score is weighted and summed with the weighted index scores developed for the other cause categories to obtain the total likelihood index. The likelihood index is multiplied by the consequence index to obtain the total risk score for the pipeline segment.

Some operators use one of the "standard" risk-index models that have been developed by various industry consultants, while other operators have developed their own in-house index models. One commonly used industry model is the model, presented in the Muhlbauer *Pipeline Risk Management Manual.*[70]

Significant differences exist among index models in the specific input variables that are included in the quantification of the likelihood index, how scores are assigned to these variables, how the scores are weighted, and how the weighted scores are combined to provide an overall index. In the most common approach, the likelihood index is calculated simply as a weighted sum of the variable scores. Each variable weight is multiplied by the corresponding variable score for a segment and the products of the variable weights and scores are summed to calculate the likelihood index. If any interacting threats were applicable, an additional score would be added to the likelihood index to reflect the additional likelihood of pipeline failure (i.e., the "P_i = failure probability from threat 1 and threat 2 interactions" discussed in Section IV.E).

In the Muhlbauer[71] approach, an index model algorithm calculates the likelihood index as a weighted sum of variable scores. The Muhlbauer *Pipeline Risk Management Manual* provides a set of nominal variable scores and weights that are intended to be starting points for the incorporation of segment-specific data. Additional variables can be defined by the operator.

In-house models developed by operators have been similar in nature to these two models. In some models, the algorithm that translates the individual variable scores into the likelihood index is more complex than a simple weighted sum.

A fundamental characteristic of index models is that the quantitative output is not an actual estimate of the likelihood of failure, consequence of failure, or risk. Instead, it is a numerical index that represents these measures. In most cases, a higher index value is meant to indicate higher likelihood, consequence, or risk and a lower index value is meant to indicate lower values. Thus, the indexes provide a relative measure of risk that has been useful for comparison between different segments or sections of the pipeline (e.g., for setting integrity assessment priorities). Relative model risk results can be challenging to use for applications requiring absolute estimates of likelihood or risk.

A.3 Quantitative System and Probabilistic Models

In this category of risk model, the characteristics of segments of the pipeline and the surrounding area are used to derive an actual estimate of the risk for each segment. Likelihood is estimated as the frequency of failure along each segment over a year's time (or over some other relevant period). Expected levels of consequences in different categories (e.g., human health and safety, the environment, or the potential for economic losses) are estimated. The various consequence measures may be combined using some common units, such as equivalent

[70] Muhlbauer, W. Kent, *Pipeline Risk Management Manual*, 2004.
[71] Muhlbauer, W. Kent, *Pipeline Risk Management Manual*, 2004.

dollar cost. If so, this requires consequences such as human deaths and injuries and adverse environmental impacts to be represented by dollars in the risk equation.

The total risk for the segment is estimated as the product of the likelihood of failure and the expected consequences given failure. If the model calculates the likelihood of different pipeline failure modes (i.e., small leak, large leak, rupture), then the likelihood and consequences corresponding to each failure mode would be estimated as well. The total risk would be estimated as the sum of the product of the likelihood of failure in each failure mode and the expected consequences, given failure in that mode.

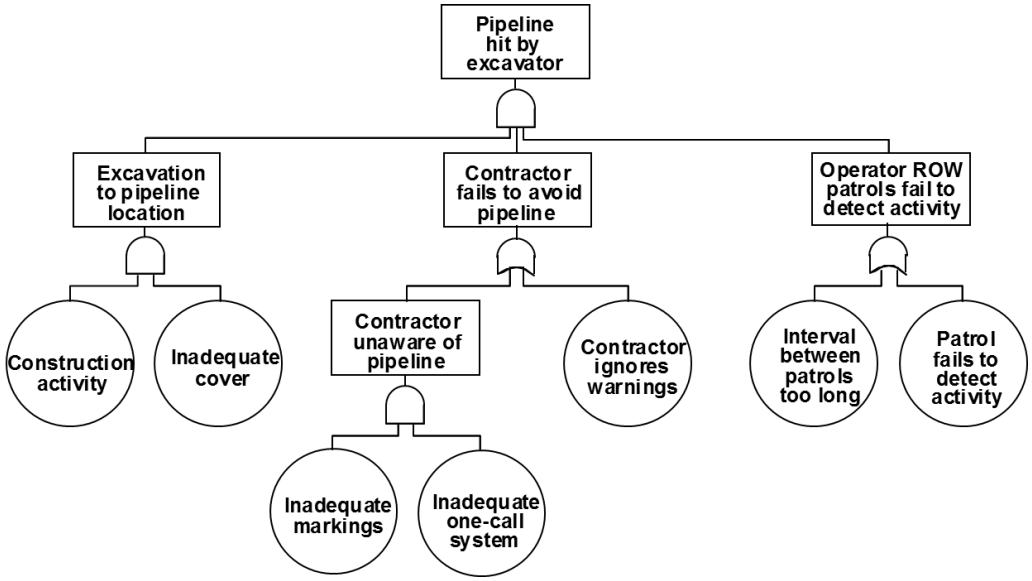
Quantitative System models calculate the likelihood and consequences of a failure along each pipeline segment using the same general types of information on pipeline segment characteristics and the surrounding area that relative assessment (index) models use. Like index models, they can use a combination of data and SME judgment to evaluate inputs in categories corresponding to important threats and consequences.

The algorithm for a Quantitative System model typically includes numerous calculations based on the physical and logical relationships that translate pipeline segment characteristics into estimates of failure likelihood and consequences.

In one model of this type, a nominal or base likelihood estimate is provided based on historical failure rates for the cause categories. This nominal failure rate is modified according to segment-specific characteristics to estimate a segment-specific failure rate (i.e., the expected number of failures for each of the different failure modes per year). The algorithm for modification of the base failure rate may be based on statistical analysis of incident data or on analytical models (e.g., fault tree models or structural reliability models). In addition, the estimate for likelihood of failure may be modified by assumptions about the inspection and maintenance history and practice along the segment. For example, segments that have had recent integrity assessment and repair of discovered defects would typically have different failure likelihood estimates than other segments whose characteristics would otherwise be similar. In addition, as shown in previous Figure IV-3, the additional threat potential from interacting threats can be explicitly accounted for in quantitative system and probabilistic models.

As an example of how an analytical tool is utilized to estimate the likelihood of pipeline failure for one threat category, see Figure A-2, which is a simplified fault tree that models the likelihood of an excavator hit on a pipeline. This model would be part of the model used to estimate the likelihood of failure from excavation damage.

Figure A-2
Simplified Example Fault Tree Model for Excavator to Hit Pipeline[72]



The frequencies or probabilities of the basic events of this fault tree (construction activity, inadequate cover, etc.) are model inputs that would be evaluated based on data or SME inputs. These quantities would be combined according to the model logic to estimate the probability of a pipeline hit by an excavator. This estimate would be combined with an estimate of pipe failure probability, given a hit, to obtain the estimated failure likelihood due to excavation damage. The failure probability, given a hit, is estimated using the probability of a hit imposing specific loads on the pipe and the probability of pipe failure to maintain integrity given those loads (based on pipe characteristics).

For time-dependent threats (e.g., corrosion), a similar "load vs. resistance" approach may be taken that includes evaluation of operating pressure, pipe properties, identified defect characteristics, and the likelihood of failure given pipe, defect, and operating characteristics. For these threats, however, defects grow over time, so the likelihood of failure is time dependent.

Consequences in some risk estimation models are estimated using analytical models to derive quantities such as economic loss and fatalities.

The CFER PIRAMID model is an example of a risk estimation model that has been employed by some pipeline operators.

Because Quantitative System model outputs are actual estimates of probability, consequences, and risk in standard units, they may potentially be applied appropriately to IM program areas

[72] From Stephens, Mark, C-FER Technologies, *Methods for Probability Estimation*, presentation to PHMSA Risk Modeling Work Group, 2016.

requiring absolute measures of risk, as well as when relative measures are needed. They may also be used in other applications that require absolute quantitative estimates of risk.

A.4 Probabilistic Models

Probabilistic models are distinguished from other quantitative system models by the use of probability distributions, rather than single point value estimates, to represent model inputs. The model algorithms combine the distributions according to the system model and obtain output distributions for standard risk measures such as probability of failure, and expected loss from consequences. The difference between a Quantitative System model and a Probabilistic model is not necessarily in the logic of the model algorithm, but a probabilistic model should utilize tools (e.g., Monte Carlo simulation[73]) that allow probabilistic input, in the form of distributions, to be processed and derive output distributions.

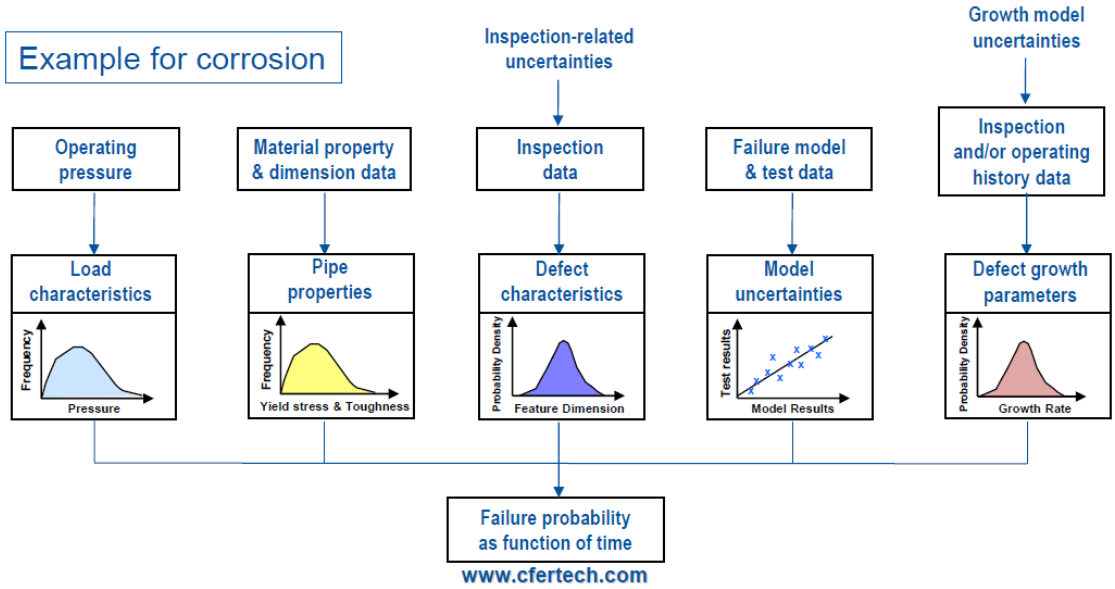
Some important inputs to pipeline risk models, such as integrity assessment results and consequences to receptors, can be highly uncertain. Allowing probabilistic input is an advantage when the input values are uncertain, so that the model output can reflect the input uncertainties. The output risk measures then give a fuller representation of the range of possible values, including potential high-consequence outcomes.

Figure A-3[74] depicts an example of distributions to represent uncertainties for inputs to a model for the time-dependent probability of failure due to corrosion. Uncertain inputs that are assigned distributions include operating pressure, pipe yield strength and toughness, defect characteristics from ILI, and defect growth. The model calculates a failure probability as a function of time, given these distributions.

Input distributions should be chosen by considering the range of possible values for the inputs and how the possible values are distributed over the range. Statistical methods, such as Bayesian analysis, may be used to choose distributions given data or SME estimates for an input.

[73] See ISO/IEC 31010:2009 – *Risk management – Risk assessment techniques*, Section B.25.
[74] Presentation by M. Stephens, C-FER Technologies, *Methods for Probability Estimation*, August 9, 2016.

Figure A-3
Example of Distribution Input to a Probabilistic Model



Appendix B – Consequence Models

B.1 Gas Transmission Consequence Models

Example of Use of FN Curves and "ALARP" by a Gas Pipeline Quantitative Risk Model

One scheme that has been used in application of the *PipeSafe*[75] quantitative risk model for a natural gas pipeline operator is a combination of the ALARP (As Low As Reasonably Practicable) principal with three societal risk bands on a frequency vs. number of fatalities ("FN") scale.[76]

Three risk bands for societal risk are defined to determine the relative value of measures to reduce risk at a location on the pipelines:

- At the top end of the scale there are risks that judged to be so great that they are not acceptable/tolerable. [Region above the red line in Figures B-1 and B-2.]
- At the bottom end are situations where the risk is, or has been made, so small that no further precaution is necessary – a 'broadly acceptable' region. [Region between the red line and blue line in Figures B-1 and B-2.]
- In between these two extremes is a region where risks are tolerable only if their level has been reduced to one that is ALARP (As Low as Reasonably Practicable). [Region below the blue line in Figures B-1 and B-2.]

See the Figure B-1 below for an illustration of an FN curve representing the societal risk of fatalities at a specific location on the pipeline. In this example, a portion of the risk curve is in the "ALARP" region, so risk reduction measures were sought to reduce risk at the location.

Figure B-2 shows FN curves for proposed preventive measures for the location with the risk illustrated in Figure B-1. Multiple risk-reducing measures are shown to move the entire FN curve into the "broadly acceptable" risk band.

[75] M. Acton, K. Dimitriadis, T. Manns, S. Martin, DNV GL; D. McCollum, S. Potts, National Grid, *Development of a Risk Based Asset Management Tool for Gas Transmission Pipelines*, 2015; and M. Acton, P. Baldwin, T. Baldwin, BG Technology; E. Jager, NV Nederlandse Gasunie, *The Development of the PIPESAFE Risk Assessment Package for Gas Transmission Pipelines*, 1998.

[76] See ISO/IEC 31010:2009 – *Risk management – Risk assessment techniques,* Section B.27.

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Figure B-1
FN Curve for a 1-mile section of natural gas pipeline

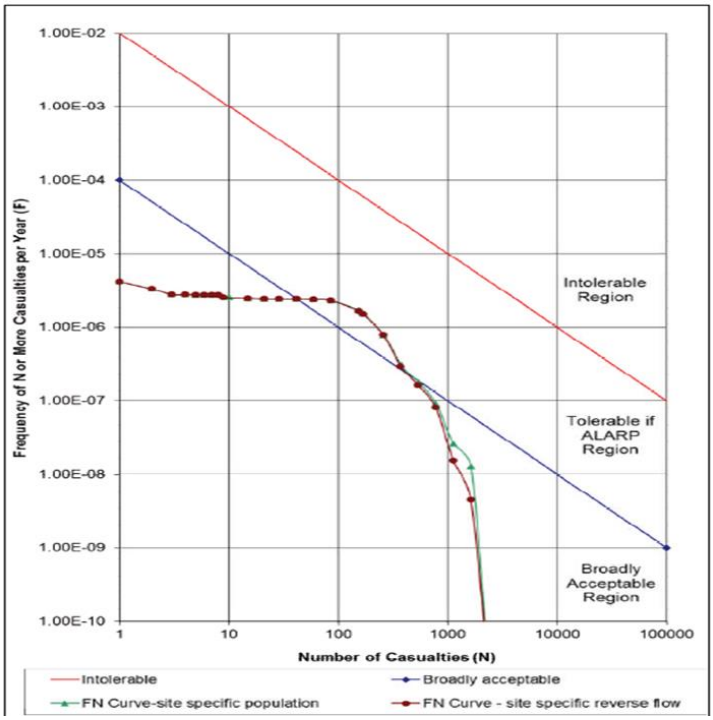
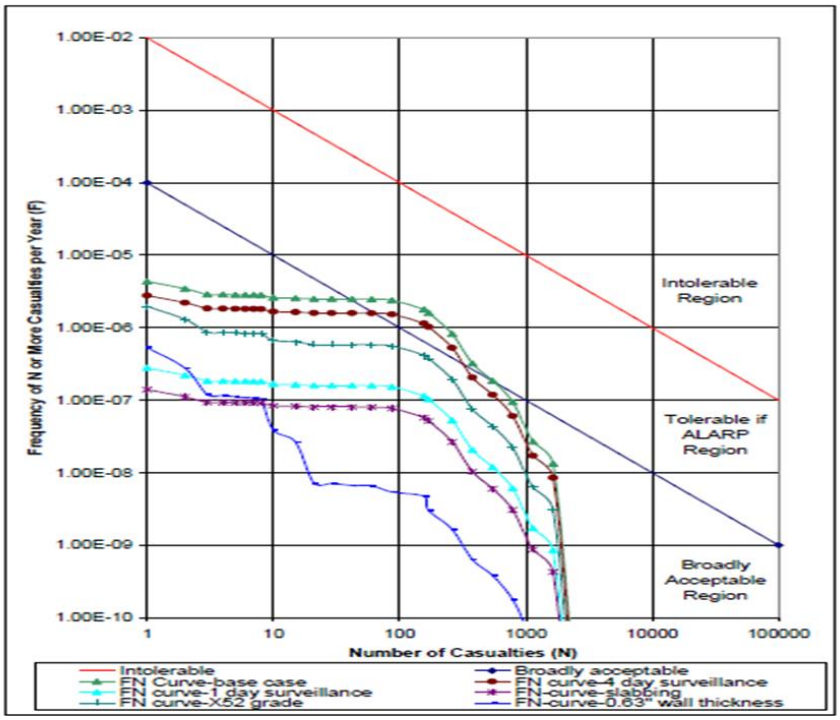


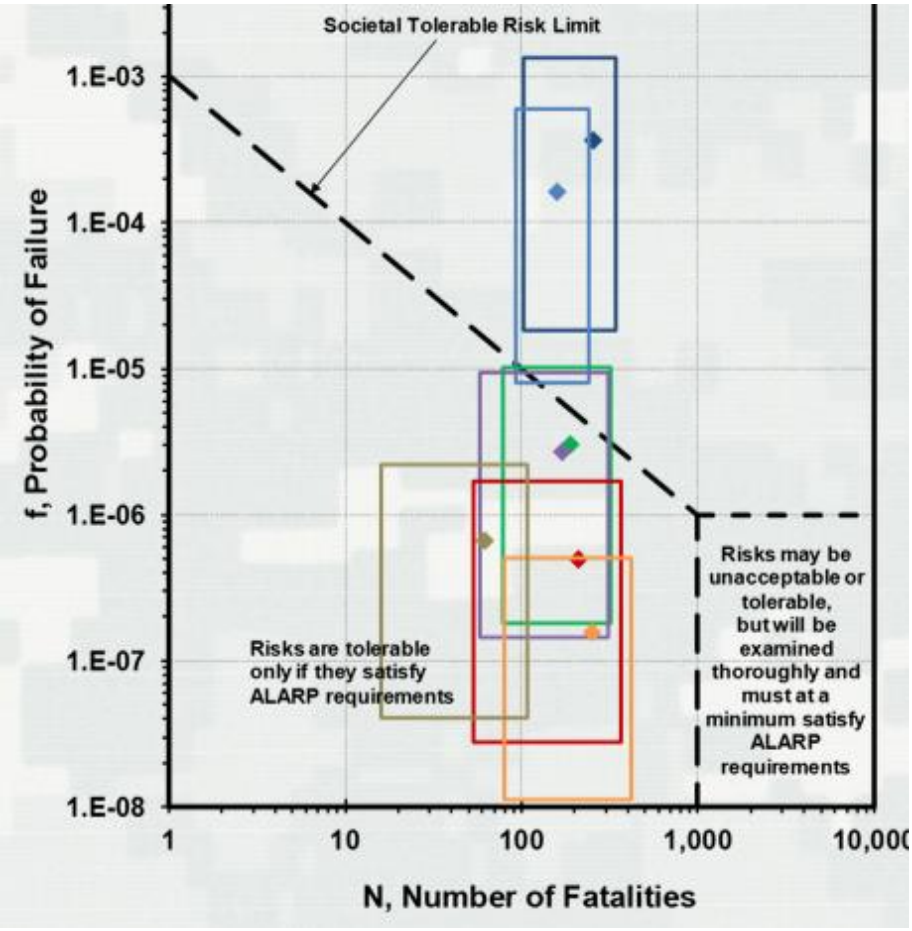
Figure B-2
FN Curves preventive measures for a 1-mile section of natural gas pipeline



An alternative application of FN curves is shown in Figure B-3. In this application, the black dashed lines indicate different risk bands. Differences with the previous example include:

1. A different upper limit is used to define the border between the intolerable risk region and the "ALARP" region.
2. There is no "broadly tolerable" risk region where risk is considered low enough so that ALARP criteria are not applied.
3. There is a separate region at the lower right end of the FN graph to indicate low probability, high consequence outcomes. Risks in this area are noted for special scrutiny and application of ALARP.

Figure B-3
Alternative Application of FN Curves



B.2 Hazardous Liquid Consequence Models

Example: Relative Risk Model Consequence Model

A risk index model, developed by Dynamic Risk,[77] and used by an operator for pipelines with diverse hazardous liquid commodities, calculates hazard areas for multiple hazards posed by a potential pipeline failure:

- Flammability
- Toxicity (based on H_2S content)
- Overpressure

For flammability and toxicity, the size of the hazard area is based on equations from API RP 581 for different commodities, considering estimated release rates, likelihood of ignition, liquid or gas release, and instantaneous or continuous release. For overpressure, the hazard area calculations use estimated release rates and "…TNT equivalent Equation for Hard radius..."[78] Estimated release rates are based on an average of assumed hole sizes assumed for failure from different threats and equations for sonic and subsonic flow.

The largest hazard area of the three hazards considered for each location is chosen to estimate consequences. Human safety consequences are derived from the product of the estimated hazard area and the assumed population density within the hazard area (units are the estimated number of persons impacted). Different population densities are assumed based on which HCA types (High-Population, Other Populated, No HCAs, etc.) are within the hazard area.

Environmental consequences are estimated as the cost to clean up spills, which is considered applicable to commodities released as liquids (including some HVLs). Different costs per gallon to clean up spill are assumed for liquids and HVLs and for different HCA types. Total costs are estimated by applying this cost per gallon to the estimated spill volume, which is based on leak detection and shut down time, volume in line between valves, and drain down factor. The units are estimated total clean-up costs in dollars.

The human safety impact measured in estimated number of persons impacted and environmental impact measured in estimated total clean-up costs are weighted to obtain a total consequence score (Figure B-4 below). Note that safety and environmental consequence scores are assigned the same weight in the overall consequence score and economic consequences are assigned zero weight.

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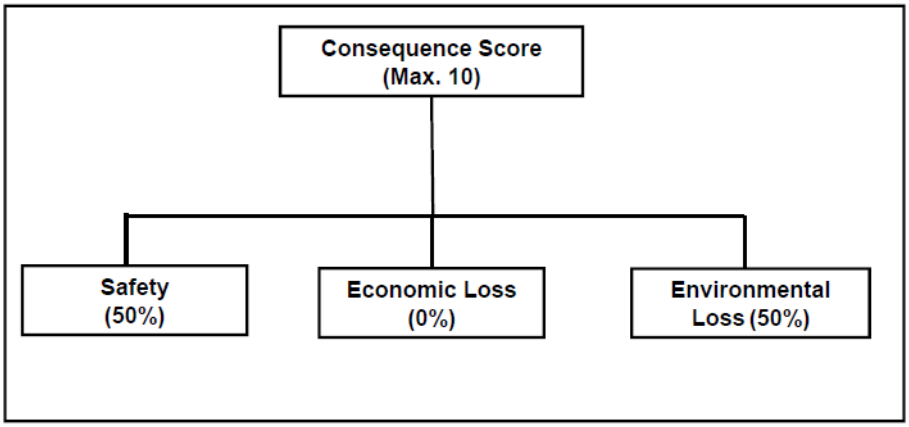
[77] MacFarlane, Trevor (Dynamic Risk), *Index Models and Applications An Industry Perspective*, June 15, 2017. Document can be accessed at: https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65841/indexmodelsandapplicationsdynamicriskrmwg0617.pdf.

[78] "TNT equivalence" is a common technique for equating properties of an overpressure impact to that from the standard TNT explosive – e.g., see https://www.science.gov/topicpages/t/tnt+equivalent+explosive.

February 1, 2020

Figure B-4
Relative Risk Model Consequence Score



Appendix C – Facility Risk Models

Example Tools for Gas Facility Risk Assessment[79]

Three examples are shown of risk assessment tools used by an operator for facility risk assessment. These examples indicate threats and risk factors that should be included in facility risk models.

Figure C-1 shows an example "threat matrix" indicating threats and risk factors for a qualitative gas system facility risk assessment. Note that this process includes threats to facility reliability and emergency response as well integrity threats. The figure shows candidate preventive measures for each threat.

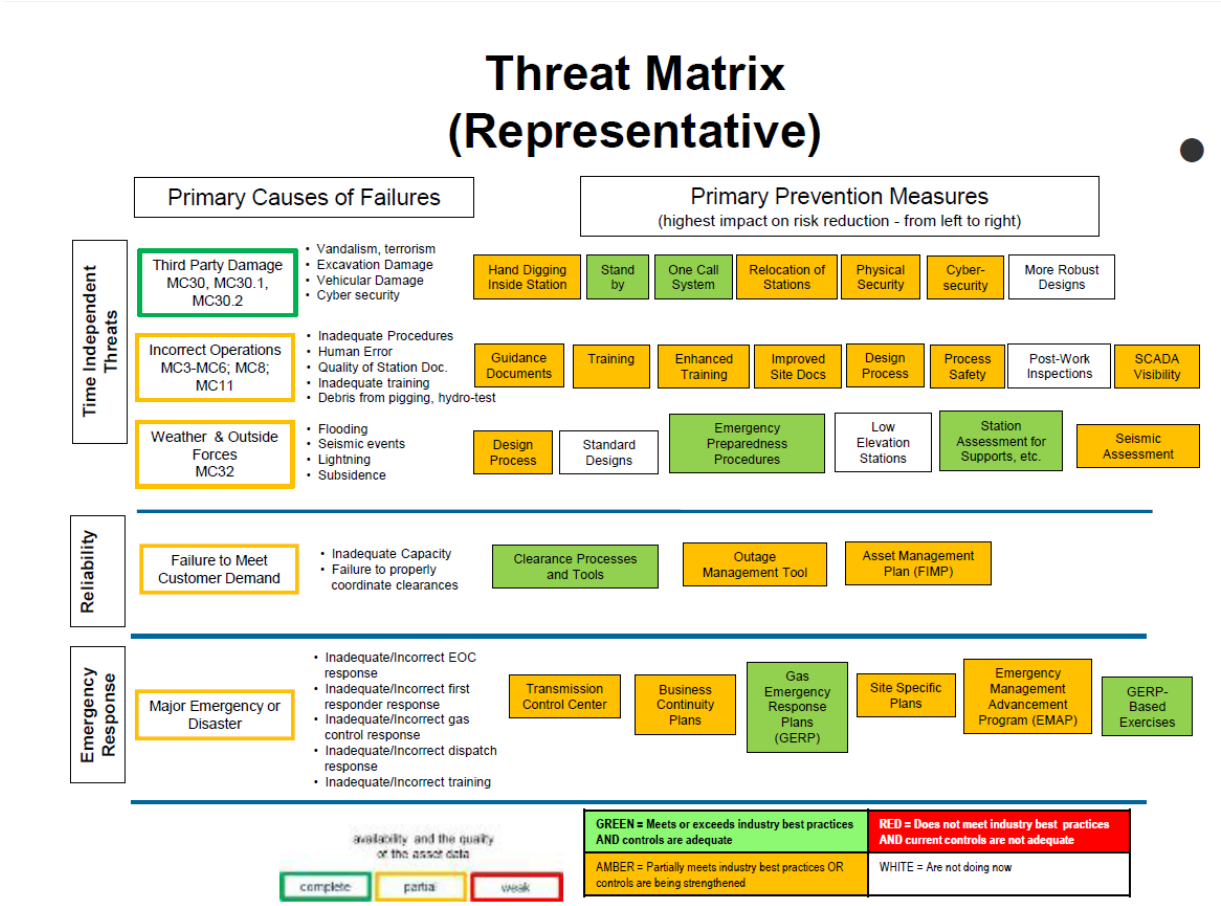
Figure C-2 shows an example table of threats and failure causes to be considered in a gas facility risk assessment process.

Figure C-3 shows a portion of a "risk register" used as a qualitative risk assessment model. The model includes:

- Seven frequency levels (the highest 2 are shown), from "Common" (>10 times per year), down to "Remote" (once every 100+ years)
- Seven impact (consequence) levels (highest 2 shown), from "Catastrophic" down to "Negligible
- Impact levels are defined for six categories (two are shown), including:
  - Safety
  - Environmental
  - Compliance
  - Reliability
  - Reputational
  - Financial

[79] All examples from RMWG presentation by T. White and T. Rovella, PG&E, *PG&E Facilities Risk Management*, November 30, 2016.

Figure C-1[80]
Example Threat Matrix for a Gas Facility Risk Assessment



[80] Figures C-1, C-2, and C-3 from RMWG presentation by T. White and T. Rovella, PG&E, *PG&E Facilities Risk Management*, November 30, 2016.

Figure C-2
Example Threats and Failure Causes for a Gas Facility Risk Assessment

	Time-Dependent Threats			Stable Threats			Time Independent Threats		
	"The threat level may grow over time if unchecked"			*"The threat is inherent but does not grow over time unless acted upon by pressure or external load"*			*"The threat exists outside of the continuum of time"*		
	External Corrosion	**Internal Corrosion**	**Stress Corrosion Cracking**	**Manufacturing Related Defects**	**Welding / Fabrication Related**	**Equipment**	**Third Party / Mechanical Damage**	**Incorrect Operations**	**Weather Related & Outside Forces**
Primary CAUSES	1) Transitions 2) Inadequate coating 3) Atmospheric conditions	1) Liquids 2) Sulfur 3) Erosion	Not a high risk for asset family	1) Poor quality manufacture 2) Inadequate specifications 3) Strength test documentation	1) Poor construction practices 2) Inadequate QC/inspection	1) Age, Obsolescence 2) Incorrect sizing/design 3) Maintenance related 4) Sulfur 5) Liquids entering the system 6) Vault flooding (LP)	1) Vandalism 2) Excavation Damage 3) Vehicular Damage 4) Cyber Threat	1) Inadequate procedures 2) Human error 3) Quality of station documentation 4) Inadequate training 5) Debris from pigging & hydrotesting	1) Flooding 2) Seismic events

Figure C-3
Portion of Example "Risk Register" for Gas Facility Risk Assessment

Frequency Description	Frequency per Year	Frequency Level
> 10 times per year	F = > 10	Common (7)
1 - 10 times per year	F = 1 - 10	Regular (6)

Impact Level	Safety	Environmental
Catastrophic (7)	o **Fatalities:** Many fatalities and life threatening injuries to the public or employees.	o **Duration:** Permanent or long-term damage greater than 100 years; or o **Hazard Level/Toxicity:** Release of toxic material with immediate, acute and irreversible impacts to surrounding environment; or o **Location:** Event causes destruction of a place of international cultural significance; or o **Size:** Event results in extinction of a species.
Severe (6)	o **Fatalities:** Few fatalities and life threatening injuries to the public or employees.	o **Duration:** Long-term damage between 11 years and 100 years; or o **Hazard Level/Toxicity:** Release of toxic material with acute and long-term impacts to surrounding environment; or o **Location:** Event causes destruction of a place of national cultural significance; or o **Size:** Event results in elimination of a significant population of a protected species.

Appendix D – Migration from Older Risk Analysis Methods to Quantitative Models

A-D.1 Introduction

This appendix discusses an example "risk model type" conversion of a scoring-type pipeline risk assessment into a quantitative model that better quantifies risks. The benefits of such an upgrade are numerous, as is discussed in Section III.A.

This model type conversion process is intended to salvage and utilize previously-collected data wherever practical. When the underlying scoring assessment is robust, only a few data sources will need to be added to supplement the existing data used in a scoring type risk assessment.

This conversion process involves four general steps:

1. Convert data currently expressed as scores into data with verifiable measurement units,
2. Establish risk estimation equations that utilize this measurement data,
3. Produce risk assessment results using the converted data and the appropriate algorithms, and
4. Perform QA/QC on results.

A-D.2 Applicability

This information applies to risk assessments performed on components or collections of components of a pipeline system. Components include line pipe, fittings, valves, appurtenances, tanks, pumps, compressors, etc. Collections of components includes typical groupings such as all types of pipeline systems (gathering, transmission, distribution, offshore, onshore, etc.), and all types of facilities (tank farms, pump or compressor stations, etc.), or to specific components such as tanks, pumps, and compressors when such equipment are assessed based on their sub-components.

A-D.3 Level of Effort

Performing the basic conversion process will take a varying level of effort, depending on factors such as those shown below. However, experience has shown that the level of effort is not as significant as some may think, and the benefits to safety and reduced consequences of a failure have been shown to significantly outweigh the costs.

- Knowledge and skills of personnel performing upgrade
    - General pipeline knowledge
    - Risk knowledge
    - Software skills
- Data previously collected for previous risk assessments
    - Data quantity
    - Data condition

    - Correctly aligned to common centerlines
    - Consistent formatting
    - Level of modifications previously done for scoring purposes
- Level of QA/QC performed

The data conversion portion of the upgrade will often require the majority of the effort. Performing the subsequent QA/QC on the assessment results will require on going attention, with more effort at initial stages as practitioners become accustomed to the upgrades.

A-D.4 Definitions

The following definitions are offered to clarify how the terms are used specifically in this appendix.

Algorithm: An equation that calculates some aspect of risk for a component of a pipeline system. Calculation are typically done using location-specific input data describing characteristics and conditions.

CoF: Consequence of failure. Multiple CoF scenarios are generally possible for each failure event.

Exposure, Mitigation, Resistance: These are essential components of a calculation of PoF for each potential failure mechanism. Synonyms for these terms are, respectively, attack, defense, and survivability. They measure:

- Exposure or attack: A measure of the aggressiveness of each failure mechanism, either 1) the frequency of integrity-threatening events or 2) the degradation rate associated with a time-dependent failure mechanism (corrosion or cracking).
- Mitigation: A measure of the effectiveness of all mitigation measures that serve as barriers, preventing or reducing the effect of the exposure.
- Resistance: A measure of the ability of the component to absorb the exposure without failing.

Mpy: Mills-per-year of pipeline degradation.

PoD (or FoD): Probability of Damage (or Frequency of Damage). A part of the PoF estimate that shows the likelihood of a component being damaged by a failure mechanism.

PoF (or FoF): For purposes of this appendix, failure means loss of integrity; i.e., a leak or rupture.

PXX: A point in a distribution of possible values, where the distribution takes into account uncertainty.

QRA: Quantitative Risk Analysis.

Receptor: Anything that can be harmed – receive damage – from a spill/release. Examples include people, property, soil, groundwater, etc.

Risk, Expected Loss (EL): An estimate of the damages or losses associated with possible failure-and-consequence pairings on a component or collection of components (e.g., a pipeline system) over a specific time period. Typically, Risk = PoF x CoF.

Time to Failure (TTF): An estimate of remaining life, based on a definition of 'failure', obtained by algorithm calculation performed on input data. For purposes of this appendix, 'failure' means loss of integrity (i.e., a leak or rupture). Considerations for either a leak or a rupture are included in the TTF value, with the one resulting in earlier failure normally dominating the final estimate of TTF.

A-D.5 Units of Measurement

In order to overcome many of the limitations of scoring type assessments, and to better understand and communicate risks, all input data and subsequent risk assessment results should be expressed in verifiable measurement units.

Verifiable measurement data is always expressed in common units of measurement. Data is obtained by either direct measurement or by estimation. These values are distinct from assigned values such as points or scores since they can be replicated without the need of a translation tool (e.g., a scoring, indexing, or point factor assignment system).

Ensuring a consistent and appropriate set of verifiable measurement units is simply ensuring that the measurement units of all inputs combine algebraically to arrive at the desired risk estimate units of measurement.

A-D.6 Input Data

Examples of typical input data with verifiable and non-verifiable units of measure, include:

Risk Issue Measured	Measurement/Verifiable Example Units	Not Deemed Verifiable Units
Pipe specification	Inches diameter, psi pressure, psi allowable stress	Diameter = "large" Stress level = 7 risk points
The frequency of excavator damage potential at a specific location	Excavations per mile-year	Excavator activity level = 'high' = 9 risk points
Soil Corrosivity	Mills-per-year pitting corrosion rate	"medium" = 4 risk points
Benefits of additional depth of cover	% reduction in excavator contact events	-11 risk points
CoF	$ / incident, fatalities / failure	'low' = 2 on risk matrix

There are multiple measurement units that can support the CoF estimates. The units used for input data will be determined by the desired units in which the final CoF will be expressed. Whichever set of units are chosen, the algebra used to combine the information (see algorithm discussion below) should result in the desired units of CoF. For example, if units of dollars per failure are sought, units of measure might be:

CoF = hazard zone x receptors x damage rate = (ft2 of hazard zone generated per failure) x (number of receptors per ft2) x (damage rate per receptor, $ / receptor) = Dollars per failure

In this example, simply adding an estimate of 'failures per year' to this chain of calculations results in risk units of 'dollars per year':

Risk = EL = PoF x CoF = (failures/year) x ($/failure) = $ / year of expected loss[81]

A-D.7 Risk Assessment Results

Since all data input into the risk assessment carry verifiable measurement units, the risk assessment results also are expressed in verifiable measurement units. For instance, units of events per year, events per mile-year, dollars per incident, TTF, expected loss per mile year, etc. are all verifiable and appropriate outputs for a QRA, as shown below.

Risk, Expected Loss (EL):

Typically, Risk = PoF x CoF. Common units of measure include dollars per year, fatalities per mile-year, and overlap units used in PoF when the consequence is defined as the failure, as was defined for PoF. For example, failures per mile-year can be a measurement unit for both FoF and Risk.[82] When risks are fully monetized, risk can be expressed as EL where EL ($/ year) = PoF (failures/year) x CoF ($/failure)

PoF (or FoF):

Common measurement units include: chance of failure per year, failures per year, failures per mile-year, incidents per year, ruptures per mile-year, etc. For time-degradation failure mechanisms, TTF in units of time (often 'years') is an intermediate calculation of the PoF estimation.

PoF Components:

Only two sets of units are needed to describe all possible failure mechanisms. When time-independent failure mechanisms are involved, units are, for example:

PoF (failures/year) = Exposure (number of potential failure-causing events/year) x Mitigation (fraction of potential failure-causing events that are not avoided) x Resistance (fraction of potential failure-causing events failure)

When time-dependent failure mechanisms are involved, units are, for example:

PoF (failures/year) = f[TTF (years to failure)] where TTF (years to failure) = Resistance (inches of effective wall thickness) / [Exposure (mpy) x Mitigation (fraction of exposure not mitigated)]

Alternate measurement units are also possible. The user should ensure that, algebraically, the units combine to result in the units of the final risk value being estimated. See overall examples in Attachment A for numerical examples using these units of measure.

[81] This example uses $/year for expected loss. Other risk units could also be utilized.
[82] However, this does not acknowledge the differences in consequences associated with various types of failures.

CoF:

Common measurement units include: dollars of loss per incident, fatalities per incident, dollars per failure, dollars per leak, dollars per rupture, consequence units per failure, etc.

A.D-8 Weightings

Weightings introduce inappropriate bias into a risk assessment and are to be avoided. The use of verifiable measurement data will automatically address all concerns that were previously attempted to be addressed by using weightings, thereby negating the need for weightings of any kind in a modern risk assessment.

When upgrading a previous risk assessment that used weightings, the intent of those weightings should be understood. The intent of weightings was typically to compensate for limited mathematical capabilities of the scoring models (e.g., limited range of possible point values with inability to capture real world orders of magnitude differences). If the intent is valid, then the intended effect of the weighting should automatically be captured either in the conversion of the previously collected data or in the set-up of algorithms. A QA/QC process should be established to confirm this.

A.D-9 Uncertainty

Every risk assessment representing real world phenomena will have at least some amount of uncertainty. This is due to natural variability in all phenomena, the probabilistic nature of the real world, and simple lack of complete information. Consideration of uncertainty results in a range of possible answers. Every risk assessment should document how it is taking uncertainty into account.

There are several ways to deal with this uncertainty in a risk assessment. A rigorous option is to generate a distribution of possible values for each input, including considerations for both lack of information and 'natural' variation in each input. All input distributions are then combined using the risk assessment algorithms. This generates distributions of all calculation results and ensures that uncertainty is accounted for in final risk estimates. Practitioners pursuing this option should seek background and information from the fields of statistics, engineering, and pipeline-specific materials science, design, operations, and maintenance practices.

A less rigorous, but usually sufficient approach is discussed here.[83] Since an understanding of the range of possible answers is sought, treating uncertainty in terms of conservatism is an efficient option to avoid the complexities of combining numerous distributions. A risk assessment can document its consideration of uncertainty by declaring the target level of conservatism used in producing its risk estimates. For regulatory compliance as well as practical utility, the recommendation is to not exclude input values that are thought to be "rare," thereby erring on the side of overstating the actual risks. By instead including all input values and specifying their perceived rarity used in the assessment, the role of

[83] While this discussed approach requires at least an approximation of the range and frequency of possible values (a distribution), similar to the more rigorous option, that distribution can often be simply approximated rather than be derived from rigorous analyses.

uncertainty is acknowledged and the entire range of risk is more readily understood. This "range of risk" concept is important for decision makers to understand when managing pipeline integrity.

"PXX" terminology, taken from probability theory, can be used to convey the way in which uncertainty/conservatism is being handled in a specific risk assessment. PXX refers to a point in a distribution of possible values, where the distribution takes into account uncertainty. The values assigned for various conservatism levels – i.e., PXX levels – arise from a known or posited distribution of all possible actual values.

A higher PXX means more conservatism – tending to overstate actual risk – is being incorporated into the risk assessment. P50 normally means the value most likely to occur[84] is being used, so zero conservatism accompanies this value. P90 means a rare value, erring on the side of overstating actual risk, is being used, thereby ensuring conservatism (tending to overstate actual risk) is being used. Numerically, P90 suggests that risk is being overstated 9 times out of ten – a negative surprise occurs once time out of ten when a P90 value is used. A P99 value means that risk has been underestimated only one time out of a hundred – i.e., actual risk will be lower 99 times out of a hundred.

Specifying the level of conservatism that is being employed in the choice of input data effectively turns distributions of possible values into point estimates of possible values. Different levels of conservatism support different intended uses of the risk assessment. The risk assessor declares the level of conservatism used in each assessment, often performing two or more assessments to show the range of possible results. A common strategy is to produce risk estimates at a high (P90 or P99) level of conservatism, for use in location-specific risk management and also to produce a P50 risk assessment for use in communications with outside stakeholders.

A.D-10 Data Conversion

The objective of this phase of the upgrade is to create a new database of converted information, where each entry in the new database carries units of verifiable measurements. The 'rules' and processes used to create the new database should be documented and preserved since they memorialize this aspect of the risk assessment upgrade.

Since a pipeline is an engineered structure placed in an often constantly changing natural environment, numerous sets of data are normally required to fully assess risk. This is true for any risk assessment methodology. Therefore, previously-collected information used in a scoring type risk assessment can often be readily upgraded for use in a quantitative risk assessment (QRA).

The first step is to identify data that is already captured in absolute terms – i.e., in verifiable units of measure. This includes all data in measurements units such as inches, feet, psi, mills-per-year (mpy), counts, frequency, etc. This data generally requires no conversion.

Next, data whose underlying measurement units can be easily extracted from its expression as a 'score' should be returned to those units. For example, if depth of cover of 24-inches was previously assigned a

[84] The mode of the distribution; also, the mean and median, if the distribution is 'Normal.'

value of 7 points in a scoring system, all values of '7' in the old risk database should be should generate a record showing 24 inches in the new database.

The next step is to assign each piece of input data to one of four categories, based on the risk information that is contained in the data.

Data Category	Examples of Data/Information	Example Units of Measure
PoF: Exposure	excavator activity, mpy external corrosion, mpy fatigue cracking, human error rates, etc.	events/mile-year
PoF: Mitigation	depth of cover, patrol, signage, coatings, procedures, training, etc.	% reduction in exposure
PoF: Resistance	wall thickness, SMYS, toughness, weaknesses (dents, gouges, seam issues, etc.), etc.	% of damage resisted without leak/rupture OR[85] effective wall thickness (inches)
CoF	population density, thermal radiation distance, dispersion distances, explosion potential, overland flow distances, soil permeability, etc.	Ft2, Count/ft2, value per unit (remediation costs), cost per incident, etc.

This categorization adds much clarity to the risk assessment since the role of each piece of information is better understood and its use in the risk assessment is transparent.

Most data will fit logically and uniquely into just one category, although it might impact several aspects within the category. Some data has application in more than one category. As an example of both, the input variable 'flow rate' can influence risk estimates of four different PoF exposures: surge potential, fatigue, internal corrosion, and erosion. Flow rates also influence CoF estimates of spill size, dispersion, leak detection, and others.

Some data might be more efficiently converted using a risk assessment algorithm, rather than a data conversion algorithm. Recall the previous example of restoring a depth of cover 'score' to the actual depth – "score of 7 is 24 inches." The record showing 24-inches of cover is important. But the risk assessment should also 'understand' the benefits of the 24-inches of cover. This can be done either by storing the risk-reduction-value of 24-inches of cover in another database or by using an algorithm that translates 24-inches into a risk reduction value.[86] The risk assessment algorithms are discussed in the next section. Either option – building a separate database of values ready to be used in the risk assessment or equating 'raw' data into risk terms using an algorithm – is viable and the choice is a matter of preference for the model designer.

[85] Two types of units are commonly used, depending on whether the failure mechanism is time dependent (corrosion or cracking) or time-independent (third party damage, geohazards, etc.).

[86] Note that translating 24" of cover into a risk reduction benefit is not the same as scoring. The understanding that equates 24" into a mitigation benefit is a measurement, can be verified, and has meaning beyond a relative comparison. The understanding underlying this translation can arise from anywhere in a range of rigor: from a detailed analysis to a simple estimate provided by a knowledgeable individual.

A.D-10.1 CoF Data Sub-Categories

As with PoF data to be used as risk assessment inputs, previously collected data for CoF will generally fall into one of only a few categories. Those categories, and sample data inputs for each, are:

1. Spill/Release size: The volume or mass released in a failure, as a function of hole size, product characteristics, operational parameters (e.g., flow rates, pressures, elevation, etc.), detection time, reaction time.
2. Dispersion: The distance traveled by the spill/release, as a function of product characteristics, terrain, atmospheric conditions, detection time, reaction time, surface flow resistance, etc.
3. Hazard area estimates: The footprint or area of the leak/rupture, in which damages to one or more receptors may occur.
4. Receptors: The types and counts of receptors that are potentially damaged by a leak/rupture.

A.D-11 Algorithms

The objective of the algorithm upgrade is to have a set of calculations the makes correct and efficient use of all relevant input information and produces complete and verifiable estimates of risk in terms of PoF, CoF, and TTF.

Algorithms should quantify all aspects of risk at all locations along each pipeline system being assessed. Algorithms to calculate risk in a modern QRA should ensure that measurement units of all inputs combine appropriately to express risks in units that are also verifiable. The upgrade algorithms should be intuitive and easily established in any calculating software platform.

This section discusses algorithm set-up concepts.

A.D-11.1 PoF

Algorithms supporting a modern QRA's PoF estimate should use or produce values for exposure, mitigation, and resistance, for each potential failure mechanism. That is, each failure mechanism should have values assigned to exposure, mitigation, and resistance at all points along each pipeline system being assessed.

Exposure, mitigation, and resistance combine to provide estimates of both PoD and PoF for each failure mechanism. However, the initial step of measuring each independently is critical. Measuring exposure independently generates knowledge of the 'area of opportunity' or the aggressiveness of the attacking mechanism. Then, the separate estimate of mitigation effectiveness shows how much of that exposure will likely be prevented from reaching the component being assessed. Finally, the resistance estimate shows how often the component will failure, if contact with the exposure occurs.

In risk management, where decision-makers contemplate possible additional mitigation measures, additional resistance, or even a re-location of the component (often the only way to change the exposure), this knowledge of the three key factors will be critical.

The PoF algorithms will differ slightly depending on which of the two types of failure mechanisms are being assessed.

A.D-11.2 Time Independent Failure Mechanisms

Each time independent failure mechanism, including excavation damages, impacts of any other kind, geohazards, human errors, sabotage, etc., that contributes to an overall PoF should have its specific PoF estimated. That estimate is made from combining the three aspects of PoF as discussed previously.

A.D-11.3 Time Dependent Failure Mechanisms

Quantifying PoF for time-dependent failure mechanisms can be more challenging than for time-independent failure mechanisms. The additional challenge arises from 1) the need to produce an intermediate estimate of TTF and 2) the need to assess the effectiveness of commonly used mitigation measures.

As a modeling convenience that generally produces PoF estimates of sufficient accuracy, each time-dependent failure mechanism can be modelled in terms of:

- Exposure expressed as mills-per-year (mpy)
- Mitigation expressed as a probability that, at a specific location, some amount of mpy degradation is occurring.
- Resistance expressed as the effective wall thickness that experiences the mpy degradation.

These terms produce an estimate of TTF. That estimate should then be expressed also as an equivalent PoF. A simple and conservative relationship to do this could be simply: PoF = 1/TTF. More accuracy is achieved when expanded relationships are used, capturing, for example, instances where failures early in the TTF time range are virtually impossible.

A.D-11.4 CoF

Consistent with the categorization of CoF input data (previously discussed), the CoF algorithms will use those same categories to produce estimates of direct CoF resulting from leak/rupture.

Many sophisticated analyses routines are available to model hydrocarbon releases and potential thermal events associated with leaks/ruptures. A review of these is beyond the scope of this appendix.

Critical to the risk assessment upgrade recommended here, is the estimation of a hazard area that could arise from a leak/rupture. The hazard area estimate should include considerations of spill/release size and duration, dispersion (travel from origination point), ignition potential, potential thermal events (fire/explosion), contamination/toxic effects.

Once a hazard area has been estimated, an accounting should be made of the types, quantities, and sensitivities of the various receptors within the hazard area. Receptors typically include human populations, property, and environmental resources.

Multiple scenarios of CoF are generally required in order to properly assess CoF at all points along a pipeline. Scenarios are generated by varying aspects of each of the four CoF categories. Spill size and dispersion are varied by varying the underlying factors such as hole size, detection time, response time, ignition potential, and terrain. Likelihoods of the respective scenarios should also be considered and reflected in the risk assessment.

A.D-12 Example

A key aspect of modern QRA is that units of measurement for all risk assessment inputs and outputs are transparent and intuitive. The following example illustrates this.

In common applications of the exposure, mitigation, resistance triad, units are as follows. Each exposure is measured in one of two ways – either **in units of 'events per time and distance,'** i.e., events/mile-year, events/km-year, etc. or **in units of degradation** – metal loss or crack growth rates, i.e., mpy, mm per year, etc. An 'event' is an occurrence that, in the absence of mitigation and resistance, will result in a failure. To estimate exposure, we envision the component completely unprotected and highly vulnerable to failure (think 'tin can' wall thickness). So, an excavator working over a buried pipeline is an event. This is counted as an event regardless of type of excavator, excavator reach, depth of burial, use of one-call, signs/markers, etc.

Mitigation and Resistance are each measured in units of percentage, representing 'fraction of damage or failure scenarios avoided.' A mitigation effectiveness of 90% means that 9 out of the next 10 exposures will not result in damage – mitigation has blocked 90% of the exposures that would otherwise have occurred. Resistance of 60% means that 40% of the next damage scenarios will result in failure, 60% will not.

For assessing PoF from time-independent failure mechanisms—those that appear random and do not worsen over time – the top-level equation can be as simple as:

PoF_time-independent = exposure x (1 - mitigation) x (1 - resistance)

With the above example units of measurement, PoF values emerge in intuitive and common units of 'events per time and distance' such as events/mile-year, events/km-year, etc.

A.D-12.1 PoF Excavator Contacts

As an example of applying this to failure potential from third party excavations, the following inputs are identified for a hypothetical pipeline segment:

- Exposure (unmitigated) is estimated to be three excavation events per mile-year.
- Using a mitigation effectiveness analysis, experts estimate that 1 in 50 of these exposures will not be successfully kept away from the pipeline by the existing mitigation measures. This results in an overall mitigation effectiveness estimate of 98%.
- Of the exposures that result in contact with the pipe, despite mitigations, experts perform load/stress analyses to estimate that 1 in 4 will result in failure, not just damage. This estimate includes the possible presence of weaknesses due to threat interaction and/or manufacturing and construction issues. So, the pipeline in this area is judged to be 75% resistive to failure from these excavation events, if mitigation fails and contact occurs.

These inputs result in the following assessment:

(3 excavation events per mile-year) x (1 - 98% mitigated) x (1 - 75% resistive)

= 0.015 failures per mile-year [87]

This suggests an excavation-related failure about every 67 years along this mile of pipeline.

This is a very important estimate. It provides context for decision-makers. When subsequently coupled with consequence potential, it paints a valuable picture of this aspect of risk.

Note that a useful intermediate calculation, probability of damage (but not failure) also emerges from this assessment:

(3 excavation events per mile-year) x (1 - 98% mitigated) = 0.06 damage events/mile-year

This suggests excavation-related damage occurring about once every 17 years.

This damage estimate can be verified by future inspections. The frequency of new top-side dents or gouges, as detected by an ILI, may yield an actual damage rate from excavation activity. Differences between the actual and the estimate can be explored: e.g., if the estimate was too high, was the exposure overestimated, mitigation underestimated, or both? This is a valuable learning opportunity.

A.D-12.2 PoF Corrosion

This same approach is used for other time-independent failure mechanisms and for all portions of the pipeline.

For assessment of PoF for time-dependent failure mechanisms – those involving degradation of materials – the previous algorithms are slightly modified to yield a time-to-failure (TTF) value as an intermediate calculation in route to PoF.

PoF_time-dependent = f(TTF_time-dependent)

TTF_time-dependent = resistance / [exposure x (1 - mitigation)]

As an example, experts have determined that, at certain locations along a pipeline, soil corrosivity creates a 5 mpy external corrosion exposure (unmitigated). Examination of coating and cathodic protection effectiveness leads experts to assign a mitigation effectiveness of 90%.[88] Recent inspections, adjusted for uncertainty, result in an 'effective' pipe wall thickness estimate of 0.220 inches (resistance). This includes allowances for possible weaknesses or susceptibilities, modeled as equivalent to a thinning of the pipe wall.[89]

Use of these inputs in the PoF assessment is shown below:

TTF = 220 mils / [5 mpy x (1 - 90%)] = 440 years.

---

[87] [Exposure vents/mile-yr.] x [damage events/exposure event] x [failures/damage events] = failures/mile-yr.
[88] This is not necessarily a trivial estimate, often requiring significant analyses.
[89] This can be a complex calculation and captures 'threat interaction' as noted in a previous column.

Next, a relationship between TTF and PoF for the future period of interest, is chosen. For example, a simple and conservative relationship yields the following.

PoF = 1 / TTF = [5 mpy x (1 - 90%)] / 220 mils = 0.22% PoF.

A.D-12.3 Total PoF

In this example, an estimate for PoF from the two failure mechanisms examined – excavator damage (see Section A.D-12.1) and external corrosion (see Section A.D-12.2) – can be approximated by 1.5% + 0.2% = 1.7% per mile-year. If risk management processes deem this to be an actionable level of risk, then the exposure-mitigation-resistance details lead the way to risk reduction opportunities.

The exposure-mitigation-resistance analyses is an indispensable step towards full understanding of PoF. Without it, understanding is incomplete. Full understanding leads to the best risk management practice – optimized resource allocation – which benefits all stakeholders.

Appendix E – Regulatory Drivers[90]

E.1 Requirements for Hazardous Liquid Pipelines

The requirements for hazardous liquid pipelines are found in § 195.452 (Pipeline integrity management in high consequence areas):

§ 195.452 (f) What are the elements of an integrity management program?

> An integrity management program begins with the initial framework. An operator must continually change the program to reflect operating experience, conclusions drawn from results of the integrity assessments, and other maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area. An operator must include, at minimum, each of the following elements in its written integrity management program: … (3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section); …

§ 195.452 (g) What is an information analysis?

> In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure. This information includes:
>
> (1) Information critical to determining the potential for, and preventing, damage due to excavation, including current and planned damage prevention activities, and development or planned development along the pipeline segment;
>
> (2) Data gathered through the integrity assessment required under this section;
>
> (3) Data gathered in conjunction with other inspections, tests, surveillance and patrols required by this Part, including, corrosion control monitoring and cathodic protection surveys; and
>
> (4) Information about how a failure would affect the high consequence area, such as location of the water intake.

§ 195.452 (h) What actions must an operator take to address integrity issues? —

> … (4) Special requirements for scheduling remediation—
>
> … (iv) Other conditions. In addition to the conditions listed in paragraphs (h)(4)(i) through (iii) of this section, an operator must evaluate any condition identified by an

[90] Regulatory references are those in effect as of the date of this document.

integrity assessment or information analysis that could impair the integrity of the pipeline, and as appropriate, schedule the condition for remediation.

§ 195.452 (i) What preventive and mitigative measures must an operator take to protect the high consequence area? —

(1) *General requirements.* An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection.

(2) Risk analysis criteria. In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to:

(i) Terrain surrounding the pipeline segment, including drainage systems such as small streams and other smaller waterways that could act as a conduit to the high consequence area;

(ii) Elevation profile;

(iii) Characteristics of the product transported;

(iv) Amount of product that could be released;

(v) Possibility of a spillage in a farm field following the drain tile into a waterway;

(vi) Ditches along-side a roadway the pipeline crosses;

(vii) Physical support of the pipeline segment such as by a cable suspension bridge;

(viii) Exposure of the pipeline to operating pressure exceeding established maximum operating pressure.

§ 195.452 (j) What is a continual process of evaluation and assessment to maintain a pipeline's integrity? —

… (2) Evaluation. An operator must conduct a periodic evaluation as frequently as needed to assure pipeline integrity. An operator must base the frequency of evaluation on risk factors specific to its pipeline, including the factors specified in paragraph (e) of this section. The evaluation must consider the results of the baseline and periodic integrity assessments, information analysis (paragraph (g) of this section), and decisions about remediation, and preventive and mitigative actions (paragraphs (h) and (i) of this section).

(3) Assessment intervals. An operator must establish five-year intervals, not to exceed 68 months, for continually assessing the line pipe's integrity. An operator must base the

assessment intervals on the risk the line pipe poses to the high consequence area to determine the priority for assessing the pipeline segments. An operator must establish the assessment intervals based on the factors specified in paragraph (e) of this section, the analysis of the results from the last integrity assessment, and the information analysis required by paragraph (g) of this section.

E.2 Requirements for Gas Transmission Pipelines

The requirements for gas transmission pipelines are found in respective portions of 49 CFR Part 192, Subpart O (Gas Transmission Pipeline Integrity Management):

§ 192.911 What are the elements of an integrity management program?

An operator's initial integrity management program begins with a framework (see § 192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S (incorporated by reference, see § 192.7) for more detailed information on the listed element.)

(c) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§ 192.917) and to evaluate the merits of additional preventive and mitigative measures (§ 192.935) for each covered segment.

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(a) *Threat identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 2, which are grouped under the following four categories:

(1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

(2) Static or resident threats, such as fabrication or construction defects;

(3) Time independent threats such as third party damage and outside force damage; and

(4) Human error.

(b) *Data gathering and integration.* To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and

information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.

(c) *Risk assessment.* An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§§ 192.919, 192.921, and 192.937), and to determine what additional preventive and mitigative measures are needed (§ 192.935) for the covered segment.

§ 192.935 What additional preventive and mitigative measures must an operator take?

(a) *General requirements.* An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (*See* § 192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs….

§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity? ...

(b) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in § 192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in § 192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§ 192.917), and decisions about remediation (§ 192.933) and additional preventive and mitigative actions (§ 192.935). An operator must use the results from this

evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

(c) *Assessment methods.* In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in the covered segment by any of the following methods as appropriate for the threats to which the covered segment is susceptible (*see* § 192.917), or by confirmatory direct assessment under the conditions specified in § 192.931.

§ 192.939 What are the required reassessment intervals?

An operator must comply with the following requirements in establishing the reassessment interval for the operator's covered pipeline segments.

(a) *Pipelines operating at or above 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. If an operator establishes a reassessment interval that is greater than seven years, the operator must, within the seven-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with §192.931. The table that follows this section sets forth the maximum allowed reassessment intervals.

(1) *Pressure test or internal inspection or other equivalent technology.* An operator that uses pressure testing or internal inspection as an assessment method must establish the reassessment interval for a covered pipeline segment by—

(i) Basing the interval on the identified threats for the covered segment (see § 192.917) and on the analysis of the results from the last integrity assessment and from the data integration and risk assessment required by § 192.917; or

(ii) Using the intervals specified for different stress levels of pipeline (operating at or above 30% SMYS) listed in ASME B31.8S (incorporated by reference, *see* § 192.7), section 5, Table 3.

Appendix F – Risk Modeling Work Group Mission Statement

Preamble

PHMSA has identified a need to provide technical overview information on

- Methods, and tools to be used in pipeline risk modeling, and
- Application of these methods and tools in pipeline risk management.

PHMSA's technical overview needs to be based on the state of the art of pipeline risk modeling, as reflected in the views of the technically informed community of practice.

Risk Modeling Work Group Mission Statement

The mission of the Risk Modeling Work Group is to:

- **Characterize the state of the art of pipeline risk modeling** for gas transmission and liquid pipelines,
- **Identify** and, if necessary in specific areas, develop **a range of state-of-the-art methods and tools capable of addressing the spectrum of pipeline risk management applications**, and
- **Provide recommendations** to PHMSA regarding the use of these methods, tools, and data requirements.

Appendix G – Federal Register Notice Commenters

PHMSA would like to thank the following individuals and organizations that provided comments on this document via the Federal Register Notice process (Docket ID PHMSA-2018-0050).

- George Alexander (Del-Chesco United for Pipeline Safety)
- B. Arrindell (Damascus Citizens for Sustainability)
- Rob Benedict (American Fuel & Petrochemical Manufacturers)
- Paul Blanch
- Bryce Brown (Rosen USA)
- Terese Buchanan
- Edward Cavey
- Elaine Cimino
- Benjamin Clark (MidAmerican Energy Company)
- Ron Cocco
- Lenora Dutczak
- Arianne Elinich
- Lynda Farrell
- Sharon Furlong, Bucks Environmental Action; Bucks County Sierra Club
- Faith Furno
- Nancy Harkins
- April Keating
- Sonya Kirby (TransCanada)
- Deborah Kratzer
- Gary Krichau (Northern Natural Gas Company)
- Richard Kuprewicz (Accufacts)
- Irene Leech
- Keith Leewis
- Jeff Marx (Quest Consultants Inc.)
- Kathy Mayo (PODS Association)
- Gillian McManus
- Jeff Millington (Kern River Gas Transmission)
- Annie Nobbie
- Ken Oliphant (JANA Corporation)
- Sonal Patni (AGA/API/APGA/AOPL/INGAA)
- Lex Pavlo
- Courtney Phillips (G2 Integrated Solutions)
- Peter Tuft
- Rosemary Wessel
- Robert Youngblood

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[91] Cited presentations may be found at https://www.phmsa.dot.gov/pipeline/risk-modeling-work-group/risk-modeling-working-group-rd-documents-presentations.

[92] Presentation may be found at https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65711/skow-dtph56-15-t00003-final-project-presentation-05-sept-2016-riskwo.pdf.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Brian E. Fellon

INFORMATION TECHNOLOGY & SERVICES

Exh. BEF-18C

REDACTED VERSION

August 29, 2025

NW Natural
PROGRAM / PROJECT ALTERNATIVES NARRATIVE

Program/Project Name: E202718 - JANA Probabilistic Risk Model
Date: 03/21/2023
Project Sponsor: Daniel Kizer
Executive Sponsor: Joe Karney
Project Manager: Scott Lundgren
Preparer: Scott Lundgren

The purpose of the Alternative Analysis requirement is to choose the best solution for NWN's need and to make sure we are utilizing resources in the most efficient manner.

BUSINESS NEED/JUSTIFICATION

What is the issue intended to be addressed and why is it needed?

As part of the NW Natural Distribution Integrity Management Program (DIMP) a risk model is performed to estimate the risk associated with gas distribution system threats. This risk model is developed by integrating facility data in GIS, compliance maintenance data and Subject Matter Expert (SME) input within an algorithm to establish and rank risk to the system. The risk model is required by the Federal Code (CFR 49 Part 192) and is an integral part of the NW Natural DIMP Program Plan.

The current risk model is a relative risk model which measures the likelihood of a failure associated with a threat. This project will transition the risk model to a probabilistic risk model which determines the probability of a failure in the system and measures the expected consequences. This risk model will be provided by a JANA Corporation product titled the Lighthouse integrity risk management software.

DIMP risk models are at the minimum run once a year as required by the Federal Code and the DIMP Program Plan. Risk models are also run to risk rank an industry or NW Natural threat to the system where these threats need to be risk ranked to address the threat.

OBJECTIVE

Clearly define the objective.

In 2020 Probabilistic risk models were identified by PHMSA as a best practice to allow natural gas operators the ability to remediate risks on the natural gas system on a risk-cost optimized basis and demonstrate proper actions are being taken on the system to regulators.

The improved interface of the JANA probabilistic risk model allows Integrity Engineers to easily produce scenario-based analysis to identify risks on the system based on 'what-if' scenarios. The improved interface also allows for more effective communication to NW Natural leadership and state regulators on future DIMP programs and the effectiveness of those programs.

RECOMMENDED OPTION

Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option.

Description	JANA probabilistic risk model software is an improved data analysis software which will help better manage risks associated with the NW Natural distribution system. This probabilistic model will incorporate NW Natural GIS data, NW Natural Compliance Management data, along with officially known data and JANA research to develop a fully quantitative risk model approach which will provide an absolute measure of risk
Decision Criteria	The most effective long-term option
Pros	• JANA probabilistic risk model software is an improved data analysis software which will help better manage risks associated with the NW Natural distribution system.

	• The model will incorporate NW Natural GIS data along with officially known data and JANA research to develop a fully quantitative risk model approach which will provide an absolute measure of risk • Complies with PHMSA best practice. • JANA risk model is not directly tied to updates to ESRI and the GIS system. The JANA risk model has full functionality and is adaptable to different versions of ESRI and the compliance data management systems. • JANA showed itself to be much more adaptable and willing to work with NW Natural regarding the data that will be used to perform the risk analysis. • JANA was more adaptable to perform "what if" scenarios and predicting future risk. • JANA model will significantly reduce workload on GIS team when the model work is performed.
Cons	• Cost of the installation.

POTENTIAL COST			
Capital	**Direct + Contingency**	**COH (43%)**	**Total**
	$1,680,000	$722,400	$2,402,400
O&M	**Program/Project**	**Ongoing Maintenance & Support**	
	$320,000 over 5 years	No forecasted costs	
Source/ Method of Cost Data	NWN estimate/JANA contract		

ALTERNATIVE 1 Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option	
Description	Transition existing risk model using [redacted] Uptime Migration to Synergy Pipeline with [redacted] Transmission and Distribution Probabilistic Risk Assessment Models. This probabilistic model will incorporate NW Natural GIS data, NW Natural Compliance Management data, along with publicly known data to transition the existing Uptime DIMP risk model to a [redacted] Synergy risk model
Pros	• Cost
Cons	• During the demonstration of the [redacted] Risk model and JANA risk model, it was not user-friendly. JANA was the program that was shown to be much more intuitive and configurable for both the GIS technicians and the Integrity Engineers. • [redacted] offers limited functionality until GIS transitions to the ESRI Utility Network, and that timeline is being determined. • During demo [redacted] was unable to produce usable results with their demonstration data. • Performing scenario-based models in [redacted] system is very time consuming for GIS technicians.

POTENTIAL COST			
Capital	**Direct + Contingency**	**COH (43%)**	**Total**
	$1,000,000	$430,000	$1,430,000
O&M	**Program/Project**	**Ongoing Maintenance & Support**	
		No forecasted costs	
Source/ Method of Cost Data	NWN estimate/[redacted] estimate		

Explain why this alternative is not recommended	

ALTERNATIVE 2 Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option	
Description	• Continue utilizing existing risk model.
Pros	• No installation cost.
Cons	• The current DIMP risk model is a relative risk model, PHMSA best practices and industry peers recommends a probabilistic risk model which is the type of risk model proposed to be implemented as part of this project. • The current DIMP risk model is tied to the current version of ESRI utilized by the GIS/Mapping team. That group is pursuing long range plans to upgrade to a utility network version which will render the current model to be out of date and require a change in risk models. • Continuing to use a risk model that is linked to a software system like ESRI presents challenges since other compliance data used in the risk model is stored in other data formats and software interfaces. The JANA risk model allows mapping and compliance software systems to evolve based on individual need with limited impact to the DIMP risk model. • The current risk model is very time-consuming and not user friendly for the GIS technicians. Implementation of the JANA risk model will reduce workload to that group.

POTENTIAL COST			
Capital	**Direct + Contingency**	**COH (43%)**	**Total**
	$0.00	$0.00	$0.00
O&M	**Program/Project**	**Ongoing Maintenance & Support**	
	$0.00	No forecasted costs	
Source/ Method of Cost Data	N/A		
Explain why this alternative is not recommended	Continually using the existing risk model does not follow PHMSA best practices and is an increased workload on the GIS technicians.		

ALTERNATIVES CONSIDERED NOT VIABLE *Provide a description of any additional alternatives that were considered but rejected up front as not viable, and explain why*		
	Description	**Why the Alternative is not viable**
Alternative 2	*Do not implement a risk model*	*Performing a risk model analysis is required by Federal Code and the NW Natural DIMP plan*
Alternative 3		
Alternative 4		

**Add rows for any additional alternatives considered not viable*

FURTHER ANALYSIS NOT REQUIRED *Describe why further analysis is not required. Please explain in enough detail that others can assess whether the existing justification is sufficient.*

PMO USE ONLY ***ELECTRONIC APPROVALS***		
Title	**Name**	**Date/Time Approved**
PMO Specialist		
AA Approver		

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Brian E. Fellon

INFORMATION TECHNOLOGY & SERVICES

Exh. BEF-19

August 29, 2025

NW Natural
PROJECT ALTERNATIVES NARRATIVE

Program/Project Name: SAP Update
Date: February 1, 2025
Project Sponsor: Dina Thompson / Karen Hayson
Executive Sponsor: Brian Fellon / Brody Wilson
Project Manager: Michael Crotty
Preparer: Jennifer Chiaratti
Was this project part of IRP: (enter "Yes, Included", "Yes, Acknowledged" or "No"): No

SECTION 1: BUSINESS CASE

This section should be solution-agnostic, and about the overarching problem we're trying to solve no matter which route we end up taking

OBJECTIVES *Why are we tackling this project?*	
Current State What is happening now? Where are we starting?	SAP S4 is our key enterprise application used to support work in the field, our financial operations, ability to pay suppliers and vendors. Current version of the application will no longer be supported at the end of 2025. Update is required to maintain supportability and security. By keeping software and equipment at supported levels, NW Natural can continue to receive critical system and security patches, take advantage of the latest technology features, and maintain license compliance as defined by support Agreements. This work is part of NWN Application Lifecycle Management.
Problem Statement In simple terms, what are we trying to solve? What is the business need this is tackling? Why is this a problem worth solving (e.g. why is the current state not working)?	SAP S4 is our key enterprise application used to support work in the field, our financial operations, ability to pay suppliers and vendors. It is necessary to update SAP S4 to mitigate risks of technical failures of the Company's essential ERP system. As with other software products, SAP requires periodic updates to address bug fixes, incorporate product improvements, and maintain support services. In this case, NW Natural's current 2020 SAP S4 version will no longer be fully supported by SAP at the end of 2025. An unsupported platform would put the Company's operations at risk, as any security patches or other system issues could not be resolved without SAP's assistance. Therefore, updating SAP S4 to the latest version is critical in ensuring the essential functionality of NW Natural's SAP system.
Desired Deliverables What high level output / scope / deliverables are core to this project?	This project will update our major version of SAP S4 Hana from 2020 which is out of support at the end of 2025 to version 2023.

SECTION 2: ALTERNATIVES SUMMARY

OVERVIEW *How did we review these options?*	
Review Process Summarize how options were chosen, who was involved in the choice and how options were evaluated. If some criteria were considered more important based on the type of project, please explain here.	SAP has provided notice that our version of the software will be unsupported at the end of 2025. Only two alternatives are possible: Update or Do Nothing.

DECISION CRITERIA *Describe the criteria used to determine the selection from the various alternatives considered. For example, is this a program/project where the least cost option should be selected? Are there other factors, such as safety or quality that come into play? Include both quantitative and qualitative factors as appropriate.*	
Criteria: Alignment to NW Natural's IT Strategy	Maintaining application supportability
Criteria: Cost-Benefit Analysis	Most cost-effective option for the business
Criteria: Timing	Ability to complete a project in time to meet a regulatory, business, product lifecycle, or safety requirement.

SECTION 3: ALTERNATIVES DETAIL

RECOMMENDED OPTION *Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option. If positive /neutral/negative observations do not exist, enter N/A*		
Description	Update SAP S4 HANA 2020 to remain in support window	
In brief, why is this the recommended option?	Given the importance of the SAP platform to NWN's financial and compliance needs, an unsupported platform presents significant risk to NWN's regulatory requirements. It is necessary for NWN to stay within SAP product support to ensure fixes, patches, and support for any issues is maintained.	
Assessment	**Analysis Against Criteria:** Alignment to NW Naturals IT Strategy	NW Natural IT Strategy requires critical business systems maintain vendor supportability.
	Analysis Against Criteria: Cost	Although there are costs associated with updating the SAP S4 ERP, $2.2M - $2.75M, this known cost is likely far less than the cost of attempting to maintain business operations without vendor support, up to and including potential significant impacts to business continuity and regulatory compliance.
	Analysis Against Criteria: Timing	Work needs to be completed prior to end of 2025 and prior to NWN busy winter season.
	Additional Risks	Overall business resource availability for testing; same as with any significant testing effort.
	Additional Benefits	SAP S4 is our key enterprise application used to support work in the field, our financial operations, and the ability to pay suppliers and vendors. Having an unsupported platform would put NWN at risk in the event we have a defect that requires SAP support to resolve or security fixes.

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$2.0M - $2.5M	$200k - $250k	$2.2M - $2.75M
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$0 - $4k	$xx - $xx	
Source/ Method of Cost Data	Statement of Work, Internal and External Resource Costs		

ALTERNATIVE 1 *Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.*		
Description	N/A	
In brief, why is this option not recommended?	N/A	
Assessment	**Analysis Against Criteria:** Alignment to NW Naturals IT Strategy	N/A
	Analysis Against Criteria: Cost	N/A
	Analysis Against Criteria: Timing	N/A
	Additional Risks	N/A
	Additional Benefits	N/A

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	N/A	N/A	N/A
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$0 - $0	$xx - $xx	
Source/ Method of Cost Data	N/A		

ALTERNATIVES CONSIDERED NOT VIABLE *Provide a description of any additional alternatives that were considered but rejected up front as not viable, and explain why*		
	Description	**Why the Alternative is not viable**
Alternative 2	Do nothing. Remain on NWN's current SAP system as-is without updating SAP S4 HANA 2020 to a supported version.	The only alternative to an update is remaining on the current SAP S4 version. This would place NW Natural at significant risk as it results in limited vendor support for its critical enterprise application. The reduction in support would prevent the delivery of legal and regulatory changes, support for integrations, and functional enhancements. In addition, there is no guarantee of technical updates including support of new operating systems and database versions, and if available, the updates may include additional fees for problem resolution.
Alternative 3		
Alternative 4		

**Add rows for any additional alternatives considered not viable*

SUPPLEMENTARY INFORMATION

As needed, you may include any useful information gathered during the assessment phase including analysis like cost benefit / risk analysis / sensitivity analysis, etc.

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INFORMATION TECHNOLOGY & SERVICES

Exh. BEF-20

August 29, 2025

CDM Optimization – Project Options

January 2024

Ron Wagner (PM) & Laura Mumford (CM)

NW Natural®

The Journey to Today

NW Natural®

CDM Assessment and Project Planning

- Completed assessing CDM process, technology, and people gaps and presented findings in December
- With approval from leadership, focus has shifted to planning remediation project options to put CDM on a stable, sustainable footing for future success
- With 36+ gaps identified, team has developed a project approach with 4 possible approaches:
  - Bare – address bare minimum mission critical gaps
  - Base - Base project plus remaining mission critical gaps
  - MVP – Bare plus Base projects plus high criticality gaps
  - Full Scope – Bare plus Base plus MVP projects plus medium and low criticality gaps

CDM Remediation Project Options

Recommended Option

	Bare	Base	MVP	Full	
Percent of CDM Gaps Remediated	**6%**	**27%**	**68%**	**100%**	
Approximate Cost	**$799k**	**$2.1M**	**2.5M**	**$2.7M**	**Comments**
Gap Remediation Scope	Minimum Mission Critical	Bare + Remaining Mission Critical	Bare + Base + High Severity	Bare + Base + MVI + Medium/ Low Severity	
Automation of Maintenance Plan Creation	●	●	●	●	
IQGeo Integration with CIS	●	●	●	●	
Revamping CDM Referral Process and Consolidate		●	●	●	
Linking Repair Orders for Full Traceability		●	●	●	
Management of Change Tracking for Compliance Parameters		●	●	●	
Automation of Functional Location and Equipment Data Creation			●	●	
Improved Data Collection and Processing in SAP and Clevest			●	●	
Object Types for Tagalongs, Master Sets, Landslides, Grace Period Mgt, Audit Reports, Historical Data			●	●	
Dedicated Supervisory Role for CDM			●	●	
Role-Based LMS Training Materials			●	●	
Automated Notification to Field Groups for New Assets/Compliance Obligations				●	
Permits for Key Operating Valves				●	
Streamline Heath Reported Leaks and Improve Clevest and IQGeo Data Capture				●	

CDM Remediation Project Options

Recommended Option

	Bare	Base	MVP	Full	
Percent of CDM Gaps Remediated	**6%**	**27%**	**68%**	**100%**	
Approximate Cost	**$799k**	**$2.1M**	**2.5M**	**$2.7M**	**Comments**
Gap Remediation Scope	Minimum Mission Critical	Bare + Remaining Mission Critical	Bare + Base + High Severity	Bare + Base + MVP + Medium/ Low Severity	
Benefits					
Elimination of error prone manual effort to setup recurring compliance plan data	●	●	●	●	Elimination of manual effort; avoid need for contractor support
Eliminate contractor support to enter field referrals from IQGeo into CIS	●	●	●	●	Up to $405k contractor costs in O&M saved per year
Ensuring integrity of referral process and avoiding lost or delayed reporting		●	●	●	
Integration of Follow-On Orders into CDM Lifecycle		●	●	●	Elimination of manual effort; up to 2 FTE refocus incl above
Elimination of effort to clean up data errors in missing or incorrect FLOCs and equipment			●	●	Up to $45k contractor costs in O&M saved per year
Improved Field Data Capture / Data Integrity / Real Time Feedback to Field			●	●	
Standardized Master Data and Parameters, Data Integrity, and Historical Data Access			●	●	
Improved Compliance Oversight and Management			●	●	Avoidance of regulatory fee assessment risks
Improved Ability to Forecast and Allocate Work		●	●	●	
Field Alignment and Awareness of CDM Obligations		●	●	●	Improved capability, employee experience, retention
Improved CDM User Experience, Turnover and Staff Retention		●	●	●	
Improved Contractor Data Capture to Support CDM Master Data Collection and Compliance				●	
Streamlined Ad Hoc Master Set Inspections Process				●	
Achieve CDM Steady State and Avoid Future Business Disruption				●	Full scope = highest chance of returning to steady state
Fully Documented End2End Process for Comprehensive Training and Compliance Support Program		●	●	●	Full scope = full LMS training program for sustainability
Systems Aligned for Future Growth			●	●	
Systems and Processes Aligned with Gas Industry Leading Practices		●	●	●	

Benefits Level ● Low ● Med ● High

CDM Staffing Model Changes by Project

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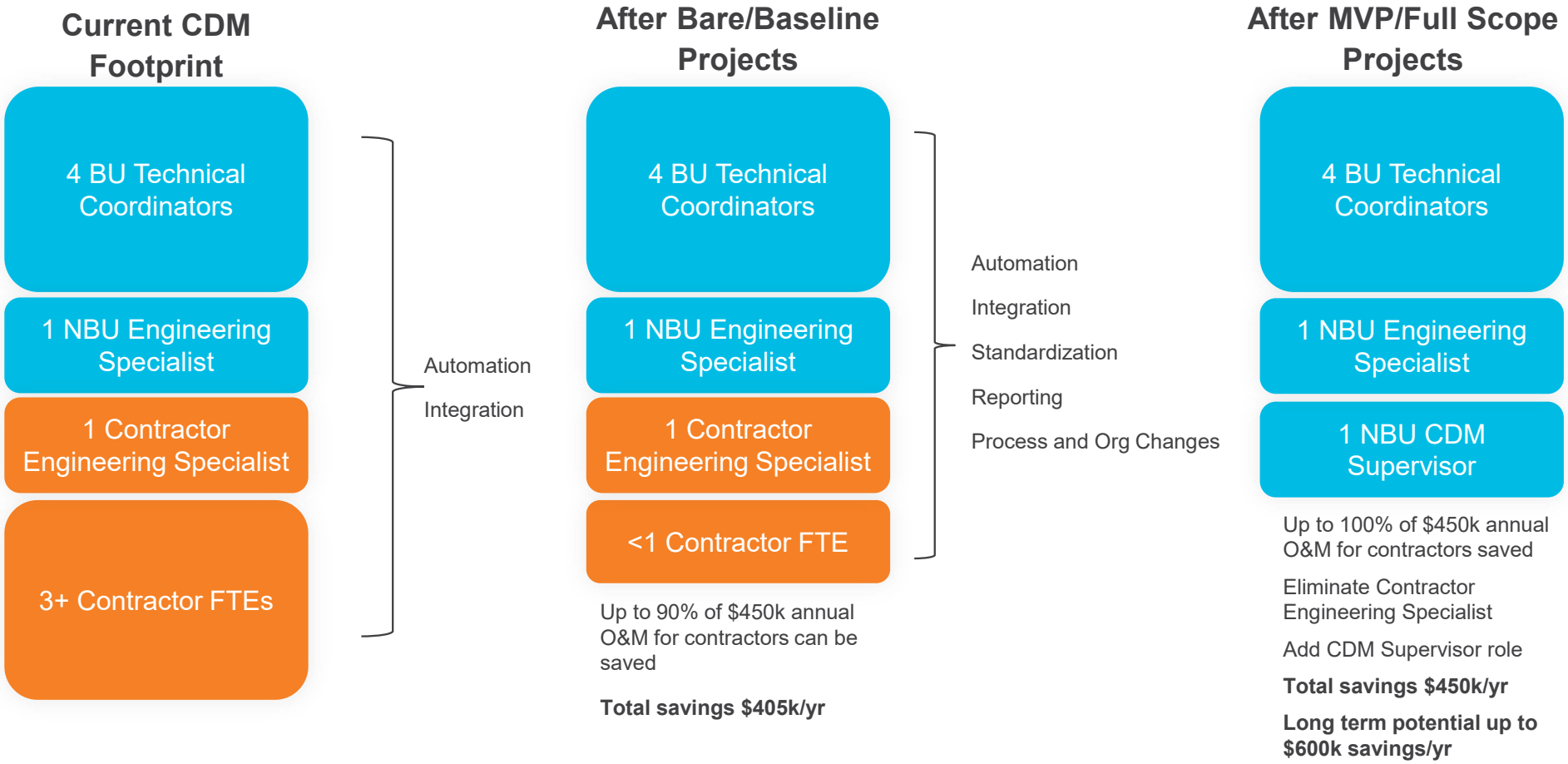

Project Option Timelines

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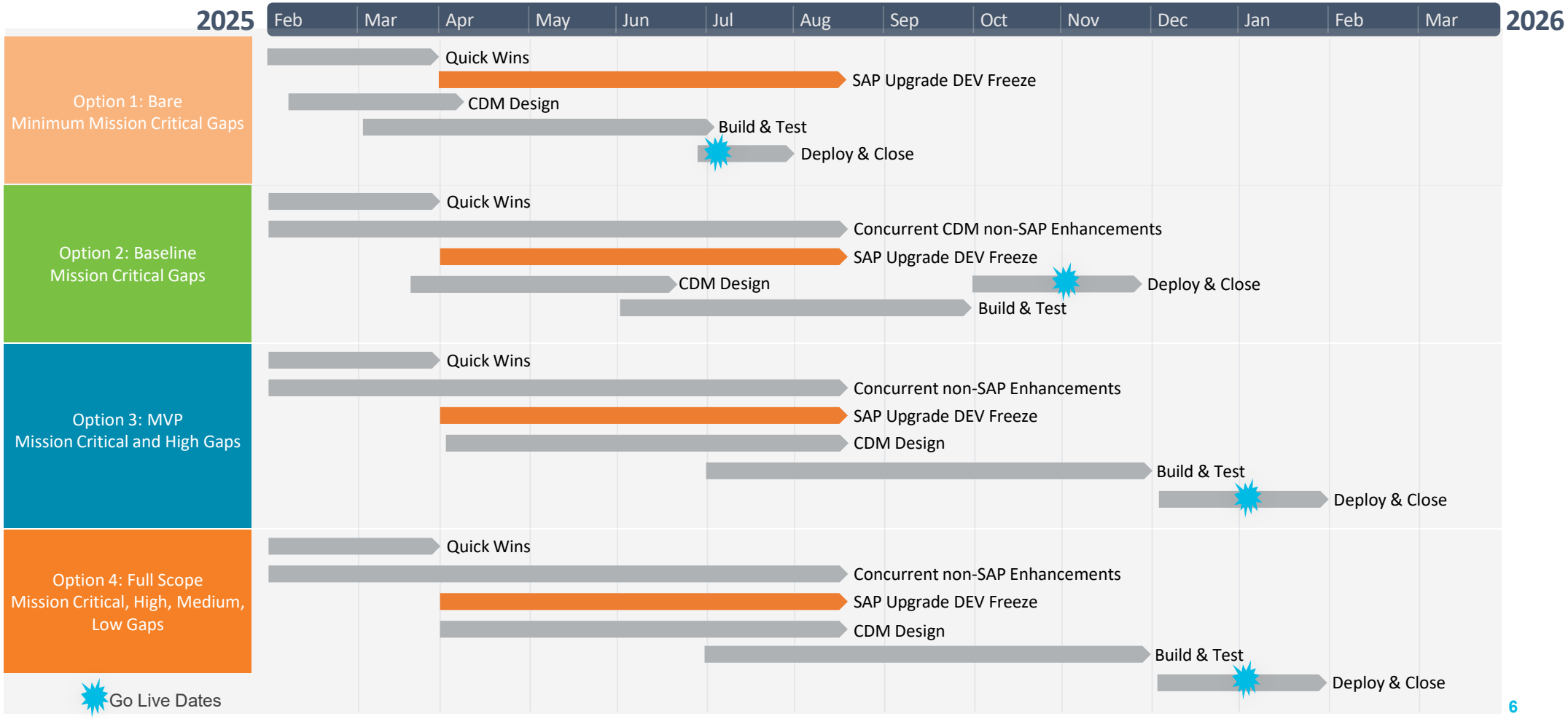

Target State Options Overview

	Bare	Baseline	Minimum Viable Product	Full Scope Project
Guiding Principles / Costs	Minimal cost option to eliminate most contractor support	Low-cost option to remediate only mission critical gaps	Medium cost option to remediate all mission critical, high, and medium priority gaps	Full cost full scope option to remediate all gaps
Eliminate Contractor Support	◑	◑	●	●
Focus CDM Staff on Management not Fixing/Data Processing	◑	◑	◕	●
Build Sustainable Org Model and Staff Retention	◔	◔	◑	●
Avoid Compliance Risks	◔	◔	◕	●
Total Costs incl. 10% contingency	**$799,266**	**$2,065,024**	$2,533,955	$2,747,130
Internal Costs	**$183,753**	**$416,675**	$498,343	$494,176
External Costs	**$543,761**	**$1,461,529**	$1,806,161	$2,004,123
Contingency	**$71,752**	**$186,820**	$229,451	$248,831
Contractor Costs Avoided	**Up to $405k/yr**	**Up to $405k/yr**	Up to $450k/yr	Up to $450k/yr
Internal Staff Savings	**$0**	**$0**	-1 BU FTE + 1Supervisor Net Zero	-1 BU FTE + 1Supervisor Net Zero*

Project partners included in estimate: IFS, Gartrell, Accenture (validation of assumptions pending)
Current forecasted budget: $250k
*Potential for long term savings of $600k/year due to reduction of BU headcount

Legend: ◔ Doesn't Align ◑ Partially Aligns ◕ Mostly Aligns ● Fully Aligns

CDM Remediation Project Options

Recommended Option

2025

	Bare	Base	MVP	Full	
Percent of CDM Gaps Remediated	**6%**	**27%**	**68%**	**100%**	
Approximate Cost	**$799k**	**$2.1M**	**2.5M**	**$2.7M**	**Comments**
Gap Remediation Scope	Minimum Mission Critical	Bare + Remaining Mission Critical	Bare + Base + High Severity	Bare + Base + MVP + Medium/ Low Severity	
Automation of Maintenance Plan Creation	●	●	●	●	
IQGeo Integration with CIS	●	●	●	●	
Revamping CDM Referral Process and Consolidate		●	●	●	
Linking Repair Orders for Full Traceability		●	●	●	
Management of Change Tracking for Compliance Parameters		●	●	●	
Automation of Functional Location and Equipment Data Creation			●	●	
Improved Data Collection and Processing in SAP and Clevest			●	●	
Object Types for Tagalongs, Master Sets, Landslides, Grace Period Mgt, Audit Reports, Historical Data			●	●	
Dedicated Supervisory Role for CDM			●	●	
Role-Based LMS Training Materials			●	●	
Automated Notification to Field Groups for New Assets/Compliance Obligations				●	
Permits for Key Operating Valves				●	
Streamline Heath Reported Leaks and Improve Clevest and IQGeo Data Capture				●	

2026

Budget Constrained Option: *Complete Bare Project in 2025 and remaining scope in Full Project in 2026. Assumed same total $2.7m cost but only $799k in 2025. All benefits realized but over a longer timeframe.*

Recommendation Summary

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- Option 1: Bare Project – proceed to PMC now, confirm resource requirements and commitments needed – may need to defer start depending on constraints. Need to cover funding for delta between $250k authorized and $800k budget estimate.
- Option 2: Baseline Project
- Option 3: MVP Project
- Option 4: Full Scope Project – work on alternative analysis, confirm justification of full spend amount, seek funding for Jan 2026 start as second leadership review and PMC submission

Approvers:
- ☑ Brian Fellon
- ☑ Joe Karney
- ☑ Dan Kizer
- ☑ Dina Thompson
- ☑ Joe Sciacca
- ☑ Jaime Ulestad

Appendix

CDM Scope and Challenges/Gaps

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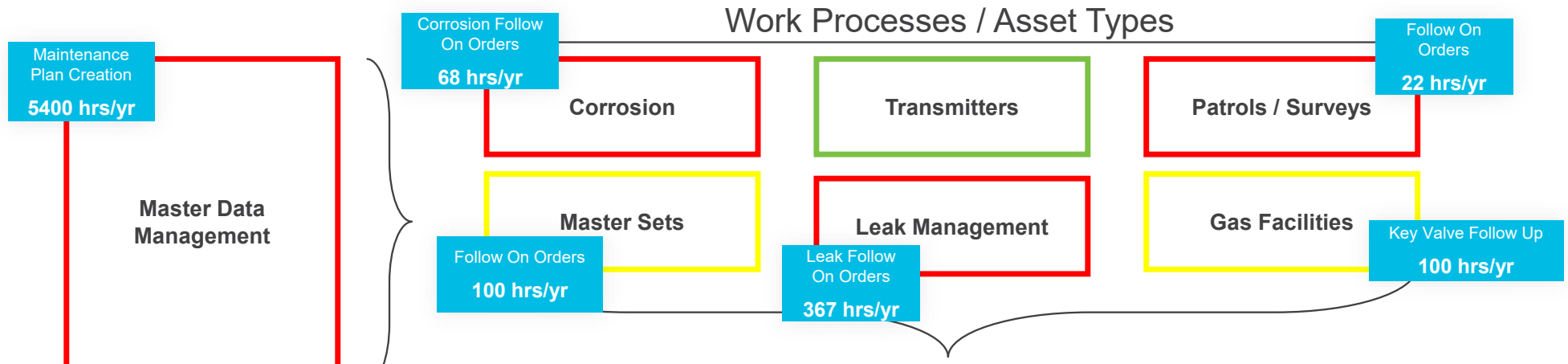

- Multiple disparate intake sources, methods, tools for master data creation
- High level of manual input leads to inconsistent plan setup

- Disparate processes and ownership for compliance plans and orders based on asset type
- Lack of common tools and processes to ensure coordination between CDM, RMC, Field
- Stranded alerts and referrals (e.g. IQGeo)

- Multiple intake sources and methods for follow-on work and lack of traceability for repairs

High Gaps/Pain Points
Medium Gaps/Pain Points
Minimal Gaps/Pain Points

Summary of Gaps by Bucket - Appendix

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CDM Discovery Log Gaps Categorized by Project Bucket

- **Mission Critical (11)**

Automation of maintenance plan creation

Linking repair work orders to inspection orders

Revamping of CDM referral process including automation of IQGeo alerts into CIS

IQGeo dashboard

MoC

- **High Priority (15)**

Automation of FLOC and EQP creation and full integration of GIS-SAP

Improve data collection and processing in Clevest and SAP

Object types for Tagalongs, Master Sets, Landslides (low effort, Clevest impacts)

Grace period management

Conversion of required history

Supervisory role for CDM

GIS/SAP audit report

Role based training program

- **Medium/Low Priority (10)**

Process documentation

Automated notifications to responsible field groups when plans are added

Fully document task list design

Permits for KOVs (Loy Clark contractors)

Adding characteristics (low effort)

Heath reported leaks – streamline

Asset data capture in IQGeo and Clevest

Creation of partial orders

CDM Scope and Challenges/Gaps

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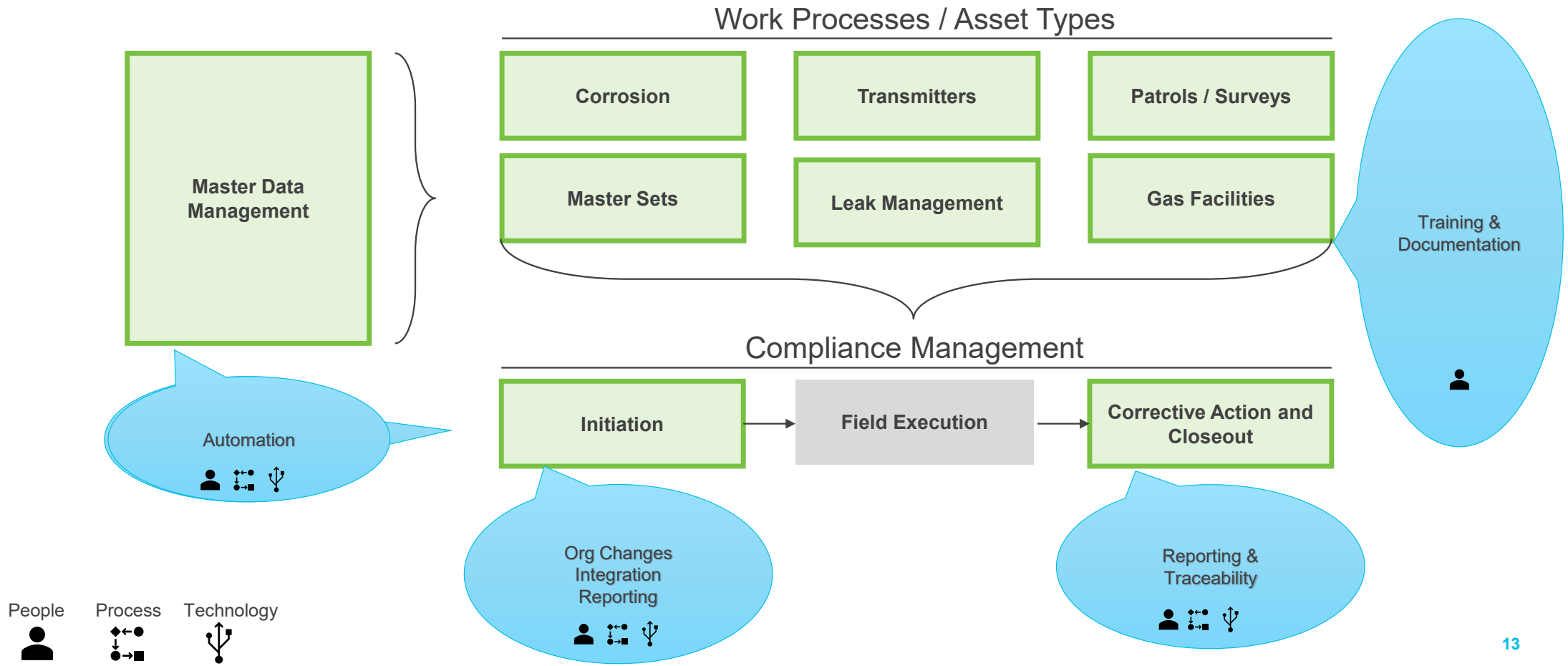
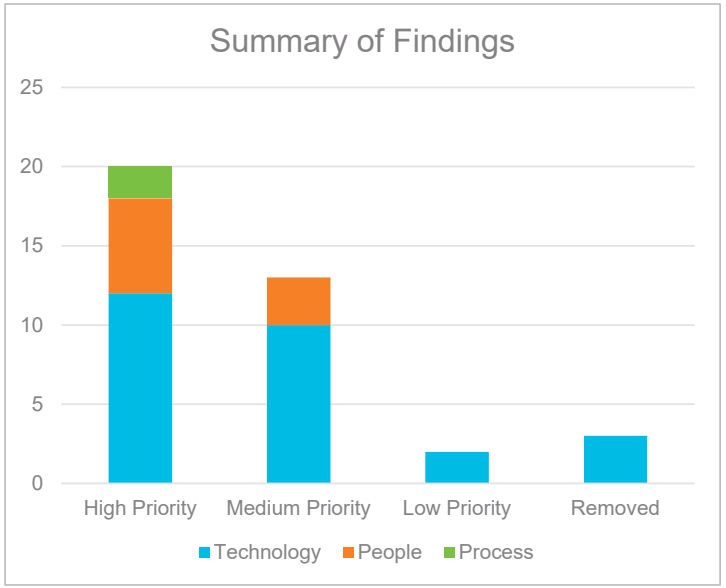


Summary of Findings

- The team identified **38 gaps** to improve operational efficiency that fall into the categories below. Many items are interconnected, and **project team recommends solutions for all areas are addressed in parallel**.
  - People: Org Design, Roles & Responsibilities, Training
  - Process: Business Process Gaps, Data Cleanup
  - Technology: Enhancements, Reports, Integrations

- Overall assessment is that core operating model is sound, but efficiency gains are required for current headcount to manage workload. Recommendation is to invest in technology solutions to create a scalable operating model aligned with industry best practices. This will create capacity for the CDM team to focus their time on the greatest value add tasks.

Technology investment paired with People & Process support measures Short term pain, long term gain	People & Process support measures alone would still demand significant headcount investment Long term O&M spend



People, Process, & Technology

NW Natural®

Once proposed efficiency gains are realized, CDM's responsibilities are appropriately aligned with business operations and NWN's tactical and strategic goals

Asset Creation	Master Data Management	Compliance Management			Asset Retirement
		Monitoring	Ad hoc support and follow up	Data Integrity Maintenance	
Wide ranging inputs	Highly manual processes	Lack of reporting *Recently rectified for CDM*	Wide ranging alerts and notifications	High volume of issues requiring research and mitigation	Manual tracking

In current state, significant human effort is required to manage the workload. O&M overhead is high.

Leadership team spread thin to provide oversight, strategic solutioning, and lead cross functional collaboration. Contractor support required. Lack of clarity on division of labor with RMC/Field Supervisors. Documentation Gaps: Role based training, cross functional business process maps, etc..

Enhanced GIS/SAP integration	Master Data, FLOC, & Maintenance Plan Automation	EDP reporting suite for compliance Field leadership	Z3 notifications enhancement Enhanced field referrals Required reason for accepted out of tolerance reading CIS order automation for IQGeo Exception alerts	GIS/SAP Audit report + automation at asset creation Change management tracking solution	Construction orders linked to originating compliance order

Investment into solutioning People & Process gaps is best made ***as efficiencies are gained*** through technology enhancements and steady state is achieved

CDM Staffing Model

NW Natural

Current CDM Footprint

- 4 BU Technical Coordinators
- 1 NBU Engineering Specialist
- 1 Contractor Engineering Specialist — *2025 O&M $156k*
- 3+ Contractor FTEs — *2025 O&M $450k*

90% of time spent on data creation and fixes, rest on IQGeo alert creation and field support

Firefighting, issue remediation, training and support for TCs

90% of time spent on IQGeo alert processing, rest of time on data fixes

Automation

Automation, Reporting, & Training

Automation Integration

80% of data creation and fixing time is eliminated Focus on field support, and compliance management

Value added support, less data firefighting, more compliance management based on robust dashboards

Up to 2/3 of IQGeo alerts can be automated, and longer term possibly all. Over time reduce contractor support to zero

CDM Footprint After Enhancements Delivered

- 4 BU Technical Coordinators
- 1 NBU Engineering Specialist
- 1 NBU CDM Supervisor — *Est $170k*

Up to $450k O&M saved per year

Prioritize automation of CIS orders from IQGeo Exception alerts – would enable earlier realization of O&M savings

**Savings would help offset cost of proposed new supervisor and newly approved addition to TC headcount*

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INFORMATION TECHNOLOGY & SERVICES

Exh. BEF-21

August 29, 2025

Full Project Charter

Final Objectives and Outcomes

The planning and discovery scope of work aims to ensure a comprehensive approach to the Website upgrade project, extending beyond supporting system version upgrades. This requires effort to address the current state, functionalities, support, and security gaps, helping identify a path forward that meets technical and functional challenges, including but not limited to the platform's effectiveness, user experience, and support will identify key areas for improvement. Potential solutions, including replacing outdated components and integrating new technologies if required, will be evaluated for feasibility and cost-effectiveness. The intent is to reduce complexity, address gaps and implement improvements that will enable NWN to enhance support and enabling a better support and administrative experience.

Final Cost / Benefit Analysis

This Discovery and Planning project will cost $1.3M, inclusive of Accenture fee of $565K, and team cost of $651K

Benefits of program are to reduce complexity, address gaps and implement improvements that will enable NWN to enhance support and enabling a better support and administrative experience.

Final Scope

Document current state and future state requirements:
a. Work with NW Natural stakeholders to gather and organize existing website business and technical requirements and document gaps in requirements where further investigation and requirement definition will be necessary.
b. Conduct workshops and meetings with NW Natural stakeholders, to deep dive into the following areas and document findings to support Deliverables outlined in Section 6 (additional areas maybe identified during project planning):
• High Level business objectives and capabilities
• Self-service objectives and capabilities
• Authoring & Workflows
• Search
• Future capabilities (CDP/Personalize/Portals)
• Detailed Component Discovery
• Images and Video
• Detailed Template Discovery
• Content Serialization
• User Management, Authentication
• Forms, Form APIs, Tools, and Calculators
• Current UX walkthrough / Functionalities
• DevOps pipelines
• Marketing Automation use cases
• Personalization using use cases.
• CLM and CIS Roadmaps Reviews
c. Document business and technology requirements captured during the stakeholder workshops and meetings and documentation provided by NWNNW Natural or gathered by Accenture through review of the site.
d. Review all legacy documentation, identify and document gaps (including all aspects detailed within RFP such as functional, technical, and logic details), update reviewed documentation to accuracy, create user story and business logic documentation to fill identified gaps, provide a summary/overview of findings to be leveraged.
e. Create a gap analysis indicating for which features requirements currently exist which features are undocumented; will include an

Known Assumptions at Assess Phase

NW Natural team has identified approximately 450 features for as-is functionality. This does not include future state considerations (self service + CLM technical roadmap) and findings.

Key architectural, solution and technical decisions need to document as ADRs and approved by NW Natural as part architecture prior to any new implementation.

Per discussion, NW Natural estimates 2500 test cases.

We Accenture estimates that a core base of 22 epics covers majority new and existing functionality; and test cases

Known Constraints at Assess Phase

TIming of project is constrained by key NWN resource availability and conflicts with other ongoing projects.

Project must be complete by August, 2025

Final Change Control Plan

Change identified in the project will be discussed within the project team and assessed for impacts. Change propos discussed with Stakeholders and Executive Sponsors with project team recommendation. With alignment on chang change request creation and approval will be done in Planview following our project governance structure.

Final Project Governance Structure

Project Governance Structure
This Project is part of the CLM project portfolio 'pod' following this below governance structure:

IT&S Alignment Team:
• Communicates with CEO, stakeholders, and leadership as appropriate

Exec steering committee
• Provide vision, goal strategy, priority, budget, and direction for program.
• Significant changes to scope, timeline, and budget.
• Provide oversight and guidance to all team members.
• Resolve non-projects relegated roadblocks.
• Resolve enterprise level strategic issues as they arise

Program Stakeholders
• Responsible for overall business priorities for the workstream
• Approve deliverables and project completions
• Advocate for required process changes within their business areas
• Resolve across functional issues as they arise
• Reallocate team members responsibilities as needed to meet project requirements
• Communicate with exec steering committee

Skip over navigation

Work Detail	2 Active Lifecycle Steps	WRK14 NWN Status Report	WRK15 - Milestone Status	1 Milestones Due this Period	WRK09 - Risk Matrix	WRK11 - Issue Matrix	WRK08 - Change Request Matrix	WRK14LL - Project Lessons Learned	RPT01_DR_Regulato	more ...

Related Information: Lifecycle

Work Breakdown Structure

Description	Work-ID	Actual Start	Scheduled Finish	SMI	Seq-ID
Project Web Technology	1002377	3/24/2025	6/30/2026	7	72970

Basic

Work Status:	Open/Active	Requested Start:	10/1/2024	Lifecycle Administrator:	Chiar
Investment Approval:	Accept	Requested Finish:	12/31/2025	Allow Support Tickets:	No
Internal Priority:	Low	Requester Priority:	3 - Low	Status Work with Percent Complete:	No
Work Type	Project	Calendar:	Standard	Do Not Progress	No
				Progress As Planned	No

Project Categorization Information

Title	Web Technology

Project Description Information

Work Description	Current phase of work is the Planning and Discovery scope of work. Implementation phase is targeted to begin later in 2025 The project will address the current state, functionalities, support, and security gaps, helping identify a path forward that meets technical and functional challenges, including but not limited to the platform's eff experience, and support. Potential solutions, including replacing outdated components and integrating new technologies if required, will be evaluated for feasibility and cost-effectiveness. The intent is to redu gaps and implement improvements that will enable NWN to enhance overall functionality, especially customer self-service enablement as well as improving internal technical support capabilities.
Published Rank	54
Requested Start Date	10/1/2024
Requested Finish Date	12/31/2025
Lifecycle Stage	8-Plan
Current Gate	Move to Plan
Next Gate	Move to Execute
Tier	Tier 4 - $1MM+
Executive Sponsor	✓
	✓ 1. Fellon, Brian
Project Sponsor	✓

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Exh. BEF-22C

REDACTED VERSION

August 29, 2025

NW Natural
PROJECT ALTERNATIVES NARRATIVE

Program/Project Name: Gas Control Daily Operations Platform Implementation project
Date: August 15, 2025
Project Sponsors: Jeremy Coleman, Steven Foster
Executive Sponsors: Dave Weber, Brian Fellon
Project Manager: Josh Mathis
Was this project part of IRP: Yes

SECTION 1: BUSINESS CASE

This section should be solution-agnostic, and about the overarching problem we're trying to solve no matter which route we end up taking

OBJECTIVES *Why are we tackling this project?*	
Current State What is happening now? Where are we starting?	NW Natural's Gas Control Daily Operations Platform Implementation project is a strategic initiative to ensure the Gas Control team is able to operate the NW Natural distribution and transmission gas system during all operating conditions, develop accurate forecasts of system demand for daily system operating plans, and produce all required reports and compliance documentation. The current 20-year-old custom-built Supervisory Control and Data Acquisition (SCADA) system utilizes a set of software designed for controlling industrial plants in the pharmaceutical and manufacturing environments developed by GE called iFIX. iFIX provides the capability to manage repetitive standard control processes to ensure consistent manufacturing results e.g. are fixed in structure and only change when major product changes are required. Local Gas Distribution Company (LDC) gas control systems continually evolve as system distribution and transmission resources are added and sensors are upgraded or replaced. Since the development of the current system, software vendors have developed LDC and electric specific SCADA frameworks and software designed to evolve with the distribution/transmission system and operating needs of LDCs. These systems are modular and provide a more cyber secure SCADA platform. The current system has reached the end of its planned 15-year lifespan and has experienced numerous outages caused by several factors including a defect in the underlying iFIX software, which was only recently fixed by GE. GE doesn't support NWN architecture and implementations of our custom software that sits on top of iFIX. It is unlikely we will receive additional support for any defect that is discovered in the future. This is partly due to the customized software NW Natural has developed, which uses iFIX to execute system controls and telemetry functions and calculations. This project will evaluate the alternatives to the current system and select an implementation partner to enhance operational performance and reliability, improve maintenance and distribution capabilities, and position NW Natural to meet future demands in gas control operations. In 2023, NW Natural engaged Accenture to conduct an initial system assessment and explore options that would provide another 15-year lifespan solution. Accenture recommended [redacted] In 2024, IBM was engaged for requirements gathering, gap analysis, and to lead a comprehensive RFP process targeting full replacement of foundational SCADA components. NW Natural received responses from a number of vendors, selected Aspen Technologies OSI ("Aspen Tech") and [redacted] as finalists

	and conducted substantial due diligence into both options. [redacted] Based on this assessment, NW Natural selected Aspen Tech as the lower-cost and better service option to provide a new SCADA software platform. This project will implement the Aspen Tech platform, interfaces and baseline reports.
Problem Statement In simple terms, what are we trying to solve? What is the business need this is tackling? Why is this a problem worth solving (e.g. why is the current state not working)?	The Company's current SCADA platform is currently stable after a long timeframe of increasingly unstable and unreliable operation caused by a defect in iFIX, interfaces with unsupported software components, and issues with reporting failures caused by the growth of the historical database. As the existing software was modified over time to accommodate changes in NW Natural's gas distribution pipeline system, the system software developed defects, and the underlying architecture reached storage boundary limits and is unreliable at times resulting in system disconnects and manual restarts. While NW Natural has a back-up server to respond to such outages, transitioning to this back-up is a manual process, which can take between 30 minutes and 2 hours. During this manual transition, the SCADA system, including Gas Control's real-time situational awareness, is offline. NW Natural is the developer of the NW Natural SCADA system and the only company using this solution, so NW Natural must maintain the system and respond to any changes GE may put into the iFIX without support from any other LDC or software vendor. This represents a significant risk in the future if GE decides to significantly change the interfaces to the product, end support for the iFIX product, or replace it with another product. Any of these changes could require the complete replacement of the system with another system prior to the end of the desired 15-year lifespan. Forecasting and reporting are essential tools for the gas control and gas supply team. The current system reporting is based on SQL Server Database tools. These tools are extremely effective for a number of implementations and provided an effective tool for data capture and reporting when the current system was developed over 15 years ago. Unfortunately, after 15 years of data capture, the underlying data storage has reached the limits of the tool's storage addressing and indexing capability and must be modified continually for the forecasting and reporting functions to be performed. This requires external contract experts to support, and this component of the existing system must be reimplemented or replaced to stabilize this essential function.
Desired Deliverables What high level output / scope / deliverables are core to this project?	This project will provide a long-term stable platform for NW Natural's central gas system operations and management system, while improving reliability and ensuring accurate, consistent reporting. In addition, the new system will feature: • A secure architecture. • Centralized management of display maintenance and distribution. • Streamlined product and patch releases through vendor-managed source code. • Cybersecurity compliant with ISO-27001 standards. • Simplified database administration and improved system release efficiency. • Enhanced system administration and operational resiliency. • Enhanced user experience

SECTION 2: ALTERNATIVES SUMMARY

OVERVIEW *How did we review these options?*	
Review Process	Accenture conducted an initial system assessment and explored options that would provide another 15-year lifespan solution including redeveloping the current iFIX-based solution. IBM facilitated an RFP process which identified twelve potential vendors; eight vendors were asked to submit proposals in the process. [redacted] The NW Natural Controller team, the SCADA Engineering team and the IT Enterprise Architecture teams completed detailed review and scoring of each vendors technical capabilities, pricing and overall ability to meet NW Natural Gas Control Platform and SCADA requirements. Two vendors were considered finalists, Aspen Tech and [redacted]
DECISION CRITERIA *Describe the criteria used to determine the selection from the various alternatives considered. For example, is this a program/project where the least cost option should be selected? Are there other factors, such as safety or quality that come into play? Include both quantitative and qualitative factors as appropriate.*	
Criteria: Meeting NW Natural Objectives	Industry standard • Is the solution based upon shared industry standards that are implementable with no or minimal modifications? Meets foundational needs • Does the solution meet foundational needs but has extensible functionality for future improvements through configuration, utilizing primarily commercial-off-the-shelf solutions? • Does the solution offer a single solution for Alarm and Event management that is integrated and extensible? • Is it a solution that can combine duplicated components of the current infrastructure, e.g., Historians? • Does the solution meet all requirements for a Critical Cyber System (CCS) as defined by SD2E? Meets the functional and non-functional requirements - examples • Functional: Simplified SCADA system architecture and simplified Network systems integration. • Functional: Real time monitoring and Record keeping. • Non-functional: Usability: quick access to critical measurements and high level of controller usability • Non-functional: Data management- automated data processing ability
Criteria: RFP Written Responses	Vendors submitted detailed written responses to questions on their ability to meet the functional business, functional technical and non-functional technical requirements across the following areas: • UX/HMI • SCADA • Integration • Architecture • Alarms and Incident Management • System resilience/continuity • Gas management applications • Historian • Asset Management • Compliance

	• Data management • Training/learning management
Criteria: Oral Presentations/Demonstrations	Each vendor completed on-site demonstrations of solutions to representations of Gas Control, SCADA Engineering, Enterprise Architecture, Cybersecurity, and other IT&S functions. **Demonstrations included:** Controller User experience: • Customization of user interfaces and system dashboards. • Advanced forecasting, trend analysis, and data overlay capabilities. • Training enhancements using SCADA simulators and digital learning platforms. • Solution alarms that enhance Controller awareness. • Navigation techniques and features to improve user experience. SCADA Engineer experience: • RTU Site Setup and Configuration • Develop a Custom Operational Screen • Ad-hoc Trend Analysis and Reporting • Maintenance and Updates Integrations: • Integrations with current Core NWN systems. • Integration with existing network management tools and platforms. • Simplification of system configurations for new SCADA applications. • Unified system log integration across platforms. System Performance: • Live failover tests to show minimal downtime and quick recovery. • Redundancy demonstrations to highlight the system's stability during updates. • Telemetry system's feedback rate improvements showcasing real-time operational capabilities.
Criteria: Overall Cost Implications	Initial Expenditure: • What are the upfront costs associated with each option, including licensing, hardware, and setup? Ongoing Costs: • Are there recurrent expenses, such as maintenance fees, subscription costs, or additional licenses?

SECTION 3: ALTERNATIVES DETAIL

<table>
<tr><th colspan="4">RECOMMENDED OPTION
Describe the option selected/recommended for approval. Explain in detail how the option measured against the decision criteria, whether it was the lowest cost option, and if there were qualitative factors considered in selecting the option. Provide all information necessary to understand the decision process that was undertaken with respect to the recommended option. If positive /neutral/negative observations do not exist, enter N/A</th></tr>
<tr><td>Description</td><td colspan="3">Implement a vendor supplied LDC SCADA platform and configure it to meet the requirements of NW Natural.

In 2024, IBM was engaged for requirements gathering, gap analysis, and to lead a comprehensive RFP process targeting full replacement of foundational SCADA components. Based on the review of the RFP responses, NW Natural selected two vendors as finalists for substantial due diligence, Aspen Tech and [redacted]. Based on this evaluation, NW Natural selected Aspen Technologies OSI (“Aspen Tech”) as the lower-cost and better service option to provide a new SCADA software platform.</td></tr>
<tr><td>In brief, why is this the recommended option?</td><td colspan="3">This option is recommended to ensure:

• Integrated Gas LDC SCADA platform with integrated data capture and reporting capabilities.
• Safe, reliable and efficient management of the distribution/transmission pipeline system.
• Able to maintain and update system configuration and software using vendor provided system tools to centrally manage display maintenance and distribution while leveraging a modularized approach to add increased capabilities in the future.
• Built in connectivity of pipeline asset-enabling.
• Improved Controller information and web user interfaces with Geographic Information System (GIS) capabilities, facilitating display creation and addressing situational awareness challenges.
• Enhanced cybersecurity measures with ISO-27001 certification.

As explained in the Alternative 1 analysis, after NW Natural had moved forward with an RFP, GE issued a patch for iFix after five years of NW Natural requesting fixes to the software. This patch resolved a critical functionality issue with iFix. At this point, NW Natural evaluated whether remaining on the iFix system was a viable alternative to Aspen Tech.</td></tr>
<tr><td rowspan="4">Assessment</td><td>Criteria</td><td colspan="2">Aspen Tech achieved the highest scoring in our initial RFP response and finalist evaluation.
• Functional and technical evaluations
  ○ Ability to meet NW Natural objectives/requirements
  ○ Scoring vendor RFP written responses
  ○ Scoring of oral presentations/demonstrations
  ○ Scoring of sandbox demo/simulations
• Commercial Pricing Evaluation</td></tr>
<tr><td>Cost to implement</td><td colspan="2">The cost of this option has been evaluated to be the most flexible and leverages opportunities for lowering costs as this solution is targeted to the foundational layer with options to expand the functionality as costs can be supported. This option still requires NW Natural to keep existing integration licenses as well to include TiPs/Logmate, Kepware, and J5/Hexagon.</td></tr>
<tr><td>Additional Risks</td><td colspan="2">Requires significant investment over a three-year period</td></tr>
<tr><td>Additional Benefits</td><td colspan="2">Delivery of the foundational project allows us to improve and increase future capabilities to include reporting, communications, and integrations.</td></tr>
<tr><td colspan="4">POTENTIAL COST (EXCLUDING CONTINGENCY)</td></tr>
<tr><td rowspan="2">Capital Range</td><td>Direct</td><td>CURRENT COH</td><td>Total</td></tr>
<tr><td>$17M
• Study & Foundational RFP $2.4M</td><td>12%</td><td>$19M</td></tr>
</table>

	• Implementation Costs $14.7M		
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$250,000	2028-2035 = $3M	
Source/ Method of Cost Data	Aspen Tech team/study provided solution costs. COH was calculated based on duration of project. O&M was estimated based upon the license agreement and the shelf life of the solution.		

<table>
<tr><th colspan="3">ALTERNATIVE 1
Provide details of any viable alternatives for meeting the objective, other than the option above. Please provide enough detail so that the reader can understand how the alternative compares to the recommended option.</th></tr>
<tr><td>Description</td><td colspan="2">Rebuild and re-architect the existing GE iFIX solution, removing customizations to enable an upgrade and address SCADA system resilience and known support concerns.</td></tr>
<tr><td>In brief, why is this option not recommended?</td><td colspan="2">NW Natural is the developer of the NW Natural SCADA system and the only known LDC using the iFIX software solution for an LDC SCADA. NW Natural must maintain the system and respond to any changes GE may introduce into the iFIX product. As the only known LDC customer using iFIX for an LDC SCADA solution, NW Natural does not have any other LDC peers to encourage GE to support iFIX as a Gas Control SCADA solution. This represents a significant risk in the future if GE decides to end support for the iFIX product, make significant changes to the operating interfaces of iFIX, or decide to replace it with another product. Any investment made in the iFIX platform is at risk for replacement before the desired 15-year lifespan of the investment.

Additionally, reliability issues have remained consistent since the last upgrade (2017), with alarm mismatch (4 years) and workspace crashing (5 years) plaguing the environment. GE issued a patch that addressed the cause of the SCADA system's crashes over the past five years. This patch has substantially reduced the need for manual restarts. As a result, the Company reevaluated whether to update and maintain the existing hybrid iFIX SCADA platform solution as an alternative to replacement but determined the history of reliability and instability issues to be an unacceptable risk.

NW Natural's existing SCADA platform was customized to enhance the iFIX software to meet the operational requirements for a gas distribution pipeline control room. The iFIX system is based on a human-machine interface (HMI) server that is designed to manage plant operations, rather than a gas distribution pipeline system for an enterprise control room. When the platform was installed in 2005, this type of HMI-server based software was commonly used because it was (a) cost-effective; (b) readily transitioned between the preexisting hardware systems to networking with field telemetry devices; and (c) allowed development of custom applications to fill gaps in functionality required for enterprise control room. The iFIX system platform did not provide enterprise solutions and integrations required for gas distribution system operations. NW Natural substantially modified the iFIX platform over time with custom gas management services that are now offered by SCADA vendors. The system has also been customized to meet compliance requirements.

Forecasting and reporting tools are essential components of the Gas Controller and Gas Supply team's daily, monthly, and yearly planning. These reports are based on collecting telemetry data over time and matching it with weather and other demand dynamics. The existing system relies on SQL Server databases to collect the data and provide the reporting needed. The underlying database has grown beyond its design limitations which has caused numerous reporting failures and will continue to do so until the data capturing and reporting system is rebuilt under a new framework. The reporting mitigations have been provided by highly paid external contract resources. Going forward with the SQL Server architecture may result in loss of valuable reporting information.

As the only known LDC with this SCADA solution, NW Natural is also the only LDC investing in enhancements for future needs and optimization of operations. There are a number of operational enhancements NW Natural would benefit from that are available within vendor-provided SCADA systems. If NW Natural identifies an urgent need for one of these enhancements, NW Natural must develop the solution without any support from the vendor or cost sharing with other LDCs. The development and lifecycle risk for the iFIX based SCADA is entirely NW Natural's.</td></tr>
<tr><td rowspan="2">Assessment</td><td>Planning and Deliverables</td><td>While this option utilizes the existing architectural approach and software platform instead of upgrading to a new platform, it will still involve substantial modifications to existing software systems, infrastructure, and network, as well as comprehensive testing and validation.</td></tr>
<tr><td>Solution complexity</td><td>This option maintains the high level of complexity in the existing system and the high level of software development effort which would be carried out by NW Natural SCADA Engineering, Enterprise Architecture and the Controller teams, which has been noted as problematic within the existing infrastructure.</td></tr>
</table>

		Hiring people and maintaining the skills needed to maintain and support software updates for the existing system is a major risk factor over time. Currently the needed resources and skills are on the SCADA team but there is uncertainty about hiring and replacing them over time to address attrition
	Cost to implement	This is a lower cost option in the short term than implementing a new SCADA system, but the ongoing support costs for the existing solution coupled with the high risk of the operational instability of the system make the cost of ownership of this option difficult to budget for. Additionally, the iFIX-based solution would eventually have to be replaced with an LDC industry specific solution. The useful life of this option is unknown and timing of replacement unpredictable.
	Additional Risks	Complexity and time to address foundational issues may be beyond the organizational capacity and expertise of the NW Natural Gas Control, SCADA Engineering, IT Enterprise Architecture & Infrastructure organizations, requiring either expensive external support or eventual replacement (Recommended Option)
	Additional Benefits	

POTENTIAL COST (EXCLUDING CONTINGENCY)			
Capital Range	**Direct**	**CURRENT COH**	**Total**
	$9.4 million	12%	$10.1M
O&M Range	**Program/Project**	**Ongoing Maintenance & Support**	
	$237K	2028-2035 = $1.1M	
Source/ Method of Cost Data	For O&M: Current software costs are **$134K** per year: (GE/iFIX SW $76K; Logmate $30K; J5 licenses $21K; KEPServer = $5K)		

ALTERNATIVES CONSIDERED NOT VIABLE *Provide a description of any additional alternatives that were considered but rejected up front as not viable, and explain why*		
	Description Remain on the existing iFIX solution without upgrading and rebuilding.	No vendor support; application will be insecure and will continue to have reliability and instability issues. Infrastructure is nearing end of life and will need to be replaced.

SUPPLEMENTARY INFORMATION

As needed, you may include any useful information gathered during the assessment phase including analysis like cost benefit / risk analysis / sensitivity analysis, etc.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Direct Testimony of Brian E. Fellon

TRANSPORTATION SECURITY ADMINISTRATION PROJECTS

Exh. BEF-23HCT

August 29, 2025

Exh. BEF-23HCT contains information designated as Sensitive Security Information by the U.S. Department of Homeland Security and is withheld pursuant to WAC 480-07-160 (6)(f). A complete unredacted and redacted version of the document will be submitted as soon as practicable after the Commission enters a Protective Order in this proceeding.

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NORTHWEST NATURAL GAS COMPANY

Exhibit of Brian E. Fellon

TRANSPORTATION SECURITY ADMINISTRATION PROJECTS

Exh. BEF-24HC

August 29, 2025

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Exh. BEF-25HC

August 29, 2025

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TRANSPORTATION SECURITY ADMINISTRATION PROJECTS

Exh. BEF-26HC

August 29, 2025

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TRANSPORTATION SECURITY ADMINISTRATION PROJECTS

Exh. BEF-27HC

August 29, 2025

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TRANSPORTATION SECURITY ADMINISTRATION PROJECTS

Exh. BEF-28HC

August 29, 2025

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NORTHWEST NATURAL GAS COMPANY

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TRANSPORTATION SECURITY ADMINISTRATION PROJECTS

Exh. BEF-29HC

August 29, 2025

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TRANSPORTATION SECURITY ADMINISTRATION PROJECTS

Exh. BEF-30HC

August 29, 2025

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NORTHWEST NATURAL GAS COMPANY

Exhibit of Brian E. Fellon

TRANSPORTATION SECURITY ADMINISTRATION PROJECTS

Exh. BEF-31HC

August 29, 2025

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NORTHWEST NATURAL GAS COMPANY

Direct Testimony of Joe S. Karney

METER MODERNIZATION

Exh. JSK -1T

August 29, 2025

DIRECT TESTIMONY OF JOE S. KARNEY

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position at Northwest Natural Gas Company ("NW Natural" or "the Company").

A. My name is Joe S. Karney. I am the Vice President of Engineering and Utility Operations and Chief Engineer for NW Natural. I am responsible for the design, construction, emergency response, operations, maintenance, and operational regulatory compliance of the Company's distribution system.

Q. Please describe your education and employment background.

A. I graduated from the University of Illinois at Urbana-Champaign with a Bachelor of Science in Mechanical Engineering, and I am a registered Professional Engineer. Before being promoted to my current position at NW Natural in April 2023, I was the Senior Director of Operations and Field Services. In that role I was responsible for internal construction, external contractor construction, customer field services, emergency response, pressure regulation, operation, and maintenance of the Company's distribution system. Prior to holding that role, I served as the Engineering Senior Director and Chief Engineer for NW Natural. In that role, I was responsible for design, construction, operation, and maintenance of the gas distribution system and utility storage plants, as well as operations support services, including work management functions, mapping and compliance. Prior to holding that role, I served as the Engineering Director. I have also previously served as the Senior Manager of Code Compliance for the Company, managed the regulatory compliance department, and represented the Company during safety audits performed by the Washington Utilities and Transportation Commission. I also reviewed and ensured Company

compliance with pending regulatory changes from the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA"). Previously, I managed the Company's Construction and System Operations groups. I started my career at the Company with the Integrity Management group and worked on the development and implementation of the Transmission Integrity Management Program ("TIMP") and the Distribution Integrity Management Program ("DIMP"). Before joining NW Natural, I worked as an Integrity Management Engineer for Colonial Pipeline Company for four years.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the Company's Meter Modernization Program ("MMP"), including the background and drivers for the MMP, NW Natural's evaluation of technology options, MMP deployment plans, and new employees associated with the MMP. I also describe the Company's cost recovery proposal for the MMP.

Q. Please provide a summary of your testimony.

A. NW Natural has an immediate need to replace portions of its aging metering system, and has embarked on a four-year process from 2024 to 2027 to replace metering infrastructure nearing end-of-life, including both Periodic Cause for Change ("PCC") meters, which are meter families that have been tested and are determined to run fast, and failing Encoder Receiver Transmitter ("ERT") devices. The MMP is also designed to ensure meter modernization and diversity and to meet the challenges of mechanical meter procurement by implementing new meters with new capabilities like ultrasonic meters. New ultrasonic meters are now part of the Company's purchasing strategy and

are being used for meter exchanges within the MMP as well as for the normal daily exchanges that occur outside of this program. Additionally, the MMP addresses a need to update current meter reading software. The four primary components of the MMP are as follows:

1. ERT Replacement: Due to ERTs in the Company's service territory reaching the end of their approximately 20-year battery life, a replacement program was needed for approximately 500,000 ERTs on a system basis over the duration of the program (2024 through 2027). NW Natural will continue utilizing current technology (500G ERTs).
2. PCC Meter Replacement: Within the population of the 500,000 ERTs, on a system basis, there is a subset of meters (90,000) that are also eligible for meter replacement as PCCs. These meters, along with the aging ERTs attached to them, will be replaced throughout the duration of the program (2024 through 2027).
3. Field Collection System ("FCS") replacement with Temetra: The current meter reading software in use, FCS, is being retired by the vendor, Itron Inc., meaning that it will not be supported in late 2028. As part of the MMP, the Company will migrate from its existing metering software to its replacement Temetra. The use of Temetra will ensure meter reading functionality in 2028 and beyond and allow cellular backhaul as a communication method for collecting meter reads.

4. Introducing new metering technologies: NW Natural has purchased and installed various different meters throughout its history, and in 2024, the Company added ultrasonic residential meters to its meter complement. The key reasons for adding ultrasonic meters include: meter diversification and preparing for an eventual transition away from mechanical meters; supply chain issues creating long lead times for mechanical meters (52 weeks) in comparison with ultrasonic meters (28 weeks); safety related benefits such as remote shutoff capability; alerts/alarms related to high flow and high temperature; and reduction of ERT purchasing needs due to ultrasonic meters not requiring separate ERTs.

The MMP is a four-year program that began in 2024 and will continue through 2027.

II. BACKGROUND REGARDING NW NATURAL'S METERING SYSTEM

Q. Please describe NW Natural's existing Washington metering system prior to the MMP.

A. NW Natural operates a metering system containing a mix of residential, commercial, and industrial meters. The meters are located on the premises of the customer, and system-wide were a mix of diaphragm, rotary, and turbine meters, which are all mechanical meters.

Q. What types of meters are the focus of the MMP?

A. The MMP focuses on residential meters. Prior to 2024, NW Natural used primarily mechanical diaphragm meters for most residential customers. These meters use a flexible membrane, or diaphragm, to measure the volume of gas passing through the

meter. As gas flows through the meter, it causes the diaphragm to flex, which moves a set of gears that drive the mechanical counter. The index displays the amount of gas that has passed through the meter in cubic meters or cubic feet.

Q. How does NW Natural collect usage data from its mechanical meters?

A. For mechanical meters, the meter data is collected and transmitted through the use of an Encoder Receiver Transmitter device, or ERT. ERT devices are lithium battery powered devices that electronically record and transmit metered gas consumption data from meters via radio frequency protocol. The radio frequency signals from these devices are picked up via data receiving devices placed in NW Natural's trucks, which allows the Company to pick up meter readings as the trucks drive by the premises. NW Natural's meter reading system uses automated meter reading ("AMR") technology.

Q. What is the typical life of the lithium battery within the ERT?

A. The lithium battery within an ERT carries a typical life of approximately 20 years. However, the batteries within the ERTs may begin to perform poorly earlier than 20 years—and by year 17 or 18, the failure rate begins to increase, requiring the Company to plan for replacement several years before the end of the 20-year life.

Q. When NW Natural began planning the MMP, were there a significant number of ERTs that were approaching the age at which a replacement is required?

A. Yes. As shown in Figure 1 below, many ERTs across the Company's service territory were entering their 18th year post-installation and starting in 2024, there was a significant uptick in ERT change-outs required.

Figure 1. End-of-Life ERTs (18-Year Life)

Q. What timing considerations are relevant to replacing end-of-life ERTs?

A. There are three key timing considerations relevant to the replacement of these ERTs: (1) replacing ERTs early enough to avoid malfunction; (2) optimizing ERT replacement on a geographic basis for efficiency; and (3) navigating supply chain issues to avoid procurement delays. Regarding the risk of malfunction, NW Natural needed to be proactive about ERT change-outs and began installations of ERT replacements during the 18th year of an ERT's lifespan, as they begin to start failing in meaningful quantities after 17.5 years. Additionally, to optimize ERT replacement on a geographic basis, NW Natural plans to replace ERTs strategically in geographically organized batches across its service territory rather than responding to individual ERT failures as they occur. As a result, the Company deploys its resources more efficiently. Finally, regarding supply chain issues, the current lead time for the ERTs used by the Company—Itron 500G AMR ERTs—is approximately 1 year, meaning ERT purchase orders must be made approximately 1.5 to 2 years prior to installation.

Q. In addition to replacing end-of-life ERTs, are there other metering issues driving NW Natural's MMP?

A. Yes. Through routine testing, the Company has identified certain meters requiring a "periodic cause for change." These are the PCC meters.

Q. What meters are identified as requiring a "periodic cause for change"?

A. Periodic cause for change meters are meter families that have been tested and are determined to run fast. Because the problem is associated with the family of meters (meters of the same manufacture, model, and vintage), the entire family of meters needs to be replaced.

Q. What does it mean when NW Natural identifies a "fast" meter?

A. A "fast" meter is a meter that inaccurately measures consumption. Instead of capturing the gas volume within the accurate range, the meter is instead producing a number higher than the actual metered volume. NW Natural defines a "fast" meter as one that is reading at 102 percent of the actual metered volume or more.

Q. How does NW Natural define an "accurate" meter?

A. Consistent with NW Natural's tariff Schedule M, "Meter Testing Procedures," for existing meters in service, NW Natural considers an "accurate" meter to be one that captures the metered volume within two percentage points from the true metered volume. NW Natural assesses the true metered volume by using a calibrated meter-proving device. As long as the meter is between 98 percent to 102 percent of the true metered volume, NW Natural considers that meter to be "accurate." However, for all new meters, NW Natural requires the meter be measuring at 99 – 101 percent to be

"accurate," and NW Natural rejects meters outside of that range and returns them to the supplier.

Q. How does NW Natural test the accuracy of its meters and identify PCC meters?

A. NW Natural has a Meter Sampling Program[1] to evaluate the accuracy of its in-service diaphragm meters. Each in-service meter is part of a group of meters, referred to as a "family." NW Natural aims to group meters into "families" based on several criteria, one of which is performance records. Families allow NW Natural to pull a random sampling of similarly performing meters to assess a group of similar meters more efficiently.

NW Natural typically groups meter families based on manufacture date or date placed in service. For example, for all meter sets prior to 2020, a family is created based on manufacturer, meter size, meter type, and installation year. For all meters from 2020 onward, a family is created based on the manufacturer, meter size, meter type and meter manufacture date, to better align with manufacturer warranties. NW Natural can modify these families based on performance of certain meters to ensure similarly performing meters are in the same family. Similarly, some families have sub-families according to additional criteria. Sub-families permit NW Natural to remove underperforming meters without affecting the performance of the larger family.

At least once per year, NW Natural utilizes meter test data for all meters tested within the previous 5 years, and additionally takes a random sample from meters where additional test data is needed to determine each meter family's performance. Any

[1] NW Natural's Meter Sampling Program is described in its tariff Schedule M – Meter Testing Procedures, pursuant to WAC 480-90-348(3).

meter in the family is eligible to be used in the random sample. Meters selected for sampling are removed from service and tested in accordance with the relevant standards, ANSI B109.1 and B109.2 (2000 version).[2] Because the sampling is intended to be an evaluation of working meters, NW Natural excludes data on meters which are damaged, meters which do not register, meters which do not pass gas, and meters that measure either less than 90.0 percent or more than 110.0 percent on the accuracy scale. NW Natural keeps records of and refers to the samples taken from the past five years to make calculations relating to the accuracy of the meter family and whether the meter family should be categorized as "fast" or "not fast."[3]

Q. What are the criteria for meter replacement?

A. For all meters, NW Natural uses the sampling acquired either through the Meter Sampling Program or per the schedule applicable to that meter type and calculates whether a proportion of 80 percent of the family results in "accurate" readings and at least 90 percent of the family is not "fast." To make this determination, NW Natural uses methods defined in ANSI/ASQ Z1.4 "Sampling Procedures and Tables for Inspection by Attributes."[4] First, the sampling measurements are compared to threshold proportions and control limits on a control chart. Second, NW Natural determines whether the meter family's performance meets a satisfactory level based on the control standards. Third, NW Natural determines the accuracy of the family, then

[2] See confidential Exh. JSK-2C, Engineering Procedure Z-1 for an explanation of these standards.

[3] See also confidential Exh. JSK-2C, Engineering Procedure Z-1, which explains how the Company addresses meters that are "slow" (i.e., under-recording actual customer deliveries) and is addressed in further detail below.

[4] Confidential Exh. JSK-2C, Engineering Procedure Z-1.

the proportion of meters that are "not fast." If the results of these calculations exceed the control, and the sample size is determined insufficient, an additional random sample is obtained for families that are more than 10 years old. Based on where the samples fall within the control standards, NW Natural determines whether the sample readings are satisfactory, at or below limits, or insufficient.

Meters in families that are acceptable—or satisfactory—will remain in service and be tested again during the next period for sampling. If a meter family passes the "not fast" test but fails on "accuracy," it is determined to be slow and under-recording usage. NW Natural has the option to remove these meters based on economic and operating factors. NW Natural may also leave the meters in service and continue to test the meters during the next period for sampling. Meters that fail the sampling, are not accurate, and are fast are determined "non-conforming" and are scheduled for change out by NW Natural.

Q. Please provide the amount of meters that are non-conforming.

A. NW Natural identified a total of 144,229 meters that were determined non-conforming from 2021 to 2025, with approximately 15,134 meters located in Washington. Out of these 144,229 meters, 73,499 meters remained in service as of February 2025, with approximately 10,465 of those meters located in Washington.

Q. What is the timeline for replacement of meters identified for change-out?

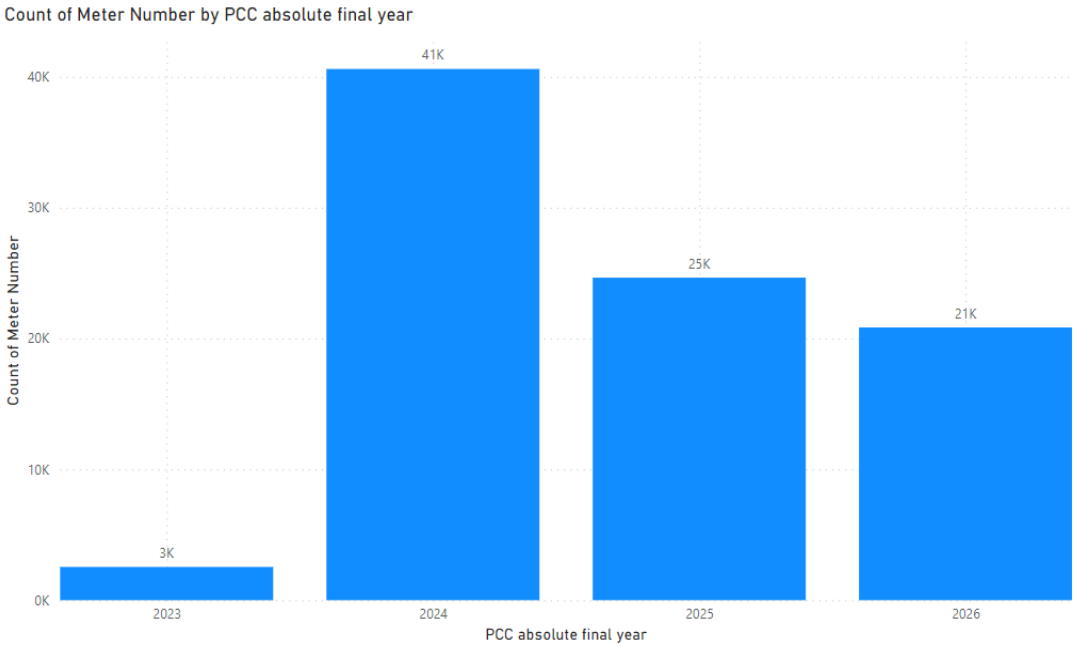
A. Meters that are identified as needing to be replaced will be changed out by December 31st of the year following the year in which the need for replacement was determined. However, in the case where in any given year the number of meters identified for change-out exceeds 3 percent of the total population of meters in the Meter Sampling

Program, NW Natural may extend the timeline so that the meter family is changed within four years of determining the need for replacement.

Q. How many PCC meters did the Company identify across its service territory at the beginning of the program?

A. When the project began, there were almost 90,000 identified PCC eligible meters across NW Natural's service territory on a system basis, 10,000 of which are in Washington, that required replacement between 2024 and 2026. While the MMP continues until 2027, PCC exchanges end in 2026.

Figure 2. PCC Meters

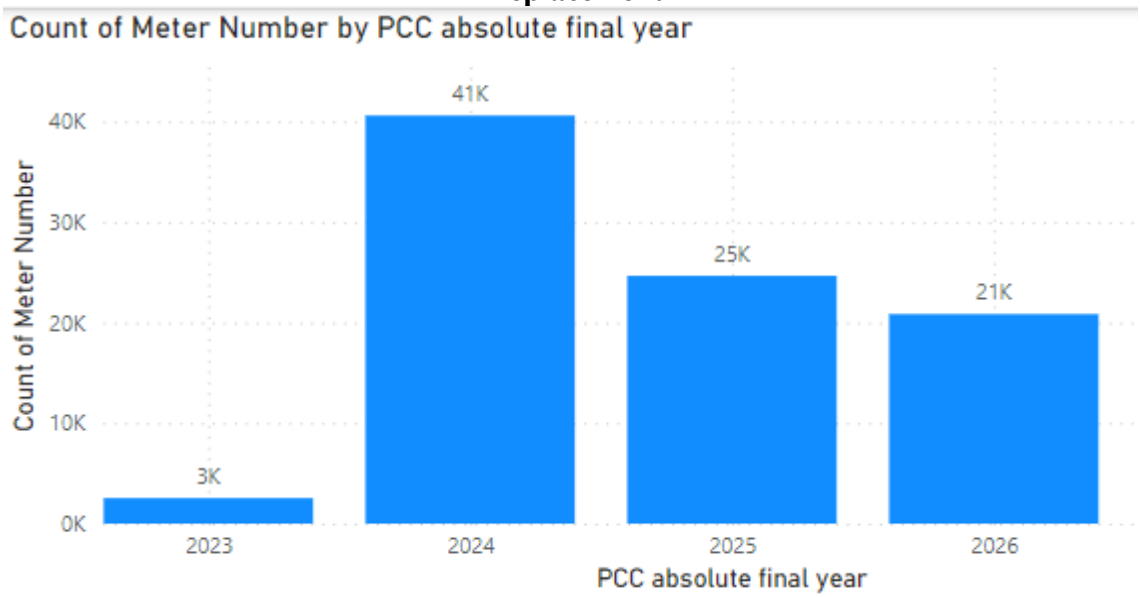


The graphic in Figure 2 above depicts PCC figures by the year in which the PCC meters must be replaced (within four years of the date identified) and shows a significant uptick in PCC meters requiring replacement during the term of the MMP. Figure 2 includes dying meters identified in 2023 and therefore need replacement in the MMP.

Q. Is there any overlap among the PCC meters and the meters requiring ERT replacements?

A. Yes. The PCC meters shown above in Figure 2 also fall into the ERT replacement timeline during the 2023 – 2026 years, as shown below in Figure 3. Thus, regardless of PCC status, over 99 percent of these meters would require ERT replacement, independent of being identified as a PCC meter.

Figure 3. Timing for Replacement of PCC Meters Also Requiring ERT Replacement



Q. Beyond the need to replace the end-of-life ERTs and PCC meters, are there other issues that are informing NW Natural's meter modernization strategy?

A. A key issue that informed the meter modernization strategy was the lack of available supply from vendors for both mechanical meters as well as ERTs. The mechanical meter lead times at the beginning of the program's planning stretched to approximately 85 weeks, while ERT lead times were approximately 52-60 weeks. Current lead time on ERTS are still 84 weeks and mechanical meters currently are averaging 52 weeks.

Due to supply chain issues, the Company has established a minimum safety stock metric of 9,800 meters as a standard. At this inventory level, Sherwood (the Company's central warehouse headquarters) did not hold any meters, as any available meters were held at satellite warehouses across the Company's service territory.

Q. Under normal circumstances—meaning without the supply chain issues that have been experienced recently—how quickly does NW Natural replace PCC meters?

A. Prior to 2018, NW Natural would typically determine that approximately 5,000 PCC meters were eligible for replacement per year, and the PCC meters would be replaced in the year after they were identified through the meter sampling process. However, more recently, volumes have been in the 15,000 to 40,000 yearly range for meters that have been identified as part of the PCC sample testing process. The maximum number of meters changed out internally during a one-year period was 26,000 meters during the COVID-19 pandemic, which was possible because a number of other work orders had ceased due to COVID-19 restrictions. But this recent uptick in volume coupled with supply chain issues has caused NW Natural to target a four-year window to change out these meters as part of the MMP, as described above.

Q. Why is it important for NW Natural to have fully functional metering equipment?

A. Having fully functional metering equipment is a best utility practice and key to ensuring accurate billing. NW Natural's metering equipment is an essential component of the Company's system, and thus must work properly. The Washington Administrative Code ("WAC") requires the Company to provide meters with a tolerance of no more

than two percent fast or slow,[5] and specify meter test procedures and corrective actions in its tariff.[6] Consistent with the WAC, NW Natural must ensure that all customer meters accurately meter gas usage, and meters that do not conform to the testing program be replaced with accurate meters.

Q. Are there other aspects of NW Natural's metering system that require updating?

A. Yes. The Company's current meter reading technology (FCS) is set to be removed from service by the vendor, Itron in 2028. In order to ensure the Company can retain a functional meter reading system, the Company will implement a new software solution (Temetra) in 2026.

III. ULTRASONIC METERS

Q. What is an ultrasonic meter?

A. Ultrasonic meters use a metering technology that has been available on the U.S. market since the 1980s and was initially used primarily in industrial applications but has not been widely adopted for residential application until recently. Many utilities in the U.S. are moving toward the use of ultrasonic meters as they need to replace meters on their system. In particular, Southwest Gas, CenterPoint, Spire, NiSource, Northwestern Energy, and Dominion are using ultrasonic metering technology.

Q. How do ultrasonic meters measure the flow of gas?

A. Ultrasonic meters use sound waves to measure gas flow. Specifically, ultrasonic sound waves are transmitted through the gas flowing through the meter and then the

[5] WAC 480-90-338.

[6] WAC 480-90-343.

measurement is produced by recording the time it takes for the sound waves to travel between two transducers placed in the pipe. The difference in the time it takes for the sound waves to travel upstream and downstream gives an accurate measurement of the gas flow rate.

Q. How is the ultrasonic meter different from the mechanical meter?

A. While a diaphragm gas meter uses mechanical components to measure the flow of gas, an ultrasonic gas meter uses non-invasive sound waves to make its measurements. As a result, ultrasonic gas meters are generally more accurate and have fewer moving parts, which means they require less maintenance. Additionally, ultrasonic gas meters are suitable for a wider range of applications, including corrosive or dirty gas environments, where mechanical meters may be less reliable. Ultrasonic meters also have a number of operational and safety benefits in comparison with mechanical meters. The Itron Intelis meters have been tested with renewable natural gas and hydrogen blends, preparing NW Natural for a higher capacity of blended gas flowing through to customers.

Q. Do ultrasonic meters require the use of an external 500G ERT?

A. No. The recording and transmitting equipment is included as an integral component of the ultrasonic meters, and thus these meters do not require the use of an external ERT (as the ERT is embedded within the meter) to enable the collection and transmission of usage data.

Q. How do ultrasonic meters transmit data?

A. Ultrasonic meters are designed to use either radio frequency or cellular technology to transmit meter data. At this time, the cellular ultrasonic meters are not yet in production, though they are expected to begin to be produced in 2026.

Q. Are the ultrasonic meters compatible with NW Natural's data collection system?

A. Yes, the Itron Intelis ultrasonic meter in AMR mode can integrate with the current meter reading system (FCS). The Company expects that ultrasonic meters will integrate seamlessly with Temetra, the Company's new system for collecting customer usage data in 2026.

Q. What are the safety-related benefits associated with ultrasonic meters?

A. Ultrasonic meters include the following features that are not available through mechanical meters:

- Automatic high temperature and high flow shut off;
- Additional tamper alarms (examples: air in pipe, valve status, communication error); and
- 70 percent smaller in size, which means a reduction in field worker injuries due to a lighter meter size.

Q. Please describe the operational benefits of ultrasonic meters.

A. Ultrasonic meters provide measures to a higher degree of precision and are less likely to drift and require re-calibration. Due to these meters' electronic design, they have self-diagnostic capabilities. The ultrasonic meters are also approximately 70 percent smaller than the mechanical meters, which allows more flexibility in storage and shipping of meters as well as an ability to optimize the Company's multi-family installs

with smaller meter sets. The meters have a high heat and high flow threshold that when triggered will automatically close the meter's outlet valve preventing the passage of gas into the customer's home.

Additionally, it is easier to forecast end-of-life for ultrasonic meters because there is only one device (the ultrasonic meter) rather than two devices (mechanical meter and ERT), and when those meters reach end-of-life, ultrasonic meters are less complex than mechanical meters and thus allow for easier and faster meter change outs.

Q. What is the typical life span for an ultrasonic meter?

A. The typical life span of an Itron Intelis meter is 20 years.

Q. What is the cost difference between a mechanical meter and an ultrasonic meter?

A. In March 2023, at the time NW Natural was performing its analysis in support of the MMP, a mechanical meter with an ERT was approximately $164 per unit, and an ultrasonic meter with radio frequency (AMR) capabilities was $200 per unit. Current costs are $179 per unit for a mechanical meter with ERT and $200 per unit for an ultrasonic meter with ERT included.

IV. OVERVIEW OF MMP

Q. What is NW Natural's Meter Modernization Program, or MMP?

A. NW Natural has initiated a four-year process to replace end-of-life ERTs and meters that are both PCC eligible and have ERTs that are end-of-life. The MMP will help modernize and maintain the Company's current metering system, including maintenance of existing assets, enabling the integration of a more diverse meter complement, and facilitating an expanded array of backhaul options into its billing

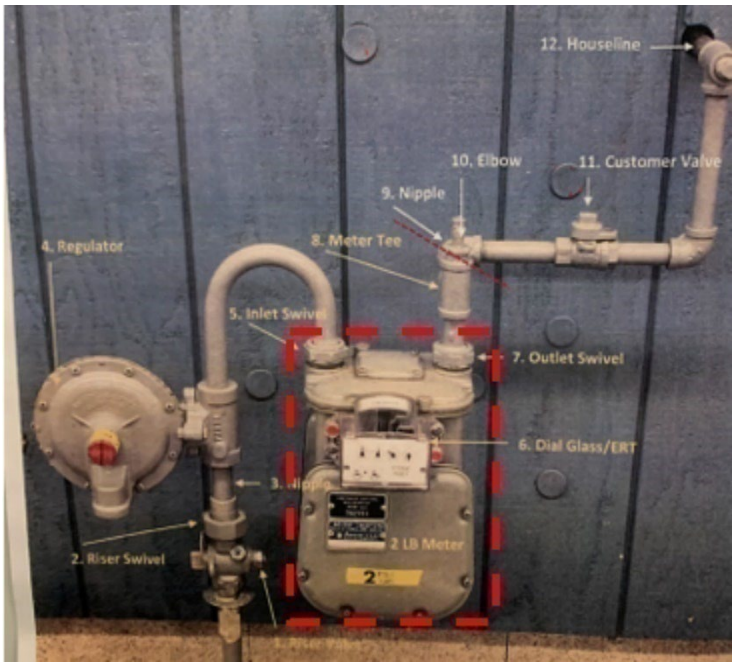
system. This new complement will help alleviate supply chain challenges and leave us in a less homogenized metering position.

Q. What components of a meter will be replaced under the PCC program versus the ERT replacement program?

A. Figure 4, below, shows the components of a mechanical meter. The MMP includes both the meter and ERT device as outlined in the red dashed box in Figure 4.

- **Meter Replacement.** When a meter is changed out, the entire meter and ERT are removed and replaced with a new meter and ERT combination or an ultrasonic meter (containing communication device built in).
- **ERT Replacement.** An ERT change out does not impact the meter itself; instead, the plastic ERT covering is removed and the ERT device gets removed for recycling.

Figure 4. Photograph of Mechanical Meter



Q. How long has NW Natural been planning ERT replacements?

A. The Company initiated planning for the replacement of ERTs in 2019.

Q. Did NW Natural's plans for the MMP change over time?

A. Yes. Prior to the MMP, NW Natural initially developed a plan for the replacement of ERTs that would include the installation of an advanced metering infrastructure ("AMI") Mesh Network and would be deployed over the timeframe 2020-2049. At the outset of the COVID-19 pandemic, NW Natural put its planning for the ERT replacements on hold, and then in 2022 reinitiated planning. This pause provided NW Natural an opportunity to reassess the project, which led to two significant changes in project scope, ultimately resulting in lower costs to customers. Specifically, NW Natural reevaluated the prior decision to use AMI technology, and NW Natural combined the ERT replacement project with the PCC replacement project to capture operational efficiencies compared to replacing ERTs and PCCs as two stand-alone projects. Please see confidential Exh. JSK-3C, NW Natural Meter Modernization Implementation (Nov. 3, 2022) for additional context regarding the Company's reevaluation of the use of AMI technology leading to the changes in project scope.

Q. Please describe NW Natural's reevaluation of AMR and AMI technologies.

A. NW Natural studied scenarios including AMR and ultrasonic, AMI (network), and AMI (cellular). NW Natural has used AMR technology for nearly 20 years. AMR eliminated the need for manual meter reading (physical visits to the meter to record gas usage) by transmitting usage through a radio frequency signal. Trucks are rolled across NW Natural's service territory with data collector devices that pick up the radio frequency signal being transmitted from the AMR ERTs. In an AMI system, these

truck rolls would not be needed for meter reading as the usage can be backhauled via cellular transmission, through a mesh network, or through cellular enabled access points. Ultimately, as described below, an AMR system is a lower cost than other solutions and provides NW Natural with the necessary data required for billing.

Q. Why did NW Natural decide to combine the PCC meter replacement program with the ERT replacement program to create the MMP?

A. As noted above, the combination of these two programs created operational efficiencies, resulting in lower costs to customers. The PCC meter replacement program is a daily operational activity requiring the change out of meters across the Company's service territory. The ERT replacement program is also a daily operational activity centered around replacing end-of-life ERTs with replacement ERTs. Each of these two projects requires a visit to the premises with an asset replacement of either the meter, the ERT, or both. During NW Natural's strategic planning for each of these projects, it calculated an approximate $10 million, on a system basis, cost reduction by combining these two projects into the MMP, reducing the need to touch a meter premise twice for one customer. Please see confidential Exh. JSK-4C, NW Natural Meter Modernization Proposed Strategy (Jan. 14, 2023) and confidential Exh. JSK-5C, NW Natural Meter Modernization Program (June 2023) for additional information regarding the Company's decision to proceed with the MMP.

Q. What were the estimated costs of the MMP associated with the different ERT technologies?

A. For the AMR and ultrasonic technologies, the estimated costs ranged from $90-120 million. For the AMI (network) technology, the estimated costs ranged from $150-180

million. And for the AMI (cellular) technology, the estimated costs ranged from $160-190 million. See confidential Exh. JSK-5C.

Q. Why did NW Natural initiate the MMP in 2024?

A. NW Natural had an immediate need to replace ERTs nearing the end of their useful lives, and to replace PCC meters. Critically, this is a multi-year project, and due to the age of the ERTs and the number of ERTs that reached end-of-life in 2024, the work on this project was mandatory.

Q. Were there additional refinements to the MMP after it was initiated?

A. Yes. In 2024, the Company was informed that the ultrasonic cellular meter that had been previously forecasted for installation within the project's timeline had been delayed. The delay resulted in this meter type not being included within the program's deployment schedule. This resulted in the project adapting its buying forecast to supplement the number of forecasted ultrasonic cellular meters to be purchased with ultrasonic AMR meters, which saved $30 per meter from the forecasted population.

Q. You had previously mentioned that the four key elements of the MMP include the replacement of PCC meters, gradual transition to ultrasonic meters, replacement of end-of-life ERTs, and installation of the new software system. Please elaborate on the Company's decision-making regarding the selection of these resources.

A. In the testimony that follows, I will describe the selection of the ERTs, meters (including exhausting existing inventory and integration of ultrasonic meters), and software, in turn.

A. Selection of ERTs Used in MMP

Q. What ERT technologies are currently available?

A. In general, there are three types of ERT communication available for purchase at present, as shown in Table 1, below.

Table 1. Available ERT Technologies

	AMR – Radio Frequency	AMI –Mesh Network	AMI – Cellular
500G	Current technology. Read through radio frequency drive by reads.	Read through a network of end points. NW Natural considered with solar powered access points	Read through cellular backhaul via sim card within the ERT

Q. Why did the Company select the 500G AMR ERT technology?

A. NW Natural has been using the 500G AMR ERTs since 2019, which are capable of storing 40 days of hourly data and more interval data. The Company selected this technology as the least cost option and because it allows for maintaining billing functionality. In order to ensure that the Company received a fair and reasonable quote for ERTs, it issued a request for information for ERTs to five ERT vendors.[7] A decision was made to choose Itron for ERT purchases due to the reasonable price and ease of software integration.

[7] See confidential Exh. JSK-3C, NW Natural Meter Modernization Implementation (Nov. 3, 2022).

B. Selection of Meters Used in MMP

Q. What meter technology options are currently available or expected to become available in the near term?

A. As shown in Table 2 below, the two primary technology options are mechanical and ultrasonic, with variations in AMI and AMR meter reading capabilities. As discussed above, the current technology used by NW Natural is both mechanical and ultrasonic AMR meters that allows for radio frequency drive-by reads.

Table 2. Meter Technologies

	AMR – Radio Frequency	AMI – Radio Frequency	AMI – Mesh Network	AMI – Cellular
Mechanical	Mechanical (AMR – Radio Frequency)	Mechanical (AMI – Radio Frequency)	Mechanical (AMI – Mesh network) – with 500G mesh network ERTs and solar power access points	Mechanical (AMI – cellular) – with 500G cellular ERTs
Ultrasonic	Ultrasonic (AMR – Radio Frequency)	Ultrasonic (AMI – Radio Frequency)		Ultrasonic (AMI – Cellular) – embedded communication device with cellular backhaul capability-forecasted for production in 2026

Q. What technology did NW Natural select for the MMP?

A. NW Natural plans to replace the PCC meters with 30,000 mechanical and 60,000 ultrasonic meters. All ultrasonic meters will be AMR, as ultrasonic meters that use cellular technology delivery times do not align with the deployment timeline of the MMP.

Q. How did NW Natural decide to use a combination of mechanical meters and ultrasonic meters in the MMP?

A. NW Natural had approximately 30,000 mechanical meters at its warehouse inventory prior to the program's deployment in 2024. In 2024, NW Natural had committed to purchase an additional 20,000 mechanical meters from two separate vendors. In addition to the safety and operational benefits previously described in my testimony, the industry appears to be adding capacity for the manufacturing of ultrasonic meters, while moving away from mechanical meters. In fact, the Company's current ERT supplier, Itron, used to make mechanical meters but has since stopped production to focus on ultrasonic meters. The Company must ensure it is moving where the industry is moving so the Company's hardware does not become obsolete with regard to replacement.

Q. In light of the changes in the industry toward the adoption of ultrasonic meters, did NW Natural evaluate a fully ultrasonic ERT replacement program?

A. Yes, early in the ERT study process, in 2019, the Company modeled a budget for a scenario with ultrasonic meters—and even considered replacing its entire meter population in the short-term (800,000 meters) with ultrasonic meters. The Company ultimately determined that the approach of replacing the entire meter population with ultrasonic meters over a short period of time would be far too burdensome on the Company's customers. The Company also believes that there will be benefits in moving towards ultrasonic meters gradually over a longer time horizon and will ensure it is providing the best possible service at an appropriate cost. Importantly, the plan to use a combination of ultrasonic meters and mechanical meters will allow the Company

to make use of its existing inventory and committed contracts while taking steps towards diversifying its metering system.

Q. Why is NW Natural including ultrasonic meters in the MMP instead of simply replacing the PCC meters entirely with mechanical meters?

A. The key reasons for including ultrasonic meters include additional meter diversity, supply chain issue curtailment, safety related benefits, and operational improvements.

Q. Please elaborate on the meter diversity rationale.

A. Including ultrasonic meters supports meter diversity amongst NW Natural's meter population. This is particularly important because the large volumes of PCCs the Company has been seeing since 2018 have a direct correlation with purchasing and installing large populations of the same meter families at the same time. By diversifying its meter complement, the Company avoids all of its meters having issues at the same time.

C. Selection of Software to be Implemented in MMP

Q. Please describe the software updates that are included as part of the MMP.

A. As detailed above, the current meter reading technology will reach its end of life in 2028. Accordingly, the Company is updating to Temetra, which is supported by the vendor Itron and will continue to be supported for the foreseeable future. The Company's plan is to fully adopt Temetra by the end of 2026.

Q. What are the primary features provided by Temetra?

A. Temetra supports meter reading for drive-by and cellular enabled devices, and with certain meter types (ultrasonic meters), provides capability for over-the-air upgrades.

An additional benefit of the Temetra system is that the user experience for internal field force will not be significantly impacted.

Q. Please discuss whether the Company considered alternatives to updating to Temetra.

A. There were no viable alternatives to Temetra. Itron only has one service that primarily serves utilities that read meters via AMR. That current software is FCS, and its replacement system is Temetra. Other vendors that offer metering head end systems would require a hardware replacement at every meter in the Company's system in order to be compatible.

Q. After deploying Temetra, are there additional software modifications needed to accommodate ultrasonic meters?

A. The ultrasonic AMR meters that are installed will need to be compatible with the Company's current AMR-meter reading technology until the system is replaced. The vendor for the current system, Itron, stated they will be discontinuing the system used by the Company for meter reading, which will be replaced by Temetra. Itron has indicated that when ultrasonic cellular meters become available, and if NW Natural wanted to purchase them, add-on software will be required.

D. FTEs Required for the MMP

Q. Are additional employee resources required to implement the MMP?

A. Yes. NW Natural needs significant resources to complete the MMP. Two of the hired resources were incremental NW Natural full-time employees. NW Natural is also using short-term contractors, which were not proposed for inclusion in base rates because the

Company does not intend to retain them beyond the duration of the MMP. I will address the permanent full-time employees here.

Q. Please describe the additional full-time resources that were required for the MMP.

A. The two positions were:

1. Itron Applications Suite Application Engineer 2: Because the MMP scope includes implementing new hardware and software from Itron, it was necessary to add a fully dedicated employee to manage the Itron suite of applications that will continue to grow in complexity as the MMP onboards new metering types. This role maintains all metering-related technology and is responsible for technical configuration and application administration of Itron-related apps (Temetra, Temetra Mobile, Field Tools, ISM, FDM).
2. Metering Business Lead: This role is responsible for the MMP and all related/dependent projects or workstreams, supporting long-term MMP strategy, managing scope, budget, and program outcomes, and ensuring integration with other critical transformation programs such as H2: Vista (which is discussed in the confidential Direct Testimony of Brian E. Fellon, Exh. BEF-1CT).

Q. What is the status of these roles?

A. The Itron Applications Suite Application Engineer 2 was filled in Q4 of 2023 and the Metering Business Lead was filled in Q3 of 2023.

V. MMP DEPLOYMENT

Q. What steps have been taken to procure and install the ERT hardware?

A. As discussed above, the Company is using 500G ERTs to replace ERTs with end-of-life batteries. The Company executed a $28.8 million agreement with Itron on December 31, 2022, to facilitate hardware purchases over the 5-year period, 2023-2027. Entering into the agreement with Itron was intended to support supply and reduce constraints. The Company expects to deploy approximately 400,000 500G AMR ERTs that will be supplied by Itron, system wide. 40,000 of those ERTS are within NW Natural Washington service territory. As of June 30, 2025, 35,975 ERTs have been installed in the Company's Washington service territory. And, 1,154 ERTs will be changed out towards the end of the project due to their location in the Columbia Gorge.

Q. What steps have been taken to procure and install the meter hardware?

A. The Company is depleting its existing current stock of mechanical and ultrasonic meters and will also purchase new meters (a combination of both mechanical and ultrasonic) to replace PCC-eligible meters. NW Natural has an outstanding purchase order for 10,000 ultrasonic AMR meters in addition to Sensus and Honeywell mechanical meter purchase orders totaling approximately 1,000 meters. The Company expects to deploy:

- On a system basis, approximately 30,000 mechanical meters with ERTs attached.
- Approximately 60,000 ultrasonic meters in AMR (to be supplied by Itron) on a system basis.

As of June 30, 2025, 1,704 meters have been installed in the Company's Washington service territory for PCC replacements within the MMP. An additional 7,657 additional meters are planned for PCC change out in Washington by the end of the project.

Q. How has NW Natural implemented the MMP in Washington?

A. ERT deployment forecasts for ERT changes are determined based on geography and based on their age. The primary focus is to exchange the ERTs before their batteries stop communicating. All ERTs in Clark County were forecasted for installation January through June of 2025. The area of the Columbia Gorge that is within Washington is slated for 2027.

VI. COST RECOVERY PROPOSAL

Q. How is the Company seeking to recover the costs of the MMP?

A. The MMP is a sizeable project for NW Natural. The total capital cost of the project, on a system basis, is approximately $83.9 million. As discussed previously, this is a four-year project and the Company expects to recover the capital investments in rate cases. On a Washington-allocated basis, in this rate case, NW Natural is proposing to recover the following capital investments in Table 3 below:

Table 3. MMP Capital Additions

	Rate Year 1[8]	Rate Year 2[9]	Rate Year 3
Capital Investment	$10,279,937	$3,453,949	$0

[8] All of the capital additions for the MMP in Rate Year 1 are in-service prior to the start of Rate Year 1.

[9] Due to end of period treatment applied in July 2026 for Rate Year 1, the capital additions recognized in Rate Year 1 are proposed to be recovered in Rate Year 2.

Q. Is the MMP similar to a traditional capital project from a cost recovery perspective?

A. No. There are two main differences between the MMP and traditional capital projects. The first difference is that the MMP has significant structural lag associated with the timing of the daily installations. For most of NW Natural's major capital projects, the work is performed during the summer construction season, and the projects are placed in service in the fall, prior to the winter heating season. The MMP, on the other hand, involves daily installation of meters and ERTs over a four-year period. After installation, the meters and ERTs are used and useful, but the Company will experience significantly more lag on recovery due to the daily deployment of the MMP. The second difference is that the MMP has a significant amount of non-routine, one-time O&M expense associated with the deployment of the MMP. In other words, there are several key aspects of the project that cannot be capitalized and result in a significant O&M expense increases over a short period. These costs are not appropriate to be included in base rates, however, because the costs will immediately drop off at the conclusion of the program and, consequently, would result in the Company unnecessarily over-recovering its costs at that time. For these reasons, NW Natural is deferring these one-time costs for later recovery.

Q. Has the Company made any other regulatory filings concerning cost recovery for the MMP in Washington?

A. Yes, as detailed above, the MMP will involve a significant amount of limited duration O&M expense incurred over the four-year term of the program. Because the O&M expense will only be incurred during the term of the MMP and will include an initial

ramp up at the beginning of the program and a ramp down at the end of the program, the Company does not propose building this O&M expense into base rates. Instead, the Company filed an accounting petition for the one-time O&M expense incurred for the limited duration of this program, which NW Natural estimates will be approximately $14.2 million, or $2 million on a Washington-allocated basis. The deferral was approved on February 22, 2024 in UG-240012 Order 01. Please refer to Mr. Walker's Direct Testimony (Exh. KTW-1T) for details on cost recovery of the deferral.

Q. What is included as O&M expense in the deferral?

A. The preliminary estimate for Washington-allocated costs that cannot be capitalized and are included within the O&M deferral include the following categories:

- Meter and ERT replacement: $0.8 million, which covers Southern Cross' installation labor costs for approximately 30 field-techs and supporting positions working across NW Natural's service territory to replace PCC meters and end-of-life ERTs.
- ERT and PCC Hardware Recycling: $0.4 million, which covers shipping and recycling approximately 400,000 lithium-ion batteries (40,000 on a Washington basis) in ERTs and shipping, testing, and recycling of approximately 90,000 (10,000 on a Washington basis) PCC meters and ERTs. Due to the materials in meters and ERTs, the Company must "dispose" of these items in accordance with stated regulations.
- Incremental Non-field Labor: $0.7 million, which includes incremental resource costs (non-field) to support the MMP. These positions will provide customer call

support with increased customer touch points, scheduling support, billing support, internal change communication, external communications, quality assurance inspection of installations, meter shop support, and support in deploying field techs for change-outs. Each of these roles contributes to an increased operational workload for the program due to the elevated number of ERT and meter change-outs required during the coming four-year period. Internal resources will transition to support the program, and their role will be backfilled to ensure business as usual operations. Additional contractor support from Ernst and Young supplements these efforts.

- Other external expenses: $0.1 million, which includes bill inserts and door hangers related to communicating and educating the customer base about the MMP. Due to the increased presence of field workers during the four-year deployment, NW Natural will need to inform customers of the reasoning for trucks and field technicians being in their neighborhoods.

Q. How has NW Natural tracked O&M expenses throughout the program?

A. The Company tracks both actual expenditures and the remaining forecasted costs for the entirety of the MMP. The actual expenses and remaining forecast are compared against the originally approved budget to ensure alignment. While the Company's forecast reflects current estimates of what it expects to spend through the remainder of the MMP, the original budget remains unchanged. This approach allows the Company to monitor spending in real time while staying aligned with the original approved budget. The budget was approved by NW Natural executives during the planning phases of the MMP.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

VII. LIST OF EXHIBITS

Exh. JSK-2C	Engineering Procedure Z-1 (Confidential and Redacted)
Exh. JSK-3C	NW Natural Meter Modernization Implementation (Nov. 3, 2022) (Confidential and Redacted)
Exh. JSK-4C	NW Natural Meter Modernization Proposed Strategy (Jan. 14, 2023) (Confidential and Redacted)
Exh. JSK-5C	NW Natural Meter Modernization Program (June 2023) (Confidential and Redacted)

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Joe S. Karney

METER MODERNIZATION

Exh. JSK-2C

REDACTED VERSION

August 29, 2025

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UNDER WAC 480-07-160 AND HAS BEEN REDACTED.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Joe S. Karney

METER MODERNIZATION

Exh. JSK-3C

REDACTED VERSION

August 29, 2025

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BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Joe S. Karney

METER MODERNIZATION

Exh. JSK-4C

REDACTED VERSION

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BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Joe S. Karney

METER MODERNIZATION

Exh. JSK-5C

REDACTED VERSION

August 29, 2025

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BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Direct Testimony of Melinda B. Rogers

COMPENSATION & BENEFITS

Exh. MBR-1CT

REDACTED VERSION

August 29, 2025

DIRECT TESTIMONY OF MELINDA B. ROGERS

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position at Northwest Natural Gas Company ("NW Natural" or "the Company").

A. My name is Melinda B. Rogers. My title is Vice President, Chief Human Resources and Diversity Officer. I am responsible for overseeing various administrative functions at NW Natural, including Human Resources, Diversity, Equity and Inclusion, Safety, Labor Relations, and Payroll.

Q. Please describe your education and employment background.

A. I received a Bachelor of Business Administration from Bryant University in 1987. Prior to NW Natural, I was employed by the Atkinson Graduate School at Willamette for three years as Director of Executive Education. Before joining Willamette, I served as Vice President of Enterprise Learning and the Vice President of Human Resources for four years at Knowledge Universe in Portland. I was employed in other senior human resource roles and management positions at Qualcomm and Hewlett Packard for 14 years prior to joining Knowledge Universe. I joined NW Natural in September of 2015 and have been an officer for the Company since August of 2018.

Q. Please summarize your testimony.

A. In my testimony, I:

- Describe the Company's compensation practices, which result in total compensation that is at the market median for comparable companies;
- Describe the employee benefits program offered by NW Natural, demonstrate that it is aligned with the market, and that the Company has carefully managed benefits to ensure reasonable costs;

- Describe the overall level of compensation and benefits costs included in the Company's multi-year rate plan requested revenue requirements; and
- Describe the Company's requested employee headcount for Full-Time Equivalent ("FTE") positions during the multi-year rate plan.

II. NW NATURAL'S COMPENSATION PHILOSOPHY

Q. What is NW Natural's approach to determining the compensation it provides to its employees?

A. NW Natural's approach is to provide a level of total compensation that is necessary to attract, motivate, and retain qualified employees needed to run a safe and reliable natural gas delivery business, with high-quality customer service and at a cost that is reasonable. To do this, we provide a competitive total compensation package for employees that allows us to hire and retain a qualified workforce.

Q. Please explain what you mean by "competitive total compensation."

A. Total compensation is the combination of base pay, merit-based incentive pay, medical benefits, and retirement benefits. Total compensation is competitive when its total value is at the median level for total compensation offered in the marketplace for comparable jobs. It is through offering a competitive total compensation package that NW Natural is able to compete in the job market to attract, hire and retain the employees it requires to run a safe, reliable, customer service-focused gas utility.

Q. How does NW Natural determine that its total compensation is at the median level?

A. As I will explain in my testimony, the Company performs research to ensure that each aspect of its compensation is at the median level and is therefore competitive with the compensation offered by its competitors for comparable jobs.

Q. Are there established practices that allow you to be confident that you are offering a competitive total compensation, and not more?

A. Yes. There are well-established methodologies that we employ in order to ensure that we offer competitive compensation, based on comparable jobs. I will describe those in more detail in my testimony.

III. BASE PAY

Q. You mentioned that "base pay" is a major component of offering competitive total compensation. How are you defining base pay?

A. Base pay is the guaranteed financial compensation provided to employees for the work performed. It is delivered on either an hourly or salaried basis. Base pay excludes the other important components of compensation (*e.g.*, merit-based incentive pay) that are not guaranteed but are nevertheless a critical component of offering competitive compensation to attract qualified employees.

Q. How does the Company determine Non-Bargaining Unit ("NBU") employees' base pay?

A. NW Natural purchases and regularly analyzes comprehensive survey data to ensure that its base pay is aligned with the median of the market for comparable jobs with other companies that would typically compete with NW Natural for employee talent.

See confidential Exh. MBR-2. A summary of NW Natural's most recent analysis, as completed by the Company in 2024, is attached as Exh. MBR-3. The analysis demonstrates that NW Natural's current base pay midpoints for NBU jobs are at the median of comparable companies. This well-established process confirms that NW Natural is offering an appropriate level of base pay to its employees as a component of competitive total compensation.

Q. How does the Company determine Bargaining Unit ("BU") employees' base pay?

A. BU employees' total compensation—including base pay—is determined through a negotiated process. The Company utilizes selected market survey data sources and union contracts, primarily of Northwest gas utility companies, as the points of comparison for proposing BU wage steps. The sources the Company uses for this data are agreed upon between the Company and the labor union (OPEIU) and include peer utility contracts and national databases that include gas jobs as well as local compensation studies. Pay increase trend data and union contracts are consulted when negotiating annual wage increases throughout the term of the Collective Bargaining Agreement ("CBA" or "Agreement"). See Exh. MBR-4. As with any labor negotiations, trade-offs are negotiated for other terms and conditions in the CBA.

Q. Please explain the terms of the current CBA.

A. The current CBA for BU employees was executed on May 20, 2024. The CBA covers the period June 1, 2024 through May 31, 2028. BU employees received a 6 percent wage increase on June 1, 2024. There was an additional 4 percent increase on December 1, 2024, and every December 1 thereafter through December 1, 2027. BU

employee health care costs reflect an 85 percent/15 percent sharing between the employer and employee, respectively, whereas previously the sharing was 80 percent/20 percent, respectively. Lastly, six job titles were re-graded, increasing the wages for those approximately 100 employees whose positions moved to a new pay group.

Q. How does NW Natural determine competitive compensation for Company officers?

A. As with other employees, NW Natural uses competitive compensation data to determine compensation for Company officers. In the case of officers, competitive compensation data include base pay and merit-based incentive pay comprised of both short- and long-term incentives. The data are collected and analyzed by an independent compensation consultant, Pay Governance, using peer company and survey data. Pay Governance's analysis, which is attached as Exh. MBR-5 demonstrates that the Company's compensation for officers is within the market competitive range of peer and survey data.

Q. What is the cost of utility employees' base pay for the Test Year (April 1, 2024 to March 31, 2025) and subsequent Rate Years (RY1, RY2, RY3) on a Washington-allocated basis?

A. Table 1 below provides the cost of base pay for the Test Year and the subsequent Rate Years. These amounts include only the cost for gas utility employees of NW Natural and represent the Washington-allocated base pay for FTEs.

Table 1[1]

Utility Employee Total Base Pay (Wages & Salaries) – Washington-Allocated ($000)

	Wages and Salaries Costs			
Employee Type	**Officers**	**NBU**	**BU**	**Total**
Test Year (restated)	$691	$9,352	$7,032	$17,075
Pro-Forma: 8/1/25-7/31/26	$735	$10,040	$7,593	$18,368
Rate Year 1: 8/1/26-7/31/27	$771	[redacted]	$8,046	[redacted]
Rate Year 2: 8/1/27-7/31/28	$808	[redacted]	$8,523	[redacted]
Rate Year 3: 8/1/28-7/31/29	$846	[redacted]	[redacted]	[redacted]

Q. Does the Company propose to adjust the actual Test Year base pay levels?

A. Yes. As described below, the Company has adjusted actual Test Year base pay amounts to reflect annualizations of past pay increases, as well as known and measurable increases after the end of the Test Year.

Q. How did NW Natural determine the cost of base pay in Table 1 for NBU employees and officers in the Test Year and the Rate Years?

A. For NBU employees and officers, we adjusted Test Year base pay to annualize the increase that occurred on March 1, 2025. For each subsequent rate year, we also adjusted base pay to account for the wage increase of [redacted] planned annually for March 1st (2026, 2027, 2028 and 2029). This reflects a [redacted] to reflect promotions and equity adjustments. The percentages were derived using the pay movement of competitor companies as provided in compensation trend surveys. The additional percentage for promotions and equity adjustments was determined based upon past experience and compensation trend surveys. See confidential Exh. MBR-6C.

[1] See confidential Exh. TFD-2C, tab "Restating FTE & Pay Increase" for calculations.

Q. How did NW Natural determine the cost of base pay in Table 1 for BU employees in the Test Year and the Rate Years?

A. The Company adjusted BU payroll costs to reflect the CBA's 4.00 percent wage increase effective December 1, 2025, 2026 and 2027. The current CBA runs through May 31, 2028. For this proceeding in which Rate Year 3 goes beyond this date, the Company assumed the [redacted] adjustment would apply on December 1, 2028. In addition, on top of the wage increase, the Company applied an additional 1.05 percent for each year of the CBA to account for promotions and movements from entry rate to experienced rate as described in the CBA. For Rate Year 3 that goes beyond the term of the CBA, the Company used the [redacted] adjustment to account for such promotions and movements.

IV. MERIT-BASED INCENTIVE PAY

Q. In describing competitive total compensation, you stated that merit-based incentive pay is an important component. Please define what you mean by this term.

A. Merit-based incentive pay is compensation made to employees only if certain performance goals are met within a defined timeframe. Merit-based incentive pay is not guaranteed for employees and is intended to foster high performance. It represents an essential part of competitive total compensation, as it is necessary for NW Natural to compete in the job market to attract and retain the employees that it requires to run its utility business.

Q. Is merit-based incentive pay compensation a standard practice in your industry?

A. Yes, merit-based incentive pay is widely employed by our competitors for labor, and is expected by the professional workforce. Therefore, we believe we need to provide merit-based incentive pay (at different levels depending on the employee's position) in order to compete and meet pay expectations of the workforce. Merit-based incentive pay is preferred by organizations, rather than adding this pay directly to base pay. For general industry on average, 78 percent of companies have at least one incentive plan. See confidential Exh. MBR-7C.

Q. Does NW Natural's merit-based incentive compensation result in above-market median total compensation?

A. No, it does not. As a regulated utility, NW Natural recognizes the importance of balancing fiscal responsibility with the need to attract, retain, and motivate a skilled workforce capable of delivering safe, reliable, and cost-effective utility services. Our annual incentive compensation programs are a key component of our total rewards strategy and are designed to align employee performance with corporate operational goals and objectives that ultimately benefit customers.

Our merit-based incentive compensation is a component of total compensation, which is targeted to align with market median total compensation. In other words, if NW Natural did not provide merit-based incentive pay, its total cash compensation would be below the market median. Without the opportunity to receive this pay, total cash compensation would be below the comparative market.

Q. Is merit-based incentive pay provided at the same level for all employees?

A. No. To be consistent with competitive market pay practices, targets are differentiated by employee level. Generally, the market practice is to provide higher levels of at-risk compensation to officers, directors, and managers who may have a broader influence on Company activities. See confidential Exh. MBR-8C. Table 2 below represents the pay-at-risk for our short-term incentive program for NBU employees.

Table 2
Short-Term Incentive Merit-Based Incentive Pay

Incentive Program Type	Participants	Target Percent of Pay	Amount Requested in RYs as Percent of Pay
NBU Short-Term Incentive	All NBU employees (excluding officers)	7.5 percent-20 percent depending on level	7.5 percent-20.0 percent

Q. Please briefly summarize the merit-based incentive pay that NW Natural is seeking to recover in this proceeding.

A. NW Natural is seeking to recover the costs to two merit-based pay incentive programs. The first program is designed for NBU non-officer employees, called the Goals Incentive Program. The second program is for officers, called the Executive Annual Incentive Plan.

Q. Please describe the Goals Incentive Program that is designed for NBU non-officer employees.

A. The Goals Incentive Program recognizes and rewards NBU employees who have demonstrated strong individual performance and rewards those NBU employees who achieve or exceed their annual performance objectives. These performance objectives include an operational component with the following goals: (1) customer satisfaction,

(2) Company growth, and (3) public safety and employee safety, with each described in more detail as follows:

- Customer satisfaction has two components—satisfaction with the Company as a whole, and satisfaction with employee interaction. Both are measured by customer surveys. NW Natural employees further customer satisfaction by providing efficient, courteous, and knowledgeable service in customer interactions. Customers benefit from employee behavior that increases customer satisfaction.
- Company growth measures the number of new meter sets for customers. NW Natural employees contribute to this goal by providing timely hook-ups for new customers. New customers benefit when their meters are installed in an efficient manner, while existing customers benefit from growth through sharing fixed costs with an expanding customer base.
- The public safety goal has two components—damage call response time and odor call response time. Both are measured in percent of calls responded to in less than 45 minutes. Customers benefit when the Company works quickly to resolve leaks and other potentially dangerous situations.
- The employee safety goal has two components—Days Away Restricted Time ("DART" rate) and number of Preventable Motor Vehicles Collisions ("PMVC"). The DART rate is measured by percent of time away due to on-the-job injuries and the PMVC is measured by number of preventable collisions. Customers benefit from the Company emphasizing a safe working environment that reduces injuries to its employees because it helps ensure safe and timely service.

All of these operational goals promote the Company's provision of safe, reliable, efficient, and timely natural gas service and customer service to its customers.

Q. Please describe the Executive Annual Incentive Plan that is designed for officers.

A. The Executive Annual Incentive Plan is designed to reward officers who deliver results that benefit both the Company and its customers. Specifically, the Executive Annual Incentive Plan is a merit-based incentive compensation program that is designed to incentivize efficiencies that benefit the utility's provision of safe and reliable service at reasonable costs. The Executive Annual Incentive Plan is based upon three separate components: net income (50 percent), operational goals (20 percent), and individual goals specific to the officer (30 percent). Even though a portion of the Executive Annual Incentive Plan is tied to financial goals, it is important to recognize that customers benefit from, and the Commission should encourage, utilities maintaining good financial metrics.

Operational and individual goals vary by officer based on their responsibilities. An example of such goals includes ensuring smooth and timely responses to odor and damage calls. Tying merit-based incentive pay to strong financial metrics enables the utility to efficiently raise the capital necessary to operate its business at rates that are favorable to utility customers, who ultimately pay the utility's cost of capital as part of the utility's revenue requirement. See confidential Exh. BJW-1CT.

Q. What percent of an officer's total pay is "at risk" due to the merit-based incentive programs?

A. NW Natural, like other companies around the country, believes that merit-based incentive pay is important in promoting high performance among all employees,[2] and is even more critical for the officers of the Company. The amount of total merit-based incentive pay varies by officer position and competitive market practice. The chief executive officer has between 74 and 83 percent of pay-at-risk whereas other officers average between 51 and 64 percent of pay-at-risk. In all cases, the total pay-at-risk is comprised of short- and long-term opportunities.

Q. Is NW Natural seeking to recover the entire cost of its merit-based incentive programs in this proceeding?

A. No. NW Natural recognizes that the size of its proposed rate increase, especially in the first year of the multi-year rate plan, is considerable. To limit the size of this request, NW Natural is proposing to only recover the costs of its annual merit-based incentive programs—Goals Incentive Program and Executive Annual Incentive Plan. NW Natural is not seeking recovery of the long-term portion of the Company's executive compensation program that applies to officers, high-performing managers, and key employees. Under this program, qualifying executives receive two components of long-term incentive compensation: restricted stock units ("RSUs") and performance shares. RSUs are stock units that vest over time if certain retention and financial performance threshold conditions are satisfied. Performance shares are a promise of

[2] See confidential Exh. MBR-7C.

Company stock units earned if NW Natural achieves certain performance goals during a three-year cycle. Officers receive 35 percent of their long-term incentive opportunity in the form of RSUs and 65 percent in the form of performance shares.

NW Natural believes that long-term merit-based compensation is an important part of competitive total compensation for executives, drives operational and financial goals, and is a consistent practice among its peers. Nonetheless, while NW Natural believes these costs to be reasonable and prudent, it has decided to not seek recovery of these costs in this proceeding in order to limit the size of its rate request.

Q. How else is NW Natural attempting to mitigate rate impacts related to compensation in this proceeding?

A. NW Natural is proposing to recover the same amount of merit-based incentive compensation for each year of the multi-year rate plan. By not escalating these costs, NW Natural is not seeking to incorporate inflation that will almost certainly cause merit-based incentive pay to increase over the course of the multi-year rate plan.[3]

Q. What is the total cost of short-term annual incentive compensation pay for NBU employees and officers that NW Natural has sought to recover as part of its revenue requirements in this rate case?

A. That amount of cost, by employee type and Rate Year, is shown in Table 3 below. The amounts shown below are the same amounts NW Natural will be requesting for all three Rate Years of the multi-year rate plan. Importantly, as stated above, the Company is not increasing those amounts over the course of the three Rate Years.

[3] See Exh. JEN-1T ("[I]nflation is expected to remain markedly above levels experienced prior to the COVID-19 pandemic").

Table 3[4]

Washington-Allocated Utility Employee Target Merit-Based Incentive Pay ($000)

Type of Utility Employee	All Rate Years
Non-Bargaining Unit (NBU) Employees	$1,163
Officers	$301
Total	$1,464

V. MEDICAL BENEFITS

Q. Please explain why NW Natural provides its employees with medical benefits.

A. NW Natural needs to provide competitive medical benefits to its employees in order to attract and retain a skilled, reliable workforce and because medical benefits are part of the package required to get to median total compensation levels. Additionally, quality medical benefits are necessary to ensure employees are receiving good care in a timely fashion. Good and timely care prevents the development of more serious health problems that would lead to more costly claims and higher employee absentee rates. Customers depend on receiving the safe, efficient, and reliable service that can only be delivered through a healthy and present workforce.

Q. Please describe the medical benefits NW Natural provides to its utility employees.

A. The Company provides medical and pharmacy insurance to its NBU employees and officers through Regence and Kaiser Permanente. Under the CBA, BU employees receive medical and pharmacy insurance from Regence and Kaiser Permanente through the Western States Health and Welfare Trust Fund of the OPEIU, a multi-employer union trust.

[4] See confidential Exh. TFD-2C, tab "Bonuses" for calculations.

Q. How did the Company develop the medical benefits expense proposed for recovery in this case?

A. As shown in Table 4 below, the Company has included $2.3 million (Washington allocated) of medical and dental benefits costs experienced in the historical Test Year. The Company then added an expected premium increase of 9.5 percent for 2025, 9 percent for 2026, 8.5 percent for 2027, 8 percent for 2028 and 7 percent for 2029.

Table 4[5]

Medical Expense	Total in ($1,000)
Test Year	$2,333
Pro Forma: 8/1/25-7/31/26	$2,612
RY 1: 8/1/26-7/31/27	$2,839
RY 2: 8/1/27-7/31/28	$3,072
RY 3: 8/1/28-7/31/29	$3,301

Q. Has the Company taken action to manage medical costs?

A. Yes. For the 2025 plan year, NW Natural increased the deductible on the Regence PPO plan, resulting in lower costs ($85,000 on an overall, systemwide basis). Also, NW Natural changed the cost share structure of its PPO and HMO plans over a three-year period (2021 – 2023) that gradually increased the employee contribution from 20 percent to 25 percent. This change was made to both mitigate increasing health plan costs on the Company and to encourage employees to move to more cost-effective high-deductible health plans. Finally, NW Natural conducts request-for-proposals ("RFPs") approximately every five years to determine if changing insurers would be cost effective. NW Natural's most recent RFP was issued in 2021. See confidential

[5] See confidential Exh. TFD-2C, tab "Health & Life" for calculations.

Exh. MBR-9C. At that time, changing one of the Company's medical and pharmacy insurance providers for NBU employees and officers from Cigna to Regence resulted in an annual savings of $1.0 million on an overall, system-wide basis. Given these savings, NW Natural decided to offer medical and pharmacy insurance through Regence beginning in 2022.

Q. How do NW Natural's medical expenses compare with trend factors?

A NW Natural compares renewal rate increases to trend factors for the Pacific Northwest. While for four out of the last five years NW Natural's active NBU employees' medical expenses have been increasing at a rate at or below trend factors, NW Natural medical expenses have recently exceeded the regional trend. Specifically, based on periodic survey data collected by Milliman, the regional cost for NW Natural was a 7.9 percent increase in costs for 2024, nearly the same as the regional increase of 7.4 percent. For 2025, NW Natural's renewal increase is expected to be 12.3 percent compared to the regional trend of 9.5 percent for 2025. See Exh. MBR-10.

Q. What are the key factors that influence increases in medical costs?

A. The Company's medical benefits rates are greatly influenced by the medical experience of the population being insured. Regence increases rates entirely (100 percent) on our actual insured population. On the other hand, Kaiser Permanente utilizes a combination of both manual rating and actual NW Natural experience. It places 60 percent of the formula on its book of business (manual rating) and 40 percent on the actual claims of the plan participants.

In addition to claims experience, we also know that other factors impact medical costs including age, gender and family size. Based on Kaiser Permanente's and

Regence's 2024 Clinical Utilization Reports, we know that NW Natural's average age under the pre-65 covered NBU participants in 2024 was 49 years old, compared to their overall databases that indicated an average age of 40.6 for the same time period. See Exh. MBR-11. Having a higher average age means our employee base is more expensive to insure than a younger workforce and is more likely to have more serious medical issues than would be seen on average with a younger workforce. In addition, NW Natural's Kaiser plan also has dependent enrollment of 2.5 dependents compared to the overall database, which indicated an average of 1.6 dependents, and the Regence plan has a dependent enrollment of 2.4 dependents compared to the overall database of 2.0 dependents. See Exh. MBR-11. Having a higher dependent enrollment also means that our employee base is more expensive to insure.

Finally, there are external factors that impact our renewal costs each year, and in the recent years those impacts have been especially significant. Inflation has made for even higher costs on the pharmacy side and the shortage of healthcare providers has also added costs as providers renegotiate their contracts. See Exh. MBR-12.

Q. How does the design of NW Natural's medical plans compare with those of other companies?

A. In 2024, Parker, Smith & Feek completed an analysis of the Company's medical benefits in 2024 relative to 35 utilities in the Pacific Northwest through the Milliman survey. See Exh. MBR-13. In this comparison, Parker, Smith & Feek compared our medical benefits to those of the 35 regional utilities in everything from deductibles to coinsurance (premium sharing), to co-pays for office visits and prescriptions. There

was a range of ratings depending upon the specific item being rated, although the overall rating was "Equal."

Q. Why does this testimony address medical benefits and not all components of health benefits?

A. The Company focused on medical benefits (medical and pharmacy) in my testimony because those components make up 95.5 percent of the total health care costs (medical, pharmacy, dental, vision, life, and disability) and has been the area in which significant increases have been experienced in the past 10 plus years.

Q. Are the other health benefits being offered also market competitive?

A. Yes. The same survey source noted above for medical benefits also evaluated the competitiveness of other health care and welfare benefits including dental, vision, life, and disability. All the benefits plans were found to be "Equal" to the 35 utility companies provided in the Milliman survey. While there were some variations in certain categories overall, Parker, Smith & Feek's analysis of the Milliman survey indicated that NW Natural's benefits plans were substantially at market when compared to other utilities. See Exh. MBR-13.

Q. What is the total cost of medical benefits that NW Natural has sought to recover as part of its revenue requirement for the multiyear rate plan in this rate case?

A. That amount, by employee type, is shown in Table 5 below:

Table 5
Utility Employee Medical Benefits ($1,000)

Employee Type	Medical Expense by Employee type (Washington Allocated) in ($1,000)		
	NBU[6]	**BU**	**Total**
Test Year (restated)	$1,194	$1,139	$2,333
Pro-Forma: 8/1/25-7/31/26	$1,349	$1,262	$2,612
Rate Year 1: 8/1/26-7/31/27	$1,467	$1,372	$2,839
Rate Year 2: 8/1/27-7/31/28	$1,587	$1,485	$3,072
Rate Year 3: 8/1/28-7/31/29	$1,705	$1,596	$3,301

VI. RETIREMENT BENEFITS

Q. Please provide an overview of your retirement benefits.

A. Table 6 below shows the retirement benefits programs, which provide market median retirement offerings to employees:

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[6] Including officers.

Table 6
Retirement Benefits

Retirement Program	Eligible Employees	Summary Description of Benefits
Retirement K Savings Plan (401k) ("RKSP") - Employee Savings with Employer Match	All employees	Defined Contribution Savings plan with match: Match is 50 percent of first 8 percent saved by BU employee and 60 percent of first 8 percent saved by NBU employee
RKSP -Enhanced	NBU employees hired after December 31, 2006 and BU employees hired after December 31, 2009 (covers employees not eligible for pension benefits)	Contribution made by Company into "Enhanced" account-no employee contribution required Contribution is 5 percent for NBU; 4 percent for BU
NW Natural Pension Plan for BU and NBU Employees (NW Natural Retirement Plan) (closed)	Non-bargaining (NBU) and Bargaining (BU) employees	Defined benefit plan that was closed to new NBU employees hired after 12/31/06 and BU hired after 12/31/09.

Q. Are there significant changes that NW Natural has made since the Company's last rate case?

A. No. The Company is proposing no changes to retirement benefits for this case.

Q. How do NW Natural's retirement benefits compare to the benefits provided by other companies?

A. In 2024, the Company asked Parker, Smith & Feek to analyze the Company's 401(k) defined contribution retirement benefits relative to other utilities. Based on data from the Milliman survey, NW Natural's 401(k) defined contribution match benefits were found to be "Equal" for BU and NBU employees when compared to the Utility

database. The Enhanced 401(k), for those hired after the Pension Plan was closed, was found to be "Worse" when compared to the Utility database. See Exh. MBR-13.

Q. Please explain the total retirement benefits included for recovery in this rate case.

A. Table 7 below shows the amount requested for recovery for retirement benefits in the Test Year. The Company is not proposing to escalate the historical Test Year amount over the course of the multi-year rate plan. Instead, the Company is seeking to recover the same amount for each of the Rate Years.

Table 7[7]
Utility Total Retirement Benefits– Washington-Allocated ($000)

Component	Test Year
RKSP-Matching Contribution	$697
RKSP-Enhanced Contribution	$516
Western States Pension-withdrawal liability	$63
Total	**$1,276**

VII. EMPLOYEE HEAD COUNT

Q. Is the Company proposing to adjust FTE count for the Rate Years 1, 2 and 3?

A. Yes. Table 8 below shows System level FTEs the Company proposed to include in each of the Rate Years.

[7] See confidential Exh. TFD-2C, tab "401k" for calculations.

Table 8[8]

	Officers	NBU	BU	Total
Test Year (restated)	**13**	**648**	**618**	**1,280**
Pro-Forma: 8/1/25-7/31/26	**13**	**654**	**624**	**1,290**
Rate Year 1: 8/1/26-7/31/27	**13**	**660**	**629**	**1,302**
Rate Year 2: 8/1/27-7/31/28	**13**	**666**	**635**	**1,314**
Rate Year 3: 8/1/28-7/31/29	**13**	**672**	**641**	**1,326**

Q. How did NW Natural calculate the number of FTEs for the Test Year.

A. NW Natural calculated the number of FTEs that NW Natural employed during at the end of the Test Year—1,280 on a systemwide level.

Q. How did NW Natural adjust the number of FTEs over the course of the multi-year rate plan?

A. For pro forma adjustments to the number of FTEs, NW Natural examined near-term hiring expectations through July 31, 2026, to arrive at the number of FTEs it expects to have during that time. For adjustments to the number of FTEs each rate year, NW Natural estimated the number of FTEs it would have based on its experience in recent years. This experience indicates relatively small but sustained growth in the number of NBU and BU employees throughout the multi-year rate plan. We expect the number of officers to remain constant during this time, however.

[8] See confidential Exh. TFD-2C, tab "Restating FTE & Pay Increase" for calculations.

Q. Is NW Natural seeking recovery of employees' compensation and benefits based on the FTE amounts for each Rate Year?

A. Yes. NW Natural is seeking cost recovery of employees' compensation and benefits based on the gas utility FTEs that NW Natural projects to have in each Rate Year, as explained in the confidential Direct Testimony of Tobin F. Davilla (Exh. TFD-1CT). Since the Company serves customers in Washington and Oregon, it allocates a certain percentage (approximately 11.12 percent) of its employees' compensation and benefits costs to Washington. Cost allocation between Washington and Oregon is further explained in the Direct Testimony of Kyle T. Walker (Exh. KTW-1T). All employees' compensation and benefits costs referenced in this testimony reflect Washington-allocated values.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

VIII. LIST OF EXHIBITS

Exh. MBR-2C	Market Data Analysis (Confidential and Redacted)
Exh. MBR-3	2024 Base Pay Analysis
Exh. MBR-4	Collective Bargaining Agreement
Exh. MBR-5	Pay Governance Total Remuneration
Exh. MBR-6C	NBU Regional Merit and Structure Awards (Confidential and Redacted)
Exh. MBR-7C	Incentive Plan Prevalence (Confidential and Redacted)
Exh. MBR-8C	Market Data for Goals Incentives (Confidential and Redacted)
Exh. MBR-9C	2021 Medical RFP (Confidential and Redacted)
Exh. MBR-10	Milliman 2024 Benchmarking Data: Medical Renewal Increases
Exh. MBR-11	Kaiser and Regence 2024 Demographic Benchmarking Data
Exh. MBR-12	Medical Renewal Trend Report
Exh. MBR-13	Milliman 2024 Benchmarking Data

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Melinda B. Rogers

COMPENSATION & BENEFITS

Exh. MBR-2C

REDACTED VERSION

August 29, 2025

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY (PAGES 1-38)
UNDER WAC 480-07-160 AND HAS BEEN REDACTED.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Melinda B. Rogers

COMPENSATION & BENEFITS

Exh. MBR-3

August 29, 2025

Base Pay Analysis

2024 Salary Structure - Base Pay Analysis

2024 Salary Structure		
NWN Grade	NWN 2024 Midpoint	NWN Midpoint vs. Market Median
14	$62,500	108.9%
15	$67,500	104.5%
16	$72,900	103.1%
17	$79,450	101.3%
18	$86,600	101.9%
19	$94,400	101.7%
20	$104,800	101.6%
21	$116,350	101.7%
22	$130,300	100.5%
23	$145,950	98.5%
24	$163,450	99.5%
25	$183,050	104.3%
26	$205,000	103.1%
	Overall	**102.3%**

Data Source: NW Natural Market Analysis 2023 for 2024

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Melinda B. Rogers

COMPENSATION & BENEFITS

Exh. MBR-4

August 29, 2025

Collective Bargaining Agreement

A vested interest in a successful future.

NW Natural®

Effective: June 1, 2024 – May 31, 2028

2024 Collective Bargaining Agreement
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COLLECTIVE BARGAINING AGREEMENT

THIS COLLECTIVE BARGAINING AGREEMENT, hereinafter called "Agreement," is entered into on June 1, 2024, between NORTHWEST NATURAL GAS COMPANY, a corporation, its successors or assigns, hereinafter called "the Company" or "the Employer," and OFFICE AND PROFESSIONAL EMPLOYEES INTERNATIONAL UNION, LOCAL 11, AFL-CIO, hereinafter called "the Union," collectively referred to as "the parties," to promote a balance between the needs of the employees and those of the Employer while fostering an environment of mutual respect and cooperation.

COLLABORATIVE MISSION STATEMENT

The Union and the Company will work together to:

- Achieve collaborative and transparent relationships at all levels of the organization;
- Resolve concerns at the lowest level possible;
- Foster an environment in which employees are valued and supported in their development, engagement and success; and
- Promote NW Natural's core values and continued success.

ARTICLE 1
GUARANTEES AND FLEXIBILITY

Section 1.1 Introduction

To support our ability to acquire and serve customers, and to outperform our competitors, thereby promoting employment security and enhancing job opportunities, the parties share responsibility for developing and rewarding a flexible and skilled work force. To successfully compete requires the ability to quickly adjust our products, services and processes.

Section 1.2 Flexibility

The parties agree that during the term of this Agreement, the Company has the flexibility to redesign and change its business operations, the work and the workforce. In exchange, the Company agrees that certain employees shall have Employment Security and Pay Guarantees, as defined in Section 1.4 and Section 1.5 of this Article.

Section 1.3 Involvement

It is the Company's right and responsibility to make business decisions, including such matters as redesigns, changes in business operations, the work and workforce. The Company acknowledges its obligation to bargain employee impacts with the Union.

The Company will meet quarterly with Union Representative to review the number of contractor personnel working, the type of work performed, and the current and projected workload to discuss the feasibility of increasing the bargaining unit work force or using overtime when practical and economical as an alternative.

Section 1.4 Employment Security

1.4.1 The parties agree that during the term of this Agreement there will be no layoff of any regular employee whose current period of employment was on or before May 31, 2023. Probationary and Term Employees are not eligible for employment security.

1.4.2 Employees without employment security are subject to layoff for any reason. However, the Company will not contract work to others that would cause employees with employment security to be laid off. The Company will eliminate individual, third-party contract workers, and temporary and Term employees who are performing the same bargaining unit duties in the impacted location and workgroup prior to laying off full or part-time employees. This excludes elimination of contract workers doing non-routine work that customarily uses contractors. Non-routine work performed by contractors will be reviewed by the parties to determine if regular employees can perform the work before laying off full or part-time employees.

1.4.3 The Company agrees to meet with the Union if it is considering laying off bargaining unit employees for any reason.

Section 1.5 Pay Guarantee

Pay for regular employees in jobs that are affected by work redesign, regional lack of work, or certain disability situations, will be guaranteed at no less than their current rate of pay, as provided for in Section 11.4 within this Agreement.

ARTICLE 2
GENERAL PROVISIONS

Section 2.1 Application and Coverage

2.1.1 Definition of Bargaining Unit

This Agreement applies to and covers NW Natural Gas Company individuals who are employed in the jobs shown in the Job Titles by Group list of this Agreement. The terms of this Agreement do not extend to any NW Natural affiliate.

2.1.1.1 It is not the intent to have Supervisors perform the job duties of bargaining unit employees except in circumstances such as training, testing, inspection(s)/QA, a threat to public safety or emergency (e.g., inclement weather, volcanic eruption, earthquake, hazardous material release, or other natural or man-made disaster or employee absenteeism; excluding scheduled PTO), or in occasional circumstances where needed to support the continuity of local business operations.

2.1.1.2 The Parties agree to a standard process by which all new jobs will be evaluated for inclusion in the bargaining unit.

- This process applies to newly created jobs that do not exist at the Company as of June 1, 2024. This does not apply to the creation of additional numbers of existing jobs (or positions). The Parties will consider the definitions which describe inclusion as a bargaining unit position in the National Labor Relations Act (NLRA) found on the website www.nlrb.gov.

- New jobs at these levels are excluded from possible inclusion in the Bargaining Unit: Executives, Directors, Managers, and Supervisors with direct reports as well as jobs that require advanced formal education (e.g., Financial Analysts, Attorneys, Human Resource Professionals). New jobs involving a high level of confidentiality will be excluded from consideration. Company-sensitive strategic, financial, and working with private individual employee data are examples of types of confidentiality.

- The Company will meet with the Union to review its analysis of the new jobs and to obtain the Union's input following the requirements of

2.1.1.2 of this agreement. However, it is ultimately the Company who will make the decision as to whether the new jobs should be included in the bargaining unit and will inform the Union of the final decision. If the Union disagrees with the Company's decision, they may pursue any avenue already available.

2.1.2 Employee and Other Worker Definitions

2.1.2.1 Employee

An employee is a common-law employee of the Employer whose job is within the bargaining unit as defined in 2.1.1 to this Article.

2.1.2.2 Regular Employee

A regular employee is an employee who is employed by the Employer to work on a full or part-time basis.

- A Full-Time regular employee is a regular employee who is employed by the Employer to work an average of forty (40) or more hours per work week.

- A Part-Time regular employee is a regular employee who is employed by the Employer to fill a continuing work requirement that averages less than forty (40) hours per work week.

- A Job-Share employee is a part-time regular employee who is employed by the Employer to share the responsibilities of one (1) full-time position with one (1) other job-share employee.

    - The incumbent in a job-share position will have a share of a full-time position determined by Management to be appropriate for a job-share arrangement.

    - Both job-share employees must meet the bidding and performance qualifications for the shared position.

    - Work schedules will be agreed to between the job-share employees and will be subject to approval by the workgroup Supervisor.

    - When a job-share vacancy occurs, the position will be first posted as a job-share arrangement. If the job-share vacancy cannot be filled from the posting, then the remaining incumbent will be offered a full-time position. If that is refused, a full-time position will

be posted. The remaining incumbent will then be placed into redeployment.

2.1.2.3 Probationary Employee

A Probationary Employee is a newly hired or rehired employee in their first year of employment (three hundred and sixty-five [365] calendar days) with the Company. Probationary employees who are regular employees retain all rights and benefits of regular employees under the Collective Bargaining Agreement; except as limited in 4.3.2 and Section 20.1 within this Agreement.

Probationary employees who are term employees retain only the rights and benefits provided to term employees.

If a probationary employee uses protected leave for thirty (30) calendar days or more, the Company may exercise its sole discretion to extend the employee's probationary period by the same number of calendar days.

2.1.2.4 Term Employee

A Term Employee is an employee engaged for a limited duration to complete a special project as specifically defined in their Term Employment Agreement. An Intern is a type of employee hired for a limited duration to work in a structured internship program as a BU Term Employee as specifically defined in their Term Employee Agreement. Term employees have only those benefits and rights expressly defined in their Term Employment Agreement.

- The Company will not hire Term employees for the purpose of replacing or restricting the hiring of regular employees for ongoing work. The Company will ensure that Term positions do not limit the advancement opportunities of regular employees. Unless mutually agreed by the LMC Co-Chairs, the duration of a Term position shall not exceed twelve (12) months.

- Term employees do not have regular employee bidding rights. When seeking a regular position, term employees will be considered as external applicants and will be required to complete the full external bargaining unit selection process even if they are seeking a position involving the same type of work as that done while a Term employee.

- Term employees shall be provided the benefits of regular employees only as defined in the Term Employee Agreement.

2.1.2.5 Temporary Worker

A temporary worker is an external agency worker engaged for an assignment lasting for one hundred and eighty (180) or fewer calendar days. Temporary workers are not employees of the Company and do not have Union membership rights or employee benefits. Any extension of a temporary worker on the same assignment beyond one hundred and eighty (180) calendar days requires the mutual agreement of the Parties. The Company may not rotate temporary employees into the position or assignment where there is a need to create a regular position and hire a regular employee.

Any person working in a position covered by this Agreement as a temporary worker must obtain a working permit from the Union after each thirty (30) days worked.

2.1.3 Union Security and Recognition

The Company recognizes the Union as the exclusive bargaining agent for all employees who are classified by the Company in the Job Titles (Schedule A) covered by this Agreement.

2.1.4 Union Membership Requirements

It shall be a condition of employment that all employees covered by this document shall pay dues to OPEIU Local 11, and all new employees shall, on the last calendar day of the month following the beginning of such employment, begin payment of dues and such initiation fee as is customary to the Union.

Upon receipt of a written request signed by an employee, the Company will deduct and remit to the Union dues and other fees from the pay of the employee once in each month and an accounting for such deductions. Such form will be provided by the Union.

In case any Employee shall fail to tender the initiation fee and periodic dues uniformly required as a condition of acquiring or retaining membership (which payment of fees and dues shall be a condition of continued employment), the Union will notify the executives responsible for labor relations. A Company representative will then notify the delinquent employee in writing by the end of their next workday that, unless the executives responsible for labor relations receive from the Union office notification of the employee's tender of required dues, the employee will be terminated within the next ten (10) working days.

Section 2.2 Management Rights

The Company retains all rights to manage its business and direct its work force, except as those rights are limited by the express and specific language of this Agreement. The Company's rights include, but are not limited to, the right and flexibility to redesign and change its business operations, the work and the workforce; determine the number and nature of positions needed across the Company and by work location; protect and preserve Company property; open and close work locations; contract work*; set schedules; assign and direct work; define work duties, including duties performed within any job description or job family; implement and utilize existing and new automation and technologies; and require that work be performed, including overtime.

*It is the intent and preference of the Company to use women and minority-owned contractors as well as utilize Union contractors whenever practical.

Job descriptions will be maintained for all jobs and positions in the bargaining unit. The Company has the right to change and create jobs and position descriptions. If requested by the Union, the Parties will meet to discuss and determine the impacts to the bargaining unit.

Management's right to contract work out is further described in Section 1.4 within this Agreement. While it is Management's right and responsibility to make business decisions, it is agreed that the Company will discuss the impact of the Company's decision on employees as described in Section 1.3 within this Agreement.

Section 2.3 No Strike, No Lockout

There shall be no strike, work stoppage, work slowdown, sympathy strike, lockout, or other interruption of work during the life of this Agreement. The Union shall take every reasonable means within its power to prevent such occurrences and induce employees engaged in or supporting any such prohibited conduct to cease such activity.

Any member of OPEIU Local 11 employed by the Company who recognizes a lawful primary picket line sanctioned by OPEIU Local 11 shall not be disciplined for recognizing that picket line, notwithstanding the provisions of this Article, provided that such employee shall have no greater rights under law or contract than does a striking employee.

Section 2.4 Union Member Time Off

The Union's Stewards shall be allowed time off with pay to investigate and present issues/grievances as necessary to fulfill their duty of fair representation. Whenever possible, such time shall be scheduled in advance with the Steward's Supervisor to minimize the impact on business operations.

The Parties shall meet with the Union Stewards and Management representatives after the ratification of this Agreement to provide joint training on all modifications of this Agreement.

Upon written request from the Union, members shall be given short-term leaves of absence to transact Union business and be paid by the Union. An employee covered by this Agreement who is elected, appointed or hired to an office in the Union requiring a long-term leave of absence from the Company, shall, upon two (2) weeks' written notice, be granted a voluntary leave of absence without pay not to exceed two (2) years.

Section 2.5 Union Bulletin Boards

The Company will make available space on its bulletin boards for the posting of Union notices and bulletins.

Section 2.6 Compliance with Laws Governing the Workplace

The Union shares the Company's commitment to maintaining a business in compliance with all applicable laws governing the workplace, ensuring an environment free from discrimination, harassment or retaliation and supporting business and workplace decisions promoting diversity.

The Company agrees not to discriminate or retaliate against any member of the Union for their activity on behalf of or because of membership in the Union.

The Company promptly investigates and addresses complaints regarding discrimination, retaliation, or harassment. The Union recognizes the importance of the prompt and effective investigation and resolution of such complaints and will support and cooperate with the Company in the Company's investigation and resolution of such complaints.

Section 2.7 Modifications and Agreements

2.7.1 The Parties with mutual agreement have the right to renegotiate the Agreement in the event there are external events or significant business changes which in the opinion of either party require renegotiation of the Agreement. Amendments to this Agreement are made by a Memorandum of Agreement (MOA), must be in writing, agreed to, and signed by both parties.

The language described above does not have the intention of opening the entire Collective Bargaining Agreement for negotiations.

2.7.2 Interpretations regarding this Agreement are outlined and assigned at the direction of the LMC Co-Chairs. This assignment shall be given to bargaining unit members, management, and subject matter experts; who shall review the contract language and clarify the intent within the Agreement; and which shall be submitted to the Company and Union Leadership for approval.

2.7.3 A Memorandum of Agreement is a written document signed by both the Union and the Company Executive Sponsors that states what the Union and the Company agree to when they reach agreement on something other than what is stated within the Collective Bargaining Agreement. Memorandums of Agreement can

remain in effect for the duration of the current Agreement or may be limited to a specific period of time, or incorporated into the Collective Bargaining Agreement upon opening for negotiations.

2.7.4 Except as expressly noted otherwise, this Agreement supersedes all prior CBAs, Joint Accords, Joint Accord Guidelines (JAGs), Interpretations, and Memorandums of Agreement. To the extent the terms of this Agreement were to conflict with any other agreement, the terms of this Agreement control.

Section 2.8 Labor/Management Committee

The Labor/Management Committee or LMC shall be organized for the purpose of addressing contract issues, clarifying the intent of the labor contract, monitoring for unanticipated consequences of the labor contract and anticipating change. The LMC will consist of up to ten (10) members from the Union and ten (10) members of from the Company. Members are inclusive of the LMC Leadership Team, Management employees, Stewards, and Chief Stewards. The Committee shall meet monthly at a mutually agreed location, time, and date, and with an outlined agenda set by the LMC Co-Chairs. Meetings may be cancelled by the mutual agreement of the LMC Co-Chairs. The Committee shall consider only those contract issues which are mutually agreed upon or otherwise designated in the contract.

ARTICLE 3
SENIORITY

Section 3.1 Company Seniority

Company seniority is established on the date of hire or rehire as a regular employee. When multiple regular employees are hired on the same day, Company seniority is then established based on name at date of hire in ascending alphabetical order of last name, then first name.

Any previous regular employee who was separated due to disability (industrial or non-industrial) and is subsequently awarded or placed in a position under Article 15 within this Agreement is eligible for adjusted seniority abridgement of Company seniority.

Section 3.2 Job Seniority

Job seniority is based on the days that a particular job is held. When multiple regular employees have the same number of days the job was held, the ranking will be based on Company seniority. Job seniority is only accumulated for jobs that are not in a Line of Progression.

Section 3.3 Line of Progression Seniority

Line of Progression seniority is based on the days that any job within that Line of Progression is held. When multiple regular employees have the same number of days in the Line of Progression, the ranking will be based on Company seniority. For jobs in a Line of Progression, job seniority is not accumulated.

Section 3.4 Term and Intern Employee Seniority

3.4.1 Term and Intern Employees do not accrue seniority while in Term employment status; however, if subsequently hired as a Regular Employee with no break in service, Company Seniority will be established on the date of hire as a Term or Intern Employee.

3.4.2 Job or Line of Progression seniority (as applicable) is calculated for positions involving the same type of work as that done as a Term or Intern Employee.

Section 3.5 Job and Line of Progression Seniority Accumulation

Accumulation of seniority is based on straight-time days of employment. For full-time regular employees, this is equivalent to five (5) eight-hour workdays per seven (7) calendar days. For part-time regular employees, seniority will be accumulated at seventy-five percent (75%) of the rate of full-time regular employees.

Section 3.6 Seniority Retained

Seniority accumulated by a regular employee in a job or in a Line of Progression is retained. Any employee who leaves the bargaining unit or ends employment will not retain any job, Line of Progression, or Company seniority. Any previous regular employee who was separated due to disability (industrial or non-industrial) and is subsequently awarded or placed in a position under Article 15 within this Agreement is eligible for adjusted seniority abridgement of Company seniority.

Section 3.7 Application of Seniority

For the application of seniority, refer to the appropriate articles within this Agreement.

Section 3.8 Line of Progression and Job Seniority Calculations

The process of seniority calculations related to the definitions under this Agreement shall be as follows:

3.8.1 Name changes after the date of hire will not impact a regular employee's seniority ranking or subsequent seniority calculations.

3.8.2 Regular employees who receive a fourteen (14) calendar day award will earn seniority in both the new job and the old job until they start in the new job.

3.8.3 Regular employees who hold a Combo Position earn seniority in each distinct job that makes up their Combo Position.

3.8.4 Regular employees who fail to qualify for a job for reasons within their control (e.g., bidding to another job or failing to qualify) will not earn any seniority for that job.

3.8.5 Regular employees on a Long-Term Special Assignment (LTSA) earn seniority in the temporary job and continue to earn seniority in their regular job.

3.8.6 Regular employees on a Short-Term Assignment only earn seniority in their regular job.

3.8.7 Regular employees on a Temporary Development Opportunity (TDO) do not earn seniority in their regular job.

3.8.8 During a leave of absence, a regular employee will continue to earn seniority.

3.8.9 A temporary, unplanned reduction in work resulting in an interruption of paid status will not interrupt a regular employee's seniority calculation.

3.8.10 Regular employees in redeployment due to a work redesign or a bump will continue to earn seniority in the job from which they were redeployed until they secure a new regular job.

3.8.11 Positions that become obsolete or honored will be mapped to a current job or Line of Progression and applicable seniority credited to regular employees who hold those positions accordingly.

3.8.12 Regular employees who exercise a right to return will not earn seniority in either the new job or the old job to which they return for the duration of the transfer to the new job in accordance with Article 4 within this Agreement.

ARTICLE 4
SELECTION AND ASSIGNMENT

Section 4.1 General

This Article describes the selection and assignment provisions and processes for regular employees. Term employees are not eligible for these provisions or processes, as explained in the Term Employee Agreement.

Section 4.2 Definitions

All bargaining unit job descriptions, including general task bars, will be maintained by the Company. The Company has the right to change and create job descriptions. Upon completion, the Company will notify the Union of substantive changes to existing job descriptions and newly created job descriptions. Substantive changes will follow the review process outlined in Section 11.3. All job descriptions and General Task Bars are made available on the Company intranet site.

- Job: A paid role of employment.

- Job Title: Describes the occupation, function, and, if applicable, the level of a job if part of a larger job family.

- Job Description: Written documentation of a job title that may include general purpose, job requirements, position specific essential functions, and requirements for a particular job.

- Job Family: A group of jobs that are related because of similar job content, skill requirements, and/or career paths.

- General Task Bar: A list of tasks that everyone in a Job Family can be expected to perform, with training, as needed.

- Position: Role within the organization that is assigned a job title and used for headcount management. All employees are assigned to a position and job title.

Section 4.3 Postings and Consideration of Bids

4.3.1 When a position has been approved, the position will be posted Company-wide for seven (7) calendar days. Open and available positions are posted on the Company's intranet. It is every employee's responsibility to check the intranet on a regular basis for postings upon which they may want to bid. The intranet shall be available to access at all resource centers or remotely on the Company device/application.

4.3.2 All applications received from regular employees* prior to the expiration of a posting shall be considered in accordance with the Position Posting and Bidding Company policies, processes and procedures. Probationary employees will only be allowed to apply as external candidates.

*Regular employees already in the Construction line of progression at the resource center where a posted position in Construction is located are considered auto-bidders and automatically included in the bidding process. If an auto-bidder declines an award, must sign a Progression Waiver (existing rate retention will be forfeited). When bidding between Distribution and Transmission Construction, auto bidding does not apply.

4.3.3 The internal bidding and selection process applies for bidding and/or selection of non-probationary regular employees to fill regular, term and Long-Term Special Assignment (LTSA) bargaining unit positions that have been approved by the Company. This process applies to the bidding and selection process for non-probationary regular employees bidding on internal bargaining unit positions. This process is also used to determine if displaced employees meet bidding qualifications when being assigned/placed into a bargaining unit position through redeployment and/or when an employee is bumping into a position.

4.3.4 The Parties agree to use and continue to refine the currently agreed to internal bidding and selection processes as outlined in the Internal Bidding and Selection Process Company policies, processes and procedures.

4.3.5 Employees who are off on Paid Time Off (PTO), Short-Term Disability, Long-Term Disability, Workers' Compensation, unpaid active status, or protected leave as defined under Federal, State or local law; or by Company policy for an entire posting period shall be eligible to submit a bid on any posted position within the seven (7) calendar days following the expiration of the posting period in accordance with the Position Bidding and Award Eligibility for Regular Employees Company policies, processes and procedures.

Section 4.4 Position Awards

Seniority and qualifications will be considerations in awarding a posted position. With agreement between the Parties, certain positions will be awarded based on qualifications first and then seniority. Bidders will be considered for posted positions regardless of their currently assigned Company-based location except as provided for in Section 4.9 of this Article.

Position awards will be published within fourteen (14) calendar days of acceptance by the employee. Employees will be moved to the new position as soon as possible, usually within twenty-one (21) calendar days of accepting the award.

- Extensions to the above timelines from twenty-two (22) calendar days up to a maximum of one hundred and twenty (120) calendar days may be made after discussion with the employee and upon mutual agreement between the releasing and receiving Supervisors.

- Employees not in the new position after fourteen (14) calendar days from the position award will receive any applicable pay increases and begin accumulating either Job seniority or Line of Progression seniority as of the fourteenth (14th) calendar day from the employee’s acceptance of the award.

The following are the principles that apply when awarding positions for: Open Jobs, Line of Progression Jobs, and Jobs involving Progression without Bidding (unless otherwise agreed that the position is selected on qualifications first and then seniority).

4.4.1 Open Positions

An open position is one that, if posted, all regular employees are eligible to bid. These positions do not include those within a Line of Progression or Progression without Bidding except at the entry level. Qualified bidders will be awarded positions based on seniority in the following order:

- Job seniority for the position posted for bid, then
- Company seniority.

4.4.2 Line of Progression (LoP) Jobs

A LoP is a sequence of specifically related jobs that require successively higher skills to advance sequentially to the next higher position. The following are the currently recognized LoPs:

- Construction (2, 3, 4)
- Customer Field Service (2, 3, 4)

LoP jobs may be added to, or removed from, or changed with mutual agreement of management and the Union during the life of the contract.

Qualified bidders will be awarded positions based on seniority in the following order:

- Line of Progression seniority in the line of the position posted for bid, then
- Company seniority.

Advancing in a LoP requires that a regular employee meet all the qualifications, certifications, and training for the current level prior to being eligible to move into a vacant and available position at the next level. Regular employees in a LoP earn days toward rate retention when they work up.

4.4.3 Qualification Based Progression

Certain jobs are posted based on business need and awarded based on qualifications regardless of Company, Job, or Line of Progression seniority. Additional jobs may be added to the qualifications based process by mutual agreement between management and the Union. The parties agree that when filling vacancies or promotional opportunities, the goal is to encourage growth and opportunity for advancement from within and to hire the most qualified candidate for the position. When, in the judgment of the hiring manager and Human Resources Department, sufficient candidates who apply from within the Company are qualified, available and interested, the recruitment may be restricted to internal candidates.

The current jobs are:

- Accounting 4
- Customer Service 4
- Construction 4
- Customer Field Service 4
- Gas Storage 1
- General Services 4
- Transportation 3
- Transportation 4
- Welding & Fabrication 4

4.4.4 Jobs Involving Progression without Bidding

Employees will progress based on meeting the qualifications and performance standards for the higher-level job. Jobs may be added to, removed, or changed by mutual agreement between management and the Union. Progression may be limited by position availability. In this case, the most senior qualified person will progress, based on seniority in the following order:

- Job seniority in the lower position, then
- Company seniority.

The jobs involving Progression without Bidding are:

- Accounting = Accounting 2 to 3
- Account Services = Accounting 2 to 3
- Customer Field Service 2 to 3 in Astoria / Warrenton, Coos Bay, The Dalles, Lincoln City
- Customer Service 2 to 3
- Distribution Arc Welder 1 to 2
- Electronic Technician 1 to 2
- Gas Storage 1 to 2
- GIS Tech 1 to 2; 2 to 3
- Specialty Construction 1 to 2
- System Operations 1 to 2
- Technical Coordinator 2 to 3
- Transmission Maintenance 1 to 2
- Transportation 1 to 2

Some of the above workgroups have specific rules for progression without bidding. In the absence of such rules, the default criteria for progression will be the accumulation of working two hundred and sixty (260) days at the higher-level position with satisfactory performance.

4.4.5 Qualifying Standards

An employee awarded a new position must satisfy the Performance Qualifying Standards during the established qualifying period per Article 5 within this Agreement.

Section 4.5 Right to Return to Former Position

Employees have sixty (60) calendar days after reporting to a new and different position to voluntarily return to their former position. This right provides a one-time ability to return for any reason. An employee wanting to return to a former position must have previously qualified in order to return to that position. Any subsequent request to return to their former position within a rolling five (5) year period from the date of award must be mutually agreed upon by the

Parties. Employees who exercise their right to return within five (5) workdays will not be subject to the five (5) year restriction. An employee may relinquish their right to return at any time. Written notification will be sent to Human Resources (Talent Acquisition).

An employee still retains the right to bid on any position posting at any time. The employee will not continue to accumulate Job or Line of Progression seniority while they are away from the former position.

Right to return to former position does not apply to situations where movement is to the same position at any location.

Section 4.6 Waivers

A waiver is a mechanism for an employee to voluntarily return to a former position or to forego advancement. In all cases of waiver, the employee will be paid the applicable rate for the position waiving into, and is waiving rate retention and all days currently earned towards rate retention.

In a Lack of Work situation, restrictions on returning to a waived position are removed. There are two (2) types of waivers: Progression (Advancement) Waivers and Position Waivers. The waiver definitions and processes are as described herein.

4.6.1 Progression (Advancement) Waiver

An employee elects to forego advancement (move up and/or work up). An employee who waives advancement is also waiving working up. When exercised, the employee waives the right to advance to a specific opening, but does not waive the right to advance should a subsequent posting/work-up opportunity occur. For convenience, this waiver is considered in effect until “pulled” by the employee (by notifying their Department and Human Resources in writing). For Progression Waivers related to a declined auto-bid award, there is a minimum of one (1) year term before the waiver can be pulled. There is no duration requirement for other Progression Waivers.

4.6.2 Position Waiver

An employee elects to vacate a position to return to a lower rated position at the same resource center for which they previously qualified. A Position Waiver has a minimum one (1) year term. After one (1) year, the waiver remains in effect until “pulled” by the employee (by notifying their Department and Human Resources in writing). Employees who wish to return to the waived position may bid (or progress in the case of Progression Without Bidding or Qualification Based Progression) to an opening of that position.

The Chief Steward and Manager for the requesting employee approve this waiver and shall meet to discuss.

Section 4.7 Workplace Location Exchange

Employees may request a workplace location exchange by completing a "Workplace Location Exchange Request" form. Human Resources will notify the Chief Stewards and the Union office of the finalized exchange including the nature of the exchange (lateral or non-lateral), qualifying periods, pay rates, and effective dates.

Section 4.8 Retention of Higher Rate

4.8.1 Jobs awarded based on qualifications are not eligible for rate retention.

4.8.2 When an employee in a Line of Progression position is working up a grade, the employee will be paid at the entry level rate for the first two hundred and sixty (260) working days. Once an employee in a Line of Progression position has worked up a grade for two hundred and sixty (260) working days, the employee will continue to receive the higher rate of pay at the experienced level, until such employee leaves their position or signs a Progression Waiver.

4.8.3 When an employee with less seniority in a Line of Progression works up a grade ahead of a senior employee in the same Line of Progression at the same Company-based location, the most senior employee will also be paid entry level at the higher rate for the day, except when the less senior employee is working up into a qualifications-based job (e.g., Construction 4).

4.8.4 If a less senior employee at the same Company-based location reaches rate retention prior to a senior employee at the same Company-based location in the same Line of Progression because the senior employee was on a Short-Term Assignment, the senior employee will be designated as rate retained.

4.8.5 When working up into qualification-based jobs, only the employee working up is paid the higher rate for the day.

Section 4.9 Temporary Positions / Internal Assignment of Employees

4.9.1 **Short-Term Assignment of Employees**

Employees may be temporarily assigned for one hundred and eighty (180) calendar days or less per calendar year to a position for which they qualify or may be trained based on Company needs. Any individual employee assignment longer than one hundred and eighty (180) calendar days shall be by mutual agreement of the Parties. The Chief Stewards and Union will be notified by management no later than the start of any Short-Term Assignment expected to last longer than seven (7) calendar days.

An employee who is assigned to perform a higher-grade position will be compensated at the higher of the employee's current or assigned rate for the hours worked at that rate up to four (4) hours of the day. An employee who works four (4) hours or more is paid for the full day at the higher rate.

Employees will continue to accumulate Job or Line of Progression seniority in their regular position during such assignments.

An employee returning from an authorized leave of absence may be temporarily assigned to other work regardless of seniority.

4.9.2 Long-Term Special Assignment

A Long-Term Special Assignment (LTSA) is a posted special, voluntary work opportunity that is up to twelve (12) months in length. Requests for extensions beyond the initial term will be mutually reviewed and agreed upon by the Parties. All LTSAs are subject to the following:

- An LTSA is not a replacement for a vacant regular position. Recurring LTSAs shall be reviewed by the Parties to determine whether there is a need for a regular position; the Union may include a Chief Steward for the review. The term “voluntary,” as used here, means that either the employee or the Company may end the LTSA at any time for any reason.

- Because an LTSA goes through the post, bid and award process, the pay rate for the LTSA will apply in all situations. If the LTSA is a lateral move, the employee will retain their current pay rate. An employee bidding from a higher paying position will not retain that higher pay rate while in the LTSA position; they will receive the experienced level of the lower position.

- At the conclusion of the LTSA, the employee will return to their original position. While in the LTSA, the employee will be included in any work redesign, as it may occur, that might affect their regular position.

- If there are no qualified bidders, the position will be temporarily assigned based on this Article.

4.9.3 Assignment to Non-Bargaining Position - Temporary Development Opportunity (TDO)

The Company’s TDO procedure applies with respect to the assignment. The employee will continue to retain Union membership status (including benefits) and pay Union dues. Per 3.8.7, Regular Employees on a TDO do not earn seniority in their regular job. The Company will notify the Chief Stewards and the Union no later than the start of the non-bargaining assignment.

ARTICLE 5
PERFORMANCE QUALIFYING STANDARDS

Section 5.1 General

Employees must acquire and maintain Performance Qualifying Standards per these four (4) following processes:

- Failure to Qualify During Qualifying Period
- Failure to Maintain Performance Qualifying Standards
- Field Operations Testing Failure to Qualify
- Welding Procedure to Recertify

Section 5.2 Failure to Qualify During Qualifying Period

5.2.1 **Application**

The process outlined below applies when a regular employee is failing to meet performance-qualifying standards during the qualifying period for that position.

5.2.2 **Process**

5.2.2.1 Employees may exercise their right to return per Section 4.5 within this Agreement.

5.2.2.2 Employees ineligible for a right to return may:

- Return to original position if previously qualified and position is still vacant.
- Return to previous status when outside of a regular position (e.g., redeployment, leave of absence due to Failure to Maintain Performance Qualifying Standards). If original status was a leave of absence resulting from Failure to Maintain Performance Qualifying Standards or a third Testing Failure, employee's leave of absence will be restarted from the point at which it had been paused at the time of the employee's successful bid (See Failure to Maintain Performance Qualifying Standards and Field Operations Testing Failure to Qualify process within this Article).
- Return to the department if the position is not vacant and the department can absorb the employee, as determined by Management.

5.2.2.3 If no job is available, the employee will be placed in the redeployment process at the pay group and pay rate of the job in which the employee last qualified, or Pay Group O Experienced Pay Rate if never previously qualified, or Pay Group M Experienced Pay Rate if prior status was a third testing failure on a new task or content area and Paid Time Off (PTO) is exhausted (See Redeployment Process in Section 7.3 within this Agreement).

Section 5.3 Failure to Maintain Performance Qualifying Standards

5.3.1 Application

This process applies to regular employees who have successfully completed the qualifying period and who are subsequently unable to maintain performance qualifying standards for a position.

For failure to qualify situations involving Operator Qualifications or welding, refer to the Field Operations Testing Failure to Qualify process within this Article or Welding Procedure to Recertify within this Article, as appropriate.

5.3.2 Process

After the employee has received coaching and direct performance feedback, which may include a Performance Development Plan (PDP), and still does not maintain performance qualifying standards, the following occurs:

5.3.2.1 A Failure to Maintain Performance Qualifying Standards Disciplinary Action Plan (DAP) will be utilized and will specify:

- The changes that must occur for the employee to meet standards;
- The timeline for the employee to accomplish those changes. (The DAP should generally be no longer than the qualifying period for the employee's position. If the DAP is longer than the qualifying period for the employee's position, it must be approved by the LMC Co- Chairs and must be signed by the Manager and Union Representative.); and
- Consequences if the employee does not meet the requirements of the DAP.

5.3.2.2 The employee may:

- Bid on any open positions (if any are available) for which they meet bidding qualifications; and/or
- Apply for a position waiver in accordance with Section 4.6 within this Agreement.

5.3.3 If the employee does not successfully complete the DAP:

- The employee will be placed on leave for a period equivalent to one (1) month per year of service during which time they may bid to an open posted position (other than the position from which they were disqualified) for which they meet bidding qualifications; and
- The employee will use Paid Time Off (PTO) until PTO is exhausted; then the employee will be placed on leave without pay; and
- If the employee's leave of absence extends beyond the period equivalent to one (1) month per year of service with the Company, the employee shall be terminated.

Section 5.4 Field Operations Testing Failure to Qualify

5.4.1 **Application**

This Section outlines the process to be followed when a field operations employee fails to pass required testing for their current job, including but not limited to testing related to Operator Qualifications (OQ).

5.4.1.1 This process covers:

- The consequences after each failure of a required test;
- The criteria that must be met before an employee can attempt to retest;
- The time intervals between testing opportunities; and
- The resources available to the employee.

5.4.1.2 This process does not apply to:

- Testing that is part of initial position training (Refer to the Failure to Qualify During Qualifying Period process within this Article or department guidelines);or
- Performance issues identified on the job (Refer to the Failure to Maintain Performance Qualifying Standards process within this Article or Failure to Qualify During Qualifying Period process within this Article, as appropriate); or
- Weld testing (Refer to the Welding Procedure to Recertify within this Article, as appropriate).

5.4.1.3 Certification testing provided by outside agencies may be covered by this Article as determined appropriate.

5.4.2 **Process**

At any point during this process, the regular employee has the option to do any of the following, if applicable:

- Bid to an open position, if available, for which they meet bidding Qualifications;
- Apply for a Waiver per Section 4.6 within this Agreement, as available, or
- Exercise their right to return to a former position per Section 4.5 within this Agreement.

5.4.3 **First Failure**

5.4.3.1 Employee is immediately restricted from performing the task or associated task(s) (e.g., tasks connected to a failed Abnormal Operating Condition [AOC]), unless directed by a qualified worker, as permitted and approved by management. If the employee will not be directed by a qualified worker, the employee will be assigned work that does not involve performing the associated task(s) for which they are now unqualified, if such work is available.

5.4.3.2 The employee will be provided focused training on the tasks or AOCs, which may include individual review, training, and/or time to practice or study as deemed appropriate by a training representative, with consideration of input from the employee. Training will be documented on the FTQ Training Documentation form.

5.4.3.3 On the day of first failure:

- Employee may be afforded additional time to prepare (e.g., receive training or study) for retesting, as necessary.
- Employee may choose to utilize PTO or leave without pay, as appropriate, for rest of shift. Such PTO will be approved without penalty.

5.4.3.4 The employee must be scheduled to retest at a minimum next shift and maximum of fourteen (14) calendar days, excluding scheduled PTO or approved leave. Within this timeframe and with regard to input from the employee, a training representative will schedule retesting. Any exceptions to minimum or maximum time to retest must be approved by the Training Manager or designee.

5.4.4 **Second Failure**

5.4.4.1 Employee restriction from performing the associated task(s) continues, unless directed by a qualified worker, as permitted and approved by management. If the employee will not be directed by a qualified worker, the employee will continue to be assigned work that does not involve performing the task(s) for which they are now unqualified, if such work is available.

5.4.4.2 Prior to retraining, the employee will have a meeting with their Supervisor, a Union Steward if one is requested, and a representative from Human Resources (HR) to review this Article and discuss concerns and options.

5.4.4.3 The employee will be provided focused training on the tasks or AOCs, which may include individual review, training, and/or time to practice or study as deemed appropriate by a training representative, with consideration of input from the employee. The employee may request to waive the focused training session. Training will be documented on the FTQ Training Documentation form.

5.4.4.4 The employee must be scheduled to retest at a minimum seven (7) calendar days and maximum of thirty (30) calendar days, excluding scheduled PTO or approved leave. Within this timeframe and with regard to input from the employee, a training representative will schedule retesting. Any exceptions to minimum or maximum time to retest must be approved by the Training Manager or designee.

5.4.5 **Third Failure**

5.4.5.1 If the employee is in their qualifying period, see Failure to Qualify During Qualifying Period process within this Article. If the previous position held by the employee requires the same task, then the employee moves into redeployment.

5.4.5.2 If the employee is not in their qualifying period:

- Following third failure of a required test for requalification (i.e., employee has previously passed testing and was “qualified”).
- Employee will be placed on leave for a period equivalent to one (1) month per full year completed from date of hire, during which time they may bid to an open position (other than the position for which they were disqualified) for which they meet bidding qualifications.
- Employee will use all accrued and banked PTO until PTO is exhausted; then employee will continue on leave without pay.

- If the employee's leave of absence extends beyond the period equivalent to one (1) month per year of service with the Company, the employee shall be terminated.

Following third failure of a required test on a new task or content area introduced to an incumbent's position:

- Employee will be placed on leave for a period equivalent to one (1) month per full year completed from date of hire, during which time they may bid to an open position (other than the position for which they were disqualified) for which they meet bidding qualifications.

- While on leave, the employee may be assigned to temporary work, as available. Assignments of temporary work will not exceed one (1) month per year of service up to a maximum of twelve (12) months from the date of the third (3rd) failure. Days assigned to temporary work do not extend the length of the leave of absence.

- Employee will use all accrued and banked PTO until PTO is exhausted; then the employee will continue on leave without pay.

- Once PTO is exhausted, the employee is removed from their current position and will be reclassified to Pay Group M, Experienced Pay Rate. Employee continues to accumulate only Company seniority.

- While performing temporary work, additional PTO will be accrued at Pay Group M. When temporary work is not available, the employee will use additional accrued PTO until PTO is exhausted; then the employee will be returned to leave without pay.

- Employee will not be eligible for preferential bidding, redeployment, or bumping as a result of this process.

- If the employee's leave of absence extends beyond the period equivalent to one (1) month per year of service with the Company, the employee shall be terminated.

5.4.6 An employee who has successfully bid to another job or exercised the waiver option at any point during this process may reapply for the position (if available) after a period of one (1) year if the employee can demonstrate that a substantial change has occurred making it possible for the employee to qualify, based upon management's approval.

Section 5.5 Welding Procedure to Recertify

5.5.1 Application

This procedure applies to all regular employees who are required to maintain Welding qualifications. This procedure covers failure on any of the following Welding tests:

- Requalification Testing
- Probable Cause Testing
- Random Testing

It is the employee's responsibility to actively participate in this process.

5.5.2 First Failure

- Employee is immediately restricted from performing the task.
- Employee is issued Welding Documented Verbal Warning.
- Employee does not earn days toward Experienced rate, if at Entry rate.
- Employee is provided a minimum of eight (8) hours of formal, paid, documented training.
- The minimum time to retest is the second (2nd) business day after failure. Maximum time to retest is fourteen (14) calendar days after failure. Any exceptions to minimum or maximum time to retest must be approved by Management.

5.5.3 Second Failure

- Employee restriction from performing the task continues.
- Refer to "Failure to Maintain Performance Qualifying Standards" or "Failure to Qualify During Qualifying Period" process. Employee issued Welding DAP.
- Employees at the Experienced rate return to Entry rate of their current grade.
- Employee is provided a minimum of eight (8) hours of formal, paid, documented training.
- The minimum time to retest is fourteen (14) calendar days after failure. Maximum time to retest is thirty (30) calendar days after failure. Any exceptions to minimum or maximum time to retest must be approved by Management.

5.5.4 **Third Failure**

- Refer to “Failure to Maintain Performance Qualifying Standards” or “Failure to Qualify During Qualifying Period” processes within this Article.
- Loss of position.
- One (1) year minimum from loss of position to bid on open Welding position.

ARTICLE 6
WORKING CONDITIONS

Section 6.1 Schedules and Overtime

This Article recognizes the fact that the Company must provide uninterrupted continuous service to our customers, twenty-four (24) hours per day, seven (7) days per week, as a matter of public safety and health. In accordance with Article 2 within this Agreement, the Company retains the right to manage the business and direct the work and workforce, including the right to determine schedules and require overtime, subject to the rules listed below.

6.1.1 **General Definitions and Rules**

6.1.1.1 Workweek: For the purposes of calculating overtime and establishing schedules, the seven (7) day workweek for all employees begins at 12:01 a.m. on Monday.

6.1.1.2 Work Schedule: For most employees, a regular full-time schedule will be five (5) workdays of eight (8) hours duration; including two (2) consecutive days off. Some work groups have alternate schedules which may be required by Management based on business needs. Work schedules define the workdays and shifts and shall be documented by each department and/or workgroup as appropriate and will be made available to all employees on the Company intranet.

Employee selection process guidelines for work outside a typical schedule, such as 6th and 7th day, night work, or out of town work, will include recognition and application of Job Seniority, and will be made available to all employees on the Company intranet.

6.1.1.3 Workday: Each employee’s workday begins at the start of their shift and continues for twenty-four (24) hours or until the beginning of their next shift, whichever is sooner. For payroll purposes, all hours worked on a workday will be paid based on the start of the shift.

6.1.1.4 Shift: An employee's shift is defined as scheduled working hours within a workday.

6.1.1.5 Shift types are defined based on the scheduled start time as follows:

Shift Type	Start Time
Day Shift	06:00 a.m. – 9:59 a.m.
Swing Shift	10:00 a.m. – 5:59 p.m.
Graveyard	06:00 p.m. – 5:59 a.m.

6.1.1.6 For work groups that operate a 24/7 schedule, starting times will be rotated as equitably as practicable between members of the same position.

6.1.1.7 Work groups that offer shift bid opportunities will do so at least annually to eligible workers in Job Seniority order. Processes will be developed and documented by department and/or work group as appropriate and will be made available to all employees on the Company intranet.

6.1.1.8 The Parties agree that there shall be a minimum of an eight (8) hour period between scheduled shifts.

6.1.1.9 An employee who reports for work on a regularly scheduled workday and is then sent home for lack of work shall be paid for their entire scheduled shift at the rate such employee would have received if they worked.

6.1.1.10 Unless otherwise stated within the Agreement, overtime is calculated on actual hours worked, not hours paid. The calculation of time worked for overtime purposes shall include paid leave, paid rest period, holidays, floating holidays, and PTO used.

6.1.1.11 If pay is due to an employee under two (2) or more provisions under this Article, only the highest payment required under any provision of this Article shall be paid. This should only be used when a situation is ambiguous and all Articles within the Agreement have been reviewed.

6.1.1.12 Employees will not be required or expected to perform any work before their designated start time or after the end of their shift without compensation.

6.1.2 Flexible Schedules/Work Arrangements

6.1.2.1 An employee may work a flexible work schedule (e.g., four [4] ten-hour days), flex start and end times of their shift, and/or make up lost time in their work schedule within the same workweek if mutually agreed upon by the employee and Management. Not every Flexible Schedule/Work Arrangement option will be available for every work group, position, or employee and approval of a flexible schedule/work arrangement will be at the Manager's

discretion. Company policies and department guidelines will define specific and/or additional requirements for a flexible schedule/work arrangement.

6.1.2.2 If an employee requests a temporary flexible work schedule, this temporary schedule is not considered a regularly scheduled workweek and Saturday/Sunday and Shift Work premiums will not apply for the shift(s) impacted by the temporary schedule change.

6.1.2.3 Remote Work. An employee may request to work remotely, which allows a reporting location off Company property. An employee who is working remotely must log in to the appropriate Company software systems at the employee's scheduled start time. The remote work location is not considered a fixed official work location/station. Remote work will not be available for every work group, position, or employee. Hybrid work schedules will be approved on a case-by-case basis. Flexible Work Company policy and department guidelines will define specific and/or additional requirements for working remotely and will be made available to all employees on the Company intranet.

6.1.3 Unplanned Schedule and Shift Changes

6.1.3.1 Unplanned Schedule Changes

Changes in an employee's scheduled workdays affecting the employee's scheduled days off made with less than forty-eight (48) hours advance notice are considered Unplanned Schedule Changes and hours worked shall be paid at the applicable overtime rate.

6.1.3.2 Unplanned Shift Changes

Changes in an employee's scheduled working hours (i.e., shift) made with less than twelve (12) hours notification prior to the start of the new shift are considered Unplanned Shift Changes and include:

- When an employee meets the conditions for a rest period under 6.1.6 within this Article and is required to return to work before the end of the employee's eight (8) hour rest period, all hours worked are considered an Unplanned Shift Change and paid per 11.5.1.

- After the start of an employee's shift, if an employee is released and rescheduled for a later start time, all hours worked are considered an Unplanned Shift Change and paid per 11.5.1.

6.1.3.3 Unplanned Shift Changes are not eligible for schedule-based premium pay rates.

6.1.3.4 It is not an Unplanned Shift Change when a Call-In extends into the regularly scheduled shift.

6.1.4 On-Call Assignment

6.1.4.1 On-Call Assignments shall be filled between the qualified resource center, department and/or workgroup employees as equitably as practicable; qualified employees are those identified by Management as having the necessary skills to handle emergency response work.

6.1.4.2 If employees are assigned a Company vehicle for the purposes of emergency response when On-Call, travel to and from work is not considered commuting for the purposes of 6.1.3.2 nor is it considered paid time. Employees working On-Call Assignment are required to accept any Call-Ins.

6.1.4.3 Employees are responsible for the accuracy of their contact information. On-Call guidelines shall be documented by each department and/or workgroup as applicable and will be made available to all employees on the Company intranet.

6.1.4.4 An On-Call Assignment on an employee's regularly scheduled workday begins at the end of the employee's regular work shift including overtime worked beyond the end of the employee's regular shift and ends at the start of the employee's next shift the following day. An On-Call Assignment on an employee's scheduled days off begins at their normal shift start time and ends after twenty-four (24) hours or the start of the employee's next regular shift.

6.1.4.5 If an employee has an On-Call Assignment for which the Company provides lodging, the Company will provide a minimum of eight (8) hours work for the employee on the assigned day. Current guidelines for establishing On-Call Assignments will be utilized.

6.1.4.6 Pay for On-Call Assignment will be in accordance with 11.5.3 within this Agreement.

6.1.5 Call-In

6.1.5.1 When an Employee is notified to report for emergency, immediate or unplanned work either before or after completion of the employee's shift, or on a scheduled day off, the time worked shall be considered a Call-In.

6.1.5.2 For Call-Ins that extend into a regularly scheduled shift, the Call-In rate will be paid until the start of the regular scheduled shift or for a minimum of 2

hours, whichever is greater. The regular scheduled shift will be worked and paid at the regular rate of pay.

6.1.5.3 Employees may be required to work through to the end of their original shift and may be required to work additional overtime.

6.1.5.4 Call-Ins are not eligible for schedule based premium pay rates.

6.1.5.5 It is not a Call-In when:

- An employee is requested to extend hours in conjunction with a regular shift.
- An employee is requested at least twelve (12) hours in advance to work additional hours on a scheduled day off. A minimum of two (2) hours at the appropriate overtime rate will apply and the work time shall start at the reporting location.

6.1.5.6 **Call-In Procedure.** Call-In procedures shall be developed and documented by each department and/or workgroup as appropriate and will be made available to all employees on the Company intranet.

6.1.5.7 For immediate response (unplanned), paid time for the Call-In begins when the employee is notified when On-Call or accepts the work for a Call-In.

6.1.5.8 For non-immediate response (planned), paid time for the Call-in begins at the agreed upon start time.

6.1.5.9 Call-Ins that do not extend into a regularly scheduled shift end upon completion of work and return to the reporting location unless an employee is assigned a Company vehicle during this time period, in which case time ends when the employee returns to their originating location.

6.1.5.10 Employees called in will be paid a minimum of two (2) hours at two (2) times their rate of pay. All subsequent Call-Ins that begin on the same scheduled day off or workday will be paid at two (2) times the employee's rate of pay for actual hours worked. Employees called in are obligated to remain in contact and be available to work for the full two (2) hours that they are being compensated.

6.1.6 Excused Rest Period

When an employee is called into work and the last Call-In ends less than eight (8) hours before start of the employees' next scheduled shift, the employee will be given eight (8) hours of rest if:

- The Call-In totals six (6) or more hours duration (consecutive or aggregate); or

- The employee has three (3) or more Call-Ins within the twelve (12) hour period before the start of their next scheduled shift.

6.1.6.1 Additionally, for safety reasons, following unscheduled work and/or Call-Ins prior to a regularly scheduled shift, Management reserves the right to excuse an Employee for some or all of the employee's regularly scheduled shift in accordance with the established Company policy and procedure and the shift will be paid per 6.1.6.3.

6.1.6.2 An employee that does not qualify for a rest period or after a rest period feels they cannot safely perform their assigned duties may request to be excused for the beginning or remainder of their shift not to exceed more than one half of the regular scheduled shift. Available PTO must be used prior to leave without pay.

6.1.6.3 Hours excused from original shift shall be paid at the straight-time rate and shall be counted as time worked for the purpose of calculating overtime.

6.1.7 **Paid Transition Time**

At Management's discretion, when transitioning from scheduled nights to days, or scheduled days to nights, the employee may receive pay per 6.1.6.3 in lieu of working a shift to ensure appropriate rest.

Section 6.2 Work Reporting Methods

6.2.1 **General**

Work reporting methods, including facility-based reporting, jobsite reporting and telecommuting, are defined below. All employees have a work reporting method, in addition to a Company-based location, both of which are determined and assigned by the Company. The Company may change employees' Company-based location and work reporting method based on business needs.

6.2.1.1 Work reporting methods contained in Section 6.2 do not address mileage reimbursement or compensation for time spent traveling in accordance with provisions outlined in this Article.

6.2.1.2 When a work reporting method other than facility-based reporting is utilized, department/workgroup guidelines addressing the application of the method will be established and utilized.

6.2.2 Facility-Based Reporting Method

The facility-based reporting method establishes a location to which the employee reports (e.g., resource center, corporate office or storage facility). Under this method, the Company-based location is the reporting location. The employee must be at that reporting location and ready to work at the employee's scheduled start time.

6.2.3 Travel When Facility-Based Reporting

Employees beginning and ending their shift at a temporary location within thirty (30) miles of their Company-based location will travel to and from the temporary location on their own time.

- Employees beginning and ending their shift at a temporary location greater than thirty (30) miles from their Company-based location will be compensated for travel time.

- Employees beginning and ending their shift at a temporary location will be paid mileage based on the distance between their Company-based location and the temporary location, unless a Company vehicle or other transportation is provided.

6.2.4 Jobsite Reporting Method

The jobsite reporting method establishes varying reporting locations (e.g., job sites, facilities or geographic work areas) to which the employee reports. The employee must be at the employee's reporting location and ready to work at their scheduled start time. Additionally, the employee must be at the employee's reporting location at the end of their shift, unless otherwise directed. Under this method, the Company-based location is not considered the fixed official work location/station.

6.2.5 Travel When Jobsite Reporting

For jobsite reporting, the region is defined as the geographic area within a forty-five (45) mile radius of the Company-based location.

For travel within the region:

- Time spent traveling to and from the reporting location is considered personal commuting time and is not time worked.

- If an employee uses a personal vehicle to commute to and from the reporting location, there will be no mileage reimbursement for that commute.

For travel outside the region:

- Time spent traveling to and from the reporting location will be compensated as time worked based on the calculated travel time from the employee's Company-based location to the reporting location.

- If an employee uses a personal vehicle to commute to and from the reporting location, mileage reimbursement will be provided for that commute based on the calculated mileage between the employee's Company-based location and the reporting location.

Section 6.3 Health and Safety

6.3.1 It is the Company's responsibility to provide a safe work environment and to operate its system safely. The parties mutually agree to promote safe work and stop work practices, which include providing appropriate personnel and equipment to meet health and safety obligations. Personal Protective Equipment (PPE) allowances provided by the Company shall be in accordance with Section 17.8 within this Agreement; unless otherwise required by applicable law.

6.3.2 All employees are subject to the Company's Drug and Alcohol policies.

Section 6.4 Emergency Operations

If adverse or emergency conditions exist, employees may be given alternative work assignments, schedules, shifts, and/or work locations. The Parties agree that the Company will maintain safe operation in their service territory.

Mutual Aid/Assistance. In the event of mutual aid requested by another utility, the employee selection process will include recognition and application of Job Seniority and will be made available to all employees on the Company intranet.

Section 6.5 Dash Camera

The vehicle dash cameras are to be used for triggering events such as collisions, litigation around collisions, and public complaints or other triggering events such as hard braking. Video footage from a triggering event will first be reviewed by a third party. The Company and the Union recognize the intent of the dash cameras is to improve driving habits and the overall safety of our employees, customers, and the communities in which they drive.

The camera will only upload video footage for viewing when there has been a triggering event or as requested by the Company. The cameras will not be used for real-time video or audio surveillance of employees, or to track employee work performance.

At no time will the device be used for audio voice recording of employees.

The use of cab facing cameras are not considered discipline. The cab facing cameras will only be activated in conjunction with discipline related to violations of Company Driving Policies. Activation of cab facing cameras longer than one hundred and eighty (180) calendar days must be signed by the Manager and the Union Representative. Forward facing cameras will continue to be used.

ARTICLE 7
EMPLOYEE DISPLACEMENT

Section 7.1 General

Employee displacement includes work redesign, redeployment, lack of work, bumping process, and layoff.

Section 7.2 Work Redesign

Work redesign may occur within a department, a workgroup, a resource center, or company-wide resulting in employee position status change or displacement from position. Before a work redesign, the Company will bargain the impact of the redesign and identify issues that are covered under this Agreement or are considered mandatory subjects of bargaining and must be resolved before the application of the Company's Work Redesign Job Allocation Process. When a redesign has projected reductions in occupied positions or changes in Company-based location, the Company agrees to inform the Union in accordance with Section 7.3 to this Article and Company processes.

7.2.1 **Acceptance or Declination Timelines**

Regarding position selection, the employee shall be given a minimum of forty-eight (48) hours (two [2] complete workdays) from point of notification to make their decision.

Failure or refusal by a regular employee to complete the documents within the agreed timeframe will be considered a declination.

7.2.2 **Position Reinstatement**

An eliminated position in the impacted group that is reinstated within one (1) year of a regular employee's displacement date will be offered in Company seniority order to those regular employees displaced by this redesign provided that the reinstated position is not in a location declined by that employee. This reinstatement applies to regular employees displaced due to the initial redesign only and not regular employees displaced due to any subsequent assignments or bumps.

Section 7.3 Redeployment

7.3.1 Redeployment is a process utilized to retain a regular employee whose job has been eliminated due to work redesign, or may be used in a regional lack of work if mutually agreed upon by the Union and the Company. This process may also be used as a result of Failure to Qualify During Qualifying Period as defined in Section 5.2 within this Agreement.

7.3.2 This process shall include preferential consideration for the displaced regular employee in the bidding and selection process for equivalent or lower grade positions for which the employee meets bidding qualifications. As an alternative to bumping, the Company may assign such employee to a position for which the employee meets bidding qualifications. Refer to the Redeployment Process and Failure to Qualify During Qualifying Period in accordance with Article 5 within this Agreement.

Section 7.4 Lack of Work

7.4.1 If the Company declares a regional lack of work in a location or workgroup, regular employees may be permanently assigned from one work location to another. Regular employees involved in regional lack of work will have their pay guaranteed per Section 1.5 within this Agreement. Once the Company has declared a regional lack of work, the impact and application of that determination shall be mutually agreed upon by the Union and the Company.

7.4.2 If the Company declares a Company-wide lack of work, the bumping process shall be applied per Section 7.5 to this Article.

7.4.3 The Parties agree that in the case of unforeseen events that could cause the need for a temporary reduction in the amount of work available either Company-wide, in a location, or workgroup, the Parties will meet to determine the method by which they may meet the challenges of the unforeseen event(s). Before any forced reduction in available work hours is initiated, the Parties will exhaust as many voluntary options as appropriate that meet the joint interests of the parties. Situations covered under this Section are not considered a permanent event and will not be subject to other provisions of this agreement such as layoff or bumping rights.

Section 7.5 Bumping

Bumping, as described in 7.5.1 to this Article, General Bumping Principles, and in the Company process, may be available for use in the following circumstances:

- Redeployment resulting from work redesign (refer to the Redeployment Process in accordance with Section 7.3 within this Agreement)

- Company-declared lack of work.

7.5.1 General Bumping Principles

An employee:

- Cannot bump an employee who has more Company seniority.
- Cannot bump into a higher graded job.
- Cannot bump into a job for which bidding qualifications are not met as defined in Article 4 within this Agreement.
- Cannot bump into a previously declined job at any location due to Work Redesign.
- Cannot bump into a previously declined job at that specific location due to assignment in redeployment.
- Can decline to bump into positions that change their employment status (FT, PT>20, PT<20). In such cases, the Parties will convene a Committee to provide oversight on significant redeployment and bumping activities. The process will be based on seniority, and the Committee will also consider employee preference for work location, current job held, previous jobs worked and maintaining group.
- Can bump into a different employment status (FT, PT>20, PT<20), but must elect to change employment status accordingly.

Section 7.6 Layoff

The parties agree that a layoff will only occur when the Company determines a need to reduce its workforce. The Company may layoff any employee who has not earned employment security as defined in Section 1.4 within this Agreement.

Regular employees shall be given ten (10) working days' advance notice before a layoff expected to last longer than ten (10) working days.

ARTICLE 8
PERFORMANCE DEVELOPMENT AND MANAGEMENT

Section 8.1 Performance Appraisal

Management will maintain an appraisal system to determine if performance requirements have been or continue to be satisfied for the Probationary period and the Qualifying period.

Line of Progression

Advancing within Line of Progression jobs requires a regular employee currently meet all the standards for the previous job prior to being eligible to move into the next job.

Section 8.2 Performance Development Plan

A Performance Development Plan (PDP) shall be used for incumbent regular employees who have been assessed as "not meeting" performance qualifying standards. However, Performance Development Plans are not to be used for term employees, probationary regular employees, and regular employees in their qualifying period, or situations warranting immediate use of the progressive discipline process. The Performance Development Plan will be kept in Human Resources (HR) in the employee's personnel file.

Successful completion of the Performance Development Plan does not change anniversary dates for pay progression timelines.

8.2.1 Responsibility of the Supervisor

Using a Performance Development Plan, Supervisors shall provide monitoring of regular employees so that the employees are aware of any standards they are not meeting, and what they need to do to meet the standard.

8.2.2 Responsibility of the Employee

Regular employees on a Performance Development Plan have the responsibility to follow through on the agreed plan, including any training or use of tools/resources provided by the Supervisor, and to inform the Supervisor if there are any barriers to completing the plan. Regular employees who know they are not meeting an essential function may ask Supervisors for a Performance Development Plan to help ensure that they can meet the standards.

Section 8.3 Statement of Expectations

A Statement of Expectations is a non-disciplinary coaching tool a Supervisor may use to outline and help an employee understand the Supervisor's expectations of the employee.

At times a Supervisor may choose to provide an Employee with a Statement of Expectations to further communicate or document expectations. A Statement of Expectations may be retained in the employee's personnel file.

Section 8.4 Relationship to the Disciplinary Process

A Performance Development Plan or Statement of Expectations **cannot** be construed as the first step of the disciplinary process and cannot be used or referenced in any future disciplinary documents. All disciplinary action must be conducted as described in Article 20 within this Agreement.

ARTICLE 9
ATTENDANCE

Section 9.1 General

The Union and the Company agree that employees' regular and reliable attendance is critical to the success of the Company. The Parties further agree that late arrivals to work, early departures from work, and other unscheduled and unapproved absences are disruptive and should be avoided. Employees are expected to be at work each scheduled workday, on time and ready and able to work and all employees are expected to have regular, reliable and punctual attendance. Appropriate use of Paid Time Off (PTO), disability benefits (Short-Term Disability, Long-Term Disability and Workers' Compensation), and protected forms of leave as defined by Company policy are essential to employee well-being, a healthy work environment, and a committed workforce, which are integral factors in Company performance.

Section 9.2 Relationship to Paid Time Off

Employees may use Paid Time Off (PTO) per Article 12 within this Agreement for vacation, illness, accident, family illness, medical appointments or personal business.

Section 9.3 Attendance Guidelines

9.3.1 **Definitions**

9.3.1.1 Time away from scheduled work is:

- **Absence**: one (1) hour or more of time away is considered one (1) absence. This includes late arrivals and early departures as well as full day absences.
- **Tardy**: Late arrivals or returns and early departures of less than one (1) hour. This includes late arrivals or returns from breaks or meal periods.
- **Days Off**: Negotiated days off such as PTO, holidays, floating days, bereavement leave, etc.

9.3.1.2 **Approved**: Time away will be considered approved when the time away is:

- Protected leave, defined under applicable local, state or federal laws (i.e., FMLA, OFLA, WFLA, *Oregon and Washington Paid Sick Leave), or relevant leave laws. Protected leave is applied before absences are determined to be unapproved. Employees need to work with Matrix or current leave administrator and the Human Resources team to determine whether any particular absence is covered by protected leave.

* As of June 1, 2024, Oregon Paid Sick Leave is 40 hours of protected leave and Washington State Sick Leave is 50 hours of protected leave. Subject to change, refer to Company Policy.

- Discipline or retaliation based on an employee's use of protected leave is not permitted by law. Employees are responsible for providing appropriate notice and documentation of protected leave as described in the Company's Family Medical Leave policy.

- Approved bereavement leave (per Article 13 within this Agreement), approved military leave, protected leave (as defined in Company policy), jury duty, witness duty on behalf of NW Natural, and approved absences due to industrially related injuries or illnesses.

- Granted approval with at least forty-eight (48) hours' notice, e.g., floating days, PTO, appointments. *

  *Requests for time away from work with less than forty-eight (48) hours' notice may be considered approved. This is an exception and the decision is at the sole discretion of the Supervisor/Manager/designated approving authority.

9.3.1.3 **Unapproved:** An absence will be considered unapproved when the time away from work does not meet the criteria for approved absence within this Article or if the employee failed to notify their department's designated approving authority or failed to follow the applicable department reporting procedures for the absence, tardy, or early departure before the start of the scheduled shift or as soon as practicable upon the employee's knowledge that they would be late or absent.

9.3.1.4 **Use of PTO for Unapproved Absence:** Employees may use their accrued Paid Time Off (PTO) for unanticipated absences with less than forty-eight (48) hours' advance notice, but the time away is not considered approved just because the employee has PTO available to cover the time they were away from work.

9.3.1.5 **Unacceptable Amounts/Patterns of Unapproved Absences:** An unacceptable pattern of unapproved absence is demonstrated generally by the following:

- Except as provided in 9.3.1.2 to this Article, after five (5) unapproved absences within a rolling twelve (12) month period measured backward from the date of the most recent unapproved absence.

- Unacceptable amounts/patterns of unapproved absence may be subject to discipline per Article 20 within this Agreement. The Company has

discretion to assess an employee's overall attendance record as it relates to unapproved absences to determine if there is an unacceptable pattern and, if so, the appropriate level of discipline.

9.3.1.6 **No Call/No Show:** An employee is considered a No Call/No Show when the employee fails to report for work without contacting their Supervisor (or the Supervisor's documented designee, or if no documented designee, the next level of Supervision) or without following any applicable department-level procedures for absence notification. After three (3) or more consecutive workdays in which a No Call/No Show has occurred, an employee is considered to have voluntarily abandoned employment with the Company.

ARTICLE 10
ISSUE RESOLUTION

Section 10.1 Introduction

The Issue Resolution Process is the agreed to method to address questions, conflicts and disputes, regarding any provisions of this Agreement, at the lowest level possible prior to going through the Grievance Process. The Issue Resolution Process is not intended to be a substitute for direct dialogue between employee and Supervisor. The objective of the Issue Resolution Process is to promote open and continuous communication to determine what's right, not who's right, regarding concerns in the workplace. This process is established on the premise of trust, respect and the mutual goal of resolving issues at the earliest opportunity and appropriate level.

Section 10.2 Issue Resolution Process

Step One

Prior to filing a formal issue (OPEIU Local 11 form), the employee and the Supervisor should first meet informally to discuss and attempt to resolve the issue(s).

Step Two

In the event there is no resolution, the Steward, the employee and the Supervisor should meet and discuss the issue(s) and attempt to resolve the issue(s) informally.

Section 10.3 The Issue Resolution Committee

Step Three

Should the issue not get resolved between the employee, the Steward and the Supervisor, it shall be presented to an Issue Resolution Committee, hereinafter referred to as the "Committee," for consideration.

10.3.1 An Issue Resolution Committee is organized on an as needed basis for the purpose of dealing with possible conflict(s) with the Agreement and in accordance with Section 10.1 to this Article. The Committee shall not have the authority to change, delete, or modify any terms and conditions of the Agreement.

10.3.2 The Committee shall be comprised of two (2) bargaining unit members from the current list of Stewards and Chief Stewards appointed by the Union and two (2) management employees appointed by the Company. These Committee members will be mutually agreed upon by the LMC Co-Chairs. The appointed Committee members with mutual agreement may at their discretion bring in a subject matter expert (SME).

10.3.3 For any single topic the Committee may meet for up to three (3) hours total.

The Committee shall consider only those contract issues which are mutually agreed upon or otherwise designated in the Agreement or bylaws of the Committee.

The Committee resolution decisions will be made by consensus and the Committee shall submit their findings and decision to the employee, Supervisor, and the LMC Co-Chairs. Resolutions that are changes to work rules/conditions or other items that may impact other workgroups or employees shall be submitted to the LMC Co-Chairs for review, approval, and communication to members and/or workgroups impacted.

Should these four (4) Committee members not reach consensus within fourteen (14) calendar days, they shall immediately communicate this to the LMC Co-Chairs for resolution or movement to the grievance process.

All timelines above may be extended by mutual agreement of the Parties. If extended, notification will generally be provided to all parties along with status and anticipated action within three (3) working days of the decision to extend or as soon as possible thereafter.

Nothing in this language precludes a party from withdrawing an issue at any time with notification to the Union office and Human Resources.

ARTICLE 11
WAGES

Section 11.1 Compensation

The parties agree to ensure that there will be a compensation system that supports business operations while maintaining internal and external equity.

11.1.1 **Pay Rates.** Each job will be placed in a pay group. Each pay group will have at least two (2) pay steps.

11.1.2 **Entry Rate.** This rate of pay is one step below the Experienced Rate.

11.1.2.1 An employee entering a position which has only two (2) pay steps shall receive the Entry Rate when:

- Entering a new position in a higher pay grade,
- Entering a new position in the same grade when an employee is currently receiving the entry pay rate,
- Entering the same or lower position and an employee has never received the Experienced Rate for either position.

11.1.3 **Experienced Rate.** This is the top rate of pay an employee will receive for that grade.

11.1.3.1 In order to receive the Experienced Rate an employee must first successfully complete all of the following:

- Any applicable in training programs or required certifications.
- Receive the Entry Rate for the new position for a period not less than two hundred and sixty (260) working days (credit towards the two hundred and sixty [260] working days will be given for any previous days worked in the same or higher grade at the entry rate). The parties agree for absences of twenty (20) workdays or more, the Company may, at its sole discretion, extend the two hundred and sixty (260) day timeframe by the same number of workdays missed.
- The qualifying period for the position.

11.1.3.2 Employees who have previously held the same or higher grade and who have received the experience rate for the same or higher grade shall also be paid the experienced rate.

11.1.4 **Additional Pay Steps**

11.1.4.1 Under certain circumstances, positions may have additional pay steps. These positions must be mutually agreed to and have formal In-Training programs and as defined below.

11.1.4.2 An employee entering a position with these additional pay steps will receive the appropriate rate of pay in accordance with the provisions within this

Article. The starting rate shall not be less than eighty percent (80%) of the Experienced Rate.

11.1.4.3 A formal In-Training program is required for a position to have additional pay steps. Not all positions with a formal training program will have additional pay steps. The starting step for any such position shall not be less than eighty percent (80%) of the experienced rate as deemed appropriate by the Company.

11.1.4.4 **Positions with Approved Additional Pay Steps**

Currently, the following positions have additional pay steps. The pay steps are tied to timeframes and not to completion of training phases or qualifying periods. During the life of this Agreement, positions with additional pay steps may be added to, removed from or changed by mutual agreement between Management and the Union.

- Corrosion Technician
- Construction 2
- Service Technician (CFS 2)
- Mechanic Welder (Welding & Fabrication 4)

11.1.4.5 Time starts on the date of hire for external hires and rehires or first day of training for internal hires. Employees shall progress through Steps 1 through 4 in accordance with the schedule below.

Employees may progress from Step 4 to Step 5 (Experienced Rate), after successfully meeting all the conditions as described in 11.1.3.1 to this Article and receiving satisfactory performance evaluations. Steps as a percentage of Experienced Pay Rate are listed below:

Step	Time in Program	% of Experienced Pay Rate
1	0 months	80%
2	6 months	85%
3	12 months	90%
4	24 months	96% (Entry)
5	36 months	100%

Pay rates for internal employees entering an In-Training program will be determined as follows:

- When promoting into a job with a higher pay grade the employee shall be placed at the Step closest to their current rate of pay that results in a pay increase.

- When bidding into a job in the same pay grade, they shall be placed at the same Step the employee currently holds, except in the case of an employee who currently holds the Experienced Rate where it will be the Step below the Experienced Rate.

- When bidding into a job with a lower pay grade they shall be placed at the Step below the Experienced Rate which results in the least reduction in pay.

11.1.4.6 Internal employees entering an In-Training program at a step higher than Step 1 will advance to the next Step within the timeframes as defined in the above chart. For example, an employee who enters at Step 3 will move to the Step 4 pay rate after twelve (12) months.

11.1.4.7 **Benchmark-based Progression**

At Management's discretion, with mutual agreement from the employee, benchmark-based progression may be used for the following workgroups:

- Weld & Fab 4
- Corrosion Technician

Benchmark-based progression would allow an employee to advance to the next step/pay scale as described in 11.1.4.5, not to exceed Step 4, by completing the required testing ahead of the time-based progression. In the absence of benchmark-based progression, the employee will follow the additional step/pay scale schedule.

Section 11.2 Scheduled Annual Increases and Wage Adjustments

Increases to wages are incorporated into "Schedule B – Wage Scale" within this Agreement. These negotiated rates were achieved utilizing the guiding principle of alignment with market practices and internal equity considerations. This principle was applied to comparable companies, surveys and job matches. Internal equity ranking shall be applied by mutual agreement in comparison to peer utilities. Market matches and internal equity shall both be considered when achieving alignment.

11.2.1 An employee's rate of pay shall be adjusted depending upon the employee's current rate of pay as follows:

- Effective June 1, 2024, all bargaining unit employees shall be moved to the appropriate rate for their job group in accordance with "Schedule A – Job Titles by Pay Group" to this Agreement.

- Employees in positions covered by pay guarantees in Section 1.5 within this Agreement are covered in Section 11.4 to this Article below.

11.2.2 For Employees whose current rate of pay is equal to that contained in "Schedule B – Wage Scale," the minimum Scheduled Annual Increase is specified in the table below.

Scheduled Annual Increases	
Effective Date	**Percentage Increase**
June 1, 2024	6.0 %
December 1, 2024	4.0 %
December 1, 2025	4.0 %
December 1, 2026	4.0 %
December 1, 2027	4.0 %

Section 11.3 Job Compensation and Approval Process

11.3.1 Human Resources Professional Review

When a new bargaining unit job is established or if there is a substantive change, initiated by the Human Resource Compensation Professional or submission of the Job Compensation Evaluation Form, to the job that requires changing the job match used in the market evaluation as determined by the Human Resources Compensation Professional, the Company shall conduct a market evaluation of wages using the same comparable companies, surveys, job matches, and methodology used in the negotiations for this Agreement. For purposes of determining whether there is a substantive change to a job, the Company's Human Resources Compensation professional will make the ultimate determination which will focus on whether there is a material change in job duties that significantly affect the nature and level of the work being performed and using the process described below.

11.3.2 Labor Management Committee Review

The Labor Management Committee Leadership Team (LMC LT) will review and approve recommended changes to Job Matches, Pay Groups, Wage Rates and Adjustments as described in this Article and presented by the Company Compensation Professional following the Job Compensation Evaluation Form,

which will be made available to all employees on the Company intranet. The LMC LT reserves the right to bring in subject matter experts to inform their decisions.

11.3.3 Changes and additions of a significant nature to "Position Specific Essential Functions" will follow these steps:

(1) Employee(s) shall submit the Job Compensation Evaluation to their department Manager for consideration. The manager will consult with the HR Compensation Professional prior to approving a request for job description changes or evaluation. If after review with the HR Compensation Professional it is determined there are changes of a substantive nature to the job description that would warrant a review (material change of job duties that significantly affect the nature and level of the work), the manager will approve the job evaluation form and compensation will notify the employee that a review is pending and will be presented to the LMC-LT.

(2) If the HR Compensation Professional determines there is not a substantive change to the job to warrant a review, the HR Compensation Professional will inform the manager and requesting employee that a market review will not be completed. The HR Compensation Professional will inform the LMC Co-Chairs of the request, and non-substantive changes to the job description. The LMC Co-Chairs have the option to request a deeper review if other material information is presented to the HR Compensation Professional that was not included in the initial request.

(3) The HR Compensation Professional is responsible for communicating decisions on review requests to the LMC-LT, the requesting manager, and employee(s).

(4) The effective date of any change will be the date of the decision by the LMC-LT. If the compensation review has taken an extended period of time (i.e., more than three (3) months), the LMC-LT will agree on an appropriate effective date.

Section 11.4 Honored Pay Rate Employees

11.4.1 Effective June 1, 2024, and for the term of this Agreement, Honored Pay Rate employees shall receive a lump sum equal to the scheduled annual increase. This lump sum payment shall continue until the difference between their current rates of pay prior to the scheduled annual increase is less than three percent (3%) more than the rate of the "Schedule B – Wage Scale." At that time, they will receive that percentage amount necessary for their current wage to equal that in the "Schedule B – Wage Scale" with the difference between that amount and the scheduled annual increase in a lump sum*.

* Lump sums owed under these provisions shall be calculated based on the employee's regular and overtime earnings for pay periods ending in the preceding

twelve (12) months period prior to the increase, and shall be paid on the employee's second pay check in the month the increase was issued.

11.4.2 In the event an Honored Pay Rate employee bids into a position with a Wage Scale rate lower than the pay rate for the position the employee was placed or preferentially bid into that resulted in the pay guarantee, the employee's pay shall be decreased to the rate contained in the Wage Scale for the position into which the employee bid.

Section 11.5 Premium Pay Rates

11.5.1 Overtime Pay

11.5.1.1 An employee shall be paid at one and one-half (1.5) times the regular rate, including applicable premiums for:

- The first twelve (12) hours worked on the first scheduled day off for any time worked.
    - The first twelve (12) hours worked on an Unplanned Schedule Change or an Unplanned Shift Change except as provided for in 11.5.1.2 to this Article.
- Hours worked in excess of an employee's shift (minimum eight [8] hours) when working a regular full-time schedule.
- Hours worked in excess of forty (40) regular hours in a workweek, when working a regular full-time, flexible or part-time schedule.

11.5.1.2 An employee shall be paid at two (2) times the employee's regular rate, including applicable premiums for:

- More than four (4) hours worked in excess of an employee's shift (minimum eight [8] hours), or hours worked in excess of forty (40) regular hours plus twenty (20) time-and-one-half hours in a workweek.
- All hours worked on the second scheduled day off in a workweek when no schedule change is involved. This applies only if an employee works at least eight (8) hours on the first scheduled day off.
- All hours worked on a Sunday that is a scheduled day off.
- Call-Ins as provided for in 6.1.5 within this Agreement.
- All hours worked on holidays as provided for in Section 14.5 within this Agreement.

11.5.2 **Pay for On-Call Assignment**

- Sixty-nine dollars and fifty-three cents ($69.53) for each On-Call Assignment on an employee's regularly scheduled workday,

- One hundred four dollars and twenty-nine cents ($104.29) for each On-Call Assignment on an employee's scheduled days off, and

- One hundred thirty-five dollars and forty-six cents ($135.46) for each On-Call Assignment that begins on an actual (not an Observed) holiday as defined in Section 14.1 within this Agreement.

Effective June 1, 2024, the amounts listed in this Section above will be increased annually at the same time and percentage as the scheduled annual increase in accordance with 11.2.2 to this Article.

11.5.3 **Recognition for On-Call Assignments**

11.5.3.1 Employees who have eighty (80) to one hundred four (104) On-Call Assignments in a calendar year will receive a payment of one and a half percent (1.5%) of that Employee's regular and overtime earnings for that same calendar year payable in a lump sum on the second regularly scheduled paycheck in January of the next year. An employee who retires or separates employment prior to the end of the calendar year and has earned the On-Call Assignment Recognition Incentive shall be paid the on-Call Assignment Incentive with their final paycheck.

11.5.3.2 Employees who have one hundred five (105) or more On-Call Assignments in a calendar year will receive a payment of two and a half percent (2.5%) of that Employee's regular and overtime earnings for that same calendar year payable in a lump sum on the second regularly scheduled paycheck in January of the next year. An employee who retires or separates employment prior to the end of the calendar year and has earned the On-Call Assignment Recognition Incentive shall be paid the on-Call Assignment Incentive with their final paycheck.

11.5.3.3 Call-In pay is in addition to On-Call Assignment pay as provided in 6.1.5 within this Agreement. On-Call Assignment periods are not to be counted as time worked for the purpose of calculating overtime.

11.5.4 **Schedule Based Premium Pay**

11.5.4.1 **Saturday/Sunday Pay.** Hours worked on Saturday and/or Sunday as part of the employee's regularly scheduled workweek; as defined in Article 6 within this Agreement; shall be compensated an additional four dollars ($4.00) per hour.

11.5.4.2 **Shift Work Pay.** Hours worked on Swing and/or Graveyard shift as part of the employee's regularly scheduled workweek shall be compensated an additional two dollars ($2.00) per hour for Swing shift and three dollars ($3.00) per hour for Graveyard shift.

11.5.5 **Skill Based Premium Pay**

11.5.5.1 **HAZWOPER Work Pay.** Employees trained to perform duties identified by the Company as HAZWOPER (Hazardous Waste Operations and Emergency Response) will receive an additional three dollars and fifty cents ($3.50) per hour for the entire shift when performing such duties.

11.5.5.2 **Bilingual Pay.** All hours worked by an employee who is qualified for and participating in an approved Bilingual Program shall be compensated an additional two dollars ($2.00) per hour.

11.5.5.3 **High Angle Work Pay.** Employees identified, trained and certified in high angle work and rescue skills shall be paid an additional three dollars and fifty cents ($3.50) per hour when performing such duties.

When an employee is eligible and earning premium pay under any of the categories listed in this Section, that premium pay will be included when calculating the employee's overtime rate.

Section 11.6 Accurate Timekeeping

It is the Company's intention to perform accurate timekeeping and payroll entry. In the event of a discrepancy with an employee's submitted time, the employee will be contacted as soon as possible to identify and correct the discrepancy.

ARTICLE 12
PAID TIME OFF (PTO)

Section 12.1 General

Paid Time Off (PTO) benefits are available to employees and may be used for vacation, illness, accident, family illness, medical appointments, or other personal business. PTO shall accrue according to Length of Service with the Company as defined in Section 12.3 to this Article.

12.1.1 **Guidelines for PTO Scheduling**

Established PTO selection groups based on a department, work group or resource center with more than one (1) bargaining unit employee may create their own guidelines for PTO scheduling.

These guidelines shall be made available to all employees on the Company intranet and:

- Include signatures of the department Manager and the Union Representative.
- Include date the guidelines were completed or reviewed.
- Be reviewed no more than once each calendar year, and changes must be finalized sixty (60) days prior to the start of the department's PTO selection process.

12.1.2 Unless otherwise defined in an employee's department, work group or resource center guidelines, scheduling of available PTO will be as follows:

- During the first round of scheduling, full work weeks, including weeks with holidays, and consecutive weeks may be scheduled.
- During the second round, partial weeks and single days can be scheduled.
- Carry over PTO hours accrued in previous years may be scheduled once all employees have been afforded the opportunity to schedule their current year accrual.
- Groups without guidelines will review the need for guidelines not more than annually and if mutually agreed to, then, the group can continue to operate without guidelines.

12.1.3 Employees will be required to take a minimum number of PTO hours annually (Annual Minimum Usage) as described in 12.2.2 to this Article, but will otherwise be able to carry over accrued but unused PTO up to a total of four hundred and eighty (480) PTO hours.

All other PTO provisions of the Agreement apply (i.e., requests must be made forty-eight [48] hours in advance, etc.).

12.1.4 **Previously Approved PTO Scheduling When Awarded a Position**

Once a position has been awarded, the awarding group will accommodate the PTO requests that were previously approved, subject to availability and approval. If an employee exercises the right of return, the group that the employee is returning to will attempt to accommodate the PTO request that was previously approved, subject to availability and returning Supervisor approval.

12.1.5 The LMC Co-Chairs may approve payout of annual minimum usage time not taken that otherwise would be forfeited due to the inability to schedule the

minimum because of a disability or protected leave. In all other cases, for employees who do not take the full annual minimum usage of PTO, the PTO will be forfeited.

12.1.6 **Annual Minimum PTO Usage Exceptions**

12.1.6.1 Employees are responsible to schedule and take annual minimum PTO within department guidelines.

12.1.6.2 For employees whose medical disability time off or protected leave does not allow them to schedule their entire annual minimum PTO usage hours, unused minimum hours may be paid out rather than rolled over. In these cases, employees need to make their request via email to the LMC Co-Chairs prior to December 31st. Requests are reviewed on a case-by-case basis; approval is not automatic. Employees will be advised via email of the final decision.

12.1.6.3 On a voluntary basis, employees may donate up to 40 PTO hours annually to other employees. Donated time does not count towards minimum usage for either the giver or the recipient and must be scheduled in accordance with 12.1.1 and 12.1.2. The recipient must have satisfied their probationary period.

Section 12.2 Accrual

12.2.1 Regular employees begin to accrue PTO benefits from the first day of regular employment. PTO benefits are credited to the employee's account at the end of each pay period.

12.2.2 The rate of PTO accrual is based on a regular employee's Length of Service as follows:

Length of Service	Annual PTO Accrual	Annual Accrual In Hours	Annual Minimum PTO Usage
0 to less than 1 year	16 days	128 Hours	0 Hours
1 to less than 5 years	16 days	128 Hours	40 Hours
5 to less than 13 years	21 days	168 Hours	80 Hours
13 to less than 22 years	26 days	208 Hours	120 Hours
22 years and more	31 days	248 Hours	160 Hours

12.2.3 During the year in which an increase in annual PTO accrual occurs, the change will take place during the pay period of the regular employee's anniversary date and will be prorated for the calendar year.

12.2.4 Term and Intern Employees accrue PTO only as provided for in their Term Employment Agreement.

12.2.5 Employees who qualify for Short-Term Disability (STD), Workers' Compensation (WC), or protected leave as defined in Company policy will continue to accrue PTO during their first six (6) months of absence.

12.2.6 Employees do not accrue PTO while on Long-Term Disability (LTD) or after six (6) months on WC or protected leave as defined in Company policy, unless otherwise required by applicable law.

12.2.7 PTO will not accrue during a voluntary unpaid leave of absence of any duration (See Section 12.7 to this Article).

12.2.8 Employees may borrow PTO in advance up to their current year annual accrual. An employee who terminates employment with a negative PTO balance will be required to reimburse the Company for the PTO advanced to the employee. Employees agree and understand that this reimbursement will be deducted from the employee's final paycheck and that such deduction is specifically authorized as a term of this Agreement.

12.2.9 PTO accrual for part-time regular employees will be prorated based on the actual hours worked as compared to a full-time year of two thousand eighty (2,080) hours.

Section 12.3 Length of Service

12.3.1 Length of Service for purposes of determining PTO accrual shall be defined to include:

- The time during which the regular employee was an employee and received income (pay) or income replacement (e.g., STD, LTD, WC), regardless of whether that previous service was as a regular, Term, or Intern employee; and

- An approved period of absence without pay that is less than sixty (60) consecutive calendar days. In such a circumstance, the regular employee will retain their original hire date for the calculation of the Length of Service.

12.3.2 Length of Service does not include periods of absence without pay of sixty (60) or more consecutive calendar days, unless otherwise required by applicable law.

12.3.3 Regular employees who have a break in service may be eligible for an adjusted PTO abridgement date for PTO accrual if their prior eligible Length of Service is greater than the time they were not an employee of the Company. If so eligible for abridgement date, the duration of the break in service will not be credited toward

Length of Service. The determination of this adjustment will be done at the time of rehire.

12.3.4 Section 12.3 to this Article addresses Length of Service for purposes of determining PTO accrual. Length of Service may be defined differently in other benefits plans including, for example, the Retirement Plan for bargaining unit employees. In such cases, the terms of the individual plan(s) control.

Section 12.4 Buy Back Provision

Employees may request a buy back of their annual PTO accrual which exceeds the minimum usage requirement. Requests for buy back will be permitted so long as the PTO balance is not reduced below thirty-two (32) hours. The thirty-two (32) hour buy back restriction does not apply to the scheduling of PTO (i.e., PTO can be scheduled to a zero [0] balance, but not sold below the thirty-two [32] hour balance).

In all buy back instances, the calculation of pay for buy back requests refers to the current rate of pay at the time of the buy back, which means the rate of pay contained in the Wage Scale for the current awarded position. If rate retained, the higher rate applies. This applies only to situations of PTO buy back and has no impact on the language contained in Section 12.5 to this Article.

All PTO buy back shall be in accordance with IRS rules and Company guidelines and will be made available to all employees on the Company intranet.

Section 12.5 Rate of Pay

The rate of pay for PTO shall be computed at the employee's wage rate for the employee's current awarded position. If rate retained, this higher rate applies. In addition, the rate of pay shall include the appropriate shift work pay and other premium pay if the employee works (is scheduled to work) shift work and/or receives premium pay every working day.

Section 12.6 Scheduling of PTO

12.6.1 Except for emergencies, bereavement and PTO for unanticipated illness as described in Section 15.1 within this Agreement, requests for PTO for full or partial day absences must be made forty-eight (48) hours in advance and require prior Supervisor approval. The minimum increment of time that may be used for PTO is fifteen (15) minutes.

12.6.2 Employees will schedule PTO on a Company seniority basis according to workgroup, department or resource center guidelines and in accordance with this Article. Guidelines will be made available to all employees on the Company intranet.

Section 12.7 Voluntary Leave of Absence without Pay

A voluntary unpaid leave of absence is a leave of absence without pay that does not fall within any category of protected leave as defined in Company policy. Employees are eligible for a voluntary unpaid leave of absence only as provided for in Company policy. Annual PTO accrual must be exhausted before an employee may take a voluntary unpaid leave of absence and PTO will not accrue during a voluntary unpaid leave of absence of any duration. Under certain business conditions the Executive Officer responsible for Human Resources may waive the requirement to use the annual PTO accrual prior to allowing voluntary leave without pay.

Section 12.8 PTO Counts as Time Worked

Any PTO used by an employee shall be treated as if it were time worked for the purpose of computing overtime.

Section 12.9 PTO at Separation

At the time an employee retires or separates employment, all accrued and unused PTO will be paid to the employee with their final paycheck. Accrued PTO is not intended to be used to extend employment prior to retirement or separation, therefore, employees shall not schedule more than a maximum of one (1) month of PTO just prior to their retirement or separation date.

ARTICLE 13
PAID BEREAVEMENT LEAVE

Section 13.1 General

13.1.1 Employees are eligible for Paid Bereavement Leave in the event of the death of a covered family member. Eligible employees may take up to a maximum of three (3) workdays of Paid Bereavement Leave for each death of a covered family member to grieve and attend to matters related to the loss. A covered family member is defined in the Company's Bereavement Leave policy.

13.1.2 Employees must notify the Company as soon as practical when taking Paid Bereavement Leave or any extension of bereavement leave covered by PTO in accordance with departmental absence reporting practices. Employees may be required to provide documentation.

Section 13.2 Rate of Pay

The rate of pay for Paid Bereavement Leave shall be computed in the same manner as PTO as described in Section 12.5 within this Agreement.

ARTICLE 14
HOLIDAYS

Section 14.1 Holidays Defined

14.1.1 **Paid Holidays**

New Year's Day
Martin Luther King Jr. Day
Memorial Day
Independence Day
Labor Day
Veterans Day
Thanksgiving Day
Day after Thanksgiving
Christmas Day
Three (3) Floating Days per calendar year
One (1) Additional Designated Holiday

14.1.2 **Paid Holidays Falling on a Saturday and/or Sunday**

Any Holiday which falls on a Sunday shall be observed on the following Monday; any Holiday which falls on a Saturday shall be observed on the Friday before. However, for employees with regular schedules that include scheduled workdays of Saturday and/or Sunday, the holiday shall be recognized on the actual date of the Holiday and not on the Observed Holiday.

Section 14.2 Holiday Pay

14.2.1 Full-Time regular employees shall receive holiday pay based upon an eight (8) hour day regardless of assigned shift (e.g., ten [10] or twelve [12] hours) and will be paid at the employee's regular straight time pay. For remaining hours beyond eight (8) hours, employee may use PTO or Leave without Pay.

14.2.2 Part-Time regular employees receive holiday pay based on the actual hours compensated in the two (2) full pay periods prior to the pay period in which the Holiday occurs as compared to a normal two (2) full pay periods of one hundred sixty (160) hours.

Section 14.3 Floating Days

14.3.1 Floating days are additional paid days off which are not defined holidays and during which the Company will remain open. Employees are eligible for three (3) floating days per calendar year. Floating days must be used within the calendar year or they are forfeited. Floating days will be made available by Management to the limit required by the department to assure appropriate business staffing. Employees must schedule their floating days within these limits with the mutual agreement of their Supervisor.

14.3.2 Employees in their first year of employment will be eligible for floating days during that calendar year as follows:

Hire Date	Floating Days Qualified For
January 1 through April 30	Three (3) 8-hour days
May 1 through September 30	Two (2) 8-hour days
October 1 through November 30	One (1) 8-hour day
December 1 through December 31	0 days

14.3.3 Scheduled floating days qualify as a holiday for pay. Part-Time regular employees receive pay for floating days per 14.2.2 within this Article.

Section 14.4 Additional Designated Holiday

Employees will be given one (1) additional designated holiday to be used on the workday before or after Christmas or New Year's Day. The day or days available for scheduling the additional designated holiday will be based upon staffing requirements as determined by the department Manager, which may vary by employee if the department is not closed. Date(s) to be determined and communicated before annual PTO scheduling.

Scheduled additional designated holidays qualify as a holiday for pay.

Section 14.5 Holiday Allowance for Work on a Holiday

Employees who are scheduled to work during a holiday (actual and/or observed), additional designated holiday, or on a previously scheduled floating day shall be paid at two (2) times the employee's regular rate and the rate of pay shall include the shift differential and other applicable premium pay if the employee works or is scheduled to work an alternate shift and/or receives premium pay every working day. In addition, the employee will receive eight (8) hours of holiday pay.

Section 14.6 Holiday Pay if Absent

14.6.1 Employees who are absent are eligible for holiday pay when on:

- Approved PTO or absences, including State(s) Paid Sick Leave, the scheduled workday before or scheduled workday after a holiday;
- Paid status for a continuous absence for a period of not more than six (6) months and when the pay is in some form directly from the Company;
- Unpaid status in conjunction with a protected leave; or
- Short-Term Disability (STD). The employee receives holiday pay to supplement the portion of the employee's earnings not paid through STD,

calculated at the employee's regular straight-time rate not to exceed a total of one hundred percent (100%) of the employee's regular pay.

14.6.2 Employees are not eligible for paid holiday(s) when the employee is:

- Absent the scheduled workday before or the scheduled workday after the scheduled holiday(s) and the absence is unapproved, and in accordance with 9.3.1.4 within this Agreement*;
- On Workers' Compensation (Industrial Disability) paid leave. The Employee will continue to receive time loss payments from the Workers' Compensation carrier;
- Absent for six (6) months or more;
- On a voluntary unpaid leave of absence of any duration;
- On a period of absence for which the employee is already receiving full pay from the Company; or,
- On Long-Term Disability (LTD). The employee receives LTD pay through the LTD provider and is not eligible for holiday pay.

*When an employee has an unapproved absence due to treatment at a healthcare provider (doctor's office), urgent care facility, emergency room, or admission to a hospital and the employee provides documentation of such treatment, the employee shall be eligible for holiday pay.

Section 14.7 Holiday Counts as Time Worked

Paid holidays shall be counted as time worked for the purposes of computing overtime if the holiday falls on an employee's scheduled workday. If the holiday falls on an employee's scheduled day off, it shall be treated the same as a Saturday and be paid at the employee's regular straight time pay.

ARTICLE 15
DISABILITY

Section 15.1 Non-Industrial Disability

15.1.1 **Short-Term Disability (Non-Industrial)**

Short-Term Disability (STD) benefits are available to eligible regular employees.

Qualified absences for eligible full-time regular employees that exceed four (4) consecutive or non-consecutive workdays in a consecutive fourteen (14) calendar

day period for the same non-industrial illness or injury are covered under STD subject to the provisions and eligibility requirements of the NW Natural Short-Term Disability Income Protection Plan (STD Plan). For part-time regular employees the elimination period will be prorated based on the actual hours compensated in the two (2) full pay periods prior to the pay period in which the initial absence occurs as compared to a normal two (2) full pay periods of one hundred sixty (160) hours.

STD income replacement is based on a regular employee's Length of Service, as defined in Section 12.3 within this Agreement, and as follows:

Length of Service	Percentage of Income Replacement
0 to less than 10 years	70%
10 to less than 15 years	80%
15 years and more	85%
Date of hire 1994 and earlier (honored)	100%

STD benefits are provided to eligible regular employees for as long as the employee(s) have an accepted disability claim supported by the employee's health care provider, and determined by the disability carrier. However, the maximum period for a STD claim is one hundred eighty (180) consecutive calendar days. All STD requests require documentation from a qualified healthcare provider supporting the illness/injury. A period of short-term disability may require the employee's qualified healthcare provider's release to return to work when directed by the third-party STD Plan Administrator.

While an employee is on company paid STD Plan, the Company will continue to contribute to the employee's retirement plan(s), transfer Union dues, and contribute Company portion of the Health & Welfare premium share.

While an employee is receiving benefits from a State Paid Leave Program the Company will continue to pay the employer share of the Health and Welfare premium.

Regular employees may elect to supplement their STD income replacement up to one hundred percent (100%) of their regular rate of pay by drawing on their PTO account.

For more details regarding STD, including eligibility requirements and coordination with State Paid Leave Laws, refer to the STD Plan summary plan description or contact Human Resources. All plan descriptions will be made available to all employees on the Company intranet.

15.1.2 **Long-Term Disability (Non-Industrial)**

Long-Term Disability (LTD) benefits are available to eligible regular employees. A qualified disability for eligible regular employees that extends beyond one hundred eighty (180) calendar days will be covered under LTD subject to the provisions and eligibility requirements of the bargaining unit Group Long Term Disability Insurance Program (LTD Plan). The LTD Plan provides income continuation at sixty percent (60%) of the regular employee's pay for as long as disabled, until the regular employee reaches the Maximum Duration of Benefits as outlined in the LTD Plan. Each period of Long-Term Disability requires a qualified healthcare provider's release to return to work as coordinated through the third-party LTD Plan Administrator. For more details regarding LTD, including eligibility requirements, refer to the LTD Plan or contact Human Resources.

A regular employee's employment will end on the anniversary date of the first day of absence, as defined in Consecutive Disability Period (per Section 15.5 to this Article). LTD benefits may continue as described above and per the terms of the LTD Plan. Nothing in Article 15 is intended to indicate a guarantee of employment; employment may be ended for other reasons during the year, subject to other provisions of this Agreement.

A regular employee whose employment has ended as described in this Article will retain the right to apply for an open and available position as an internal bidder for a time period equal to two (2) years or one (1) month per full year completed from date of hire, whichever is greater, from the date of first absence related to the disability. The employee's Company, Job and/or Line of Progression seniority accumulated as of the last day of employment will be used for bids and awards per Article 4 within this Agreement.

Section 15.2 Workers' Compensation (Industrial Disability)

If an employee is injured on the job, the employee may be eligible for Workers' Compensation benefits, including industrial disability pay. If injured on the job, the employee will contact their Supervisor immediately to report the injury and complete any required form(s) in a timely manner. In no case shall an employee receive non-industrial disability pay and industrial disability pay for the same period(s) of time. If for any reason an employee's Workers' Compensation claim is denied, the employee may apply for coverage of the disability using the non-industrial disability programs outlined in 15.1.1 and 15.1.2 to this Article.

Section 15.3 Workers' Compensation (Industrial Disability) Supplemental Pay Allowance

Industrial disability pay or "time loss" in connection with a Workers' Compensation claim generally begins following a waiting period (currently three [3] days). The Company will compensate the employee during the waiting period with a supplemental allowance equal to the employee's statutory rate of sixty-six and sixty-seven hundredths' percent (66.67%) of an employee's regular straight time pay on a tax-free basis.

Section 15.4 Reemployment and Reinstatement Arising from Industrial Disability

15.4.1 If it is determined that a regular employee has ongoing restrictions which prevent them from returning to their current regular job, the Parties will consider applicable ADA (Americans with Disabilities Act) reasonable accommodations and/or state workers' compensation reemployment or reinstatement provisions to explore options for that employee.

15.4.1.1 Employees on permanent restrictions due to Industrial Disability are encouraged to seek open positions that fit with their restrictions and must follow the bidding process per Article 4 within this Agreement.

15.4.1.2 With joint Union and Management agreement, these employees may be placed into an open position without posting the open position.

15.4.2 If a regular Employee exceeds one (1) year of Consecutive Disability Period (as defined in Section 15.5 to this Article) related to the covered industrial disability, the employee's employment will end. Workers' Compensation benefits may continue, subject to eligibility in accordance with applicable Workers' Compensation laws. The regular employee also retains the right to apply for any open and available position for which they meet bidding qualifications as an internal bidder for a time period equal to two (2) years from date of separation of employment. The employee's Company, Job and/or Line of Progression seniority accumulated as of the last day of employment will be used for bids and awards per Article 4 within this Agreement.

15.4.3 A regular employee who is placed, awarded, or reemployed in a lower classification per Section 15.4 to this Article shall have their pay administered as an Honored Pay Rate Employee subject to provisions in Section 11.4 within this Agreement.

15.4.4 A regular employee whose employment is ended per 15.4.2 to this Article will be eligible for a COBRA (Consolidated Omnibus Budget Reconciliation Act) subsidy equivalent to the amount and duration provided through the LTD Plan. This subsidy will be adjusted to match the LTD benefit as needed.

Section 15.5 Consecutive Disability Period (Industrial and Non-Industrial)

The Consecutive Disability Period starts with the first day of absence for the covered disability and includes time off on STD and/or LTD and/or Workers' Compensation. Any return to work for twenty-nine (29) calendar days or less, excluding PTO, does not restart or extend this Consecutive Disability Period.

The Consecutive Disability Period ends when an employee returns to work, without restriction (with or without accommodation), for a period of thirty (30) or more consecutive calendar days, excluding PTO, in either the employee's original position or a new regular position. Any

subsequent absence related to the same initial disability would start a new Consecutive Disability Period.

Section 15.6 Family and Medical Leave Act and Americans with Disabilities Act (ADA)

As detailed in Section 2.6 within this Agreement, the parties strive to comply with all applicable laws, rules and regulations governing the workplace, including but not limited to the Family and Medical Leave Act (and applicable state law) and the Americans with Disabilities Act (and applicable state law). To the extent applicable laws include exceptions for parties in a collectively bargained relationship, this Section does not address or waive the application of such exceptions.

15.6.1 **Family and Medical Leave Act (and Related State Laws)**

Federal and State laws permit eligible employees to take unpaid leave in certain circumstances. These laws include, for example, the federal Family and Medical Leave Act (FMLA), the Oregon Family Leave Act (OFLA), the Washington State Family Leave Act (WFLA), the Washington State Family Care Act (WFCA), and the Washington State Military Family Leave Act (WMFLA).

15.6.2 **Americans with Disabilities Act (and Related State Laws)**

Employees must be able to perform essential job functions with or without reasonable accommodation.

ARTICLE 16
HEALTHCARE

Section 16.1 Employees

The Company shall pay into the Western States Health & Welfare Trust Funds of the OPEIU, hereinafter the Welfare Trust Fund, the costs necessary to establish and maintain coverage for medical, dental, vision, and life insurance benefits for eligible employees through the Welfare Trust Fund, including that percentage specified in 16.1.1.3 to this Article as the responsibility of the employee. The terms and conditions of coverage are set forth in the Welfare Trust Fund's plan documents and are not the subject of negotiation between the Parties.

16.1.1 **General**

16.1.1.1 These Company payments will be made only for eligible employees who are regularly scheduled to work twenty (20) or more hours per week. Term employees are eligible only for the benefits identified in their Term Employee Agreement.

16.1.1.2 For the term of this Agreement the Company will share in the cost of benefits with employees as necessary to provide benefits under the Welfare Trust Fund, on the effective dates and in the amounts described below.

16.1.1.3 Effective with the benefit year beginning January 1, 2025, and for the term of the Agreement, eligible employees shall be responsible for fifteen percent (15%) of the cost of the premium. The premium share payments for the Company and employees described above are based on composite rates provided by the Welfare Trust Fund and will apply regardless of the number of dependents that the employee enrolls. If the Trustees of the Welfare Trust Fund make alternate rates available during the term of this Agreement, the Parties agree to negotiate the impact of any alternate rates.

The Company is authorized to deduct from each eligible employee's wages the percentage amount described above as the employee's cost of premium in such amount that is necessary to maintain coverage under the Welfare Trust Fund.

16.1.2 **Spouses or Partners Both Working for NW Natural**

An employee who is married to, or in a domestic partnership with, a current or former Company employee who is eligible for Company payments to the Welfare Trust Fund will not be required to opt out of coverage, but may elect to opt out. In which case, the employee will be covered under the voluntary provisions of 16.1.3 to this Article.

16.1.3 **Opt Out Due to Other Coverage**

Employees eligible for Company payments to the Welfare Trust Fund may voluntarily opt out of Welfare Trust Fund medical, dental, and vision coverage, provided that they produce evidence of other such coverage. Employees who opt out of coverage will receive a cash payment of three hundred dollars ($300.00) per month in lieu of Company payments to the Welfare Trust Fund. This monthly cash payment can be applied to other benefits offered by the Company (such as additional life insurance or additional life insurance or additional LTD, subject to the terms of those benefits), deferred into the RKSP 401(k) Plan, taken as cash, and/or directed into the Flexible Spending Account.

16.1.4 **Timing of Elections**

In any case where an employee can elect a cash payment in lieu of Company payments to the Welfare Trust Fund, the employee's election must be made under, and in compliance with, a cafeteria plan under Section 125 of the Internal Revenue Code, as amended (Code). The provisions of Section 16.1 to this Article shall be interpreted and applied in a manner that complies with Section 125 of the Code.

Section 16.2 Retirees

16.2.1 **General.** A covered retiree is a former employee who (i) is eligible for and elects to retire at or after age sixty (60) with a total of fifteen (15) years of service, or at or after age fifty-eight (58) with a total of twenty (20) years of service, under the Retirement Plan and (ii) enrolls in retiree coverage through the Welfare Trust Fund. A covered retiree may enroll their eligible dependents (as defined by the Welfare Trust Fund). Retiree medical coverage through the Welfare Trust Fund ends when the covered retiree becomes Medicare eligible, currently age sixty-five (65). The Company's obligations under this Agreement are to make payments to the Welfare Trust Fund for retiree medical coverage through the term of this Agreement.

16.2.2 Effective through the term of this Agreement, the premium necessary to maintain benefits for each covered retiree under the Welfare Trust Fund shall be paid by the Company and covered retiree, as of the effective date of this Agreement (seventy-five percent [75%] Company/twenty- five percent [25%] Covered Retiree).

16.2.3 The premium share payments for the Company and covered retirees are based on composite rates and will apply regardless of the number of dependents (if any) that the covered retiree enrolls. If the Trustees of the Welfare Trust Fund make alternate rates available during the term of this Agreement, the parties agree to negotiate the impact of any alternate rates.

16.2.4 **Exclusion of Certain Employees**

Employees hired on or after January 1, 2010, are not eligible for retiree medical coverage under the Welfare Trust Fund or for Company payments to the Welfare Trust Fund. Employees who terminate employment with the Company and who are rehired on or after January 1, 2010, are not eligible for retiree medical coverage under the Welfare Trust Fund or for Company payments to the Welfare Trust Fund. This exclusion applies regardless of the length of the rehired employee's break in Company employment and regardless of whether the rehired employee previously would have been eligible for retiree medical benefits.

Section 16.3 Retirees with Spouses or Partners Eligible for Company Paid Benefits

A Company retiree who is eligible for coverage under the Welfare and Trust Fund will not be required to opt out of coverage but may elect to opt out. In which case, the company retiree will be covered under the voluntary provisions of 16.1.3 to this Article.

ARTICLE 17
OTHER BENEFITS

Section 17.1 Meal Stipend

17.1.1 **Meal Stipend.** Employees, except for those on per diem, shall be provided a meal stipend for any of the listed situations:

a. Working three (3) or more hours in addition to the assigned shift duration (minimum eight [8] hour shift);

b. Each four (4) hours of continuous overtime beyond the original three (3) hours;

c. Unplanned Shift Change or Call-In without at least three (3) hours advance notice to provide for a meal; or,

d. After four (4) consecutive hours of work on a Call-In.

17.1.2 **Time Stipend.** Employees who meet the criteria of 17.1.1 (a), including those on per diem, shall be paid the amount equivalent of thirty (30) minutes of time at one and one-half (1.5) times the regular rate. The thirty (30) minutes will be paid one (1) time per continuous work period and shall not be counted as time worked for the purpose of calculating overtime.

17.1.3 Effective November 1, 2023, the meal stipend is twenty-three dollars and sixty cents ($23.60). The meal stipend will be adjusted annually by the same percentage adjustment made to the per diem rate, if any. The dollar amount of meals will be recalculated annually by indexing it to the Government Services Administration's per diem rate for the State of Oregon as described in 17.2.2 of this Article.

Section 17.2 Per Diem

17.2.1 An employee shall be provided per diem for each day the employee is temporarily assigned job duties away from the regular work area which requires an overnight stay, including the first and last scheduled workdays. Such allowance shall include all personal expenses other than lodging and travel, and is provided to cover such items as meals, tips, personal phone calls, and local transportation. Meal stipends are not provided when the employee receives per diem.

17.2.2 Effective December 1, 2023, the per diem rate is sixty-six dollars ($66.00). The per diem rate will be adjusted annually by averaging the Government Services Administration's State of Oregon rates as published on the website (www.gsa.gov). This per diem rate will be adjusted not less than thirty (30) days after publication by averaging the Meals and Incidental rate column for the close

of the government fiscal year, published approximately October of each year for the following twelve (12) month period.

Section 17.3 Compensation for Travel

Employees will be compensated for travel and mileage. Federal applicable state wage and hour regulations apply as a minimum in these situations, absent an agreement between the Parties.

17.3.1 Paid Travel Guidelines

Paid travel is to be completed during regular scheduled working hours if possible. With the appropriate advance notice, an employee's schedule can be changed to accommodate travel time. (To determine if an Unplanned Shift/Schedule change, see 6.1.3 within this Agreement).

- Paid travel at a time other than the employee's regular scheduled working hours must be pre-approved by Management.
- Paid travel time shall be counted as time worked for the calculation of overtime. To determine appropriate pay, refer to 11.5.1 within this Agreement for overtime calculation with the exception that travel on Sundays or holidays is not automatically paid at two (2) times the regular rate.
- Paid travel time is eligible for applicable premium pay.
- For standard travel times and mileage between Company-based locations, refer to the Hub. Travel times and mileage between locations other than Company-based locations will be calculated by management utilizing the method used by the Labor/Management Committee (LMC) [e.g., currently GoogleMaps]. Time exceeding those calculated will be reported to Management for compensation.
- When applicable, mileage reimbursement will be paid in accordance with the Company's Mileage Reimbursement Policy and will be made available to all employees on the company intranet.
- A Company vehicle may be temporarily or permanently assigned to employees for "drive home" use based on business needs.

17.3.2 Travel within Company Territory Requiring Overnight Stay

The Company will provide lodging when an overnight stay is required. The Company is responsible for all associated costs of lodging prior to travel. Employees will not be responsible for any out-of-pocket expenses for lodging,

excluding incidentals. Employees may be required to provide personal credit card to cover incidentals.

- If the employee requests and Management agrees, the employee may travel on a normal day off ahead of the desired reporting day to the temporary reporting location. Under these circumstances, the Company will provide lodging for that day and time spent traveling to the temporary location will be compensated as time worked based on the calculated travel time from the employee's Company-based location to the temporary reporting location. Per diem will not be provided for that day.

- Employees returning home on the last day of a work assignment will be paid for time worked that day including the standard time to drive from the temporary reporting location to the employee's Company-based location. They will also receive per diem for that day.

- If an employee uses a personal vehicle to commute to and from the temporary reporting location, mileage reimbursement will be provided for that commute based on the standard mileage between the employee's Company-based location and the temporary reporting location.

17.3.3 Travel Outside Company Territory

The Company may ask employees to travel to training or other events outside of the territory. Such travel can normally be completed within an eight (8) hour timeframe, but due to unforeseen circumstances (e.g., weather or mechanical delays) may exceed this time.

- All travel arrangements, including scheduled travel day, and itinerary, are to be mutually agreed to by the employee and Management prior to travel. The Company is responsible for all associated costs of lodging prior to travel. Employees will not be responsible for any out-of-pocket expenses for lodging, excluding incidentals. Employees may be required to provide personal credit card to cover incidentals.

- Paid travel time for travel outside of scheduled working hours shall be up to a maximum of eight (8) hours per day in addition to any time already worked that day, unless otherwise required by applicable law. Employees will also receive per diem for that day.

- Travel time is only those hours spent in transit to or from the travel destination.

- Company Policy "Business Travel Procurement and Expense Reimbursement" also applies for travel arrangements outside NWN territory.

17.3.4 **Voluntary Travel Alternatives**

Travel alternatives at the employee's discretion (mode of travel, early arrival or late departure for personal reasons) must be mutually agreed upon by the employee and Management. Such travel should be cost neutral to the Company.

When voluntary travel arrangements result in missed workdays, those days will be charged to Paid Time Off (PTO).

Section 17.4 Transportation

17.4.1 **Basis of Allowance**

Employees who use their personal vehicles for Company business shall be compensated at the rate authorized by the Company, taking into consideration the rate established by the Internal Revenue Service (IRS). The current rate will be made available to all employees on the Company intranet.

17.4.2 **Parking**

The Company has no obligation to provide employee parking, but will make parking available to the extent possible. A parking Flexible Spending Account (FSA) will be available to employees to allow for pre-tax benefit account that can be used to pay or get reimbursed for qualified parking expenses.

17.4.3 **Transit Passes**

Transit passes will be made available to Headquarters-based bargaining unit employees at no cost to the employee. Oregon residents will be provided a TriMet pass. Washington residents who are reporting at 250 Taylor two (2) or more times per week will be provided a C-Tran pass upon request.

In the event of a personal emergency, the Company may provide accommodations to transport the employee to their destination.

Section 17.5 Jury Duty

17.5.1 Employees will receive their regular straight-time rate of pay while serving on jury duty, provided the employee has:

- Promptly notified a designated Company representative and presented a legally enforceable subpoena,
- Requested a transfer to a Monday through Friday Day Shift schedule, if applicable, and

- Called a designated Company representative on weekdays when excused from jury duty to determine whether to report to work.

17.5.2 Employees shall retain any compensation paid by the court while performing this civic function.

Section 17.6 Recognition Programs

In recognition of employee flexibility and support of continuous operations, departments or workgroups may develop recognition programs. Any new recognition programs are subject to approval of the LMC Leadership Team.

Section 17.7 Paid Parental Leave

Regular employees who are regularly scheduled to work twenty (20) or more hours per week are eligible for Paid Parental Leave following the birth, adoption of a child, or foster care placement. Eligible full-time employees qualify for one hundred and twenty (120) hours of pay at their regular rate of pay.

Eligible employees who are typically scheduled to work between twenty (20) to thirty-nine (39) hours per week will receive a pro-rated benefit, based on their weekly schedule. Additional details are provided in the Company's Paid Parental Leave policy.

17.7.1 If and when any new state or federal laws are passed that include a requirement for employers to provide additional paid or unpaid leave, the parties agree to meet and discuss total paid leave allocation. Paid Parental Leave will run concurrently with leave taken under the Oregon Family Leave Act, the federal Family and Medical Leave Act, and/or paid leave provided under any state law when applicable.

17.7.2 Eligible employees should provide thirty (30) days' advance notice or as much advance notice as practicable under the circumstances when requesting paid parental leave. Any paid parental leave provided will run concurrently with leave taken under applicable state or federal leave laws.

17.7.3 **Rate of Pay**

The rate of pay for Paid Parental Leave shall be computed in the same manner as PTO as described in Section 12.5 within this Agreement.

Section 17.8 Personal Protective Equipment (PPE) Allowances

PPE allowances will be reviewed annually and adjusted as necessary based on Tyndale's average price increase.

17.8.1 **FR (Fire Resistant) Clothing Allowance**

- Newly hired or rehired field employees who are required to wear FR clothing shall receive two thousand one hundred seventy-five dollars ($2,175.00) for the purchase of approved FR clothing by the end of the calendar year.

- All field employees who are required to wear FR clothing shall receive an annual allowance of nine hundred dollars ($900.00) for the purchase of approved FR clothing, effective January 1st, 2025.

- Employees have the obligation to take reasonable care of FR clothing. Employees are responsible for laundering. Employees may receive replacement of damaged FR clothing due to unanticipated work-related situations with Supervisor approval.

17.8.2 **Footwear Protection Allowance**

Employees required to wear safety footwear shall be provided up to three hundred dollars ($300.00) per calendar year for either purchase or refurbishment of boots (e.g., boot rebuilds or toe guards).

17.8.3 **Prescription Safety Glasses**

Employees requiring prescription safety glasses receive up to four hundred fifty dollars ($450.00) for two (2) pairs of prescription safety glasses during their initial year in the program, and thereafter an annual allowance of up to two hundred twenty-five dollars ($225.00) for replacement prescription safety glasses.

ARTICLE 18
RETIREMENT PLANS

Section 18.1 Bargaining Unit Employees' Retirement Plan

The Company shall continue to maintain the NW Natural Gas Company Retirement Plan. The Company will make contributions to the Retirement Plan in amounts determined by the Company in consultation with an enrolled actuary, that are sufficient on a sound actuarial basis to provide for the payment of benefits.

18.1.1 Regular employees employed on or before December 31, 2009, are eligible to participate in the Retirement Plan to the extent provided for in the written terms and conditions of the Retirement Plan. Term employees are eligible only for the benefits described in the Term Employee Agreement. Term employees are not eligible to participate in the Retirement Plan.

18.1.2 Regular employees hired on or after January 1, 2010, are not eligible to participate in the Retirement Plan. Regular employees who terminate employment

with the Company and who are rehired on or after January 1, 2010, are not eligible to participate in, or to accrue any additional benefits under, the Retirement Plan. This exclusion applies regardless of the length of the rehired employee's break in Company employment and regardless of whether the rehired employee previously participated in the Retirement Plan.

18.1.3 Western States Pension Plan (Western States Plan B)

Upon establishment of the plan, the Company will perform its due diligence for acceptance. Company and Trust Representatives will present the Western States Pension Plan B to the NW Natural RKSP Committee and to the NW Natural Board of Directors for approval. If approval is given the Company will make contributions to the Western States Office and Professional Employees Pension Fund on behalf of each eligible Regular Employee beginning the first of the calendar year following approval.

For employees hired or rehired on or after January 1, 2010, the Company will contribute four percent (4%) of the employee's compensation including overtime. Benefits are determined by the Board of Trustees of the Western States Plan and are not subject to negotiation between the Company and the Union.

If the plan is not approved in order to commence contribution on January 1, 2025, 18.1.3 will be opened to renegotiate.

Section 18.2 Retirement K Savings Plans (401(k) Plan)

18.2.1 **Retirement K Savings Plan (RKSP 401(k) Plan)**

Except as provided in this Agreement, all bargaining unit employees shall be eligible to participate in the RKSP 401(k) Plan under the terms and conditions set forth in the RKSP 401(k) Plan document. For purposes of Section 18.2 to this Article, employees participating in the RKSP 401(k) Plan shall be referred to as "RKSP Participants." During the term of this Agreement, the Company will make a cash matching contribution each pay period on behalf of each RKSP Participant who has made elective deferrals to the RKSP 401(k) Plan during that pay period.

- During the term of this Agreement, the matching contribution shall be equal to fifty percent (50%) of the RSKP participant's elective deferrals (excluding catch-up contributions under Code Section 414(v)) for the pay period, but disregarding elective deferrals exceeding eight percent (8%) of the RKSP Participant's compensation, as defined in the RKSP 401(k) Plan, for the pay period.

- Term employees are eligible only for the benefits identified in their Term Agreements.

18.2.2 **Enhanced RKSP 401(k) Plan Contributions for Employees Hired or Rehired On or after January 1, 2010**

For employees hired or rehired on or after January 1, 2010, who are eligible to participate in the RKSP 401(k) Plan, the Company will separately contribute four percent (4%) of the employee's compensation for each plan year to the RKSP 401(k) Plan account (Enhanced RKSP 401(k) Plan Benefit). This Enhanced RKSP 401(k) Plan Benefit is available only to employees hired or rehired on or after January 1, 2010, as they are not eligible to participate in the NW Natural Gas Company Retirement Plan.

Pursuant to 18.1.3, the Enhanced RKSP 401(k) plan contribution will be redirected to Western State Pension Plan B in the same manner as the Enhanced Contributions are structured. Employees that are not eligible to enroll in the Western State Pension Plan will continue to participate in the Enhanced RKSP 401(k) plan.

ARTICLE 19
EMPLOYEE STOCK PURCHASE PLAN

Employees are eligible to participate in the Company's Employee Stock Purchase Plan ("ESPP") according to the terms and conditions set forth in the written ESPP document. The Company shall continue to have sole discretion to determine the terms and conditions of the ESPP applicable to employees, including contributions, benefits, and administrative provisions. The Company retains the right to terminate the ESPP at any time and will notify the Union of such decision prior to its implementation. Term employees are eligible only for the benefits identified in their Term Agreements.

ARTICLE 20
PROGRESSIVE DISCIPLINE

Section 20.1 General

The Company may discipline or terminate any employee for Just Cause and will determine the appropriate level of discipline based on the facts and circumstances presented. The Company shall conduct investigations and issue all discipline in an expedient manner. Notwithstanding the inclusion of Just Cause, the Union and the Company agree to a reasonable person standard to determine what's right, not who's right, in matters of discipline. To ensure the reasonable person standard is adhered to, discipline defense based purely on Just Cause must be approved by the Executive Secretary-Treasurer of OPEIU Local 11 or their designee.

20.1.1 **New Hire Probationary Periods**

Any probationary new employee can be terminated for any reason without intervention by the Union and without right of appeal to the Grievance and Mediation/Arbitration Process in Article 21 within the Agreement.

20.1.2 **Progressive Discipline**

Regular employees may be disciplined in the form of a Documented Verbal Warning, Disciplinary Action Plan, suspension, or termination for Just Cause. Discipline should be progressive to allow the employee the opportunity for improvement prior to moving to a higher level of discipline.

Section 20.2 Definitions

20.2.1 **Documented Verbal Warning (DVW)**

A disciplinary document a Manager or Supervisor may use that identifies in writing an employee's performance problems or other conduct that requires correction.

20.2.2 **Disciplinary Action Plan (DAP)**

A written disciplinary document a Manager or Supervisor may use that states specific performance problems or conduct requiring correction and requires that the employee fully correct the problem within a specified period of time.

20.2.3 **Suspension**

A disciplinary suspension is unpaid and may be used by a Manager or Supervisor in conjunction with a DVW or DAP.

20.2.4 **Last Chance Agreement (LCA)**

A written disciplinary document a Manager or Supervisor may use that states that employee misconduct could have led to termination, but the employee is being offered one final opportunity. An LCA is not subject to the grievance process.

Section 20.3 Disciplinary and Investigatory Meetings

During a disciplinary or investigatory meeting, an employee shall be afforded Union representation as associated with Weingarten Rights, upon the employee's request. The Company shall notify the appropriate representative of the Union (e.g., Steward, Chief Steward, Union Representative) and provide a reasonable period of time to be available for the meeting.

Employees shall be advised of their right to Union representation during any investigatory interview or meeting which could reasonably be expected to lead to disciplinary action.

Section 20.4 Process

Progressive discipline shall normally include the following steps:

20.4.1 **Documented Verbal Warning (DVW):** Supervisor is to keep the original in the supervisory file. A copy will be provided in accordance with Section 20.5 to this Article. Documented Verbal Warnings shall remain in effect for no more than two (2) years, at which time they shall be considered removed from the employee's supervisory file.

20.4.2 **Disciplinary Action Plan (DAP):** Copies of the DAP will be sent to Human Resources to be placed in the employee's personnel file and copies provided in accordance with Section 20.5 to this Article. Typically, a DAP will be in effect for up to one hundred and eighty (180) calendar days. Duration of DAPs longer than one hundred and eighty (180) calendar days must be signed by the Manager and the Union Representative.

Three (3) years after the satisfactory completion of a DAP, it will be considered moved from the employee's personnel file to the employee's "employee history file," provided no additional DAPs have been issued to the employee. This "employee history file" will be retained in Human Resources and will be considered a part of the employee's personnel record.

20.4.3 **Suspension:** In case of a suspension, the Company agrees that the employee and the Union shall be provided written documentation setting forth the reason(s) for such action, and in accordance with Section 20.5 of this Article. Employees are entitled to Union representation at such meetings.

To avoid undue burden on the workgroup the date(s) that the employee will be away from work for disciplinary suspension will be determined by applicable PTO guidelines. For work group(s) that do not have documented PTO scheduling guidelines the accepted departmental process will apply; if the suspension dates are not selected and agreed to within five (5) working days management will assign the dates.

For suspensions that are three (3) days or fewer, the date(s) will not be adjacent to employee's regular scheduled day(s) off. No suspension days will be taken adjacent to an observed Holiday. Unpaid dates will occur within sixty (60) days from the date of discipline.

20.4.4 **Last Chance Agreement (LCA):** Copies of the LCA will be sent to Human Resources to be placed in the employee's personnel file permanently and copies will be provided in accordance with Section 20.5 of this Article.

20.4.5 Employees will be required to acknowledge receipt in writing of any disciplinary action; which the employee's signature shall not be construed as agreement or

concurrence with the discipline; and in accordance with Section 20.5 of this Article.

Section 20.5 Distribution of Documents

The Company will provide copies of DVWs, DAPs, LCAs, and Terminations to the employee, Human Resources, Union Office, and Steward or Chief Steward. Sensitive information (e.g., LCAs) may be only shared with the Union Office to ensure privacy for the employee.

Section 20.6 Repetition of Infraction

Repetition of the infraction or failure to complete an action plan within the time specified may lead to further discipline up to and including termination.

Section 20.7 Discipline

As stated in Section 20.1 of this Article, any infraction may also warrant an immediate DAP, suspension, or termination.

Section 20.8 Bidding

Bidding on positions, advancing in a Line of Progression, or Progression without Bidding may be affected as a condition of progressive discipline.

Section 20.9 Grievance

The employee may file a written grievance appealing disciplinary action per Article 21 within this Agreement.

ARTICLE 21
GRIEVANCE AND MEDIATION / ARBITRATION PROCESS

Section 21.1 Introduction

The Grievance Process is limited to matters of discipline and unresolved Issue Resolution items, and in accordance with Section 21.3 to this Article. This Grievance Process is established on the premise of trust, respect and the mutual goal of resolving differences at the earliest opportunity and appropriate level. It is not intended to be a substitute for direct dialogue between employee and Supervisor or to be used for events covered by the Issue Resolution Process as per Article 10 to this Agreement.

Section 21.2 Timelines

When computing timelines under this Article, the day which triggers the grievance (contract violation, receipt of grievance, etc.) shall not be included. “Working days” means Monday through Friday, excluding holidays. Filing and response time limits shall be met by mailing, e-mail, hand delivery or facsimile transmission. Receipt shall be considered to be the date of actual receipt.

The time limits prescribed herein may be waived or extended by mutual agreement, in writing by the Steward, Chief Steward, or the Union, and the appropriate Company representative at each step.

A grievance not brought within the time limit prescribed for every step shall be considered settled on the basis of the Company's last decision received by the Steward, Chief Steward, or the Union. A grievance or complaint not responded to by the Company representative may be moved to the next step in the procedure.

Section 21.3 Written Grievances

A written grievance shall be documented on the official OPEIU Local 11 Grievance form and must be signed and dated and indicate the step at which it is being filed. Grievances not meeting the requirements of this Section shall not be considered officially filed or may not be moved to the next step until missing information is provided. Grievances or responses to grievances missing information may be referred to the LMC Co-Chairs or timelines can be extended in accordance with Section 21.2 to this Article. Written grievances and responses at all levels shall address, at a minimum, the following points:

- The statement of the grievance/response and the facts upon which it is based;
- Signed by the grievant and the represented parties involved;
- A statement of the specific provision(s) of the Agreement that is (are) the basis of the grievance/response;
- The manner in which the provision is purported to have been violated, misapplied, or misinterpreted (or in which the provision supports the response);
- The date or dates on which the alleged violation, misinterpretation, or misapplication occurred; and
- The specific remedy sought or offered.

Section 21.4 Grievance Process

A grievance can be initiated in the following ways:

- If the concern is about discipline, it should start at Level 1 in the grievance process.
- If the grievance is related to an employee's involuntary termination, Level 1 and Level 2 of the grievance process will be bypassed and the grievance process will start at Level 3 in accordance with this Article.
- The concern may be referred from the issue resolution process at the discretion of the LMC Co-Chairs. In these instances, the LMC Co-Chairs may elect to bypass Levels 1 and 2 of the grievance processes.

Grievances may necessitate meeting more than once at any particular level or obtaining information from additional sources; however, each level will be addressed in an expedient manner.

For grievances that start in the Grievance Resolution Process, the Steward and the Supervisor should first meet informally to understand and potentially resolve the unfiled grievance.

For grievances referred through the Issue Resolution Process, it is required that the Issue Resolution Committee write up what was agreed to, what the parties were unable to agree to, and narrowly describe the open question that has not been resolved.

21.4.1 **Level 1 – Process**

Participants: Employee, Steward(s) or the Union Representative, and the first line Supervisor or their designee.

Procedure: The Union Steward has twenty (20) working days to file a formally documented grievance for the employee(s) or on behalf of the employee(s) from the event or knowledge of the event and should be submitted to the Supervisor of the employee(s).

The Supervisor will schedule a meeting with the Steward to occur within ten (10) working days of receiving the documented grievance to potentially resolve the grievance or to provide additional background information. Resolved and unresolved outcomes of the grievance resolution meeting will be documented.

It is the intent of the Parties to strive to resolve grievances at this level.

Copies will be sent to the Union office and the Chief Steward by the Steward, and to Human Resources and the Manager by the Supervisor within ten (10) working days from the Level 1 meeting. Unresolved Grievances will enter the Level 2 process.

21.4.2 **Level 2 – Process**

Participants: Individuals involved in Level 1 plus Chief Steward and Manager(s) responsible for department (or representative) and any Subject Matter Expert (SME) needed to reach resolution.

Procedure: Within ten (10) working days of receipt of the unresolved Level 1 grievance filing, the Manager (or designee) will schedule a meeting with the Chief Steward; this meeting is to occur at a mutually agreeable time.

Resolved outcomes of the grievance resolution meeting between the Chief Steward and the Manager will be documented. Copies will be sent to the Union

office by the Chief Steward and to Human Resources by the Manager within ten (10) working days from the Level 2 meeting.

Unresolved grievances, within ten (10) working days from the Level 2 meeting, will be documented with recommendations and forwarded by the Manager and Chief Steward to the LMC Co-Chairs (or designee) for review and recommended action prior to entering the Level 3 process.

21.4.3 **Level 3 – Process**

Participants: LMC Co-Chairs; and as needed, the Chief Steward and the Department Manager.

Procedure: LMC Co-Chairs shall review the grievance, and meet to discuss said grievance within ten (10) working days of receipt of the grievance, and determine a resolution within fifteen (15) working days of receiving the Level 2 grievance meeting documentation. If the grievance is not resolved by the LMC Co-Chairs, it shall be submitted in writing to the LMC Executive Sponsors within five (5) business days from the Level 3 grievance meeting for continued discussion or consideration of next steps. All Level 3 documented resolutions must be approved by the Company's Executives responsible for labor relations and the Executive Secretary-Treasurer of OPEIU Local 11, or their designees. Resolutions reached at this level will be final and binding on both parties and documentation will be forwarded to the filing parties within ten (10) working days of the decision.

All timelines above may be extended by mutual agreement of the Parties. If extended, notification will generally be provided to all parties along with status and anticipated action within three (3) working days of the decision to extend, or as soon as possible thereafter.

Section 21.5 Mediation and Arbitration

If the grievance cannot be resolved at Level 3, the Parties may, by mutual agreement, seek the assistance of the Federal Mediation and Conciliation Service in a non-binding attempt to resolve the dispute. Mediation communications are not admissible in arbitration.

In the event the grievance has not been settled, the Union or the Company may seek arbitration. The Arbitrator shall be selected by Union and Company representatives from a panel obtained from the Federal Mediation and Conciliation Service or as otherwise mutually agreed by the parties. The authority of the Arbitrator is limited to interpreting the express provisions of this Agreement or related terms and conditions of employment of covered employees. The decision of such arbitrator shall be final and binding upon both parties. The parties shall each pay their own fees and costs, and each shall pay one-half (½) of the Arbitrator's fees and any other joint costs of the arbitration.

Nothing in this Article precludes a party from withdrawing a grievance at any time with written notification to the Union office and to Human Resources.

ARTICLE 22
SEPARABILITY OF PROVISIONS

If any provision of this Agreement shall be found to be invalid by any court having jurisdiction in respect thereof, such finding as to such provision shall not affect the remainder of this Agreement, and all other terms and provisions hereof shall continue in full force and effect as set forth herein. If the provision is found to be invalid by the court having final jurisdiction in respect thereof, the parties shall promptly negotiate and endeavor to reach agreement upon a suitable substitute for said provision.

Nothing in this Collective Bargaining Agreement shall be interpreted or enforced to cause a violation of any applicable Federal, State, or local law or regulation.

ARTICLE 23
TERM OF THE AGREEMENT AND METHOD OF REOPENING

The Collective Bargaining Agreement and all terms and provisions hereof shall be and continue in effect from and after the date first written hereof until midnight on May 31, 2028, and until May 31st from year to year thereafter until and unless either party shall have served written notice to the other party at least sixty (60) calendar days prior to said May 31, 2028, or prior to any May 31st thereafter stating that it desires to negotiate modifications or to terminate this Agreement.

IN WITNESS WHEREOF, the parties have caused this Collective Bargaining Agreement to be executed in duplicate by their respective officers, thereunto duly authorized.

NORTHWEST NATURAL GAS COMPANY

By
Larry R. Buchanan

Cari L. Colton

James C. Hart

Darcy D. Noxon

Joseph S. Karney, LMC LT Executive Sponsor

Michelle L. Ewaniec, LMC LT Co-Chair

Melinda B. Rogers, LMC LT Executive Sponsor
VP, Chief HR & Diversity Officer

David Anderson, Chief Executive Officer

Justin Palfreyman, President

Mardilyn Saathoff
Senior VP, General Counsel & Regulation

OFFICE & PROFESSIONAL EMPLOYEES INTERNATIONAL UNION, LOCAL-11, AFL-CIO

By
Jonathan P. Hughes

Michael K. Jamison

Christine N. Jelbmann

Konswaylu S. Nelson

Ernest H. Pech

Aron P. Ruljancich

Jordan Fosdick, LMC LT Co-Chair

Howard Bell, LMC LT Executive Sponsor
Executive Secretary-Treasurer

SCHEDULE A – JOB TITLES BY PAY GROUP

Pay Group	Job Title *(Position Title)*
A1	Construction 4 *(Transmission Foreman/woman)*
	Electronic Technician 2
	Journeyman Electrician
	Journeyman Millwright
A	System Ops 2
	Transmission Maintenance 2
	*Weld & Fab 4 *(Mechanic Welder)*
B	Construction 3 *(Distribution Foreman/woman)*
	*Corrosion Technician
	Customer Field Service 4 *(Industrial Tech)*
	Electronic Technician 1
	Gas Storage 2 *(Chief Operator)*
	Instrumentation Technician
C	Customer Field Service 3 (Commercial Tech)
	Distribution Arc Welder 2
	Field Support 3 (Field Engineering Tech)
	General Services 4 (Sr Machinist)
	Leakage Inspector
	System Ops 1
	Transportation 4 (Auto Shop Foreman/Woman)
	Transmission Maintenance 1
D	Construction 2 - Honored
	*Customer Field Service 2 (Service Tech)
	Distribution Arc Welder 1
	Field Support 2 (Field Measurement Tech)
	Gas Storage 1 (Plant Operator)
	Specialty Construction 2
	Transportation 3 (Auto Mechanic)
	Weld & Fab 3 (Sr Fabricator)
E	*Construction 2
	Field Support 1 *(Field Data Tech)*
	Fire & Safety Technician
	General Services 2 *(Maintenance Tech)*
	GIS Tech 3
	Meter & Reg Shop 2
	Semi & Crane
	Weld & Fab 2 *(Fabricator)*

Pay Group	Job Title *(Position Title)*
F	Accounting 4
	Customer Service 4
	Specialty Construction 1
	Stores 3 *(Head Storekeeper)*
	Stores 3 *(Storekeeper - Delivery)*
	Stores 3 *(Storekeeper - Transportation)*
G	GIS Tech 2
	Stores 2 *(Storekeeper)*
	Technical Coordinator 3
	Weld & Fab 1 *(Body Repair Tech)*
H	Accounting 3
	Computer Support 1
	Customer Service 3
	GIS Tech 1
	Operational Support 3
	Technical Coordinator 2
	Transportation 2 (Lube Tech Specialist)
	Utility Support 3 *(Field Maint Worker)*
I	*Currently No Positions*
J	Accounting 2
	Customer Service 2
	Office Services 2
K	Operational Support 2
	Transportation 1 *(Garage Attendant)*
L	Accounting 1
	General Services 1 *(Delivery Driver)*
	Office Services 1
	Stores 1 *(Warehouse Worker)*
M	Customer Service 1
	Utility Support 2 *(AMR Driver)*
N	*Currently No Positions*
O	Utility Support 1 *(Motor Messenger)*

* Designates job titles with additional pay steps

SCHEDULE B – WAGE SCALES

Pay Group	Step Description	June 2024 Wage Rate with 6.0% Increase	December 2024 Wage Rate with 4.0% Increase	December 2025 Wage Rate with 4.0% Increase	December 2026 Wage Rate with 4.0% Increase	December 2027 Wage Rate with 4.0% Increase
A1	Experienced	$57.00	$59.28	$61.65	$64.11	$66.67
A1	Entry	$54.72	$56.90	$59.18	$61.54	$64.00
A	Experienced	$55.26	$57.47	$59.76	$62.15	$64.63
A	Entry	$53.04	$55.17	$57.36	$59.66	$62.04
A	3 - Training	$49.73	$51.72	$53.78	$55.93	$58.16
A	2 - Training	$46.97	$48.84	$50.79	$52.82	$54.93
A	1 - Training	$44.20	$45.97	$47.80	$49.72	$51.70
B	Experienced	$53.53	$55.67	$57.89	$60.20	$62.60
B	Entry	$51.38	$53.44	$55.57	$57.79	$60.09
B	3 - Training	$48.17	$50.10	$52.10	$54.18	$56.34
B	2 - Training	$45.50	$47.31	$49.20	$51.17	$53.21
B	1 - Training	$42.82	$44.53	$46.31	$48.16	$50.08
C	Experienced	$50.28	$52.29	$54.38	$56.55	$58.81
C	Entry	$48.26	$50.19	$52.20	$54.28	$56.45
D	Experienced	$47.21	$49.09	$51.05	$53.09	$55.21
D	Entry	$45.32	$47.12	$49.00	$50.96	$53.00
D	3 - Training	$42.48	$44.18	$45.94	$47.78	$49.68
D	2 - Training	$40.12	$41.72	$43.39	$45.12	$46.92
D	1 - Training	$37.76	$39.27	$40.84	$42.47	$44.16
E	Experienced	$44.33	$46.10	$47.94	$49.85	$51.84
E	Entry	$42.55	$44.25	$46.02	$47.85	$49.76
E	3 - Training	$39.89	$41.49	$43.14	$44.86	$46.65
E	2 - Training	$37.68	$39.18	$40.74	$42.37	$44.06
E	1 - Training	$35.46	$36.88	$38.35	$39.88	$41.47
F	Experienced	$41.62	$43.28	$45.01	$46.81	$48.68
F	Entry	$39.95	$41.54	$43.20	$44.93	$46.73
G	Experienced	$39.10	$40.66	$42.28	$43.97	$45.72
G	Entry	$37.53	$39.03	$40.58	$42.21	$43.89
H	Experienced	$36.54	$38.00	$39.52	$41.10	$42.74
H	Entry	$35.07	$36.48	$37.93	$39.45	$41.03

Pay Group	Step Description	June 2024 Wage Rate with 6.0% Increase	December 2024 Wage Rate with 4.0% Increase	December 2025 Wage Rate with 4.0% Increase	December 2026 Wage Rate with 4.0% Increase	December 2027 Wage Rate with 4.0% Increase
I	Experienced	$34.15	$35.51	$36.93	$38.40	$39.93
I	Entry	$32.78	$34.08	$35.45	$36.86	$38.33
J	Experienced	$31.89	$33.16	$34.48	$35.85	$37.28
J	Entry	$30.61	$31.83	$33.10	$34.41	$35.78
K	Experienced	$29.55	$30.73	$31.95	$33.22	$34.54
K	Entry	$28.36	$29.50	$30.67	$31.89	$33.15
L	Experienced	$27.36	$28.45	$29.58	$30.76	$31.99
L	Entry	$26.26	$27.31	$28.39	$29.52	$30.71
M	Experienced	$25.32	$26.33	$27.38	$28.47	$29.60
M	Entry	$24.30	$25.27	$26.28	$27.33	$28.41
N	Experienced	$23.43	$24.36	$25.33	$26.34	$27.39
N	Entry	$22.49	$23.38	$24.31	$25.28	$26.29
O	Experienced	$21.69	$22.55	$23.45	$24.38	$25.35
O	Entry	$20.82	$21.64	$22.51	$23.40	$24.33

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Melinda B. Rogers

COMPENSATION & BENEFITS

Exh. MBR-5

August 29, 2025

Pay Governance®
Advisory Services to Compensation Committees

NW Natural Gas Company & NW Natural Holding Company

Total Remuneration Review

Organization and Executive Compensation Committee Meeting – February 2024

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Key Findings

1. NW Natural's compensation program (target total remuneration) is competitive with the Proxy Peer Group, broader energy industry and general industry
   - Long-term incentive awards are generally higher than the survey data.
2. Officers positioned below competitive TDC and total remuneration levels (-10% or more) should be reviewed for continued movement toward competitive compensation.
   - Currently, total remuneration levels for the Officers are generally meeting the Company's compensation philosophy target (50th percentile) except for the VP, Chief HR & Diversity Officer, and the VP, Engineering & Utility Operations which are below the philosophy target.
3. All elements of compensation are generally aligned with the NW Natural philosophy of targeting median.
4. NW Natural internal equity generally aligns with the pay ranking of CEO and highest paid executives at energy industry companies (see p. 15).

Pay Component	NW Natural Variance to Market								
	Peer Group			Energy Industry - Survey			General Industry - Survey		
	25th %ile	50th %ile	75th %ile	25th %ile	50th %ile	75th %ile	25th %ile	50th %ile	75th %ile
Base Salary	2%	-2%	-4%	12%	-2%	-15%	8%	-8%	-23%
Target Total Cash	-4%	-7%	-9%	21%	-1%	-19%	19%	-9%	-25%
Long-term Incentives	10%	-5%	-8%	139%	16%	-33%	454%	23%	-17%
Target Total Direct	2%	-6%	-9%	40%	4%	-23%	52%	-2%	-23%
Target Remuneration	1%	-5%	-7%	41%	4%	-24%	55%	0%	-23%

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BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Melinda B. Rogers

COMPENSATION & BENEFITS

Exh. MBR-6C

REDACTED VERSION

August 29, 2025

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UNDER WAC 480-07-160 AND HAS BEEN REDACTED.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

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COMPENSATION & BENEFITS

Exh. MBR-7C

REDACTED VERSION

August 29, 2025

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BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

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COMPENSATION & BENEFITS

Exh. MBR-8C

REDACTED VERSION

August 29, 2025

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BEFORE THE

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WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

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COMPENSATION & BENEFITS

Exh. MBR-9C

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BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

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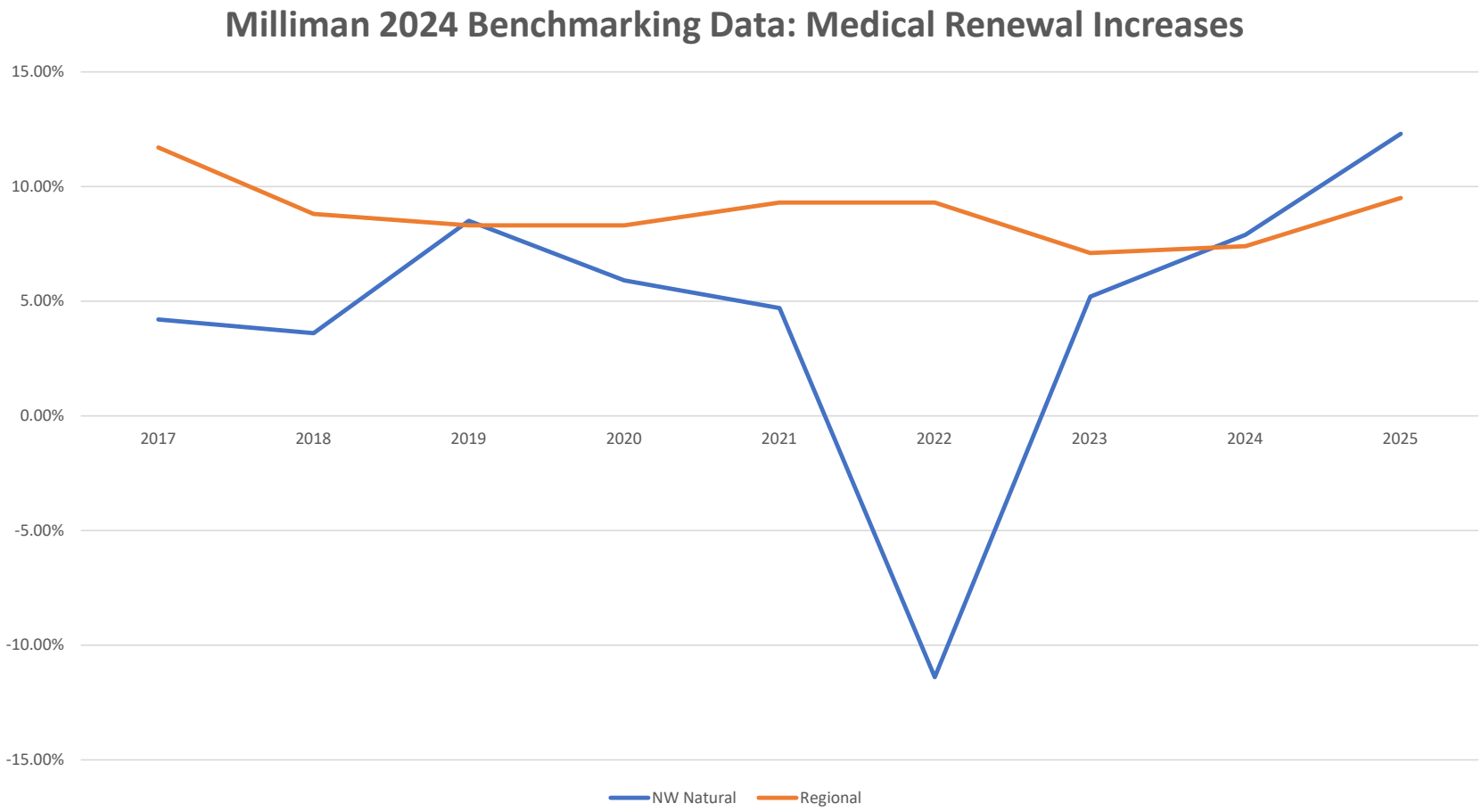
COMPENSATION & BENEFITS

Exh. MBR-10

August 29, 2025


Milliman 2024 Benchmarking Data: Medical Renewal Increases
15.00%
10.00%
5.00%
0.00%
-5.00%
-10.00%
-15.00%
2017
2018
2019
2020
2021
2022
2023
2024
2025
NW Natural
Regional

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

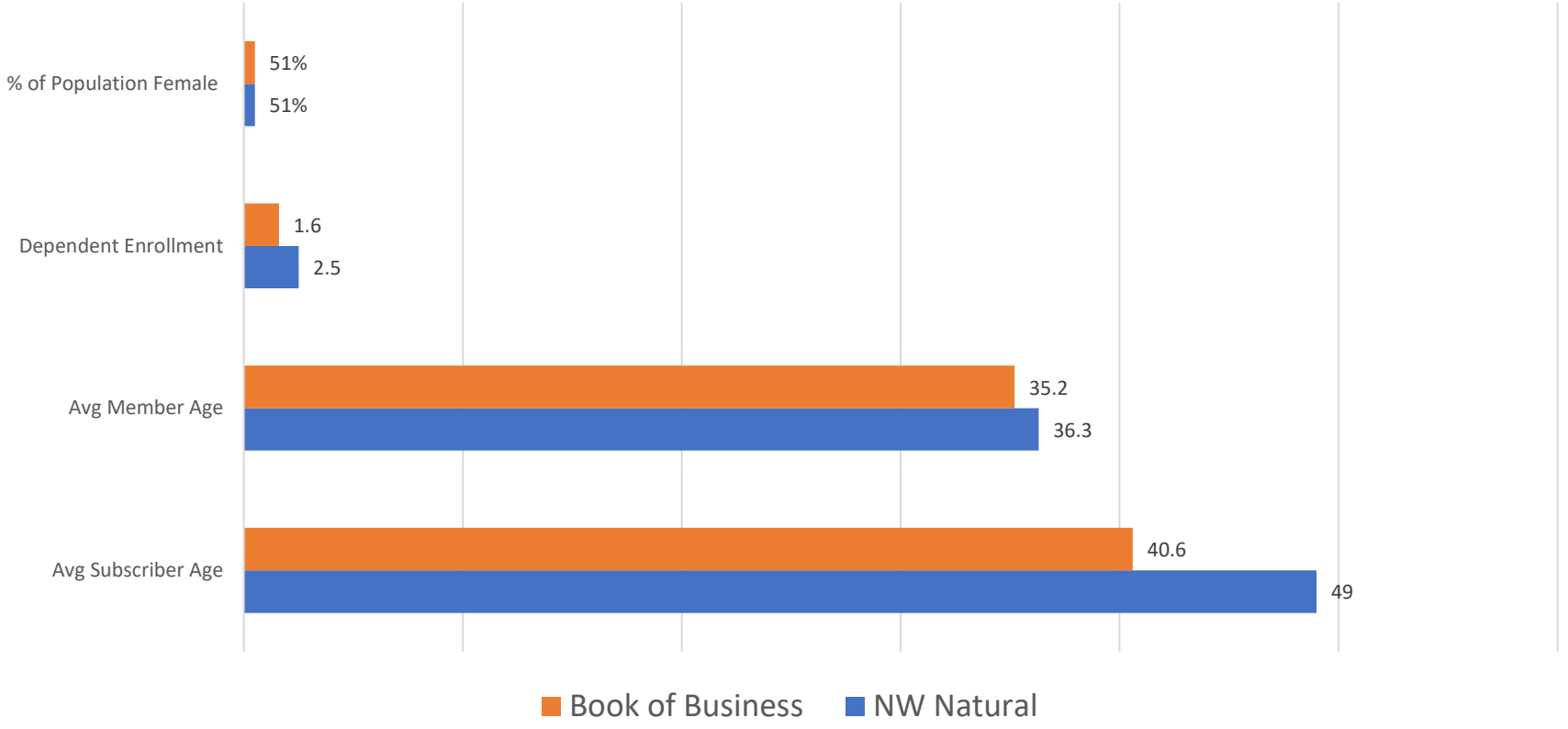
Exhibit of Melinda B. Rogers

COMPENSATION & BENEFITS

Exh. MBR-11

August 29, 2025

Kaiser and Regence 2024 Demographic Benchmarking Data



BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Melinda B. Rogers

COMPENSATION & BENEFITS

Exh. MBR-12

August 29, 2025

DFR | Division of Financial Regulation

Department of Consumer and Business Services

Consumer Guide to 2025 Health Insurance Rate Filings

Factors and considerations in the Health Rate Review process

Prepared in 2024 for plans starting in 2025

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INTRODUCTION

Each year, the Division of Financial Regulation (DFR) conducts a transparent health insurance rate review process for health plans that comply with the Affordable Care Act for small businesses and people who buy their own coverage rather than getting it through an employer. Conducting a yearly rate review ensures that premium rates charged to Oregonians adequately cover health care costs without being too high or too low.

This guide provides an overview of the rate change insurers requested, an explanation of the factors and trends affecting rates, and a summary of DFR's recommended rates formally communicated in DFR's preliminary decision documents, published on www.OregonHealthRates.org. The purpose of this guide is to aid in understanding DFR's preliminary decision document for rates set to become effective Jan. 1, 2025.

The 2025 health rate review process began in the fall of 2023 with insurance companies submitting filings that included information about their financial experience and assumptions. Pursuant to the authority granted by ORS 743.018(5), DFR actuaries review that data to ensure the requested rates are "reasonable and not excessive, inadequate or unfairly discriminatory."

The review process takes into account a three-year window:

- The year the plan takes effect (2025)
- The year the rates are prepared, filed, and reviewed (2024)
- The most recent full year of data that can be referenced (2023)

That three-year window means that rates are set using data from prior years that is then projected forward to produce current rates. Trained and certified actuaries, experts in mathematics and statistical methods, make those projections. DFR also employs actuaries to review the information provided by insurers and to provide an independent assessment of the insurer's calculations.

The rate review process is designed to foster a healthy insurance marketplace that maximizes consumer choice, minimizes consumer cost, and maintains the solvency of insurers to prevent consumer harm. Because of rising costs throughout the market, annual cost increases are to be expected most years – over time, inflation drives all costs up in healthy economies. The rate review process allows DFR actuaries to "check the math" of insurance companies, ensuring that their requested cost increases are justified by actuarial standards and market forces, and are necessary to maintain the solvency of the insurance company.

RATE CHANGE REQUESTS

The table below shows the rate change requested by each insurer this year. It shows the rate increase requested, a representative "base rate," and the total number of members affected.

The base rate represents what a 40-year-old on a "silver" plan in the Portland area would pay (without any subsidies or financial assistance) for health insurance. Rates vary based on geographic location and age.

Plans are rated on a "metals" system: bronze, silver, and gold. Those metal levels correlate to upfront premium costs (low for bronze, high for gold) and out-of-pocket cost sharing (high for bronze, low for gold). Consequently a Silver is the middle cost plan.

	Individual			Small Group		
Company	**% Increase**	**Rate**	**Members**	**% Increase**	**Rate**	**Members**
BridgeSpan	10.2%	$582	264			
Kaiser	5.0%	$486	34,574	6.4%	$426	27,959
Moda	9.4%	$522	29,992	9.8%	$435	8,828
PacificSource	11.6%	$576	24,943	5.7%	$459	12,171
Providence	11.2%	$578	44,753	16.3%	$467	46,501
Regence BCBS*	9.3%	$555	35,290	13.6%	$459	63,653
Health Net				7.8%	$435	3,140
UHC IC**				13.2%	$518	9,523
UHC of OR***				13.8%	$518	3

* BlueCross BlueShield

** UnitedHealthcare Insurance Company

*** United Healthcare of Oregon

Each insurers rate change request, and supporting documentation, underwent a comprehensive review.

RATE CHANGE CONTRIBUTING FACTORS

The table below shows the amount each rate component contributes to the requested rate change per company. The percent change is shown as a portion of the requested rate change, so the columns add up to the total rate change request.

Experience and trend are the primary factors driving cost increases. In short, trend accounts for both changes in the cost of services as well as changes in the utilization of services. Trend is explained in greater detail further in this document.

Individual market rate change contribution

Contribution factor	Kaiser	PacificSource	Moda	Providence	BridgeSpan	Regence
Experience and trend	9.8%	8.9%	12.3%	6.0%	8.7%	8.5%
Admin, taxes, and fees	-0.9%	0.7%	-1.2%	1.0%	1.0%	0.5%
Benefits, plan, and network	-2.9%	-0.6%		2.0%	0.5%	0.3%
Demographics	-0.6%					
Morbidity		2.5%				
Oregon Reinsurance	0.9%					
Margin	-1.4%					
Cost share reduction load				2.0%		
Other			-1.7%			
Total	**4.9%**	**11.5%**	**9.4%**	**11.0%**	**10.2%**	**9.3%**

Small group market rate change contribution

Contribution factor	Kaiser	PacificSource	Moda	Providence	Regence	HealthNet	UHC IC	UHC OR
Experience and trend	5.6%	9.1%	7.5%	11.0%	13.4%	7.3%	13.6%	13.3%
Admin, taxes, and fees	0.7%		-0.5%	3.0%	1.1%	0.5%	-0.4%	-0.4%
Plan design changes	-0.4%			2.0%	-0.5%		-0.1%	0.7%
Profit		2.6%		-2.0%			0.2%	0.2%
Morbidity		-5.7%						
Other	0.4%		2.8%					
Total	**6.3%**	**6.0%**	**9.8%**	**14.0%**	**14.0%**	**7.8%**	**13.3%**	**13.8%**

Experience and trend includes risk adjustment. More information on risk adjustment available here.

WHAT IS TREND?

Trend simply refers to the change in cost of providing services. Trend includes many factors, but it generally ends up illustrating how certain key costs are changing, influencing the premiums an insurer must charge to stay solvent.

Trend can be broken down into two key categories – medical and pharmacy – each with a handful of items contained within.

Trend Components

Medical

- Unit cost – when considering the same service is being provided, the cost of providing that service has gone up. This includes forces such as:
  - Medical inflation
  - Provider contract changes
  - Changes in intensity of medical care
- Utilization – In a given period, more services are being provided than before, causing an increase in costs. This includes forces such as:
  - Changes in medical care practices
  - Supply of services
  - Changes in health or behavior of the covered population

Pharmacy

- Typically, most insurers use a pharmacy benefit manager (PBM) model. In short, a third party is contracted to negotiate drug prices and coordinate with pharmacies. Includes forces such as:
  - Introduction of new drugs
  - Expiration of patents
  - Issuer-specific utilization by drug class

Trend has marketwide forces, but will also vary by specific insurer. Each insurers' trend calculation is reviewed by DFR actuaries.

Historical overall trend

Trend varies over time based on changes in the market. The table below illustrates the changes to trend over the last two years and compares it to the projected 2025 trend. Overall, trend is projected to be higher in 2025 than it was in 2024.

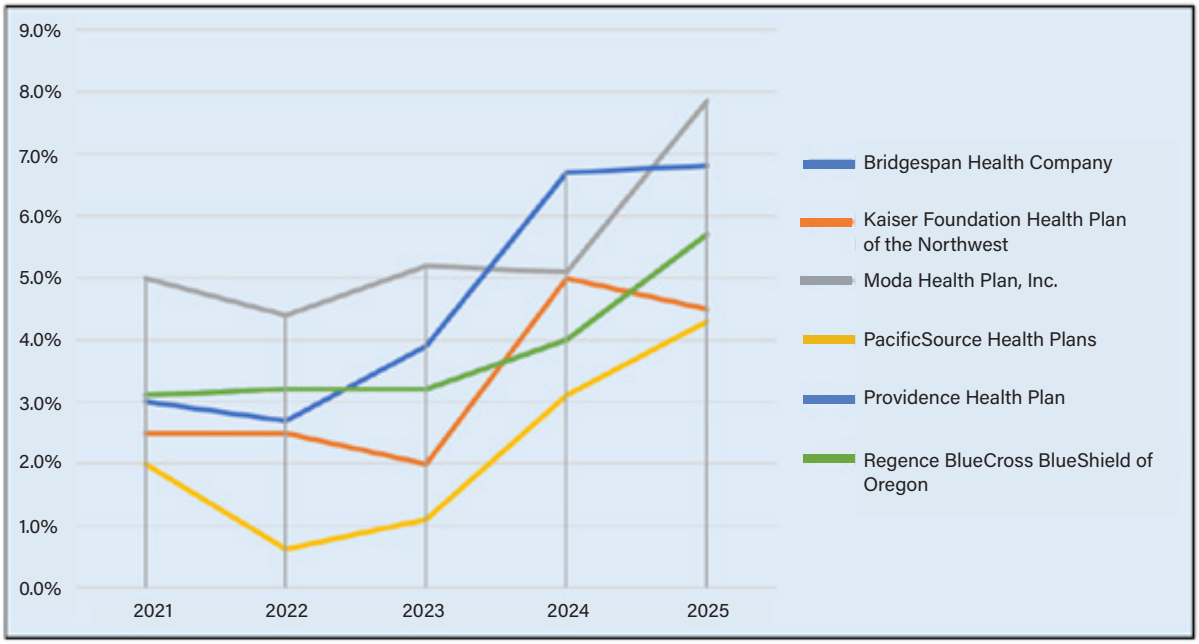
		Medical			RX			Overall		
	Year	Avg.	Min.	Max.	Avg.	Min.	Max.	Avg.	Min.	Max.
Individual	2023	4.6%	2.0%	6.1%	7.4%	2.0%	11.3%	5.2%	2.0%	6.6%
	2024	6.1%	5.0%	8.0%	8.3%	5.0%	10.2%	6.6%	5.0%	8.2%
	2025 (proj.)	7.9%	4.5%	9.4%	8.7%	4.5%	11.7%	8.0%	4.5%	9.6%
Small Group	2023	4.8%	2.0%	6.6%	7.3%	2.0%	11.3%	5.2%	2.0%	6.6%
	2024	6.4%	3.5%	8.7%	7.6%	3.5%	10.2%	6.6%	3.5%	8.5%
	2025 (proj.)	7.4%	4.1%	9.9%	7.9%	4.1%	11.2%	7.4%	4.1%	9.5%

Projected trend by insurer – individual market

The tables below compare the trend projected by each insurer. Variance here is normal as each insurer experiences different trend forces unique to the population covered by their policies as well as the contracts the insurer is able to negotiate with providers.

	Medical			RX			Overall		
Company	Cost	Util.	Total	Cost	Util.	Total	Cost	Util.	Total
BridgeSpan	5.7%	2.6%	8.4%	5.0%	2.6%	7.7%	5.5%	2.6%	8.2%
Kaiser	4.5%	0.0%	4.5%	4.5%	0.0%	4.5%	4.5%	0.0%	4.5%
Moda	7.9%	1.0%	8.9%	8.5%	2.5%	11.2%	8.0%	1.3%	9.4%
PacificSource	4.3%	3.1%	7.5%	4.2%	5.1%	9.6%	4.3%	3.5%	8.0%
Providence	6.8%	2.5%	9.4%	4.8%	6.5%	11.7%	6.3%	3.0%	9.6%
Regence BCBS	5.7%	2.6%	8.4%	5.0%	2.6%	7.7%	5.5%	2.6%	8.2%

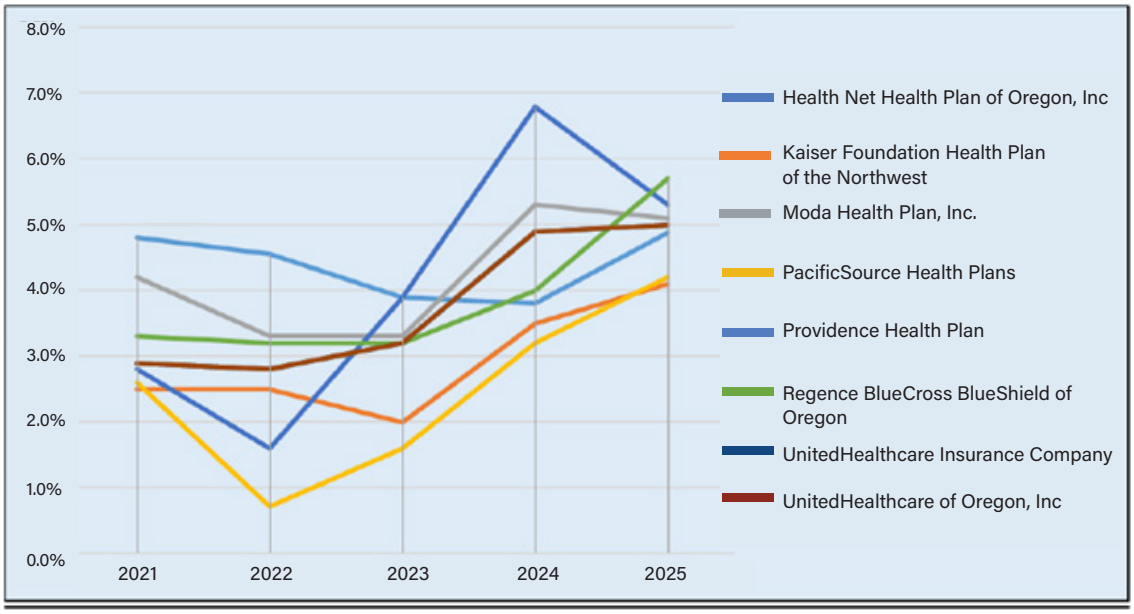
Projected medical cost trend by year – individual market



Projected trend by insurer – small group market

	Medical			RX			Overall			Quarterly Increase
Company	Cost	Util.	Total	Cost	Util.	Total	Cost	Util.	Total	
Health Net	4.9%	-0.1%	4.8%	4.5%	0.0%	4.5%	4.8%	-0.1%	4.7%	1.3%
Kaiser	4.1%	0.0%	4.1%	4.1%	0.0%	4.1%	4.1%	0.0%	4.1%	0.6%
Moda	5.1%	1.1%	6.3%	8.5%	2.5%	11.2%	5.6%	1.3%	7.0%	1.9%
PacificSource	4.2%	3.1%	7.4%	4.2%	5.1%	9.6%	4.2%	3.5%	7.8%	2.3%
Providence	5.3%	4.4%	9.9%	6.8%	2.7%	9.7%	6.8%	2.5%	9.5%	2.3%
Regence BCBS	5.7%	2.5%	8.2%	4.7%	2.5%	7.2%	5.4%	2.5%	7.9%	2.4%
UHC	5.0%	4.2%	9.4%	4.2%	4.2%	8.6%	4.9%	4.2%	9.3%	1.8%
UHC of OR	5.0%	4.2%	9.4%	4.2%	4.2%	8.6%	4.9%	4.2%	9.3%	1.8%

Projected medical cost trend by year – small group market



COST GROWTH TARGET ANALYSIS

While much of trend is the result of market forces, some costs can be influenced by insurer choices, such as contract negotiations. Oregon's Sustainable Health Care Cost Growth Target Program sets a statewide target for the annual per person growth rate of total health care spending in the state. The "cost growth target" (CGT) that it sets is meant to help ensure that health care costs are not growing faster than wages, inflation, and other economic indicators so that people continue to have access to high quality, affordable care.

The CGT is currently set at 3.4 percent. It is calculated at a high level, using a total cost of care approach. This view of health care spending includes all costs related to an individual's care, rather than focusing on a single factor such as prices. The CGT is not a spending cap and does not limit health care spending. Instead, the target aims to achieve a sustainable rate of growth.

The CGT is measured at four levels: statewide, by market (commercial, Medicaid, Medicare), for payers, and for provider organizations. The Cost Growth Target Program at the Oregon Health Authority annually measures and publicly reports on how the state is measuring against the CGT. More information is available here: OHA CGT.

The Cost Growth Target Program has developed a series of accountability focused rules that begin with transparency. Payers and provider organizations who exceed the CGT with statistical confidence **and** without an acceptable reason may be subject to a performance improvement plans. Payers and provider organizations who continue to exceed the target without an acceptable reason may be subject to financial penalties. More information on that available here: OHA CGT Accountability

Cost growth under the program is measured in two ways: total health care expenditures and total medical expenses, each of which are specifically defined. More information available here: Data Specification Manual. While not an exact comparison, the CGT is substantially similar to the medical unit cost trend reported by insurers. The table below shows how much lower premiums could be in 2025 if each insurer met the CGT target of 3.4% for its medical and pharmacy unit cost trend.

Company	Individual	Small Group
BridgeSpan	-2.0%	
Kaiser	-1.1%	-0.7%
Moda	-2.1%	-2.1%
PacificSource	-0.9%	-0.8%
Providence	-2.7%	-3.2%
Regence BCBS	-2.0%	-1.9%
Health Net		-1.3%
UHC IC		-1.4%
UHC of OR		-1.4%

PROJECTED MEDICAL LOSS RATIO

The Affordable Care Act (ACA) requires that 80 percent of premiums must be used to pay claims. The table below shows what percentage of premium costs each insurer paid in claims.

There is more than one way to calculate this figure. In the "federal medical loss ratio" (MLR) column below, "quality improvement" expenses are included in the claim amount, and taxes and fees are excluded from the premium in the calculation. This results in a higher projected medical loss ratio. In either case, all Oregon health insurers have exceeded this requirement.

Should an insurer go below 80 percent MLR, the ACA requires that insurers return the excess premiums collected to plan holders in the form of rebates.

	Individual		Small Group	
Company	**Pricing**	**Federal**	**Pricing**	**Federal**
BridgeSpan	83.7%	88.1%		
Kaiser	83.9%	84.9%	83.3%	87.3%
Moda	88.7%	90.5%	89.0%	90.9%
PacificSource	86.6%	90.9%	85.0%	87.7%
Providence	83.8%	88.7%	85.7%	88.6%
Regence BCBS	84.7%	89.0%	84.2%	87.6%
Health Net			83.9%	86.2%
UHC IC			83.8%	86.8%
UHC of OR			83.8%	86.8%

Pricing MLR – This calculation is strictly claims divided by premiums

Federal MLR – In this calculation, the quality improvement expense is included in the claim amount, and taxes and fees are excluded from the premium in the calculation.

RETENTION

This table shows what is done with the money left over after claims – the other side of the MLR shown above. This amount includes all salaries paid to insurer staff and any premium expected to be retained as profits or margin for the individual market.

Individual market retention

PMPM = per member per month

	BridgeSpan		Kaiser		Moda		PacificSource		Providence		Regence BCBS	
	PMPM	% of Prem.	PMPM	% of Prem.	PMPM	% of Prem.	PMPM	% of Prem.	PMPM	% of Prem.	PMPM	% of Prem.
Expenses	$56.96	7.0%	$56.93	9.1%	$47.97	6.3%	$50.36	6.6%	$65.48	9.0%	$43.98	6.4%
Commissions	$3.09	0.4%	$6.62	1.1%	$5.86	0.8%	$7.74	1.0%	$8.20	1.1%	$6.97	1.0%
Vendor fees	$3.26	0.4%									$3.26	0.5%
Insurer fee	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
Regulatory surcharge									$0.36	0.1%		
Risk Adj. Program Fee	$0.18	0.0%	$0.18	0.0%	$0.18	0.0%	$0.18	0.0%	$0.18	0.0%	$0.18	0.0%
Oregon Reinsurance	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$15.34	2.0%	$0.00	0.0%	$0.00	0.0%
Health care reform (HCR) pooling amount			$2.62	0.4%								
HCR - funding of Patient-Centered Outcomes Research (PCOR)	$0.30	0.0%	$0.30	0.1%	$0.20	0.0%	$0.30	0.0%	$0.28	0.0%	$0.30	0.0%
Oregon Exchange Fee	$17.41	2.1%	$14.22	2.3%	$12.53	1.7%	$10.40	1.4%	$14.33	2.0%	$13.36	1.9%
Oregon Premium Tax			$12.52	2.0%	$15.12	2.0%			$14.60	2.0%		
Profit/margin	$32.78	4.0%	$7.51	1.2%	$15.12	2.0%	$15.34	2.0%	$14.60	2.0%	$20.59	3.0%
Total premium retention	**$113.98**	**13.9%**	**$100.90**	**16.1%**	**$96.98**	**12.8%**	**$99.65**	**13.0%**	**$118.02**	**16.2%**	**$88.64**	**12.9%**

Individual market retention – expenses detailed view

This table shows the detailed breakdown of the "expenses" line in the table above for the individual market.

	BridgeSpan		Kaiser		Moda		PacificSource		Providence		Regence BCBS	
	PMPM	% of Prem.	PMPM	% of Prem.	PMPM	% of Prem.	PMPM	% of Prem.	PMPM	% of Prem.	PMPM	% of Prem.
Salaries and wages	$36.97	4.5%	$49.05	7.8%	$29.91	4.0%	$35.63	4.6%	$35.03	4.8%	$26.29	3.8%
Cost depreciation	$5.04	0.6%	$0.01	0.0%	$3.58	0.5%	$1.20	0.2%	$1.67	0.2%	$4.50	0.7%
Rent (occupancy)	$1.21	0.1%	$2.74	0.4%	$1.72	0.2%	$0.68	0.1%	$2.01	0.3%	$1.07	0.2%
Marketing and advertising	$0.40	0.0%	$3.00	0.5%	$1.34	0.2%	$4.41	0.6%	$1.30	0.2%	$1.38	0.2%
General office expenses	$1.33	0.2%	$0.18	0.0%	$0.53	0.1%	$2.49	0.3%	$13.81	1.9%	$0.90	0.1%
Third-party admin. expenses or fees	$6.11	0.7%	$0.60	0.1%	$6.10	0.8%	($7.52)	-1.0%	$8.33	1.1%	$4.82	0.7%
Legal and consulting fees	$5.49	0.7%	$1.34	0.2%	$4.60	0.6%	$13.06	1.7%	$3.29	0.5%	$4.65	0.7%
Traveling expenses	$0.41	0.0%	$0.02	0.0%	$0.19	0.0%	$0.41	0.1%	$0.03	0.0%	$0.37	0.1%
Total expenses incurred	**$56.96**	**7.0%**	**$56.93**	**9.1%**	**$47.97**	**6.3%**	**$50.36**	**6.6%**	**$65.48**	**9.0%**	**$43.98**	**6.4%**

Small group market retention

	HealthNet		Kaiser		Moda		PacificSource		Providence		Regence		UHC IC		UHC OR	
	PMPM	% of Prem.	PMPM	% of Prem.	PMPM	% of Prem.	PMPM	% of Prem.	PMPM	% of Prem.	PMPM	% of Prem.	PMPM	% of Prem.	PMPM	% of Prem.
Expenses	$51.86	8.4%	$63.30	11.1%	$40.59	6.6%	$48.28	7.7%	$62.63	9.3%	$44.28	6.9%	$65.30	10.2%	$65.30	10.2%
Commissions	$21.49	3.5%	$17.02	3.0%	$14.18	2.3%	$16.64	2.7%	$18.99	2.8%	$16.19	2.5%	$17.07	2.7%	$17.07	2.7%
Vendor fees											$6.60	1.0%				
Insurer fees	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
Regulatory surcharge									$0.36	0.1%						
Risk Adj. Prog. Fee	$0.20	0.0%	$0.18	0.0%	$0.18	0.0%	$0.18	0.0%	$0.18	0.0%	$0.18	0.0%	$0.22	0.0%	$0.22	0.0%
Oregon Reinsurance	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$12.54	2.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
HCR - funding of PCOR fee	$0.29	0.0%	$0.30	0.1%	$0.31	0.1%	$0.30	0.0%	$0.30	0.0%	$0.30	0.0%	$0.29	0.0%	$0.29	0.0%
Oregon Exchange Fee	$0.00	0.0%	$0.00	0.0%			$0.41	0.1%	$0.40	0.1%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
Income tax	$3.44	0.6%														
Payroll tax	$0.00	0.0%														
OR Premium tax	$12.28	2.0%	$11.36	2.0%	$12.31	2.0%			$13.43	2.0%						
HB 2391 premium assessment													$12.78	2.0%	$12.78	2.0%
Profit/margin	$9.30	1.5%	$2.84	0.5%	$0.00	0.0%	$15.68	2.5%	$0.00	0.0%	$15.99	2.5%	$7.58	1.2%	$7.58	1.2%
Total premium retention	**$98.85**	**16.1%**	**$95.00**	**16.7%**	**$67.57**	**11.0%**	**$94.03**	**15.0%**	**$96.29**	**14.3%**	**$83.54**	**13.1%**	**$103.25**	**16.2%**	**$103.25**	**16.2%**

Small group market retention – expenses detailed view

This table shows the detailed breakdown of the "expenses" line in the table above for the small group market.

	HealthNet		Kaiser		Moda		PacificSource		Providence		Regence		UHC IC		UHC OR	
	PMPM	% of Prem.	PMPM	% of Prem.	PMPM	% of Prem.	PMPM	% of Prem.	PMPM	% of Prem.	PMPM	% of Prem.	PMPM	% of Prem.	PMPM	% of Prem.
Salaries and wages	$26.05	4.2%	$54.54	9.6%	$25.30	4.1%	$34.16	5.4%	$36.23	5.4%	$28.64	4.5%	$34.26	5.4%	$34.26	5.4%
Cost depreciation	$3.10	0.5%	$0.02	0.0%	$3.03	0.5%	$1.15	0.2%	$1.84	0.3%	$4.90	0.8%	$5.16	0.8%	$5.16	0.8%
Rent (occupancy)	$1.86	0.3%	$3.04	0.5%	$1.45	0.2%	$0.65	0.1%	$2.23	0.3%	$1.10	0.2%	$1.73	0.3%	$1.73	0.3%
Marketing and advertising	$1.37	0.2%	$3.33	0.6%	$1.14	0.2%	$4.23	0.7%	$1.03	0.2%	$0.51	0.1%	$2.61	0.4%	$2.61	0.4%
General office expenses	$2.24	0.4%	$0.20	0.0%	$0.45	0.1%	$2.39	0.4%	$8.94	1.3%	$0.39	0.1%	$3.01	0.5%	$3.01	0.5%
Third-party admin. expenses or fees	$8.68	1.4%	$0.66	0.1%	$5.17	0.8%	-$7.21	-1.2%	$8.77	1.3%	$3.19	0.5%	$6.33	1.0%	$6.33	1.0%
Legal and consulting fees	$8.29	1.4%	$1.49	0.3%	$3.89	0.6%	$12.52	2.0%	$3.55	0.5%	$5.11	0.8%	$16.25	2.5%	$16.25	2.5%
Traveling expenses	$0.26	0.0%	$0.02	0.0%	$0.16	0.0%	$0.39	0.1%	$0.04	0.0%	$0.45	0.1%	$1.15	0.2%	$1.15	0.2%
Total expenses incurred	**$51.86**	**8.4%**	**$63.30**	**11.1%**	**$40.59**	**6.6%**	**$48.28**	**7.7%**	**$62.63**	**9.3%**	**$44.28**	**6.9%**	**$65.30**	**10.2%**	**$65.30**	**10.2%**

OHP BRIDGE - BASIC HEALTH PROGRAM, COST-SHARING REDUCTION PLANS, AND SILVER-LOADING

There is a complex interaction between two different federal subsidy programs and Oregon's newly created Basic Health Program, officially called OHP Bridge – Basic Health Program. In short, Marketplace silver-tier plans will have reduced premiums following implementation, but federal premium tax credits may simultaneously be reduced for enrollees in other plan tiers. For some individuals on bronze and gold Marketplace plans, this will result in a higher net monthly premium payment than before.

To explain how this interaction unfolds, we need to describe the different elements at play.

OHP Bridge - Basic Health Program

OHP Bridge - Basic Health Program (OHP Bridge - BHP) is a program required by the legislature through House Bill 4035 (2022) and run by the Oregon Health Authority. It provides free health coverage for adults between 138 percent to 200 percent of the federal poverty level. More information available here: OHP Bridge

Cost-Sharing Reduction Plans

Cost-sharing reduction plans (CSR plans) are a type of silver plan required by the Affordable Care Act and are available for consumers with incomes under 250% of the federal poverty level (FPL). These plans have lower deductibles, co-pays, and other out-of-pocket expenses for low-income enrollees. Insurance companies are obligated to pay providers the difference in the reduced cost-sharing for eligible consumers who enroll in these plans. Prior to 2017, carriers would submit those expenses to the federal government for reimbursement. In 2017, however, the federal government stopped paying carriers to cover the costs of these subsidies.

Silver-loading

When the federal government stopped reimbursing cost-sharing reductions directly to carriers, states came up with a plan known as "Silver Loading". To cover the costs of the missing CSR payments, additional costs are "loaded" onto silver plan premiums, which makes silver plans more expensive.

However, because silver plans are the basis for calculating Premium Tax Credits (PTC), the increased cost of the silver-loaded plans caused the overall tax credits provided by the federal government to increase as well. In summary, the silver loading strategy results in higher premium tax credits giving consumers higher purchasing power towards bronze and gold plans.

The effect of the BHP on Marketplace Tax Credits

Based on the eligibility criteria for the BHP, enrollment in CSR-eligible plans is anticipated to decrease until 2027. As that happens, the amount carriers need to pay to cover CSR plans goes down, so premiums for silver plans go down as well. As stated above, premium tax credits for Marketplace plans are tied to the cost of premiums for the silver plans. As the premium goes down, the available premium tax credits also go down. For some individuals on bronze and gold plans, the decrease in premium tax credits will result in a monthly premium payment that is higher than it was before.

Reinsurance and risk adjustment – individual

The Oregon Reinsurance Program and the federal Risk Adjustment Program both work to offset risk (costs) experienced by insurers, ultimately lowering premiums.

Reinsurance is based on claim costs – when claims exceed a certain value, an insurer can receive payments from the reinsurance program to offset that risk, ultimately keeping costs lower for consumers.

The federal Risk Adjustment Program is designed to distribute the impact of high-risk, low-probability events across the market. These numbers represent payments made to the insurer or contributions to the pool.

	Reinsurance		Risk Adjustment		
Company	**Experience (prelim. 2023)**	**Projected (2025)**	**Experience (2023)**	**Actual (2023)**	**Projected (2025)**
BridgeSpan	$0.7	$0.3	$0.7	$0.3	$0.4
Kaiser	$15.0	$7.6	($30.5)	$-29.8	($19.4)
Moda	$29.5	$31.8	$10.9	$12	$12.0
PacificSource	$19.2	$20.6	$1.4	$10.7	$0.9
Providence	$27.4	$30.9	$22.9	$25.3	$22.6
Regence BCBS	$15.6	$24.2	($16.7)	$-18.6	($18.1)
Total	**$107.4**	**$115.5**	**($11.3)**	**$-0.1**	**($1.5)**

Values shown in millions

The small group market does not participate in the Oregon Reinsurance Program, so only Risk Adjustment Program data is shown

	Risk Adjustment				
Company	**Experience (prelim. 2023)**	**Actual (2023)**		**Projected (2025)**	
Health Net	$0.1	$0.3	$0.2	$0.3	$0.4
Kaiser	($9.8)	$-11.4	($11.3)	$-29.8	($19.4)
Moda	($1.8)	$-1.9	($3.6)	$12	$12.0
PacificSource	$6.3	$6.6	-	$10.7	$0.9
Providence	$1.4	$2.4	$0.9	$25.3	$22.6
Regence BCBS	$4.4	$2.1	$8.4	$-18.6	($18.1)
UHC	$1.3	$2.1	$0.9	$-0.1	($1.5)
UHC of OR	$1.8	$0	($4.4)		
Total	$0.1	$0.2	$0.2		

Values shown in millions

DFR RATE RECOMMENDATIONS

After a thorough review of the filed rates, DFR has recommended some adjustments to the rate increases requested. The changes are driven by two key factors: administrative cost adjustments and silver-load adjustments. The table below details those recommended changes per insurer.

These recommended changes are formally communicated in DFR's preliminary decision documents, published on www.OregonHealthRates.org.

	Individual				Small Group		
Company	**Orig. Req.**	**Admin**	**Basic Health Plan (BHP)**	**Final**	**Orig. Req.**	**Admin**	**Final**
BridgeSpan	10.2%	-0.3%	-1.2%	8.7%			
Kaiser	5.0%	-	-	5.0%	6.4%	-	6.4%
Moda	9.4%	-0.3%	-1.5%	7.6%	9.8%	-	9.8%
PacificSource	11.6%	-0.5%	-	11.1%	5.7%	-	5.7%
Providence	11.2%	-0.5%	-1.2%	9.5%	16.3%	-	16.3%
Regence BCBS	9.3%	-0.2%	-1.2%	7.9%	13.6%	-	13.6%
Health Net					7.8%	-	7.8%
UHC IC					13.2%	-0.5%	12.7%
UHC of OR					13.8%	-0.5%	13.3%
Average	**9.3%**			**8.1%**	**12.3%**		**12.2%**

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Melinda B. Rogers

COMPENSATION & BENEFITS

Exh. MBR-13

August 29, 2025

Milliman 2024 Benchmarking Data

Medical	Ranking as compared to 35 Utilities in the PNW
Deductible	Equal
Out of Pocket Maximum	Equal
Coinsurance	Equal
Office Visit – Primary	Better
Office Visit – Specialist	Better
Telehealth Visit	Better
Pharmacy	Worse
HSA Contributions	Equal
Employer Contributions	Worse

Vision and Dental	Ranking as compared to 35 Utilities in the PNW
Vision Exam	Equal
Vision Hardware	Better
Dental Deductible	Better
Dental Annual Maximum	Equal
Class 1: Preventative	Equal
Class 2: Basic/Restorative	Equal
Class 3: Major Services	Better
Orthodontia	Equal

Continued: Milliman 2024 Benchmarking Data

Long-term Disability	Ranking as compared to 35 Utilities in the PNW
Benefit Percentage	Equal
Monthly Maximum	Equal
Elimination Period	Equal

Short-term Disability	Ranking as compared to 35 Utilities in the PNW
Benefit Percentage	Better
Elimination Period	Equal
Maximum Benefit Period	Better

Life Insurance	Ranking as compared to 35 Utilities in the PNW
Employee Coverage	Worse
Dependent Coverage	Equal
Voluntary Buy-up	Equal

Other	Ranking as compared to 35 Utilities in the PNW
Flexible Spending Accounts	Equal
Employee Assistance Program	Better

Defined Contribution	Ranking as compared to 35 Utilities in the PNW
Company Match	Equal
Enhanced (Non-Match)	Worse

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Direct Testimony of Tobin F. Davilla

OPERATIONS & MAINTENANCE EXPENSE

Exh. TFD-1CT

REDACTED VERSION

August 29, 2025

DIRECT TESTIMONY OF TOBIN F. DAVILLA

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position with Northwest Natural Gas Company ("NW Natural" or "the Company").

A. My name is Tobin Davilla. I am the Director of Financial Planning and Analysis at NW Natural. I am responsible for producing the annual operations and maintenance ("O&M") expense budget, the capital expenditures budget, the income statement budget, developing the short-term and long-term financial forecasts for senior management, and generally supporting the organization with financial modeling and analysis.

Q. Please summarize your educational background and experience.

A. I hold both a Bachelor of Science degree and a Master of Business Administration degree from Oregon State University. Prior to joining NW Natural, I held a position in Finance at PacifiCorp. I joined NW Natural in 2007 as a financial analyst and have held numerous positions within the Finance department and have been in my current position since 2018.

Q. Please provide a summary of your testimony.

A. My testimony explains how NW Natural calculated the O&M expense included in its revenue requirement in this proceeding. Specifically, I provide an overview of how the Company adjusted Test Year O&M (April 2024 – March 2025) and the adjustments to O&M for the provisional years to arrive at its rate case request.

II. OPERATIONS AND MAINTENANCE EXPENSE

Q. What is the Washington-allocated O&M expense included in the Company's revenue requirement in this case?

A. The Washington-allocated expense included in the revenue requirement in the first year that rates are in effect (August 1, 2026, to July 31, 2027) ("RY1") is $29.6 million. This amount increases to $31.5 million beginning for the second year of the rate period (August 1, 2027, to July 31, 2028) ("RY2"), and increases to $32.5 million for the third year of the rate period (August 1, 2028, to July 31, 2029) ("RY3").

Q. How did the Company calculate its Washington-allocated O&M expense?

A. The Company calculated its Washington-allocated O&M expense[1] by:

1. Determining the Washington-allocated O&M expense that it incurred during the historical Test Year—April 1, 2024, through March 31, 2025.
2. Making certain restating, pro forma, and provisional adjustments to better reflect the expense the Company expects to incur during the rate effective periods.

Each of these steps is discussed in further detail below.

A. Washington-Allocated O&M Expense Incurred During Test Year

Q. What was the total O&M expense that the Company incurred during the Test Year?

A. The Company incurred $250.4 million in total O&M expense during the Test Year. Since the Company serves customers in Washington and Oregon, it must allocate a

[1] Confidential Exh. TFD-2C, O&M development excel model.

certain amount of O&M expense to its Washington customers.

Q. How did the Company allocate O&M expense to its Washington customers?

A. The total O&M expense incurred during the Test Year—$250.4 million—was allocated to O&M Federal Energy Regulatory Commission ("FERC") accounts. The Company then applied Washington allocation factors to each FERC account to calculate Washington-allocated O&M.[2] This resulted in $26.0 million of Washington-allocated O&M incurred during the Test Year, which is then further adjusted as explained in sections B below.

B. Restating, Pro Forma and Provisional Adjustments to O&M Expense

Q. Please summarize the restating, proforma and provisional adjustments to O&M expense.

A. The Company made restating, proforma and provisional adjustments to better reflect the expense the Company will incur during the rate effective periods or to remove expenses for which the Company is not seeking recovery. Restating adjustments were made to annualize ongoing costs, normalize the balances in accordance with historical ratemaking practices, or remove costs that were incurred during the Test Year for which the Company is not seeking recovery. Proforma adjustment were made to reflect costs for the twelve-month period from August 1, 2025, through July 31, 2026, the immediately preceding twelve-month period prior to the initial Rate Year 1 effective date. Finally, the Company included provisional O&M adjustments for the following periods: August 1, 2026, through July 31, 2027 (RY1); August 1, 2027, through July

[2] *See* the Direct Testimony of Kyle T. Walker (Exh. KTW-1T) for further detail on how costs were allocated between Washington and Oregon.

31, 2028 (RY2); and August 1, 2028, through July 31, 2029 (RY3). These adjustments incorporate the Company's projected expense and other known and measurable changes, as further discussed below. Each of these restating, proforma and provisional adjustments are reflected in Table 1 below (found in confidential Exh. TFD-2C) and in subsequent subsections of my testimony.

Table 1

	Test Year 4/1/24-3/31/25	Proforma 8/1/25-7/31/26	Rate Yr1 8/1/26-7/31/27	Rate Yr2 8/1/27-7/31/28	Rate Yr3 8/1/28-7/31/29
Test Year / Prior Period Expense	$ 25,936,550	$ 25,175,350	$ 28,027,769	$ 29,647,682	$ 31,474,057
Test Year Removals					
A. FERC 913 removal	$ (101,050)				
B. SERP and ESRIP removal	$ (227,492)				
C. LTIP removal	$ (112,840)				
D. Stock Expense removal	$ (249,103)				
Restating, Proforma and Provisional Adj.					
E. Claims Adjustment	$ (12,390)				
F. Annual Incentive Adjustment	$ (166,239)				
G. Rate Case Expense Adjustment	$ (148,523)			$ 750,000	
H. Savings		$ (10,710)			
I. FTE Adjustment	$ 256,438	$ 80,292	$ 91,762	$ 91,762	$ 91,762
J. Wage and Salary Increase	[redacted]				
K. Health & Life Adjustment		$ 164,120	$ 134,170	$ 137,646	$ 134,922
L. Pension		$ 349,375	$ 58,686	$ (95,091)	$ (192,241)
M. General Non Payroll (with CPI)		$ 480,554	$ 292,284	$ 250,824	$ 238,697
N. Information Technology and Services (IT&S)		$ 553,949	$ 204,631	$ 23,758	$ 8,267
O. Contracted Locating and Survey Services		$ 44,727	$ 74,091	$ 72,307	$ 71,816
P. Insurance		$ 203,941	$ 76,969	$ 36,235	$ 39,604
Q. Pipeline Inspection Integrity Program		$ 34,701	$ 5,178	$ (479)	$ 2,730
R. Well Casing Integrity Inspection Program		$ 219,418	$ 99,527	$ (71,741)	$ (110,537)
S. Contracted Cust. Payment Processing Fee		$ 51,807	$ 48,483	$ 56,797	$ 64,302
T. Thermal Energy Network "TEN" project				$ 9,529	$ 47,707
Total O&M Expense	[redacted]				

1. O&M Costs for which the Company is Not Seeking Cost-Recovery

Q. Please describe the Test Year O&M costs for which the Company is not seeking cost recovery in this case.

A. The Company removed four expenses (lines labeled A-D in Table 1 above) from the Test Year as part of their restating adjustments. The Company removed all FERC 913

(Promotional Advertising Expense), the Supplemental Executive Retirement Plan ("SERP") and Executive Supplemental Retirement Income Plan ("ESRIP"), expenses related to the Long-Term Incentive Plan ("LTIP"), and all expenses related to Stock Expense (which include Restricted Stock Units, or "RSUs"). The cumulative effect of not seeking cost recovery of these O&M costs is a $690 thousand reduction in Washington-allocated O&M (Table 2 below).

Table 2

	Test Year 4/1/24-3/31/25
Test Year Removals	
A. FERC 913 removal	$ (101,050)
B. SERP and ESRIP removal	$ (227,492)
C. LTIP removal	$ (112,840)
D. Stock Expense removal	$ (249,103)
Total	**$ (690,485)**

2. Claims Adjustment (line E in Table 1)

Q. Please describe the Claims restating adjustment.

A. The Company includes a restating adjustment to include actual ordinary claims for the Test Year, replacing the expense accrual activity that is used for claims reserve accounting. The Direct Testimony of Kyle T. Walker (Exh. KTW-1T) provides more information on the claims adjustment included in the case.

Q. What is the impact to O&M of the Claims restating adjustment?

A. The restated O&M Test Year adjustment for claims is a decrease of $12 thousand to align the Test Year amount to the actuals ordinary claim amount instead of the expense accrual activity in the Test Year results.

3. Annual Incentive Adjustment (line F in Table 1)

Q. Please describe the Annual Incentive restating adjustment, and quantify the impact to O&M of that adjustment.

A. The Company used the historical average of annual incentive compensation paid to make a restating adjustment to the Test Year amount. Specifically, a three-year historical average was applied to restate the annual incentive compensation for Non-Bargaining Unit ("NBU") employees, while a six-year historical average was used for Officers. Bargaining Unit ("BU") employees were not included in this restatement because they are not eligible for incentive compensation under the Collective Bargaining Agreement ("Agreement"). The confidential Direct Testimony of Melinda B. Rogers (Exh. MBR-1CT) provides more information on the incentive compensation expense included in the case. The total impact of the restating adjustments above is a reduction of $166 thousand.

4. Rate Case Expense Adjustment (line G in Table 1)

Q. Please describe the Rate Case restating adjustment, and quantify the impact to O&M of that adjustment.

A. During the Test Year period, the Company incurred expenses of $1.24 million for rate –case related expenses occurring in jurisdictions unrelated to this case. Therefore, a restating adjustment was made to remove all costs related to those expenses allocated to Washington. The Washington-allocated amount in the Test Year was $149 thousand. This was removed as a Test Year restarting adjustment.

Q. Is the Company included any rate case related costs in this case?

A. Yes, the Company is forecasting to spend $1.5 million in rate case related expenses in this case. To minimize the immediate impact to customers in Rate Year 1, instead of spreading the costs over the three provisional periods, the Company layered additional expense beginning in Rate Year 2 of $750 thousand for both Rate Year 2 and Rate Year 3 to recover those expenses.

5. Resource Scheduling Optimization Savings Adjustment (line H in Table 1)

Q. Please describe the Resource Scheduling Optimization Savings adjustment.

A. As further described more fully in the confidential Direct Testimony of Brian E. Fellon (Exh. BEF-1CT), the Resource Scheduling Optimization Project will improve the software used by NW Natural's Resource Management Center ("RMC") to manage field worker schedules and timesheets, thus allowing the Company to better track and assign work. The Resource Scheduling Optimization Project will resolve issues with the Workforce software that currently require several manual workarounds and will implement functionality improvements. Accordingly, the Company includes a proforma expense adjustment to reducing O&M in this case to reflect a reduction of two contracted workers because of the expected reduced manual workarounds. The total savings are $322 thousand on a system level. The Washington-allocated adjustment is a reduction of $11 thousand to O&M, and a reduction of $28 thousand to rate base.

6. FTE Adjustment (line I in Table 1)

Q. Please describe the full-time equivalent ("FTE") restating adjustment.

A. The Company makes an O&M Test Year restating adjustment to annualize the expense of the actual FTE count at the conclusion of the Test Year. The adjustment increases O&M by $256 thousand.

Q. Is the Company requesting additional FTEs in the Rate Years?

A. Yes, the Company projects continued annual FTE growth of 12 on a system basis going forward.

Q. What is the impact to O&M of the additional forecasted FTEs?

A. The additional FTE expense in the proforma period is an increase as compared to the Test Year by $80 thousand. Rate Year 1 is an increase in expense of $92 thousand as compared to the proforma period. Rate Year 2 is an increase of $92 thousand as compared to Rate Year 1, and Rate Year 3 is an additional increase of $92 thousand as compared to Rate Year 2. The confidential Direct Testimony of Melinda B. Rogers (Exh. MBR-1CT) provides more information on the FTE increases included in the case.

7. Wage and Salary Increase Adjustment (line J in Table 1)

Q. Please explain the adjustment to wages and salary costs.

A. The Company made proforma and provisional adjustments for wage and salary increases as shown in Table 3 below, and the confidential Direct Testimony of Melinda B. Rogers (Exh. MBR-1CT) provides more information on the wages and salary expense included in the case. BU employee payroll costs were escalated by taking the Test Year restated Washington-allocated BU employee wages, adjusting to account for expected annual FTE growth, and then applying the scheduled wage increases under

the Collective Bargaining Agreement with the Union. The Company adjusted BU payroll costs to reflect the Agreement's 4.00 percent wage increase effective December 1, 2025, December 1, 2026 and December 1, 2027. The current Collective Bargaining Agreement[3] with the Union runs through May 31, 2028. For this case in which Rate Year 3 goes beyond this date, the Company assumed the [redacted] adjustment would apply on December 1, 2028. In addition, on top of the wage increase, the Company applied an additional 1.05 percent each year for promotions and movements from entry rate to experienced rate as described in the Agreement. For Rate Year 3 that goes beyond the term of the CBA, the Company used the [redacted] adjustment to account for such promotions and movements.

Table 3

	ProForma 8/1/25-7/31/26	Rate Yr1 8/1/26-7/31/27	Rate Yr2 8/1/27-7/31/28	Rate Yr3 8/1/28-7/31/29
J. Wage and Salary Increase				
BU	$ 289,937	$ 223,279	$ 236,497	[redacted]
NBU	$ 367,080	[redacted]		
Officers	$ 23,229	$ 18,348	$ 19,228	$ 20,151
Total	**$ 680,245**	[redacted]		

The total O&M adjustment to BU payroll increased O&M expense by $290 thousand in the proforma period as compared to the Test Year. Rate Year 1 is an increase of $223 thousand as compared to the proforma period. Rate Year 2 is an increase of $236 thousand as compared to Rate Year 1, and Rate Year 3 is an additional increase of [redacted] as compared to Rate Year 2.

[3] Exh. MBR-4.

Like BU payroll costs above, NBU and Officer payroll costs were escalated by taking the Test Year restated NBU and Officer salaries, adjusting to account for expected annual NBU employee growth, and then applying forecasted wage and salary increases.

The Company included a [redacted] annual increase each March beginning in 2026. The [redacted] is made up of [redacted] projected salary increases [redacted] for promotions that have historically occurred each year.

The total O&M adjustment to NBU payroll increased O&M expense by $367 thousand in the proforma period as compared to the Test Year. Rate Year 1 is an increase of [redacted] as compared to the proforma period. Rate Year 2 is an increase of [redacted] as compared to Rate Year 1, and Rate Year 3 is an additional increase of [redacted] as compared to Rate year 2.

The total O&M adjustment to Officer payroll increased O&M expense by $23 thousand in the proforma period as compared to the Test Year. Rate Year 1 is an increase of $18 thousand as compared to the proforma period. Rate Year 2 is an increase of $19 thousand as compared to Rate Year 1, and Rate Year 3 is an additional increase of $20 thousand as compared to Rate Year 2.

Q. Does the O&M payroll expense include any non-regulated full-time equivalents (FTEs)?

A. No. The O&M payroll expense excludes all payroll related to non-regulated activity. This non-regulated activity includes any time spent by employees on affiliate activities.

8. Health and Life Adjustment (line K in Table 1)

Q. Please describe the Health and Life adjustment.

A. The Company made proforma and provisional adjustments for both medical and life benefits. For medical benefits, the Company used projected annual medical benefit increases to determine the adjustment amounts. The annual projected increase for medical benefits is 9.50 percent in 2025, 9.00 percent in 2026, 8.50 percent in 2027, 8.00 percent in 2028, and 7.00 percent in 2029. The confidential Direct Testimony of Melinda B. Rogers (Exh. MBR-1CT) includes additional information regarding the medical benefit increases. For life insurance, the Company used projected annual life insurance increases to determine the adjustment amounts. The annual projected increase for 2025 and 2026 was kept flat to Test Year amounts. Life insurance increase was applied at 3.00 percent in 2027, 3.00 percent in 2028, and 3.00 percent increase in 2029. The confidential Direct Testimony of Melinda B. Rogers (Exh. MBR-1CT) includes additional information regarding life insurance increases. The total O&M adjustment for Health and Life increased O&M expense by $164 thousand in the proforma period as compared to the Test Year. Rate Year 1 is an increase of $134 thousand as compared to the proforma period. Rate Year 2 is an increase of $138 thousand as compared to Rate Year 1, and Rate Year 3 is an additional increase of $135 thousand as compared to Rate Year 2.

9. Pension Expense Adjustment (line L in Table 1)

Q. Please describe the Pension Expense adjustment.

A. The Company has adjusted the pension expense in the proforma and provisional periods to reflect the projected expense forecasted by the Company's actuary, Fidelity

Investments, as shown in Table 4 below. The Company used the latest forecast provided by Fidelity Investments prior to filing this rate case, which reflects what the Company will incur during the period when rates are in effect. The proforma expense is projected to increase as compared to the Test Year by $349 thousand. Rate Year 1 is an increase in expense of $59 thousand as compared to the proforma period. Rate Year 2 is a decrease of $95 thousand as compared to Rate Year 1 expense, and Rate Year 3 is an additional decrease of $192 thousand as compared to Rate Year 2 expense.

Table 4

	Test Year 4/1/24-3/31/25	ProForma 8/1/25-7/31/26	Rate Yr1 8/1/26-7/31/27	Rate Yr2 8/1/27-7/31/28	Rate Yr3 8/1/28-7/31/29
L. Pension					
Beg. Balance	$ 687,345	$ 687,345	$ 1,036,720	$ 1,095,405	$ 1,000,315
Adjustment		$ 349,375	$ 58,686	$ (95,091)	$ (192,241)
Ending Balance	**$ 687,345**	**$ 1,036,720**	**$ 1,095,405**	**$ 1,000,315**	**$ 808,074**

10. General Non-Payroll (with CPI) Adjustment (line M in Table 1)

Q. Please describe the General Non-Payroll (with CPI) adjustment.

A. The Company escalated general non-payroll costs using year-over-year rates of change in the forecast of the U.S. Urban CPI, as reported in the May 2025 Oregon Economic and Revenue Forecast.[4] These escalation factors were applied on January 1st of each year in this case. The published rates are as follows: 3.40 percent in 2025, 2.90 percent in 2026, 2.20 percent in 2027, 2.00 percent in 2028 and 1.90 percent in 2029.

[4] Exh. TFD-3.

Q. What is the impact to O&M of using these escalation rates for Non-Payroll?

A. The proforma expense is projected to increase as compared to the Test Year by $481 thousand. Rate Year 1 is an increase in expense of $292 thousand as compared to the proforma period. Rate Year 2 is an increase of $251 thousand as compared to Rate Year 1, and Rate Year 3 is an additional increase of $239 thousand as compared to Rate Year 2.

Q. Does the Company include any other adjustments for specific non-payroll program costs in this case?

A. Yes, the Company identified several items where its forecasted growth projection was greater or lesser than CPI's projections and adjusted these items accordingly. This ensures that these adjustments accurately reflect changes that are known to the Company—for example, changes due to fluctuation of contractual agreements, which are both known and measurable, or expense changes that the Company knows will increase or decrease at a rate that differs from CPI's escalation rate. As shown in Table 5, below, the following areas have been adjusted for accordingly: Information Technology and Services ("IT&S"); Contracted Locating & Survey Services; Insurance; Pipeline Inspection Integrity Program; Well Casing Integrity Inspection Program; the Company's Contracted Customer Payment Processing Fees; and Thermal Energy Network ("TEN") project.

Table 5

	ProForma 8/1/25-7/31/26	Rate Yr1 8/1/26-7/31/27	Rate Yr2 8/1/27-7/31/28	Rate Yr3 8/1/28-7/31/29
Adjustments for Specific Non-Payroll				
N. Information Technology and Services (IT&S)	$ 553,949	$ 204,631	$ 23,758	$ 8,267
O. Contracted Locating and Survey Services	$ 44,727	$ 74,091	$ 72,307	$ 71,816
P. Insurance	$ 203,941	$ 76,969	$ 36,235	$ 39,604
Q. Pipeline Inspection Integrity Program	$ 34,701	$ 5,178	$ (479)	$ 2,730
R. Well Casing Integrity Inspection Program	$ 219,418	$ 99,527	$ (71,741)	$ (110,537)
S. Contracted Cust. Payment Processing Fee	$ 51,807	$ 48,483	$ 56,797	$ 64,302
T. Thermal Energy Network "TEN" project			$ 9,529	$ 47,707
Total Adjustments for Specific Non-Payroll	**$ 1,108,543**	**$ 508,880**	**$ 126,406**	**$ 123,889**

11. Information Technology and Services (IT&S) Adjustment (line N in Table 1)

Q. Please describe the IT&S adjustment.

A. The confidential Direct Testimony of Brian E. Fellon (Exh. BEF-1CT) discusses in more detail the largest components of the IT&S O&M expense increase. The forecast includes projected hardware & software maintenance as well as service expenses.

Q. What is the impact to O&M of the specific IT&S non-payroll expenses?

A. The IT&S proforma expense is projected to increase as compared to the Test Year by $554 thousand. Rate Year 1 is an increase in expense of $205 thousand as compared to the proforma period. Rate Year 2 is an increase of $24 thousand as compared to Rate Year 1, and Rate Year 3 is an additional increase of $8 thousand as compared to Rate Year 2.

12. Contracted Locating & Survey Services Adjustment (line O in Table 1)

Q. Please describe the Company's Damage Prevention Program and the locating and survey services provided under that program.

A. The Company's Damage Prevention Program and the locating and survey services provided under that program are addressed in the Direct Testimony of Daniel B. Kizer and Scott S. Johnson (Exh. DBK-SSJ-1T).

Q. What is the impact to O&M of the specific Contracted Locating & Survey Services non-payroll expenses under the Damage Prevention Program?

A. The Contracted Locating & Survey Services proforma expense is projected to decrease as compared to the Test Year by $45 thousand. Rate Year 1 is an increase in expense of $74 thousand as compared to the proforma period. Rate Year 2 is an increase of $72 thousand as compared to Rate Year 1, and Rate Year 3 is an additional increase of $72 thousand as compared to Rate Year 2.

13. Insurance Expense Adjustment (line P in Table 1)

Q. Please describe the Insurance adjustment.

A. The Company has incurred insurance premiums for the fiscal period 2024-2025, and expects that the Company's excess liability insurance costs will increase beginning November 2025. The increase is driven by two main factors: (1) pricing for excess liability insurance has increased dramatically across insurance markets, particularly for gas and electric utilities; and (2) the Company is behind its peers with respect to the levels of excess liability insurance limits purchased. Both factors are driven by unprecedented losses experienced in the United States in a number of industries. The size and frequency of catastrophic jury awards, often referred to as "nuclear verdicts,"

have been increasing at a pace that far exceeds inflation for the past several years. The effect of these verdicts is exacerbated for gas and electric utilities due to the rapid increase in size and frequency of catastrophic wildfire claims. Combined, these circumstances have resulted in significantly higher premiums and reduced market capacity for excess liability. For the 2024-2025 insurance year, the Company saw a 22 percent increase in insurance premiums for policies that provide the same level of excess liability limits purchased in the prior year and a wildfire coverage limit that was 29 percent lower than the prior year. In other words, the Company paid more in the base year for less coverage than it had the year before, and the Company expects this trend to continue.

Q. Please explain why the Company decided that increased liability coverage is necessary.

A. NW Natural's liability coverage limits are consistently below its peers. Specifically, NW Natural's limit of $120,000 falls below the average coverage limit of approximately $270,000, and its limit per connection of $150 falls below the average of $229. NW Natural will increase its current $120 million total coverage when it renews the policy on October 15, 2025, to reach $200 million in total coverage. Even after the Company increases its coverage to this range, NW Natural will still have less coverage than most of the other utilities in the benchmark group, but it will be much closer to industry standard.

Q. Please explain the insurance expense increase the Company is seeking in this case.

A. For the forecasted premium beginning October 2026, the Company is expecting an increase of 30 percent in expense that considers increases for both higher pricing as

well as the impact of the higher liability limits. Beyond the premium year ending October 2027, the Company is projecting its overall insurance expenses to increase 5.00 percent annually.

Q. What is the impact to O&M of the Insurance adjustment?

A. The Insurance proforma expense is projected to increase O&M as compared to the Test Year by $204 thousand. Rate Year 1 is an increase in expense of $77 thousand as compared to the proforma period. Rate Year 2 is an increase of $36 thousand as compared to Rate Year 1, and Rate Year 3 is an additional increase of $40 thousand as compared to Rate Year 2.

14. Pipeline Inspection Integrity Program Adjustment (line Q in Table 1)

Q. Please describe the Company's Pipeline Inspection Integrity Program.

A. The Company's Pipeline Inspection Integrity Program is described in the Direct Testimony of Daniel B. Kizer and Scott S. Johnson (Exh. DBK-SSJ-1T).

Q. What is the impact to O&M for the Pipeline Inspection Integrity Program?

A. The Pipeline Inspection Integrity Program proforma expense is projected to increase as compared to the Test Year by $35 thousand. Rate Year 1 is an increase in expense of $5 thousand as compared to the proforma period. Rate Year 2 is a decrease of $479 as compared to Rate Year 1, and Rate Year 3 is an increase of $3 thousand as compared to Rate Year 2.

15. Well Casing Inspection Program Adjustment (line R in Table 1)

Q. Please describe the Company's Well Casing Inspection Program.

A. The Company's Well Casing Inspection Program is described in the Direct Testimony of Daniel B. Kizer and Scott S. Johnson (Exh. DBK-SSJ-1T).

Q. What is the impact to O&M for the Well Casing Inspection Program?

A. The Well Casing Inspection Program proforma expense is projected to increase as compared to the Test Year by $219 thousand. Rate Year 1 is an increase in expense of $100 thousand as compared to the proforma period. Rate Year 2 is a decrease of $72 thousand as compared to Rate Year 1, and Rate Year 3 is an additional decrease of $111 thousand as compared to Rate Year 2.

16. Contracted Customer Payment Processing Fees Adjustment (line S in Table 1)

Q. What are Customer Payment Processing Fees, and why are they increasing?

A. The Company entered into an agreement with Paymentus[5] to provide electronic bill payment services to the Company's customers and has been doing so since October 2020. The parties recently amended the contract in December 2023 for services through May 2027.[6] The Company has experienced a strong customer preference to pay by bankcard. The average growth in bankcard adoption from 2013 forward has been 20 percent annually. Over the last 5 years, it was 13 percent. Over the last 2 years, it was 11 percent. In 2023, it was 10 percent. Table 6 below illustrates historical adoption.

[5] Confidential Exh. TFD-4C.

[6] Confidential Exh. TFD-5C.

Table 6

Year	Payments Incurring a Fee Count	% Increase from Prior Year
2013	$ 547,742	
2014	$ 810,976	48%
2015	$ 1,075,387	33%
2016	$ 1,288,359	20%
2017	$ 1,563,339	21%
2018	$ 1,788,861	14%
2019	$ 2,033,066	14%
2020	$ 2,413,091	19%
2021	$ 2,687,553	11%
2022	$ 2,998,596	12%
2023	$ 3,294,748	10%

Average Increase	20%
Average Increase Last 5 Years	13%
Average Increase Last 2 Years	11%

NW Natural is using the most conservative of these averages, and forecasts that transactions from the Test Year through Rate Year 3 will continue at 10 percent compound annual growth rate.

Q. What is the impact to O&M for the Contracted Customer Payment Processing Fee increase?

A. The Contracted Customer Payment Processing Fee proforma expense is projected to increase as compared to the Test Year by $52 thousand. Rate Year 1 is an increase in expense of $48 thousand as compared to the proforma period. Rate Year 2 is an increase of $57 thousand as compared to Rate Year 1, and Rate Year 3 is an additional increase of $64 thousand as compared to Rate Year 2.

17. Thermal Energy Network (TEN) Adjustment (line T in Table 1)

Q. What is TEN?

A. TEN is the Thermal Energy Network pilot project in Vancouver, for which the Company is seeking recovery in this proceeding. The confidential Direct Testimony of Holly J. Braun (Exh. HJB-1CT) provides more information on the pilot project included in the case.

Q. What is the impact to O&M for the TEN project?

A. The TEN project is projected to have O&M in Rate Year 2 of $10 thousand dollars, and Rate Year 3 is an additional increase of $48 thousand as compared to Rate Year 2 expenses.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

III. LIST OF EXHIBITS

Exh. TFD-2C	O&M development excel model (Confidential and Redacted)
Exh. TFD-3	Oregon Economic and Revenue Forecast, May 2025
Exh. TFD-4C	Paymentus Contract (Confidential and Redacted)
Exh. TFD-5C	Paymentus Contract Amendment #3 (Confidential and Redacted)

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE EXPENSE

Exh. TFD-2C

REDACTED VERSION

August 29, 2025

THIS EXHIBIT IS BEING FILED IN ITS NATIVE EXCEL FORMAT. IT CONTAINS CONFIDENTIAL INFORMATION UNDER WAC 480-07-160. NO REDACTED VERSION EXISTS.

BEFORE THE

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OPERATIONS & MAINTENANCE EXPENSE

Exh. TFD-3

August 29, 2025

DAS
DEPARTMENT OF ADMINISTRATIVE SERVICES

Oregon Economic and Revenue Forecast

May 2025

Volume XLV, No. 2
Release Date: May 14th, 2025

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Foreword

This document contains the Oregon economic and revenue forecasts. The Oregon economic forecast is published to provide information to planners and policy makers in state agencies and private organizations for use in their decision-making processes. The Oregon revenue forecast is published to open the revenue forecasting process to public review and is the basis for much of the Oregon state government budgeting process.

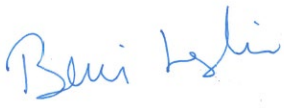
The report is published four times a year: March, May/June, September and December.

The economic model assumptions and results are reviewed by the Department of Administrative Services Economic Advisory Committee and by the Governor's Council of Economic Advisors. The Department of Administrative Services Economic Advisory Committee consists of 15 economists employed by state agencies. The Governor's Council of Economic Advisors is a group of 12 economists from academia, finance, utilities and industry.

Members of the Economic Advisory Committee and the Governor's Council of Economic Advisors provide a two-way flow of information. The Department of Administrative Services makes preliminary forecasts and receives feedback on the reasonableness of such forecasts and assumptions employed. After the discussion of the preliminary forecast, the Department of Administrative Services makes a final forecast using the suggestions and comments made by the two reviewing committees.

The results from the economic model are used to provide a preliminary forecast for state tax revenues. The preliminary results are reviewed by the Council of Revenue Forecast Advisors. The Council of Revenue Forecast Advisors consists of 15 specialists with backgrounds in accounting, financial planning and economics. Members bring specific specialties in tax issues and represent private practices, accounting firms, corporations, government (Oregon Department of Revenue and Legislative Revenue Office) and the Governor’s Council of Economic Advisors. After discussion of the preliminary revenue forecast, the Department of Administrative Services makes the final revenue forecast using the suggestions and comments made by the review committee.

Readers who have questions or wish to submit suggestions may contact the Office of Economic Analysis by email at oea.info@das.oregon.gov.



Berri Leslie
DAS Director
Chief Operating Officer

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Executive Summary

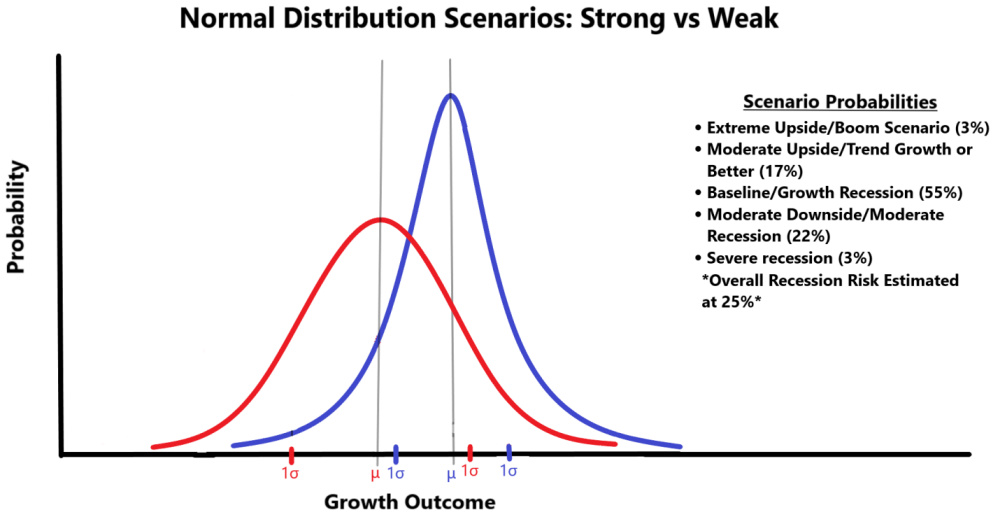
May 2025 — 'Known unknowns' foment uncertainty and wider tail risks

The national and state economies stand at a critical juncture due to a myriad of major public policy course changes and the associated uncertainties, including trade and tariff policy, restructuring of the federal government and tax reforms. The ultimate manifestation of these federal agenda priorities could have a wide range of consequences on the economic outlook—depending on the degree to which they magnify or offset one another. For example, income tax reductions for households and corporations could offset the effective levies imposed via tariffs (similar to the experience in 2018).

The timing of the 2025-27 close of session forecast comes at a time of exceptionally heightened uncertainty. Not only is it too soon to understand how the economy is responding to actions already taken—but, more broadly, the ultimate scope of critical policy decisions remains unknown. For example, even preliminary economic impacts from tariffs are unlikely to materialize in vital statistics such as employment or consumer prices for another month or two. Further, final details on tax reforms and budget reductions are only vaguely coming into view, and the eventual effective tariff rate will depend on the success of negotiations which have not yet occured.

These recognized uncertainties, or *known unknowns*, pose potentially massive risks to the economic outlook. As such, while the medium-term forecast is always subject to a distribution of potential outcomes (or risk scenarios), the elevated risks at present create unique characteristics surrounding the current projections.

Single-party control of the executive and legislative branches at the federal level create the opportunity for bold policy decisions to more forcefully push growth outcomes away from the most likely outcome based solely on economic fundamentals. As such, policy risk alone raises the probability of tail-risk scenarios, which inherently means the degree of confidence toward the baseline or central forecast is diminished.



This is worth restating—the Office of Economic Analysis has diminished confidence in the central forecast as a result of pending policy decisions which are expected to have substantial economic consequences for growth, employment, inflation and financial markets—all of which are critical variables driving the compilation of our revenue forecast.

Economic fundamentals were sound at the start of the year, and the consensus among forecasters anticipated only moderately slower growth and lower inflation relative to the prior year. Some preliminary measures of job creation even hinted at a reacceleration, both nationally and within Oregon, in the early months of 2025. After lagging the national economy for several quarters, state economic output showed compelling evidence of rebounding around yearend.

Nonetheless, Oregon is a state which is highly vulnerable to national priorities relating to tariffs, immigration, and federal expenditures. Exports and manufacturing play outsized roles in the state, so trade tensions will be borne disproportionately; particularly by key industrial pillars such as agriculture, semiconductors and sportswear/apparel. This was evident during the trade tensions of 2018-19, which were considerably smaller relative to recently enacted measures.

Growth recession, profits recession...but not an outright recession

It is admittedly too soon to comprehend the economic consequences of recent actions, although the resilience in economic data to date (and subsequent stabilization of financial markets) speaks to the broader resilience of the U.S. economy. Elevated uncertainty pertaining to the economic outlook and business climate is undoubtedly negative for capital spending and hiring plans, but the absence of more severe symptoms in the hard economic data (or forward-looking financial markets) to date is noteworthy, to be sure. As such, while the risk of recession is magnified by policy uncertainty—it is not the baseline assumption of OEA.

In the OEA forecast for 2025, growth is expected to be sufficiently slow that labor conditions soften appreciably—but not in the jarring manner of a conventional recession. Economists refer to such a scenario as a “growth recession” or near-stagnation. It is a period during which weak growth results in higher unemployment. In contrast, an outright economic recession is defined by the National Bureau of Economic Research as a significant decline in economic activity that is spread across the economy and lasts more than a few months. To be sure, a recession of some degree of severity is a plausible risk in the current environment of low growth. The economic and revenue implications of a range of scenarios, including modest and severe recessions are detailed in this document, but it is important to underscore that our central scenario is not a recession.

The revenue outlook exhibits a significant slowdown in income growth for individuals and an outright decline in business income in 2025. Normal growth conditions resume as 2026 progresses. This is a marked revision in the outlook relative to the previous forecast and results in downward changes to both the current and the next biennium’s revenue picture.

For the 2023-25 biennium—that is coming to a close—revenues are revised downward $162.3 million relative to the Q1 forecast. In addition, the 2025 legislature appropriated additional spending allowance

for the current biennium, effectively reducing the ending balance by an additional $248.9 million. All told, the ending balance in the General Fund is now projected at $2.17 billion, a change of -$414.0 million from the prior forecast.

For the 2025-27 biennium, the most significant change is to personal income taxes, which have been adjusted downward by $529.0 million. Corporate income taxes are increased slightly, up $24.6 million from the prior forecast. Total revenues have been revised down $334.2 million. Including the $414.0 decrease in the beginning balance carried forward from the prior biennium, the total change in available resources is -$755.7 million. The muted outlook also affects non-General Fund revenues such as the Corporate Activity Tax, Lottery and Marijuana Taxes. Corporate Activity Tax revenues in 2025-27 have declined $44.4 million from the previous forecast. Lottery earnings are revised downward by $36.7 million due mostly to weaker-than-expected Video Lottery sales. Marijuana tax revenues are also adjusted modestly, down $7.6 million from Q1.

Economic Outlook

Macroeconomic Setting

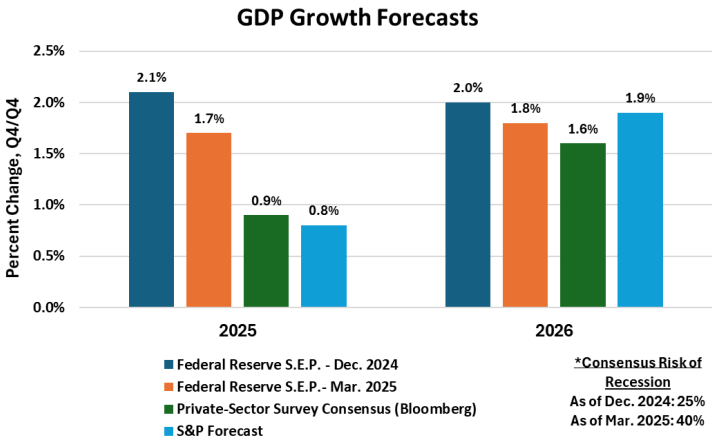
Staring into the Brink (of Recession)

Policy choices at the federal level are materially impacting the national economic outlook through both measurable actions, such as tariffs imposed, but also by sowing uncertainty among a wide range of economic entities, including households, businesses and investors. Confidence toward the economic outlook is a critical catalyst of consumption, hiring and investment, and history shows that periods of acute uncertainty can depress such activity.

International trade policy is a dominant contributor to the economic unknowns presently. The ultimate effective tariff rate, or even the direction of travel relative to current levels, is unknowable at this point in time. It is also too soon to gauge the real economic impact of measures put in place a little over a month earlier. Vital economic statistics pertaining to output, inflation and hiring are unlikely to begin showing tariff impacts until at least mid-year.

At the time of publication, the extent of progress in bilateral trade negotiations showed signs of promise, but the end result remained unclear. Similarly, the fate of the April 2 reciprocal tariffs was murky (these are currently paused through early July but also subject to various court rulings). While tariff pressures have eased in recent developments, continued progress is not assured as White House communications have hinted at upcoming tariff actions on pharmaceuticals, lumber, entertainment and other product categories.

Until the aforementioned forecasting impediments are diminished, the risk profile surrounding OEA’s forecast is distorted accordingly. Confidence toward the baseline (or central forecast) is reduced and the likelihood of alternative scenarios is elevated.



Recent developments have diminished near-term growth prospects while at the same time creating upside risks toward both inflation and unemployment. However, the magnitude of these risks is highly uncertain. The consensus among professional forecasters has trimmed growth projections accordingly while also acknowledging elevated recession risks. Some have even incorporated recession into their baseline. OEA anticipates materially slower growth relative to the prior forecast, but sees a recession narrowly avoided. Even so, growth will be sufficiently meager as to allow the unemployment rate to drift higher.

Such anemic periods of growth are described as a *growth recession*. The economy is not growing fast enough to balance labor conditions, so slack builds—embodied by rising unemployment. A growth recession is distinct from an outright recession, the latter of which is defined as a significant decline in economic activity spread across the economy, lasting more than a few months. Even so, a growth recession episode substantially increases the risk of the economy sliding into an outright recession.

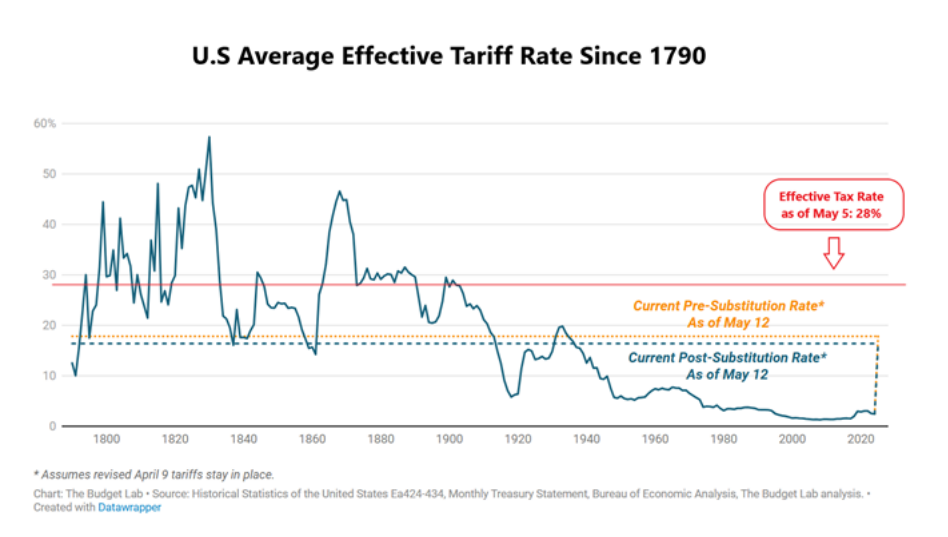
There are four main reasons why OEA thinks an outright recession could be avoided:

- **The U.S. economy has demonstrated resilience year-to-date.** In their latest assessment of economic conditions, policymakers at the Federal Reserve described economic activity as having "continued to expand at a solid pace" and labor conditions as "solid". Similarly, the pace of job creation in recent months is little changed from last year, and the unemployment rate remains stable at the national level.

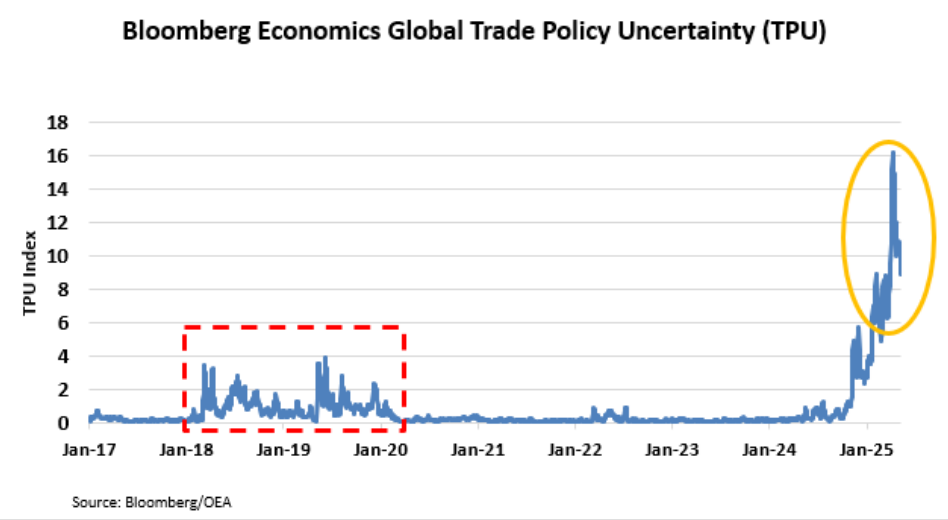
  Initial reports on Q1 2025 GDP growth showed a decline, but this occurred as households and businesses rushed to stockpile goods ahead of anticipated tariff announcements. This drove a massive surge in imports, which are subtracted from the tabulation of GDP. However, upon isolating this stockpiling effect, underlying private sector activity, known as private domestic final purchases (PDFP), showed a steady pace relative to 2024. Another factor supporting private sector resilience is robust corporate profit growth prior to the tariff announcement. The national income and product accounts show profits rising 7% in 2024 following an 11% increase in 2023.

- **Effective tariff rates appear to be at (or near) the peak.** Recent developments show the Trump administration making progress across the spectrum of trading partners in efforts to renegotiate relationships. The surprise announcement of a framework agreement with the UK on trade policy indicates a willingness from the administration to limit economic stress and also sets a template for other trade partners. Meanwhile, the fact that dialogue has begun between China and the U.S. is an encouraging sign of détente in arguably the highest-pressure point of current trade tensions. Both sides acknowledged "substantial progress" following their initial de-escalation talks in Geneva, Switzerland and subsequently agreed to reset tariffs while negotiations continue.

[It is worth noting that a number of court challenges to tariffs are also pending and could result in a rapid reduction in the effective tariff rate.]



- **Economic anxiety is starting to stabilize, maybe even subside.** Survey data shows economic sentiment souring sharply among households and businesses over the past few months. Many forecasters harbor concerns that a sustained loss of confidence will rapidly extract a toll on economic activity, including household spending, hiring and business investment. To the extent that trade tensions are driving sentiment, there are some encouraging signals of late. Financial market stress has diminished appreciably, and specific measures of trade policy uncertainty are showing tentative signs of improvement, as well. If these patterns endure, then broader measures of consumer and business confidence may soon start to thaw.



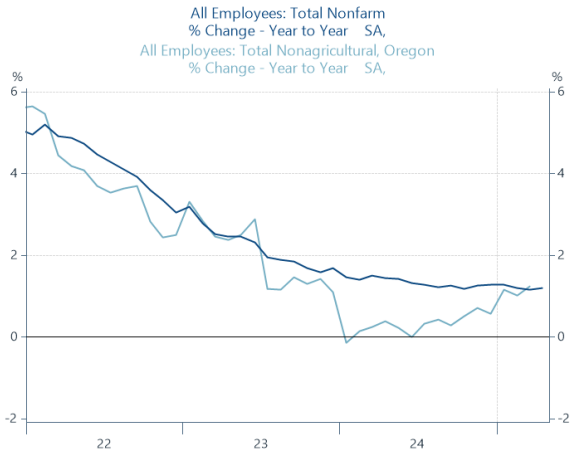
- **Policy accommodation to support the economy.** Both monetary and fiscal policy are likely to evolve toward more supportive stances later this year. Federal Reserve officials are currently signaling an unwillingness to act preemptively in cutting rates to stimulate economic activity given heightened uncertainty toward the inflation outlook. However, market expectations anticipate a series of interest rate reductions later this year.

  Fiscal policy is also likely to provide meaningful stimulus if the tax reform package working its way through Congress results in lower effective personal and corporate tax rates. Using tax cuts to offset the negative consequences of tariffs is not without precedent in the Trump administration, as a similar strategy was employed in 2018. Economic growth slowed as trade tensions amplified, but tax cuts delivered via the Tax Cuts and Jobs Act (TCJA) and interest rate reductions from the Federal Reserve ultimately stabilized activity.

To be sure, highlighting factors that may reduce the risk of recession (or its severity) should not be interpreted as downplaying the overall risk of recession. The risk of a downturn remains elevated, and has increased in recent months. The factors cited above are intended to explain why recession is an outsized downside risk—a clear and present danger—but not the OEA baseline assumption. Given the critical impact of a national recession on the economic and revenue outlook and the heighted risk at present—a robust, multi-faceted scenario analysis is included on page 30.

Oregon's Economic Outlook

Oregon's economy shows modest signs of growth in the early months of 2025, particularly in terms of job gains. The state appears to have gained growth and hiring momentum following a soft patch in late 2023/early 2024. However, its gradually increasing unemployment rate—edging higher than the national average for the past couple of months—points to a potential deviation in labor market performance.

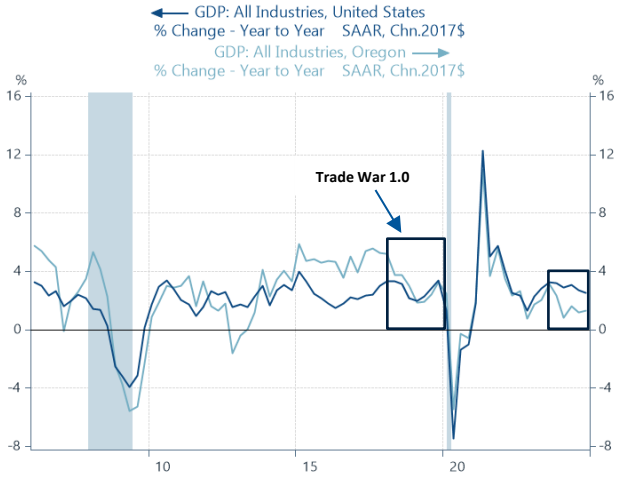


Source: Bureau of Labor Statistics/Haver Analytics

Moreover, the state is in a difficult position as headwinds related to trade wars and federal spending cutbacks threaten to further depress activity. Historically, the state has grown at an above-average rate by virtue of outsized exposure to faster growing sectors, such as tech/semiconductors, and also due to favorable demographics—namely sturdy population growth underpinned by solid in-state migration.

In the aftermath of the pandemic, the state's economic fortunes have been closely correlated with national trends. This pattern broke down at the start of 2024 as growth decelerated more sharply in Oregon due to a conflux of weak population growth and microeconomic factors among core industrial entities in the state. Over the last four quarters of reported data, Oregon GDP growth has been slower than U.S. GDP growth by about one and a half percentage points, and state job creation lagged the national average as a result. There is some tentative evidence that the state economy is bouncing back—GDP growth averaged 1.9% over Q3-Q4 2024, compared to 2.8% nationally over the same period.

The state is in a precarious position with trade tensions elevated presently, given an elevated export share of GDP. The three biggest export sectors are, respectively, computer & electronic products, transportation equipment and machinery, and the three largest export destinations are Mexico, China and Canada (comprising 45% of total exports in 2024). The economic experience of the state during the onset of tariffs and trade tensions in 2018 poses a troubling precedent.



Source: Bureau of Economic Analysis/Haver Analytics

As illustrated in the accompanying figure, the state was handily outpacing the national economy before tariffs began and then quickly downshifted the pace of growth (by about 2.5 percentage points) by mid 2019. At present, the state has less of an economic buffer: State GDP growth was averaging 4.5% in 2017 compared to about 1.3% over the last four quarters; meanwhile, job creation was substantially stronger in 2017 (+40k) compared to 2024 (+23k). The unemployment rate is comparable between the two periods. A parallel outcome in the present environment would put state economic activity close to stagnation.

Recent federal government budget cutbacks and layoffs are also likely to impact state economic activity, particularly in eastern counties where federal employment accounts for a larger share of total payrolls. At the time of publication, it is premature to discern the net impact, as the latest reported economic statistics have yet to fully capture reductions as many federal employees have been reinstated, placed on administrative leave, or await court rulings on their employment status.

Topline Forecast Changes

- *Hiring:* Anticipated job creation is revised lower relative to the previous 2025 Q1 outlook by less than one percentage point across the forecast horizon. This is in part due to the trend in payroll gains slowing more than anticipated and the expectation that growth will slow and labor conditions soften.

- *Unemployment:* The unemployment rate has been revised higher in the near term as Oregon continues to experience cooling labor conditions. With GDP growth expected to slow below trend, the unemployment rate is projected to drift higher, reaching a peak of 5.2% in 2027.

- *Income:* Personal income is now lower relative to the previous outlook. This is in large part due to a change in the outlook to a "growth recession". The impact of this can already be seen in the data as withholding and estimated payments through April are slipping below normal growth rates.

- *Population:* Population growth for Oregon has been revised lower. This forecast incorporates the 2024 mid-year population estimate and revisions released by Portland State University Population and Research Center as well as new vital statistics assumptions. The population is expected to grow by an annual average of 0.5% through the forecast horizon.

Underpinning the economic outlook is a continued rebound in migration leading to slow, but positive, population gains in the state. The labor market is expected to be sufficiently slow and labor conditions will soften. Although there is materially slower growth relative to the prior forecast, a recession is narrowly avoided.

Key forecast assumptions

The economic and revenues forecasts are developed using inputs from our national forecast vendor, Standard & Poors. Key assumptions driving the Oregon economic model are described below:

- ***Federal Fiscal Policy:*** Federal employment is lowered with an assumed 255,000 federal layoffs through August 2025. Personal tax policy includes extension beyond the scheduled expiration in 2026 of provisions in the 2017 Tax Act. Exclusion of tip and overtime pay from federal taxation.

Corporate tax rate on corporate income is lowered from 21% to 15% for corporations that produce domestically.

- ***State & local fiscal policy:*** Unspent pandemic-era funds as well as monies authorized under the Infrastructure Investment & Jobs Acts (IIJA) mitigate pressures to reduce state and local spending. States are assumed to trim Medicaid rolls through 2027.

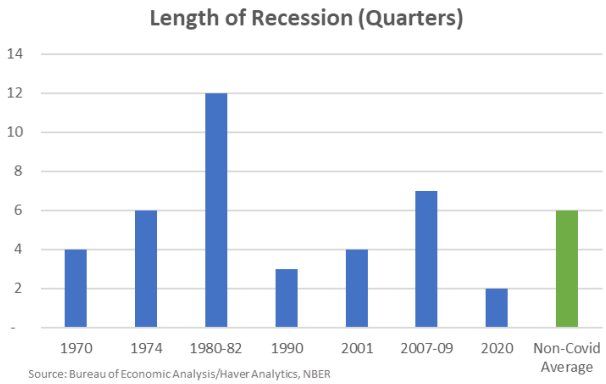
- ***Monetary Policy:*** The Federal Reserve holds the fed funds rate at current levels through much of the year, followed by three consecutive cuts spanning December 2025 through March 2026. Policymakers then slow to a pace of every other meeting over the rest of 2026, bringing the federal funds rate target to a range of 2.75%-3.00%, very close to estimates of the long-run "neutral" range.

- ***Tariffs and trade:*** Assumptions include new Section 232 tariffs on copper, lumber, semiconductors, pharmaceuticals, and critical minerals, ranging from 10% to 25%, effective in the fourth quarter of 2025. International Emergency Economic Powers Act tariffs on imports from China (20%), Canada (25%), and Mexico (25%), the latter two step down to 12% by early 2026. Reciprocal tariffs remain at a 10% universal baseline on imports from outside of North America except for China.

Oregon in Past Recessions

Given the heightened uncertainty pertaining to the economic and revenue outlook, a review of Oregon and the U.S. during prior recessions provides useful perspective on potential outcomes, particularly regarding plausible alternative scenarios for the state. It is important to underscore that our baseline scenario is not an outright recession, rather a period of anemic growth, as described in the executive summary.

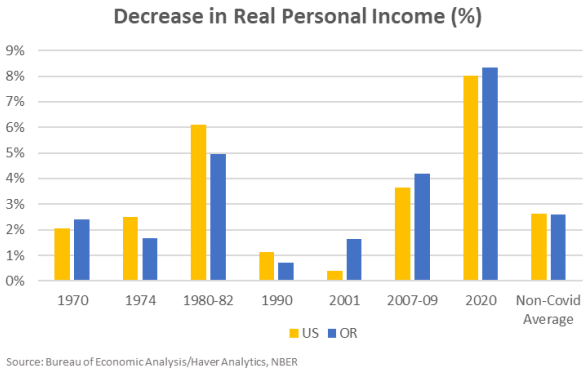
Official recessions are defined by the National Bureau of Economic Research (NBER) as a significant decline in economic activity that is spread across the economy and lasts more than a few months. Oregon's business cycle closely mirrors the U.S. cycle, so the NBER dating conventions are an appropriate benchmark for state analysis. Using these recession dates as defined by NBER, the average length of a recession dating back to 1970 is 6 quarters (excluding COVID-19). The 1980 and 2008 recessions were the longest and most severe.



With the recent emphasis on personal income less transfers and nonfarm payroll employment in NBER's decision to define a recession, our office finds it appropriate to compare Oregon vs. the U.S. in those two series, as well as the unemployment rate.

Personal Income

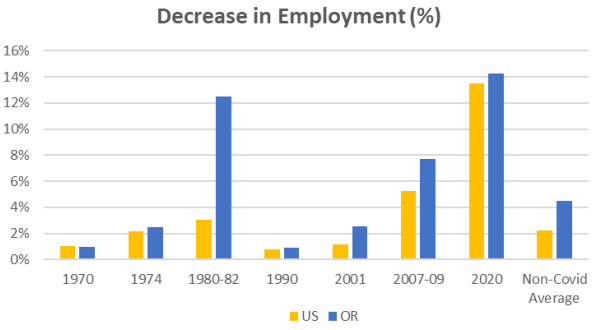
During a recession, Oregon real personal income tends to decrease in line with the national average. The non-covid average for the state is roughly the same as the national economy. However, in 1970, 2001, 2009, and 2020, Oregon experienced a greater decline in real personal income from the peak to the trough of the defined recession. For a moderate recession, Oregon typically experiences a 0.5-1.5% decline in real personal income, compared to a 4-5% decline during severe recessions.



Source: Bureau of Economic Analysis/Haver Analytics, NBER

Nonfarm Employment

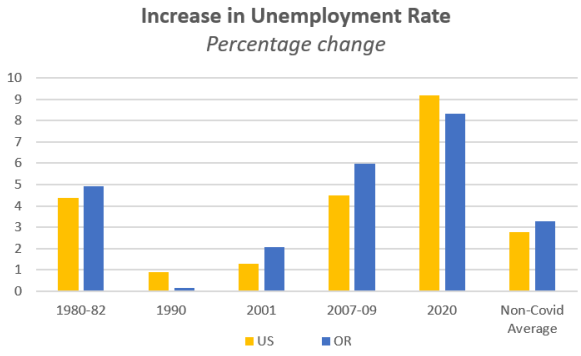
Oregon employment tends to drop more than the national average during a recession. The average decrease in employment for the U.S. is roughly 2% lower than the state's, but Oregon is also more volatile than the U.S. in terms of employment losses during recessionary periods. Much of the volatility can be attributed to the state's industrial structure. For a moderate recession, Oregon typically experiences a 1-2.5% decline in non-farm employment, compared to an 8-12% decline during severe recessions.



Source: Bureau of Economic Analysis/Haver Analytics, NBER

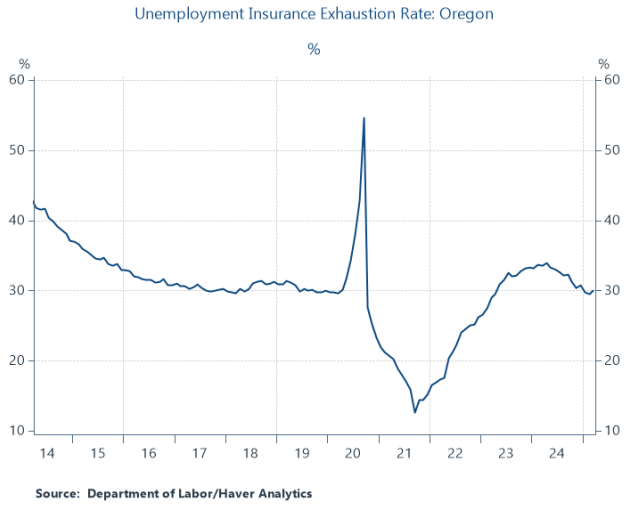
Unemployment Rate

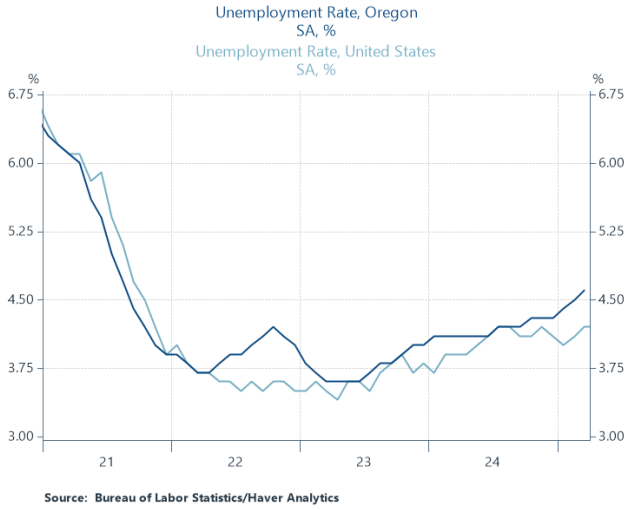
Oregon unemployment tends to increase in line with the national average during a recession. The average increase for the U.S. is roughly ¾ of a percentage point lower than the state's. For a moderate recession, Oregon typically experiences a 1-2 percentage point increase in the unemployment rate, compared to a 5-6 percentage point increase during severe recessions.



Update on Oregon Unemployment

To date, the Oregon unemployment insurance benefit exhaustion rate has been hovering around pre-pandemic levels. This measures the share of Oregonians who have received their maximum allotment of UI benefits (following 26 weeks). An elevated exhaustion rate is one symptom indicative of labor market fragility and difficulties for displaced workers to find new sources of employment. The current benefit exhaustion rate is relatively low historically, an indication that the labor market is not deteriorating further. For 2024, annual unemployment was 91,820 and the overall unemployment rate remained moderately low at 4.2%.



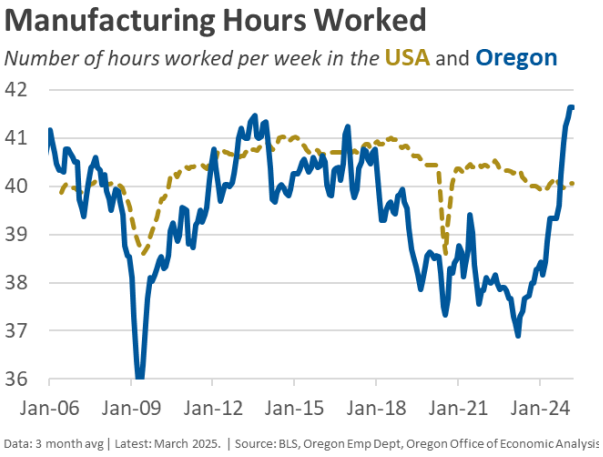


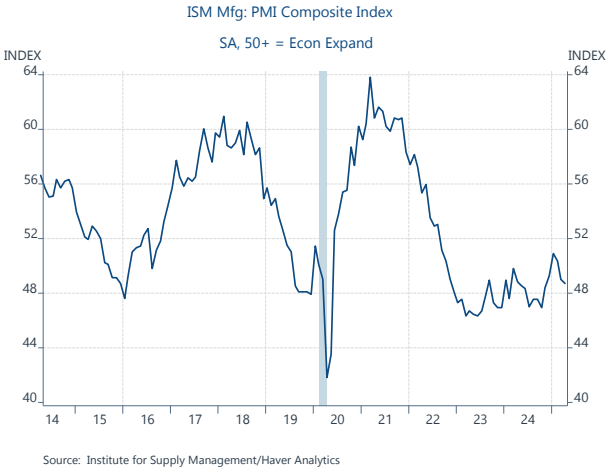
However, the unemployment situation in Oregon has soured recently. Thus far into 2025, Oregon has witnessed rising unemployment. Oregon registered a 4.6% unemployment rate in March, which is the highest rate observed since the Summer of 2021, when the rate was 4.7%.

One notable trend to emerge from these data is the divergence of Oregon and the national unemployment rate. Since August 2024, Oregon's unemployment rate has risen gradually, while the U.S. unemployment rate has remained relatively constant.

Oregon's Manufacturing Industry

Historically, manufacturing has been a key strength for the regional economy; however, over time, the industry's share of jobs has declined. As of recent, Oregon manufacturing jobs appear to have stabilized. The continuous growth in manufacturing hours worked is an encouraging signal for Oregon. It is an indication that demand for labor is rising among the remaining manufacturing employees. However, it is possible that the recent uptick in activity may have been in anticipation of changes in trade policies. The large divergence in manufacturing hours worked per week in Oregon and the U.S. warrants further watch.

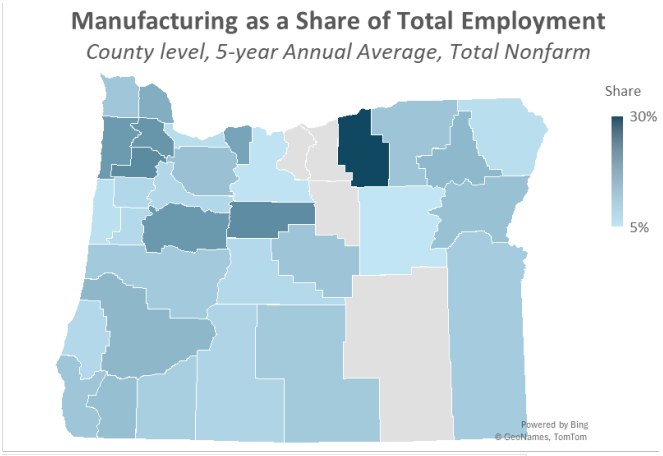




One indicator that can provide additional insights into the manufacturing sector is the Institute for Supply Management Manufacturing Purchasing Managers' Index. The ISM Manufacturing PMI® is based on survey data compiled monthly from purchasing and supply executives nationwide on new orders, production, employment, supplier deliveries and inventories.

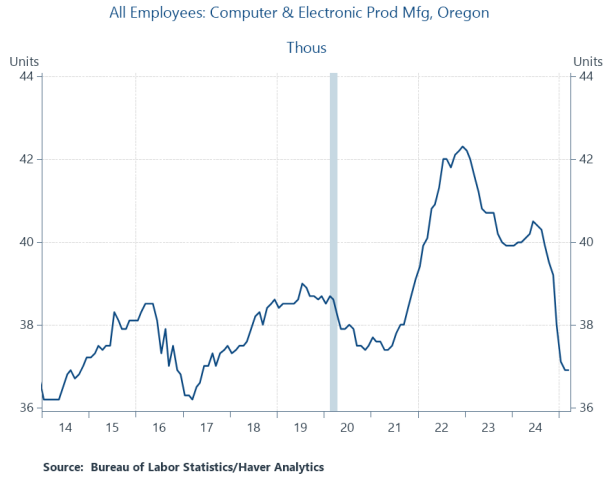
A reading above 50 indicates that the manufacturing sector is generally growing compared to the previous month, while a reading below 50 indicates that it is generally declining. The most recent Manufacturing PMI registered at 48.7. This suggests that overall U.S. manufacturing activity is marginally contracting—but it is running above levels which have historically been consistent with a broader downturn in the economy. In other words, it is not unusual for the manufacturing sector to witness a modest contraction while the overall economy continues to expand.

Oregon has a larger share of manufacturing jobs compared to the U.S. overall and is therefore more sensitive to changes in trade policy. Over the past 12 months, manufacturing accounted for 9.3% of total nonfarm employment in Oregon, compared to 8.1% nationally. The industry's importance also varies across counties as seen in the accompanying chart.



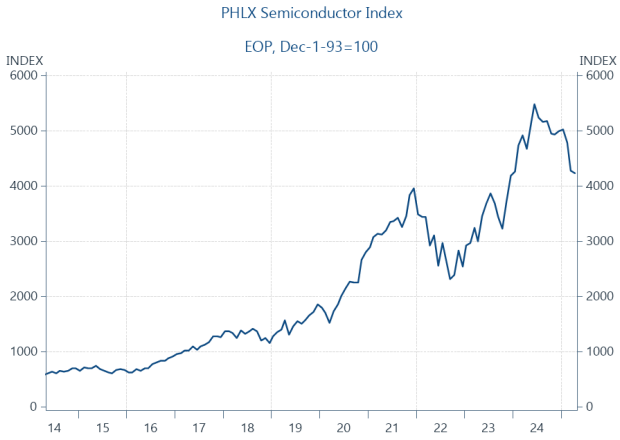
Oregon's Semiconductor Industry

Semiconductors are found in almost all modern technology and affect the operability of most Oregon industries. The semiconductor industry is one of the state's strengths, even with the continued job losses buffeting the industry.



Source: Bureau of Labor Statistics/Haver Analytics

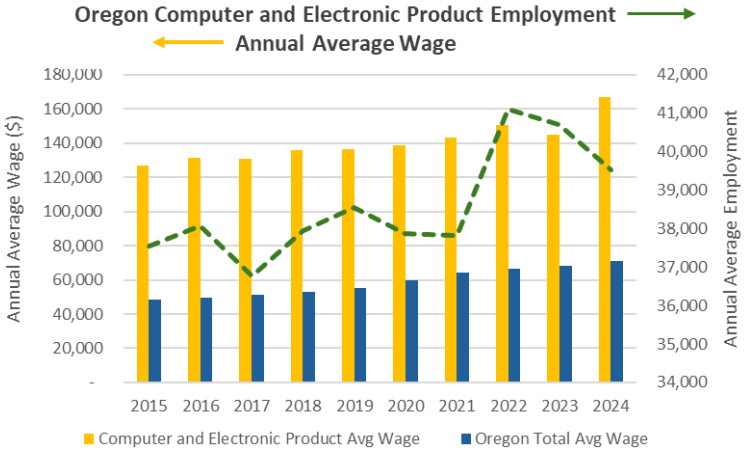
The total number of jobs in Oregon within computer and electronic manufacturing has fluctuated over the last decade, but was trending up through 2022. Over the last three years, the number of jobs has fallen from just over 42,000 to approximatley 37,000. Oregon's ability to manfucture products with semiconductors becomes even more important as the cost of importing those products increases.



Source: Wall Street Journal/Haver Analytics

A useful measure of the semiconductor industry is the Philidelphia Stock Exchange Semiconductor Sector Index (SOX), which is a market capitlization-weighted index that measures the performance of the 30 largest semiconductor and semiconductor equipment manufacturing firms. The SOX grew from 2014 to 2021, signaling a strong industry foundation and growth, after which it began to fall. The SOX rebounded in 2022 and grew to its peak in early 2024, before beginning a decline that has yet to conclude. The recent decline mirrors the decline in the number of jobs in computer and electronic manufacturing in Oregon.

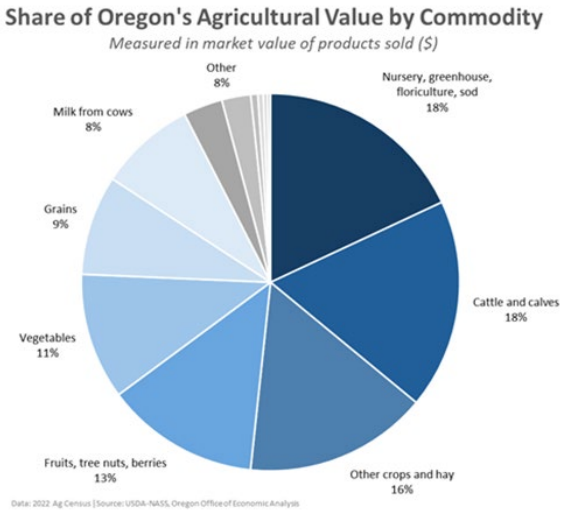
While the number of people working in this industry has been declining, wages for those employees remain strong. In 2024, the average wage for those in computer or electronic related fields was over $160,000, more than double the average wage when considering all working Oregonians. Wages in this industry continue to rise, even with job losses, suggesting the jobs remaining are those of very high skill.



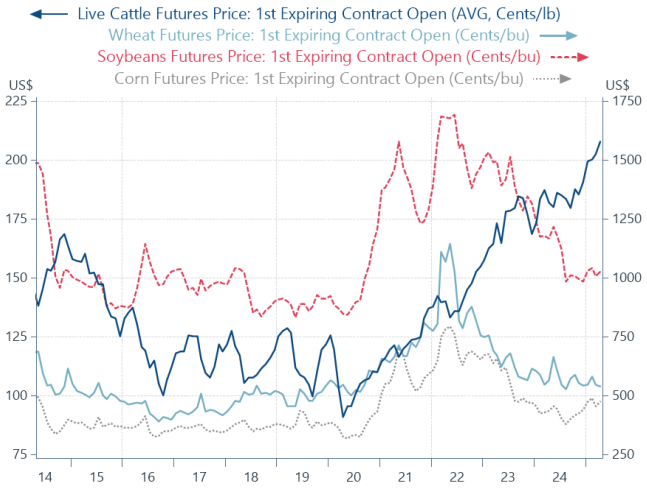
Source: Oregon Employment Department, Office of Economic Analysis

Oregon's Agricultural Economy

According to the USDA, Oregon's agricultural sales were nearly $6.8 billion, or approximately 1% of all U.S. sales in 2022. Oregon's agriculture sector has grown slower than the industry nationally, in terms of its output and job gains.



Although the agricultural industry is not large in terms of employment for the state, at about 3.1% of all private jobs in 2024, it remains a critical pillar of Oregon's economy. The state excels in the production of a diverse range of crops, including berries, wine grapes, nursery plants, and hay, as well as livestock and dairy.

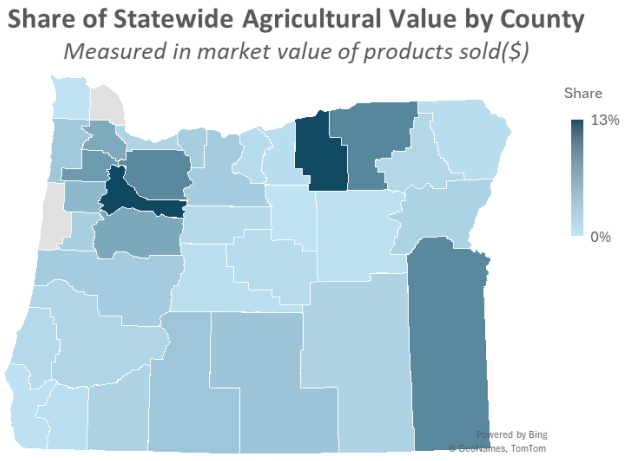


Source: Chicago Mercantile Exchange/Haver Analytics

Live cattle, wheat, soybeans, and corn are Oregon's largest agricultural staple goods. The Chicago Mercantile Exchange's data show that three of those goods (wheat, soybeans, and corn), have futures prices that have been trending down after peaking in 2022. While this may be a favorable development for moderating grocery prices, it is a headwind for producers.

Decreasing prices on futures contracts can be a projection of continued hardships for those farming and selling those goods. Live cattle prices have a more optimistic outlook and have been trending upwards since 2020. These prices are likely to be inordinately sensitive.

Oregon's counties vary in terms of both agricultural value added and by specializations in the product produced. The largest contributors to statewide value are Marion and Morrow counties. The western part of the state emphasizes fruits, berries, and nursery products, while the eastern part focuses on hay, cattle, and specialty crops like grains and oilseeds. Each region's agricultural strengths underscore how farming practices are adapted to local conditions and land use.



Source: USDA-NASS, Office of Economic Analysis

Near- to Medium-Term Forecast Risks

Oregon faces a multitude of near- to medium-term economic risks ranging from commodity price shocks to geopolitics. Brief synopses are included below:

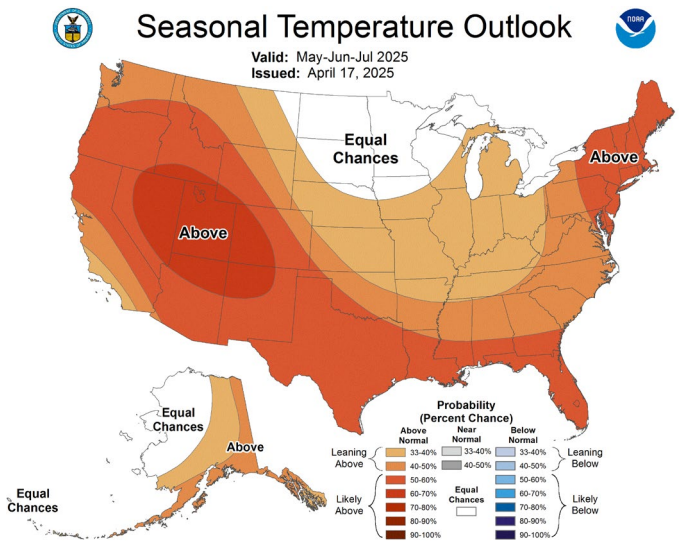
- *Trade tensions*: Ongoing trade and geopolitical disputes with major partners like China, Canada, and Mexico pose risks to Oregon's semiconductor, machinery, transportation equipment, and agricultural sectors. Given Oregon's export-reliant economy, trade restrictions or retaliatory tariffs could have an outsized impact.

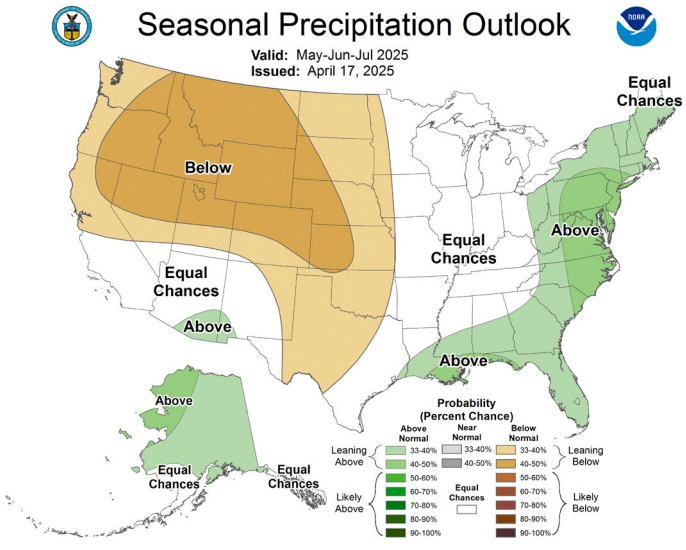
- *Oil prices*: Tensions in the Middle East and global supply uncertainties continue to create volatility in oil prices, which can affect fuel and transportation costs—particularly for rural communities and agriculture.

- *Immigration*: Large-scale deportations of undocumented immigrants would strain key industries such as agriculture, construction, hospitality, timber and food processing, which depend on immigrant labor. Removing a substantial portion of the workforce could lead to labor shortages, increased costs for businesses, and disruptions in supply chains.

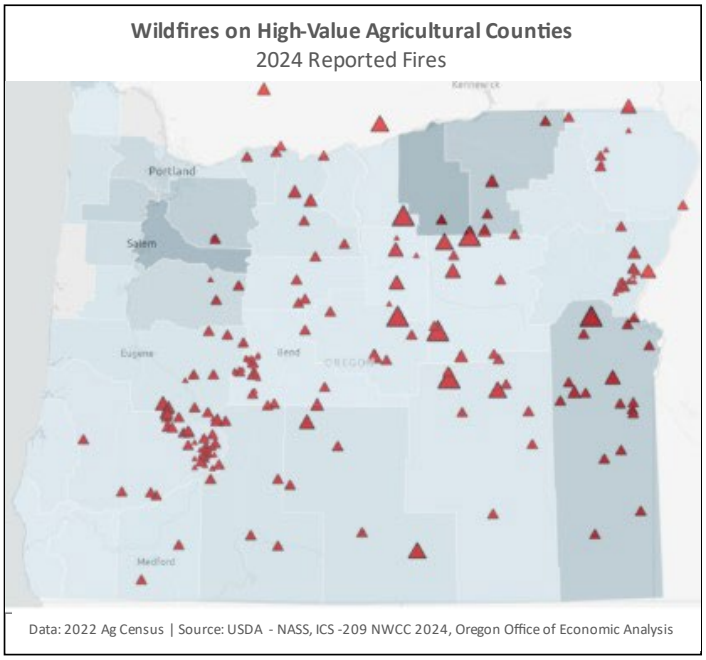
- *Bird flu/pandemic*: The spread of avian influenza to multiple species—including poultry, dairy cattle, swine, cats and humans—has raised public health concerns. While human-to-human transmission has not been observed, a wider outbreak could disrupt supply chains and consumer behavior, particularly in food and agriculture. It has already caused severe supply and price distortions for egg and poultry prices.

- *Drought*: While conditions improved in parts of southern and central Oregon due to increased snowpack and rainfall, northwestern areas saw some worsening in recent months. Water availability remains a concern for agriculture and local communities.





- *Wildfires*: Wildfire risk remains elevated, and a federal funding freeze on prevention programs heightens concerns about the 2025 season. Beyond the tangible destruction of property, wildfires worsen air quality. Prolonged exposure to wildfire smoke contributes to health issues and respiratory problems, further straining healthcare systems. The economic toll includes increased absenteeism, reduced worker productivity and higher medical costs. Sectors like tourism and agriculture are particularly vulnerable to wildfire smoke, with declines in travel and disruptions to crop production.



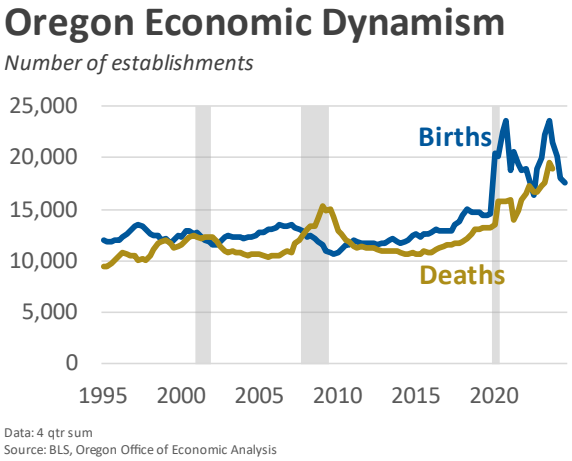
- *Flooding*: Atmospheric rivers have bolstered water supplies but increased flood risks, especially in low-lying areas like the Willamette Valley. Intense precipitation events strain infrastructure and endanger crops. Proactive flood management will be necessary to prevent significant economic losses.

- *Cascadia earthquake*: *Oregon* also faces the ever-present risk of a Cascadia Subduction Zone earthquake, an event with the potential to devastate the region's infrastructure, including transportation networks, utilities, and housing. It could displace hundreds of thousands of residents and lead to prolonged economic recovery efforts. Ongoing investments in seismic retrofitting, disaster response planning, and public awareness campaigns remain critical to mitigate the impacts of this potential catastrophe.

- *Federal fiscal policy*: Federal policy will also be a source of risk to the baseline economic forecast. The current administration has expressed a prioritization of cuts to both corporate and personal income taxes, and it has also signaled that the SALT deduction cap could be impacted. More broadly, looser fiscal policy relative to current law raises the risk of elevated interest rates (perhaps persistently) due to both supply/demand dynamics in the debt markets as well as firmer growth and inflation channels. Higher rates would be particularly harmful toward housing and residential construction—sectors which have already exhibited weakness in recent years.

- *Productivity/AI*: A recurring post-pandemic theme has been economic constraints, such as labor shortages or commodity scarcity. One factor which could mark a critical break with the recent past may come from a substantial rise in labor productivity, which would enable the existing workforce to accomplish higher levels of output, all else equal. While artificial intelligence may be among factors lifting productivity, there is a much broader increase in capital investment underway. Historically, high pressure economic periods that also coincided with increased capital investment have resulted in sustained productivity rebounds.

- *New Business Formation*: New businesses are a primary source of innovation as new ideas, products, and services help propel economic growth. Unfortunately, in the decades leading up to the pandemic, start-up activity was declining as a share of the state economy. New businesses as a share of all businesses were at or near record lows in 2019. Employment at start-ups followed a similar pattern. Since the pandemic, the number of private sector establishment births in Oregon has been volatile. In recent quarters, the number of deaths has continued to rise.



Alternative Economic Scenarios

The baseline outlook is our forecast for the most likely path for the Oregon economy. As with any forecast, however, many other scenarios are possible. The alternative scenarios below are not the upper or lower bounds to all outcomes, but rather various plausible scenarios modeled on what OEA determines to be realistic assumptions for tail risks. For the revenue implications, see page 30.

Policy risk alone raises the probability of these tail-risk scenarios, which inherently means the degree of confidence toward the baseline or central forecast is diminished. Our diminished confidence in the central forecast is a result of pending policy decisions which are expected to have substantial economic consequences for growth, employment, inflation and financial markets. As such, our baseline forecast is assigned a 55% probability. With the elevated recession risks, two additional alternative scenarios are included compared to previous editions, an extreme upside/boom scenario and a severe recession.

Alternative Scenarios				May 2025		
	2025	2026	2027	2028	2029	2030
Employment						
Opt: Boom	1.0%	1.6%	1.3%	1.3%	1.1%	1.1%
Opt: Solid Growth	0.6%	1.5%	1.5%	1.3%	1.2%	1.0%
Base: Growth Recession	0.3%	0.9%	0.8%	0.6%	0.7%	0.7%
Pes: Moderate Recession	-1.1%	-0.9%	1.0%	1.9%	2.7%	3.6%
Pes: Severe Recession	-2.1%	-1.1%	-0.9%	1.0%	1.9%	2.7%
Unemployment Rate						
Opt: Boom	4.4%	4.4%	4.3%	4.2%	4.0%	3.8%
Opt: Solid Growth	4.5%	4.6%	4.5%	4.4%	4.2%	4.0%
Base: Growth Recession	4.6%	5.0%	5.1%	5.0%	4.7%	4.5%
Pes: Moderate Recession	6.7%	6.5%	6.1%	5.2%	4.7%	4.5%
Pes: Severe Recession	6.9%	10.6%	10.8%	9.3%	6.7%	4.9%
Personal Income						
Opt: Boom	5.8%	6.4%	6.8%	5.8%	5.7%	5.2%
Opt: Solid Growth	5.2%	6.0%	6.6%	5.9%	5.5%	5.2%
Base: Growth Recession	5.1%	5.7%	6.1%	5.1%	4.9%	4.8%
Pes: Moderate Recession	3.7%	3.7%	7.2%	5.3%	5.1%	5.0%
Pes: Severe Recession	3.6%	1.6%	0.8%	6.3%	7.7%	7.9%

Pessimistic Scenario: Moderate and Severe Recession

The distribution of economic outcomes for this forecast represents a weaker scenario, with less confidence in the baseline. In contrast, the pessimistic scenarios have grown in possibility and are larger than the potential upside. For a depiction of the distribution, see page 1.

Downside economic risk accounts for 25% of the distribution. For now, the most likely pessimistic scenario is a moderate recession. This has a 22% chance of occurring or being exceeded in severity, though that includes outcomes that are roughly in the same range (not statistically different) of a moderate recession. A severe recession is associated with a probability of 3%, including outcomes similar in severity.

The moderate recession scenario is for a three-quarter decline in employment totaling 2.6%, followed by a six-quarter recovery period, more in line with the so-called jobless recoveries following the 1990 and 2001 cycles, compared to the faster recoveries in the 1950s, 1960s, and 1970s. The 2.6% decline in employment is a loss of over 52,000 jobs. The unemployment rate increases to a high of 7.6% in the second half of 2025. Nominal income does not fall outright but growth slows considerably. Next biennium, in 2025-27, total personal income in Oregon is approximately 3% below the baseline.

The severe recession scenario is for a six-quarter decline in employment totaling 8%, followed by a ten-quarter recovery period. This is similar to the contraction and recovery periods following the 2007 cycle. The 8% decline in employment is a loss of over 120,000 jobs. The unemployment rate increases to a high of 11.3% in the second half of 2026. Nominal income does not fall outright but growth stalls

relative to inflation in 2026 and 2027, resulting in a decline in real income. For a look into Oregon employment, unemployment, and real personal income during recessions, see page 9.

Optimistic Scenario: Solid Growth/Population Rebound

Some factors which could mark a critical break from the baseline forecast could come from a substantial rise in labor productivity (defined as output per hour worked) and an increasing labor force participation rate. Rising productivity enables the existing workforce to accomplish higher levels of output, all else equal. While the labor force participation rate is not particularly contingent on higher population growth and net in-migration, this is one aspect that could result in higher employment levels. Oregon has experienced periods where employment growth has exceeded population growth, necessarily driven by changes in the labor force participation rate.

Pandemic migration patterns differ from recent history substantially. There is good reason to think some of those changes will remain in the decade ahead, particularly when it comes to the combination of housing affordability and working from home resulting in lower migration to Oregon than in decades past. However, such a slow growth baseline does leave upside risks. What would happen if Oregon were to see a typical cyclical rebound in migration in the years ahead? By 2035, Oregon's employment is nearly 75,000 higher than in the baseline, and total personal income is 3.4% higher than the baseline forecast.

Revenue Outlook

Revenue Summary

The economic outlook depicted throughout this document exhibits significantly slower growth over the next year than was anticipated in the previous forecast. This translates directly through to the revenue picture. Expected income growth for individuals in 2025 is well below historical norms, driven both by lower growth in employment income and declines in capital gains. Business income is projected to turn negative in 2025 before turning positive in 2026 and 2027. After adjusting for the effects of kicker credits, the resulting General Fund revenue growth is modestly below average rates of the past four decades. This results in a mild downward revision relative to the Q1 forecast for both the current and next biennia.

General Fund revenues for 2023-25 are expected to equal $27.8 billion, down $165.2 million from the prior forecast. Personal income tax is primarily responsible for the decline, with all of the change due to weakened expectations in the outlook. The 2025 legislature passed additional appropriation allowance for current biennial spending of $460.6 million, however, an adjustment has been made for this forecast to account for the fraction of appropriations that goes unspent. The net effect of all changes is a projected ending balance of $2.17 billion, which is down $414.0 million from the prior forecast.

Table R.1

2023-25 General Fund Forecast Summary

(Millions)	2023 COS Forecast	March 2025 Forecast	May 2025 Forecast	Change from Prior Forecast	Change from COS Forecast
Structural Revenues					
Personal Income Tax	$21,019.7	$22,570.0	$22,425.2	-$144.8	$1,405.5
Corporate Income Tax	$2,228.9	$3,222.1	$3,144.8	-$77.3	$915.9
All Other Revenues	$2,011.3	$2,216.2	$2,275.9	$59.8	$264.6
Gross GF Revenues	$25,259.9	$28,008.2	$27,845.9	-$162.3	$2,586.0
Offsets, Transfers, and Actions[1]	-$437.0	-$496.8	-$502.0	-$5.1	-$64.9
Beginning Balance	$7,493.5	$8,082.5	$8,084.8	$2.3	$591.3
Net Available Resources	**$32,316.4**	**$35,593.9**	**$35,428.7**	**-$165.2**	**$3,112.3**
Expenditures	$31,873.6	$33,007.4	$33,467.9	$460.6	$1,594.4
Ending Balance	**$442.8**	**$2,586.5**	**$2,172.5**	**-$414.0**	**$1,729.7**
Confidence Intervals					
67% Confidence	+/- **1.0%**		**$271.8**	**$27.57B to $28.12B**	
95% Confidence	+/- **2.0%**		**$543.5**	**$27.30B to $28.39B**	

1 Reflects personal and corporate tax transfers, Rainy Day Fund tranfer, and Dept of Ag transfer

Changes to the revenue outlook also impact projections for the personal and corporate kicker surpluses. The personal kicker surplus is currently forecast at $1,639.1 million and will be returned to taxpayers as a credit on their 2025 tax returns. The corporate kicker now stands at $915.8 million and will be retained in the General Fund and spent on education next biennium.

Muted expectations for the economy in the coming months have a moderate impact on the 2025-27 revenue outlook. General Fund revenue has been decreased by $334.2 million due primarily to a -$529.0 million adjustment to personal income taxes. The negative headwinds are offset somewhat by a positive adjustment to anticipated Estate Taxes, as well as a smaller personal kicker credit adjustment. Including the $414.0 decrease to the projected beginning balance, total available resources are now expected to equal $37.4 billion, which is down $755.7 million from the prior forecast. It should be noted that almost $250 million of this decline is due to increased spending in the current biennium.

Non-General Fund components are also affected by the changing economic landscape. Corporate Activity Tax receipts are expected to total $3.0 billion, a $44.4 million decrease from the Q1 forecast. Lottery earnings are also revised downward $36.7 million due entirely to a weaker Video lottery sales forecast. Finally, Marijuana revenues have been adjusted down $7.6 million since the last forecast.

2023-25 General Fund Revenues

Most concurrent revenue indicators are underperforming expectations. This has played a significant role in the migration to a slower growth outlook for the coming months. As such, the 2023-25 biennium is closing on a weaker note. Revenues have been reduced by $167.5 million, primarily owing to decreases in personal and corporate income taxes.

Personal Income Tax

Tax season for the 2024 tax year is well under way. In historical terms, tax year 2024 was a very strong year with substantial growth in dividend, interest, retirement and capital gains income. Table R.2 below presents a comparison of the prior and current forecasts for the major income categories, as well as total taxable income and resulting tax liability for tax years 2024 and 2025. Note that substantial data are available to estimate tax year 2024 values while tax year 2025 is purely a forecast based on economic data.

While tax year 2024 shaped up nicely, 2025 has been revised downward significantly. This owed to the change in the outlook to a “growth recession” and a retraction in business and market performance. The impact of this is already present in the data as withholding and estimated payments through April are progressively falling below normal growth rates. This is the primary driver for the current forecast’s decline relative to the prior edition.

Table R.2: Personal Income Tax* Forecast Changes				
		Q1 Forecast	Q2 Forecast	Change
TY 2024	Wages & Salaries	6.7%	5.7%	-1.0%
	Dividends	9.0%	15.0%	6.0%
	Capital Gains	35.0%	50.0%	15.0%
	Retirement	6.8%	11.1%	4.3%
	Schedule E	10.0%	5.0%	-5.0%
	Total Income	8.5%	9.6%	1.1%
	Liability	11.6%	10.4%	-1.2%
TY 2025	Wages & Salaries	5.5%	4.5%	-1.0%
	Dividends	5.0%	-5.0%	-10.0%
	Capital Gains	3.0%	-9.0%	-12.0%
	Retirement	5.0%	8.1%	3.1%
	Schedule E	2.0%	-5.0%	-7.0%
	Total Income	4.7%	3.0%	-1.7%
	Liability	5.6%	4.1%	-1.5%
* Full-year filers only.				

The forecast for 2023-25 is now $22.4 billion, which is $144.8 million below the Q1 forecast. The personal income tax forecast is now $1.4 billion above the Close of Session forecast. Table B.8 presents tracking information for the third fiscal quarter of 2025. Personal income taxes finished $53.2 million below the prior forecast. Higher than expected refunds were the cause of the error.

Corporate Excise Tax

The corporate income tax forecast models tax receipts by tax year on U.S. corporate profits adjusted for the size of the Oregon economy relative to the nation. The outlook for corporate profitability has deteriorated in the past few months. This impact can even be seen in the most recent estimated payment data, which serves as a real-time gauge for economic activity. Since the beginning of 2025, payments for tax year 2025 are down approximately 13% relative to the same period for tax year 2024. It is possible that this is due to inventory accumulation ahead of the imposition of tariffs.

For the 2023-25 biennium, corporate income tax collections are projected to total $3.14 billion, down $77.3 million from the Q1 forecast. As indicated in Table B.8 in the appendix, collections during the quarter ending March 31st were $4.8 million above expectations. The full impact of recent events is expected to affect revenues in the final three months of the biennium.

Other Sources of Revenue

The two largest contributors to the “other sources” category are Estate Taxes and Interest Earnings. Since the 2023 Close of Session forecast, these two forecasts have increased almost $400 million

combined, now totaling just over $1.4 billion. Since the Q1 forecast, all other sources of revenue have been revised up $59.8 million.

General Fund Forecast Perspective

Over the past six biennia, there has been a kicker surplus in each biennium. Table R.4 presents each Close-of-Session (COS) forecast, adjusted for kicker credits, and its assumed growth rate. The adjacent column presents the actual growth rate, and the final column exhibits the total General Fund surplus. Note that this surplus includes any Corporate Income Tax surplus or deficit.

The first highlight to note is how the assumed growth rate for Close-of-Session forecasts continued to erode over time. In 2015-17, the projected growth was 14.6%, approximately equal to the 14.2% average growth in normal historical biennia since 1977-79. Beginning with the 2017-19 biennium, the Close-of-Session forecasted growth dropped far below normal and continued to decline as actual growth maintained its double-digit pace.

Table R.4

Actual vs. Projected Growth in General Fund Revenues*

	Adjusted COS Forecast	Gross Actuals	Forecasted Growth	Gross Growth	Difference
2009-11		$12,521,406,330			
2011-13		$14,155,019,600		13.0%	
2013-15	$15,642,599,000	$16,066,858,183	10.5%	13.5%	$424,259,183
2015-17	$18,411,984,050	$18,969,811,854	14.6%	18.1%	$557,827,804
2017-19	$20,016,613,279	$22,266,679,661	5.5%	17.4%	$2,250,066,382
2019-21	$22,700,925,689	$25,293,229,431	2.0%	13.6%	$2,592,303,742
2021-23	$25,233,356,312	$32,612,046,490	-0.2%	28.9%	$7,378,690,178
2023-25	$30,859,735,635	$33,445,686,972	-5.4%	2.6%	$2,585,951,337
2025-27	$37,444,987,648		12.0%		

* adjusted for kicker impacts.

The second highlight is that the current Q2 forecast for the 2025-27 biennium is the highest growth expectation for this forecast since 2015-17. While the economic outlook is muted in the first 6-9 months of the biennium, resumption of more normal growth in personal and corporate taxable incomes as well as a healthy increase in Estate Tax revenues result in a biennial growth that is just two and a half percentage points below historical norms. The 2025-27 biennium will only observe a significant kicker surplus if growth far surpasses historical norms.

Extended General Fund Outlook

Table R.3 exhibits the long-run forecast for General Fund revenues through the 2031-33 biennium. The 2025-27 biennium is the primary focus with the legislature now in session. The Legislatively Adopted Budget level will be constrained by the resources projected in this forecast, adjusted for any law changes that affect revenues. General Fund revenues in the coming biennium are now expected to total $35.6 billion, a $334.2 million decrease from the previous forecast. The primary reason for the decline is lower personal income taxes. With the inclusion of a lower beginning balance (down $414.0 million), available resources are projected to equal $37.4 billion. This is a downward revision of $755.7 million.

Table R.3 May 2025

General Fund Revenue Forecast Summary

Millions of Dollars, Current Law

Revenue Source	2023-25 Biennium	% Chg	2025-27 Biennium	% Chg	2027-29 Biennium	% Chg	2029-31 Biennium	% Chg	2031-33 Biennium	% Chg
Personal Income Taxes	22,425.2	-12.7%	30,302.8	35.1%	35,702.7	17.8%	39,780.1	11.4%	44,160.7	11.0%
Corporate Income Taxes	3,144.8	-0.4%	3,431.6	9.1%	3,666.3	6.8%	3,845.6	4.9%	4,171.1	8.5%
All Others	2,245.0	15.8%	2,043.1	-9.0%	2,173.5	6.4%	2,455.2	13.0%	2,786.6	13.5%
Gross General Fund	27,814.9	-9.6%	35,777.5	28.6%	41,542.6	16.1%	46,081.0	10.9%	51,118.4	10.9%
Offsets and Transfers	*(237.2)*		*(206.9)*		*(217.5)*		*(194.3)*		*(181.0)*	
Net Revenue	27,577.7	-9.9%	35,570.6	29.0%	41,325.1	16.2%	45,886.7	11.0%	50,937.4	11.0%

Note that the large percentage changes between biennia are due to kicker credits affecting personal income tax collections. Beyond 2025-27, when these considerations are no longer in effect, growth reflects underlying economic assumptions characterized elsewhere in this document. The potential for error in the forecast increases substantially the further ahead we look.

Corporate Activity Tax

Oregon's new corporate activity tax (CAT) went into effect January 2020. Revenues from this tax on business receipts are dedicated to education through the Fund for Student Success. The tax was designed to generate approximately $1 billion per year in new state resources, or $2 billion per biennium. These figures include both CAT revenues and the impact of the reduction in personal income tax rates which reduce state revenues, leaving a net revenue change of approximately $1 billion per year.

For the quarter ending March 31, 2025, net corporate activity tax receipts fell short of expectations by $7.0 million. The weakness was observed in estimated payments related to current economic activity, while reconciliation for prior tax years met expectations. Given the much milder outlook for economic growth in the next year, the forecast for tax receipts for 2025-27 has been revised down $44.4 million to $3.0 billion. Including a $17.3 million decline in the beginning balance, available resources for the coming biennium are now projected to equal $3.2 billion. This is $61.7 million below the Q1 forecast.

Table B.12 in Appendix B summarizes the 10-year forecast and the allocation of resources, while Table B.13 presents a more detailed quarterly breakdown of the forecast. The personal income tax reductions are built into the General Fund forecasts shown in Tables B.1 and B.2.

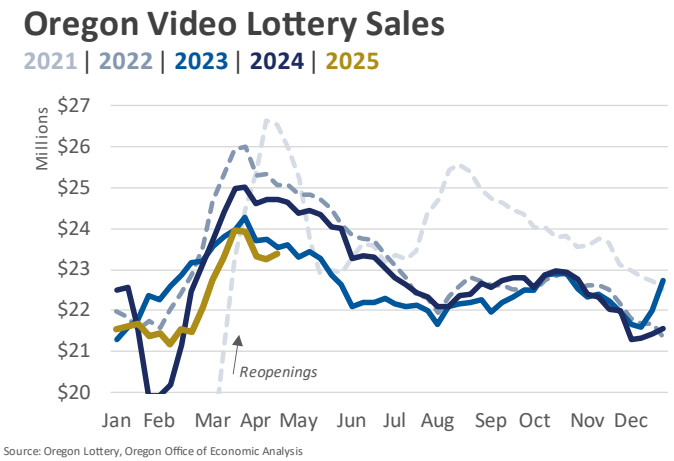
Lottery Forecast

The May lottery forecast has been revised downward from the February outlook, reflecting further reductions in overall resources. For the current 2023-25 biennium, total resources are lowered by $10.5 million, with future biennia seeing more significant decreases of $50-94 million.

Video lottery resources have seen the largest downward revision, with resources now expected to decline by $11 million (-0.7%) in 2023-25 and $50 million (-3%) in 2025-27. Future outlooks for 2027-29, 2029-31, and 2031-33 are also reduced by approximately 3.5-4.5%. Video lottery sales have continued to underperform expectations, prompting these downward adjustments to the forecast.

In contrast, traditional lottery resources show modest improvement, with projections raised by $2.3 million (1.1%) in 2023-25 and $10.0 million (5.8%) in 2025-27. The outlook for 2027-29, 2029-31, and 2031-33 biennia has also been revised upward by approximately 6.3-6.6%. Scratch-It sales have continued to increase following the introduction of a $30 ticket. Additionally, Mega Millions sales have been growing and are expected to increase further after an upcoming pricing change from $2 to $5, which is anticipated to lead to increased sales and larger jackpots.

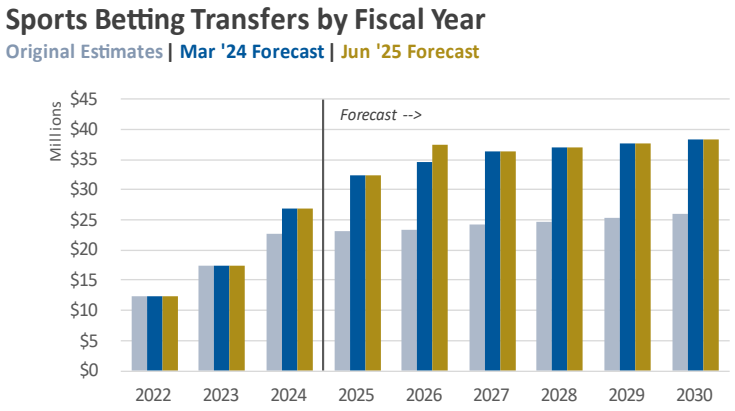
Video Lottery



Following the rapid growth during the pandemic reopening phase, video lottery sales have stabilized, with current growth rates somewhat below earlier projections. Despite the recent $5.6 billion personal income tax kicker paid out to Oregonians, no significant boost in video lottery sales was observed. Although sales in this segment continue to grow, the overall forecast is more conservative, reflecting current spending patterns and behaviors.

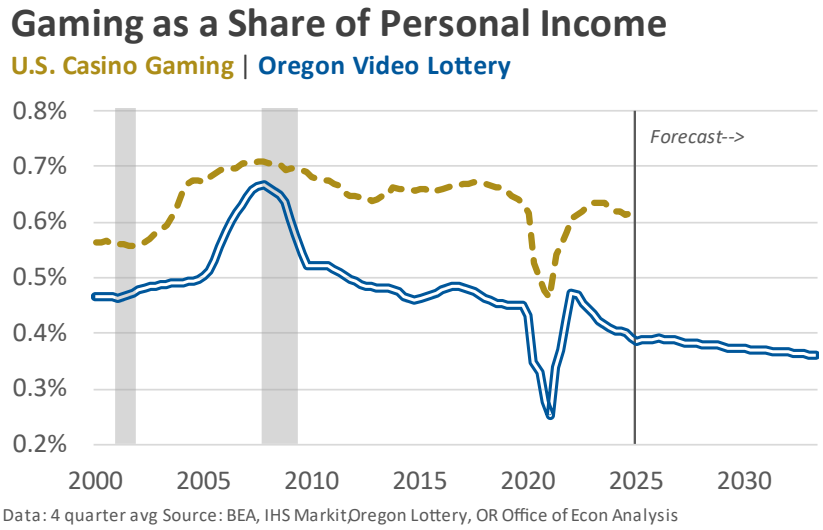
Sports Betting

The sports betting forecast remains largely in line with February's outlook, with revenues continuing to exceed early projections. While the forecast itself has not changed significantly, sports betting appears to exhibit less seasonality than previously anticipated. The steady revenue flow may be due to players engaging in a broader variety of events across staggered sports seasons, leading to more consistent betting activity throughout the year. This pattern suggests that sports betting is maturing in Oregon as player preferences diversify, contributing to stable, year-round revenue.



Longer-Term Outlook

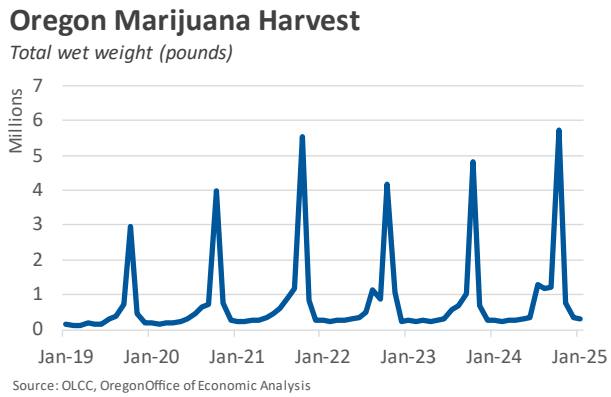
Lottery revenues continue to be closely linked to consumer behavior, household budgets and evolving entertainment preferences. Current trends point toward increased competition for entertainment dollars, shifting gaming preferences, and generational changes in gaming habits. The May forecast projects continued growth in lottery resources but at a pace slightly slower than Oregon's overall personal income growth, resulting in a marginally smaller share of the consumer spending pie over time.



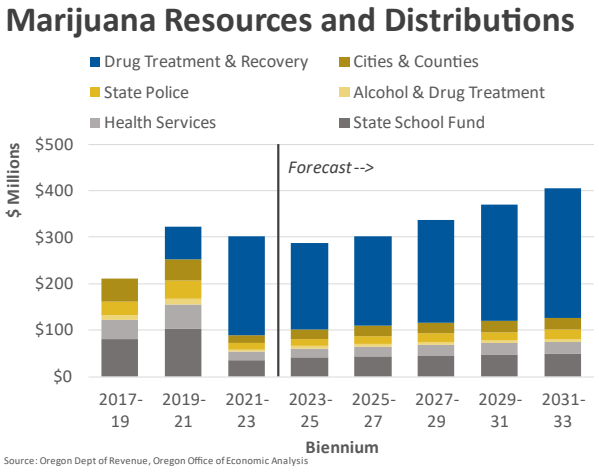
The full extended outlook for lottery earnings can be found in Table B.9 in Appendix B.

Recreational Marijuana Forecast

The May marijuana forecast has been revised downward from the March outlook. In the current 2023-25 biennium, resources are lowered by $4.8 million (-1.7%), while the 2025-27 forecast is reduced by $7.6 million (-2.5%). The outlook for outer biennia shows even larger reductions ranging from $9 million to $14 million each, which represent decreases of about 2.5-3.5%.



Last year's harvest was especially strong, with a record-breaking October yield of over 5.7 million pounds. The abundant supply continues to contribute to low prices, which are expected to remain at reduced levels. The industry faces increasing challenges, including rising input costs, particularly labor, which are squeezing profit margins. On top of that, consumption appears to have plateaued, creating difficult conditions for businesses, while intoxicating hemp-derived products are emerging as competitive substitutes.



The marijuana industry continues to face significant structural challenges at the federal level. Marijuana remains classified as a Schedule 1 drug, preventing business owners from accessing traditional banking services and disallowing common business tax deductions. These restrictions further strain financial viability in an already challenging market.

As previously noted, Oregon does not currently tax medical marijuana; however, this tax exemption is set to expire at the end of 2027, with medical marijuana taxation scheduled to begin in 2028. Although this exemption could be extended by the Legislature, the current forecast assumes medical marijuana will be taxed per current law. Overall, while marijuana tax collections are still expected to increase over time, the May forecast reflects a more challenging outlook with reduced growth projections due to persistent low prices, plateauing consumption, increased competition, and ongoing regulatory constraints.

Psilocybin Forecast

Ballot Measure 109 (2020) legalized psilocybin, including a 15% retail sales tax on the psilocybin products used. This sales tax does not apply to the overall cost of a session which can be hundreds or thousands of dollars. The vast majority of the overall cost goes to cover operational expenses for the service center and the facilitator's time and expertise.

The industry has been growing and has now been operating legally for more than a year. The current forecast remains a work in progress; however, it is now based on that first full year of data as opposed to pure assumptions. Even so, expectations are that the industry is still in its ramp-up period. The number of businesses, facilitators, and customers are all expected to grow in the years ahead. As more data becomes available, our office will adjust its outlook accordingly.

The average product price reported is approximately $40, however there is a wide range of values around that average. The average price is in line with previous conversations our office has had with multiple service centers in Oregon in recent years. And while not a low price, the cost of the product is relatively small compared to the overall cost of a session. For fiscal year 2024, which ran from July 2023 to June 2024, the sales tax revenue amounted to less than $100,000.

For now, the revenue forecast is tied to a multiyear ramp up period of stronger growth based on the patterns seen in Oregon for recreational marijuana and sports betting. After the ramp up, growth is expected to slow down to something closer to growth in the population, which is a proxy for the user base until better information is available.

Oregon Psilocybin Retail Sales Tax Revenue

May-25

	Biennium				
	2023-25	2025-27	2027-29	2029-31	2031-33
No. of Session	33,000	54,000	63,000	67,000	71,000
Avg Product Price	$40	$42	$44	$45	$47
Total Sales	$1,335,000	$2,271,000	$2,755,000	$3,049,000	$3,361,000
Taxes	$200,000	$341,000	$413,000	$457,000	$504,000

Lastly, it is important to note that the sales tax applies only to the purchase price of the psilocybin product itself. As such, service centers may charge customers the traditional retail price that includes a markup over wholesale costs which largely relates to production, testing, and distribution costs. Service centers may choose to sell the products at cost. And while they are not supposed to do this, they may charge customers a minimal product cost that is below their own cost. The potential benefit of doing so would be to increase revenues and profits for service centers and facilitators as less of the overall session price would be sent to pay taxes. To date, these data indicate this last possibility is not happening, or at least not enough to notice in industrywide information. However, as with all other sales taxes, revenue is driven by both the number of transactions and the price per transaction.

Revenue Alternative Scenarios

Given the heightened uncertainty present at the release of this forecast, the Office of Economic Analysis has engaged in extensive analysis of historical forecast outcomes and revenue performance to produce a range of scenarios that could manifest when the 2025-27 biennium is all said and done. The four alternatives to the baseline, two upside and two downside, equate to approximately one and two standard deviations in either direction. The table below presents the five scenarios along with the probabilities that each is likely to occur (e.g., the baseline outlook has a 55% chance of occurring).

General Fund Revenue* Scenarios

(millions)		2023-25	2025-27	2027-29	2029-31	2031-33
Boom (3%)	Revenues	$33,445.7	$40,815.0	$45,100.6	$50,873.5	$57,080.1
	Growth		*22.0%*	*10.5%*	*12.8%*	*12.2%*
Optimistic (17%)	Revenues	$33,445.7	$39,130.0	$43,825.6	$48,997.0	$54,680.7
	Growth		*17.0%*	*12.0%*	*11.8%*	*11.6%*
Baseline (55%)	Revenues	$33,445.7	$37,445.0	$41,542.6	$46,081.0	$51,118.4
	Growth		*12.0%*	*10.9%*	*10.9%*	*10.9%*
Pessimistic (22%)	Revenues	$33,445.7	$35,011.1	$39,912.6	$44,622.3	$49,798.5
	Growth		*4.7%*	*14.0%*	*11.8%*	*11.6%*
Severe (3%)	Revenues	$33,445.7	$32,577.1	$36,812.2	$42,886.2	$48,118.3
	Growth		*-2.6%*	*13.0%*	*16.5%*	*12.2%*

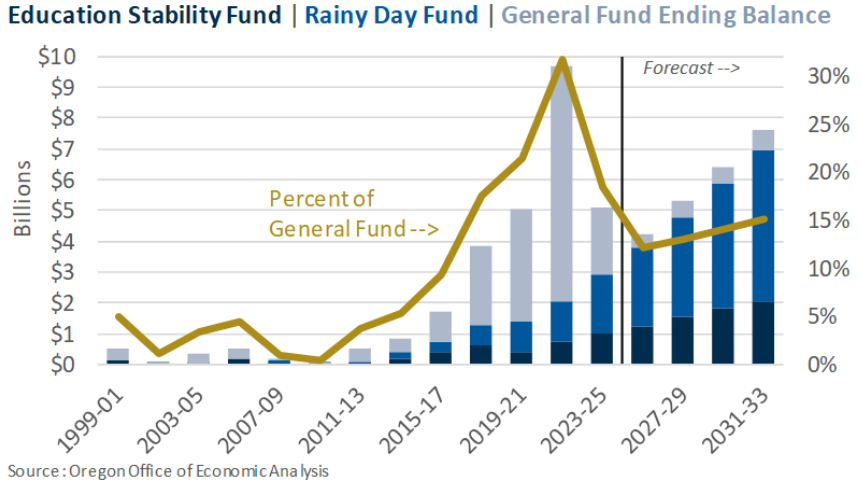
* Adjusted for kicker credits.

The first deviation is +4.5/-6.5% removed and are the traditional “optimistic” and “pessimistic” scenarios presented in past publications. It should be noted that the two scenarios are not symmetric. On the positive side, the optimistic scenario coincides with improved demographic and economic factors that are assumed to persist well into the future. The pessimistic scenario corresponds to a mild to moderate recession lasting two to three quarters followed by a healthy rebound in economic activity. The former outcome results in a boost to the General Fund of $1.7 billion while the latter produces a $2.4 billion deficit.

The second pair of scenarios (“Boom” and “Severe”) are +9.0/-13.0% removed from the baseline. The boom scenario has a few historical precedents in the last 50 years. These outlier biennia are generally followed by somewhat slower growth in the following biennium. The severe downside scenario mimics the Great Recession of 2008 in terms of both the deviation from the close-of-session forecast and the long-term impact on revenues. The boom results in a revenue gain of $3.4 billion while the severe recession costs the General Fund $4.9 billion in 2025-27.

It should be noted that the probability of recession, be it mild or more severe, is greater than the likelihood of the more optimistic outcomes. Inflation continues to pose a challenge for policy makers. In addition, many revenue indicators are showing signs of slowing or going negative. However, the slower-than-average growth exhibited by the baseline scenario does raise one upside possibility: should either optimistic outcome prevail it is almost assured that revenues will exceed the personal kicker threshold for a seventh consecutive biennium.

Budgetary Reserves



Effective Reserves ($ millions)

	End of 2023-25	*Estimated 2025-27*
ESF	$1,008	$1,237
RDF	$1,906	$2,540
Reserves	**$2,915**	**$3,777**
% of GF	10.6%	10.9%
Ending Balance	$2,184	$500
Total	**$5,099**	**$4,277**
% of GF	18.5%	12.3%

The state currently administers two general reserve accounts, the Oregon Rainy Day Fund[1] (ORDF) and the Education Stability Fund[2] (ESF). At the end of the current 2023-25 biennium, the two funds are expected to total $2.9 billion, which is equal to 10.6% of current revenues. Including the projected General Fund ending balance of $2.18 billion, the total effective reserves at the end of the current 2023-25 biennium are projected to be $5.1 billion, or 18.5% of current revenues.

As noted above, the current probability of an economic downturn is estimated at 25%. In the last 50 years, the worst decline in General Fund revenues relative to the Close-of-Session forecast was 15.3% during the 2001-03 biennium associated with the tech industry boom-bust. The final column of the table above presents the projected balances in the ORDF, ESF and a hypothetical budgetary ending balance based on historic legislatively adopted balances. Total available reserves under this scenario

[1] The ORDF is funded from ending balances each biennium, up to 1% of appropriations. The Legislature can deposit additional funds, as it did in first populating the ORDF with surplus corporate income tax revenues from the 2005-07 biennium. The ORDF also retains interest earnings. Withdrawals from the ORDF require one of three triggers, including a decline in employment, a projected budgetary shortfall, or declaration of a state of emergency, plus a simple majority vote of the Legislature. Withdrawals are capped at two-thirds of the balance as of the beginning of the biennium in question. Fund balances are capped at 7.5% of General Fund revenues in the prior biennium.

[2] [2] The ESF gained its current reserve structure and mechanics via constitutional amendment in 2002. The ESF receives 18% of lottery earnings, deposited on a quarterly basis – 10% of which are deposited in the Oregon Growth sub-account. The ESF does not retain interest earnings. The ESF has similar triggers as the ORDF but does not have the two-thirds cap on withdrawals. The ESF balance is capped at 5% of General Fund revenues collected in the prior biennium.

would amount to 12.3% of General Fund revenues. It is quite likely that Oregon's reserves are adequate to weather a potential downturn given that a mild to moderate recession is the most likely pessimistic scenario.

B.10 in Appendix B provides more details for Oregon's budgetary reserves.

Tax Law Assumptions

The revenue forecast is tied to current state law. After every legislative session, OEA incorporates adjustments to the revenue forecast produced by the Legislative Revenue Office. As each year passes and the effects of law become evident in the data, adjustments are phased out. However, many tax laws have sunsets, or end dates, built into them. These demarcations must be maintained such that the impact of extending the laws can be newly incorporated in turn.

Complication arises when considering the effects of federal law on Oregon revenues. Due to the assumptions built into these national forecasts and how national data enter the revenue models, it would be logistically difficult to maintain a current federal law revenue forecast. In addition, federal laws often have imminent sunsets and are frequently extended. Adhering to a current federal law forecast would result in large and unnecessary annual revisions. For this reason, the revenue forecast assumes the most reasonable outcomes for federal law.

For a detailed treatment of the components of the 2023 Legislatively Enacted Budget, see:

Legislative Fiscal Office's 2023-25 Budget Summary[3]

[3] https://www.oregonlegislature.gov/lfo/Documents/2023-25%20Legislatively%20Adopted%20Budget%20-%20General%20Fund%20and%20Lottery%20Funds%20Summary.pdf

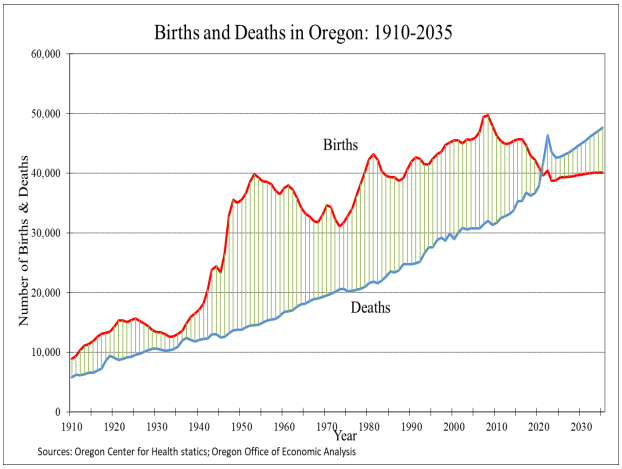
Population and Demographic Outlook

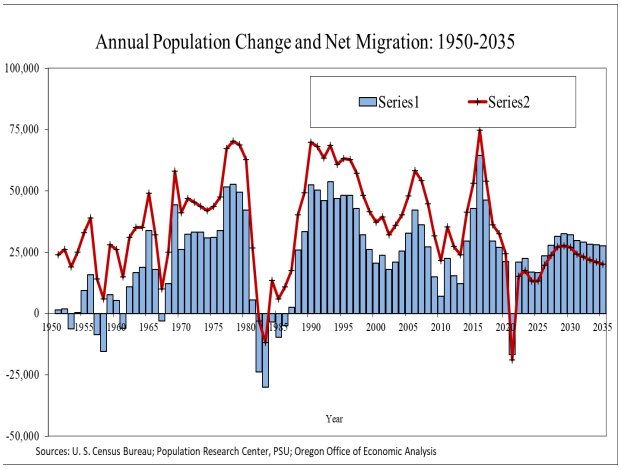
Population and Demographic Summary

Based on the most recent decennial census, Oregon's resident population on April 1, 2020, was 4,237,256. During the past decade, Oregon gained 406,182 residents or 10.6%. This decennial gain was the second lowest since the first census count in Oregon in 1860 after gaining statehood. Still, the gain was substantial enough to yield one additional congressional seat for the state. Oregon now has a total of six members in the House of Representatives. This is rare because it took 40 years for Oregon to gain one additional seat.

Oregon's population growth of 10.6% in the last decade was the 11th highest in the nation, excluding Washington D.C. The growth rate for the decade lagged all our neighboring states except California. Oregon's growth has experienced some turbulence since the 2020 census. At OEA we use the Population Research Center, PSU's recent post-censal estimate as the base for our office's population forecasts. In April 2025, the PRC released the estimate for 2024 and revised its estimates for the years 2020 through 2023. The revised estimate shows a loss of 18,962 people between 2020 and 2021. This is very unusual for Oregon since this was the first loss in population since the early 1980s.

During the early stage of the COVID-19 pandemic, according to PSU estimates, Oregon lost population. The estimates show Oregon population growth has remained low at a level not seen since the mid-1980s, indicating timid economic recovery in the post-pandemic years. The population growth is expected to show a slow positive increase in the future reaching 4.516 million in the year 2035 with an average annual rate of growth of 0.5%.



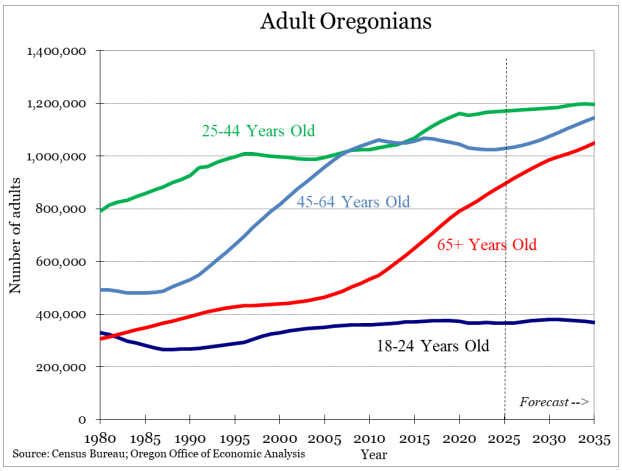


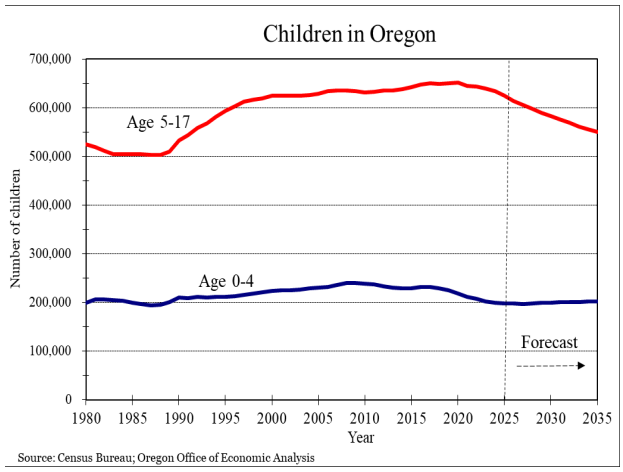
Oregon's economic environment heavily influences the state's population growth. Its economy determines the ability to retain the existing work force as well as attract job seekers from national and international labor markets. As Oregon's total fertility rate (1.4 children per woman) remains well below the replacement level (2.1 children per woman) and number of deaths continue to rise due to aging population, long-term growth relies entirely on net positive in-migration.

Working-age adults come to Oregon as long as there are favorable economic and social conditions such as: job opportunities, affordable housing and childcare, a good educational environment, and a better quality of life that projects real and perceived positivity about the state. As a result of a sudden rise in the number of deaths and a drop in the number of births coinciding with the COVID-19 pandemic,

the natural increase (number of births minus number of deaths) turned negative starting in the year 2020 and will continue through 2035 and beyond. Migration will be solely responsible for Oregon's future population growth. Without a positive net migration stream, Oregon's population will start a steady decline. Under a few scenarios, the negative natural increase may reverse itself. Such reversal can happen if women start to have more children due to behavioral or motivational factors, improved life expectancy leading to fewer deaths, or a large net in-migration contributing to an increase in the number of births.

Age structure and its change affect employment, state revenue collection, and tax expenditures. The demand for public services varies by age groups. Demographics are the major budget drivers, which are modified by policy choices on service coverage and delivery. Births, deaths, and migration histories of decades past remain impactful on the current age-sex structure. Growth in many age groups will show the effects of the depression era birth cohort, baby boom and their echo generations, and composition of migrants during the forecast period of 2025-2035.





Elderly (65+)

The overall elderly population (65+) was growing at a relatively slow pace during the late 1990s and early 2000s when the depression era birth cohort entered this age group. The elderly population picked up a faster pace of growth when the baby-boom cohort started maturing into the elderly age group. This age cohort has hit the plateau of high growth rates of above 4% annually between 2011 and 2018. The group will experience a continuously high but diminishing rate of growth in the coming years. The average annual growth of the elderly population will be 1.6% during the 2025-2035 forecast period.

As a sign of massive demographic structural change of Oregon's population, the number of elderly people has exceeded the number of children under the age of 18 since 2023. To illustrate the contrast, in 2000 the elderly population numbered a little over half of the number of children in Oregon, and now the elderly outnumber the children. Different age groups among the elderly population show quite varied and fascinating growth trends:

- The youngest elderly group (aged 65-74), which was growing at an extremely fast pace in the recent past (averaging 5.1% annually in 2010s), will taper off to negative growth after 2026 as a sign of the end of the baby boom generation transitioning to the elderly age group. This high growth period transitioning into a net loss of this youngest elderly population resulting in 0.6% annual average loss in the coming ten years.

- The next older generation of the population, aged 75-84, has been growing rapidly for a decade after several years of slow as well as negative growth. An unprecedented fast pace of growth, exceeding 6% annually in this age group, has already started as the baby boom generation is maturing and the depression era birth cohort exiting this 75-84 age group. The annual growth rate is expected to be unusually high at 3.0% during the forecast period.
- The oldest elderly population (aged 85+) will grow at a strong rate steadily gaining momentum due to the combination of cohort change, historical positive net migration, and improving longevity. The average annual rate of growth for this oldest elderly group over the forecast horizon will be 6.4%. An unprecedented annual growth exceeding 8% will commence near the end of the forecast horizon.

Working Age and Young Adults (18-64)

The oldest working age population, aged 45-64, also has seen a dramatic demographic impact as the baby boom generation matures out of this age group and is replaced by the smaller baby-bust cohort or Gen X. As the effect of this demographic transition is combined with slowing net migration, the once fast-paced growth has tapered off to negative growth. The growth rate is beginning to reverse to positive and will see gaining momentum over the forecast horizon with a 1.1% annualized rate of change. The younger working-age population of the 25-44 age group will have slow growth of 0.2% annual average over the forecast period.

The young adult population, aged 18-24, will see only a small change, averaging 0.1% annually over the forecast period. Although the slow growth of the college-age population (age 18-24) tends to ease the pressure on public spending on higher education, college enrollment typically goes up during times of a very competitive job market, high unemployment, and scarcity of well-paying jobs. The older cohort also flock back to colleges to better position themselves in a tough job market.

School Age (5-17) and pre-School Age (0-4) Children

The growth in K-12 population, aged 5-17, was very slow during the last decade, has turned negative since 2021, and is expected to decline consistently through the forecast years mainly due to the declining number of births over the years. This will translate into a decline in school enrollments. On average for the forecast period, this school-age population will decline by -1.3% annually. The growth rate for children under the age of five has remained below zero percent in the recent past and will continue negative or slow growth. The growth in pre-school age children will average 0.2% annually during the forecast period. The demand for childcare services and pre-Kindergarten programs is determined by the size of this population as well as the labor force participation and poverty rates of the parents.

Overall, the elderly population over age 65 will increase rapidly whereas the number of children will decline over the forecast horizon. The number of working-age adults in general will show slow growth. Hence, based solely on the demographics of Oregon, demand for public services geared towards children and young adults will likely decline or increase only at a slower pace, whereas demand for elderly care and services geared towards the elderly will increase rapidly.

Procedure and Assumptions

Population forecasts by age and sex are developed using the cohort-component projection procedure. The population by single year of age and sex is projected based on the specific assumptions of vital events and migrations. The projection procedure entails the model that "survives" the initial population distribution by age and sex to the next age-sex category in the following year and then applies age-sex-specific birth and migration rates to the mid-period population.

The population by single age-sex detail from the 2020 census and the most recent estimated total population for Oregon by Population Research Center of Portland State University are the base for the forecast. The numbers of births and deaths through 2023 are from Oregon's Center for Health Statistics. All other numbers and age-sex detail are generated by OEA.

Annual numbers of births are determined from the age-specific fertility rates projected based on Oregon's past trends and past and projected national trends. Oregon's total fertility rate is assumed to remain close to 1.4 per woman. This rate is well below the replacement level fertility of 2.1 children per woman during their reproductive life. Currently, all the states in the union are experiencing below replacement level fertility. Such a low fertility rate means the state will experience population decline in the long run unless fertility rate improves, along with strong net positive migration to compensate for the loss due to excess of deaths over births.

Life Table survival rates are developed for the year 2020. Male and female life expectancies for the 2020-2035 period are projected based on the past three decades of trends and national projected life expectancies. After a sudden decline during the COVID pandemic, improvements in life expectancies are expected over the forecast period. At the same time, the difference between the male and female life expectancies will continue to shrink in the long run. The male life expectancy at birth was 77.3 and the female life expectancy was 81.8 in 2010. Because of the COVID-19 pandemic, the number of deaths suddenly increased, and the actual life expectancies declined. The life expectancy at birth in 2020 was 76.9 and 81.7 years for males and females, respectively. This is expected to improve to 80.3 years for men and 84.7 years for women by 2035.

Estimates and forecasts of the number of net migrations are based on the residuals from the difference between population change and natural increase (births minus deaths) in a forecast period. Migration forecasting considers employment change, unemployment rates, income/wage of Oregon and neighboring states and the nation, and Oregon’s past population change and migration trends. Distribution of migrants by age and sex is based on detailed data from the American Community Survey. The role of net migration in Oregon’s population growth has gained prominence as the natural increase has turned negative. Between 2025 and 2035 net migration is expected to be in the range of 23,442 to 32,467, averaging 29,000 persons annually with net migration rates ranging between 5.5 to 7.4 per thousand population.

Appendix A: Economic Forecast Detail

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Table A.1 – Employment Forecast Tracking

Table A.1

Total Nonfarm Employment, 1st quarter 2025

(Employment in thousands, Annualized Percent Change)

	Preliminary Estimate		Forecast		Forecast Error		Y/Y Change
	level	% ch	level	% ch	level	%	% ch
Total Nonfarm	1,995.5	(0.0)	1,999.7	2.0	(4.2)	(0.2)	(0.0)
Total Private	1,676.6	(0.3)	1,682.0	1.7	(5.4)	(0.3)	(0.1)
Mining and Logging	6.0	(5.2)	6.1	0.4	(0.1)	(1.5)	(0.1)
Construction	114.4	(3.6)	116.4	0.5	(1.9)	(1.7)	(2.0)
Manufacturing	181.4	(6.0)	184.2	(6.0)	(2.8)	(1.5)	(3.4)
Durable Goods	126.9	(6.9)	129.9	(4.8)	(3.0)	(2.3)	(5.9)
Wood Product	22.2	(3.3)	22.4	(0.1)	(0.2)	(0.8)	(1.1)
Metals and Machinery	36.3	(1.8)	36.4	(2.0)	(0.1)	(0.4)	(1.7)
Computer and Electronic Product	37.2	(13.8)	39.2	(8.6)	(2.0)	(5.2)	(14.5)
Transportation Equipment	10.6	4.5	10.4	(22.3)	0.2	1.9	(1.6)
Other Durable Goods	20.6	(11.4)	21.5	2.5	(0.9)	(4.0)	(4.2)
Nondurable Goods	54.5	(4.1)	54.3	(8.9)	0.2	0.3	(2.2)
Food	27.9	0.4	27.4	(11.8)	0.6	2.1	(1.0)
Other Nondurable Goods	26.6	(8.5)	27.0	(5.8)	(0.4)	(1.4)	(3.4)
Trade, Transportation & Utilities	357.8	(0.6)	357.4	(1.6)	0.4	0.1	(0.3)
Retail Trade	202.2	(1.9)	202.8	(1.9)	(0.6)	(0.3)	(0.7)
Wholesale Trade	76.7	(2.5)	78.7	5.0	(1.9)	(2.5)	(1.3)
Transportation, Warehousing & Utilities	78.8	4.8	76.0	(7.2)	2.8	3.8	1.9
Information	35.9	(0.2)	36.1	3.4	(0.2)	(0.4)	(0.1)
Financial Activities	100.6	(2.3)	101.9	4.5	(1.2)	(1.2)	(1.8)
Professional & Business Services	259.1	0.9	259.6	0.5	(0.5)	(0.2)	(0.9)
Educational & Health Services	345.8	2.5	344.8	7.8	1.0	0.3	3.3
Educational Services	37.2	8.2	36.6	10.6	0.6	1.6	1.4
Health Services	308.6	1.8	308.2	7.5	0.4	0.1	3.6
Leisure and Hospitality	208.5	1.7	207.4	1.9	1.2	0.6	0.8
Other Services	67.0	2.9	68.1	12.5	(1.1)	(1.6)	0.3
Government	318.9	1.3	317.7	3.9	1.2	0.4	0.1
Federal	29.2	(4.1)	29.5	0.5	(0.3)	(1.0)	(3.0)
State	49.1	2.0	48.4	7.1	0.7	1.4	2.5
State Education	1.3	5.1	1.2	(20.6)	0.1	5.8	(1.0)
Local	240.6	1.8	239.8	3.7	0.8	0.3	0.1
Local Education	137.9	2.8	135.3	3.4	2.6	1.9	5.9

Table A.2 – Short-Term Oregon Economic Summary

Table A.2

Oregon Forecast Summary

	Quarterly						Annual				
	2025:1	2025:2	2025:3	2025:4	2026:1	2026:2	2024	2025	2026	2027	2028
Personal Income ($ billions)											
Nominal Personal Income	311.2	316.6	318.9	322.6	328.8	333.8	302.0	317.3	335.4	355.7	373.8
% change	7.2	7.2	2.9	4.8	8.0	6.2	5.2	5.1	5.7	6.1	5.1
Real Personal Income (base year=2017)	247.8	248.1	248.5	250.0	253.1	255.5	244.5	248.6	256.1	266.5	275.2
% change	3.5	0.6	0.6	2.3	5.2	3.9	2.6	1.7	3.0	4.1	3.3
Nominal Wages and Salaries	152.1	154.6	156.5	158.3	160.2	162.3	148.4	155.4	163.4	172.2	180.6
% change	5.2	7.0	4.9	4.6	5.0	5.2	4.2	4.7	5.2	5.4	4.9
Other Indicators											
Per Capita Income ($1,000)	72.8	74.0	74.4	75.2	76.5	77.6	70.8	74.1	77.9	82.1	85.7
% change	6.9	6.7	2.5	4.2	7.3	5.6	4.8	4.7	5.1	5.4	4.5
Average Wage rate ($1,000)	75.8	77.0	77.8	78.6	79.3	80.1	74.0	77.3	80.6	84.3	87.9
% change	5.7	6.8	4.2	3.9	3.7	4.2	4.0	4.4	4.2	4.6	4.2
Population (Millions)	4.3	4.3	4.3	4.3	4.3	4.3	4.27	4.28	4.31	4.33	4.36
% change	0.3	0.4	0.5	0.5	0.6	0.6	0.3	0.4	0.6	0.6	0.6
Housing Starts (Thousands)	14.3	14.5	14.6	14.7	14.8	14.9	14.1	14.5	15.0	15.5	16.2
% change	15.8	4.6	5.2	0.9	4.0	3.0	(22.4)	3.0	3.4	3.3	4.8
Unemployment Rate	4.4	4.6	4.7	4.9	4.9	5.0	4.2	4.7	5.1	5.2	5.1
Point Change	0.1	0.2	0.1	0.2	0.1	0.1	0.4	0.5	0.4	0.1	(0.1)
Employment (Thousands)											
Total Nonfarm	1,995.5	1,992.6	1,996.3	2,000.3	2,006.6	2,011.4	1,990.8	1,996.2	2,014.0	2,029.2	2,041.7
% change	(0.0)	(0.6)	0.8	0.8	1.3	1.0	0.2	0.3	0.9	0.8	0.6
Private Nonfarm	1,676.6	1,678.7	1,683.3	1,688.4	1,694.8	1,699.4	1,676.3	1,681.7	1,702.0	1,717.9	1,731.1
% change	(0.3)	0.5	1.1	1.2	1.5	1.1	(0.2)	0.3	1.2	0.9	0.8
Construction	114.4	114.7	115.2	115.5	115.6	115.7	116.6	114.9	115.8	116.5	117.7
% change	(3.6)	1.0	1.8	0.9	0.5	0.2	(1.3)	(1.4)	0.7	0.6	1.0
Manufacturing	181.4	181.7	182.1	182.9	183.8	184.2	186.8	182.0	184.5	186.2	186.6
% change	(6.0)	0.7	0.7	1.9	2.0	0.7	(2.2)	(2.5)	1.4	0.9	0.2
Durable Manufacturing	126.9	124.4	124.8	125.3	126.0	126.7	131.2	125.4	127.0	128.7	128.7
% change	(6.9)	(7.6)	1.4	1.3	2.5	2.2	(1.9)	(4.5)	1.3	1.4	0.0
Wood Product Manufacturing	22.2	22.3	22.4	22.4	22.4	22.4	22.5	22.3	22.5	23.0	23.0
% change	(3.3)	1.3	0.9	0.4	0.5	0.1	(1.3)	(0.9)	0.8	2.3	0.1
High Tech Manufacturing	37.2	34.5	35.0	35.4	36.1	36.7	39.7	35.5	36.8	38.0	38.2
% change	(13.8)	(25.8)	5.8	4.6	8.2	6.8	(2.6)	(10.7)	3.8	3.2	0.6
Transportation Equipment	10.6	10.9	10.9	10.9	11.0	11.0	11.0	10.8	11.1	11.2	11.2
% change	4.5	10.3	2.4	0.5	1.9	1.4	(1.7)	(1.2)	2.3	0.8	0.3
Nondurable Manufacturing	54.5	54.7	54.6	54.7	54.7	54.7	55.6	54.6	54.7	54.8	54.9
% change	(4.1)	1.5	(0.5)	0.4	0.1	0.3	(2.8)	(1.7)	0.2	0.1	0.3
Private nonmanufacturing	1,495.2	1,497.0	1,501.2	1,505.4	1,510.9	1,515.2	1,489.5	1,499.7	1,517.5	1,531.7	1,544.5
% change	0.5	0.5	1.1	1.1	1.5	1.2	0.0	0.7	1.2	0.9	0.8
Retail Trade	202.2	202.8	203.3	203.7	204.1	204.5	203.9	203.0	204.6	205.6	206.3
% change	(1.9)	1.1	1.0	0.8	0.9	0.7	(2.2)	(0.4)	0.8	0.5	0.4
Wholesale Trade	76.7	77.1	77.6	77.8	78.0	78.1	77.8	77.3	78.1	78.3	78.6
% change	(2.5)	1.8	2.6	1.2	1.0	0.4	(0.6)	(0.6)	1.1	0.3	0.4
Information	35.9	35.9	35.9	35.9	35.9	35.9	36.0	35.9	35.9	36.0	36.1
% change	(0.2)	(0.1)	(0.1)	(0.7)	0.2	0.3	(2.1)	(0.3)	0.0	0.2	0.2
Professional and Business Services	259.1	259.9	261.5	262.3	263.5	264.4	260.0	260.7	265.3	269.0	272.3
% change	0.9	1.2	2.5	1.3	1.8	1.3	(2.2)	0.3	1.8	1.4	1.3
Health Services	308.6	309.4	309.8	311.3	313.3	315.0	300.7	309.8	315.4	319.5	322.4
% change	1.8	1.1	0.5	1.9	2.6	2.3	5.6	3.0	1.8	1.3	0.9
Leisure and Hospitality	208.5	209.4	209.5	210.0	210.5	211.0	207.1	209.4	211.3	213.4	216.8
% change	1.7	1.6	0.2	1.0	0.9	1.0	0.0	1.1	0.9	1.0	1.6
Government	318.9	313.9	313.1	312.0	311.8	312.0	314.5	314.4	311.9	311.3	310.6
% change	1.3	(6.1)	(1.0)	(1.4)	(0.2)	0.2	2.7	(0.0)	(0.8)	(0.2)	(0.2)

Table A.3 – Oregon Economic Forecast Change

Table A.3

Oregon Forecast Change (Current vs Previous)

	Quarterly						Annual				
	2025:1	2025:2	2025:3	2025:4	2026:1	2026:2	2024	2025	2026	2027	2028
Personal Income ($ billions)											
Nominal Personal Income	311.2	316.6	318.9	322.6	328.8	333.8	302.0	317.3	335.4	355.7	373.8
% change	(0.8)	(0.6)	(1.4)	(1.7)	(1.4)	(1.3)	(0.3)	(1.1)	(1.4)	(0.9)	(1.1)
Real Personal Income (base year=2017)	247.8	248.1	248.5	250.0	253.1	255.5	244.5	248.6	256.1	266.5	275.2
% change	(1.3)	(1.7)	(2.2)	(2.2)	(1.7)	(1.6)	(0.3)	(1.8)	(1.7)	(1.2)	(1.3)
Nominal Wages and Salaries	152.1	154.6	156.5	158.3	160.2	162.3	148.4	155.4	163.4	172.2	180.6
% change	(1.9)	(1.7)	(2.2)	(2.6)	(2.8)	(2.9)	(0.6)	(2.1)	(2.6)	(1.8)	(1.4)
Other Indicators											
Per Capita Income ($1,000)	72.8	74.0	74.4	75.2	76.5	77.6	70.8	74.1	77.9	82.1	85.7
% change	(0.9)	(0.6)	(1.4)	(1.7)	(1.4)	(1.3)	(0.5)	(1.2)	(1.4)	(1.0)	(1.1)
Average Wage rate ($1,000)	75.8	77.0	77.8	78.6	79.3	80.1	74.0	77.3	80.6	84.3	87.9
% change	(1.4)	(0.9)	(1.4)	(1.9)	(2.3)	(2.5)	(0.6)	(1.4)	(2.3)	(1.7)	(1.4)
Population (Millions)	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.4
% change	0.1	0.0	(0.0)	(0.0)	(0.0)	(0.0)	0.2	0.0	(0.0)	0.1	0.1
Housing Starts (Thousands)	14.3	14.5	14.6	14.7	14.8	14.9	14.1	14.5	15.0	15.5	16.2
% change	1.4	1.9	1.9	1.5	1.7	1.9	0.0	1.7	1.9	1.5	1.0
Unemployment Rate	4.4	4.6	4.7	4.9	4.9	5.0	4.2	4.7	5.1	5.2	5.1
Point Change	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Employment (Thousands)											
Total Nonfarm	1,995.5	1,992.6	1,996.3	2,000.3	2,006.6	2,011.4	1,990.8	1,996.2	2,014.0	2,029.2	2,041.7
% change	(0.3)	(0.8)	(0.8)	(0.7)	(0.5)	(0.4)	(0.1)	(0.6)	(0.4)	(0.1)	(0.0)
Private Nonfarm	1,676.6	1,678.7	1,683.3	1,688.4	1,694.8	1,699.4	1,676.3	1,681.7	1,702.0	1,717.9	1,731.1
% change	(0.4)	(0.7)	(0.7)	(0.6)	(0.3)	(0.2)	(0.1)	(0.6)	(0.2)	0.1	0.1
Construction	114.4	114.7	115.2	115.5	115.6	115.7	116.6	114.9	115.8	116.5	117.7
% change	(1.9)	(1.9)	(1.9)	(1.9)	(1.9)	(1.9)	0.0	(1.9)	(1.9)	(1.9)	(1.9)
Manufacturing	181.4	181.7	182.1	182.9	183.8	184.2	186.8	182.0	184.5	186.2	186.6
% change	(0.3)	(0.6)	(0.4)	0.2	0.7	0.7	0.0	(0.3)	0.7	0.7	0.6
Durable Manufacturing	126.9	124.4	124.8	125.3	126.0	126.7	131.2	125.4	127.0	128.7	128.7
% change	(0.2)	(2.8)	(2.5)	(2.1)	(1.5)	(1.3)	(0.1)	(1.9)	(1.4)	(1.2)	(0.9)
Wood Product Manufacturing	22.2	22.3	22.4	22.4	22.4	22.4	22.5	22.3	22.5	23.0	23.0
% change	(0.7)	(1.9)	(0.7)	1.3	4.0	5.1	(0.1)	(0.5)	4.8	5.1	5.1
High Tech Manufacturing	37.2	34.5	35.0	35.4	36.1	36.7	39.7	35.5	36.8	38.0	38.2
% change	2.2	(5.4)	(4.4)	(4.0)	(3.6)	(3.5)	(0.3)	(2.9)	(3.5)	(3.2)	(3.2)
Transportation Equipment	10.6	10.9	10.9	10.9	11.0	11.0	11.0	10.8	11.1	11.2	11.2
% change	1.0	2.2	1.5	0.6	0.2	0.1	(0.1)	1.3	0.2	0.2	0.3
Nondurable Manufacturing	54.5	54.7	54.6	54.7	54.7	54.7	55.6	54.6	54.7	54.8	54.9
% change	(0.4)	(0.2)	(0.2)	0.1	0.2	0.4	0.3	(0.2)	0.4	0.2	0.2
Private nonmanufacturing	1,495.2	1,497.0	1,501.2	1,505.4	1,510.9	1,515.2	1,489.5	1,499.7	1,517.5	1,531.7	1,544.5
% change	(0.4)	(0.7)	(0.7)	(0.6)	(0.5)	(0.4)	(0.1)	(0.6)	(0.3)	0.0	(0.0)
Retail Trade	202.2	202.8	203.3	203.7	204.1	204.5	203.9	203.0	204.6	205.6	206.3
% change	(0.6)	(0.6)	(0.5)	(0.5)	(0.5)	(0.4)	0.0	(0.6)	(0.4)	(0.4)	(0.4)
Wholesale Trade	76.7	77.1	77.6	77.8	78.0	78.1	77.8	77.3	78.1	78.3	78.6
% change	(2.9)	(2.8)	(2.5)	(2.4)	(2.4)	(2.4)	(0.3)	(2.7)	(2.4)	(2.4)	(2.5)
Information	35.9	35.9	35.9	35.9	35.9	35.9	36.0	35.9	35.9	36.0	36.1
% change	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(0.2)	(1.0)	(1.0)	(1.0)	(1.0)
Professional and Business Services	259.1	259.9	261.5	262.3	263.5	264.4	260.0	260.7	265.3	269.0	272.3
% change	(0.7)	(1.7)	(1.6)	(1.5)	(1.3)	(1.1)	(0.2)	(1.4)	(1.0)	(0.3)	(0.6)
Health Services	308.6	309.4	309.8	311.3	313.3	315.0	300.7	309.8	315.4	319.5	322.4
% change	(0.3)	(0.6)	(0.8)	(0.6)	(0.4)	(0.3)	(0.1)	(0.6)	(0.3)	(0.1)	(0.1)
Leisure and Hospitality	208.5	209.4	209.5	210.0	210.5	211.0	207.1	209.4	211.3	213.4	216.8
% change	1.0	1.0	1.1	0.8	0.8	1.0	(0.1)	1.0	1.1	1.5	1.3
Government	318.9	313.9	313.1	312.0	311.8	312.0	314.5	314.4	311.9	311.3	310.6
% change	0.1	(1.2)	(1.3)	(1.6)	(1.5)	(1.3)	0.0	(1.0)	(1.3)	(0.9)	(0.5)

Table A.4 – Annual Economic Forecast

TABLE A.4

May 2025 - Personal Income

(Billions of Current Dollars)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Personal Income*												
Oregon	302.0	317.3	335.4	355.7	373.8	392.0	410.7	429.9	449.9	470.5	491.1	504.3
% Ch	5.2	5.1	5.7	6.1	5.1	4.9	4.8	4.7	4.7	4.6	4.4	2.7
U.S.	24,658.3	25,787.8	27,043.2	28,425.6	29,760.7	31,081.6	32,434.0	33,806.0	35,251.8	36,782.0	38,400.6	40,096.2
% Ch	5.4	4.6	4.9	5.1	4.7	4.4	4.4	4.2	4.3	4.3	4.4	4.4
Wage and Salary												
Oregon	148.4	155.4	163.4	172.2	180.6	188.7	197.4	206.1	215.2	224.4	233.7	233.0
% Ch	4.2	4.7	5.2	5.4	4.9	4.5	4.6	4.4	4.4	4.3	4.1	(0.3)
U.S.	12,389.3	12,897.0	13,483.9	14,111.8	14,742.3	15,348.9	15,965.6	16,571.7	17,199.0	17,863.4	18,569.8	19,306.8
% Ch	5.7	4.1	4.6	4.7	4.5	4.1	4.0	3.8	3.8	3.9	4.0	4.0
Other Labor Income												
Oregon	35.9	38.1	40.2	42.4	44.5	46.6	48.8	50.9	53.2	55.5	57.7	53.4
% Ch	5.1	6.0	5.6	5.5	4.9	4.7	4.7	4.5	4.4	4.3	4.0	(7.6)
U.S.	1,762.2	1,866.3	1,958.0	2,049.2	2,140.8	2,228.8	2,318.3	2,406.3	2,497.4	2,593.8	2,696.3	2,803.2
% Ch	7.2	5.9	4.9	4.7	4.5	4.1	4.0	3.8	3.8	3.9	4.0	4.0
Nonfarm Proprietor's Income												
Oregon	25.0	26.1	27.8	28.5	29.3	30.6	32.1	33.8	35.6	37.7	39.7	42.4
% Ch	4.4	4.4	6.2	2.8	2.7	4.4	4.9	5.2	5.4	5.7	5.4	6.9
U.S.	1,960.7	2,039.2	2,150.6	2,196.0	2,241.2	2,321.4	2,420.2	2,534.0	2,663.2	2,803.9	2,953.8	3,111.7
% Ch	4.4	4.0	5.5	2.1	2.1	3.6	4.3	4.7	5.1	5.3	5.3	5.3
Dividend, Interest and Rent												
Oregon	61.6	65.0	68.8	74.0	78.6	82.8	86.9	90.8	94.7	98.7	102.7	104.5
% Ch	3.9	5.4	5.9	7.5	6.2	5.4	4.9	4.5	4.4	4.2	4.0	1.7
U.S.	5,003.4	5,153.5	5,388.7	5,768.3	6,099.4	6,406.6	6,719.2	7,030.5	7,364.1	7,717.5	8,090.4	8,481.8
% Ch	4.0	3.0	4.6	7.0	5.7	5.0	4.9	4.6	4.7	4.8	4.8	4.8
Transfer Payments												
Oregon	64.8	69.0	73.5	77.9	82.2	86.5	90.9	95.6	100.6	105.8	111.1	120.8
% Ch	8.1	6.6	6.5	5.9	5.5	5.3	5.0	5.2	5.2	5.1	5.0	8.8
U.S.	4,405.9	4,697.5	4,958.6	5,215.0	5,483.2	5,760.2	6,036.8	6,330.5	6,636.7	6,955.5	7,288.6	7,639.0
% Ch	6.3	6.6	5.6	5.2	5.1	5.1	4.8	4.9	4.8	4.8	4.8	4.8
Contributions for Social Security												
Oregon	26.0	27.7	29.2	30.9	32.4	34.0	35.6	37.3	39.0	40.7	42.4	40.5
% Ch	3.2	6.5	5.4	5.6	5.1	4.8	4.8	4.8	4.5	4.3	4.3	(4.5)
U.S.	1,041.4	1,075.8	1,112.6	1,148.9	1,196.0	1,245.4	1,296.0	1,346.1	1,397.8	1,452.5	1,510.7	1,571.3
% Ch	4.6	3.3	3.4	3.3	4.1	4.1	4.1	3.9	3.8	3.9	4.0	4.0
Residence Adjustment												
Oregon	(7.9)	(8.4)	(8.7)	(9.1)	(9.4)	(9.8)	(10.2)	(10.6)	(11.0)	(11.5)	(12.0)	(10.0)
% Ch	3.8	6.0	4.2	4.2	4.0	3.9	4.1	3.9	4.1	4.1	4.1	(16.7)
Farm Proprietor's Income												
Oregon	0.1	0.3	0.4	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6
% Ch	(49.3)	173.3	24.5	27.4	15.5	6.2	2.2	1.5	2.1	2.7	(1.2)	2.6
Per Capita Income (Thousands of $)												
Oregon	70.8	74.1	77.9	82.1	85.7	89.3	93.0	96.8	100.8	104.9	109.0	111.4
% Ch	4.8	4.7	5.1	5.4	4.5	4.2	4.2	4.1	4.1	4.1	3.9	2.2
U.S.	72.4	75.3	78.8	82.6	86.2	89.8	93.4	97.0	100.8	104.8	109.1	113.6
% Ch	4.4	4.0	4.6	4.8	4.4	4.1	4.0	3.9	3.9	4.0	4.1	4.1

* Personal Income includes all classes of income minus Contributions for Social Security

TABLE A.4

May 2025 - Employment By Industry

(Oregon - Thousands, U.S. - Millions)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Nonfarm												
Oregon	1,990.8	1,996.2	2,014.0	2,029.2	2,041.7	2,056.3	2,071.6	2,082.8	2,092.9	2,102.2	2,111.8	2,118.8
% Ch	0.2	0.3	0.9	0.8	0.6	0.7	0.7	0.5	0.5	0.4	0.5	0.3
U.S.	158.0	159.5	159.9	160.2	160.8	161.8	162.8	163.3	163.8	164.2	164.6	164.9
% Ch	1.3	1.0	0.2	0.2	0.3	0.6	0.6	0.3	0.3	0.3	0.3	0.2
Private Nonfarm												
Oregon	1,676.3	1,681.7	1,702.0	1,717.9	1,731.1	1,746.1	1,760.9	1,773.0	1,783.2	1,792.5	1,802.1	1,812.6
% Ch	(0.2)	0.3	1.2	0.9	0.8	0.9	0.8	0.7	0.6	0.5	0.5	0.6
U.S.	134.6	136.0	136.4	136.7	137.1	138.0	138.9	139.4	139.8	140.1	140.5	140.8
% Ch	1.1	1.0	0.3	0.2	0.3	0.7	0.6	0.4	0.3	0.2	0.3	0.2
Mining and Logging												
Oregon	6.1	6.1	6.0	6.0	6.0	5.9	5.9	5.9	6.0	6.0	6.0	6.0
% Ch	(0.6)	(0.4)	(0.2)	(0.3)	(0.6)	(0.8)	(0.4)	0.2	0.6	0.3	(0.1)	(0.3)
U.S.	0.6	0.6	0.6	0.7	0.7	0.6	0.6	0.6	0.6	0.7	0.7	0.7
% Ch	(1.8)	(0.4)	3.4	3.6	(2.2)	(4.9)	(3.1)	0.4	5.0	5.3	4.1	1.7
Construction												
Oregon	116.6	114.9	115.8	116.5	117.7	119.5	121.1	122.6	124.3	126.1	127.9	129.7
% Ch	(1.3)	(1.4)	0.7	0.6	1.0	1.6	1.3	1.2	1.4	1.4	1.5	1.4
U.S.	8.2	8.3	8.4	8.4	8.4	8.5	8.6	8.7	8.7	8.8	8.9	8.9
% Ch	2.5	1.5	0.4	0.0	0.8	1.3	0.9	0.5	0.5	0.7	0.9	0.8
Manufacturing												
Oregon	186.8	182.0	184.5	186.2	186.6	186.7	186.4	186.1	186.0	185.4	184.5	183.6
% Ch	(2.2)	(2.5)	1.4	0.9	0.2	0.1	(0.2)	(0.1)	(0.1)	(0.3)	(0.5)	(0.5)
U.S.	12.8	12.7	12.5	12.3	12.2	12.1	12.2	12.2	12.2	12.0	11.9	11.8
% Ch	(0.4)	(0.8)	(1.3)	(1.8)	(1.1)	(0.5)	0.3	0.3	(0.4)	(1.0)	(1.4)	(0.8)
Durable Manufacturing												
Oregon	131.2	125.4	127.0	128.7	128.7	128.2	127.4	127.3	127.0	126.4	125.5	124.7
% Ch	(1.9)	(4.5)	1.3	1.4	0.0	(0.4)	(0.6)	(0.1)	(0.2)	(0.5)	(0.7)	(0.7)
U.S.	8.0	7.9	7.7	7.6	7.5	7.4	7.4	7.5	7.5	7.4	7.3	7.2
% Ch	(0.7)	(1.3)	(1.7)	(2.2)	(1.3)	(0.7)	0.3	0.6	(0.2)	(1.1)	(1.7)	(0.9)
Wood Products												
Oregon	22.5	22.3	22.5	23.0	23.0	23.0	22.7	23.1	23.5	23.3	23.1	22.8
% Ch	(1.3)	(0.9)	0.8	2.3	0.1	(0.2)	(1.1)	1.6	1.5	(0.5)	(1.0)	(1.3)
U.S.	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
% Ch	(0.4)	(0.2)	6.1	2.9	1.7	2.1	4.4	5.0	1.7	(1.1)	(2.6)	(1.5)
Metal and Machinery												
Oregon	36.6	36.1	36.1	36.5	36.5	36.4	36.3	36.1	35.8	35.7	35.5	35.4
% Ch	(2.0)	(1.4)	(0.0)	1.1	0.0	(0.3)	(0.3)	(0.6)	(0.8)	(0.5)	(0.5)	(0.3)
U.S.	2.9	2.9	2.8	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
% Ch	(0.6)	(0.5)	(2.5)	(3.4)	(1.2)	(0.6)	0.2	1.0	0.0	(0.7)	(1.3)	(0.3)
Computer and Electronic Products												
Oregon	39.7	35.5	36.8	38.0	38.2	38.0	37.7	37.5	37.2	37.0	36.8	36.6
% Ch	(2.6)	(10.7)	3.8	3.2	0.6	(0.6)	(0.8)	(0.6)	(0.6)	(0.7)	(0.6)	(0.6)
U.S.	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
% Ch	(2.4)	(1.6)	0.7	(0.2)	(1.5)	(1.8)	(1.6)	(0.7)	(0.3)	(0.2)	(0.0)	(0.1)
Transportation Equipment												
Oregon	11.0	10.8	11.1	11.2	11.2	11.3	11.3	11.3	11.3	11.3	11.3	11.3
% Ch	(1.7)	(1.2)	2.3	0.8	0.3	0.6	0.3	(0.1)	(0.2)	0.1	0.1	(0.1)
U.S.	1.8	1.7	1.7	1.7	1.7	1.6	1.7	1.6	1.6	1.6	1.6	1.5
% Ch	0.9	(3.3)	(1.9)	(1.3)	(1.6)	(0.5)	0.5	(0.4)	(0.7)	(1.9)	(2.8)	(2.2)
Other Durables												
Oregon	21.4	20.6	20.5	20.0	19.7	19.5	19.4	19.4	19.2	19.1	18.8	18.6
% Ch	(1.0)	(3.7)	(0.6)	(2.2)	(1.4)	(1.1)	(0.7)	(0.1)	(0.6)	(1.0)	(1.2)	(1.1)
U.S.	2.2	2.2	2.2	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.0
% Ch	(1.3)	(0.7)	(1.5)	(2.4)	(1.2)	(0.3)	1.3	1.4	(0.1)	(1.3)	(2.0)	(1.0)

May 2025 - Employment By Industry

(Oregon - Thousands, U.S. - Millions)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Nondurable Manufacturing												
Oregon	55.6	54.6	54.7	54.8	54.9	55.3	55.6	55.7	55.7	55.9	55.8	55.7
% Ch	(2.8)	(1.7)	0.2	0.1	0.3	0.7	0.6	0.1	0.2	0.2	(0.2)	(0.1)
U.S.	4.9	4.9	4.8	4.8	4.7	4.7	4.7	4.7	4.7	4.7	4.6	4.6
% Ch	0.0	0.0	(0.7)	(1.0)	(0.6)	(0.2)	0.2	(0.2)	(0.6)	(0.8)	(1.0)	(0.8)
Food Manufacturing												
Oregon	28.0	28.0	28.1	28.3	28.3	28.6	28.9	29.1	29.4	29.6	29.7	29.8
% Ch	(1.7)	(0.1)	0.4	0.5	0.2	1.0	1.0	0.8	0.9	0.9	0.3	0.3
U.S.	1.8	1.8	1.8	1.8	1.8	1.8	1.9	1.9	1.9	1.9	1.9	1.9
% Ch	1.9	0.7	0.7	0.3	0.8	1.3	1.9	1.4	0.9	0.5	0.1	0.5
Other Nondurable												
Oregon	27.5	26.6	26.6	26.5	26.6	26.7	26.7	26.5	26.4	26.2	26.0	25.8
% Ch	(4.0)	(3.3)	(0.1)	(0.4)	0.4	0.3	0.1	(0.8)	(0.6)	(0.6)	(0.7)	(0.7)
U.S.	3.1	3.1	3.0	3.0	2.9	2.9	2.9	2.8	2.8	2.7	2.7	2.6
% Ch	(1.0)	(0.3)	(1.5)	(1.8)	(1.5)	(1.2)	(0.9)	(1.3)	(1.6)	(1.7)	(1.8)	(1.7)
Trade, Transportation, and Utilities												
Oregon	359.3	359.7	363.1	364.9	366.3	367.3	368.5	369.1	369.6	369.5	369.8	370.2
% Ch	(1.6)	0.1	1.0	0.5	0.4	0.3	0.3	0.2	0.1	(0.0)	0.1	0.1
U.S.	28.9	29.2	29.2	29.4	29.2	29.1	29.1	29.0	29.0	28.8	28.6	28.4
% Ch	0.4	0.8	0.3	0.7	(0.9)	(0.2)	(0.1)	(0.1)	(0.3)	(0.5)	(0.6)	(0.8)
Retail Trade												
Oregon	203.9	203.0	204.6	205.6	206.3	207.1	208.2	209.0	209.4	209.8	210.6	211.5
% Ch	(2.2)	(0.4)	0.8	0.5	0.4	0.4	0.5	0.4	0.2	0.2	0.4	0.4
U.S.	15.5	15.5	15.4	15.5	15.3	15.3	15.4	15.5	15.5	15.6	15.5	15.5
% Ch	(0.1)	0.1	(0.7)	0.6	(1.5)	0.2	0.6	0.5	0.3	0.1	(0.1)	(0.3)
Wholesale Trade												
Oregon	77.8	77.3	78.1	78.3	78.6	78.8	78.9	78.9	78.8	78.6	78.5	78.4
% Ch	(0.6)	(0.6)	1.1	0.3	0.4	0.2	0.2	(0.1)	(0.1)	(0.2)	(0.1)	(0.2)
U.S.	6.1	6.2	6.3	6.3	6.3	6.2	6.2	6.1	6.1	6.0	6.0	5.9
% Ch	0.6	1.0	1.2	0.9	(0.4)	(0.9)	(1.1)	(0.7)	(0.8)	(1.0)	(0.9)	(0.9)
Transportation and Warehousing, and Utilities												
Oregon	77.6	79.4	80.4	81.0	81.4	81.4	81.3	81.3	81.4	81.1	80.7	80.3
% Ch	(0.9)	2.2	1.3	0.8	0.5	0.1	(0.1)	(0.1)	0.1	(0.4)	(0.5)	(0.5)
U.S.	7.2	7.4	7.5	7.6	7.6	7.5	7.5	7.4	7.3	7.2	7.1	7.0
% Ch	1.1	2.2	1.5	0.7	(0.1)	(0.6)	(0.8)	(0.8)	(1.1)	(1.3)	(1.2)	(1.5)
Information												
Oregon	36.0	35.9	35.9	36.0	36.1	36.2	36.2	36.3	36.4	36.6	36.7	36.8
% Ch	(2.1)	(0.3)	0.0	0.2	0.2	0.3	0.2	0.2	0.3	0.5	0.3	0.2
U.S.	2.9	3.0	3.0	3.0	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.8
% Ch	(2.1)	0.5	2.7	(2.0)	(1.9)	(0.2)	0.1	(0.3)	(0.1)	(0.1)	(1.7)	(0.9)
Financial Activities												
Oregon	101.2	100.0	101.2	102.2	102.3	102.1	101.5	101.0	101.1	101.2	101.2	101.3
% Ch	(2.6)	(1.2)	1.3	1.0	0.0	(0.1)	(0.6)	(0.5)	0.0	0.1	0.1	0.0
U.S.	9.2	9.3	9.4	9.4	9.4	9.4	9.3	9.3	9.3	9.3	9.3	9.3
% Ch	(0.0)	1.1	1.3	0.6	(0.0)	(0.5)	(0.7)	(0.2)	0.3	0.1	(0.0)	(0.3)
Professional and Business Services												
Oregon	260.0	260.7	265.3	269.0	272.3	278.3	284.5	290.2	294.2	298.3	303.3	309.3
% Ch	(2.2)	0.3	1.8	1.4	1.3	2.2	2.3	2.0	1.4	1.4	1.7	2.0
U.S.	22.6	22.5	21.7	21.3	21.6	22.2	22.9	23.3	23.6	24.0	24.7	25.3
% Ch	(0.7)	(0.7)	(3.4)	(2.0)	1.4	2.9	3.0	1.7	1.4	1.9	2.6	2.4

May 2025 - Employment By Industry

(Oregon - Thousands, U.S. - Millions)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Education and Health Services												
Oregon	337.0	346.6	352.0	355.8	358.5	361.7	365.6	368.1	369.9	371.8	373.5	375.2
% Ch	5.0	2.9	1.5	1.1	0.8	0.9	1.1	0.7	0.5	0.5	0.5	0.5
U.S.	26.5	27.4	27.9	28.3	28.7	29.0	29.4	29.7	29.9	30.2	30.4	30.5
% Ch	4.3	3.3	2.2	1.4	1.4	1.0	1.1	1.1	0.9	0.8	0.7	0.2
Educational Services												
Oregon	36.3	36.9	36.5	36.3	36.0	35.8	35.5	35.2	34.8	34.5	34.2	33.8
% Ch	0.8	1.8	(1.0)	(0.6)	(0.7)	(0.7)	(0.8)	(1.0)	(1.0)	(0.9)	(0.9)	(1.0)
U.S.	4.0	4.0	4.0	4.0	4.1	4.1	4.1	4.1	4.1	4.1	4.0	4.0
% Ch	3.0	1.4	(1.5)	0.4	2.5	1.0	(0.3)	(0.4)	(0.2)	(0.2)	(0.5)	(2.1)
Health Care and Social Assistance												
Oregon	300.7	309.8	315.4	319.5	322.4	325.9	330.1	332.9	335.1	337.3	339.3	341.4
% Ch	5.6	3.0	1.8	1.3	0.9	1.1	1.3	0.9	0.6	0.7	0.6	0.6
U.S.	22.5	23.3	24.0	24.4	24.7	24.9	25.2	25.6	25.9	26.1	26.4	26.5
% Ch	4.6	3.6	2.8	1.6	1.2	1.0	1.3	1.3	1.1	1.0	0.9	0.6
Leisure and Hospitality												
Oregon	207.1	209.4	211.3	213.4	216.8	219.2	221.5	223.2	225.0	226.3	227.2	228.3
% Ch	0.0	1.1	0.9	1.0	1.6	1.1	1.0	0.8	0.8	0.6	0.4	0.5
U.S.	16.8	17.1	17.5	17.6	17.6	17.6	17.5	17.2	17.0	16.8	16.6	16.5
% Ch	1.5	1.5	2.3	0.9	(0.2)	0.0	(0.8)	(1.3)	(1.4)	(1.2)	(1.2)	(0.6)
Other Services												
Oregon	66.3	66.5	66.9	67.9	68.6	69.2	69.7	70.3	70.8	71.4	72.0	72.3
% Ch	1.5	0.3	0.6	1.4	1.1	0.8	0.8	0.8	0.8	0.8	0.8	0.4
U.S.	6.0	6.0	6.1	6.2	6.4	6.5	6.5	6.5	6.6	6.6	6.6	6.6
% Ch	2.1	1.3	0.9	2.0	2.7	1.4	0.6	0.4	0.3	0.1	(0.0)	(0.1)
Government												
Oregon	314.5	314.4	311.9	311.3	310.6	310.1	310.7	309.8	309.7	309.7	309.7	309.6
% Ch	2.7	(0.0)	(0.8)	(0.2)	(0.2)	(0.1)	0.2	(0.3)	(0.0)	(0.0)	(0.0)	(0.0)
U.S.	23.4	23.5	23.5	23.6	23.7	23.7	23.9	23.9	24.0	24.0	24.1	24.2
% Ch	2.6	0.7	(0.2)	0.4	0.3	0.3	0.6	0.1	0.3	0.3	0.3	0.3
Federal Government												
Oregon	29.5	27.9	26.4	26.3	26.3	26.2	27.0	26.1	26.1	26.1	26.1	26.1
% Ch	3.6	(5.3)	(5.6)	(0.2)	(0.2)	(0.2)	3.0	(3.2)	(0.0)	(0.0)	(0.0)	0.0
U.S.	3.0	2.9	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
% Ch	2.5	(3.5)	(4.9)	0.0	0.0	0.0	2.3	(2.2)	0.0	0.0	0.0	0.0
State Government, Oregon												
Total	47.7	48.5	48.5	48.5	48.8	49.1	49.3	49.6	49.8	50.0	50.2	50.5
% Ch	4.1	1.7	0.0	0.1	0.6	0.5	0.5	0.6	0.5	0.4	0.5	0.5
Education	1.3	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
% Ch	(1.8)	(6.6)	(6.0)	(2.2)	(1.0)	0.1	0.3	0.5	0.5	0.2	0.2	0.2
Non-Education	46.4	47.3	47.4	47.4	47.7	48.0	48.2	48.5	48.7	48.9	49.1	49.3
% Ch	4.2	1.9	0.2	0.1	0.6	0.5	0.5	0.6	0.5	0.4	0.5	0.5
Local Government, Oregon												
Total	237.3	238.0	237.0	236.5	235.5	234.9	234.4	234.1	233.8	233.6	233.3	233.0
% Ch	2.3	0.3	(0.4)	(0.2)	(0.4)	(0.3)	(0.2)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Education	135.5	141.2	140.5	138.7	136.9	135.5	134.3	133.3	132.4	131.6	130.9	129.9
% Ch	2.6	4.2	(0.4)	(1.3)	(1.3)	(1.0)	(0.9)	(0.8)	(0.7)	(0.6)	(0.5)	(0.8)
Non-Education	101.9	96.8	96.5	97.8	98.6	99.4	100.1	100.8	101.4	102.0	102.4	103.1
% Ch	1.9	(4.9)	(0.3)	1.3	0.8	0.8	0.7	0.7	0.6	0.6	0.5	0.7

TABLE A.4

May 2025 - Other Economic Indicators

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Real GDP,												
Chain Weight (Bil of 2017$)	23,305.0	23,618.0	24,008.1	24,402.8	24,810.0	25,250.2	25,668.1	26,043.2	26,444.1	26,870.7	27,323.6	27,788.4
% Ch	2.8	1.3	1.7	1.6	1.7	1.8	1.7	1.5	1.5	1.6	1.7	1.7
Price and Wage Indicators												
GDP Implicit Price Deflator,												
Chain Weight U.S., 2017=100	125.2	129.7	133.3	135.9	138.7	141.4	144.3	147.5	150.8	154.2	157.6	161.2
% Ch	2.4	3.6	2.7	2.0	2.0	2.0	2.1	2.2	2.2	2.3	2.2	2.3
Personal Consumption Deflator,												
Chain Weight U.S., 2017=100	123.5	127.6	131.0	133.5	135.8	138.2	140.8	143.6	146.5	149.5	152.5	155.5
% Ch	2.5	3.3	2.6	1.9	1.8	1.7	1.9	2.0	2.0	2.0	2.0	2.0
CPI, Urban Consumers,												
1982-84=100												
West Region	333.0	343.5	353.5	361.5	369.0	376.6	385.0	393.9	402.9	412.0	421.0	430.4
% Ch	2.8	3.2	2.9	2.3	2.1	2.1	2.2	2.3	2.3	2.3	2.2	2.2
U.S.	313.7	324.3	333.6	340.8	347.5	354.1	361.7	370.0	378.4	386.9	395.3	404.0
% Ch	3.0	3.4	2.9	2.2	2.0	1.9	2.2	2.3	2.3	2.2	2.2	2.2
Oregon Average Wage												
Rate (Thous $)	74.0	77.3	80.6	84.3	87.9	91.2	94.7	98.4	102.2	106.2	110.2	109.5
% Ch	4.0	4.4	4.2	4.6	4.2	3.8	3.8	3.9	3.9	3.9	3.8	(0.6)
U.S. Average Wage												
Wage Rate (Thous $)	78.4	80.8	84.3	88.1	91.7	94.9	98.1	101.5	105.0	108.8	112.8	117.0
% Ch	4.3	3.1	4.3	4.4	4.1	3.5	3.4	3.4	3.5	3.6	3.7	3.8
Housing Indicators												
FHFA Oregon Housing Price Index												
1991 Q1=100	627.9	656.2	685.6	715.5	747.8	781.9	814.4	846.7	882.4	916.7	952.2	980.9
% Ch	2.9	4.5	4.5	4.4	4.5	4.6	4.2	4.0	4.2	3.9	3.9	3.0
FHFA National Housing Price Index												
1991 Q1=100	422.6	439.0	451.4	465.9	482.2	499.9	517.9	536.5	555.6	575.5	595.8	616.8
% Ch	5.4	3.9	2.8	3.2	3.5	3.7	3.6	3.6	3.6	3.6	3.5	3.5
Housing Starts												
Oregon (Thous)	14.1	14.5	15.0	15.5	16.2	17.8	19.7	20.6	20.7	20.8	20.8	21.0
% Ch	(22.4)	3.0	3.4	3.3	4.8	9.5	10.7	4.6	0.7	0.0	0.4	0.7
U.S. (Millions)	1.4	1.4	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.2	1.2
% Ch	(3.8)	1.3	(3.1)	(1.3)	0.6	0.2	(0.5)	(0.4)	(1.4)	(2.8)	(3.4)	(3.6)
Other Indicators												
Unemployment Rate (%)												
Oregon	4.2	4.7	5.1	5.2	5.1	4.8	4.5	4.5	4.5	4.6	4.6	4.6
Point Change	0.4	0.5	0.4	0.1	(0.1)	(0.3)	(0.2)	(0.0)	0.0	0.0	(0.0)	0.0
U.S.	4.0	4.4	4.9	5.0	4.8	4.5	4.2	4.2	4.2	4.2	4.1	4.1
Point Change	0.4	0.4	0.5	0.1	(0.2)	(0.3)	(0.3)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)
Industrial Production Index												
U.S, 2017 = 100	102.6	103.9	103.3	103.3	103.5	104.2	104.8	105.1	105.5	105.9	106.5	107.0
% Ch	(0.3)	1.3	(0.6)	0.0	0.1	0.7	0.6	0.3	0.4	0.4	0.5	0.5
Prime Rate (Percent)	8.3	7.5	6.6	6.0	6.0	6.3	6.3	6.3	6.3	6.3	6.3	6.3
% Ch	1.5	(10.0)	(11.8)	(9.1)	0.8	3.4	0.0	0.0	0.0	0.0	0.0	0.0
Population (Millions)												
Oregon	4.27	4.28	4.31	4.33	4.36	4.39	4.42	4.44	4.46	4.48	4.51	4.53
% Ch	0.3	0.4	0.6	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5
U.S.	340.6	342.5	343.4	344.3	345.1	346.2	347.4	348.6	349.7	350.9	351.9	352.9
% Ch	0.9	0.5	0.3	0.3	0.2	0.3	0.4	0.3	0.3	0.3	0.3	0.3
Timber Harvest (Mil Bd Ft)												
Oregon	3,273.4	3,274.4	3,384.2	3,496.5	3,546.9	3,575.6	3,597.7	3,614.3	3,627.1	3,640.1	3,651.3	3,766.0
% Ch	(0.1)	0.0	3.4	3.3	1.4	0.8	0.6	0.5	0.4	0.4	0.3	3.1

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Table B.1a – General Fund Revenues – 2023-25

Table B.1

General Fund Revenue Statement -- 2023-25

		Forecasts Dated: 3/1/2025			Forecasts Dated: 5/14/2025			Difference	
	Estimate at COS 2023	2023-24	2024-25	Total 2023-25	2023-24	2024-25	Total 2023-25	05/14/2025 Less 3/1/2025	05/14/2025 Less COS
Taxes									
Personal Income Taxes	21,019,693,000	9,149,827,000	13,420,158,000	22,569,985,000	9,149,827,000	13,275,333,000	22,425,160,000	(144,825,000)	1,405,467,000
Transfers & Offsets	(37,030,000)	(32,975,000)	(67,791,000)	(100,766,000)	(32,975,000)	(69,246,000)	(102,221,000)	(1,455,000)	(65,191,000)
Corporate Income Taxes	2,228,945,000	1,621,808,000	1,600,262,000	3,222,070,000	1,621,808,000	1,522,988,000	3,144,796,000	(77,274,000)	915,851,000
Transfer to Rainy Day Fund (Minimum Tax)	(91,604,000)	0	(131,334,000)	(131,334,000)	0	(135,000,000)	(135,000,000)	(3,666,000)	(43,396,000)
Insurance Taxes	145,011,000	55,513,000	76,453,000	131,966,000	55,513,000	73,355,000	128,868,000	(3,098,000)	(16,143,000)
Estate Taxes	539,732,000	338,976,000	364,544,000	703,520,000	338,976,000	441,687,000	780,663,000	77,143,000	240,931,000
Transfer to PERS UAL	0	0	0	0	0	0	0	0	0
Cigarette Taxes	43,144,000	21,151,000	17,664,000	38,815,000	21,151,000	17,088,000	38,239,000	(576,000)	(4,905,000)
Other Tobacco Products Taxes	61,303,000	26,767,000	27,377,000	54,144,000	26,767,000	27,353,000	54,120,000	(24,000)	(7,183,000)
Other Taxes	1,796,000	1,370,000	1,008,000	2,378,000	1,370,000	553,000	1,923,000	(455,000)	127,000
Fines and Fees									
State Court Fees	123,317,000	53,784,000	54,827,000	108,611,000	53,784,000	54,440,000	108,224,000	(387,000)	(15,093,000)
Secretary of State Fees	101,804,000	43,777,000	45,421,000	89,198,000	43,777,000	45,421,000	89,198,000	0	(12,606,000)
Criminal Fines & Assessments	15,514,000	0	0	0	0	0	0	0	(15,514,000)
Securities Fees	31,595,000	15,062,000	13,346,000	28,408,000	15,062,000	13,308,000	28,370,000	(38,000)	(3,225,000)
Central Service Charges	16,100,000	8,077,000	8,077,000	16,154,000	8,077,000	8,077,000	16,154,000	0	54,000
Liquor Apportionment	401,822,000	178,852,000	169,661,000	348,513,000	178,852,000	168,576,000	347,428,000	(1,085,000)	(54,394,000)
Interest Earnings	473,325,000	413,015,000	226,879,000	639,894,000	413,015,000	214,966,000	627,981,000	(11,913,000)	154,656,000
One-time/Miscellaneous Revenues	56,834,635	11,076,000	14,936,000	26,012,000	11,076,000	12,736,000	23,812,000	(2,200,000)	(33,022,635)
Reversions[1]	0	21,708,000	6,861,000	28,569,000	21,708,000	9,246,000	30,954,000	2,385,000	30,954,000
Gross General Fund Revenues	25,259,935,635	11,960,763,000	16,047,474,000	28,008,237,000	11,960,763,000	15,885,127,000	27,845,890,000	(162,347,000)	2,585,954,365
Total Transfers	(128,634,000)	(32,975,000)	(199,125,000)	(232,100,000)	(32,975,000)	(204,246,000)	(237,221,000)	(5,121,000)	(108,587,000)
Net General Fund Revenues	25,131,301,635	11,927,788,000	15,848,349,000	27,776,137,000	11,927,788,000	15,680,881,000	27,608,669,000	(167,468,000)	2,477,367,365
Plus Beginning Balance	7,493,482,790			8,082,487,603			8,084,793,649	2,306,046	591,310,858
Less Anticipated Administrative Actions*	0			0			0	0	0
Less Statutory Transfers**	(308,375,734)			(264,732,444)			(264,732,444)	0	43,643,290
Available Resources	32,316,408,692			35,593,893,159			35,428,730,205	(165,162,954)	3,112,321,513
Appropriations	31,873,575,550			33,007,363,141			33,467,944,380	460,581,239	1,594,368,830
Less Unspent Appropriation				0			(211,710,620)	(211,710,620)	
Projected Expenditures				33,007,363,141			33,256,233,760	248,870,619	
Estimated Ending Balance	442,833,142			2,586,530,018			2,172,496,445	(414,033,573)	1,729,663,303

Notes: Corporate income tax figure includes Corporate Multistate taxes. Other taxes include General Fund portions of the Eastern Oregon Severance Tax, Western Oregon Severance Tax and Amusement Device Tax. Cigarette, Other Tobacco, and Liquor are the General Fund portions only, see Table B.6 and B.7 for more.

* The Anticipated Administrative Actions line includes items like Tax Anticipation Note borrowing costs. None of these costs are anticipated for the 2023-25 biennium.

** "Statutory Transfers" amounts to the Rainy Day Fund transfer.

1 "Reversions" are monies returned to the General Fund and are not new money. As such, they are not counted towards the Kicker surplus. The Kicker surplus is the sum of the latest forecast less COS for Gross Revenue less Corporate Income Tax and Reversions.

Table B.1b – General Fund Revenues – 2025-27

Table B.1b

General Fund Revenue Statement -- 2025-27

	Forecasts Dated: 3/1/2025			Forecasts Dated: 5/14/2025			Difference
	2025-26	2026-27	Total 2025-27	2025-26	2026-27	Total 2025-27	05/14/2025 Less 3/1/2025
Taxes							
Personal Income Taxes	14,692,107,000	16,139,702,000	30,831,809,000	14,302,926,000	15,999,874,000	30,302,800,000	(529,009,000)
Transfers & Offsets	(32,048,000)	(33,060,000)	(65,108,000)	(33,017,000)	(34,029,000)	(67,046,000)	(1,938,000)
Corporate Income Taxes	1,719,645,000	1,687,350,000	3,406,995,000	1,602,278,000	1,829,313,000	3,431,591,000	24,596,000
Transfer to Rainy Day Fund (Minimum Tax)	0	(138,871,000)	(138,871,000)	0	(139,874,000)	(139,874,000)	(1,003,000)
Insurance Taxes	98,827,000	101,790,000	200,617,000	97,718,000	101,002,000	198,720,000	(1,897,000)
Estate Taxes	341,550,000	357,925,000	699,475,000	447,929,000	488,644,000	936,573,000	237,098,000
Transfer to PERS UAL	0	0	0	0	0	0	0
Cigarette Taxes	17,448,000	16,764,000	34,212,000	16,793,000	16,002,000	32,795,000	(1,417,000)
Other Tobacco Products Taxes	25,559,000	24,311,000	49,870,000	24,290,000	22,983,000	47,273,000	(2,597,000)
Other Taxes	1,008,000	1,008,000	2,016,000	553,000	553,000	1,106,000	(910,000)
Fines and Fees							
State Court Fees	57,851,000	59,720,000	117,571,000	56,843,000	58,667,000	115,510,000	(2,061,000)
Secretary of State Fees	46,120,000	46,533,000	92,653,000	46,120,000	46,533,000	92,653,000	0
Criminal Fines & Assessments	476,000	476,000	952,000	0	0	0	(952,000)
Securities Fees	13,735,000	14,088,000	27,823,000	14,097,000	14,553,000	28,650,000	827,000
Central Service Charges	8,884,000	8,884,000	17,768,000	8,884,000	8,884,000	17,768,000	0
Liquor Apportionment	130,908,000	139,564,000	270,472,000	143,933,000	144,276,000	288,209,000	17,737,000
Interest Earnings	178,917,000	160,056,000	338,973,000	148,491,000	114,900,000	263,391,000	(75,582,000)
One-time/Miscellaneous Revenues	10,000,000	10,500,000	20,500,000	10,000,000	10,500,000	20,500,000	0
Reversions	0	0	0	0	0	0	0
Gross General Fund Revenues	17,343,035,000	18,768,671,000	36,111,706,000	16,920,855,000	18,856,684,000	35,777,539,000	(334,167,000)
Total Transfers	(32,048,000)	(171,931,000)	(203,979,000)	(33,017,000)	(173,903,000)	(206,920,000)	(2,941,000)
Net General Fund Revenues	17,310,987,000	18,596,740,000	35,907,727,000	16,887,838,000	18,682,781,000	35,570,619,000	(337,108,000)
Plus Beginning Balance			2,586,530,018			2,172,496,445	(414,033,573)
Less Anticipated Administrative Actions*			0			0	0
Less Statutory Transfers**			(330,073,631)			(334,679,444)	(4,605,812)
Available Resources			38,164,183,386			37,408,436,001	(755,747,385)

Notes: Corporate income tax figure includes Corporate Multistate taxes. Other taxes include General Fund portions of the Eastern Oregon Severance Tax, Western Oregon Severance Tax and Amusement Device Tax. Cigarette, Other Tobacco, and Liquor are the General Fund portions only, see Table B.6 and B.7 for more.

* The Anticipated Administrative Actions line includes items like Tax Anticipation Note borrowing costs. None of these costs are currently anticipated for the 2025-27 biennium.

** "Statutory Transfers" is the Rainy Day Fund transfer based on the previous biennium's expenditures, and ending balance.

Table B.2 – General Fund Revenues by Fiscal Year

TABLE B.2 **May 2025**

General Fund Revenue Forecast

Millions of dollars

Fiscal Years	2021-22 Fiscal Year	2022-23 Fiscal Year	2023-24 Fiscal Year	2024-25 Fiscal Year	2025-26 Fiscal Year	2026-27 Fiscal Year	2027-28 Fiscal Year	2028-29 Fiscal Year	2029-30 Fiscal Year	2030-31 Fiscal Year	2031-32 Fiscal Year	2032-33 Fiscal Year
Taxes												
Personal Income	12,436.6	13,246.9	9,149.8	13,275.3	14,302.9	15,999.9	17,338.2	18,364.5	19,368.1	20,412.0	21,497.2	22,663.4
Offsets and Transfers	(26.2)	(27.4)	(33.0)	(69.2)	(33.0)	(34.0)	(34.0)	(34.0)	(27.5)	(10.0)	(8.5)	(2.5)
Corporate Excise & Income	1,538.5	1,618.5	1,621.8	1,523.0	1,602.3	1,829.3	1,835.4	1,831.0	1,886.4	1,959.2	2,031.1	2,140.0
Offsets and Transfers	0.0	(128.6)	0.0	(135.0)	0.0	(139.9)	0.0	(149.4)	0.0	(156.8)	0.0	(170.0)
Insurance	86.2	96.0	55.5	73.4	97.7	101.0	103.6	106.7	109.6	112.5	115.2	118.0
Estate	325.5	297.6	339.0	441.7	447.9	488.6	533.2	581.9	635.2	693.6	757.5	827.6
Offsets and Transfers	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cigarette	24.4	21.4	21.2	17.1	16.8	16.0	15.2	14.6	13.7	12.8	11.9	11.3
Other Tobacco Products	30.3	29.4	26.8	27.4	24.3	23.0	21.7	20.8	20.0	19.3	18.8	18.3
Other Taxes	1.0	0.8	1.4	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Other Revenues												
Licenses and Fees	111.8	113.3	112.6	113.2	117.1	119.8	121.7	124.3	126.3	128.8	130.8	133.4
Charges for Services	6.4	6.4	8.1	8.1	8.9	8.9	9.8	9.8	10.7	10.7	11.8	11.8
Liquor Apportionment	160.0	172.3	178.9	168.6	143.9	144.3	127.8	130.0	129.4	131.9	134.3	136.7
Interest Earnings	40.0	262.5	413.0	215.0	148.5	114.9	109.7	119.3	132.3	142.8	155.7	166.1
Others	103.2	50.1	32.8	22.0	10.0	10.5	11.0	11.5	12.0	12.5	13.0	13.5
Gross General Fund	14,863.9	15,915.2	11,960.8	15,885.1	16,920.9	18,856.7	20,227.7	21,314.8	22,444.4	23,636.6	24,877.8	26,240.5
Net General Fund	14,837.7	15,759.2	11,927.8	15,680.9	16,887.8	18,682.8	20,193.7	21,131.3	22,416.8	23,469.8	24,869.3	26,068.0

Biennial Totals	2021-23 BN	*Change (%)*	2023-25 BN	*Change (%)*	2025-27 BN	*Change (%)*	2027-29 BN	*Change (%)*	2029-31 BN	*Change (%)*	2031-33 BN	*Change (%)*
Taxes												
Personal Income	25,683.5	*28.4%*	22,425.2	*-12.7%*	30,302.8	*35.1%*	35,702.7	*17.8%*	39,780.1	*11.4%*	44,160.7	*11.0%*
Corporate Excise & Income	3,157.0	*60.5%*	3,144.8	*-0.4%*	3,431.6	*9.1%*	3,666.3	*6.8%*	3,845.6	*4.9%*	4,171.1	*8.5%*
Insurance	182.3	*14.5%*	128.9	*-29.3%*	198.7	*54.2%*	210.3	*5.8%*	222.1	*5.6%*	233.2	*5.0%*
Estate Taxes	623.0	*18.9%*	780.7	*25.3%*	936.6	*20.0%*	1,115.1	*19.1%*	1,328.8	*19.2%*	1,585.1	*19.3%*
Cigarette	45.8	*-17.0%*	38.2	*-16.4%*	32.8	*-14.2%*	29.7	*-9.3%*	26.4	*-11.2%*	23.2	*-12.2%*
Other Tobacco Products	59.8	*-2.5%*	54.1	*-9.4%*	47.3	*-12.6%*	42.5	*-10.1%*	39.3	*-7.5%*	37.1	*-5.7%*
Other Taxes	1.9	*85.4%*	1.9	*3.8%*	1.1	*-42.5%*	1.1	*0.0%*	1.1	*0.0%*	1.1	*0.0%*
Other Revenues												
Licenses and Fees	225.1	*-9.7%*	225.8	*0.3%*	236.8	*4.9%*	246.0	*3.9%*	255.0	*3.7%*	264.1	*3.6%*
Charges for Services	12.7	*11.1%*	16.2	*26.7%*	17.8	*10.0%*	19.5	*10.0%*	21.5	*10.0%*	23.6	*10.0%*
Liquor Apportionment	332.4	*-2.5%*	347.4	*4.5%*	288.2	*-17.0%*	257.8	*-10.5%*	261.3	*1.4%*	270.9	*3.7%*
Interest Earnings	302.5	*225.5%*	628.0	*107.6%*	263.4	*-58.1%*	229.0	*-13.1%*	275.1	*20.1%*	321.7	*17.0%*
Others	153.3	*-17.5%*	54.8	*-64.3%*	20.5	*-62.6%*	22.5	*9.8%*	24.5	*8.9%*	26.5	*8.2%*
Gross General Fund	30,779.1	*30.1%*	27,845.9	*-9.5%*	35,777.5	*28.5%*	41,542.6	*16.1%*	46,081.0	*10.9%*	51,118.4	*10.9%*
Net General Fund	30,596.9	*30.0%*	27,608.7	*-9.8%*	35,570.6	*28.8%*	41,325.1	*16.2%*	45,886.7	*11.0%*	50,937.4	*11.0%*

Note: Detailed entries may not add to totals due to rounding

Table B.3 – Summary of 2023 Legislative Session Adjustments

	23-25	25-27	27-29	Revenue Impact Statement
Personal Income Tax Impacts (millions)				
R&D Tax Credit – HB 2009	-$0.9	-$2.0	-$2.2	HB 2009
Gain Share (5-year extension)	$0.0	-$18.1	-$36.8	
Omnibus & Tax Credits – HB 2071	-$0.30	-$30.2	-$60.4	HB 2071
Child Tax Credit – HB 3235	-$71.5	-$74.1	-$77.5	HB 3235
Opportunity Grant Tax Credit – SB 129	$5.0	$0.1	$0.0	SB 129
Wildfire Deduction – HB 2812	-$0.6	-$0.2	$0.0	HB 2812
Film Tax Credit – HB 2093	Minimal			HB 2093
Reconnect – SB 141	Minimal			SB 141
SALT Workaround – HB 2083	Minimal			HB 2083
Personal Income Tax Total	**-$68.3**	**-$124.4**	**-$177.0**	
Corporate Income Tax Impacts (millions)				
R&D Tax Credit – HB 2009	-$24.0	-$53.6	-$61.3	HB 2009
Omnibus & Tax Credits – HB 2071	-$0.4	-$3.1	-$9.0	HB 2071
Opportunity Grant Tax Credit – SB 129	$8.7	$0.2	$0.0	SB 129
Film Tax Credit – HB 2093	Minimal			HB 2093
Reconnect – SB 141	Minimal			SB 141
Corporate Income Tax Total	**-$15.7**	**-$56.5**	**-$70.3**	
Other Tax/Revenue Impacts (millions)				
Estate Tax – SB 498	-$8.0	-$15.5	-$16.4	SB 498
Criminal Fine Account, Photo Radar – HB 2095	$5.2	$8.9	$8.5	HB 2095
OLCC, Alcohol Delivery – HB 3308	$3.9	$5.7	$6.0	HB 3308
Close Wildfire Account – HB 3215	$0.2	$0.0	$0.0	HB 3215
Program Change – SB 1049	$40.6	$0.0	$0.0	SB 1049
Forestland Tax Credit – HB 2161	Minimal			HB 2161
Other Tax Total	**$42.0**	**-$0.9**	**-$1.9**	

Table B.4 – Personal Income Tax Forecast

Table B.4 **May 2025**

Oregon Personal Income Tax Revenue Forecast

Quarterly tax collections (thousands of dollars, not seasonally adjusted)

	2017:3	2017:4	2018:1	2018:2	FY 2018	2018:3	2018:4	2019:1	2019:2	FY 2019
Withholding	1,748,844	1,836,249	2,011,564	1,851,177	7,447,834	1,925,880	2,039,120	2,079,900	1,999,015	8,043,914
%CHYA	*6.9%*	*9.0%*	*5.0%*	*-0.1%*	*5.2%*	*10.1%*	*11.0%*	*3.4%*	*8.0%*	*8.0%*
Est. Payments	321,032	451,037	464,534	512,671	1,749,274	367,772	284,002	321,858	532,273	1,505,905
%CHYA	*12.4%*	*4.3%*	*16.9%*	*-19.4%*	*0.6%*	*14.6%*	*-37.0%*	*-30.7%*	*3.8%*	*-13.9%*
Final Payments	92,364	169,785	174,096	878,587	1,314,832	104,644	156,592	225,515	1,385,562	1,872,312
%CHYA	*25.7%*	*24.6%*	*-29.2%*	*-76.2%*	*-56.4%*	*13.3%*	*-7.8%*	*29.5%*	*57.7%*	*42.4%*
Refunds	(133,143)	(266,467)	(686,100)	(610,486)	(1,696,196)	(140,701)	(335,635)	(546,225)	(445,573)	(1,468,133)
%CHYA	*2.5%*	*-13.8%*	*105.1%*	*65.2%*	*56.0%*	*5.7%*	*26.0%*	*-20.4%*	*-27.0%*	*-13.4%*
Other	(192,251)	-	-	237,300	45,049	(237,300)	-	-	222,477	(14,823)
Total	**1,836,845**	**2,190,604**	**1,964,094**	**2,869,249**	**8,860,793**	**2,020,295**	**2,144,078**	**2,081,049**	**3,693,754**	**9,939,176**
%CHYA	*7.7%*	*14.5%*	*8.0%*	*-0.2%*	*6.6%*	*10.0%*	*-2.1%*	*6.0%*	*28.7%*	*12.2%*

	2019:3	2019:4	2020:1	2020:2	FY 2020	2020:3	2020:4	2021:1	2021:2	FY 2021
Withholding	2,059,715	2,223,410	2,183,444	1,997,661	8,464,230	2,127,124	2,291,161	2,321,603	2,266,779	9,006,667
%CHYA	*6.9%*	*9.0%*	*5.0%*	*-0.1%*	*5.2%*	*3.3%*	*3.0%*	*6.3%*	*13.5%*	*6.4%*
Est. Payments	413,316	296,072	376,127	428,769	1,514,284	497,544	292,601	432,742	701,877	1,924,764
%CHYA	*12.4%*	*4.3%*	*16.9%*	*-19.4%*	*0.6%*	*20.4%*	*-1.2%*	*15.1%*	*63.7%*	*27.1%*
Final Payments	131,560	195,074	159,708	330,328	816,671	758,710	142,228	220,765	1,500,229	2,621,931
%CHYA	*25.7%*	*24.6%*	*-29.2%*	*-76.2%*	*-56.4%*	*476.7%*	*-27.1%*	*38.2%*	*354.2%*	*221.1%*
Refunds	(144,251)	(289,464)	(1,120,326)	(735,922)	(2,289,962)	(432,836)	(360,529)	(558,588)	(672,421)	(2,024,375)
%CHYA	*2.5%*	*-13.8%*	*105.1%*	*65.2%*	*56.0%*	*200.1%*	*24.6%*	*-50.1%*	*-8.6%*	*-11.6%*
Other	(222,477)	-	-	175,167	(47,310)	(175,167)	-	-	194,880	19,713
Total	**2,237,864**	**2,425,092**	**1,598,954**	**2,196,004**	**8,457,914**	**2,775,375**	**2,365,460**	**2,416,522**	**3,991,345**	**11,548,702**
%CHYA	*10.8%*	*13.1%*	*-23.2%*	*-40.5%*	*-14.9%*	*24.0%*	*-2.5%*	*51.1%*	*81.8%*	*36.5%*

	2021:3	2021:4	2022:1	2022:2	FY 2022	2022:3	2022:4	2023:1	2023:2	FY 2023
Withholding	2,393,995	2,525,865	2,611,195	2,467,726	9,998,782	2,509,729	2,641,474	2,680,227	2,569,226	10,400,656
%CHYA	*12.5%*	*10.2%*	*12.5%*	*8.9%*	*11.0%*	*4.8%*	*4.6%*	*2.6%*	*4.1%*	*4.0%*
Est. Payments	495,468	340,639	508,064	904,746	2,248,917	659,287	713,409	575,127	789,444	2,737,267
%CHYA	*-0.4%*	*16.4%*	*17.4%*	*28.9%*	*16.8%*	*33.1%*	*109.4%*	*13.2%*	*-12.7%*	*21.7%*
Final Payments	153,160	208,665	255,615	2,115,965	2,733,405	162,621	259,627	349,752	1,658,281	2,430,281
%CHYA	*-79.8%*	*46.7%*	*15.8%*	*41.0%*	*4.3%*	*6.2%*	*24.4%*	*36.8%*	*-21.6%*	*-11.1%*
Refunds	(162,428)	(300,852)	(1,082,458)	(960,617)	(2,506,355)	(293,038)	(559,280)	(822,472)	(720,282)	(2,395,072)
%CHYA	*-62.5%*	*-16.6%*	*93.8%*	*42.9%*	*23.8%*	*80.4%*	*85.9%*	*-24.0%*	*-25.0%*	*-4.4%*
Other	(194,880)	-	-	183,017	(11,863)	(183,017)	-	-	284,139	101,122
Total	**2,685,315**	**2,774,318**	**2,292,417**	**4,710,837**	**12,462,887**	**2,855,581**	**3,055,230**	**2,782,635**	**4,580,808**	**13,274,254**
%CHYA	*-3.2%*	*17.3%*	*-5.1%*	*18.0%*	*7.9%*	*6.3%*	*10.1%*	*21.4%*	*-2.8%*	*6.5%*

	2023:3	2023:4	2024:1	2024:2	FY 2024	2024:3	2024:4	2025:1	2025:2	FY 2025
Withholding	2,622,334	2,773,397	2,861,267	2,778,879	11,035,878	2,780,433	3,009,018	3,000,081	2,833,554	11,623,086
%CHYA	*4.5%*	*5.0%*	*6.8%*	*8.2%*	*6.1%*	*6.0%*	*8.5%*	*4.9%*	*2.0%*	*5.3%*
Est. Payments	577,023	524,217	493,608	825,136	2,419,984	625,959	626,436	578,501	910,575	2,741,471
%CHYA	*-12.5%*	*-26.5%*	*-14.2%*	*4.5%*	*-11.6%*	*8.5%*	*19.5%*	*17.2%*	*10.4%*	*13.3%*
Final Payments	195,731	260,845	273,319	962,274	1,692,169	181,306	190,237	360,103	2,015,192	2,746,838
%CHYA	*20.4%*	*0.5%*	*-21.9%*	*-42.0%*	*-30.4%*	*-7.4%*	*-27.1%*	*31.8%*	*109.4%*	*62.3%*
Refunds	(339,947)	(574,864)	(2,773,723)	(2,265,639)	(5,954,173)	(811,568)	(1,066,395)	(1,097,560)	(871,669)	(3,847,192)
%CHYA	*16.0%*	*2.8%*	*237.2%*	*214.5%*	*148.6%*	*138.7%*	*85.5%*	*-60.4%*	*-61.5%*	*-35.4%*
Other	(284,139)	-	-	240,108	(44,031)	(240,108)	-	-	251,237	11,129
Total	**2,771,003**	**2,983,595**	**854,471**	**2,540,758**	**9,149,827**	**2,536,023**	**2,759,297**	**2,841,125**	**5,138,888**	**13,275,333**
%CHYA	*-3.0%*	*-2.3%*	*-69.3%*	*-44.5%*	*-31.1%*	*-8.5%*	*-7.5%*	*232.5%*	*102.3%*	*45.1%*

Note: Other includes July withholding accrued to June (30 Day Number)

Table B.4 **May 2025**

Oregon Personal Income Tax Revenue Forecast

Quarterly tax collections (thousands of dollars, not seasonally adjusted)

	2025:3	2025:4	2026:1	2026:2	FY 2026	2026:3	2026:4	2027:1	2027:2	FY 2027
Withholding	2,946,059	3,141,967	3,195,246	3,043,923	12,327,195	3,177,784	3,389,101	3,391,659	3,225,069	13,183,613
%CHYA	*6.0%*	*4.4%*	*6.5%*	*7.4%*	*6.1%*	*7.9%*	*7.9%*	*6.1%*	*6.0%*	*6.9%*
Est. Payments	695,161	564,080	619,624	959,484	2,838,350	753,134	611,121	668,814	1,010,341	3,043,410
%CHYA	*11.1%*	*-10.0%*	*7.1%*	*5.4%*	*3.5%*	*8.3%*	*8.3%*	*7.9%*	*5.3%*	*7.2%*
Final Payments	177,387	314,662	277,232	1,558,560	2,327,841	157,061	261,869	333,629	2,297,167	3,049,727
%CHYA	*-2.2%*	*65.4%*	*-23.0%*	*-22.7%*	*-15.3%*	*-11.5%*	*-16.8%*	*20.3%*	*47.4%*	*31.0%*
Refunds	(252,689)	(474,667)	(1,340,995)	(1,141,870)	(3,210,221)	(311,565)	(640,773)	(1,267,990)	(1,072,675)	(3,293,003)
%CHYA	*-68.9%*	*-55.5%*	*22.2%*	*31.0%*	*-16.6%*	*23.3%*	*35.0%*	*-5.4%*	*-6.1%*	*2.6%*
Other	(251,237)	-	-	270,999	19,761	(270,999)	-	-	287,126	16,127
Total	**3,314,681**	**3,546,042**	**2,751,107**	**4,691,096**	**14,302,926**	**3,505,415**	**3,621,318**	**3,126,113**	**5,747,028**	**15,999,874**
%CHYA	*30.7%*	*28.5%*	*-3.2%*	*-8.7%*	*7.7%*	*5.8%*	*2.1%*	*13.6%*	*22.5%*	*11.9%*

	2027:3	2027:4	2028:1	2028:2	FY 2028	2028:3	2028:4	2029:1	2029:2	FY 2029
Withholding	3,366,896	3,590,789	3,573,325	3,395,585	13,926,595	3,544,910	3,780,641	3,765,950	3,579,039	14,670,540
%CHYA	*6.0%*	*6.0%*	*5.4%*	*5.3%*	*5.6%*	*5.3%*	*5.3%*	*5.4%*	*5.4%*	*5.3%*
Est. Payments	793,053	643,513	704,688	1,068,868	3,210,122	838,994	680,790	745,612	1,131,995	3,397,391
%CHYA	*5.3%*	*5.3%*	*5.4%*	*5.8%*	*5.5%*	*5.8%*	*5.8%*	*5.8%*	*5.9%*	*5.8%*
Final Payments	190,888	355,651	394,714	2,484,750	3,426,004	224,173	397,333	410,341	2,611,144	3,642,991
%CHYA	*21.5%*	*35.8%*	*18.3%*	*8.2%*	*12.3%*	*17.4%*	*11.7%*	*4.0%*	*5.1%*	*6.3%*
Refunds	(300,748)	(606,398)	(1,262,067)	(1,070,478)	(3,239,692)	(290,554)	(598,923)	(1,337,750)	(1,135,524)	(3,362,751)
%CHYA	*-3.5%*	*-5.4%*	*-0.5%*	*-0.2%*	*-1.6%*	*-3.4%*	*-1.2%*	*6.0%*	*6.1%*	*3.8%*
Other	(287,126)	-	-	302,307	15,181	(302,307)	-	-	318,640	16,333
Total	**3,762,963**	**3,983,555**	**3,410,660**	**6,181,032**	**17,338,210**	**4,015,216**	**4,259,841**	**3,584,152**	**6,505,294**	**18,364,504**
%CHYA	*7.3%*	*10.0%*	*9.1%*	*7.6%*	*8.4%*	*6.7%*	*6.9%*	*5.1%*	*5.2%*	*5.9%*

	2029:3	2029:4	2030:1	2030:2	FY2030	2030:3	2030:4	2031:1	2031:2	FY 2031
Withholding	3,736,432	3,984,899	3,965,369	3,768,112	15,454,811	3,933,820	4,195,412	4,175,472	3,967,832	16,272,536
%CHYA	*5.4%*	*5.4%*	*5.3%*	*5.3%*	*5.3%*	*5.3%*	*5.3%*	*5.3%*	*5.3%*	*5.3%*
Est. Payments	888,544	720,997	789,528	1,197,451	3,596,520	939,923	762,688	835,197	1,266,867	3,804,674
%CHYA	*5.9%*	*5.9%*	*5.9%*	*5.8%*	*5.9%*	*5.8%*	*5.8%*	*5.8%*	*5.8%*	*5.8%*
Final Payments	232,660	416,185	451,294	2,765,727	3,865,866	257,863	449,796	476,044	2,910,956	4,094,660
%CHYA	*3.8%*	*4.7%*	*10.0%*	*5.9%*	*6.1%*	*10.8%*	*8.1%*	*5.5%*	*5.3%*	*5.9%*
Refunds	(308,498)	(636,136)	(1,417,668)	(1,203,619)	(3,565,921)	(325,634)	(673,459)	(1,502,711)	(1,275,850)	(3,777,653)
%CHYA	*6.2%*	*6.2%*	*6.0%*	*6.0%*	*6.0%*	*5.6%*	*5.9%*	*6.0%*	*6.0%*	*5.9%*
Other	(318,640)	-	-	335,473	16,833	(335,473)	-	-	353,254	17,781
Total	**4,230,498**	**4,485,945**	**3,788,523**	**6,863,144**	**19,368,109**	**4,470,499**	**4,734,438**	**3,984,002**	**7,223,059**	**20,411,998**
%CHYA	*5.4%*	*5.3%*	*5.7%*	*5.5%*	*5.5%*	*5.7%*	*5.5%*	*5.2%*	*5.2%*	*5.4%*

	2031:3	2031:4	2032:1	2032:2	FY2032	2032:3	2032:4	2033:1	2033:2	FY 2033
Withholding	4,142,323	4,417,781	4,401,983	4,183,657	17,145,744	4,367,639	4,658,080	4,645,156	4,415,183	18,086,057
%CHYA	*5.3%*	*5.3%*	*5.4%*	*5.4%*	*5.4%*	*5.4%*	*5.4%*	*5.5%*	*5.5%*	*5.5%*
Est. Payments	994,410	806,901	883,760	1,342,039	4,027,110	1,053,416	854,780	936,306	1,422,910	4,267,412
%CHYA	*5.8%*	*5.8%*	*5.8%*	*5.9%*	*5.8%*	*5.9%*	*5.9%*	*5.9%*	*6.0%*	*6.0%*
Final Payments	272,100	473,957	500,966	3,063,331	4,310,354	286,351	498,776	527,687	3,227,786	4,540,600
%CHYA	*5.5%*	*5.4%*	*5.2%*	*5.2%*	*5.3%*	*5.2%*	*5.2%*	*5.3%*	*5.4%*	*5.3%*
Refunds	(344,851)	(713,645)	(1,593,633)	(1,353,046)	(4,005,175)	(365,723)	(756,828)	(1,692,070)	(1,436,656)	(4,251,277)
%CHYA	*5.9%*	*6.0%*	*6.1%*	*6.1%*	*6.0%*	*6.1%*	*6.1%*	*6.2%*	*6.2%*	*6.1%*
Other	(353,254)	-	-	372,468	19,215	(372,468)	-	-	393,081	20,613
Total	**4,710,728**	**4,984,994**	**4,193,077**	**7,608,449**	**21,497,248**	**4,969,214**	**5,254,808**	**4,417,078**	**8,022,304**	**22,663,404**
%CHYA	*5.4%*	*5.3%*	*5.2%*	*5.3%*	*5.3%*	*5.5%*	*5.4%*	*5.3%*	*5.4%*	*5.4%*

Note: Other includes July withholding accrued to June (30 Day Number)

Table B.5 – Corporate Income Tax Forecast

Table B.5 **May 2025**

Oregon Corporate Income and Excise Tax Revenue Forecast

Quarterly tax collections (thousands of dollars, not seasonally adjusted)

	2017:3	2017:4	2018:1	2018:2	FY 2018	2018:3	2018:4	2019:1	2019:2	FY 2019
Advance Payments	179,603	185,787	182,395	303,835	851,619	222,891	249,768	158,748	264,445	895,852
%CHYA	*31.4%*	*-13.9%*	*77.7%*	*55.5%*	*30.9%*	*24.1%*	*34.4%*	*-13.0%*	*-13.0%*	*5.2%*
Final Payments	42,600	66,460	46,270	108,539	263,869	74,735	102,942	68,818	174,861	421,355
%CHYA	*-4.8%*	*-28.9%*	*-11.3%*	*32.6%*	*-3.1%*	*75.4%*	*54.9%*	*48.7%*	*61.1%*	*59.7%*
Refunds	-72,225	-129,963	-122,291	-54,224	-378,702	-43,428	-167,871	-128,586	-50,616	-390,501
%CHYA	*82.0%*	*-22.0%*	*67.4%*	*-6.1%*	*12.4%*	*-39.9%*	*29.2%*	*5.1%*	*-6.7%*	*3.1%*
Total	**149,978**	**122,285**	**106,374**	**358,149**	**736,786**	**254,199**	**184,839**	**98,979**	**388,690**	**926,707**
%CHYA	*5.8%*	*-14.2%*	*30.1%*	*63.2%*	*25.8%*	*69.5%*	*51.2%*	*-7.0%*	*8.5%*	*25.8%*

	2019:3	2019:4	2020:1	2020:2	FY 2020	2020:3	2020:4	2021:1	2021:2	FY 2021
Advance Payments	236,341	346,651	137,782	263,138	983,912	260,668	378,192	249,855	381,413	1,270,128
%CHYA	*6.0%*	*38.8%*	*-13.2%*	*-0.5%*	*9.8%*	*10.3%*	*9.1%*	*81.3%*	*44.9%*	*29.1%*
Final Payments	67,657	105,446	66,346	111,149	350,598	114,684	98,371	78,356	263,524	554,934
%CHYA	*-9.5%*	*2.4%*	*-3.6%*	*-36.4%*	*-16.8%*	*69.5%*	*-6.7%*	*18.1%*	*137.1%*	*58.3%*
Refunds	-73,866	-247,403	-91,312	-86,858	-499,439	-62,538	-254,020	-154,026	-153,392	-623,975
%CHYA	*70.1%*	*47.4%*	*-29.0%*	*71.6%*	*27.9%*	*-15.3%*	*2.7%*	*68.7%*	*76.6%*	*24.9%*
Total	**230,133**	**204,694**	**112,816**	**287,429**	**835,071**	**312,814**	**222,542**	**174,186**	**491,545**	**1,201,087**
%CHYA	*-9.5%*	*10.7%*	*14.0%*	*-26.1%*	*-9.9%*	*35.9%*	*8.7%*	*54.4%*	*71.0%*	*43.8%*

	2021:3	2021:4	2022:1	2022:2	FY 2022	2022:3	2022:4	2023:1	2023:2	FY 2023
Advance Payments	356,491	494,937	288,546	416,777	1,556,751	428,034	568,160	406,675	468,642	1,871,512
%CHYA	*36.8%*	*30.9%*	*15.5%*	*9.3%*	*22.6%*	*20.1%*	*14.8%*	*40.9%*	*12.4%*	*20.2%*
Final Payments	56,491	96,179	115,111	261,579	529,361	72,368	50,907	83,324	304,427	511,026
%CHYA	*-50.7%*	*-2.2%*	*46.9%*	*-0.7%*	*-4.6%*	*28.1%*	*-47.1%*	*-27.6%*	*16.4%*	*-3.5%*
Refunds	-49,631	-255,602	-197,775	-44,052	-547,060	-116,377	-247,875	-320,324	-92,796	-777,372
%CHYA	*-20.6%*	*0.6%*	*28.4%*	*-71.3%*	*-12.3%*	*134.5%*	*-3.0%*	*62.0%*	*110.7%*	*42.1%*
Total	**363,352**	**335,513**	**205,883**	**634,305**	**1,539,052**	**384,025**	**371,192**	**169,676**	**680,273**	**1,605,166**
%CHYA	*16.2%*	*50.8%*	*18.2%*	*29.0%*	*28.1%*	*5.7%*	*10.6%*	*-17.6%*	*7.2%*	*4.3%*

	2023:3	2023:4	2024:1	2024:2	FY 2024	2024:3	2024:4	2025:1	2025:2	FY 2025
Advance Payments	378,791	584,136	336,447	492,579	1,791,954	403,947	598,852	425,281	459,673	1,887,753
%CHYA	*-11.5%*	*2.8%*	*-17.3%*	*5.1%*	*-4.3%*	*6.6%*	*2.5%*	*26.4%*	*-6.7%*	*5.3%*
Final Payments	106,469	77,027	85,407	357,338	626,241	102,069	73,384	77,771	324,350	577,574
%CHYA	*47.1%*	*51.3%*	*2.5%*	*17.4%*	*22.5%*	*-4.1%*	*-4.7%*	*-8.9%*	*-9.2%*	*-7.8%*
Refunds	-63,414	-297,105	-260,296	-175,571	-796,387	-102,686	-333,600	-346,919	-159,134	-942,340
%CHYA	*-45.5%*	*19.9%*	*-18.7%*	*89.2%*	*2.4%*	*61.9%*	*12.3%*	*33.3%*	*-9.4%*	*18.3%*
Total	**421,846**	**364,058**	**161,557**	**674,346**	**1,621,808**	**403,330**	**338,636**	**156,133**	**624,889**	**1,522,988**
%CHYA	*9.8%*	*-1.9%*	*-4.8%*	*-0.9%*	*1.0%*	*-4.4%*	*-7.0%*	*-3.4%*	*-7.3%*	*-6.1%*

Table B.5 **May 2025**

Oregon Corporate Income and Excise Tax Revenue Forecast

Quarterly tax collections (thousands of dollars, not seasonally adjusted)

	2025:3	2025:4	2026:1	2026:2	FY 2026	2026:3	2026:4	2027:1	2027:2	FY 2027
Advance Payments	447,573	617,788	315,168	492,818	1,873,347	478,961	685,018	351,339	524,200	2,039,518
%CHYA	*10.8%*	*3.2%*	*-25.9%*	*7.2%*	*-0.8%*	*7.0%*	*10.9%*	*11.5%*	*6.4%*	*8.9%*
Final Payments	98,480	147,012	107,356	335,763	688,611	110,541	168,822	119,692	386,720	785,774
%CHYA	*-3.5%*	*100.3%*	*38.0%*	*3.5%*	*19.2%*	*12.2%*	*14.8%*	*11.5%*	*15.2%*	*14.1%*
Refunds	-114,684	-418,658	-294,480	-131,857	-959,679	-119,377	-433,420	-304,897	-138,285	-995,979
%CHYA	*11.7%*	*25.5%*	*-15.1%*	*-17.1%*	*1.8%*	*4.1%*	*3.5%*	*3.5%*	*4.9%*	*3.8%*
Total	**431,369**	**346,141**	**128,044**	**696,724**	**1,602,278**	**470,125**	**420,420**	**166,133**	**772,635**	**1,829,313**
%CHYA	*7.0%*	*2.2%*	*-18.0%*	*11.5%*	*5.2%*	*9.0%*	*21.5%*	*29.7%*	*10.9%*	*14.2%*

	2027:3	2027:4	2028:1	2028:2	FY 2028	2028:3	2028:4	2029:1	2029:2	FY 2029
Advance Payments	508,038	714,893	364,267	534,623	2,121,821	517,641	724,297	368,669	544,290	2,154,897
%CHYA	*6.1%*	*4.4%*	*3.7%*	*2.0%*	*4.0%*	*1.9%*	*1.3%*	*1.2%*	*1.8%*	*1.6%*
Final Payments	121,074	178,568	128,956	392,073	820,671	123,926	179,278	130,696	392,934	826,834
%CHYA	*9.5%*	*5.8%*	*7.7%*	*1.4%*	*4.4%*	*2.4%*	*0.4%*	*1.3%*	*0.2%*	*0.8%*
Refunds	-125,916	-486,423	-342,130	-152,671	-1,107,139	-138,494	-502,468	-352,588	-157,209	-1,150,759
%CHYA	*5.5%*	*12.2%*	*12.2%*	*10.4%*	*11.2%*	*10.0%*	*3.3%*	*3.1%*	*3.0%*	*3.9%*
Total	**503,196**	**407,038**	**151,094**	**774,026**	**1,835,353**	**503,073**	**401,106**	**146,778**	**780,014**	**1,830,971**
%CHYA	*7.0%*	*-3.2%*	*-9.1%*	*0.2%*	*0.3%*	*0.0%*	*-1.5%*	*-2.9%*	*0.8%*	*-0.2%*

	2029:3	2029:4	2030:1	2030:2	FY 2030	2030:3	2030:4	2031:1	2031:2	FY 2031
Advance Payments	527,195	739,268	376,860	560,857	2,204,180	543,502	764,278	389,989	581,125	2,278,893
%CHYA	*1.8%*	*2.1%*	*2.2%*	*3.0%*	*2.3%*	*3.1%*	*3.4%*	*3.5%*	*3.6%*	*3.4%*
Final Payments	127,369	182,873	133,005	406,488	849,735	134,377	190,793	136,288	419,184	880,642
%CHYA	*2.8%*	*2.0%*	*1.8%*	*3.4%*	*2.8%*	*5.5%*	*4.3%*	*2.5%*	*3.1%*	*3.6%*
Refunds	-142,144	-507,832	-357,085	-160,414	-1,167,475	-144,937	-523,185	-367,089	-165,121	-1,200,332
%CHYA	*2.6%*	*1.1%*	*1.3%*	*2.0%*	*1.5%*	*2.0%*	*3.0%*	*2.8%*	*2.9%*	*2.8%*
Total	**512,420**	**414,309**	**152,780**	**806,931**	**1,886,440**	**532,941**	**431,886**	**159,188**	**835,188**	**1,959,204**
%CHYA	*1.9%*	*3.3%*	*4.1%*	*3.5%*	*3.0%*	*4.0%*	*4.2%*	*4.2%*	*3.5%*	*3.9%*

	2031:3	2031:4	2032:1	2032:2	FY 2032	2032:3	2032:4	2033:1	2033:2	FY 2033
Advance Payments	563,181	792,277	404,662	607,616	2,367,737	589,122	830,980	424,900	639,842	2,484,844
%CHYA	*3.6%*	*3.7%*	*3.8%*	*4.6%*	*3.9%*	*4.6%*	*4.9%*	*5.0%*	*5.3%*	*4.9%*
Final Payments	137,750	197,300	140,926	434,494	910,470	141,844	205,718	147,366	456,573	951,501
%CHYA	*2.5%*	*3.4%*	*3.4%*	*3.7%*	*3.4%*	*3.0%*	*4.3%*	*4.6%*	*5.1%*	*4.5%*
Refunds	-149,384	-544,393	-381,880	-171,456	-1,247,113	-155,215	-565,626	-397,065	-178,453	-1,296,359
%CHYA	*3.1%*	*4.1%*	*4.0%*	*3.8%*	*3.9%*	*3.9%*	*3.9%*	*4.0%*	*4.1%*	*3.9%*
Total	**551,548**	**445,184**	**163,708**	**870,654**	**2,031,094**	**575,751**	**471,072**	**175,201**	**917,962**	**2,139,986**
%CHYA	*3.5%*	*3.1%*	*2.8%*	*4.2%*	*3.7%*	*4.4%*	*5.8%*	*7.0%*	*5.4%*	*5.4%*

Table B.6 – Cigarette and Tobacco Tax Distribution

TABLE B.6 **May 2025**

Cigarette & Tobacco Tax Distribution[1]

Millions of dollars

	Cigarette Tax Distribution								Other Tobacco Tax Distribution				Inhalent Delivery Distribution		
						TURA[3]									
	Total	General Fund	Health Plan	Mental Health	Health Authority[2]	Old	New	Cities, Counties & Public Transit	Total	General Fund	Health Plan	TURA	Total	Health Authority	TURA
2023-24	**294.1**	19.4	75.7	13.2	159.0	3.0	17.7	6.0	**49.6**	26.7	20.6	2.3	**29.7**	26.8	3.0
2024-25	**258.7**	17.1	66.6	11.7	139.8	2.7	15.5	5.3	**50.8**	27.4	21.1	2.3	**27.2**	24.5	2.7
2023-25 BN	**552.8**	36.5	142.3	24.9	298.8	5.7	33.2	11.4	**100.4**	54.0	41.7	4.6	**56.9**	51.2	5.7
2025-26	**254.2**	16.8	65.4	11.4	137.4	2.7	15.3	5.2	**45.1**	24.3	18.7	2.1	**29.9**	26.9	3.0
2026-27	**242.3**	16.0	62.4	10.9	130.9	2.5	14.5	5.0	**42.7**	23.0	17.7	2.0	**29.1**	26.2	2.9
2025-27 BN	**496.5**	32.8	127.8	22.4	268.3	5.2	29.8	10.2	**87.8**	47.3	36.5	4.1	**59.0**	53.1	5.9
2027-28	**230.1**	15.2	59.2	10.4	124.3	2.4	13.8	4.7	**40.3**	21.7	16.7	1.9	**28.4**	25.5	2.8
2028-29	**220.3**	14.6	56.7	9.9	119.1	2.3	13.2	4.5	**38.7**	20.8	16.1	1.8	**27.6**	24.9	2.8
2027-29 BN	**450.4**	29.7	115.9	20.3	243.4	4.7	27.0	9.2	**79.0**	42.5	32.8	3.6	**56.0**	50.4	5.6
2029-30	**206.7**	13.7	53.2	9.3	111.7	2.2	12.4	4.2	**37.2**	20.0	15.4	1.7	**26.9**	24.2	2.7
2030-31	**193.4**	12.8	49.8	8.7	104.5	2.0	11.6	4.0	**35.9**	19.3	14.9	1.7	**26.2**	23.6	2.6
2029-31 BN	**400.1**	26.4	103.0	18.0	216.2	4.2	24.0	8.2	**73.0**	39.3	30.3	3.4	**53.2**	47.8	5.3
2031-32	**180.8**	11.9	46.5	8.1	97.7	1.9	10.9	3.7	**34.9**	18.8	14.5	1.6	**25.6**	23.0	2.6
2032-33	**170.4**	11.3	43.9	7.7	92.1	1.8	10.2	3.5	**34.0**	18.3	14.1	1.6	**24.9**	22.4	2.5
2031-33 BN	**351.2**	23.2	90.4	15.8	189.8	3.7	21.1	7.2	**68.9**	37.1	28.6	3.2	**50.4**	45.4	5.0

[1] All figures are net of administrative costs.

[2] Includes the cigarette floor tax in FY21 of $27.7 million and FY22 of $1.6 million

[3] Tobacco Use Reduction: Old and New refere to pre- and post-Measure 108 (2020) taxes and programs

Table B.7 – Liquor Apportionment and Revenue Distribution to Local Government

TABLE B.7 **May 2025**

Liquor Apportionment and Revenue Distribution to Local Governments

Millions of dollars

	Liquor Apportionment Distribution								
					City Revenue				
	Total Liquor Revenue Available	General Fund (56%)	Mental Health[1]	Oregon Wine Board	Revenue Sharing	Regular	Total	Counties	Cigarette Tax Distribution[2]
2023-24	315.299	179.221	9.682	0.324	54.945	40.114	95.059	28.653	6.041
2024-25	261.208	149.799	8.615	0.421	48.894	32.573	81.467	23.266	5.313
2023-25 BN	**576.507**	**329.020**	**18.297**	**0.745**	**103.839**	**72.687**	**176.526**	**51.919**	**11.353**
2025-26	252.225	143.933	9.138	0.372	44.901	31.431	76.332	22.451	5.221
2026-27	252.826	144.276	9.159	0.373	45.008	31.506	76.514	22.504	4.975
2025-27 BN	**505.052**	**288.209**	**18.297**	**0.745**	**89.910**	**62.937**	**152.846**	**44.955**	**10.196**
2027-28	237.706	127.828	9.072	0.369	45.653	31.957	77.610	22.826	4.725
2028-29	241.706	129.979	9.225	0.376	46.421	32.495	78.916	23.211	4.525
2027-29 BN	**479.412**	**257.807**	**18.297**	**0.745**	**92.074**	**64.452**	**156.526**	**46.037**	**9.249**
2029-30	240.579	129.442	9.064	0.369	46.229	32.360	78.590	23.115	4.245
2030-31	245.064	131.855	9.233	0.376	47.091	32.964	80.055	23.545	3.972
2029-31 BN	**485.643**	**261.296**	**18.297**	**0.745**	**93.320**	**65.324**	**158.644**	**46.660**	**8.217**

[1] Mental Health Alcoholism and Drug Services Account, per ORS 471.810

[2] For details on cigarette revenues see Table B.6 on previous page

Table B.8 – Track Record for the March 2025 Forecast

Table B.8 Track Record for the March 2025 Forecast

Millions of Dollars for Quarter ending March 31, 2025

Personal Income Tax

	Revenues		Difference		Year-over-Year Change		
	Actuals	Prev Forecast	$ Diff.	% Diff.	Year Ago	$ Change	% Change
Withholding	$3,000.1	$3,020.8	-$20.7	-0.7%	$2,861.3	$138.8	4.9%
Estimated Payments*	$578.5	$560.9	$17.6	3.1%	$493.6	$84.9	17.2%
Final Payments*	$360.1	$350.0	$10.2	2.9%	$273.3	$86.8	31.8%
Refunds	-$1,097.6	-$1,037.3	-$60.2	5.8%	-$2,773.7	$1,676.2	-60.4%
Other	$0.0	$0.0	$0.0		$0.0	$0.0	
Total	**$2,841.1**	**$2,894.3**	**-$53.2**	**-1.8%**	**$854.5**	**$1,986.7**	**232.5%**

Corporate Income Tax

	Revenues		Difference		Year-over-Year Change		
	Actuals	Prev Forecast	$ Diff.	% Diff.	Year Ago	$ Change	% Change
Estimated Payments	$425.3	$414.6	$10.7	2.6%	$336.4	$88.8	26.4%
Final Payments	$77.8	$95.1	-$17.3	-18.2%	$85.4	-$7.6	-8.9%
Refunds	-$346.9	-$358.4	$11.4	-3.2%	-$260.3	-$86.6	33.3%
Total	**$156.1**	**$151.3**	**$4.8**	**3.2%**	**$161.6**	**-$5.4**	**-3.4%**

Combined Personal and Corporate Income Tax

	Revenues		Difference		Year-over-Year Change		
	Actuals	Prev Forecast	$ Diff.	% Diff.	Year Ago	$ Change	% Change
SUM	**$2,997.3**	**$3,045.6**	**-$48.4**	**-1.6%**	**$1,016.0**	**$1,981.2**	**195.0%**

* Data separating estimated and other personal income tax payments is no longer available. Tracking represents estimates based on banking data.

Table B.9 – Lottery Forecast

TABLE B.9 **May 2025 Forecast**

Summary of Lottery Resources

(in millions of dollars)	2023-25 Current Forecast	2023-25 Change from March 2025	2023-25 Change from COS 2023	2025-2027 Current Forecast	2025-2027 Change from March 2025	2027-29 Current Forecast	2027-29 Change from March 2025	2029-31 Current Forecast	2029-31 Change from March 2025	2031-33 Current Forecast	2031-33 Change from March 2025
LOTTERY EARNINGS											
Traditional Lottery	207.421	*2.250*	*43.725*	184.159	10.038	188.400	11.181	191.443	11.549	195.041	12.013
Video Lottery	1,541.800	*(10.544)*	*(83.184)*	1,627.291	(49.786)	1,754.666	(65.358)	1,886.272	(84.893)	2,033.789	(93.557)
Sports Betting1	59.369	*0.000*	*15.054*	73.842	3.006	74.769	0.001	77.178	(0.331)	79.877	(0.433)
Administrative Actions	42.882	*0.000*	*42.882*	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Available to Transfer	**1,851.472**	*(8.294)*	*18.477*	**1,885.293**	(36.742)	**2,017.834**	(54.175)	**2,154.893**	(73.675)	**2,308.707**	(81.978)
ECONOMIC DEVELOPMENT FUND											
Beginning Balance	84.396	*0.000*	*0.000*	45.086	(5.553)	0.000	0.000	0.000	0.000	0.000	0.000
Transfers from Lottery	1,851.472	*(8.294)*	*18.477*	1,885.293	(36.742)	2,017.834	(54.175)	2,154.893	(73.675)	2,308.707	(81.978)
Other Resources2	7.685	*0.000*	*5.685*	2.000	0.000	2.000	0.000	2.000	0.000	2.000	0.000
Total Available Resources	**1,943.553**	*(8.294)*	*24.163*	**1,932.378**	(42.295)	**2,019.834**	(54.175)	**2,156.893**	(73.675)	**2,310.707**	(81.978)
ALLOCATION OF RESOURCES											
Constitutional Distributions											
Education Stability Fund3	333.265	*(1.493)*	*3.326*	254.358	(4.132)	363.210	(9.752)	340.709	41.506	204.543	(7.210)
Oregon Capital Matching Fund3	0.000	*0.000*	*0.000*	70.829	(2.068)	0.000	0.000	39.310	(45.640)	175.853	(6.289)
Parks and Natural Resources Fund4	277.721	*(1.244)*	*2.772*	282.794	(5.511)	302.675	(8.126)	323.234	(11.051)	346.306	(12.297)
Veterans' Services Fund5	27.772	*(0.124)*	*0.277*	28.279	(0.551)	30.268	(0.813)	32.323	(1.105)	34.631	(1.230)
Other Distributions											
Outdoor School Education Fund5	36.406	*0.000*	*(20.000)*	59.821	0.000	63.183	0.000	65.936	0.000	69.062	0.000
County Economic Development	59.982	*0.000*	*0.000*	62.390	(1.909)	67.274	(2.506)	72.320	(3.255)	77.975	(3.587)
HECC Collegiate Athletic & Scholarships6	18.330	*0.000*	*0.000*	18.853	(0.367)	20.178	(0.542)	21.549	(0.737)	23.087	(0.820)
Gambling Addiction 7	18.473	*0.000*	*0.143*	18.853	(0.367)	20.178	(0.542)	21.549	(0.737)	23.087	(0.820)
County Fairs	3.828	*0.000*	*0.000*	5.744	0.000	6.073	0.000	6.350	0.000	6.650	0.000
Other Legislatively Adopted Allocations8	1,094.504	*0.120*	*32.559*	342.983	0.000	287.141	0.000	236.879	0.000	186.892	0.000
Employer Incentive Fund (PERS)1	28.186	*0.000*	*0.000*	48.921	1.987	48.973	0.001	50.833	(0.526)	53.536	(0.291)
Total Distributions	**1,898.468**	*(2.741)*	*19.077*	**1,193.826**	(12.920)	**1,209.154**	(22.279)	**1,210.992**	(21.545)	**1,201.622**	(32.542)
Ending Balance/Discretionary Resources	**45.086**	*(5.553)*	*5.086*	**738.552**	(29.375)	**810.681**	(31.896)	**945.901**	(52.131)	**1,109.085**	(49.436)

Note: Some totals may not foot due to rounding.

1. Per HB 4304 (2020 Second Special Session), the Sports Betting revenue transfer to the Employer Incentive Fund is repealed
2. Includes interest earnings on Economic Development Fund and reversions.
3. Eighteen percent of proceeds accrue to the Ed. Stability Fund, until the balance equals 5% of GF Revenues. Thereafter, 15% of proceeds accrue to the School Capital Matching Fund.
4. The Parks and Natural Resources Fund Constitutional amendment requires 15% of net proceeds be transferred to this fund.
5. Per Ballot Measure 96 (2016), 1.5% of net lottery proceeds are dedicated to the Veterans' Services Fund
6. Per Ballot Measure 99 (2016), the lesser of 4% of Lottery transfers or $22 million per year is transferred to the Outdoor Education Account. Adjusted annually for inflation.
7. Approximately one percent of net lottery proceeds are dedicated to each program. Certain limits are imposed by the Legislature.
8. Includes Debt Service Allocations, Allocations to State School Fund and Other Agency Allocations, including Business Oregon

Table B.10 –Budgetary Reserve Summary

Table B.10 **May 2025**

Budgetary Reserve Summary and Outlook

Rainy Day Fund

(Millions)	2021-23	2023-25	2025-27	2027-29	2029-31	2031-33
Beginning Balance	$962.2	$1,353.5	$1,911.8	$2,548.5	$3,245.9	$4,046.0
Interest Earnings	$43.6	$158.6	$162.2	$178.6	$234.2	$289.1
Deposits[1]	$347.2	$399.7	$474.6	$518.8	$565.8	$624.2
Triggered Withdrawals	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Ending Balance[2]	**$1,352.9**	**$1,911.8**	**$2,548.5**	**$3,245.9**	**$4,046.0**	**$4,959.3**

Education Stability Fund[3]

(Millions)	2021-23	2023-25	2025-27	2027-29	2029-31	2031-33
Beginning Balance	$414.6	$710.8	$1,008.3	$1,237.3	$1,564.1	$1,870.8
Interest Earnings[4]	$21.9	$85.1	$85.6	$88.0	$113.6	$131.1
Deposits[5]	$294.0	$299.9	$228.9	$326.9	$306.6	$184.1
Distributions	$19.8	$87.5	$85.6	$88.0	$113.6	$131.1
Oregon Education Fund	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Oregon Opportunity Grant	$19.8	$87.5	$85.6	$88.0	$113.6	$131.1
Withdrawals	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Ending Balance	**$710.8**	**$1,008.3**	**$1,237.3**	**$1,564.1**	**$1,870.8**	**$2,054.9**

Total Reserves

(Millions)	2021-23	2023-25	2025-27	2027-29	2029-31	2031-33
Ending Balances	**$2,063.7**	**$2,920.1**	**$3,785.8**	**$4,810.1**	**$5,916.7**	**$7,014.1**
Percent of General Fund Revenues	6.7%	10.6%	10.6%	11.6%	12.9%	13.8%

Footnotes:
1. Includes transfer of ending General Fund balances up to 1% of budgeted appropriations as well as private donations. Assumes future appropriations equal to 98.75 percent of available resources. Includes forecast for corporate income taxes above rate of 6.6% for the biennium are deposited on or before Jun 30 of each odd-numbered year.
2. Available funds in a given biennium equal 2/3rds of the beginning balance under current law.
3. Excludes funds in the Oregon Growth and the Oregon Resource and Technology Development subaccounts.
4. Interest earnings are distributed to the Oregon Education Funds (75%) and the State Scholarship Fund (25%), provided there remains debt outstanding. In the event that debt is paid off, all interest earnings distributed to the State Scholarship Fund.
5. Contributions to the ESF are capped at 5% of the prior biennium's General Fund revenue total. Quarterly contributions are made until the balance exceeds the cap.

Table B.11 – Recreational Marijuana Forecast

TABLE B.11 **May 2025**

Summary of Marijuana Resources

(in millions of dollars)	2023-25 Current Forecast	2023-25 Change from Mar-25	2023-25 Change from COS 2023	2025-27 Current Forecast	2025-27 Change from Mar-25	2027-29 Current Forecast	2027-29 Change from Mar-25	2029-31 Current Forecast	2029-31 Change from Mar-25	2031-33 Current Forecast	2031-33 Change from Mar-25
MARIJUANA EARNINGS											
+ Tax Revenue [1]	305.376	*(4.793)*	*(11.484)*	319.997	*(7.624)*	342.579	(8.689)	370.839	(11.851)	404.169	(12.917)
+ Medical Marijuana Tax Revenue [2]	0.000	*0.000*	*0.000*	0.000	*0.000*	13.109	(0.382)	18.803	(0.602)	20.492	(0.656)
- Administrative Costs [3]	18.374	*0.000*	*0.000*	18.746	*0.000*	19.144	0.000	19.571	0.000	20.027	0.000
Net Available to Transfer	**287.002**	*(4.793)*	*(11.484)*	**301.251**	*(7.624)*	**336.544**	*(9.071)*	**370.072**	*(12.453)*	**404.634**	*(13.573)*
OREGON MARIJUANA ACCOUNT											
Beginning Balance	0.000	*0.000*	*0.000*	0.000	*0.000*	0.000	0.000	0.000	0.000	0.000	0.000
Revenue Transfers	287.002	*(4.793)*	*(11.484)*	301.251	*(7.624)*	336.544	(9.071)	370.072	(12.453)	404.634	(13.573)
Other Resources	0.000	*0.000*	*0.000*	0.000	*0.000*	0.000	0.000	0.000	0.000	0.000	0.000
Total Available Resources	**287.002**	*(4.793)*	*(11.484)*	**301.251**	*(7.624)*	**336.544**	*(9.071)*	**370.072**	*(12.453)*	**404.634**	*(13.573)*
ALLOCATION OF RESOURCES [4]											
Drug Treatment & Recovery	185.126	*(4.793)*	*(11.484)*	192.331	*(7.624)*	221.059	(9.071)	249.786	(12.453)	278.895	(13.573)
State School Fund	40.751	*0.000*	*0.000*	43.568	*0.000*	46.194	0.000	48.114	0.000	50.296	0.000
Mental Health, Alcoholism, & Drug Services	20.375	*0.000*	*0.000*	21.784	*0.000*	23.097	0.000	24.057	0.000	25.148	0.000
State Police	15.281	*0.000*	*0.000*	16.338	*0.000*	17.323	0.000	18.043	0.000	18.861	0.000
Cities	10.188	*0.000*	*0.000*	10.892	*0.000*	11.548	0.000	12.029	0.000	12.574	0.000
Counties	10.188	*0.000*	*0.000*	10.892	*0.000*	11.548	0.000	12.029	0.000	12.574	0.000
Alcohol & Drug Abuse Prevention, Intervention & Treatment	5.094	*0.000*	*0.000*	5.446	*0.000*	5.774	0.000	6.014	0.000	6.287	0.000
Total Distributions	**287.002**	*(4.793)*	*(11.484)*	**301.251**	*(7.624)*	**336.544**	*(9.071)*	**370.072**	*(12.453)*	**404.634**	*(13.573)*
Ending Balance	**0.000**	*0.000*	*0.000*	**0.000**	*0.000*	**0.000**	0.000	**0.000**	0.000	**0.000**	0.000

Note: Some totals may not foot due to rounding.

1. Retailers pay taxes monthly, however taxes are not available for distribution to recepient programs until the Department of Revenue receives and processes retailers' quarterly tax returns. As such, there is a one to two quarter lag between when the initial monthly payments are made and when monies be come available to distribute.

2. Medical marijuana being exempt from tax is an explicit tax expenditure per HB 2433 (2021). Tax expenditures sunset after 6 years, although they may be renewed at that time. Current law is that medical marijuana sales will be taxed beginning January 1, 2028.

3. Administrative Costs reflect monthly collection costs for the Department of Revenue in addition to distributions to the Criminal Justice Commission and OLCC per SB 1544 (2018)

4. The first $11.25 million per quarter ($45m per year) is distributed via forumula to the initial recipient programs. These distributions are adjusted for inflation. All additional revenues go to the Drug Treatment & Recovery Fund.

Table B.12 – Fund for Student Success (Corporate Activity Tax)

TABLE B.12 **May 2025**

Summary of Corporate Activity Tax Resources

	2023-25			2025-27		2027-29		2029-31		2031-33	
(in millions of dollars)	**Current Forecast**	*Change from Mar-25*	*Change from COS 2023*	**Current Forecast**	*Change from Mar-25*	**Current Forecast**	*Change from Mar-25*	**Current Forecast**	*Change from Mar-25*	**Current Forecast**	*Change from Mar-25*
Corporate Activity Tax											
+ Tax Revenue	2,735.290	*(21.817)*	*(43.808)*	3,071.711	*(44.391)*	3,428.648	*(45.866)*	3,767.476	*(52.640)*	4,127.849	*(59.992)*
- Administrative Costs	21.312	*0.000*	*0.000*	23.656	*0.000*	26.259	*0.000*	28.689	*0.000*	31.234	*0.000*
Net Available to Transfer	**2,713.978**	(21.817)	(43.808)	**3,048.054**	(44.391)	**3,402.389**	(45.866)	**3,738.787**	(52.640)	**4,096.616**	(59.992)
Fund for Student Success											
Beginning Balance	326.038	*0.000*	*7.511*	111.228	*(17.328)*	0.000	*0.000*	0.000	*0.000*	0.000	*0.000*
Revenue Transfers	2,713.978	*(21.817)*	*(43.808)*	3,048.054	*(44.391)*	3,402.389	*(45.866)*	3,738.787	*(52.640)*	4,096.616	*(59.992)*
Other Resources	0.000	*0.000*	*0.000*	0.000	*0.000*	0.000	*0.000*	0.000	*0.000*	0.000	*0.000*
Total Available Resources	**3,040.016**	(21.817)	(36.297)	**3,159.282**	(61.720)	**3,402.389**	(45.866)	**3,738.787**	(52.640)	**4,096.616**	(59.992)
Distributions											
State School Fund	792.727	*(4.488)*	*90.773*	839.625	*(7.817)*	927.825	*1.205*	1,013.802	*3.217*	1,104.877	*3.550*
Student Investment Acc.	1,087.179	*0.000*	*0.000*	1,159.828	*(26.951)*	1,237.282	*(23.536)*	1,362.492	*(27.928)*	1,495.869	*(31.771)*
Statewide Ed. Initiative Acc.	548.451	*0.000*	*(8.945)*	695.897	*(16.171)*	742.369	*(14.121)*	817.495	*(16.757)*	897.522	*(19.063)*
Early Learning Account	500.430	*0.000*	*(29.352)*	463.931	*(10.780)*	494.913	*(9.414)*	544.997	*(11.171)*	598.348	*(12.708)*
Total Distributions	**2,928.788**	(4.488)	52.475	**3,159.282**	(61.720)	**3,402.389**	(45.866)	**3,738.787**	(52.640)	**4,096.616**	(59.992)
Ending Balance	**111.228**	(17.328)	(88.772)	**0.000**	0.000	**0.000**	0.000	**0.000**	0.000	**0.000**	0.000

Note: The State School Fund distribution equals an estimate of the lost General Fund due to the Personal and Corporate Income Tax changes enacted in HB 3427. In addition, each biennium includes an additional $40 million dedicated to the High Cost Disabilities Account. The 2021-23 distribution equals the Legislatively Adopted Budget Other Fund limitation. The 2023-25 distribution includes a $30.99 million reconciling adjustment for the prior biennium.
Some totals may not foot due to rounding.

Table B.13 – Fund for Student Success Quarterly Revenues

Table B.13 **May 2025**

Corporate Activity Tax Collections By Quarter

Quarterly tax collections (thousands of dollars, not seasonally adjusted)

	2019:3	2019:4	2020:1	2020:2	FY 2020	2020:3	2020:4	2021:1	2021:2	FY 2021
Estimated Payments	0	0	4,023	222,495	**226,518**	224,973	254,387	223,550	270,784	**973,693**
Final Payments	0	0	0	0	**0**	0	0	26,911	163,436	**190,348**
Refunds	0	0	0	0	**0**	0	0	-997	-14,657	**-15,654**
Total	**0**	**0**	**4,023**	**222,495**	**226,518**	**224,973**	**254,387**	**249,464**	**419,563**	**1,148,387**
%CHY								*6101%*	*88.6%*	***407.0%***

	2021:3	2021:4	2022:1	2022:2	FY 2022	2022:3	2022:4	2023:1	2023:2	FY 2023
Estimated Payments	271,858	389,810	230,942	279,349	**1,171,959**	292,325	391,140	251,283	285,645	**1,220,391**
Final Payments	15,153	41,892	41,950	168,644	**267,640**	59,490	75,201	65,187	173,094	**372,971**
Refunds	-16,356	-141,389	-15,151	-50,166	**-223,062**	-41,565	-170,978	-21,976	-20,314	**-254,833**
Total	**270,656**	**290,314**	**257,741**	**397,828**	**1,216,538**	**310,249**	**295,362**	**294,493**	**438,425**	**1,338,529**
%CHY	*20.3%*	*14.1%*	*3.3%*	*-5.2%*	***5.9%***	*14.6%*	*1.7%*	*14.3%*	*10.2%*	***10.0%***

	2023:3	2023:4	2024:1	2024:2	FY 2024	2024:3	2024:4	2025:1	2025:2	FY 2025
Estimated Payments	289,041	317,340	314,961	302,191	**1,223,533**	309,063	404,681	295,893	313,028	**1,322,664**
Final Payments	41,981	53,324	65,943	185,622	**346,870**	47,701	53,540	71,841	200,275	**373,357**
Refunds	-29,313	-56,912	-101,932	-38,258	**-226,416**	-30,480	-136,480	-80,099	-57,661	**-304,720**
Total	**301,708**	**313,753**	**278,972**	**449,555**	**1,343,988**	**326,283**	**321,740**	**287,636**	**455,643**	**1,391,302**
%CHY	*-2.8%*	*6.2%*	*-5.3%*	*2.5%*	***0.4%***	*8.1%*	*2.5%*	*3.1%*	*1.4%*	***3.5%***

	2025:3	2025:4	2026:1	2026:2	FY 2026	2026:3	2026:4	2027:1	2027:2	FY 2027
Estimated Payments	321,721	403,316	283,768	343,402	**1,352,207**	344,479	434,113	305,804	363,411	**1,447,807**
Final Payments	55,306	67,199	68,186	204,046	**394,737**	58,819	71,727	73,387	220,214	**424,147**
Refunds	-38,365	-111,333	-67,098	-46,849	**-263,645**	-40,779	-119,651	-72,507	-50,606	**-283,543**
Total	**338,662**	**359,182**	**284,856**	**500,599**	**1,483,299**	**362,519**	**386,189**	**306,685**	**533,019**	**1,588,412**
%CHY	*3.8%*	*11.6%*	*-1.0%*	*9.9%*	***6.6%***	*7.0%*	*7.5%*	*7.7%*	*6.5%*	***7.1%***

	2027:3	2027:4	2028:1	2028:2	FY 2028	2028:3	2028:4	2029:1	2029:2	FY 2029
Estimated Payments	364,179	458,110	322,238	381,890	**1,526,418**	382,653	481,215	338,371	400,383	**1,602,623**
Final Payments	63,438	77,390	78,192	232,516	**451,536**	67,125	81,743	82,255	244,259	**475,382**
Refunds	-44,045	-129,218	-78,128	-53,811	**-305,202**	-46,708	-136,482	-82,328	-56,590	**-322,108**
Total	**383,572**	**406,282**	**322,302**	**560,595**	**1,672,751**	**403,070**	**426,476**	**338,299**	**588,052**	**1,755,897**
%CHY	*5.8%*	*5.2%*	*5.1%*	*5.2%*	***5.3%***	*5.1%*	*5.0%*	*5.0%*	*4.9%*	***5.0%***

	2029:3	2029:4	2030:1	2030:2	FY 2030	2030:3	2030:4	2031:1	2031:2	FY 2031
Estimated Payments	401,148	504,393	354,620	419,450	**1,679,611**	420,306	528,444	371,512	439,133	**1,759,395**
Final Payments	70,538	85,875	86,288	256,034	**498,736**	73,953	90,018	90,409	268,212	**522,592**
Refunds	-49,100	-143,383	-86,448	-59,354	**-338,286**	-51,487	-150,300	-90,598	-62,187	**-354,572**
Total	**422,586**	**446,885**	**354,460**	**616,130**	**1,840,061**	**442,772**	**468,162**	**371,323**	**645,158**	**1,927,415**
%CHY	*4.8%*	*4.8%*	*4.8%*	*4.8%*	***4.8%***	*4.8%*	*4.8%*	*4.8%*	*4.7%*	***4.7%***

	2031:3	2031:4	2032:1	2032:2	FY 2032	2032:3	2032:4	2033:1	2033:2	FY 2033
Estimated Payments	439,947	553,102	388,827	459,556	**1,841,433**	460,406	578,818	406,876	480,618	**1,926,718**
Final Payments	77,473	94,300	94,661	280,733	**547,167**	81,096	98,703	99,067	293,785	**572,651**
Refunds	-53,941	-157,450	-94,897	-65,107	**-371,394**	-56,468	-164,802	-99,320	-68,136	**-388,726**
Total	**463,480**	**489,952**	**388,591**	**675,182**	**2,017,206**	**485,035**	**512,719**	**406,624**	**706,267**	**2,110,644**
%CHY	*4.7%*	*4.7%*	*4.7%*	*4.7%*	***4.7%***	*4.7%*	*4.6%*	*4.6%*	*4.6%*	***4.6%***

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Table C.1 Oregon's Population Forecasts and Component of Change 1990-2035

Year		Population Change		Births		Deaths		Natural	Net Migration	
(July 1)	Population	Number	Percent	Number	Rate/1000	Number	Rate/1000	Increase	Number	Rate/1000
1990-91	2,928,500	68,100	2.38	42,682	14.75	24,944	8.62	17,738	50,362	17.40
1991-92	2,991,800	63,300	2.16	42,427	14.33	25,166	8.50	17,261	46,039	15.55
1992-93	3,060,400	68,600	2.29	41,442	13.69	26,543	8.77	14,899	53,701	17.75
1993-94	3,121,300	60,900	1.99	41,487	13.42	27,564	8.92	13,923	46,977	15.20
1994-95	3,184,400	63,100	2.02	42,426	13.46	27,552	8.74	14,874	48,226	15.30
1990-95		**324,000**		**210,464**		**131,769**		**78,695**	**245,305**	**16.30**
1995-96	3,247,100	62,700	1.97	43,196	13.43	28,768	8.95	14,428	48,272	15.01
1996-97	3,304,300	57,200	1.76	43,625	13.32	29,201	8.91	14,424	42,776	13.06
1997-98	3,352,400	48,100	1.46	44,696	13.43	28,705	8.62	15,991	32,109	9.65
1998-99	3,393,900	41,500	1.24	45,188	13.40	29,848	8.85	15,340	26,160	7.76
1999-00	3,431,100	37,200	1.10	45,534	13.34	28,909	8.47	16,625	20,575	6.03
1995-2000		**246,700**		**222,239**		**145,431**		**76,808**	**169,892**	**10.24**
2000-01	3,470,400	39,300	1.15	45,536	13.20	29,934	8.67	15,602	23,698	6.87
2001-02	3,502,600	32,200	0.93	44,995	12.91	30,828	8.84	14,167	18,033	5.17
2002-03	3,538,600	36,000	1.03	45,686	12.98	30,604	8.69	15,082	20,918	5.94
2003-04	3,578,900	40,300	1.14	45,599	12.81	30,721	8.63	14,878	25,422	7.14
2004-05	3,626,900	48,000	1.34	45,892	12.74	30,717	8.53	15,175	32,825	9.11
2000-05		**195,800**		**227,708**		**152,804**		**74,904**	**120,896**	**6.86**
2005-06	3,685,200	58,300	1.61	46,946	12.84	30,771	8.42	16,175	42,125	11.52
2006-07	3,739,400	54,200	1.47	49,404	13.31	31,396	8.46	18,008	36,192	9.75
2007-08	3,784,200	44,800	1.20	49,659	13.20	32,008	8.51	17,651	27,149	7.22
2008-09	3,815,800	31,600	0.84	47,960	12.62	31,382	8.26	16,578	15,022	3.95
2009-10	3,837,300	21,500	0.56	46,256	12.09	31,689	8.28	14,567	6,933	1.81
2005-10		**210,400**		**240,225**		**157,246**		**82,979**	**127,421**	**6.80**
2010-11	3,872,700	35,400	0.92	45,381	11.77	32,437	8.41	12,944	22,456	5.83
2011-12	3,900,100	27,400	0.71	44,897	11.55	32,804	8.44	12,093	15,307	3.94
2012-13	3,924,100	24,000	0.62	44,969	11.49	33,168	8.48	11,801	12,199	3.12
2013-14	3,965,400	41,300	1.05	45,447	11.52	33,731	8.55	11,716	29,584	7.50
2014-15	4,018,500	53,100	1.34	45,660	11.44	35,318	8.85	10,342	42,758	10.71
2010-15		**181,200**		**226,354**		**167,458**		**58,896**	**122,304**	**6.24**
2015-16	4,093,200	74,700	1.86	45,647	11.25	35,339	8.71	10,308	64,392	15.88
2016-17	4,147,200	54,000	1.32	44,602	10.83	36,773	8.93	7,829	46,171	11.21
2017-18	4,183,400	36,200	0.87	42,906	10.30	36,268	8.71	6,638	29,562	7.10
2018-19	4,216,000	32,599	0.78	42,220	10.05	36,622	8.72	5,598	27,001	6.43
2019-20	4,240,296	24,296	0.58	40,920	9.68	37,821	8.95	3,099	21,197	5.01
2015-20		**221,796**		**216,295**		**182,823**		**33,472**	**188,324**	**9.08**
2020-21	4,221,334	-18,962	-0.45	39,654	9.37	41,893	9.90	-2,239	-16,723	-3.95
2021-22	4,236,503	15,169	0.36	40,470	9.57	46,351	10.96	-5,881	21,050	4.98
2022-23	4,254,095	17,592	0.42	38,756	9.13	43,521	10.25	-4,765	22,357	5.27
2023-24	4,267,261	13,166	0.31	38,799	9.11	42,577	9.99	-3,778	16,944	3.98
2024-25	4,280,600	13,339	0.31	39,322	9.20	42,746	10.00	-3,424	16,763	3.92
2020-25		**40,304**		**197,001**		**217,088**		**-20,087**	**60,391**	**2.84**
2025-26	4,300,300	19,699	0.46	39,342	9.17	43,084	10.04	-3,743	23,442	5.46
2026-27	4,324,000	23,701	0.55	39,420	9.14	43,438	10.07	-4,018	27,719	6.43
2027-28	4,351,100	27,100	0.63	39,532	9.11	43,910	10.12	-4,379	31,478	7.26
2028-29	4,378,800	27,700	0.64	39,667	9.09	44,434	10.18	-4,767	32,467	7.44
2029-30	4,405,800	27,000	0.62	39,792	9.06	44,970	10.24	-5,178	32,178	7.33
2025-30		**125,199**		**197,751**		**219,837**		**-22,085**	**147,285**	**6.79**
2030-31	4,429,900	24,100	0.55	39,906	9.03	45,522	10.30	-5,616	29,716	6.73
2031-32	4,452,900	23,000	0.52	40,001	9.01	46,062	10.37	-6,060	29,060	6.54
2032-33	4,474,700	21,800	0.49	40,084	8.98	46,597	10.44	-6,513	28,313	6.34
2033-34	4,495,700	21,000	0.47	40,133	8.95	47,125	10.51	-6,992	27,992	6.24
2034-35	4,515,800	20,100	0.45	40,121	8.90	47,647	10.57	-7,526	27,626	6.13
2030-35		**110,000**		**200,246**		**232,953**		**-32,707**	**142,708**	**6.40**

Sources: 1980-2019 intercensal population estimates by the U.S. Census Bureau; 2020-2024 population by Population Resear Center, PSU; births and deaths 1990-2023: Oregon Center for Health Statistics. Forecaasts of population, births, deaths, and net migration are by the Oregon Office of Economic Analysis.

IMPORTANT: PRC/PSU revised the prior estimates for the years 2020 through 2024 for Oregon and its counties in April, 2025. PRC/PSU estimates are here: https://www.pdx.edu/population-research/population-estimate-reports

NOTE: The Census Bureau's 2010-2019 intercensal estimates of total population in November 2024 and.the estimates by single year of age are expected in the Fall of 2025.

Table C.2 Population Forecasts by Age and Sex: 2010-2035

	2020			2021			2022			2023			2024			2025		
Age	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total
0-4	111,915	106,892	218,807	107,901	102,924	210,825	105,975	100,925	206,900	103,746	98,782	202,528	101,981	96,972	198,953	101,196	96,281	197,477
5- 9	124,639	118,396	243,035	122,465	116,990	239,455	120,989	115,543	236,532	119,177	113,599	232,775	116,730	111,177	227,907	113,562	107,834	221,396
10-14	132,195	125,117	257,312	131,011	124,162	255,173	130,214	123,094	253,308	128,946	121,622	250,568	127,587	120,326	247,913	126,572	119,499	246,071
15-19	130,545	125,563	256,108	128,868	122,594	251,462	130,531	123,641	254,172	132,679	125,629	258,308	133,930	126,699	260,629	134,609	127,257	261,866
20-24	135,121	132,107	267,228	134,196	132,062	266,257	134,293	132,499	266,791	134,092	131,943	266,035	133,399	130,504	263,902	132,446	128,184	260,630
25-29	145,603	142,009	287,612	140,161	137,028	277,189	138,052	134,499	272,551	137,158	133,220	270,378	136,983	133,199	270,182	137,214	134,413	271,627
30-34	152,673	148,902	301,575	151,415	148,308	299,723	153,087	149,380	302,467	153,923	149,523	303,446	152,769	148,105	300,874	150,068	145,448	295,516
35-39	150,269	148,083	298,351	150,272	147,406	297,678	150,724	147,804	298,528	151,372	148,449	299,821	152,353	149,293	301,646	153,934	150,469	304,403
40-44	138,155	136,490	274,645	140,916	139,386	280,303	143,989	142,908	286,897	146,405	145,978	292,382	148,266	148,079	296,345	149,725	149,228	298,953
45-49	130,040	127,316	257,356	128,156	125,823	253,979	128,471	126,789	255,260	130,607	129,275	259,882	133,591	132,575	266,166	137,090	136,619	273,709
50-54	125,542	125,774	251,315	127,544	127,013	254,557	129,293	128,395	257,688	129,850	128,808	258,657	129,180	128,094	257,274	127,793	126,726	254,518
55-59	128,333	134,690	263,023	124,786	130,040	254,826	121,996	126,581	248,577	120,109	124,042	244,150	119,886	123,222	243,109	121,777	124,551	246,328
60-64	130,342	142,988	273,330	128,498	140,640	269,138	127,027	139,031	266,058	125,656	137,174	262,830	124,220	134,855	259,075	122,172	131,905	254,077
65-69	125,136	139,203	264,340	125,018	139,955	264,973	124,813	140,424	265,237	124,008	140,037	264,045	122,684	138,966	261,651	121,593	137,885	259,477
70-74	102,924	114,480	217,404	106,828	119,455	226,283	108,891	122,625	231,516	110,370	125,286	235,656	112,031	128,198	240,228	113,426	130,740	244,166
75-79	65,311	75,551	140,863	68,492	79,426	147,918	73,259	84,985	158,245	78,389	91,052	169,441	82,973	96,644	179,617	87,692	102,456	190,148
80-84	38,031	46,661	84,693	39,624	48,686	88,310	41,655	51,401	93,056	44,481	54,963	99,444	47,332	58,693	106,025	49,731	61,981	111,712
85+	31,785	51,513	83,298	32,134	51,151	83,285	32,157	50,562	82,719	32,783	50,964	83,747	33,876	51,889	85,765	35,291	53,235	88,526
Total	2,098,560	2,141,736	4,240,296	2,088,285	2,133,049	4,221,334	2,095,418	2,141,085	4,236,503	2,103,750	2,150,345	4,254,095	2,109,773	2,157,488	4,267,261	2,115,889	2,164,712	4,280,600
Mdn. Age	38.9	40.8	39.8	39.2	41.2	40.2	39.5	41.5	40.5	39.7	41.8	40.7	40.0	42.1	41.0	40.3	42.4	41.3

	2026			2027			2028			2029			2030			2031		
Age	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total
0-4	101,179	96,237	197,415	100,775	95,829	196,605	101,349	96,342	197,690	101,940	96,876	198,816	102,262	97,165	199,428	102,550	97,439	199,989
5- 9	110,379	104,453	214,831	108,614	102,525	211,138	106,600	100,488	207,089	105,157	98,880	204,037	104,676	98,402	203,078	104,766	98,446	203,211
10-14	125,739	118,786	244,524	124,429	117,459	241,888	122,846	115,661	238,507	120,819	113,461	234,280	118,025	110,293	228,319	114,909	106,916	221,826
15-19	134,873	127,373	262,246	134,401	126,585	260,986	133,538	125,460	258,999	132,748	124,615	257,363	132,245	124,173	256,419	131,557	123,550	255,107
20-24	132,670	126,969	259,639	134,655	128,364	263,019	137,259	130,875	268,135	139,301	132,753	272,053	140,778	134,084	274,863	141,387	134,503	275,890
25-29	137,960	136,197	274,157	138,549	136,986	275,535	138,926	136,836	275,762	138,940	136,026	274,966	138,570	134,261	272,831	138,980	133,223	272,203
30-34	147,552	142,631	290,183	146,013	140,417	286,430	146,007	139,681	285,688	147,199	140,619	287,818	148,720	142,824	291,544	150,014	145,091	295,105
35-39	156,025	152,092	308,118	157,904	153,427	311,331	158,957	153,859	312,817	158,694	153,089	311,784	157,093	151,120	308,213	155,114	148,552	303,666
40-44	150,722	149,980	300,702	151,411	150,671	302,082	152,301	151,692	303,993	153,655	153,139	306,795	155,625	154,924	310,549	157,898	156,835	314,733
45-49	140,813	140,787	281,600	144,087	144,519	288,605	146,742	147,834	294,576	149,023	150,421	299,444	150,931	152,103	303,034	152,156	153,119	305,276
50-54	126,661	126,039	252,700	127,206	127,235	254,440	129,554	129,986	259,540	132,844	133,666	266,509	136,657	138,094	274,752	140,538	142,459	282,997
55-59	124,523	126,833	251,356	126,528	128,527	255,055	127,362	129,294	256,656	127,094	129,063	256,157	126,118	128,138	254,256	125,214	127,644	252,858
60-64	119,668	128,639	248,306	117,364	125,570	242,934	115,892	123,421	239,313	116,118	123,148	239,266	118,393	125,021	243,414	121,321	127,583	248,904
65-69	120,835	136,965	257,800	119,951	135,824	255,776	119,095	134,422	253,517	118,240	132,719	250,959	116,770	130,380	247,150	114,663	127,449	242,111
70-74	114,348	132,557	246,905	114,704	133,433	248,138	114,426	133,437	247,864	113,765	132,925	246,690	113,320	132,427	245,748	112,996	131,884	244,880
75-79	91,716	107,581	199,297	94,094	110,984	205,078	95,880	113,860	209,740	97,852	116,985	214,837	99,594	119,771	219,365	100,797	121,767	222,564
80-84	52,655	65,701	118,356	56,978	70,940	127,918	61,518	76,551	138,069	65,603	81,736	147,339	69,756	87,063	156,819	73,304	91,738	165,043
85+	36,965	55,196	92,162	39,091	57,951	97,042	41,751	61,394	103,145	44,611	65,077	109,688	47,356	68,664	116,019	50,598	72,940	123,538
Total	2,125,281	2,175,018	4,300,300	2,136,756	2,187,244	4,324,000	2,150,005	2,201,095	4,351,100	2,163,602	2,215,198	4,378,800	2,176,890	2,228,909	4,405,800	2,188,762	2,241,138	4,429,900
Mdn. Age	40.5	42.7	41.6	40.8	43.0	41.9	41.0	43.4	42.2	41.2	43.6	42.4	41.4	43.9	42.7	41.7	44.2	42.9

	2032			2033			2034			2035		
Age	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total
0-4	102,824	97,704	200,527	103,073	97,949	201,022	103,286	98,158	201,445	103,439	98,308	201,747
5- 9	104,340	98,044	202,384	104,841	98,514	203,355	105,341	98,987	204,329	105,566	99,211	204,777
10-14	113,108	104,949	218,057	110,910	102,806	213,716	109,267	101,086	210,353	108,625	100,524	209,150
15-19	130,193	122,161	252,355	128,396	120,179	248,575	126,106	117,759	243,865	123,025	114,347	237,372
20-24	140,973	133,715	274,687	139,919	132,353	272,272	138,871	131,230	270,101	138,125	130,539	268,663
25-29	141,053	134,724	275,777	143,608	137,207	280,816	145,539	138,962	284,501	146,892	140,141	287,033
30-34	150,714	145,986	296,700	150,809	145,598	296,407	150,406	144,428	294,833	149,610	142,265	291,875
35-39	153,757	146,365	300,123	153,627	145,492	299,119	154,627	146,289	300,916	155,945	148,383	304,327
40-44	159,854	158,262	318,116	160,878	158,590	319,468	160,544	157,634	318,177	158,849	155,445	314,295
45-49	152,934	153,910	306,843	153,793	154,883	308,675	155,089	156,243	311,332	157,015	157,946	314,961
50-54	143,886	146,284	290,170	146,536	149,595	296,132	148,793	152,142	300,934	150,679	153,771	304,450
55-59	125,868	128,923	254,791	128,221	131,664	259,885	131,484	135,313	266,797	135,272	139,719	274,991
60-64	123,417	129,392	252,809	124,279	130,126	254,405	124,050	129,824	253,874	123,148	128,839	251,987
65-69	112,641	124,558	237,200	111,335	122,457	233,792	111,645	122,186	233,831	113,926	124,047	237,973
70-74	112,436	131,004	243,440	111,797	129,759	241,555	111,120	128,181	239,301	109,863	125,983	235,846
75-79	101,442	122,842	224,284	101,471	123,070	224,541	101,143	122,808	223,951	101,013	122,559	223,573
80-84	75,602	95,008	170,610	77,442	97,847	175,290	79,413	100,873	180,286	81,190	103,590	184,779
85+	55,115	78,911	134,026	60,097	85,579	145,676	64,859	92,015	156,874	69,571	98,430	168,001
Total	2,200,157	2,252,743	4,452,900	2,211,031	2,263,670	4,474,700	2,221,581	2,274,119	4,495,700	2,231,752	2,284,048	4,515,800
Mdn. Age	42.0	44.5	43.2	42.2	44.8	43.5	42.5	45.1	43.8	42.7	45.4	44.1

Table C.3 Population of Oregon: 1990-2035

Year (July 1)	Total Population	Change from previous year Number	Percent
1990	2,860,400	-	-
1991	2,928,500	68,100	2.38%
1992	2,991,800	63,300	2.16%
1993	3,060,400	68,600	2.29%
1994	3,121,300	60,900	1.99%
1995	3,184,400	63,100	2.02%
1996	3,247,100	62,700	1.97%
1997	3,304,300	57,200	1.76%
1998	3,352,400	48,100	1.46%
1999	3,393,900	41,500	1.24%
2000	3,431,100	37,200	1.10%
2001	3,470,400	39,300	1.15%
2002	3,502,600	32,200	0.93%
2003	3,538,600	36,000	1.03%
2004	3,578,900	40,300	1.14%
2005	3,626,900	48,000	1.34%
2006	3,685,200	58,300	1.61%
2007	3,739,400	54,200	1.47%
2008	3,784,200	44,800	1.20%
2009	3,815,800	31,600	0.84%
2010	3,837,300	21,500	0.56%
2011	3,872,700	35,400	0.92%
2012	3,900,100	27,400	0.71%
2013	3,924,100	24,000	0.62%
2014	3,965,400	41,300	1.05%
2015	4,018,500	53,100	1.34%
2016	4,093,200	74,700	1.86%
2017	4,147,200	54,000	1.32%
2018	4,183,400	36,200	0.87%
2019	4,216,000	32,599	0.78%
2020	4,240,296	24,296	0.58%
2021	4,221,334	-18,962	-0.45%
2022	4,236,503	15,169	0.36%
2023	4,254,095	17,592	0.42%
2024	4,267,261	13,166	0.31%
2025	4,280,600	13,339	0.31%
2026	4,300,300	19,699	0.46%
2027	4,324,000	23,701	0.55%
2028	4,351,100	27,100	0.63%
2029	4,378,800	27,700	0.64%
2030	4,405,800	27,000	0.62%
2031	4,429,900	24,101	0.55%
2032	4,452,900	23,000	0.52%
2033	4,474,700	21,800	0.49%
2034	4,495,700	20,999	0.47%
2035	4,515,800	20,100	0.45%

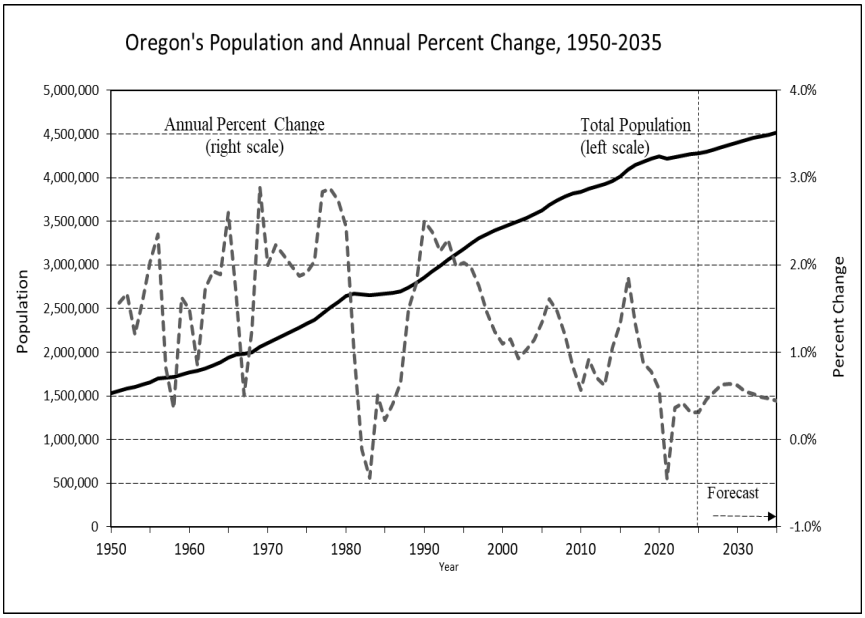

Table C.4 Children: Ages 0-4

Table C.5 School Age Population: Ages 5-17

Table C.6 Young Adult Population: Ages 18-24

Year (July 1)	Population	% Change from previous decade/yr. Number	Percent	Population	% Change from previous decade/yr. Number	Percent	Population	% Change from previous decade/yr. Number	Percent
1980	199,525	---	---	524,446	---	---	329,407	---	---
1990	209,638	10,113	5.07%	532,727	8,281	1.58%	268,134	-61,273	-18.60%
2000	223,207	13,569	6.47%	624,316	91,589	17.19%	330,328	62,194	23.20%
2010	238,443	15,236	6.83%	631,132	6,815	1.09%	359,854	29,526	8.94%
2011	237,025	-1,418	-0.59%	632,768	1,637	0.26%	362,539	2,685	0.75%
2012	233,718	-3,307	-1.40%	634,848	2,080	0.33%	364,881	2,342	0.65%
2013	230,245	-3,474	-1.49%	636,043	1,194	0.19%	367,398	2,517	0.69%
2014	229,266	-979	-0.43%	638,822	2,780	0.44%	369,948	2,550	0.69%
2015	229,564	298	0.13%	642,298	3,476	0.54%	372,011	2,063	0.56%
2016	231,814	2,250	0.98%	648,018	5,720	0.89%	374,147	2,136	0.57%
2017	232,124	310	0.13%	650,561	2,544	0.39%	375,736	1,588	0.42%
2018	229,135	-2,989	-1.29%	649,580	-982	-0.15%	376,274	539	0.14%
2019	224,616	-4,520	-1.97%	650,249	669	0.10%	375,249	-1,025	-0.27%
2020	218,807	-5,808	-2.59%	651,388	1,139	0.18%	372,296	-2,953	-0.79%
2021	210,825	-7,982	-3.65%	645,612	-5,776	-0.89%	366,735	-5,560	-1.49%
2022	206,900	-3,925	-1.86%	643,360	-2,252	-0.35%	367,444	709	0.19%
2023	202,528	-4,371	-2.11%	639,726	-3,634	-0.56%	367,960	516	0.14%
2024	198,953	-3,575	-1.77%	633,589	-6,137	-0.96%	366,762	-1,198	-0.33%
2025	197,477	-1,476	-0.74%	624,413	-9,176	-1.45%	365,550	-1,212	-0.33%
2026	197,415	-62	-0.03%	614,448	-9,965	-1.60%	366,792	1,242	0.34%
2027	196,605	-811	-0.41%	606,439	-8,009	-1.30%	370,592	3,799	1.04%
2028	197,690	1,086	0.55%	597,857	-8,583	-1.42%	374,873	4,281	1.16%
2029	198,816	1,126	0.57%	590,072	-7,784	-1.30%	377,661	2,788	0.74%
2030	199,428	612	0.31%	583,150	-6,923	-1.17%	379,529	1,867	0.49%
2031	199,989	561	0.28%	576,137	-7,013	-1.20%	379,897	369	0.10%
2032	200,527	538	0.27%	569,107	-7,030	-1.22%	378,377	-1,520	-0.40%
2033	201,022	494	0.25%	561,887	-7,220	-1.27%	376,031	-2,346	-0.62%
2034	201,445	423	0.21%	555,500	-6,386	-1.14%	373,148	-2,883	-0.77%
2035	201,747	302	0.15%	550,955	-4,545	-0.82%	369,007	-4,141	-1.11%

Table C.7 Criminally At-Risk Population (males): Ages 15-39

Table C.8 Prime Wage Earners: Ages 25-44

Table C.9 Older Wage Earners: Ages 45-64

Year (July 1)	Table C.7 Population	Table C.7 % Change from previous decade/yr. Number	Table C.7 % Change from previous decade/yr. Percent	Table C.8 Population	Table C.8 % Change from previous decade/yr. Number	Table C.8 % Change from previous decade/yr. Percent	Table C.9 Population	Table C.9 % Change from previous decade/yr. Number	Table C.9 % Change from previous decade/yr. Percent
1980	561,931	---	---	790,750	---	---	491,249	---	---
1990	544,738	-17,193	-3.06%	926,326	135,576	17.15%	531,181	39,932	8.13%
2000	616,988	72,250	13.26%	996,500	70,174	7.58%	817,510	286,329	53.90%
2010	653,357	36,370	5.89%	1,025,787	29,287	2.94%	1,049,941	232,431	28.43%
2011	654,254	897	0.14%	1,032,760	6,973	0.68%	1,060,368	10,428	0.99%
2012	656,074	1,820	0.28%	1,038,435	5,675	0.55%	1,055,522	-4,846	-0.46%
2013	659,512	3,437	0.52%	1,044,222	5,787	0.56%	1,049,177	-6,345	-0.60%
2014	667,013	7,502	1.14%	1,054,896	10,674	1.02%	1,050,631	1,454	0.14%
2015	676,749	9,735	1.46%	1,068,810	13,914	1.32%	1,056,585	5,954	0.57%
2016	690,908	14,159	2.09%	1,092,436	23,627	2.21%	1,067,462	10,876	1.03%
2017	701,566	10,657	1.54%	1,114,454	22,017	2.02%	1,066,781	-681	-0.06%
2018	707,231	5,666	0.81%	1,132,587	18,133	1.63%	1,059,475	-7,306	-0.68%
2019	712,352	5,120	0.72%	1,148,691	16,104	1.42%	1,051,630	-7,845	-0.74%
2020	714,211	1,859	0.26%	1,162,184	13,493	1.17%	1,045,024	-6,605	-0.63%
2021	704,912	-9,299	-1.30%	1,154,893	-7,291	-0.63%	1,032,500	-12,525	-1.20%
2022	706,688	1,776	0.25%	1,160,444	5,551	0.48%	1,027,583	-4,917	-0.48%
2023	709,224	2,537	0.36%	1,166,028	5,584	0.48%	1,025,520	-2,063	-0.20%
2024	709,434	210	0.03%	1,169,046	3,018	0.26%	1,025,623	103	0.01%
2025	708,271	-1,163	-0.16%	1,170,498	1,452	0.12%	1,028,632	3,009	0.29%
2026	709,079	809	0.11%	1,173,160	2,662	0.23%	1,033,963	5,331	0.52%
2027	711,522	2,443	0.34%	1,175,379	2,219	0.19%	1,041,034	7,072	0.68%
2028	714,689	3,166	0.44%	1,178,261	2,882	0.25%	1,050,086	9,051	0.87%
2029	716,881	2,193	0.31%	1,181,362	3,101	0.26%	1,061,376	11,291	1.08%
2030	717,407	525	0.07%	1,183,137	1,774	0.15%	1,075,456	14,080	1.33%
2031	717,052	-355	-0.05%	1,185,706	2,570	0.22%	1,090,036	14,579	1.36%
2032	716,690	-361	-0.05%	1,190,716	5,010	0.42%	1,104,614	14,579	1.34%
2033	716,359	-332	-0.05%	1,195,810	5,093	0.43%	1,119,097	14,483	1.31%
2034	715,548	-811	-0.11%	1,198,427	2,618	0.22%	1,132,937	13,841	1.24%
2035	713,596	-1,952	-0.27%	1,197,530	-898	-0.07%	1,146,389	13,452	1.19%

Table C.10 Elderly Population by Age Group

Year (July 1)	Ages 65+	%Change from previous decade/yr.	Ages 65-74	%Change from previous decade/yr.	Ages 75-84	%Change from previous decade/yr.	Ages 85+	%Change from previous decade/yr.
1980	305,841	---	185,863	---	91,137	---	28,841	---
1990	392,369	28.29%	224,772	20.93%	128,813	41.34%	38,784	34.48%
2000	439,239	11.95%	218,997	-2.57%	162,187	25.91%	58,055	49.69%
2010	532,145	21.15%	289,744	32.31%	164,244	1.27%	78,156	34.62%
2011	547,239	2.84%	302,099	4.26%	165,476	0.75%	79,664	1.93%
2012	572,696	4.65%	324,844	7.53%	167,189	1.04%	80,663	1.25%
2013	597,016	4.25%	346,105	6.55%	169,663	1.48%	81,248	0.72%
2014	621,837	4.16%	366,153	5.79%	174,052	2.59%	81,632	0.47%
2015	649,233	4.41%	388,002	5.97%	179,353	3.05%	81,878	0.30%
2016	679,324	4.63%	410,279	5.74%	186,278	3.86%	82,767	1.09%
2017	707,545	4.15%	430,698	4.98%	194,088	4.19%	82,759	-0.01%
2018	736,350	4.07%	448,385	4.11%	205,211	5.73%	82,754	-0.01%
2019	765,566	3.97%	465,975	3.92%	216,829	5.66%	82,762	0.01%
2020	790,596	3.27%	481,743	3.38%	225,555	4.02%	83,298	0.65%
2021	810,769	2.55%	491,256	1.97%	236,228	4.73%	83,285	-0.01%
2022	830,773	2.47%	496,753	1.12%	251,301	6.38%	82,719	-0.68%
2023	852,333	2.60%	499,701	0.59%	268,885	7.00%	83,747	1.24%
2024	873,287	2.46%	501,879	0.44%	285,643	6.23%	85,765	2.41%
2025	894,029	2.38%	503,644	0.35%	301,860	5.68%	88,526	3.22%
2026	914,520	2.29%	504,705	0.21%	317,653	5.23%	92,162	4.11%
2027	933,951	2.12%	503,913	-0.16%	332,996	4.83%	97,042	5.30%
2028	952,334	1.97%	501,380	-0.50%	347,809	4.45%	103,145	6.29%
2029	969,512	1.80%	497,649	-0.74%	362,175	4.13%	109,688	6.34%
2030	985,101	1.61%	492,898	-0.95%	376,184	3.87%	116,019	5.77%
2031	998,136	1.32%	486,991	-1.20%	387,606	3.04%	123,538	6.48%
2032	1,009,559	1.14%	480,640	-1.30%	394,893	1.88%	134,026	8.49%
2033	1,020,855	1.12%	475,348	-1.10%	399,830	1.25%	145,676	8.69%
2034	1,034,242	1.31%	473,131	-0.47%	404,237	1.10%	156,874	7.69%
2035	1,050,172	1.54%	473,819	0.15%	408,352	1.02%	168,001	7.09%

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE EXPENSE

Exh. TFD-4C

REDACTED VERSION

August 29, 2025

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY (PAGES 1-14)
UNDER WAC 480-07-160 AND HAS BEEN REDACTED.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE EXPENSE

Exh. TFD-5C

REDACTED VERSION

August 29, 2025

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY (PAGES 1-6)
UNDER WAC 480-07-160 AND HAS BEEN REDACTED.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Direct Testimony of John J. Spanos

DEPRECIATION

Exh. JJS-1T

August 29, 2025

DIRECT TESTIMONY OF JOHN J. SPANOS

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I. INTRODUCTION

Q. Please state your name and address.

A. John J. Spanos. My business address is 300 Sterling Parkway, Mechanicsburg, Pennsylvania (formerly 207 Senate Avenue, Camp Hill, Pennsylvania).

Q. With what firm are you associated?

A. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming").

Q. How long have you been associated with Gannett Fleming?

A. I have been associated with the firm since June 1986.

Q. What is your position in the firm?

A. I am President.

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College of Pennsylvania.

Q. Are you a member of any professional societies?

A. Yes. I am a Past President and member of the Society of Depreciation Professionals. I am also a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Have you taken the certification examination for depreciation professionals?

A. Yes. I passed the certification examination of the Society of Depreciation Professionals in September 1997 and was recertified in August 2003, February 2008, January 2013, February 2018 and February 2023.

Q. Will you outline your experience in the field of depreciation?

A. Yes. I have over 38 years of depreciation experience which includes giving expert testimony in more than 490 cases before 47 regulatory commissions, including this Commission. These cases have included depreciation studies in the electric, gas, water, wastewater and pipeline industries. In addition to cases where I have submitted testimony, I have also supervised over 900 other depreciation or valuation assignments. Please refer to Exh. JJS-2 for my qualifications statement, which includes further information with respect to my work history, case experience, and leadership in the Society of Depreciation Professionals.

Q. What is the purpose of your testimony?

A. My testimony is in support of the gas depreciation study conducted under my direction and supervision for Northwest Natural Gas Company (the "Company"). Based upon the study, I am recommending that new depreciation accrual rates be adopted by the Company.

II. OVERVIEW

Q. Please define the concept of depreciation.

A. Depreciation refers to the loss in service value that is not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation, against which the Company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and the requirements of public authorities.

Q. Have you prepared an exhibit with your testimony?

A. Yes. The report titled, "2023 Depreciation Study – Calculated Annual Depreciation Accruals Related to Gas Plant as of December 31, 2023," which has been marked Exh. JJS-3, sets forth the results of my depreciation study. I will refer to this report throughout my testimony as the "Depreciation Study."

Q. Please describe the contents of the Depreciation Study.

A. The Depreciation Study is presented in nine parts. Part I, Introduction, contains statements with respect to the plan of the report and the basis of the study. Part II, Estimation of Survivor Curves, presents descriptions of the considerations and the methods used in the service life and net salvage studies. Part III, Service Life Considerations, presents the factors and judgment utilized in the average service life analysis. Part IV, Net Salvage Considerations, presents the judgment utilized for the net salvage study. Part V, Calculation of Annual and Accrued Depreciation, describes the procedures used in the calculation of group depreciation. Part VI, Results of Study, presents summaries by depreciable group of annual depreciation accrual rates and amounts, as well as composite remaining lives. Part VII, Service Life Statistics, presents the statistical analysis of service life estimates. Part VIII, Net Salvage Statistics, sets forth the statistical indications of net salvage percents. Part IX, Detailed Depreciation Calculations, presents the detailed tabulations of annual depreciation.

The table on Pages VI-5 through VI-8 of the Depreciation Study presents the estimated survivor curve, the net salvage percent, the original cost as of December 31, 2023, the book depreciation reserve, and the calculated annual depreciation accrual amount and rate for each account or subaccount. The section beginning on Page VII-

2 of the Depreciation Study presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on Page VIII-2 of the Depreciation Study presents the results of the net salvage analysis. The section beginning on Page IX-2 of the Depreciation Study presents the depreciation calculations related to surviving original cost as of December 31, 2023.

In the Depreciation Study that I performed, and which is the basis for my testimony, I used the straight line remaining life method of depreciation, with the average service life procedure to develop recommended depreciation accrual rates. The total annual depreciation is based on a system of depreciation accounting which aims to distribute the cost of fixed capital assets over the estimated useful life of the unit, or group of assets, in a systematic and rational manner.

For General Plant Accounts 391.10, 391.20, 391.21, 392.22, 393.00, 394.00, 397.00, 397.10, 397.20, 397.30, 397.40, 397.50, 398.10, 398.20, 398.30, 398.40 and 398.50 for gas assets, I used the straight line method of amortization. The annual amortization is based on amortization accounting which distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account and vintage.

Q. How did you determine the recommended annual depreciation accrual rates?

A. The determination of annual depreciation accrual rates consists of two phases. In the first phase, service life and net salvage characteristics are estimated for each depreciable group, that is, each plant account or subaccount identified as having similar characteristics. In the second phase, the annual depreciation accrual rates are calculated based on the service life and net salvage estimates determined in the first phase.

III. ESTIMATION OF SERVICE LIFE AND NET SALVAGE

Q. Please describe the first phase of each study, that is, the manner in which you estimated the service life and net salvage characteristics for each depreciable group.

A. The service life studies consisted of compiling historical data from records related to the Company's plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning the Company's practices and plans as they relate to plant operations; and interpreting the above data and the estimates used by other gas utilities to form judgments of average service life and net salvage characteristics.

Q. What historical data did you analyze for the purpose of estimating the service life characteristics of the Company's plant?

A. The data consisted of the entries made by the Company to record plant transactions through 2023. The transactions included additions, retirements, transfers and the related balances. The Company, in accordance with my instructions, classified the data by depreciable group, type of transaction, the year in which the transaction took place, and the year in which the plant was installed.

Q. Was there any emphasis on other factors in this study?

A. Yes. First, we focused on the results from the last depreciation study in 2020, docketed as UG-210974, which was adopted by the Commission in Order No. 01, entered October 26, 2023. Second, we considered changes to certain assets to better align with the expected useful life and because NW Natural's current expected depreciable life for a service line is an industry outlier among natural gas utilities.

Q. What method did you use to analyze this service life data?

A. I used the retirement rate method. That method is the most appropriate when aged retirement data are available, because it develops the average rates of retirement actually experienced during the period of study. Other methods of life analysis infer the rates of retirement based on a selected type of survivor curve.

Q. Please describe the results of your use of the retirement rate method.

A. Each retirement rate analysis resulted in a life table which, when plotted, formed an original survivor curve. Each original survivor curve as plotted from the life table represents the average survivor pattern experienced by the several vintage groups during the experience band studied. Inasmuch as this survivor pattern does not necessarily describe the life characteristics of the property group, interpretation of the original curves is required in order to use them as valid considerations in service life estimation. Iowa-type survivor curves were used in these interpretations.

Q. What is an "Iowa-type survivor curve" and how did you use such curves to estimate the service life characteristics for each property group?

A. Iowa-type survivor curves are a widely used group of generalized survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. The Iowa survivor curves were developed at the Iowa State University College of Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired. Iowa-type survivor curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa survivor curves and truncated Iowa survivor curves were used in

the Depreciation Study to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements. As I will explain, the use of truncated curves is appropriate to reflect retirements of plant components that may not be fully depreciated at the time a plant is retired.

The estimated survivor curve designations for each depreciable group indicate the average service life, the family within the Iowa system and the relative height of the mode. For example, the Iowa 58-R2 indicates an average service life of fifty-eight years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a low height, 2, for the mode (possible modes for R type curves range from 1 to 5).

Q. What approach did you use to estimate the lives of significant facilities such as storage facilities?

A. I used the life span technique to estimate the lives of significant facilities for which concurrent retirement of the entire facility is anticipated. In this technique, the survivor characteristics of such facilities are described by the use of interim survivor curves and estimated probable retirement dates.

The interim survivor curves describe the rate of retirement related to the replacement of elements of the facility, such as, for a building, the retirements of plumbing, heating, doors, windows, roofs, etc., that occurs during the life of the facility. The probable retirement date provides the rate of final retirement for each year of installation for the facility by truncating the interim survivor curve for each installation year at its attained age at the date of probable retirement. The use of interim survivor curves truncated at the date of probable retirement provides a consistent method for

estimating the lives of the several years of installation for a particular facility inasmuch as a single concurrent retirement for all years of installation will occur when it is retired.

Q. Has this approach been adopted in other regulatory proceedings?

A. Yes. My firm has used the life span technique in performing depreciation studies presented to and accepted by many public utility commissions across the United States and Canada, including this Commission.

Q. What are the bases for the probable retirement years that you have estimated for each facility?

A. The bases for the probable retirement years are life spans for each facility that are based on judgment and incorporate consideration of the age, use, size, nature of construction, management outlook and typical life spans experienced and used by other gas utilities for similar facilities. At the appropriate time, detailed studies of the economics of rehabilitation and continued use or retirement of the structure will be performed and the results incorporated in the estimation of the facility's life span.

Q. Have you physically observed the Company's plants and equipment as part of your depreciation work?

A. Yes. The most recent field review of the Company's property was on September 28 and 29, 2021 in order to observe representative portions of plant. Field reviews are conducted to become familiar with Company operations and obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. This knowledge, as well as information from other discussions with management, was incorporated in the interpretation and extrapolation of the statistical analyses.

Q. How did your experience in development of other depreciation studies affect your work in this case?

A. Because I customarily conduct field reviews for my depreciation studies, I have had the opportunity to visit scores of similar plants and meet with operations personnel at other companies. The knowledge accumulated from those visits and meetings provide me useful information that I can draw on to confirm or challenge my numerical analyses concerning plant condition and remaining life estimates.

Q. Would you please explain the concept of "net salvage"?

A. Net salvage is a component of the service value of capital assets that is recovered through depreciation rates. The service value of an asset is its original cost less its net salvage. Net salvage is the salvage value received for the asset upon retirement less the cost to retire the asset. When the cost to retire exceeds the salvage value, the result is negative net salvage.

Inasmuch as depreciation expense is the loss in service value of an asset during a defined period, *e.g.,* one year, it must include a ratable portion of both the original cost and the net salvage. That is, the net salvage related to an asset should be incorporated in the cost of service during the same period as its original cost so that customers receiving service from the asset pay rates that include a portion of both elements of the asset's service value, the original cost and the net salvage value.

For example, the full recovery of the service value of a $10,000 regulator will include not only the $10,000 of original cost, but also, on average, $550 to remove the regulator at the end of its life and $50 in salvage value. In this example, the net salvage

component is negative $500 ($50 - $550), and the net salvage percent is negative 5 percent (($50 - $550)/$10,000).

Q. Please describe how you estimated net salvage percentages.

A. I estimated the net salvage percentages based on judgment. In doing so, for most accounts, I incorporated analyses of the historical data for the period 1993 through 2023 for gas plant and considered estimates for other gas companies. In the historical analyses, the net salvage, cost of removal and gross salvage amounts were expressed as percents of the original cost retired. These percents were calculated on annual and three-year moving average bases for the 1993-1995 through 2021-2023 periods.

IV. CALCULATION OF DEPRECIATION

Q. Please describe the second phase of the process that you used, that is, the calculation of annual depreciation accrual rates.

A. After I estimated the service life and net salvage characteristics for each depreciable group, I calculated annual depreciation accrual rates for each group in accordance with the straight line remaining life method, using the average service life procedure. The annual depreciation accrual rates were developed as of December 31, 2023.

Q. Please describe the straight line remaining life method of depreciation.

A. The straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life.

Q. Please describe the average service life procedure for calculating remaining life accrual rates.

A. The average service life procedure defines the group for which the remaining life annual accrual is determined. Under this procedure, the annual accrual rate is determined for the entire group or account based on its average remaining life and this rate is applied to the surviving balance of the group's cost. The average remaining life of the group is calculated by first dividing the future book accruals (original cost less allocated book reserve less future net salvage) by the average remaining life for each vintage. The average remaining life for each vintage is derived from the area under the survivor curve between the attained age of the vintage and the maximum age. Then, the sum of the future book accruals is divided by the sum of the annual accruals to determine the average remaining life of the entire group for use in calculating the annual depreciation accrual rate.

Q. Please briefly describe the amortization of certain General Plant accounts.

A. For General Plant Accounts 391.10, 391.20, 391.21, 392.22, 393.00, 394.00, 397.00, 397.10, 397.20, 397.30, 397.40, 397.50, 398.10, 398.20, 398.30, 398.40 and 398.50 for gas assets, I used the straight line method of amortization. General Plant Accounts include a large number of units but represent slightly less than three percent of depreciable gas plant. Depreciation accounting is difficult for these assets, inasmuch as periodic inventories are required to properly reflect plant in service. In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. However, retirements are recorded when a vintage is fully amortized rather than as the units are removed from service. That is, there is no

dispersion of retirement. All units are retired when the age of the vintage reaches the amortization period.

V. DESCRIPTION OF REPORT

Q. Please use an example to illustrate the manner in which the studies were presented in the report.

A. I will use Account 380.00, Services, as my example because it is the largest depreciable mass account and represents 23 percent of the depreciable plant.

The retirement rate method was used to analyze the survivor characteristics of this property group. Aged plant accounting data were compiled from 1919 through 2023 and analyzed for periods that best represent the overall service life of this property. The life tables for the 1919-2023, 1976-2015 and 1981-2015 experience bands are presented on pages VII-102 through VII-110 of the report. The life table displays the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page VII-102 shows $2,348,906 retired during age interval 0.5-1.5 with $1,024,432,762 exposed to retirement at the beginning of the interval. Consequently, the retirement ratio is 0.0023 ($2,348,906/$1,024,432,762) and the surviving ratio is 0.9977 (1-.00023). The percent surviving at age 0.5 of 0.9990 percent is multiplied by the survivor ratio of 99.77 to derive the percent surviving at age 1.5 of 99.67 percent. This process continues for the remaining age intervals for which plant was exposed to retirement during the period 1919-2023. The resultant life table, or original survivor curve, is plotted along with the estimated smooth survivor curve, the 60-R2.5 on page VII-101. The 60-R2.5 reflected the overall expected shorter life cycle into the future than what has been statistically experienced in the past.

The net salvage percent is presented on pages VIII-4 and VIII-5 for Account 380.00. The percentage is based on the result of annual gross salvage minus the cost to remove plant assets as compared to the original cost of plant retired during the period 1993 through 2023. The 31-year period experienced $51,864,733 (($108,345)-$51,756,388) in negative net salvage for $48,143,634 plant retired. The result is negative net salvage of 108 percent ($51,864,733/$48,143,634) on the statistics for the account for the entire 31-year period. The three-year rolling averages and the most recent five-year averages trend to more negative net salvage, however, based on the current net salvage estimate and the industry averages, the recommended net salvage for gas services is negative 108 percent.

My calculation of the annual depreciation related to the original cost of Account 380.00, Services, as of December 31, 2023, is presented on pages IX-73 through IX-75 of the report. The calculation is based on the 60-R2.5 survivor curve, 100 percent negative net salvage, the attained age, and the allocated book reserve. The tabulation sets forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. These totals are brought forward to the table on page VI-6.

VI. RECOMMENDATION

Q. What is your recommendation regarding annual depreciation accrual rates for the Company?

A. I recommend that the Company use a composite annual depreciation accrual rate for gas accounts or subaccounts. My recommended depreciation accrual rates, based on the Depreciation Study, are set forth for each account in column 9 of Table 1 on pages

VI-5 through VI-8 of Exh. JJS-3. In my opinion, these are reasonable and appropriate depreciation accrual rates for the Company.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

VII. LIST OF EXHIBITS

Exh. JJS-2	Qualifications Statement
Exh. JJS-3	2023 Depreciation Study

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of John J. Spanos

DEPRECIATION

Exh. JJS-2

August 29, 2025

Exhibit JJS-2

JOHN SPANOS

DEPRECIATION EXPERIENCE

Q. Please state your name.

A. My name is John J. Spanos.

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College.

Q. Do you belong to any professional societies?

A. Yes. I am a member and past President of the Society of Depreciation Professionals and a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003, February 2008, January 2013, February 2018 and February 2023.

Q. Please outline your experience in the field of depreciation.

A. In June 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June 1986 through December 1995, I helped prepare numerous depreciation and original cost studies for utility companies in various industries. I helped perform depreciation studies for the following telephone companies: United Telephone of Pennsylvania, United Telephone of New Jersey, and Anchorage Telephone Utility. I helped perform depreciation studies for the following companies in

the railroad industry: Union Pacific Railroad, Burlington Northern Railroad, and Wisconsin Central Transportation Corporation.

I helped perform depreciation studies for the following organizations in the electric utility industry: Chugach Electric Association, The Cincinnati Gas and Electric Company (CG&E), The Union Light, Heat and Power Company (ULH&P), Northwest Territories Power Corporation, and the City of Calgary - Electric System.

I helped perform depreciation studies for the following pipeline companies: TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

I helped perform depreciation studies for the following gas utility companies: Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, CG&E, ULH&P, Lawrenceburg Gas Company and Penn Fuel Gas, Inc.

I helped perform depreciation studies for the following water utility companies: Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service life and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E.

In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July 1999, I was promoted to the position of Manager, Depreciation and

Valuation Studies. In December 2000, I was promoted to the position as Vice-President of Gannett Fleming Valuation and Rate Consultants, Inc., in April 2012, I was promoted to the position as Senior Vice President of the Valuation and Rate Division of Gannett Fleming Inc. (now doing business as Gannett Fleming Valuation and Rate Consultants, LLC) and in January of 2019, I was promoted to my present position of President of Gannett Fleming Valuation and Rate Consultants, LLC. In my current position I am responsible for conducting all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory bodies.

Since January 1996, I have conducted depreciation studies similar to those previously listed including assignments for Pennsylvania-American Water Company; Aqua Pennsylvania; Kentucky-American Water Company; Virginia-American Water Company; Indiana-American Water Company; Iowa-American Water Company; New Jersey-American Water Company; Hampton Water Works Company; Omaha Public Power District; Enbridge Pipe Line Company; Inc.; Columbia Gas of Virginia, Inc.; Virginia Natural Gas Company National Fuel Gas Distribution Corporation - New York and Pennsylvania Divisions; The City of Bethlehem - Bureau of Water; The City of Coatesville Authority; The City of Lancaster - Bureau of Water; Peoples Energy Corporation; The York Water Company; Public Service Company of Colorado; Enbridge Pipelines; Enbridge Gas Distribution, Inc.; Reliant Energy-HLP; Massachusetts-American Water Company; St. Louis County Water Company; Missouri-American Water Company; Chugach Electric Association; Alliant Energy; Oklahoma Gas & Electric Company; Nevada Power Company; Dominion Virginia Power; NUI-Virginia Gas Companies; Pacific Gas & Electric Company; PSI Energy; NUI - Elizabethtown Gas Company; Cinergy Corporation – CG&E; Cinergy

Corporation – ULH&P; Columbia Gas of Kentucky; South Carolina Electric & Gas Company; Idaho Power Company; El Paso Electric Company; Aqua North Carolina; Aqua Ohio; Aqua Texas, Inc.; Aqua Illinois, Inc.; Ameren Missouri; Central Hudson Gas & Electric; Centennial Pipeline Company; CenterPoint Energy-Arkansas; CenterPoint Energy – Oklahoma; CenterPoint Energy – Entex; CenterPoint Energy - Louisiana; NSTAR – Boston Edison Company; Westar Energy, Inc.; United Water Pennsylvania; PPL Electric Utilities; PPL Gas Utilities; Wisconsin Power & Light Company; TransAlaska Pipeline; Avista Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; Public Service Company of North Carolina; South Jersey Gas Company; Duquesne Light Company; MidAmerican Energy Company; Laclede Gas; Duke Energy Company; E.ON U.S. Services Inc.; Elkton Gas Services; Anchorage Water and Wastewater Utility; Kansas City Power and Light; Duke Energy North Carolina; Duke Energy South Carolina; Monongahela Power Company; Potomac Edison Company; Duke Energy Ohio Gas; Duke Energy Kentucky; Duke Energy Indiana; Duke Energy Progress; Northern Indiana Public Service Company; Tennessee- American Water Company; Columbia Gas of Maryland; Maryland-American Water Company; Bonneville Power Administration; NSTAR Electric and Gas Company; EPCOR Distribution, Inc.; B. C. Gas Utility, Ltd; Entergy Arkansas; Entergy Texas; Entergy Mississippi; Entergy Louisiana; Entergy Gulf States Louisiana; the Borough of Hanover; Louisville Gas and Electric Company; Kentucky Utilities Company; Madison Gas and Electric; Central Maine Power; PEPCO; PacifiCorp; Minnesota Energy Resource Group; Jersey Central Power & Light Company; Cheyenne Light, Fuel and Power Company; United Water Arkansas; Central Vermont Public Service Corporation; Green Mountain Power; Portland General Electric Company; Atlantic City Electric; Nicor Gas Company; Black Hills Power; Black Hills Colorado Gas; Black Hills Energy Arkansas, Inc.; Black Hills Kansas

Gas; Black Hills Service Company; Black Hills Utility Holdings; Public Service Company of Oklahoma; City of Dubois; Peoples Gas Light and Coke Company; North Shore Gas Company; Connecticut Light and Power; New York State Electric and Gas Corporation; Rochester Gas and Electric Corporation; Greater Missouri Operations; Tennessee Valley Authority; Omaha Public Power District; Indianapolis Power & Light Company; Vermont Gas Systems, Inc.; Metropolitan Edison; Pennsylvania Electric; West Penn Power; Pennsylvania Power; PHI Service Company - Delmarva Power and Light; Atmos Energy Corporation; Citizens Energy Group; PSE&G Company; Berkshire Gas Company; Alabama Gas Corporation; Mid-Atlantic Interstate Transmission, LLC; SUEZ Water; WEC Energy Group; Rocky Mountain Natural Gas, LLC; Illinois-American Water Company; Northern Illinois Gas Company; Public Service of New Hampshire; FirstEnergy Service Corporation; Northeast Ohio Natural Gas Corporation; Blue Granite Water Company; Spire Missouri, Inc.; Dominion Energy South Carolina, Inc.; South FirstEnergy Operating Companies; Dayton Power and Light Company; Liberty Utilities; East Kentucky Power Cooperative; Bangor Natural Gas; Hanover Borough Municipal Water Works; West Virginia American Water Company; Evergy Metro; Evergy Missouri West; Granite State Electric; Bluegrass Water; The Borough of Ambler; Newtown Artesian Water Company and Connecticut Water Company.

My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

Q. Have you submitted testimony to any state utility commission on the subject of utility plant depreciation?

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission; the

Commonwealth of Kentucky Public Service Commission; the Public Utilities Commission of Ohio; the Nevada Public Utility Commission; the Public Utilities Board of New Jersey; the Missouri Public Service Commission; the Massachusetts Department of Telecommunications and Energy; the Alberta Energy & Utility Board; the Idaho Public Utility Commission; the Louisiana Public Service Commission; the State Corporation Commission of Kansas; the Oklahoma Corporate Commission; the Public Service Commission of South Carolina; Railroad Commission of Texas – Gas Services Division; the New York Public Service Commission; Illinois Commerce Commission; the Indiana Utility Regulatory Commission; the California Public Utilities Commission; the Federal Energy Regulatory Commission ("FERC"); the Arkansas Public Service Commission; the Public Utility Commission of Texas; Maryland Public Service Commission; Washington Utilities and Transportation Commission; The Tennessee Regulatory Commission; the Regulatory Commission of Alaska; Minnesota Public Utility Commission; Utah Public Service Commission; District of Columbia Public Service Commission; the Mississippi Public Service Commission; Delaware Public Service Commission; Virginia State Corporation Commission; Colorado Public Utility Commission; Oregon Public Utility Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission; Wyoming Public Service Commission; the Public Service Commission of West Virginia; Maine Public Utility Commission; Iowa Utility Board; Connecticut Public Utilities Regulatory Authority; New Mexico Public Regulation Commission; Commonwealth of Massachusetts Department of Public Utilities; Rhode Island Public Utilities Commission and the North Carolina Utilities Commission.

Q. Have you had any additional education relating to utility plant depreciation?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.:

"Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation," and "Managing a Depreciation Study." I have also completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

Q. Does this conclude your qualification statement?

A. Yes.

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
01.	1998	PA PUC	R-00984375	City of Bethlehem – Bureau of Water	Original Cost and Depreciation
02.	1998	PA PUC	R-00984567	City of Lancaster	Original Cost and Depreciation
03.	1999	PA PUC	R-00994605	The York Water Company	Depreciation
04.	2000	D.T.&E.	DTE 00-105	Massachusetts-American Water Company	Depreciation
05.	2001	PA PUC	R-00016114	City of Lancaster	Original Cost and Depreciation
06.	2001	PA PUC	R-00017236	The York Water Company	Depreciation
07.	2001	PA PUC	R-00016339	Pennsylvania-American Water Company	Depreciation
08.	2001	OH PUC	01-1228-GA-AIR	Cinergy Corp – Cincinnati Gas & Elect Company	Depreciation
09.	2001	KY PSC	2001-092	Cinergy Corp – Union Light, Heat & Power Co.	Depreciation
10.	2002	PA PUC	R-00016750	Philadelphia Suburban Water Company	Depreciation
11.	2002	KY PSC	2002-00145	Columbia Gas of Kentucky	Depreciation
12.	2002	NJ BPU	GF02040245	NUI Corporation/Elizabethtown Gas Company	Depreciation
13.	2002	ID PUC	IPC-E-03-7	Idaho Power Company	Depreciation
14.	2003	PA PUC	R-0027975	The York Water Company	Depreciation
15.	2003	IN URC	R-0027975	Cinergy Corp – PSI Energy, Inc.	Depreciation
16.	2003	PA PUC	R-00038304	Pennsylvania-American Water Company	Depreciation
17.	2003	MO PSC	WR-2003-0500	Missouri-American Water Company	Depreciation
18.	2003	FERC	ER03-1274-000	NSTAR-Boston Edison Company	Depreciation
19.	2003	NJ BPU	BPU 03080683	South Jersey Gas Company	Depreciation
20.	2003	NV PUC	03-10001	Nevada Power Company	Depreciation
21.	2003	LA PSC	U-27676	CenterPoint Energy – Arkla	Depreciation
22.	2003	PA PUC	R-00038805	Pennsylvania Suburban Water Company	Depreciation
23.	2004	AB En/Util Bd	1306821	EPCOR Distribution, Inc.	Depreciation
24.	2004	PA PUC	R-00038168	National Fuel Gas Distribution Corp (PA)	Depreciation
25.	2004	PA PUC	R-00049255	PPL Electric Utilities	Depreciation
26.	2004	PA PUC	R-00049165	The York Water Company	Depreciation
27.	2004	OK Corp Cm	PUC 200400187	CenterPoint Energy – Arkla	Depreciation
28.	2004	OH PUC	04-680-El-AIR	Cinergy Corp. – Cincinnati Gas and Electric Company	Depreciation
29.	2004	RR Com of TX	GUD#	CenterPoint Energy – Entex Gas Services Div.	Depreciation
30.	2004	NY PUC	04-G-1047	National Fuel Gas Distribution Gas (NY)	Depreciation
31.	2004	AR PSC	04-121-U	CenterPoint Energy – Arkla	Depreciation
32.	2005	IL CC	05-ICC-06	North Shore Gas Company	Depreciation
33.	2005	IL CC	05-ICC-06	Peoples Gas Light and Coke Company	Depreciation
34.	2005	KY PSC	2005-00042	Union Light Heat & Power	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
35.	2005	IL CC	05-0308	MidAmerican Energy Company	Depreciation
36.	2005	MO PSC	GF-2005	Laclede Gas Company	Depreciation
37.	2005	KS CC	05-WSEE-981-RTS	Westar Energy	Depreciation
38.	2005	RR Com of TX	GUD #	CenterPoint Energy – Entex Gas Services Div.	Depreciation
39.	2005	US District Court	Cause No. 1:99-CV-1693-LJM/VSS	Cinergy Corporation	Accounting
40.	2005	OK CC	PUD 200500151	Oklahoma Gas and Electric Company	Depreciation
41.	2005	MA Dept Tele-com & Ergy	DTE 05-85	NSTAR	Depreciation
42.	2005	NY PUC	05-E-934/05-G-0935	Central Hudson Gas & Electric Company	Depreciation
43.	2005	AK Reg Com	U-04-102	Chugach Electric Association	Depreciation
44.	2005	CA PUC	A05-12-002	Pacific Gas & Electric	Depreciation
45.	2006	PA PUC	R-00051030	Aqua Pennsylvania, Inc.	Depreciation
46.	2006	PA PUC	R-00051178	T.W. Phillips Gas and Oil Company	Depreciation
47.	2006	NC Util Cm.	G-5, Sub522	Pub. Service Company of North Carolina	Depreciation
48.	2006	PA PUC	R-00051167	City of Lancaster	Depreciation
49.	2006	PA PUC	R00061346	Duquesne Light Company	Depreciation
50.	2006	PA PUC	R-00061322	The York Water Company	Depreciation
51.	2006	PA PUC	R-00051298	PPL GAS Utilities	Depreciation
52.	2006	PUC of TX	32093	CenterPoint Energy – Houston Electric	Depreciation
53.	2006	KY PSC	2006-00172	Duke Energy Kentucky	Depreciation
54.	2006	SC PSC		SCANA	Accounting
55.	2006	AK Reg Com	U-06-6	Municipal Light and Power	Depreciation
56.	2006	DE PSC	06-284	Delmarva Power and Light	Depreciation
57.	2006	IN URC	IURC43081	Indiana American Water Company	Depreciation
58.	2006	AK Reg Com	U-06-134	Chugach Electric Association	Depreciation
59.	2006	MO PSC	WR-2007-0216	Missouri American Water Company	Depreciation
60.	2006	FERC	IS05-82-002, et al	TransAlaska Pipeline	Depreciation
61.	2006	PA PUC	R-00061493	National Fuel Gas Distribution Corp. (PA)	Depreciation
62.	2007	NC Util Com.	E-7 SUB 828	Duke Energy Carolinas, LLC	Depreciation
63.	2007	OH PSC	08-709-EL-AIR	Duke Energy Ohio Gas	Depreciation
64.	2007	PA PUC	R-00072155	PPL Electric Utilities Corporation	Depreciation
65.	2007	KY PSC	2007-00143	Kentucky American Water Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
66.	2007	PA PUC	R-00072229	Pennsylvania American Water Company	Depreciation
67.	2007	KY PSC	2007-0008	NiSource – Columbia Gas of Kentucky	Depreciation
68.	2007	NY PSC	07-G-0141	National Fuel Gas Distribution Corp (NY)	Depreciation
69.	2008	AK PSC	U-08-004	Anchorage Water & Wastewater Utility	Depreciation
70.	2008	TN Reg Auth	08-00039	Tennessee-American Water Company	Depreciation
71.	2008	DE PSC	08-96	Artesian Water Company	Depreciation
72.	2008	PA PUC	R-2008-2023067	The York Water Company	Depreciation
73.	2008	KS CC	08-WSEE1-RTS	Westar Energy	Depreciation
74.	2008	IN URC	43526	Northern Indiana Public Service Company	Depreciation
75.	2008	IN URC	43501	Duke Energy Indiana	Depreciation
76.	2008	MD PSC	9159	NiSource – Columbia Gas of Maryland	Depreciation
77.	2008	KY PSC	2008-000251	Kentucky Utilities	Depreciation
78.	2008	KY PSC	2008-000252	Louisville Gas & Electric	Depreciation
79.	2008	PA PUC	2008-20322689	Pennsylvania American Water Co. - Wastewater	Depreciation
80.	2008	NY PSC	08-E887/08-00888	Central Hudson	Depreciation
81.	2008	WV TC	VE-080416/VG-8080417	Avista Corporation	Depreciation
82.	2008	IL CC	ICC-09-166	Peoples Gas, Light and Coke Company	Depreciation
83.	2009	IL CC	ICC-09-167	North Shore Gas Company	Depreciation
84.	2009	DC PSC	1076	Potomac Electric Power Company	Depreciation
85.	2009	KY PSC	2009-00141	NiSource – Columbia Gas of Kentucky	Depreciation
86.	2009	FERC	ER08-1056-002	Entergy Services	Depreciation
87.	2009	PA PUC	R-2009-2097323	Pennsylvania American Water Company	Depreciation
88.	2009	NC Util Cm	E-7, Sub 090	Duke Energy Carolinas, LLC	Depreciation
89.	2009	KY PSC	2009-00202	Duke Energy Kentucky	Depreciation
90.	2009	VA St. CC	PUE-2009-00059	Aqua Virginia, Inc.	Depreciation
91.	2009	PA PUC	2009-2132019	Aqua Pennsylvania, Inc.	Depreciation
92.	2009	MS PSC	Docket No. 2011-UA-183	Entergy Mississippi	Depreciation
93.	2009	AK PSC	09-08-U	Entergy Arkansas	Depreciation
94.	2009	TX PUC	37744	Entergy Texas	Depreciation
95.	2009	TX PUC	37690	El Paso Electric Company	Depreciation
96.	2009	PA PUC	R-2009-2106908	The Borough of Hanover	Depreciation
97.	2009	KS CC	10-KCPE-415-RTS	Kansas City Power & Light	Depreciation
98.	2009	PA PUC	R-2009-	United Water Pennsylvania	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
99.	2009	OH PUC		Aqua Ohio Water Company	Depreciation
100.	2009	WI PSC	3270-DU-103	Madison Gas & Electric Company	Depreciation
101.	2009	MO PSC	WR-2010	Missouri American Water Company	Depreciation
102.	2009	AK Reg Cm	U-09-097	Chugach Electric Association	Depreciation
103.	2010	IN URC	43969	Northern Indiana Public Service Company	Depreciation
104.	2010	WI PSC	6690-DU-104	Wisconsin Public Service Corp.	Depreciation
105.	2010	PA PUC	R-2010-2161694	PPL Electric Utilities Corp.	Depreciation
106.	2010	KY PSC	2010-00036	Kentucky American Water Company	Depreciation
107.	2010	PA PUC	R-2009-2149262	Columbia Gas of Pennsylvania	Depreciation
108.	2010	MO PSC	GR-2010-0171	Laclede Gas Company	Depreciation
109.	2010	SC PSC	2009-489-E	South Carolina Electric & Gas Company	Depreciation
110.	2010	NJ BD OF PU	ER09080664	Atlantic City Electric	Depreciation
111.	2010	VA St. CC	PUE-2010-00001	Virginia American Water Company	Depreciation
112.	2010	PA PUC	R-2010-2157140	The York Water Company	Depreciation
113.	2010	MO PSC	ER-2010-0356	Greater Missouri Operations Company	Depreciation
114.	2010	MO PSC	ER-2010-0355	Kansas City Power and Light	Depreciation
115.	2010	PA PUC	R-2010-2167797	T.W. Phillips Gas and Oil Company	Depreciation
116.	2010	PSC SC	2009-489-E	SCANA – Electric	Depreciation
117.	2010	PA PUC	R-2010-22010702	Peoples Natural Gas, LLC	Depreciation
118.	2010	AK PSC	10-067-U	Oklahoma Gas and Electric Company	Depreciation
119.	2010	IN URC	Cause No. 43894	Northern Indiana Public Serv. Company - NIFL	Depreciation
120.	2010	IN URC	Cause No. 43894	Northern Indiana Public Serv. Co. - Kokomo	Depreciation
121.	2010	PA PUC	R-2010-2166212	Pennsylvania American Water Co. - WW	Depreciation
122.	2010	NC Util Cn.	W-218,SUB310	Aqua North Carolina, Inc.	Depreciation
123.	2011	OH PUC	11-4161-WS-AIR	Ohio American Water Company	Depreciation
124.	2011	MS PSC	EC-123-0082-00	Entergy Mississippi	Depreciation
125.	2011	CO PUC	11AL-387E	Black Hills Colorado	Depreciation
126.	2011	PA PUC	R-2010-2215623	Columbia Gas of Pennsylvania	Depreciation
127.	2011	PA PUC	R-2010-2179103	City of Lancaster – Bureau of Water	Depreciation
128.	2011	IN URC	43114 IGCC 4S	Duke Energy Indiana	Depreciation
129.	2011	FERC	IS11-146-000	Enbridge Pipelines (Southern Lights)	Depreciation
130.	2011	IL CC	11-0217	MidAmerican Energy Corporation	Depreciation
131.	2011	OK CC	201100087	Oklahoma Gas & Electric Company	Depreciation
132.	2011	PA PUC	2011-2232243	Pennsylvania American Water Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
133.	2011	FERC	RP11-___-000	Carolina Gas Transmission	Depreciation
134.	2012	WA UTC	UE-120436/UG-120437	Avista Corporation	Depreciation
135.	2012	AK Reg Cm	U-12-009	Chugach Electric Association	Depreciation
136.	2012	MA PUC	DPU 12-25	Columbia Gas of Massachusetts	Depreciation
137.	2012	TX PUC	40094	El Paso Electric Company	Depreciation
138.	2012	ID PUC	IPC-E-12	Idaho Power Company	Depreciation
139.	2012	PA PUC	R-2012-2290597	PPL Electric Utilities	Depreciation
140.	2012	PA PUC	R-2012-2311725	Borough of Hanover – Bureau of Water	Depreciation
141.	2012	KY PSC	2012-00222	Louisville Gas and Electric Company	Depreciation
142.	2012	KY PSC	2012-00221	Kentucky Utilities Company	Depreciation
143.	2012	PA PUC	R-2012-2285985	Peoples Natural Gas Company	Depreciation
144.	2012	DC PSC	Case 1087	Potomac Electric Power Company	Depreciation
145.	2012	OH PSC	12-1682-EL-AIR	Duke Energy Ohio (Electric)	Depreciation
146.	2012	OH PSC	12-1685-GA-AIR	Duke Energy Ohio (Gas)	Depreciation
147.	2012	PA PUC	R-2012-2310366	City of Lancaster – Sewer Fund	Depreciation
148.	2012	PA PUC	R-2012-2321748	Columbia Gas of Pennsylvania	Depreciation
149.	2012	FERC	ER-12-2681-000	ITC Holdings	Depreciation
150.	2012	MO PSC	ER-2012-0174	Kansas City Power and Light	Depreciation
151.	2012	MO PSC	ER-2012-0175	KCPL Greater Missouri Operations Company	Depreciation
152.	2012	MO PSC	GO-2012-0363	Laclede Gas Company	Depreciation
153.	2012	MN PUC	G007,001/D-12-533	Integrys – MN Energy Resource Group	Depreciation
154.	2012	TX PUC	SOAH 582-14-1051/ TECQ 2013-2007-UCR	Aqua Texas	Depreciation
155.	2012	PA PUC	2012-2336379	York Water Company	Depreciation
156.	2013	NJ BPU	ER12121071	PHI Service Company– Atlantic City Electric	Depreciation
157.	2013	KY PSC	2013-00167	Columbia Gas of Kentucky	Depreciation
158.	2013	VA St CC	2013-00020	Virginia Electric and Power Company	Depreciation
159.	2013	IA Util Bd	2013-0004	MidAmerican Energy Corporation	Depreciation
160.	2013	PA PUC	2013-2355276	Pennsylvania American Water Company	Depreciation
161.	2013	NY PSC	13-E-0030, 13-G-0031, 13-S-0032	Consolidated Edison of New York	Depreciation
162.	2013	PA PUC	2013-2355886	Peoples TWP LLC	Depreciation
163.	2013	TN Reg Auth	12-0504	Tennessee American Water	Depreciation
164.	2013	ME PUC	2013-168	Central Maine Power Company	Depreciation
165.	2013	DC PSC	Case 1103	PHI Service Company – PEPCO	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
166.	2013	WY PSC	2003-ER-13	Cheyenne Light, Fuel and Power Company	Depreciation
167.	2013	FERC	ER13-2428-0000	Kentucky Utilities	Depreciation
168.	2013	FERC	ER13- -0000	MidAmerican Energy Company	Depreciation
169.	2013	FERC	ER13-2410-0000	PPL Utilities	Depreciation
170.	2013	PA PUC	R-2013-2372129	Duquesne Light Company	Depreciation
171.	2013	NJ BPU	ER12111052	Jersey Central Power and Light Company	Depreciation
172.	2013	PA PUC	R-2013-2390244	Bethlehem, City of – Bureau of Water	Depreciation
173.	2013	OK CC	UM 1679	Oklahoma, Public Service Company of	Depreciation
174.	2013	IL CC	13-0500	Nicor Gas Company	Depreciation
175.	2013	WY PSC	20000-427-EA-13	PacifiCorp	Depreciation
176.	2013	UT PSC	13-035-02	PacifiCorp	Depreciation
177.	2013	OR PUC	UM 1647	PacifiCorp	Depreciation
178.	2013	PA PUC	2013-2350509	Dubois, City of	Depreciation
179.	2014	IL CC	14-0224	North Shore Gas Company	Depreciation
180.	2014	FERC	ER14- -0000	Duquesne Light Company	Depreciation
181.	2014	SD PUC	EL14-026	Black Hills Power Company	Depreciation
182.	2014	WY PSC	20002-91-ER-14	Black Hills Power Company	Depreciation
183.	2014	PA PUC	2014-2428304	Borough of Hanover – Municipal Water Works	Depreciation
184.	2014	PA PUC	2014-2406274	Columbia Gas of Pennsylvania	Depreciation
185.	2014	IL CC	14-0225	Peoples Gas Light and Coke Company	Depreciation
186.	2014	MO PSC	ER-2014-0258	Ameren Missouri	Depreciation
187.	2014	KS CC	14-BHCG-502-RTS	Black Hills Service Company	Depreciation
188.	2014	KS CC	14-BHCG-502-RTS	Black Hills Utility Holdings	Depreciation
189.	2014	KS CC	14-BHCG-502-RTS	Black Hills Kansas Gas	Depreciation
190.	2014	PA PUC	2014-2418872	Lancaster, City of – Bureau of Water	Depreciation
191.	2014	WV PSC	14-0701-E-D	First Energy – MonPower/PotomacEdison	Depreciation
192	2014	VA St CC	PUC-2014-00045	Aqua Virginia	Depreciation
193.	2014	VA St CC	PUE-2013	Virginia American Water Company	Depreciation
194.	2014	OK CC	PUD201400229	Oklahoma Gas and Electric Company	Depreciation
195.	2014	OR PUC	UM1679	Portland General Electric	Depreciation
196.	2014	IN URC	Cause No. 44576	Indianapolis Power & Light	Depreciation
197.	2014	MA DPU	DPU. 14-150	NSTAR Gas	Depreciation
198.	2014	CT PURA	14-05-06	Connecticut Light and Power	Depreciation
199.	2014	MO PSC	ER-2014-0370	Kansas City Power & Light	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
200.	2014	KY PSC	2014-00371	Kentucky Utilities Company	Depreciation
201.	2014	KY PSC	2014-00372	Louisville Gas and Electric Company	Depreciation
202.	2015	PA PUC	R-2015-2462723	United Water Pennsylvania Inc.	Depreciation
203.	2015	PA PUC	R-2015-2468056	NiSource - Columbia Gas of Pennsylvania	Depreciation
204.	2015	NY PSC	15-E-0283/15-G-0284	New York State Electric and Gas Corporation	Depreciation
205.	2015	NY PSC	15-E-0285/15-G-0286	Rochester Gas and Electric Corporation	Depreciation
206.	2015	MO PSC	WR-2015-0301/SR-2015-0302	Missouri American Water Company	Depreciation
207.	2015	OK CC	PUD 201500208	Oklahoma, Public Service Company of	Depreciation
208.	2015	WV PSC	15-0676-W-42T	West Virginia American Water Company	Depreciation
209.	2015	PA PUC	2015-2469275	PPL Electric Utilities	Depreciation
210.	2015	IN URC	Cause No. 44688	Northern Indiana Public Service Company	Depreciation
211.	2015	OH PSC	14-1929-EL-RDR	First Energy-Ohio Edison/Cleveland Electric/ Toledo Edison	Depreciation
212.	2015	NM PRC	15-00127-UT	El Paso Electric	Depreciation
213.	2015	TX PUC	PUC-44941; SOAH 473-15-5257	El Paso Electric	Depreciation
214.	2015	WI PSC	3270-DU-104	Madison Gas and Electric Company	Depreciation
215.	2015	OK CC	PUD 201500273	Oklahoma Gas and Electric	Depreciation
216.	2015	KY PSC	Doc. No. 2015-00418	Kentucky American Water Company	Depreciation
217.	2015	NC UC	Doc. No. G-5, Sub 565	Public Service Company of North Carolina	Depreciation
218.	2016	WA UTC	Docket UE-17	Puget Sound Energy	Depreciation
219.	2016	NY PSC	Case No. 16-W-0130	SUEZ Water New York, Inc.	Depreciation
220.	2016	MO PSC	ER-2016-0156	KCPL – Greater Missouri	Depreciation
221.	2016	WI PSC		Wisconsin Public Service Corporation	Depreciation
222.	2016	KY PSC	Case No. 2016-00026	Kentucky Utilities Company	Depreciation
223.	2016	KY PSC	Case No. 2016-00027	Louisville Gas and Electric Company	Depreciation
224.	2016	OH PUC	Case No. 16-0907-WW-AIR	Aqua Ohio	Depreciation
225.	2016	MD PSC	Case 9417	NiSource - Columbia Gas of Maryland	Depreciation
226.	2016	KY PSC	2016-00162	Columbia Gas of Kentucky	Depreciation
227.	2016	DE PSC	16-0649	Delmarva Power and Light Company – Electric	Depreciation
228.	2016	DE PSC	16-0650	Delmarva Power and Light Company – Gas	Depreciation
229.	2016	NY PSC	Case 16-G-0257	National Fuel Gas Distribution Corp – NY Div	Depreciation
230.	2016	PA PUC	R-2016-2537349	Metropolitan Edison Company	Depreciation
231.	2016	PA PUC	R-2016-2537352	Pennsylvania Electric Company	Depreciation
232.	2016	PA PUC	R-2016-2537355	Pennsylvania Power Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
233.	2016	PA PUC	R-2016-2537359	West Penn Power Company	Depreciation
234.	2016	PA PUC	R-2016-2529660	NiSource - Columbia Gas of PA	Depreciation
235.	2016	KY PSC	Case No. 2016-00063	Kentucky Utilities / Louisville Gas & Electric Co	Depreciation
236.	2016	MO PSC	ER-2016-0285	KCPL Missouri	Depreciation
237.	2016	AR PSC	16-052-U	Oklahoma Gas & Electric Co	Depreciation
238.	2016	PSCW	6680-DU-104	Wisconsin Power and Light	Depreciation
239.	2016	ID PUC	IPC-E-16-23	Idaho Power Company	Depreciation
240.	2016	OR PUC	UM1801	Idaho Power Company	Depreciation
241.	2016	ILL CC	16-	MidAmerican Energy Company	Depreciation
242.	2016	KY PSC	Case No. 2016-00370	Kentucky Utilities Company	Depreciation
243.	2016	KY PSC	Case No. 2016-00371	Louisville Gas and Electric Company	Depreciation
244.	2016	IN URC	Cause No. 45029	Indianapolis Power & Light	Depreciation
245.	2016	AL RC	U-16-081	Chugach Electric Association	Depreciation
246.	2017	MA DPU	D.P.U. 17-05	NSTAR Electric Company and Western Massachusetts Electric Company	Depreciation
247.	2017	TX PUC	PUC-26831, SOAH 973-17-2686	El Paso Electric Company	Depreciation
248.	2017	WA UTC	UE-17033 and UG-170034	Puget Sound Energy	Depreciation
249.	2017	OH PUC	Case No. 17-0032-EL-AIR	Duke Energy Ohio	Depreciation
250.	2017	VA SCC	Case No. PUE-2016-00413	Virginia Natural Gas, Inc.	Depreciation
251.	2017	OK CC	Case No. PUD201700151	Public Service Company of Oklahoma	Depreciation
252.	2017	MD PSC	Case No. 9447	Columbia Gas of Maryland	Depreciation
253.	2017	NC UC	Docket No. E-2, Sub 1142	Duke Energy Progress	Depreciation
254.	2017	VA SCC	Case No. PUR-2017-00090	Dominion Virginia Electric and Power Company	Depreciation
255.	2017	FERC	ER17-1162	MidAmerican Energy Company	Depreciation
256.	2017	PA PUC	R-2017-2595853	Pennsylvania American Water Company	Depreciation
257.	2017	OR PUC	UM1809	Portland General Electric	Depreciation
258.	2017	FERC	ER17-217-000	Jersey Central Power & Light	Depreciation
259.	2017	FERC	ER17-211-000	Mid-Atlantic Interstate Transmission, LLC	Depreciation
260.	2017	MN PUC	Docket No. G007/D-17-442	Minnesota Energy Resources Corporation	Depreciation
261.	2017	IL CC	Docket No. 17-0124	Northern Illinois Gas Company	Depreciation
262.	2017	OR PUC	UM1808	Northwest Natural Gas Company	Depreciation
263.	2017	NY PSC	Case No. 17-W-0528	SUEZ Water Owego-Nichols	Depreciation
264.	2017	MO PSC	GR-2017-0215	Laclede Gas Company	Depreciation
265.	2017	MO PSC	GR-2017-0216	Missouri Gas Energy	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
266.	2017	ILL CC	Docket No. 17-0337	Illinois-American Water Company	Depreciation
267.	2017	FERC	Docket No. ER18-22-000	PPL Electric Utilities Corporation	Depreciation
268.	2017	IN URC	Cause No. 44988	Northern Indiana Public Service Company	Depreciation
269.	2017	NJ BPU	BPU Docket No. WR17090985	New Jersey American Water Company, Inc.	Depreciation
270.	2017	RI PUC	Docket No. 4800	SUEZ Water Rhode Island	Depreciation
271.	2017	OK CC	Cause No. PUD 201700496	Oklahoma Gas and Electric Company	Depreciation
272.	2017	NJ BPU	ER18010029 & GR18010030	Public Service Electric and Gas Company	Depreciation
273.	2017	NC Util Com.	Docket No. E-7, SUB 1146	Duke Energy Carolinas, LLC	Depreciation
274.	2017	KY PSC	Case No. 2017-00321	Duke Energy Kentucky, Inc.	Depreciation
275.	2017	MA DPU	D.P.U. 18-40	Berkshire Gas Company	Depreciation
276.	2018	IN IURC	Cause No. 44992	Indiana-American Water Company, Inc.	Depreciation
277.	2018	IN IURC	Cause No. 45029	Indianapolis Power and Light	Depreciation
278.	2018	NC Util Com.	Docket No. W-218, Sub 497	Aqua North Carolina, Inc.	Depreciation
279.	2018	PA PUC	Docket No. R-2018-2647577	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
280.	2018	OR PUC	Docket UM 1933	Avista Corporation	Depreciation
281.	2018	WA UTC	Docket No. UE-108167	Avista Corporation	Depreciation
282.	2018	ID PUC	AVU-E-18-03, AVU-G-18-02	Avista Corporation	Depreciation
283.	2018	IN URC	Cause No. 45039	Citizens Energy Group	Depreciation
284.	2018	FERC	Docket No. ER18-	Duke Energy Progress	Depreciation
285.	2018	PA PUC	Docket No. R-2018-3000124	Duquesne Light Company	Depreciation
286.	2018	MD PSC	Case No. 948	NiSource - Columbia Gas of Maryland	Depreciation
287.	2018	MA DPU	D.P.U. 18-45	NiSource - Columbia Gas of Massachusetts	Depreciation
288.	2018	OH PUC	Case No. 18-0299-GA-ALT	Vectren Energy Delivery of Ohio	Depreciation
289.	2018	PA PUC	Docket No. R-2018-3000834	SUEZ Water Pennsylvania Inc.	Depreciation
290.	2018	MD PSC	Case No. 9847	Maryland-American Water Company	Depreciation
291.	2018	PA PUC	Docket No. R-2018-3000019	The York Water Company	Depreciation
292.	2018	FERC	ER-18-2231-000	Duke Energy Carolinas, LLC	Depreciation
293.	2018	KY PSC	Case No. 2018-00261	Duke Energy Kentucky, Inc.	Depreciation
294.	2018	NJ BPU	BPU Docket No. WR18050593	SUEZ Water New Jersey	Depreciation
295.	2018	WA UTC	Docket No. UE-180778	PacifiCorp	Depreciation
296.	2018	UT PSC	Docket No. 18-035-36	PacifiCorp	Depreciation
297.	2018	OR PUC	Docket No. UM-1968	PacifiCorp	Depreciation
298.	2018	ID PUC	Case No. PAC-E-18-08	PacifiCorp	Depreciation
299.	2018	WY PSC	20000-539-EA-18	PacifiCorp	Depreciation
300.	2018	PA PUC	Docket No. R-2018-3003068	Aqua Pennsylvania, Inc.	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
301.	2018	IL CC	Docket No. 18-1467	Aqua Illinois, Inc.	Depreciation
302.	2018	KY PSC	Case No. 2018-00294	Louisville Gas & Electric Company	Depreciation
303.	2018	KY PSC	Case No. 2018-00295	Kentucky Utilities Company	Depreciation
304.	2018	IN URC	Cause No. 45159	Northern Indiana Public Service Company	Depreciation
305.	2018	VA SCC	Case No. PUR-2019-00175	Virginia American Water Company	Depreciation
306.	2019	PA PUC	Docket No. R-2018-3006818	Peoples Natural Gas Company, LLC	Depreciation
307.	2019	OK CC	Cause No. PUD201800140	Oklahoma Gas and Electric Company	Depreciation
308.	2019	MD PSC	Case No. 9490	FirstEnergy – Potomac Edison	Depreciation
309.	2019	SC PSC	Docket No. 2018-318-E	Duke Energy Progress	Depreciation
310.	2019	SC PSC	Docket No. 2018-319-E	Duke Energy Carolinas	Depreciation
311.	2019	DE PSC	DE 19-057	Public Service of New Hampshire	Depreciation
312.	2019	NY PSC	Case No. 19-W-0168 & 19-W-0269	SUEZ Water New York	Depreciation
313.	2019	PA PUC	Docket No. R-2019-3006904	Newtown Artesian Water Company	Depreciation
314.	2019	MO PSC	ER-2019-0335	Ameren Missouri	Depreciation
315.	2019	MO PSC	EC-2019-0200	KCP&L Greater Missouri Operations Company	Depreciation
316.	2019	MN DOC	G011/D-19-377	Minnesota Energy Resource Corp.	Depreciation
317.	2019	NY PSC	Case 19-E-0378 & 19-G-0379	New York State Electric and Gas Corporation	Depreciation
318.	2019	NY PSC	Case 19-E-0380 & 19-G-0381	Rochester Gas and Electric Corporation	Depreciation
319.	2019	WA UTC	Docket UE-190529 / UG-190530	Puget Sound Energy	Depreciation
320.	2019	PA PUC	Docket No. R-2019-3010955	City of Lancaster	Depreciation
321.	2019	IURC	Cause No. 45253	Duke Energy Indiana	Depreciation
322.	2019	KY PSC	Case No. 2019-00271	Duke Energy Kentucky, Inc.	Depreciation
323.	2019	OH PUC	Case No. 18-1720-GA-AIR	Northeast Ohio Natural Gas Corp	Depreciation
324.	2019	NC Util.	Docket No. E-2, Sub 1219	Duke Energy Carolinas	Depreciation
325.	2019	FERC	Docket No. ER20-277-000	Jersey Central Power & Light Company	Depreciation
326.	2019	MA DPU	D.P.U. 19-120	NSTAR Gas Company	Depreciation
327.	2019	SC PSC	Docket No. 2019-290-WS	Blue Granite Water Company	Depreciation
328.	2019	NC Util.	Docket No. E-2, Sub 1219	Duke Energy Progress	Depreciation
329.	2019	MD PSC	Case No. 9609	NiSource Columbia Gas of Maryland, Inc.	Depreciation
330.	2019	HI PUC	Docket No. 2019-0117	Young Brothers, LLC	Depreciation
331.	2020	NJ BPU	Docket No. ER20020146	Jersey Central Power & Light Company	Depreciation
332.	2020	PA PUC	Docket No. R-2020-3018835	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
333.	2020	PA PUC	Docket No. R-2020-3019369	Pennsylvania-American Water Company	Depreciation
334.	2020	PA PUC	Docket No. R-2020-3019371	Pennsylvania-American Water Company	Depreciation
335.	2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation
336.	2020	NM PRC	Case No. 20-00104-UT	El Paso Electric Company	Depreciation
337.	2020	MD PSC	Case No. 9644	Columbia Gas of Maryland, Inc.	Depreciation
338.	2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
339.	2020	VA St CC	Case No. PUR-2020-00095	Virginia Natural Gas Company	Depreciation
340.	2020	SC PSC	Docket No. 2020-125-E	Dominion Energy South Carolina, Inc.	Depreciation
341.	2020	WV PSC	Case No. 20-0745-G-D	Hope Gas, Inc. d/b/a Dominion Energy West Virginia	Depreciation
342.	2020	VA St CC	Case No. PUR-2020-00106	Aqua Virginia, Inc.	Depreciation
343.	2020	PA PUC	Docket No. R-2020-3020256	City of Bethlehem – Bureau of Water	Depreciation
344.	2020	NE PSC	Docket No. NG-109	Black Hills Nebraska	Depreciation
345.	2020	NY PSC	Case No. 20-E-0428 & 20-G-0429	Central Hudson Gas & Electric Corporation	Depreciation
346.	2020	FERC	ER20-598	Duke Energy Indiana	Depreciation
347.	2020	FERC	ER20-855	Northern Indiana Public Service Company	Depreciation
348.	2020	OR PSC	UE 374	PacifiCorp	Depreciation
349.	2020	MD PSC	Case No. 9490 Phase II	Potomac Edison – Maryland	Depreciation
350.	2020	IN URC	Case No. 45447	Southern Indiana Gas and Electric Company	Depreciation
351.	2020	IN URC	IURC Cause No. 45468	Indiana Gas Company, Inc. d/b/a Vectren Energy Delivery	Depreciation
352.	2020	KY PSC	Case No. 2020-00349	Kentucky Utilities Company	Depreciation
353.	2020	KY PSC	Case No. 2020-00350	Louisville Gas and Electric Company	Depreciation
354.	2020	FERC	Docket No. ER21- 000	South FirstEnergy Operating Companies	Depreciation
355.	2020	OH PUC	Case Nos 20-1651-EL-AIR, 20-1652-EL-AAM & 20-1653-EL-ATA	Dayton Power and Light Company	Depreciation
356.	2020	OR PSC	UG 388	Northwest Natural Gas Company	Depreciation
357.	2020	MO PSC	Case No. GR-2021-0241	Ameren Missouri Gas	Depreciation
358.	2021	KY PSC	Case No. 2021-00103	East Kentucky Power Cooperative	Depreciation
359.	2021	MPUC	Docket No. 2021-00024	Bangor Natural Gas	Depreciation
360.	2021	PA PUC	Docket No. R-2021-3024296	Columbia Gas of Pennsylvania, Inc.	Depreciation
361.	2021	NC Util.	Doc. No. G-5, Sub 632	Public Service of North Carolina	Depreciation
362.	2021	MO PSC	ER-2021-0240	Ameren Missouri	Depreciation
363.	2021	PA PUC	Docket No. R-2021-3024750	Duquesne Light Company	Depreciation
364.	2021	KS PSC	21-BHCG-418-RTS	Black Hills Kansas Gas	Depreciation
365.	2021	KY PSC	Case No. 2021-00190	Duke Energy Kentucky	Depreciation
366.	2021	OR PSC	Docket UM 2152	Portland General Electric	Depreciation
367.	2021	ILL CC	Docket No. 20-0810	North Shore Gas Company	Depreciation
368.	2021	FERC	ER21-1939-000	Duke Energy Progress	Depreciation
369.	2021	FERC	ER21-1940-000	Duke Energy Carolina	Depreciation
370.	2021	KY PSC	Case No. 2021-00183	NiSource Columbia Gas of Kentucky	Depreciation
371.	2021	MD PSC	Case No. 9664	NiSource Columbia Gas of Maryland	Depreciation
372.	2021	OH PUC	Case No. 21-0596-ST-AIR	Aqua Ohio	Depreciation
373.	2021	PA PUC	Docket No. R-2021-3026116	Hanover Borough Municipal Water Works	Depreciation
374.	2021	OR PSC	UM-2180	Idaho Power Company	Depreciation
375.	2021	ID PUC	Case No. IPC-E-21-18	Idaho Power Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
376.	2021	WPSC	6690-DU-104	Wisconsin Public Service Company	Depreciation
377.	2021	PAPUC	Docket No. R-2021-3026116	Borough of Hanover	Depreciation
378.	2021	OH PUC	Case No. 21-637-GA-AIR; Case No. 21-638-GA-ALT; Case No. 21-639-GA-UNC; Case No. 21-640-GA-AAM	NiSource Columbia Gas of Ohio	Depreciation
379.	2021	TX PUC	Texas PUC Docket No. 52195; SOHA Docket No. 473-21-2606	El Paso Electric	Depreciation
380.	2021	MO PSC	Case No. GR.2021-0108	Spire Missouri	Depreciation
381.	2021	WV PSC	Case No. 21-0215-WS-P	West Virginia American Water Company	Depreciation
382.	2021	FERC	ER21-2736	Duke Energy Carolinas	Depreciation
383.	2021	FERC	ER21-2737	Duke Energy Progress	Depreciation
384.	2021	IN URC	Cause #45621	Northern Indiana Public Service Company	Depreciation
385.	2021	PA PUC	Docket No. R-2021-3026682	City of Lancaster	Depreciation
386.	2021	OH PUC	Case No. 21-887-EL-AIR; Case No. 21-888-EL-ATA; Case No. 889-El-AAM	Duke Energy Ohio	Depreciation
387.	2021	AK PSC	Docket No. 21-097-U	Black Hills Energy Arkansas, Inc.	Depreciation
388.	2021	OK CC	Cause No. PUD202100164	Oklahoma Gas & Electric	Depreciation
389.	2021	FERC	Case ER-22-392-001	El Paso Electric	Depreciation
390.	2021	FERC	Case ER-21-XXX	MidAmerican Electric	Depreciation
391.	2021	PA PUC	Docket Nos. R-2021-3027385, R-2021-3027386	Aqua Pennsylvania, Inc. Aqua Pennsylvania Wastewater, Inc.	Depreciation
392.	2022	FERC	Case ER-22-282-000	El Paso Electric	Depreciation
393.	2022	ILL CC	Docket No. 22-0154	MidAmerican Gas	Depreciation
394.	2022	MO PSC	Case No. ER-2022-0129	Evergy Metro	Depreciation
395.	2022	MO PSC	Case No. ER-2022-0130	Evergy Missouri West	Depreciation
396.	2022	PA PUC	Docket No. R-2022-3031211	NiSource Columbia Gas of Pennsylvania, Inc.	Depreciation
397.	2022	MA DPU	D.P.U. 22-20	The Berkshire Gas Company	Depreciation
398.	2022	PA PUC	R-2022-3031672; R-2022-3031673	Pennsylvania-American Water Company	Depreciation
399.	2022	SD PUC	Docket No. NG22-	MidAmerican Gas	Depreciation
400.	2022	MD PSC	Case No. 9680	NiSource Columbia Gas of Maryland	Depreciation
401.	2022	WYPSC	Docket No. 20003-214-ER-22	Black Hills Energy – Cheyenne Light, Fuel and Power	Depreciation
402.	2022	MA DPU	D.P.U. 22.22	NSTAR Electric Company d/b/a Eversource Energy	Depreciation
403.	2022	NC Util Com	Docket No. W-218, Sub 573	Aqua North Carolina, Inc.	Depreciation
404.	2022	OR PUC	UM2213	Northwest Natural Gas	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
405.	2022	OR PUC	UM2214	Northwest Natural Gas	Depreciation
406.	2022	ME PUC	Docket No. 2022-00152	Central Maine Power	Depreciation
407.	2022	SC PSC	Docket No. 2022-254-E	Duke Energy Progress	Depreciation
408.	2022	NC Util Com	Docket No. E-2, SUB 1300	Duke Energy Progress	Depreciation
409.	2022	IN URC	Cause #45772	Northern Indiana Public Service Company	Depreciation
410.	2022	PA PUC	R-2022-3031340	The York Water Company	Depreciation
411.	2022	PA PUC	R-2022-3032806	The York Water Company	Depreciation
412.	2022	PA PUC	R-2022-3031704	Borough of Ambler	Depreciation
413.	2022	MO PSC	ER-2022-0337	Ameren Missouri	Depreciation
414.	2022	OH PUC	Case No. 22-507-GA-AIR	Duke Energy Ohio	Depreciation
415.	2022	PA PUC	R-2022-3035730	National Fuel Gas Distribution Corporation – PA Division	Depreciation
416.	2022	NC Util Com	Docket No. E-22, Sub 493	Virginia Electric and Power Company	Depreciation
417.	2022	WY PSC	20003-214-ER-22	Cheyenne Light, Fuel and Power Company	Depreciation
418.	2022	NJ BPU	BPU Docket No. ER2303144	Jersey Central Power & Light Company	Depreciation
419.	2022	KY PSC	Case No. 2022-00372	Duke Energy Kentucky	Depreciation
420.	2022	TX PUC	SOAH Docket No. 473-23-04521	Aqua Texas, Inc.	Depreciation
421.	2022	NC Util Com	Docket No. E-7, Sub 1276	Duke Energy Carolinas, LLC	Depreciation
422.	2022	KY PSC	Case No. 2022-00432	Bluegrass Water	Depreciation
423.	2023	ILL CC	Docket No. 23-0069	The Peoples Gas Light and Coke Company	Depreciation
424.	2023	ILL CC	Docket No. 23-0068	North Shore Gas Company	Depreciation
425.	2023	WV PSC	Case No. 23-0030-E-D	Monongahela Power Company and The Potomac Edison	Depreciation
426.	2023	ID PUC	AVU-E-23-01; AVU-G-23-01	Avista Corporation	Depreciation
427.	2023	ILL CC	Docket No. 23-0066	Northern Illinois Gas Company d/b/a Nicor Gas Company	Depreciation
428.	2023	SC PSC	Docket No. 2023-70-G	Dominion Energy South Carolina, Inc.	Depreciation
429.	2023	FERC	Docket No. ER23-xxx-00	Duke Energy Ohio, Inc.	Depreciation
430.	2023	WY PSC	Docket No. 30036-78-GR-23	Black Hills Wyoming Gas Company d/b/a Black Hills Energy	Depreciation
431.	2023	MD PSC	Case No. 9695	The Potomac Edison Company	Depreciation
432.	2023	OR PUC	Case No. UM2277	Avista Corporation	Depreciation
433.	2023	FERC	Docket No. ER23-1629-000	PPL Electric Utilities	Depreciation
434.	2023	OH PUC	Case No. 23-0154-GA-AIR	Northeast Ohio Natural Gas Corporation	Depreciation
435.	2023	DE PSC	PSC Docket No. 23-0601	Artesian Water Company	Depreciation
436.	2023	CO PUC	No. 23AL-0231G	Black Hills Colorado d/b/a Black Hills Energy	Depreciation
437.	2023	NH PUC	Docket No. DE 23-039	Granite State Electric d/b/a Liberty Utilities	Depreciation
438.	2023	MD PSC	Case No. 9701	Columbia Gas of Maryland	Depreciation
439.	2023	NY PSC	Case Nos. 23-E-0418; 23-G-0419	Central Hudson Gas and Electric	Depreciation
440.	2023	FERC	Docket No. ER23-xxx-000	Central Maine Power Company	Depreciation
441.	2023	SD PUC	Docket Number EL23-016	Northwestern Energy	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
442.	2023	CT PURA	Docket No. 23-08-32	Connecticut Water Company	Depreciation
443.	2023	OH PUC	Case 23-0894-GA-AIR	The East Ohio Gas Company d/b/a Dominion Energy Ohio	Depreciation
444.	2023	IN URC	Cause No. 45911	Indianapolis Power & Light	Depreciation
445.	2023	IN URC	Cause No. 45967	Northern Indiana Public Service Company	Depreciation
446.	2023	PA PUC	Docket No. R-2023-3043189 and Docket No. R-2023-3043190	Pennsylvania-American Water Company	Depreciation
447.	2023	IN URC	Cause No. 45988	Citizens Energy Group	Depreciation
448.	2023	NY PSC	Case No. 23-G-0627	National Fuel Gas Distribution Corporation	Depreciation
449.	2023	IN URC	Cause No. 45990	Southern Indiana Gas and Electric Company d/b/a	Depreciation
450.	2023	PA PUC	Docket No. R-2023-3044549	Peoples Natural Gas Company LLC	Depreciation
451.	2023	OR PUC	Docket No. UM-2312	Northwest Natural Gas Company	Depreciation
452.	2023	AZ PCC	Docket No. WS-21182A-23-2092	Northwest Natural Water Company, LLC	Depreciation
453.	2023	SC PSC	Docket No. 2023-388-E	Duke Energy Carolinas	Depreciation
454.	2024	FERC	Docket No. ER24-768-000	Duke Energy Progress	Depreciation
455.	2024	FERC	Docket No. ER24-2057	Duke Energy Carolina	Depreciation
456.	2024	FERC	Docket No. SPP-0007	Evergy Metro, Inc. and Evergy Missouri West, Inc.	Depreciation
457.	2024	NJ BPU	Docket No. WR24010057	Aqua New Jersey, Inc.	Depreciation
458.	2024	ILL CC	Docket No. 24-0044	Aqua Illinois, Inc.	Depreciation
459.	2024	PA PUC	Docket No. R-2024-3046519	NiSource – Columbia Gas of Pennsylvania, Inc.	Depreciation
460.	2024	KY PSC	Case No. 2024-00092	NiSource – Columbia Gas of Kentucky, Inc.	Depreciation
461.	2024	VA SCC	Case No. PUR-2024-00030	NiSource – Columbia Gas of Virginia, Inc.	Depreciation
462.	2024	NE PSC	Docket No. 24-	Northwestern Energy	Depreciation
463.	2024	IA Util Bd	Docket No. RPU-2023-0002	Alliant - Interstate Power and Light Company	Depreciation
464.	2024	PA PUC	Docket No. R-2024-3047068	FirstEnergy Pennsylvania – Metropolitan Edison; Pennsylvania Electric; Pennsylvania Power; West Penn Power	Depreciation
465.	2024	PA PUC	Docket No. R-2024-3046523	Duquesne Light Company	Depreciation
466.	2024	NCUC	Docket No. E-22, Sub 694	Dominion Energy North Carolina	Depreciation
467.	2024	IN URC	IURC Cause No. 46038	Duke Energy Indiana	Depreciation
468.	2024	NJ BPU	Docket Nos. ER23120924 and GF 23120925	Public Service Electric and Gas Company	Depreciation
469.	2024	CO PUC	Docket No. 24-AL-0275E	Black Hills Colorado Electric, LLC	Depreciation
470.	2024	OH PUC	Case No. 24-0468-EL-AIR, Case No. 24-0469-EL-ATA, Case No. 24-0470-EL-AAM, Case No. 24-0471-EL-UNC	FirstEnergy Ohio	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
471.	2024	SD PUC	Docket No. NG24-005	Northwestern Energy	Depreciation
472.	2024	PA PUC	Docket No. R-2024-3047822	Aqua Pennsylvania, Inc	Depreciation
473.	2024	PA PUC	Docket No. R-2024-3047824	Aqua Pennsylvania Wastewater, Inc	Depreciation
474.	2024	NH PUC	Docket No. DE 24-070	Eversource Energy - Public Service of New Hampshire	Depreciation
475.	2024	VA SCC	Case No. PUR-2024-00048	Virginia Natural Gas Company	Depreciation
476.	2024	WV PSC	Case No. 24-0678-G-D	Hope Gas, Inc.	Depreciation
477.	2024	MO PSC	ER-2024-0319	Ameren Missouri	Depreciation
478.	2024	PA PUC	Docket No. R-2024-3050208	Newtown Artesian Water Company	Depreciation
479.	2024	PA PUC	Docket No. RP-24-1106-00	Adelphia Gateway	Depreciation
480.	2024	OH PUC	Case No. 24-0832-GA-AIR	Centerpoint Energy Ohio	Depreciation
481.	2024	MT PSC	Docket 2024-05-053	Northwestern Energy	Depreciation
482.	2024	MD PSC	Case No. 9754	NiSource – Columbia Gas of Maryland	Depreciation
483.	2024	OR PUC	UM 2363	Northwest Natural Gas Company	Depreciation
484.	2024	IURC	Cause No. 46120	Northern Indiana Public Service Company LLC	Depreciation
485.	2024	MO PSC	GR-2024-0369	Ameren Missouri	Depreciation
486.	2024	PUCO	Case No. 24-1009-EL-AIR, Case No. 24-1010-El-AAM, Case No. 24-1011-El-ATA	The Dayton Power and Light Company d/b/a AES Ohio	Depreciation
487.	2024	KY PSC	Case No. 2024-00354	Duke Energy Kentucky	Depreciation
488.	2024	MO PSC	GR-2025-0107	Spire Missouri, Inc.	Depreciation
489.	2024	OR PUC	UG 520	Northwest Natural Gas	Depreciation
490.	2024	TX PUC	SOAH Docket No. 473-25-11219; PUC Docket No. 57568	El Paso Electric	Depreciation
491.	2024	FERC	Docket No. RP24-1106-002	Adelphia Gateway, LLC	Depreciation
492.	2025	PA PUC	Docket No.R-2025-3053499	Columbia Gas of Pennsylvania, Inc.	Depreciation
493.	2025	NE PSC	Case No. NG-124	Black Hills Nebraska	Depreciation
494.	2025	KY PSC	Case No. 2025-00114	Louisville Gas and Electric	Depreciation
495.	2025	KY PSC	Case No. 2025-00113	Kentucky Utilities	Depreciation
496.	2025	PA PUC	Docket No. R-2025-2025-3053442, R-2025-3053573	The York Water Company	Depreciation
497.	2025	NC UC	Docket No. W-218, Sub 629	Aqua North Carolina, Inc.	Depreciation
498.	2025	TX PUC	Docket No. 58124	Aqua Texas, Inc.	Depreciation
499.	2025	FERC	Docket No. ER25-2479-000	Duke Energy Indiana, LLC	Depreciation
500.	2025	IURC	Cause No. 46258	Indianapolis Power & Light Company d/b/a AES Indiana	Depreciation
501.	2025	NY PSC	Case 25-E-0375 & Case 25-G-378	New York State Electric and Gas Corporation	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
502.	2025	NY PSC	Case 25-E-0379 & Case 25-G-0380	Rochester Gas and Electric Corporation	Depreciation
503.	2025	ILL CC	Docket No. 25-0055	Northern Illinois Gas Company d/b/a Nicor Gas Company	Depreciation
504.	2025	CA PUC	A.25-01-001	San Gabriel Water Company	Depreciation
505.	2025	FERC	Docket EL25-77-000	Valley Link	Depreciation
506.	2025	KY PSC	Docket No. 2025-00125	Duke Energy Kentucky	Depreciation
507.	2025	KY PSC	Docket No 2025-00208	East Kentucky Power Cooperative	Depreciation

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of John J. Spanos

DEPRECIATION

Exh. JJS-3

August 29, 2025

NW Natural®

2023 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO GAS PLANT
AS OF DECEMBER 31, 2023

Prepared by:

GANNETT FLEMING

Excellence Delivered As Promised

NORTHWEST NATURAL GAS COMPANY
Portland, Oregon

2023 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO GAS PLANT
AS OF DECEMBER 31, 2023

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC
Camp Hill, Pennsylvania

Gannett Fleming
Valuation and Rate Consultants, LLC

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December 9, 2024

Northwest Natural Gas Company
250 SW Taylor Street
Portland, OR 97204

Attention: Zachary Kravitz
Rates and Regulatory Affairs

Ladies and Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the gas plant of Northwest Natural Gas Company as of December 31, 2023. The attached report presents a description of the methods used in the estimation of depreciation, the summary of annual depreciation accrual rates, the statistical support for the life and net salvage estimates and the detailed tabulations of annual depreciation.

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC.

JOHN J. SPANOS
President

FREDERICK B. JOHNSTON, JR.
Senior Analyst

JJS:mle

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NORTHWEST NATURAL GAS COMPANY

DEPRECIATION STUDY

EXECUTIVE SUMMARY

Pursuant to Northwest Natural Gas Company's ("NWNat" or "Company") request, Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") conducted a depreciation study related to the gas plant of NWNat as of December 31, 2023. The purpose of this study was to determine the annual depreciation accrual rates and amounts for book and ratemaking purposes.

The depreciation rates are based on the straight line method using the average service life ("ASL") procedure and were applied on a remaining life basis. The calculations were based on attained ages and estimated average service life, and forecasted net salvage characteristics for each depreciable group of assets.

NWNat's accounting policy for plant assets has not changed since the last depreciation study was prepared. However, there have been changes to the plant in service due to system improvements and there are some expected changes to future life characteristics which has created new depreciation rates.

Gannett Fleming recommends the calculated annual depreciation accrual rates set forth herein apply specifically to gas plant in service as of December 31, 2023 as summarized by Table 1 of the study. Supporting analysis and calculations are provided within the study.

The study results set forth an annual depreciation expense of $154.7 million when applied to depreciable plant balances as of December 31, 2023. The results are summarized at the functional level as follows:

SUMMARY OF ORIGINAL COST, ACCRUAL RATES AND AMOUNTS

FUNCTION	ORIGINAL COST AS OF DECEMBER 31, 2023	PROPOSED RATE	PROPOSED EXPENSE
Intangible Plant	$ 294,039,083.04	8.90	$ 26,162,477
Oil Gas Facilities	21,398.00	-	0
Other Production Facilities	628,802.00	-	0
Underground Storage Plant	239,087,512.56	2.05	4,896,830
Local Storage Plant	109,378,540.95	4.31	4,718,667
Transmission Plant	419,723,299.63	1.93	8,083,905
Distribution Plant	2,841,263,523.03	3.16	89,708,499
General Plant	369,421,300.49	5.85	21,611,140
General Plant Reserve Amortization	-	-	(434,015)
Total	**$4,273,563,459.70**	**3.62**	**$154,747,503**

PART I. INTRODUCTION

NORTHWEST NATURAL GAS COMPANY
DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for Northwest Natural Gas Company ("Company"), to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of gas plant as of December 31, 2023. The rates and amounts are based on the straight line remaining life method of depreciation. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to gas plant in service as of December 31, 2023

The service life and net salvage estimates resulting from the study were based on informed judgment which incorporated analyses of historical plant retirement data as recorded through 2023, a review of Company practice and outlook as they relate to plant operation and retirement, and consideration of current practice in the gas industry, including knowledge of service lives and net salvage estimates used for other gas companies.

PLAN OF REPORT

Part I, Introduction, contains statements with respect to the plan of the report, and the basis of the study. Part II, Estimation of Survivor Curves, presents descriptions of the considerations and methods used in the service life study. Part III, Service Life Considerations, presents the results of the average service life analysis. Part IV, Net Salvage Considerations, presents the results of the net salvage study. Part V, Calculation of Annual and Accrued Depreciation, describes the procedures used in the calculation of group depreciation. Part VI, Results of Study, presents summaries by depreciable group

of annual depreciation accrual rates and amounts, as well as composite remaining lives. Part VII, Service Life Statistics presents the statistical analysis of service life estimates, Part VIII, Net Salvage Statistics sets forth the statistical indications of net salvage percents, and Part IX, Detailed Depreciation Calculations presents the detailed tabulations of annual depreciation.

BASIS OF THE STUDY

Depreciation

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirements of public authorities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing gas utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight line method of depreciation.

For most accounts, the annual depreciation was calculated by the straight line method using the average service life procedure and the remaining life basis. For certain General Plant accounts, the annual depreciation is based on amortization accounting.

Both types of calculations were based on original cost, attained ages, and estimates of service lives and net salvage.

The straight line method, average service life procedure is a commonly used depreciation calculation procedure that has been widely accepted in jurisdictions throughout North America. Gannett Fleming recommends its continued use. Amortization accounting is used for certain General Plant accounts because of the disproportionate plant accounting effort required when compared to the minimal original cost of the large number of items in these accounts. An explanation of the calculation of annual and accrued amortization is presented beginning on page V-4 of the report.

Service Life and Net Salvage Estimates

The service life and net salvage estimates used in the depreciation and amortization calculations were based on informed judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the gas utility industry, and comparisons of the service life and net salvage estimates from our studies of other gas utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for gas plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

PART II. ESTIMATION OF SURVIVOR CURVES

PART II. ESTIMATION OF SURVIVOR CURVES

The calculation of annual depreciation based on the straight line method requires the estimation of survivor curves and the selection of group depreciation procedures. The estimation of survivor curves is discussed below and the development of net salvage is discussed in later sections of this report.

SURVIVOR CURVES

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units or by constructing a survivor curve by plotting the number of units which survive at successive ages.

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

This study has incorporated the use of Iowa curves developed from a retirement rate analysis of historical retirement history. A discussion of the concepts of survivor curves and of the development of survivor curves using the retirement rate method is presented below.

Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements (or the portion of the frequency curve with the highest level of retirements) in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family. A higher number designates a higher mode curve.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.

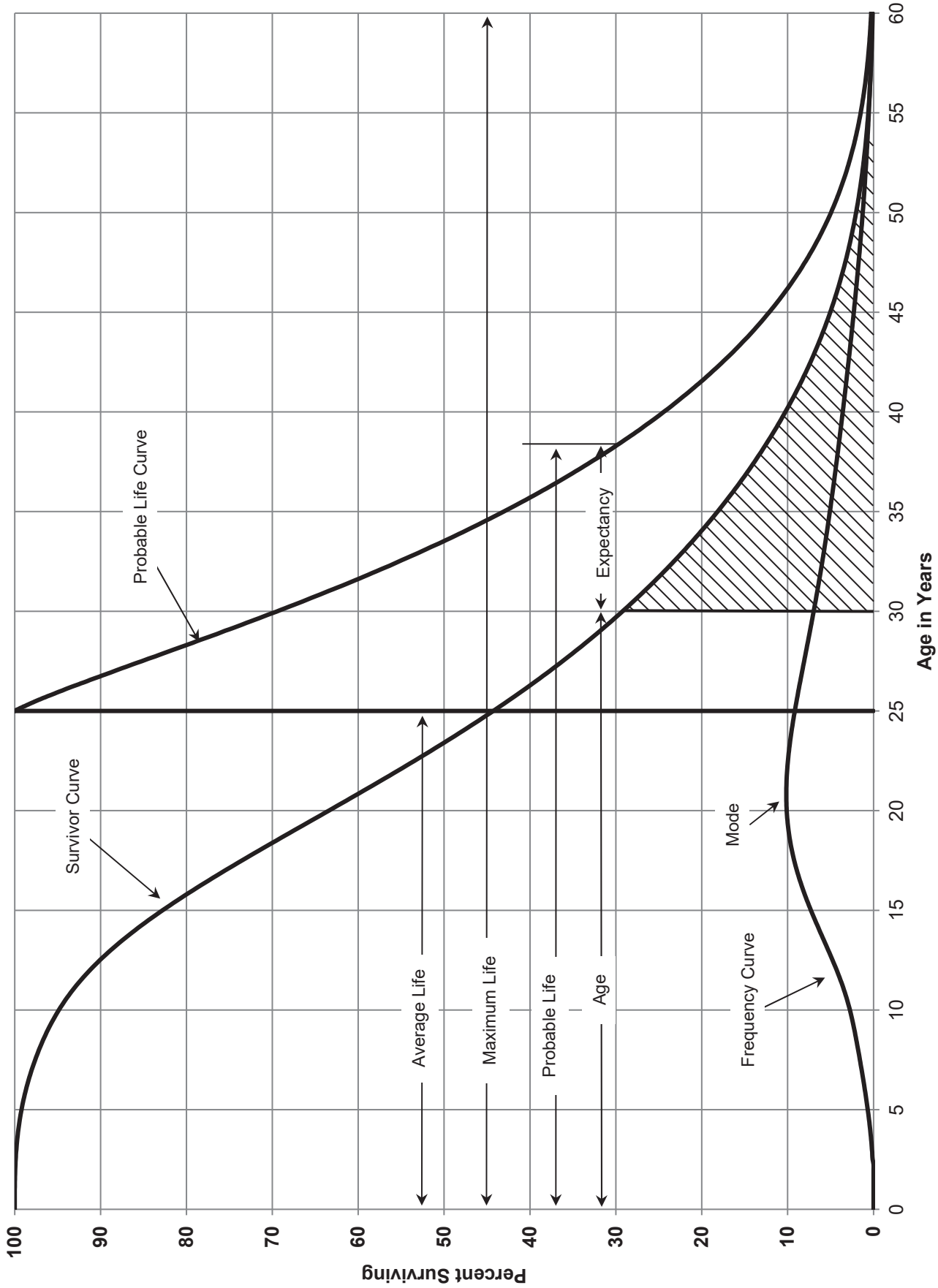


FIGURE 1. TYPICAL SURVIVOR CURVE AND DERIVED CURVES

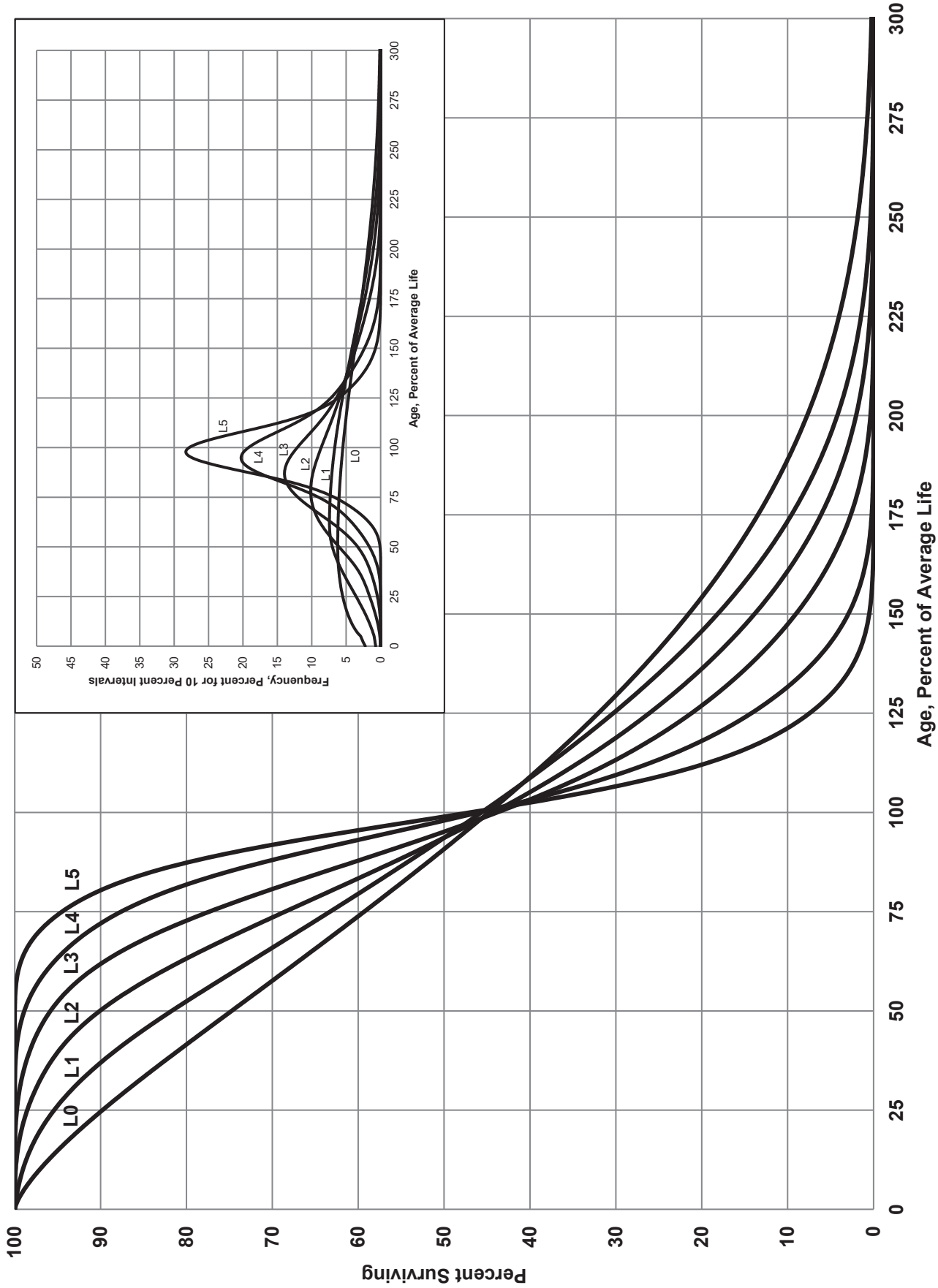


FIGURE 2. LEFT MODAL OR "L" IOWA TYPE SURVIVOR CURVES

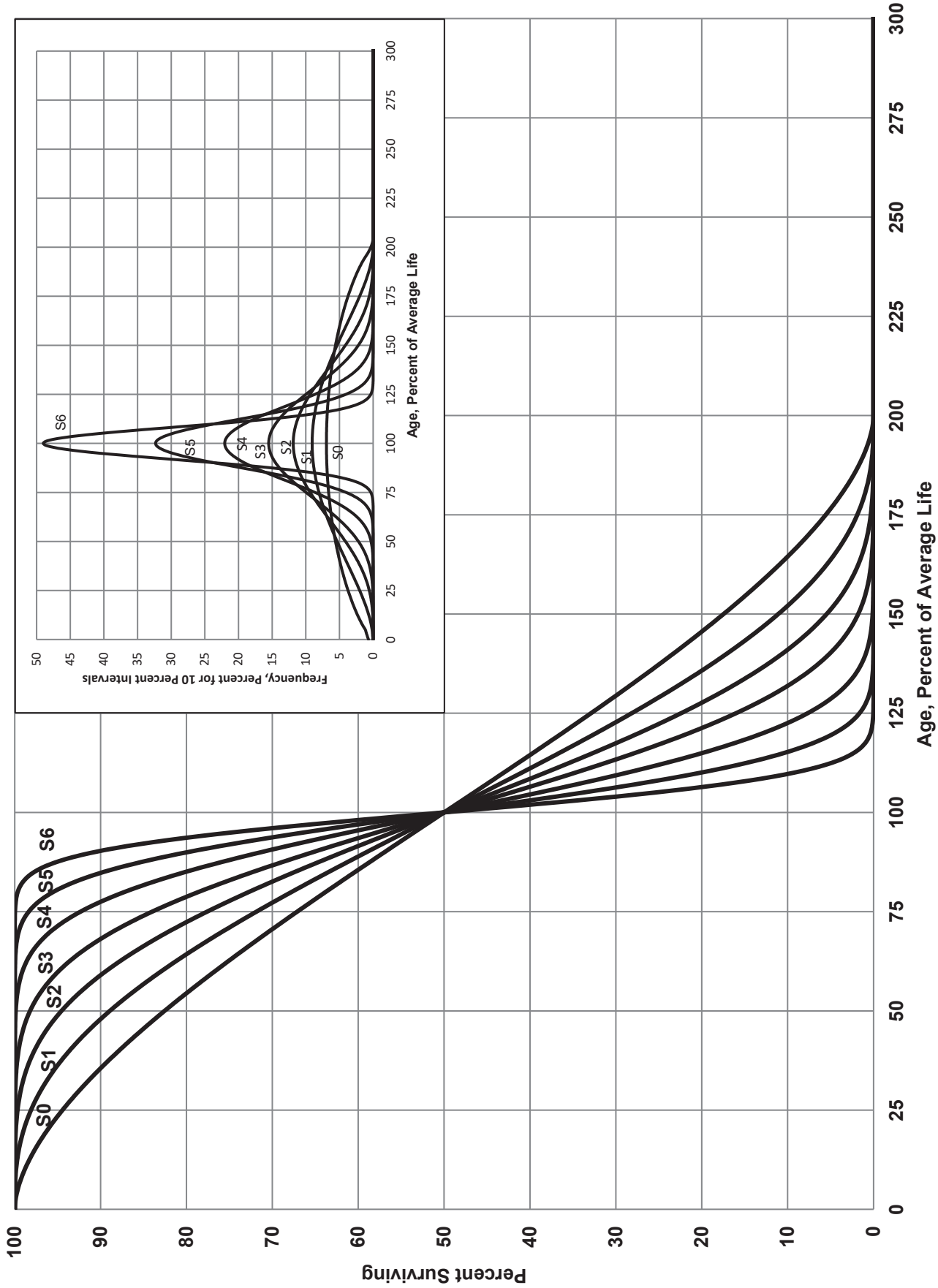


FIGURE 3. SYMMETRICAL OR "S" IOWA TYPE SURVIVOR CURVES

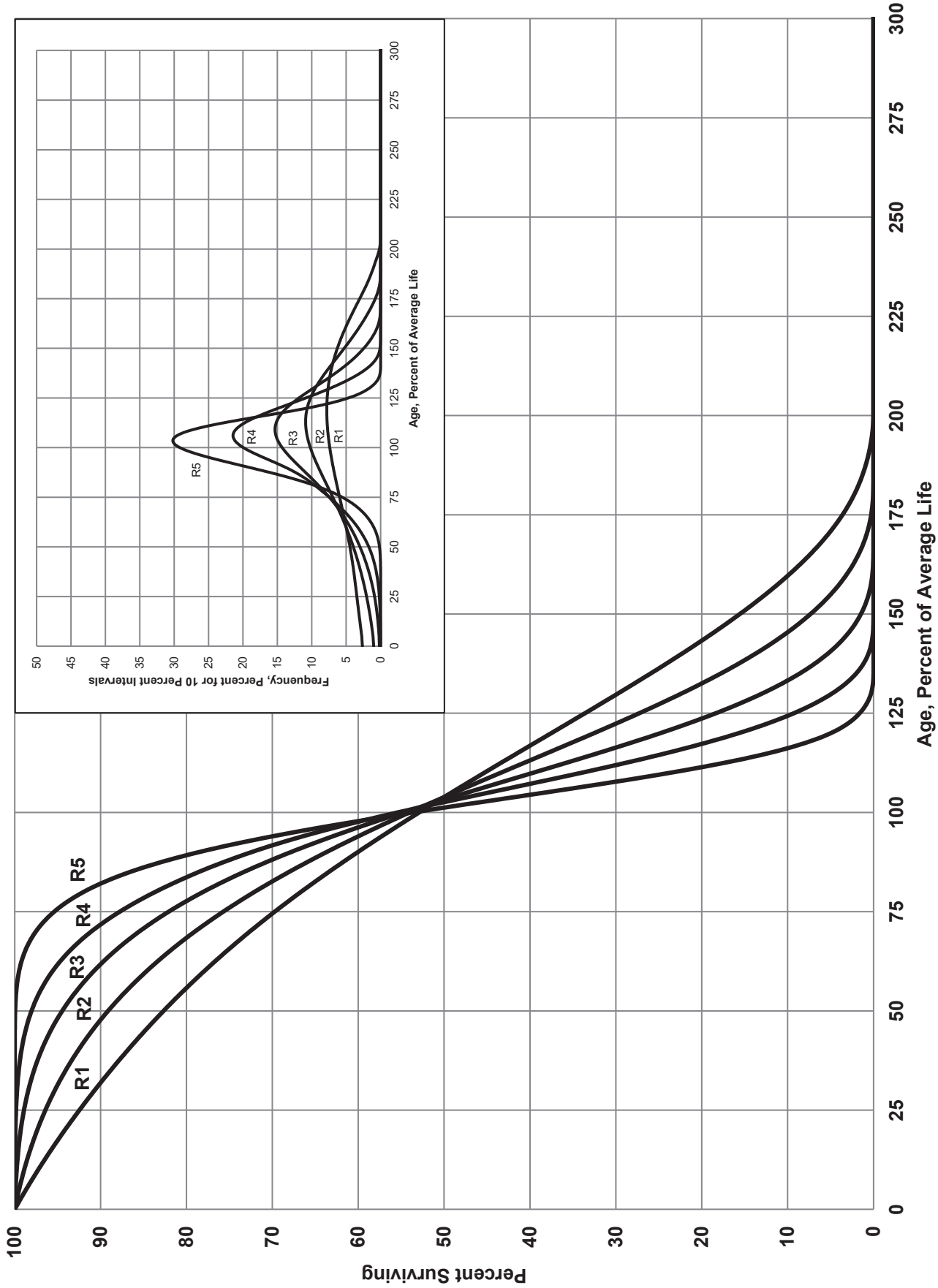


FIGURE 4. RIGHT MODAL OR "R" IOWA TYPE SURVIVOR CURVES

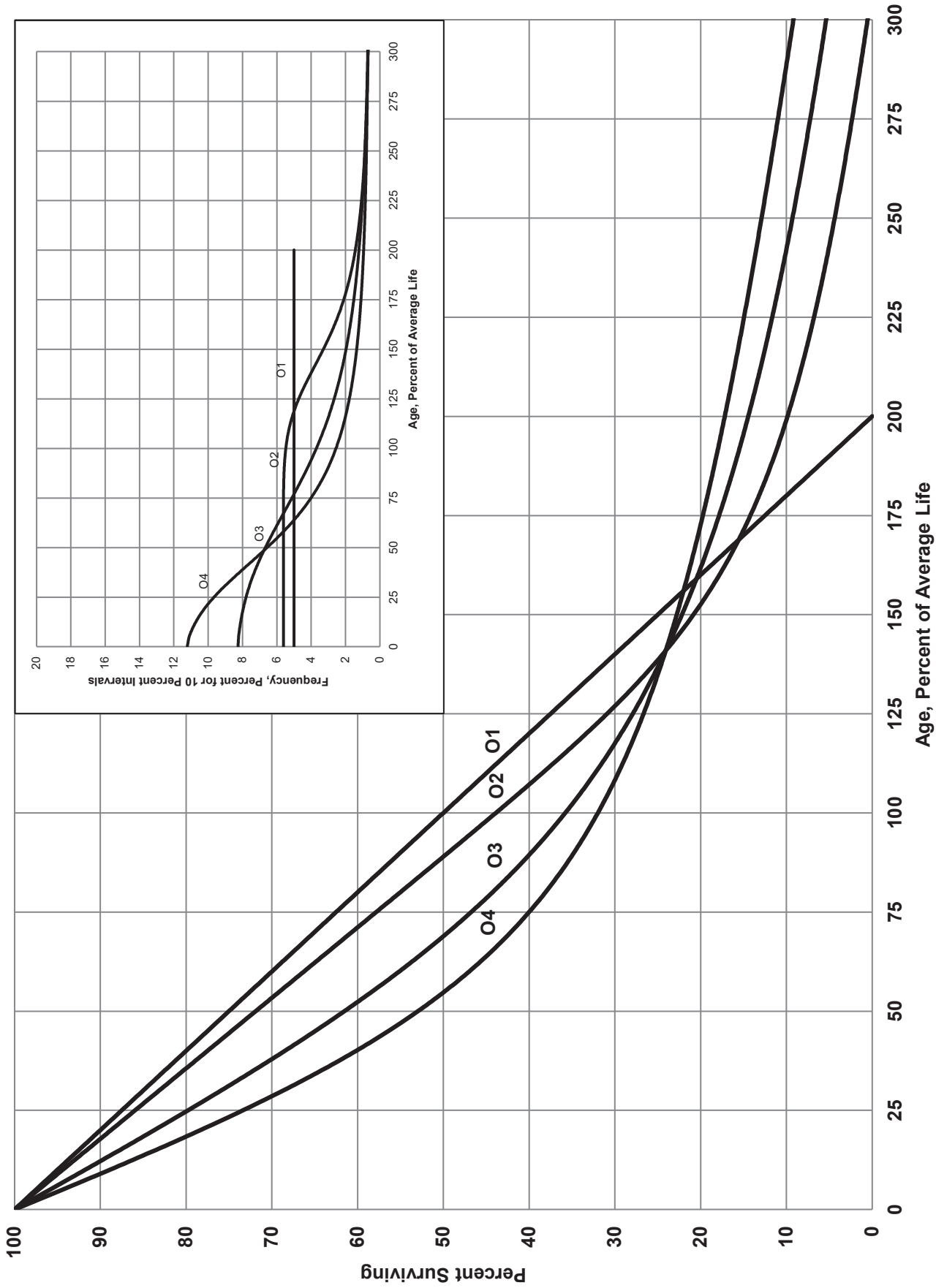


FIGURE 5. ORIGIN MODAL OR "O" IOWA TYPE SURVIVOR CURVES

These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[1] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis presenting his development of the fourth family consisting of the four O type survivor curves.

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text and is also explained in several publications including "Statistical Analyses of Industrial Property Retirements,"[2] "Engineering Valuation and Depreciation,"[3] and "Depreciation Systems."[4]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the experience band. The band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

[1]Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.
[2]Winfrey, Robley, Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.
[3]Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 1.
[4]Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2014-2023 for which there were placements during the years 2009-2023. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Schedules 1 and 2 on pages II-11 and II-12. In Schedule 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the dollars invested in 2009 were retired in 2014. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2014 retirements of 2009 installations and ending with the 2023 retirements of the 2018 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2014-2023
SUMMARIZED BY AGE INTERVAL

Experience Band 2014-2023 Placement Band 2009-2023

Year Placed	Retirements, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2009	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2010	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2011	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2012	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2013	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2014	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2015		5	11	12	13	14	15	16	18	20	113	7½-8½
2016			6	12	13	15	16	17	19	19	124	6½-7½
2017				6	13	15	16	17	19	19	131	5½-6½
2018					7	14	16	17	19	20	143	4½-5½
2019						8	18	20	22	23	146	3½-4½
2020							9	20	22	25	150	2½-3½
2021								11	23	25	151	1½-2½
2022									11	24	153	½-1½
2023										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2014-2023
SUMMARIZED BY AGE INTERVAL

Experience Band 2014-2023 Placement Band 2009-2023

Year Placed	Acquisitions, Transfers and Sales, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2009	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2010	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2011	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2012	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2013	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2014	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2015		-	-	-	-	-	-	-	-	-	6	7½-8½
2016			-	-	-	-	-	-	-	-	-	6½-7½
2017				-	-	-	-	(12)[b]	-	-	-	5½-6½
2018					-	-	-	-	22[a]	-	-	4½-5½
2019						-	-	(19)[b]	-	-	10	3½-4½
2020							-	-	-	-	-	2½-3½
2021								-	-	(102)[c]	(121)	1½-2½
2022									-	-	-	½-1½
2023											-	0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses Denote Credit Amount.

In Schedule 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 on page II-14. The surviving plant at the beginning of each year from 2014 through 2023 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2019 are calculated in the following manner:

Exposures at age 0	= amount of addition	= $750,000
Exposures at age ½	= $750,000 - $ 8,000	= $742,000
Exposures at age 1½	= $742,000 - $18,000	= $724,000
Exposures at age 2½	= $724,000 - $20,000 - $19,000	= $685,000
Exposures at age 3½	= $685,000 - $22,000	= $663,000

SCHEDULE 3. PLANT EXPOSED TO RETIREMENT
JANUARY 1 OF EACH YEAR 2014-2023
SUMMARIZED BY AGE INTERVAL

Experience Band 2014-2023

Placement Band 2009-2023

Year Placed	Exposures, Thousands of Dollars — Annual Survivors at the Beginning of the Year										Total at Beginning of Age Interval	Age Interval
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2009	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2010	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2011	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2012	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2013	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
2014	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2015		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2016			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2017				580[a]	574	561	546	530	501	482	3,057	5½-6½
2018					660[a]	653	639	623	628	609	3,789	4½-5½
2019						750[a]	742	724	685	663	4,332	3½-4½
2020							850[a]	841	821	799	4,955	2½-3½
2021								960[a]	949	926	5,719	1½-2½
2022									1,080[a]	1,069	6,579	½-1½
2023										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a]Additions during the year

For the entire experience band 2014-2023, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table

The original life table, illustrated in Schedule 4 on page II-16, is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15				
Exposures at age 4½	=	3,789,000				
Retirements from age 4½ to 5½	=	143,000				
Retirement Ratio	=	143,000	÷	3,789,000	=	0.0377
Survivor Ratio	=	1.000	-	0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15)	x	(0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless.

SCHEDULE 4. ORIGINAL LIFE TABLE
CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2014-2023 Placement Band 2009-2023

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving at Beginning of Age Interval
(1)	(2)	(3)	(4)	(5)	(6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
Column 3 from Schedule 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 Divided by Column 2.
Column 5 = 1.0000 Minus Column 4.
Column 6 = Column 5 Multiplied by Column 6 as of the Preceding Age Interval.

The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

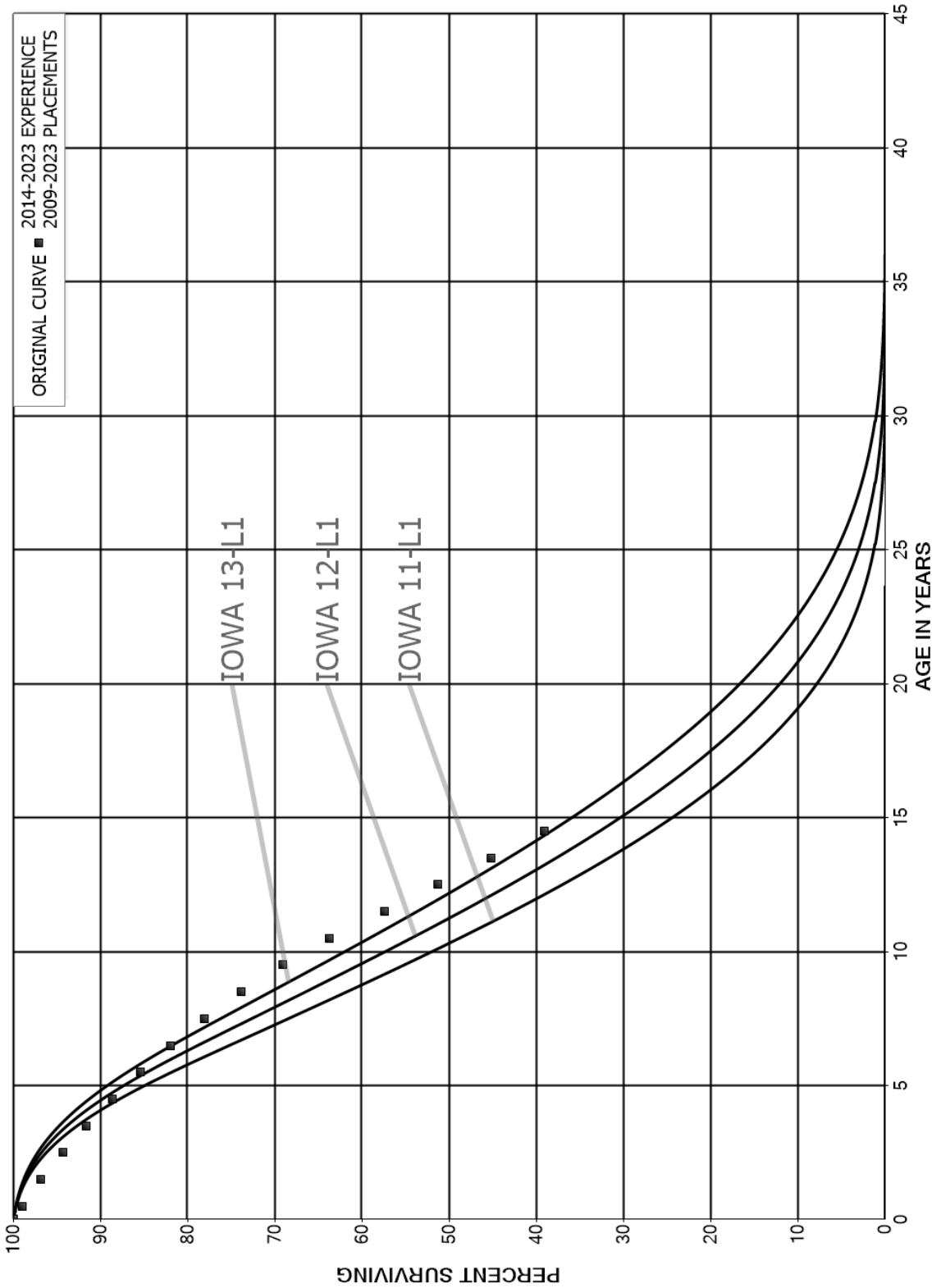


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

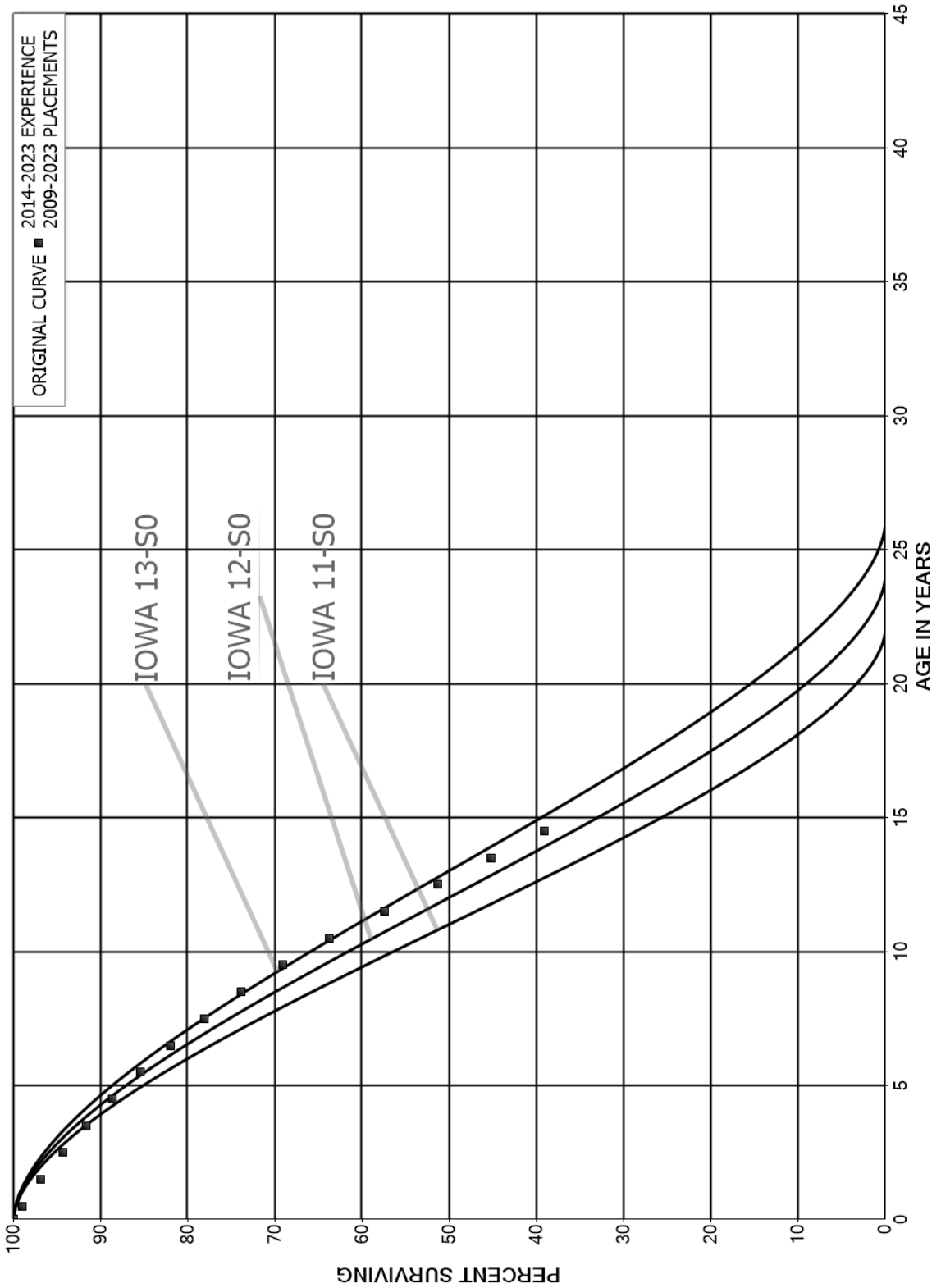


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

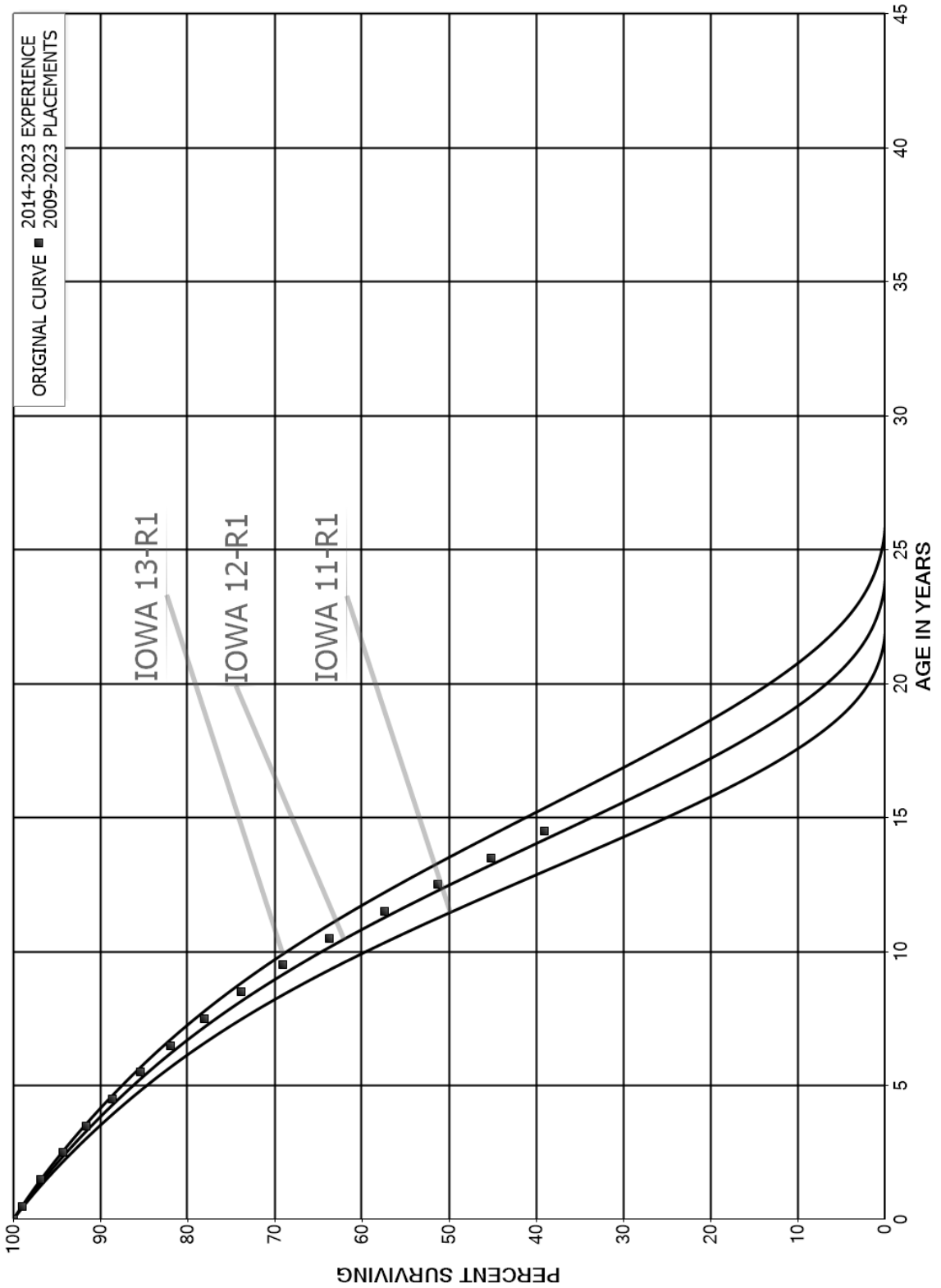
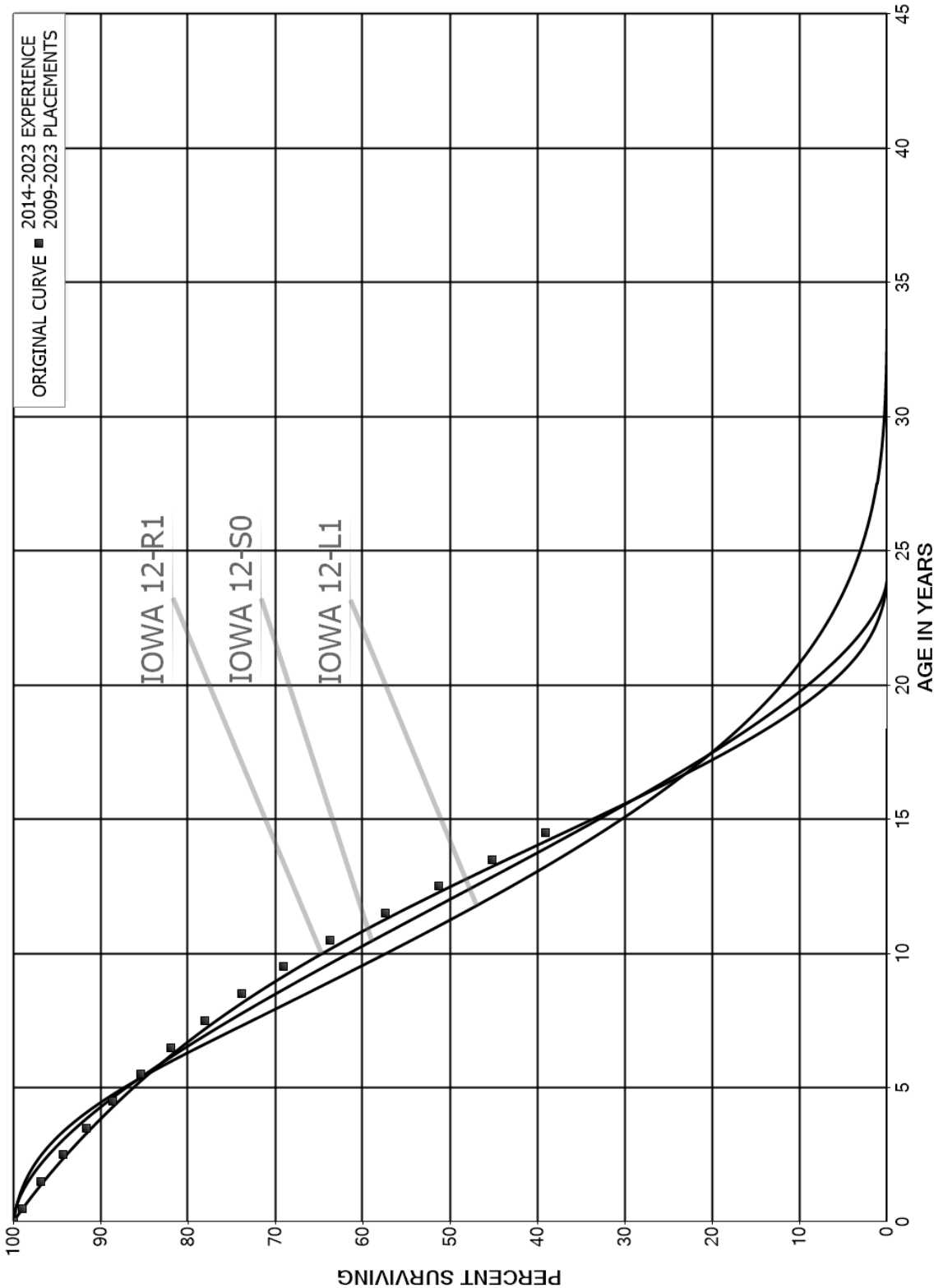


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



PART III. SERVICE LIFE CONSIDERATIONS

PART III. SERVICE LIFE CONSIDERATIONS

FIELD TRIPS

In order to be familiar with the operation of the Company and observe representative portions of the plant, field trips have been conducted during past studies. A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements are obtained during field trips. This knowledge and information were incorporated in the interpretation and extrapolation of the statistical analyses.

The following is a list of the locations visited during the most recent field trip.

September 28-29, 2021
North Mist Compressor Station
Injection Well 44-03-65
Mist (Miller Station) Compressor Station
Sauvie Island City Gate Station
Gasco Mixer Station (Measuring & Regulating Station)
Linnton (Portland) LNG Plant
Jean Road Regulating Station
Sherwood Service Center

SERVICE LIFE ANALYSIS

The service life estimates were based on informed judgment which considered a number of factors. The primary factors were the statistical analyses of data; current Company policies and outlook as determined during conversations with management; and the survivor curve estimates from previous studies of this company and other gas companies.

For many of the plant accounts and subaccounts for which survivor curves were estimated, the statistical analyses using the retirement rate method resulted in good to excellent indications of the survivor patterns experienced. These accounts represent 71 percent of depreciable plant. Generally, the information external to the statistics led to no

significant departure from the indicated survivor curves for the accounts listed below. The statistical support for the service life estimates is presented in the section beginning on page VII-2.

OIL GAS FACILITIES
- 305.50 Structures and Improvements - Other

OTHER PRODUCTION FACILITIES
- 305.11 Structures and Improvements – Gas Production
- 305.17 Structures and Improvements – Mixing Station

LOCAL STORAGE PLANT
- 361.00 Structures and Improvements
- 363.20 Vaporizing Equipment
- 363.50 CNG Refueling Facilities

DISTRIBUTION PLANT
- 375.00 Structures and Improvements
- 376.11 Mains – HP 4” and Less
- 376.12 Mains – HP 4” and Over
- 380.00 Services
- 381.00 Meters
- 381.10 Meters – Electric
- 381.20 Meters – ERT
- 382.00 Meter Installations
- 382.10 Meter Installations – Electric
- 382.20 Meter Installations – ERT
- 386.00 Other Property on Customers’ Premises

GENERAL PLANT
- 390.00 Structures and Improvements
- 390.10 Structures and Improvements – Source Control Plant
- 392.00 Transportation Equipment
- 396.00 Power Operated Equipment

The combined analysis of Accounts 376.11 - Mains, HP 4” and Less; and 376.12, Mains – HP 4” and Over, is used to illustrate the manner in which the study was conducted for the groups in the preceding list. The combined Accounts 376.11 and 376.12 represent 35 percent of the total depreciable plant. Aged plant accounting data have been compiled

for the years 1910 through 2023. These data have been coded in the course of the Company's normal record keeping according to account or property group, type of transaction, year in which the transaction took place, and year in which the gas plant was placed in service. The retirements, other plant transactions, and plant additions were analyzed by the retirement rate method.

The survivor curve estimate is based on the statistical indications for the period 1910 through 2023 and 1961 through 2023. The Iowa 65-R3 is an excellent fit of the original survivor curve. The 65-year service life is within the typical service life range of 55 to 70 years for mains. The 65-year life reflects the Company's plans and practices of the past and next few years. The previous estimate was the Iowa 67-R3.

The survivor curve estimate for Account 380.00, Services, is based on the statistical analyses of historical retirement experience for the periods 1919-2023, 1976-2015 and 1981-2015. The 60-R2.5 estimate for Account 380.00, Services, is a good fit of the original survivor curve developed from historical plant retirements for the period 1919 through 2023. However, the lack of recorded retirements in the last few years are not expected to continue so emphasis on the level of retirements through 2015 are expected into the future. The 60-R2.5 survivor curve sets forth the constant rates of retirement through approximately age 76. The 60-year average service life is above the upper end of the typical range of 40-55 years for services. The previous estimate was the Iowa 65-R1.5

The survivor curve estimates for the remaining accounts in the preceding list were based on similar statistical analyses and previous studies for this and other gas utilities. The remaining accounts were based primarily on judgment and estimates of other gas utilities.

Life Span Estimates

Inasmuch as production plant consists of large units, the life span technique was employed in conjunction with the use of interim survivor curves which reflect interim retirements that occur prior to the ultimate retirement of the major unit. An interim survivor curve was estimated for each plant account, inasmuch as the rate of interim retirements differs from account to account. The interim survivor curves estimated for local storage plant were based on the retirement rate method of life analysis which incorporated experienced aged retirements for the period 1961 through 2023.

The depreciable life span estimates for storage facilities were the result of considering experienced life spans of similar facilities, the age of surviving plants, general operating characteristics of the station, major refurbishing, and discussions with management personnel concerning the probable long-term outlook for the stations.

The estimated survivor curves for local storage plant reflect the life span or forecast concept of life estimation. In the life span concept, an interim survivor curve is selected to describe the rates of retirement between installation and the final concurrent retirement of all facilities at a location. The forecast life span for the Linnton and Newport plants in the local storage plant accounts, is set forth in years from the date of their initial major installation. Although the Company currently does not have plans to replace these plants in the foreseeable future, the forecast retirement dates represent the midpoint of a range of dates during which significant replacement of the facilities presently in service will be required due to their age and improvements in technology.

	Probable Retirement Date	Initial Major Installation	Life Span
Local Storage			
Linnton	2036	1969,2016	67,20
Newport	2042	1977,2017	55,25

Similar studies were performed for the remaining plant accounts. Each of the judgments represented a consideration of statistical analyses of aged plant activity, management's outlook for the future, and the typical range of lives used by other gas companies.

The selected amortization periods for other General Plant accounts are described in the section "Calculated Annual and Accrued Amortization."

PART IV. NET SALVAGE CONSIDERATIONS

PART IV. NET SALVAGE CONSIDERATIONS

NET SALVAGE ANALYSIS

The estimates of net salvage by account were based in part on historical data compiled for the years 1993 through 2023. Cost of removal and gross salvage were expressed as percents of the original cost of plant retired, both on annual and three-year moving average bases. The most recent five-year average also was calculated for consideration. The net salvage estimates by account are expressed as a percent of the original cost of plant retired.

Net Salvage Considerations

The estimates of future net salvage are expressed as percentages of surviving plant in service, i.e., all future retirements. In cases in which removal costs are expected to exceed salvage receipts, a negative net salvage percentage is estimated. The net salvage estimates were based on judgment which incorporated analyses of historical cost of removal and gross salvage data, expectations with respect to future removal requirements and markets for retired equipment and materials.

The analyses of historical cost of removal and gross salvage data are presented in the section titled “Net Salvage Statistics” for the plant accounts for which the net salvage estimate relied partially on those analyses.

Statistical analyses of historical data for the period 1993 through 2023 contributed significantly toward the net salvage estimates for 11 plant accounts, representing 70 percent of the depreciable plant, as follows:

DISTRIBUTION PLANT

376.11	Mains – HP 4” and Less
376.12	Mains – HP 4” and Over
380.00	Services
381.00	Meters
381.20	Meters – ERT
382.00	Meter Installations
382.20	Meter Installations – ERT

GENERAL PLANT

390.00	Structures and Improvements
390.10	Structures and Improvements – Source Control Plant
392.00	Transportation Equipment
396.00	Power Operated Equipment

The combined analyses of Account 376.11, Mains – HP 4” and Less and Account 376.12, Mains – HP 4” and Over, is used to illustrate the manner in which the study was conducted for the groups in the preceding list. Net salvage data for the period 1993 through 2023 were analyzed for this account. The data include cost of removal, gross salvage and net salvage amounts and each of these amounts is expressed as a percent of the original cost of regular retirements. Three-year moving averages for the 1993-1995 through 2021-2023 periods were computed to smooth the annual amounts.

Cost of removal fluctuated considerably during the 31-year period, 1993-2023. The practices for assigning labor costs to removing pipe versus installing new pipe had not changed in recent years however, there is a plan to allocate more to installation of the new asset and slightly less to cost of removal as compared to the retirement cost. Cost of removal for the most recent five years averaged 199 percent.

Gross salvage has been minimal throughout the period with a slight increase in recent years due to a few projects. The most recent five-year average of 12 percent gross salvage reflects moderate salvage value for pipe.

The net salvage percent based on the overall period 1993 through 2023 is 91 percent negative net salvage. The range of estimates made by other gas companies for mains is negative 15 to negative 75 percent. Because the overall statistical indications are above the upper end of the industry range and the most recent five-year period is well above the upper end of the range, the statistical indication of negative 65 percent was selected for the Company's mains. This also considers the expected reduction due to less cost of removal being assigned to main replacement projects.

The net salvage estimates for the remaining accounts were based on judgment incorporating estimates of previous studies of this and other gas utilities.

The net salvage estimates for the remaining plant accounts were estimated using the above-described process of historical indications, judgment and reviewing the typical range of estimates used by other gas companies. The results of the net salvage for each plant account are presented in account sequence beginning in the section titled "Net Salvage Statistics", page VIII-2.

Generally, the net salvage estimates for remaining general plant accounts were zero percent, consistent with amortization accounting.

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

GROUP DEPRECIATION PROCEDURES

A group procedure for depreciation is appropriate when considering more than a single item of property. Normally the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, average service life and equal life group. In the average service life procedure, the rate of annual depreciation is based on the average life or average remaining life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

Single Unit of Property

The calculation of straight line depreciation for a single unit of property is straightforward. For example, if a $1,000 unit of property attains an age of four years and has a life expectancy of six years, the annual accrual over the total life is:

$$\frac{\$1{,}000}{(4 + 6)} = \$100 \text{ per year.}$$

The accrued depreciation is:

$$\$1{,}000\left(1 - \frac{6}{10}\right) = \$400.$$

Remaining Life Annual Accruals

For the purpose of calculating remaining life accruals as of December 31, 2023, the depreciation reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and calculated accrued depreciation follow. The detailed calculations as of December 31, 2023, are set forth in the Results of Study section of the report.

Average Service Life Procedure

In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated future survivor curve in accordance with the average service life procedure.

The calculated accrued depreciation for each depreciable property group represents that portion of the depreciable cost of the group which would not be allocated to expense through future depreciation accruals if current forecasts of life characteristics are used as the basis for such accruals. The accrued depreciation calculation consists of applying an appropriate ratio to the surviving original cost of each vintage of each account based upon the attained age and service life. The straight line accrued depreciation ratios are calculated as follows for the average service life procedure:

$$Ratio = 1 - \frac{Average\ Remaining\ Life}{Average\ Service\ Life}.$$

CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is proposed for a number of accounts that represent numerous units of property, but a very small portion of depreciable gas plant in service. The accounts and their amortization periods are as follows:

Account		Amortization Period, Years
391.10	Office Furniture and Equipment	20
391.20	Office Furniture and Equipment – Computers	5
391.21	Office Furniture and Equipment – Computers Horizon	10
391.22	Office Furniture and Equipment – Computers TSA Security Directive	10
393.00	Stores Equipment	25
394.00	Tools, Shop and Garage Equipment - Non Specific	25
395.00	Laboratory Equipment	20
397.00	Communication Equipment	15
397.10	Communication Equipment – Mobile	10
397.20	Communication Equipment – Non Mobile and Telemeter	15
397.30	Communication Equipment – Telemeter Other	15
397.40	Communication Equipment – Telemeter Microwave	15
397.50	Communication Equipment – Telephone	10
398.10	Miscellaneous Equipment – Print Shop	15
398.20	Miscellaneous Equipment – Kitchen	15

398.30	Miscellaneous Equipment – Janitorial	20
398.40	Miscellaneous – Leased Buildings	20
398.50	Miscellaneous Equipment - Other	20

For the purpose of calculating annual amortization amounts as of December 31, 2023, the book depreciation reserve for each plant account or subaccount is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

PART VI. RESULTS OF STUDY

PART VI. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculated annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and net salvage and for the change of the composition of property in service. The annual accrual rates were calculated in accordance with the straight line remaining life method of depreciation, using the average service life procedure based on estimates which reflect considerations of current historical evidence and expected future conditions.

The annual depreciation accrual rates are applicable specifically to the gas plant in service as of December 31, 2023. For most plant accounts, the application of such rates to future balances that reflect additions subsequent to December 31, 2023, is reasonable for a period of three to five years.

DESCRIPTION OF STATISTICAL SUPPORT

The service life estimates were based on judgment that incorporated statistical analysis of retirement data, discussions with management and consideration of estimates made for other gas utilities. The results of the statistical analysis of service life are presented in the section beginning on page VII-2, within the supporting documents of this report.

For each depreciable group analyzed by the retirement rate method, a chart depicting the original and estimated survivor curves followed by a tabular presentation of

the original life table(s) plotted on the chart. The survivor curves estimated for the depreciable groups are shown as dark smooth curves on the charts. Each smooth survivor curve is denoted by a numeral followed by the curve type designation. The numeral used is the average life derived from the entire curve from 100 percent to zero percent surviving. The titles of the chart indicate the group, the symbol used to plot the points of the original life table, and the experience and placement bands of the life tables which where plotted. The experience band indicates the range of years for which retirements were used to develop the stub survivor curve. The placements indicate, for the related experience band, the range of years of installations which appear in the experience.

The analyses of net salvage data are presented in the section titled, “Net Salvage Statistics”. The tabulations present annual cost of removal and gross salvage data, three-year moving averages and the most recent five-year average. Data are shown in dollars and as percentages of original costs retired.

DESCRIPTION OF DETAILED TABULATIONS

A summary of the results of the study, as applied to the original cost of gas plant as of December 31, 2023, is presented on pages VI-5 through VI-8 of this report. The schedule sets forth the original cost, the book depreciation reserve, future accruals, the calculated annual depreciation rate and amount, and the composite remaining life related to gas plant.

The tables of the calculated annual depreciation applicable to depreciable assets as of December 31, 2023 are presented in account sequence starting on page IX-2 of the supporting documents. The tables indicate the estimated survivor curve and net salvage

percent for the account and set forth, for each installation year, the original cost, the calculated accrued depreciation, the allocated book reserve, future accruals, the remaining life, and the calculated annual accrual amount.

NORTHWEST NATURAL GAS COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2023

	DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2023	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
DEPRECIABLE GAS PLANT											
INTANGIBLE PLANT											
303.10	MISCELLANEOUS INTANGIBLE PLANT - SOFTWARE		15-SQ		0	128,050,933.02	26,336,695	101,714,238	9,791,008	7.65	10.4
303.11	MISCELLANEOUS INTANGIBLE PLANT - HORIZON		10-SQ		0	46,726,994.21	4,141,642	42,585,352	5,010,041	10.72	8.5
303.12	MISCELLANEOUS INTANGIBLE PLANT - SECURITY DIRECTIVE		10-SQ		0	22,242,163.51	1,789,927	20,452,237	2,403,337	10.81	8.5
303.20	MISCELLANEOUS INTANGIBLE PLANT - CUSTOMER INFORMATION SYSTEM		15-SQ		0	32,409,597.11	32,398,798	10,799	1,963	0.01	5.5
303.30	MISCELLANEOUS INTANGIBLE PLANT - INDUSTRIAL AND COMMERCIAL		10-SQ		0	4,146,951.00	4,146,951	0	0	-	-
303.70	MISCELLANEOUS INTANGIBLE PLANT - CRMS		5-SQ		0	33,207,967.40	11,320,431	21,887,536	5,597,274	16.86	3.9
303.71	MISCELLANEOUS INTANGIBLE PLANT - CLOUD-BASED SOFTWARE HORIZON		10-SQ		0	24,096,593.68	3,203,067	20,893,527	2,458,062	10.20	8.5
303.72	MISCELLANEOUS INTANGIBLE PLANT - CLOUD-BASED SOFTWARE TSA SECURITY DIRECTIVE		5-SQ		0	3,157,883.11	0	3,157,883	900,792	28.53	3.5
TOTAL INTANGIBLE PLANT						**294,039,083.04**	**83,337,511**	**210,701,572**	**26,162,477**	**8.90**	
OIL GAS FACILITIES											
305.50	STRUCTURES AND IMPROVEMENTS - OTHER		40-S1		(5)	13,156.00	13,814	0	0	-	-
311.70	LIQUEFIED PETROLEUM GAS EQUIPMENT		18-L0.5		(5)	4,033.00	8,066	(3,831)	0	-	-
311.80	LIQUEFIED PETROLEUM GAS EQUIPMENT		18-L0.5		(5)	4,209.00	6,585	(2,166)	0	-	-
TOTAL OIL GAS FACILITIES						**21,398.00**	**28,465**	**(5,997)**	**0**	**-**	
OTHER PRODUCTION FACILITIES											
305.11	STRUCTURES AND IMPROVEMENTS - GAS PRODUCTION		40-S1		(5)	8,320.00	8,736	0	0	-	-
305.17	STRUCTURES AND IMPROVEMENTS - MIXING STATION		40-S1		(5)	46,587.00	51,246	(2,330)	0	-	-
318.30	LIGHT OIL REFINING		45-S2.5		(5)	144,896.00	152,141	0	0	-	-
318.50	TAR PROCESSING		45-S2.5		(5)	243,551.00	255,729	0	0	-	-
319.00	GAS MIXING EQUIPMENT		30-R0.5		(5)	185,448.00	194,720	0	0	-	-
TOTAL OTHER PRODUCTION FACILITIES						**628,802.00**	**662,572**	**(2,330)**	**0**	**-**	
UNDERGROUND STORAGE PLANT											
350.20	LAND RIGHTS		70-R4		0	109,624.94	38,249	71,376	1,545	1.41	46.2
351.00	STRUCTURES AND IMPROVEMENTS		60-R4		0	14,554,925.77	3,598,479	10,956,447	232,069	1.59	47.2
352.00	WELLS		50-S4		0	63,027,620.00	20,130,011	42,897,609	1,219,313	1.93	35.2
352.10	STORAGE LEASEHOLDS AND RIGHTS		55-S3		0	3,939,511.52	2,053,886	1,885,626	65,283	1.66	28.9
352.20	RESERVOIRS		55-S3		0	10,834,054.54	4,520,124	6,313,931	191,859	1.77	32.9
352.30	NONRECOVERABLE GAS		55-R4		0	6,440,889.82	4,055,238	2,385,652	97,235	1.51	24.5
353.00	LINES		55-S3		(15)	12,955,423.07	4,880,336	10,018,401	267,129	2.06	37.5
354.10	COMPRESSOR STATION EQUIPMENT - TURBINE 1		50-R3		(10)	7,885,231.22	3,244,668	5,429,086	150,255	1.91	36.1
354.20	COMPRESSOR STATION EQUIPMENT - TURBINE 2		50-R3		(10)	4,154,699.00	3,255,359	1,314,810	67,461	1.62	19.5
354.30	COMPRESSOR STATION EQUIPMENT - TURBINE 3		50-R3		(10)	21,084,256.03	8,324,605	14,868,077	420,517	1.99	35.4
354.40	COMPRESSOR STATION EQUIPMENT - TURBINE 4		50-R3		(10)	16,396,554.18	7,211,285	10,824,925	325,593	1.99	33.2
354.50	COMPRESSOR STATION EQUIPMENT - TURBINE 5		50-R3		(10)	3,739,476.97	1,231,783	2,881,642	76,801	2.05	37.5
354.60	COMPRESSOR STATION EQUIPMENT - TURBINE 6		50-R3		(10)	260,041.78	55,162	230,884	5,531	2.13	41.7
355.00	MEASURING AND REGULATING EQUIPMENT		45-S2		(10)	39,474,567.00	9,593,627	33,828,397	944,101	2.39	35.8
356.00	PURIFICATION EQUIPMENT		45-S2.5		(5)	28,968,864.51	1,837,162	28,580,146	694,183	2.40	41.2
357.00	OTHER EQUIPMENT		35-R4		0	5,261,772.21	1,404,487	3,857,285	137,955	2.62	28.0
TOTAL UNDERGROUND STORAGE PLANT						**239,087,512.56**	**75,434,461**	**176,344,294**	**4,896,830**	**2.05**	
LOCAL STORAGE PLANT											
361.00	STRUCTURES AND IMPROVEMENTS										
	LINNTON	06-2036	60-R2.5	*	(5)	12,498,961.89	5,008,053	8,115,857	658,612	5.27	12.3
	NEWPORT	06-2042	60-R2.5	*	(5)	12,196,541.26	5,148,646	7,657,722	428,309	3.51	17.9
	OTHER		60-R2.5		(5)	26,757.00	14,191	13,904	399	1.49	34.8
	TOTAL STRUCTURES AND IMPROVEMENTS					24,722,260.15	10,170,890	15,787,483	1,087,320	4.40	14.5

NORTHWEST NATURAL GAS COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2023

	DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2023	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
362.00	GAS HOLDERS										
	LINNTON	06-2036	60-R3	*	(20)	4,556,064.35	3,122,790	2,344,487	197,281	4.33	11.9
	NEWPORT	06-2042	60-R3	*	(20)	5,927,103.82	6,422,031	690,494	44,938	0.76	15.4
	OTHER		60-R3		(20)	1,600.14	1,312	608	15	0.94	40.5
	TOTAL GAS HOLDERS					10,484,768.31	9,546,133	3,035,589	242,234	2.31	12.5
363.10	LIQUEFACTION EQUIPMENT										
	LINNTON	06-2036	50-R2.5	*	(5)	3,911,724.33	2,906,482	1,200,829	98,779	2.53	12.2
	NEWPORT	06-2042	50-R2.5	*	(5)	22,700,560.02	8,398,821	15,436,767	890,918	3.92	17.3
	TOTAL LIQUEFACTION EQUIPMENT					26,612,284.35	11,305,303	16,637,596	989,697	3.72	16.8
363.20	VAPORIZING EQUIPMENT										
	LINNTON	06-2036	40-R4	*	(5)	4,458,618.00	2,707,111	1,974,438	179,030	4.02	11.0
	NEWPORT	06-2042	40-R4	*	(5)	6,718,208.96	1,307,093	5,747,026	320,797	4.78	17.9
	TOTAL VAPORIZING EQUIPMENT					11,176,826.96	4,014,204	7,721,464	499,827	4.47	15.5
363.30	COMPRESSOR EQUIPMENT										
	LINNTON	06-2036	35-R1.5	*	(5)	1,362,753.51	218,613	1,212,278	102,046	7.49	11.9
	NEWPORT	06-2042	35-R1.5	*	(5)	7,731,229.09	2,477,597	5,640,194	333,389	4.31	16.9
	TOTAL COMPRESSOR EQUIPMENT					9,093,982.60	2,696,210	6,852,472	435,435	4.79	15.7
363.40	MEASURING AND REGULATING EQUIPMENT										
	LINNTON	06-2036	50-R4	*	(5)	7,882,786.81	1,490,295	6,786,631	559,147	7.09	12.1
	NEWPORT	06-2042	50-R4	*	(5)	15,384,423.80	1,109,662	15,043,983	819,145	5.32	18.4
	TOTAL MEASURING AND REGULATING EQUIPMENT					23,267,210.61	2,599,957	21,830,614	1,378,292	5.92	15.8
363.50	CNG REFUELING FACILITIES		31-R3		(5)	3,281,734.97	1,831,291	1,614,531	83,959	2.56	19.2
363.60	LNG REFUELING FACILITIES		45-S2.5		(5)	739,473.00	741,913	34,534	1,903	0.26	18.1
TOTAL LOCAL STORAGE PLANT						**109,378,540.95**	**42,905,901**	**73,514,283**	**4,718,667**	**4.31**	
TRANSMISSION PLANT											
365.20	LAND RIGHTS		75-R4		0	6,455,176.86	2,600,382	3,854,795	83,004	1.29	46.4
366.30	STRUCTURES AND IMPROVEMENTS		55-R3		0	1,546,072.61	494,039	1,052,034	26,760	1.73	39.3
367.00	MAINS		70-R3		(40)	243,891,349.30	46,553,265	294,894,624	4,855,298	1.99	60.7
367.21	MAINS - NORTH MIST		70-R3		(40)	1,994,582.39	1,342,849	1,449,566	32,816	1.65	44.2
367.22	MAINS - SOUTH MIST		70-R3		(40)	14,949,264.00	12,154,663	8,774,307	230,439	1.54	38.1
367.23	MAINS - SOUTH MIST		70-R3		(40)	34,881,341.36	17,859,027	30,974,851	657,235	1.88	47.1
367.24	MAINS - 11.7M S MIST		70-R3		(40)	17,466,181.89	7,804,954	16,647,701	330,574	1.89	50.4
367.25	MAINS - 12M NORTH S MIST		70-R3		(40)	18,613,651.15	8,025,389	18,033,723	355,046	1.91	50.8
367.26	MAINS - 38M NORTH S MIST		70-R3		(40)	68,232,675.58	29,590,611	65,935,135	1,298,659	1.90	50.8
368.00	COMPRESSOR STATION EQUIPMENT		45-R3		(5)	7,723,454.21	3,373,630	4,735,997	156,458	2.03	30.3
369.00	MEASURING AND REGULATING EQUIPMENT		50-R2.5		(10)	3,969,550.28	2,062,022	2,304,483	57,616	1.45	40.0
TOTAL TRANSMISSION PLANT						**419,723,299.63**	**131,860,831**	**448,657,216**	**8,083,905**	**1.93**	
DISTRIBUTION PLANT											
374.20	LAND RIGHTS		75-R4		0	1,886,180.64	1,725,171	161,010	2,499	0.13	64.4
375.00	STRUCTURES AND IMPROVEMENTS		35-S1		0	1,587,598.32	239,253	1,348,345	62,819	3.96	21.5
376.11	MAINS - HP 4" AND LESS		65-R3		(65)	733,069,799.15	396,483,311	813,081,858	18,030,844	2.46	45.1
376.12	MAINS - HP 4" AND OVER		65-R3		(65)	779,378,528.59	297,942,649	988,031,923	20,420,234	2.62	48.4
377.00	COMPRESSOR STATION EQUIPMENT		30-S3		(5)	860,686.82	719,546	184,175	14,348	1.67	12.8
378.00	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL		50-R3		(25)	55,197,805.30	16,175,076	52,822,181	1,415,068	2.56	37.3
379.00	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE		50-R2.5		(25)	22,002,640.72	4,561,996	22,941,305	527,644	2.40	43.5
380.00	SERVICES		60-R2.5		(100)	1,004,062,014.54	486,777,081	1,521,346,948	35,336,053	3.52	43.1
381.00	METERS		30-S0		0	111,544,967.20	16,523,475	95,021,492	4,465,795	4.00	21.3
381.10	METERS - ELECTRIC		16-S4		0	1,696,938.46	1,461,577	235,361	35,878	2.11	6.6
381.20	METERS - ERT		15-R0.5		0	48,095,881.00	16,345,841	31,750,040	3,304,178	6.87	9.6
382.00	METER INSTALLATIONS		22-L1		0	67,194,266.99	3,463,742	63,730,525	5,491,694	8.17	11.6
382.10	METER INSTALLATIONS - ELECTRIC		15-L3		0	481,019.77	298,351	182,669	33,953	7.06	5.4
382.20	METER INSTALLATIONS - ERT		18-R2.5		0	9,455,364.18	5,948,353	3,507,011	404,405	4.28	8.7
383.00	HOUSE REGULATORS		30-S2.5		0	3,244,766.96	695,743	2,549,024	115,310	3.55	22.1

NORTHWEST NATURAL GAS COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2023

	DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2023	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
386.00	OTHER PROPERTY ON CUSTOMERS' PREMISES		14-S0	0	1,162,110.41	753,163	408,947	43,878	3.78	9.3
387.10	OTHER EQUIPMENT - CATHODIC PROTECTION TESTING		25-S4	0	173,858.98	150,855	23,004	3,899	2.24	5.9
387.20	OTHER EQUIPMENT - CALORIMETERS AT GATE STATION		23-S0.5	0	96,424.00	96,424	0	0	-	-
387.30	OTHER EQUIPMENT - METER TESTING EQUIPMENT		25-S4	0	72,671.00	72,671	0	0	-	-
TOTAL DISTRIBUTION PLANT					**2,841,263,523.03**	**1,250,434,278**	**3,597,325,818**	**89,708,499**	**3.16**	
GENERAL PLANT										
390.00	STRUCTURES AND IMPROVEMENTS		48-S0	(5)	147,048,661.54	21,709,798	132,691,297	3,132,793	2.13	42.4
390.10	STRUCTURES AND IMPROVEMENTS - SOURCE CONTROL PLANT		48-S0	(5)	23,033,564.87	7,427,058	16,758,185	417,789	1.81	40.1
391.10	OFFICE FURNITURE AND EQUIPMENT									
	FULLY ACCRUED				150,625.11	150,625	0	0	-	-
	AMORTIZED		20-SQ	0	18,089,789.51	5,849,675	12,240,115	904,546	5.00	13.5
	TOTAL ACCOUNT 391.10				18,240,414.62	6,000,300	12,240,115	904,546	4.96	13.5
391.20	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS									
	FULLY ACCRUED				0.14	0	0	0	-	-
	AMORTIZED		5-SQ	0	45,049,654.91	26,473,140	18,576,515	9,008,263	20.00	2.1
	TOTAL ACCOUNT 391.20				45,049,655.05	26,473,140	18,576,515	9,008,263	20.00	2.1
391.21	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS HORIZON		10-SQ	0	2,190,419.85	328,563	1,861,857	219,042	10.00	8.5
391.22	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS TSA SECUIRTY DIRECTIVE		10-SQ	0	9,141,168.44	1,370,558	7,770,610	914,117	10.00	8.5
392.00	TRANSPORTATION EQUIPMENT		13-L2	15	57,500,630.35	22,116,078	26,759,458	3,192,238	5.55	8.4
393.00	STORES EQUIPMENT		FULLY ACCRUED		119,406.00	119,406	0	0	-	-
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT		25-SQ	0	23,892,668.61	7,467,894	16,424,775	955,705	4.00	17.2
396.00	POWER OPERATED EQUIPMENT		15-L1.5	20	16,250,386.19	3,432,764	9,567,545	893,134	5.50	10.7
397.00	COMMUNICATION EQUIPMENT		15-SQ	0	49,718.14	34,803	14,915	3,314	6.67	4.5
397.10	COMMUNICATION EQUIPMENT - MOBILE		10-SQ	0	5,340,779.26	1,977,185	3,363,594	534,079	10.00	6.3
397.20	COMMUNICATION EQUIPMENT - NON-MOBILE AND TELEMETER		15-SQ	0	9,957.65	6,970	2,988	664	6.67	4.5
397.30	COMMUNICATION EQUIPMENT - TELEMETER OTHER									
	FULLY ACCRUED				53,241.79	53,242	0	0	-	-
	AMORTIZED		15-SQ	0	13,964,358.75	3,160,000	10,804,359	931,795	6.67	11.6
	TOTAL ACCOUNT 397.30				14,017,600.54	3,213,242	10,804,359	931,795	6.65	11.6
397.40	COMMUNICATION EQUIPMENT - TELEMETER MICROWAVE									
	FULLY ACCRUED				61,119.78	61,120	0	0	-	-
	AMORTIZED		15-SQ	0	7,009,279.04	2,127,101	4,882,178	467,288	6.67	10.4
	TOTAL ACCOUNT 397.40				7,070,398.82	2,188,221	4,882,178	467,288	6.61	10.4
397.50	COMMUNICATION EQUIPMENT - TELEPHONE		10-SQ	0	340,671.19	300,650	40,021	34,146	10.00	1.2
398.10	MISCELLANEOUS EQUIPMENT - PRINT SHOP		15-SQ	0	4,359.31	3,923	436	291	6.67	1.5
398.20	MISCELLANEOUS EQUIPMENT - KITCHEN		15-SQ	0	28,864.84	15,277	13,588	1,924	6.67	7.1
398.30	MISCELLANEOUS EQUIPMENT - JANITORIAL		FULLY ACCRUED		14,873.00	14,873	0	0	-	-
398.40	MISCELLANEOUS EQUIPMENT - LEASED BUILDINGS		FULLY ACCRUED		10,120.00	10,120	0	0	-	-
398.50	MISCELLANEOUS EQUIPMENT - OTHER									
	FULLY ACCRUED				66,739.00	66,739	0	0	-	-
	AMORTIZED		20-SQ	0	243.22	12	231	12	5.00	19.2
	TOTAL ACCOUNT 398.50				66,982.22	66,751	231	12	0.02	19.3
TOTAL GENERAL PLANT					**369,421,300.49**	**104,277,574**	**261,772,667**	**21,611,140**	**5.85**	

NORTHWEST NATURAL GAS COMPANY

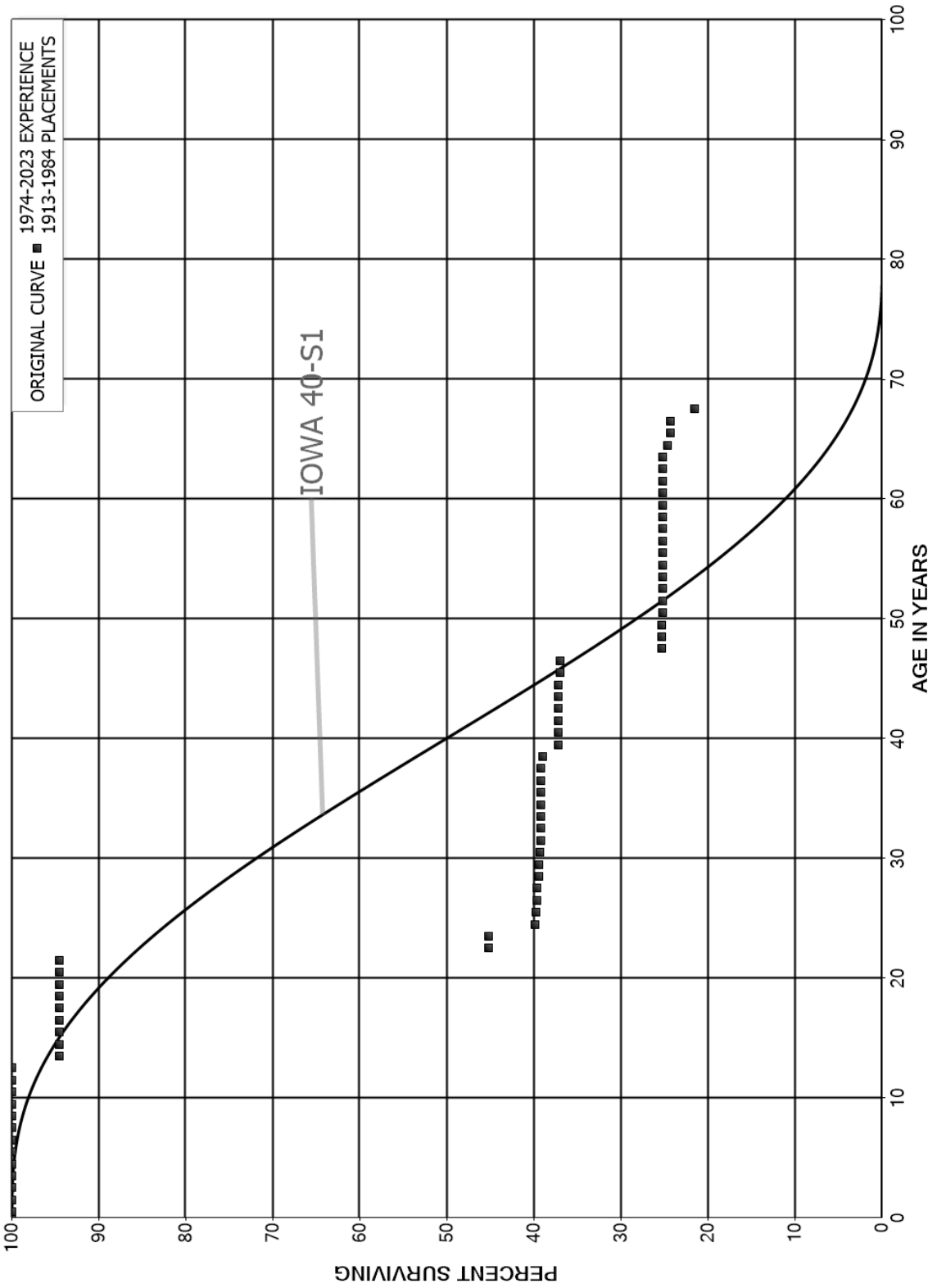
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2023

	DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2023	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(8)/(5)	(10)=(7)/(8)
RESERVE ADJUSTMENT FOR AMORTIZATION										
391.10	OFFICE FURNITURE AND EQUIPMENT					1,342,419		(268,484) **		
391.20	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS					(85,000)		17,000 **		
391.21	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS HORIZON					218,417		(43,683) **		
391.22	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS TSA SECUIRTY DIRECTIVE					961,928		(192,386) **		
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT					485,356		(97,071) **		
395.00	LABORATORY EQUIPMENT					(35)		7 **		
397.00	COMMUNICATION EQUIPMENT					5,944		(1,189) **		
397.10	COMMUNICATION EQUIPMENT - MOBILE					(104,997)		20,999 **		
397.20	COMMUNICATION EQUIPMENT - NON-MOBILE AND TELEMETER					(59,219)		11,844 **		
397.30	COMMUNICATION EQUIPMENT - TELEMETER OTHER					(318,519)		63,704 **		
397.40	COMMUNICATION EQUIPMENT - TELEMETER MICROWAVE					(330,997)		66,199 **		
397.50	COMMUNICATION EQUIPMENT - TELEPHONE					57,055		(11,411) **		
398.10	MISCELLANEOUS EQUIPMENT - PRINT SHOP					(1,527)		305 **		
398.20	MISCELLANEOUS EQUIPMENT - KITCHEN					(744)		149 **		
398.50	MISCELLANEOUS EQUIPMENT - OTHER					(12)		2		
TOTAL RESERVE ADJUSTMENT FOR AMORTIZATION						**2,170,069**		**(434,015)**		
TOTAL DEPRECIABLE GAS PLANT					**4,273,563,459.70**	**1,691,111,662**	**4,768,307,523**	**154,747,503**	**3.62**	
NONDEPRECIABLE GAS PLANT										
301.00	ORGANIZATION				1,174.00	0				
302.00	FRANCHISES AND CONSENTS				83,621.00	0				
304.10	LAND				24,998.00	0				
350.10	LAND				106,549.00	0				
360.11	LAND - LNG LINNTON				83,598.00	0				
360.12	LAND - LNG NEWPORT				536,433.00	(242)				
360.20	LAND - OTHER				106,557.00	0				
365.10	LAND				1,015,597.00	0				
374.10	LAND				211,692.00	0				
389.00	LAND				13,118,401.00	426,129				
	ROU UTILITY LEASE				0.00	15,856,270				
	FIN UTILITY LEASE				0.00	199,716				
TOTAL NONDEPRECIABLE GAS PLANT					**15,288,620.00**	**16,481,873**				
TOTAL GAS PLANT IN SERVICE					**4,288,852,079.70**	**1,707,593,535**				

* INDICATES INTERIM SURVIVOR CURVE. EACH UNIT HAS A UNIQUE TERMINAL DATE.
** 5 YEAR AMORTIZATION OF RESERVE RELATED TO AMORTIZATION ACCOUNTING.

PART VII. SERVICE LIFE STATISTICS

NORTHWEST NATURAL GAS COMPANY
ACCOUNTS 305.11, 305.17 AND 305.50 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 305.11, 305.17 AND 305.50 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1913-1984 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	13,156		0.0000	1.0000	100.00
0.5	13,156		0.0000	1.0000	100.00
1.5	13,156		0.0000	1.0000	100.00
2.5	13,156		0.0000	1.0000	100.00
3.5	13,156		0.0000	1.0000	100.00
4.5	13,156		0.0000	1.0000	100.00
5.5	13,156		0.0000	1.0000	100.00
6.5	14,409		0.0000	1.0000	100.00
7.5	16,221		0.0000	1.0000	100.00
8.5	16,221		0.0000	1.0000	100.00
9.5	16,221		0.0000	1.0000	100.00
10.5	24,541		0.0000	1.0000	100.00
11.5	22,729		0.0000	1.0000	100.00
12.5	22,729	1,253	0.0551	0.9449	100.00
13.5	21,476		0.0000	1.0000	94.49
14.5	21,476		0.0000	1.0000	94.49
15.5	34,048		0.0000	1.0000	94.49
16.5	34,048		0.0000	1.0000	94.49
17.5	87,775		0.0000	1.0000	94.49
18.5	88,093		0.0000	1.0000	94.49
19.5	88,420		0.0000	1.0000	94.49
20.5	163,371		0.0000	1.0000	94.49
21.5	163,715	85,500	0.5222	0.4778	94.49
22.5	78,108		0.0000	1.0000	45.14
23.5	78,545	9,163	0.1167	0.8833	45.14
24.5	69,586	211	0.0030	0.9970	39.88
25.5	69,375	327	0.0047	0.9953	39.75
26.5	94,601		0.0000	1.0000	39.57
27.5	94,601	344	0.0036	0.9964	39.57
28.5	94,257		0.0000	1.0000	39.42
29.5	94,257	437	0.0046	0.9954	39.42
30.5	93,820	204	0.0022	0.9978	39.24
31.5	94,256		0.0000	1.0000	39.15
32.5	98,581		0.0000	1.0000	39.15
33.5	98,581		0.0000	1.0000	39.15
34.5	98,581		0.0000	1.0000	39.15
35.5	98,671		0.0000	1.0000	39.15
36.5	98,671		0.0000	1.0000	39.15
37.5	98,720	640	0.0065	0.9935	39.15
38.5	98,353	4,325	0.0440	0.9560	38.90

NORTHWEST NATURAL GAS COMPANY

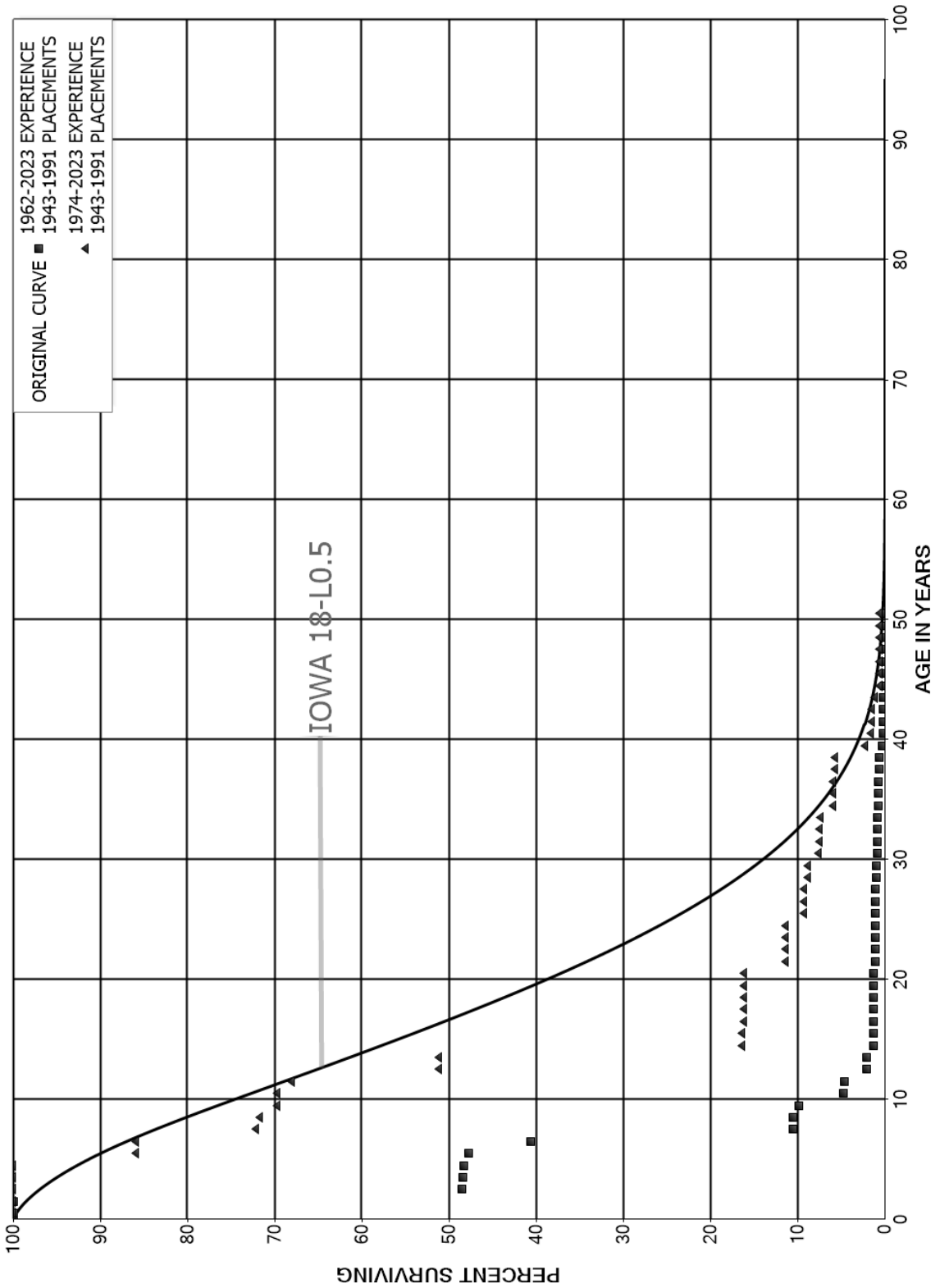
ACCOUNTS 305.11, 305.17 AND 305.50 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1913-1984 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	80,872		0.0000	1.0000	37.19
40.5	80,872		0.0000	1.0000	37.19
41.5	80,872	90	0.0011	0.9989	37.19
42.5	83,479		0.0000	1.0000	37.15
43.5	83,749	49	0.0006	0.9994	37.15
44.5	83,700	273	0.0033	0.9967	37.13
45.5	83,427		0.0000	1.0000	37.01
46.5	80,730	25,553	0.3165	0.6835	37.01
47.5	55,177		0.0000	1.0000	25.29
48.5	55,239		0.0000	1.0000	25.29
49.5	55,239	270	0.0049	0.9951	25.29
50.5	54,969		0.0000	1.0000	25.17
51.5	54,969		0.0000	1.0000	25.17
52.5	54,969		0.0000	1.0000	25.17
53.5	54,969		0.0000	1.0000	25.17
54.5	54,986	62	0.0011	0.9989	25.17
55.5	54,924		0.0000	1.0000	25.14
56.5	54,924		0.0000	1.0000	25.14
57.5	55,941		0.0000	1.0000	25.14
58.5	56,791		0.0000	1.0000	25.14
59.5	56,791		0.0000	1.0000	25.14
60.5	54,110	17	0.0003	0.9997	25.14
61.5	54,093		0.0000	1.0000	25.13
62.5	54,093		0.0000	1.0000	25.13
63.5	54,093	1,017	0.0188	0.9812	25.13
64.5	53,076	850	0.0160	0.9840	24.66
65.5	50,203		0.0000	1.0000	24.27
66.5	50,203	5,639	0.1123	0.8877	24.27
67.5					21.54

NORTHWEST NATURAL GAS COMPANY
ACCOUNTS 311.70 AND 311.80 LIQUEFIED PETROLEUM GAS EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 311.70 AND 311.80 LIQUEFIED PETROLEUM GAS EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1943-1991 EXPERIENCE BAND 1962-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	63,128		0.0000	1.0000	100.00
0.5	68,628		0.0000	1.0000	100.00
1.5	141,412	72,784	0.5147	0.4853	100.00
2.5	75,680	200	0.0026	0.9974	48.53
3.5	70,180	150	0.0021	0.9979	48.40
4.5	87,543	1,077	0.0123	0.9877	48.30
5.5	89,904	13,319	0.1481	0.8519	47.70
6.5	90,123	66,829	0.7415	0.2585	40.64
7.5	91,254	203	0.0022	0.9978	10.50
8.5	106,323	6,441	0.0606	0.9394	10.48
9.5	106,542	55,848	0.5242	0.4758	9.85
10.5	106,855	1,207	0.0113	0.9887	4.68
11.5	201,105	109,727	0.5456	0.4544	4.63
12.5	91,708		0.0000	1.0000	2.10
13.5	264,428	101,568	0.3841	0.6159	2.10
14.5	172,942		0.0000	1.0000	1.30
15.5	173,374	513	0.0030	0.9970	1.30
16.5	173,767	47	0.0003	0.9997	1.29
17.5	174,013		0.0000	1.0000	1.29
18.5	196,426		0.0000	1.0000	1.29
19.5	196,426	368	0.0019	0.9981	1.29
20.5	196,058	26,365	0.1345	0.8655	1.29
21.5	169,693	136	0.0008	0.9992	1.12
22.5	169,557		0.0000	1.0000	1.12
23.5	169,557		0.0000	1.0000	1.12
24.5	169,557	12,335	0.0727	0.9273	1.12
25.5	157,222		0.0000	1.0000	1.03
26.5	157,222		0.0000	1.0000	1.03
27.5	157,222	7,052	0.0449	0.9551	1.03
28.5	150,170		0.0000	1.0000	0.99
29.5	150,170	17,363	0.1156	0.8844	0.99
30.5	132,807	2,361	0.0178	0.9822	0.87
31.5	130,446	219	0.0017	0.9983	0.86
32.5	130,227	1,131	0.0087	0.9913	0.86
33.5	129,096	25,301	0.1960	0.8040	0.85
34.5	103,795	219	0.0021	0.9979	0.68
35.5	103,576	313	0.0030	0.9970	0.68
36.5	103,263	3,205	0.0310	0.9690	0.68
37.5	100,058	180	0.0018	0.9982	0.66
38.5	99,878	62,202	0.6228	0.3772	0.66

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 311.70 AND 311.80 LIQUEFIED PETROLEUM GAS EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1943-1991 EXPERIENCE BAND 1962-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	37,676	11,900	0.3159	0.6841	0.25
40.5	25,776	432	0.0168	0.9832	0.17
41.5	25,344	393	0.0155	0.9845	0.17
42.5	24,951	6,196	0.2483	0.7517	0.16
43.5	18,755	10,513	0.5605	0.4395	0.12
44.5	8,242		0.0000	1.0000	0.05
45.5	8,242		0.0000	1.0000	0.05
46.5	8,242		0.0000	1.0000	0.05
47.5	8,242		0.0000	1.0000	0.05
48.5	4,033		0.0000	1.0000	0.05
49.5	4,033		0.0000	1.0000	0.05
50.5	627		0.0000	1.0000	0.05
51.5	627		0.0000	1.0000	0.05
52.5	627		0.0000	1.0000	0.05
53.5	627		0.0000	1.0000	0.05
54.5	627		0.0000	1.0000	0.05
55.5	627		0.0000	1.0000	0.05
56.5	627		0.0000	1.0000	0.05
57.5	627		0.0000	1.0000	0.05
58.5	627		0.0000	1.0000	0.05
59.5	403		0.0000	1.0000	0.05
60.5					0.05

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 311.70 AND 311.80 LIQUEFIED PETROLEUM GAS EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1943-1991 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	4,209		0.0000	1.0000	100.00
0.5	13,115		0.0000	1.0000	100.00
1.5	13,115		0.0000	1.0000	100.00
2.5	13,115		0.0000	1.0000	100.00
3.5	7,615		0.0000	1.0000	100.00
4.5	7,615	1,077	0.1414	0.8586	100.00
5.5	7,615		0.0000	1.0000	85.86
6.5	7,983	1,285	0.1610	0.8390	85.86
7.5	34,348	203	0.0059	0.9941	72.04
8.5	34,484	980	0.0284	0.9716	71.61
9.5	34,708		0.0000	1.0000	69.58
10.5	50,793	1,207	0.0238	0.9762	69.58
11.5	63,128	15,682	0.2484	0.7516	67.92
12.5	47,446		0.0000	1.0000	51.05
13.5	149,014	101,568	0.6816	0.3184	51.05
14.5	54,498		0.0000	1.0000	16.25
15.5	54,498	513	0.0094	0.9906	16.25
16.5	71,861	47	0.0007	0.9993	16.10
17.5	74,222		0.0000	1.0000	16.09
18.5	74,441		0.0000	1.0000	16.09
19.5	75,572	368	0.0049	0.9951	16.09
20.5	90,273	26,365	0.2921	0.7079	16.01
21.5	64,127	136	0.0021	0.9979	11.34
22.5	64,304		0.0000	1.0000	11.31
23.5	64,509		0.0000	1.0000	11.31
24.5	64,839	12,335	0.1902	0.8098	11.31
25.5	123,656		0.0000	1.0000	9.16
26.5	133,738		0.0000	1.0000	9.16
27.5	134,170	7,052	0.0526	0.9474	9.16
28.5	127,511		0.0000	1.0000	8.68
29.5	127,757	17,363	0.1359	0.8641	8.68
30.5	132,807	2,361	0.0178	0.9822	7.50
31.5	130,446	219	0.0017	0.9983	7.37
32.5	130,227	1,131	0.0087	0.9913	7.35
33.5	129,096	25,301	0.1960	0.8040	7.29
34.5	103,795	219	0.0021	0.9979	5.86
35.5	103,576	313	0.0030	0.9970	5.85
36.5	103,263	3,205	0.0310	0.9690	5.83
37.5	100,058	180	0.0018	0.9982	5.65
38.5	99,878	62,202	0.6228	0.3772	5.64

NORTHWEST NATURAL GAS COMPANY

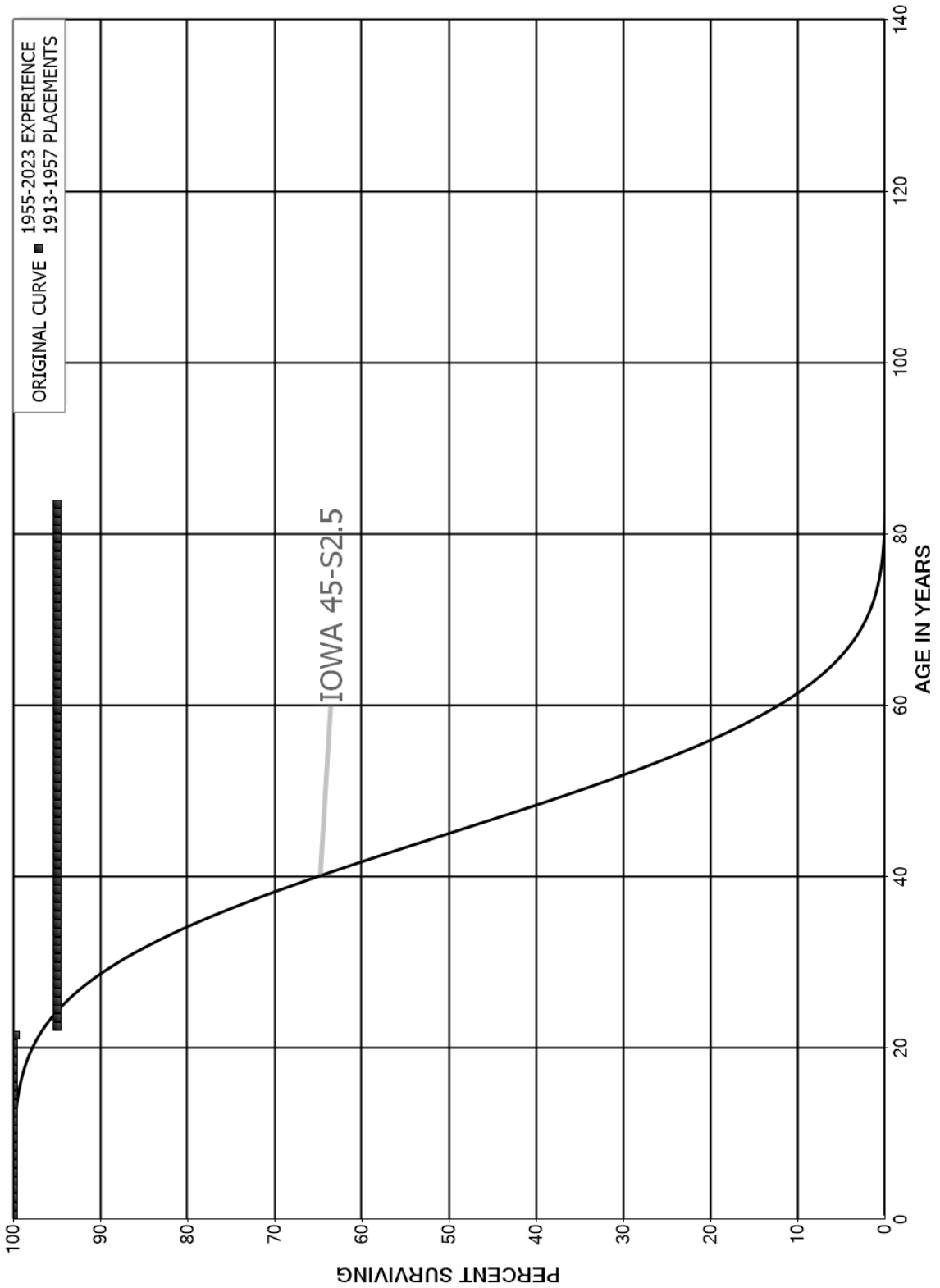
ACCOUNTS 311.70 AND 311.80 LIQUEFIED PETROLEUM GAS EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1943-1991 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	37,676	11,900	0.3159	0.6841	2.13
40.5	25,776	432	0.0168	0.9832	1.46
41.5	25,344	393	0.0155	0.9845	1.43
42.5	24,951	6,196	0.2483	0.7517	1.41
43.5	18,755	10,513	0.5605	0.4395	1.06
44.5	8,242		0.0000	1.0000	0.47
45.5	8,242		0.0000	1.0000	0.47
46.5	8,242		0.0000	1.0000	0.47
47.5	8,242		0.0000	1.0000	0.47
48.5	4,033		0.0000	1.0000	0.47
49.5	4,033		0.0000	1.0000	0.47
50.5	627		0.0000	1.0000	0.47
51.5	627		0.0000	1.0000	0.47
52.5	627		0.0000	1.0000	0.47
53.5	627		0.0000	1.0000	0.47
54.5	627		0.0000	1.0000	0.47
55.5	627		0.0000	1.0000	0.47
56.5	627		0.0000	1.0000	0.47
57.5	627		0.0000	1.0000	0.47
58.5	627		0.0000	1.0000	0.47
59.5	403		0.0000	1.0000	0.47
60.5					0.47

NORTHWEST NATURAL GAS COMPANY
ACCOUNTS 318.30 AND 318.50 RESIDUAL REFINING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 318.30 AND 318.50 RESIDUAL REFINING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1913-1957 EXPERIENCE BAND 1955-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,115		0.0000	1.0000	100.00
0.5	17,541		0.0000	1.0000	100.00
1.5	233,776		0.0000	1.0000	100.00
2.5	264,524		0.0000	1.0000	100.00
3.5	320,746		0.0000	1.0000	100.00
4.5	349,818		0.0000	1.0000	100.00
5.5	351,000		0.0000	1.0000	100.00
6.5	364,722		0.0000	1.0000	100.00
7.5	480,536		0.0000	1.0000	100.00
8.5	480,536		0.0000	1.0000	100.00
9.5	480,536		0.0000	1.0000	100.00
10.5	496,810		0.0000	1.0000	100.00
11.5	600,028		0.0000	1.0000	100.00
12.5	600,028		0.0000	1.0000	100.00
13.5	730,592		0.0000	1.0000	100.00
14.5	777,670		0.0000	1.0000	100.00
15.5	777,670		0.0000	1.0000	100.00
16.5	777,670		0.0000	1.0000	100.00
17.5	777,670	263	0.0003	0.9997	100.00
18.5	777,407		0.0000	1.0000	99.97
19.5	777,407		0.0000	1.0000	99.97
20.5	777,407	2,294	0.0030	0.9970	99.97
21.5	775,113	36,343	0.0469	0.9531	99.67
22.5	738,770		0.0000	1.0000	95.00
23.5	738,770		0.0000	1.0000	95.00
24.5	738,770		0.0000	1.0000	95.00
25.5	738,770		0.0000	1.0000	95.00
26.5	738,770		0.0000	1.0000	95.00
27.5	738,770		0.0000	1.0000	95.00
28.5	752,250		0.0000	1.0000	95.00
29.5	752,250		0.0000	1.0000	95.00
30.5	752,250		0.0000	1.0000	95.00
31.5	768,838		0.0000	1.0000	95.00
32.5	768,838		0.0000	1.0000	95.00
33.5	768,838		0.0000	1.0000	95.00
34.5	768,838		0.0000	1.0000	95.00
35.5	768,838		0.0000	1.0000	95.00
36.5	768,838		0.0000	1.0000	95.00
37.5	768,838		0.0000	1.0000	95.00
38.5	768,838		0.0000	1.0000	95.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 318.30 AND 318.50 RESIDUAL REFINING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1913-1957 EXPERIENCE BAND 1955-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	768,838		0.0000	1.0000	95.00
40.5	768,838		0.0000	1.0000	95.00
41.5	776,894		0.0000	1.0000	95.00
42.5	776,894		0.0000	1.0000	95.00
43.5	776,894		0.0000	1.0000	95.00
44.5	776,894		0.0000	1.0000	95.00
45.5	776,894		0.0000	1.0000	95.00
46.5	776,894		0.0000	1.0000	95.00
47.5	776,894		0.0000	1.0000	95.00
48.5	776,894		0.0000	1.0000	95.00
49.5	776,894		0.0000	1.0000	95.00
50.5	776,894		0.0000	1.0000	95.00
51.5	776,894		0.0000	1.0000	95.00
52.5	776,894		0.0000	1.0000	95.00
53.5	776,894		0.0000	1.0000	95.00
54.5	776,894		0.0000	1.0000	95.00
55.5	776,894		0.0000	1.0000	95.00
56.5	776,894		0.0000	1.0000	95.00
57.5	776,894		0.0000	1.0000	95.00
58.5	776,894		0.0000	1.0000	95.00
59.5	776,894		0.0000	1.0000	95.00
60.5	776,894		0.0000	1.0000	95.00
61.5	776,894		0.0000	1.0000	95.00
62.5	776,894		0.0000	1.0000	95.00
63.5	776,894		0.0000	1.0000	95.00
64.5	776,894		0.0000	1.0000	95.00
65.5	776,894		0.0000	1.0000	95.00
66.5	774,988		0.0000	1.0000	95.00
67.5	774,662		0.0000	1.0000	95.00
68.5	771,042		0.0000	1.0000	95.00
69.5	761,910		0.0000	1.0000	95.00
70.5	582,018		0.0000	1.0000	95.00
71.5	551,270		0.0000	1.0000	95.00
72.5	495,048		0.0000	1.0000	95.00
73.5	465,976		0.0000	1.0000	95.00
74.5	464,794		0.0000	1.0000	95.00
75.5	451,072		0.0000	1.0000	95.00
76.5	335,258		0.0000	1.0000	95.00
77.5	335,258		0.0000	1.0000	95.00
78.5	335,258		0.0000	1.0000	95.00

NORTHWEST NATURAL GAS COMPANY

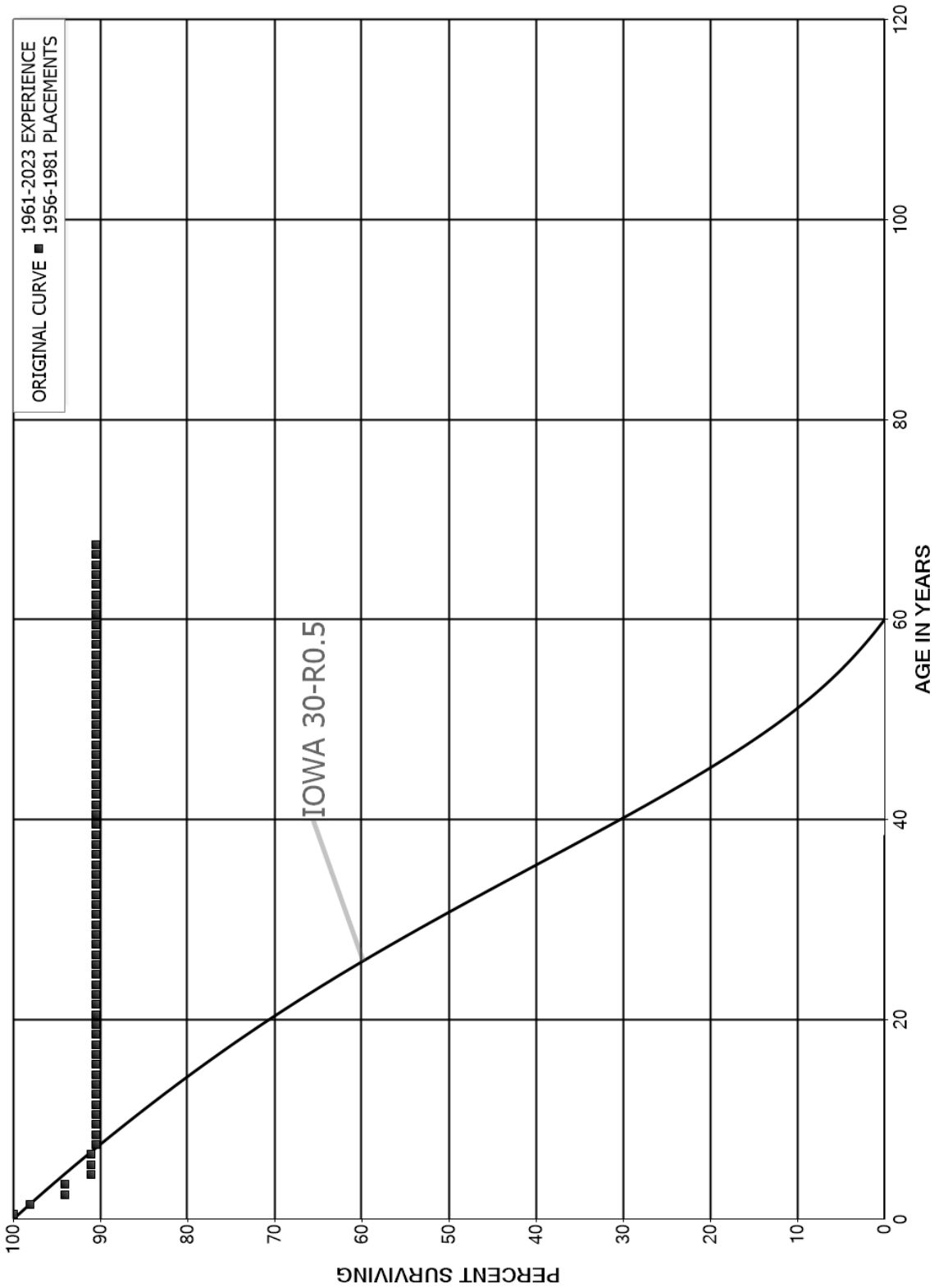
ACCOUNTS 318.30 AND 318.50 RESIDUAL REFINING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1913-1957 EXPERIENCE BAND 1955-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	318,984		0.0000	1.0000	95.00
80.5	215,766		0.0000	1.0000	95.00
81.5	215,766		0.0000	1.0000	95.00
82.5	85,202		0.0000	1.0000	95.00
83.5	38,124		0.0000	1.0000	95.00
84.5	38,124		0.0000	1.0000	95.00
85.5	38,124		0.0000	1.0000	95.00
86.5	38,124		0.0000	1.0000	95.00
87.5	38,124		0.0000	1.0000	95.00
88.5	38,124		0.0000	1.0000	95.00
89.5	38,124		0.0000	1.0000	95.00
90.5	38,124		0.0000	1.0000	95.00
91.5	38,124		0.0000	1.0000	95.00
92.5	38,124		0.0000	1.0000	95.00
93.5	38,124		0.0000	1.0000	95.00
94.5	38,124		0.0000	1.0000	95.00
95.5	38,124		0.0000	1.0000	95.00
96.5	38,124		0.0000	1.0000	95.00
97.5	24,644		0.0000	1.0000	95.00
98.5	24,644		0.0000	1.0000	95.00
99.5	24,644		0.0000	1.0000	95.00
100.5	8,056		0.0000	1.0000	95.00
101.5	8,056		0.0000	1.0000	95.00
102.5	8,056		0.0000	1.0000	95.00
103.5	8,056		0.0000	1.0000	95.00
104.5	8,056		0.0000	1.0000	95.00
105.5	8,056		0.0000	1.0000	95.00
106.5	8,056		0.0000	1.0000	95.00
107.5	8,056		0.0000	1.0000	95.00
108.5	8,056		0.0000	1.0000	95.00
109.5	8,056		0.0000	1.0000	95.00
110.5					95.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 319.00 GAS MIXING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 319.00 GAS MIXING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-1981 EXPERIENCE BAND 1961-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	18,655		0.0000	1.0000	100.00
0.5	18,932	376	0.0199	0.9801	100.00
1.5	19,149	770	0.0402	0.9598	98.01
2.5	24,885		0.0000	1.0000	94.07
3.5	40,405	1,300	0.0322	0.9678	94.07
4.5	185,448		0.0000	1.0000	91.05
5.5	185,448		0.0000	1.0000	91.05
6.5	185,448	1,025	0.0055	0.9945	91.05
7.5	185,448		0.0000	1.0000	90.54
8.5	185,448		0.0000	1.0000	90.54
9.5	185,448		0.0000	1.0000	90.54
10.5	185,448		0.0000	1.0000	90.54
11.5	185,448		0.0000	1.0000	90.54
12.5	185,448		0.0000	1.0000	90.54
13.5	185,448		0.0000	1.0000	90.54
14.5	185,448		0.0000	1.0000	90.54
15.5	185,448		0.0000	1.0000	90.54
16.5	185,448		0.0000	1.0000	90.54
17.5	185,448		0.0000	1.0000	90.54
18.5	185,448		0.0000	1.0000	90.54
19.5	185,448		0.0000	1.0000	90.54
20.5	185,448		0.0000	1.0000	90.54
21.5	185,448		0.0000	1.0000	90.54
22.5	185,448		0.0000	1.0000	90.54
23.5	185,448		0.0000	1.0000	90.54
24.5	185,448		0.0000	1.0000	90.54
25.5	185,448		0.0000	1.0000	90.54
26.5	185,448		0.0000	1.0000	90.54
27.5	185,448		0.0000	1.0000	90.54
28.5	185,448		0.0000	1.0000	90.54
29.5	185,448		0.0000	1.0000	90.54
30.5	185,448		0.0000	1.0000	90.54
31.5	185,448		0.0000	1.0000	90.54
32.5	185,448		0.0000	1.0000	90.54
33.5	185,448		0.0000	1.0000	90.54
34.5	185,448		0.0000	1.0000	90.54
35.5	185,448		0.0000	1.0000	90.54
36.5	185,448		0.0000	1.0000	90.54
37.5	185,448		0.0000	1.0000	90.54
38.5	185,448		0.0000	1.0000	90.54

NORTHWEST NATURAL GAS COMPANY

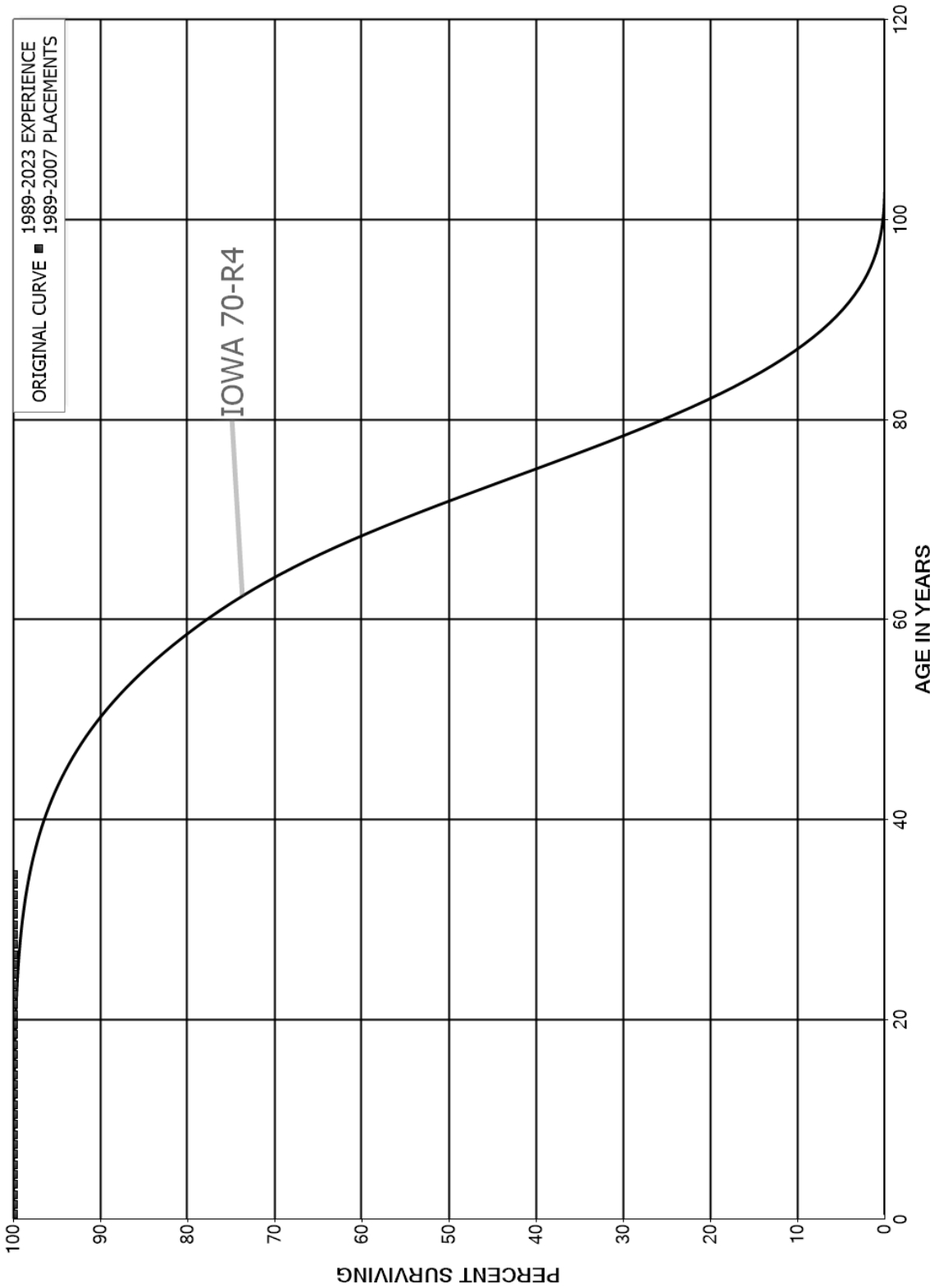
ACCOUNT 319.00 GAS MIXING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-1981 EXPERIENCE BAND 1961-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	185,448		0.0000	1.0000	90.54
40.5	185,448		0.0000	1.0000	90.54
41.5	185,448		0.0000	1.0000	90.54
42.5	181,891		0.0000	1.0000	90.54
43.5	169,470		0.0000	1.0000	90.54
44.5	169,470		0.0000	1.0000	90.54
45.5	169,470		0.0000	1.0000	90.54
46.5	169,470		0.0000	1.0000	90.54
47.5	169,470		0.0000	1.0000	90.54
48.5	169,470		0.0000	1.0000	90.54
49.5	169,470		0.0000	1.0000	90.54
50.5	169,470		0.0000	1.0000	90.54
51.5	169,470		0.0000	1.0000	90.54
52.5	169,470		0.0000	1.0000	90.54
53.5	169,470		0.0000	1.0000	90.54
54.5	169,470		0.0000	1.0000	90.54
55.5	169,470		0.0000	1.0000	90.54
56.5	169,381		0.0000	1.0000	90.54
57.5	169,381		0.0000	1.0000	90.54
58.5	169,381		0.0000	1.0000	90.54
59.5	168,460		0.0000	1.0000	90.54
60.5	168,460		0.0000	1.0000	90.54
61.5	166,793		0.0000	1.0000	90.54
62.5	166,793		0.0000	1.0000	90.54
63.5	166,516		0.0000	1.0000	90.54
64.5	166,299		0.0000	1.0000	90.54
65.5	160,563		0.0000	1.0000	90.54
66.5	145,043		0.0000	1.0000	90.54
67.5					90.54

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 350.20 LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

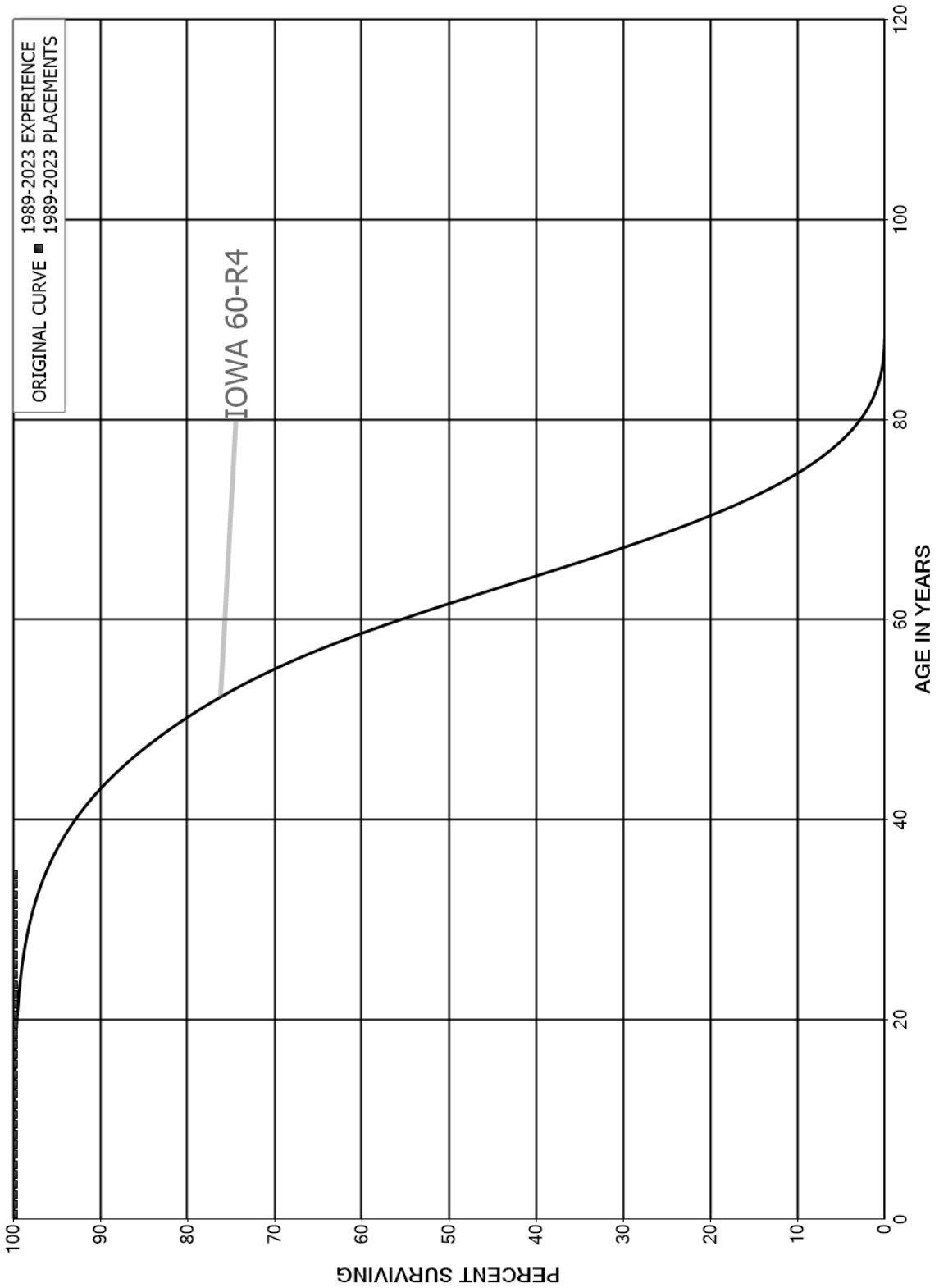
ACCOUNT 350.20 LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2007 EXPERIENCE BAND 1989-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	109,625		0.0000	1.0000	100.00
0.5	109,625		0.0000	1.0000	100.00
1.5	109,625		0.0000	1.0000	100.00
2.5	109,625		0.0000	1.0000	100.00
3.5	109,625		0.0000	1.0000	100.00
4.5	109,625		0.0000	1.0000	100.00
5.5	109,625		0.0000	1.0000	100.00
6.5	109,625		0.0000	1.0000	100.00
7.5	109,625		0.0000	1.0000	100.00
8.5	109,625		0.0000	1.0000	100.00
9.5	109,625		0.0000	1.0000	100.00
10.5	109,625		0.0000	1.0000	100.00
11.5	109,625		0.0000	1.0000	100.00
12.5	109,625		0.0000	1.0000	100.00
13.5	109,625		0.0000	1.0000	100.00
14.5	109,625		0.0000	1.0000	100.00
15.5	109,625		0.0000	1.0000	100.00
16.5	51,122		0.0000	1.0000	100.00
17.5	51,122		0.0000	1.0000	100.00
18.5	51,122		0.0000	1.0000	100.00
19.5	51,122		0.0000	1.0000	100.00
20.5	51,122		0.0000	1.0000	100.00
21.5	51,122		0.0000	1.0000	100.00
22.5	47,318		0.0000	1.0000	100.00
23.5	47,318		0.0000	1.0000	100.00
24.5	47,318		0.0000	1.0000	100.00
25.5	46,690		0.0000	1.0000	100.00
26.5	46,505		0.0000	1.0000	100.00
27.5	46,505		0.0000	1.0000	100.00
28.5	46,505		0.0000	1.0000	100.00
29.5	46,105		0.0000	1.0000	100.00
30.5	40,841		0.0000	1.0000	100.00
31.5	40,841		0.0000	1.0000	100.00
32.5	40,841		0.0000	1.0000	100.00
33.5	40,841		0.0000	1.0000	100.00
34.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 351.00 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

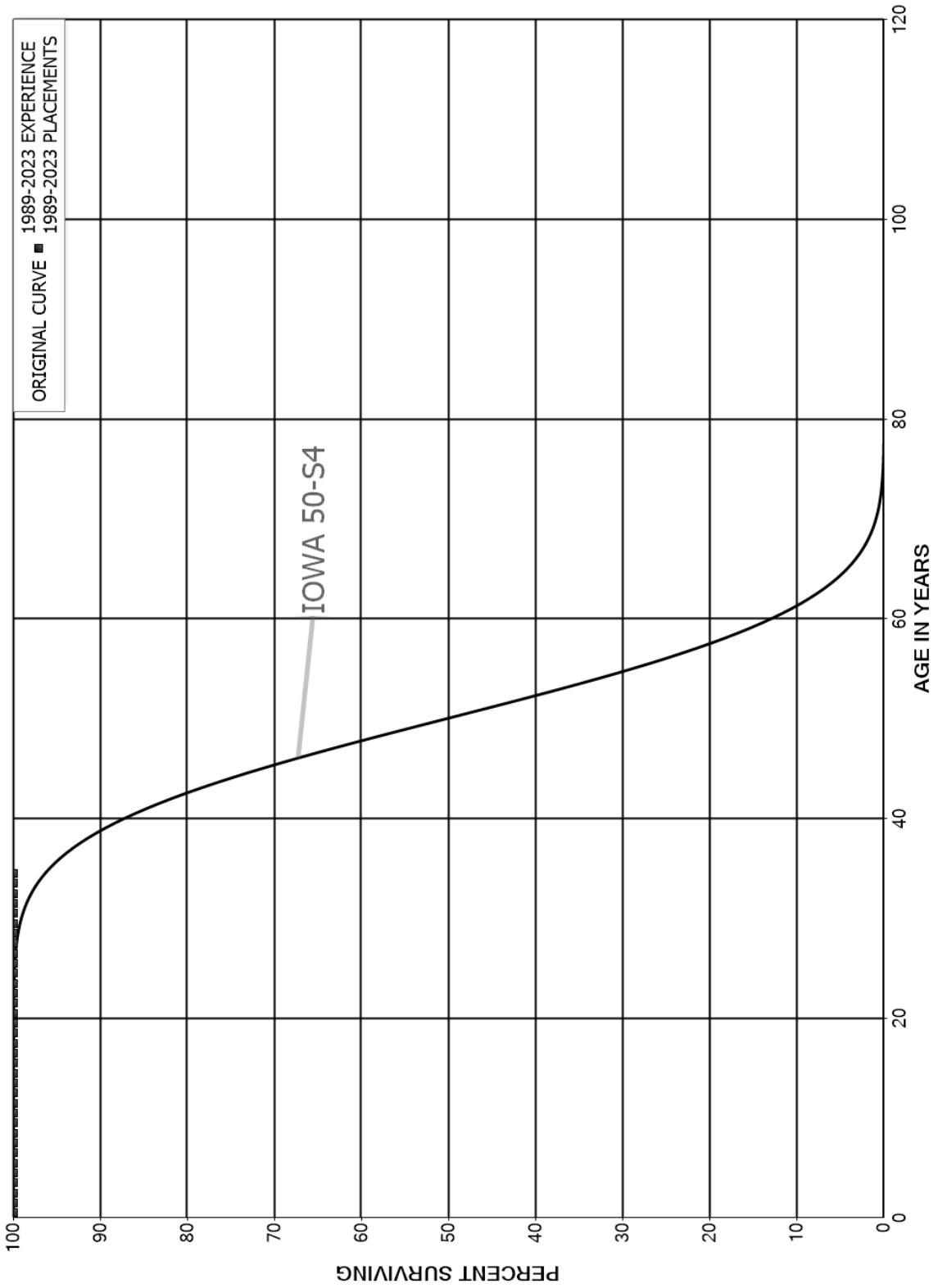
ACCOUNT 351.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2023 EXPERIENCE BAND 1989-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	14,571,122		0.0000	1.0000	100.00
0.5	9,167,746		0.0000	1.0000	100.00
1.5	8,919,522		0.0000	1.0000	100.00
2.5	8,634,151		0.0000	1.0000	100.00
3.5	8,634,151		0.0000	1.0000	100.00
4.5	8,634,151		0.0000	1.0000	100.00
5.5	7,382,069		0.0000	1.0000	100.00
6.5	7,208,245		0.0000	1.0000	100.00
7.5	7,208,245		0.0000	1.0000	100.00
8.5	7,141,840		0.0000	1.0000	100.00
9.5	6,715,064		0.0000	1.0000	100.00
10.5	6,715,064		0.0000	1.0000	100.00
11.5	6,555,425		0.0000	1.0000	100.00
12.5	6,555,425		0.0000	1.0000	100.00
13.5	6,542,426		0.0000	1.0000	100.00
14.5	6,538,592		0.0000	1.0000	100.00
15.5	6,247,670		0.0000	1.0000	100.00
16.5	6,247,670		0.0000	1.0000	100.00
17.5	6,247,670		0.0000	1.0000	100.00
18.5	6,247,546		0.0000	1.0000	100.00
19.5	6,173,312		0.0000	1.0000	100.00
20.5	6,156,413		0.0000	1.0000	100.00
21.5	5,913,514		0.0000	1.0000	100.00
22.5	5,029,273		0.0000	1.0000	100.00
23.5	4,996,462		0.0000	1.0000	100.00
24.5	4,991,499		0.0000	1.0000	100.00
25.5	2,516,340		0.0000	1.0000	100.00
26.5	2,516,340		0.0000	1.0000	100.00
27.5	2,516,340		0.0000	1.0000	100.00
28.5	2,480,692		0.0000	1.0000	100.00
29.5	2,467,430		0.0000	1.0000	100.00
30.5	2,464,204		0.0000	1.0000	100.00
31.5	2,422,299		0.0000	1.0000	100.00
32.5	2,146,801		0.0000	1.0000	100.00
33.5	2,101,010		0.0000	1.0000	100.00
34.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 352.00 WELLS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

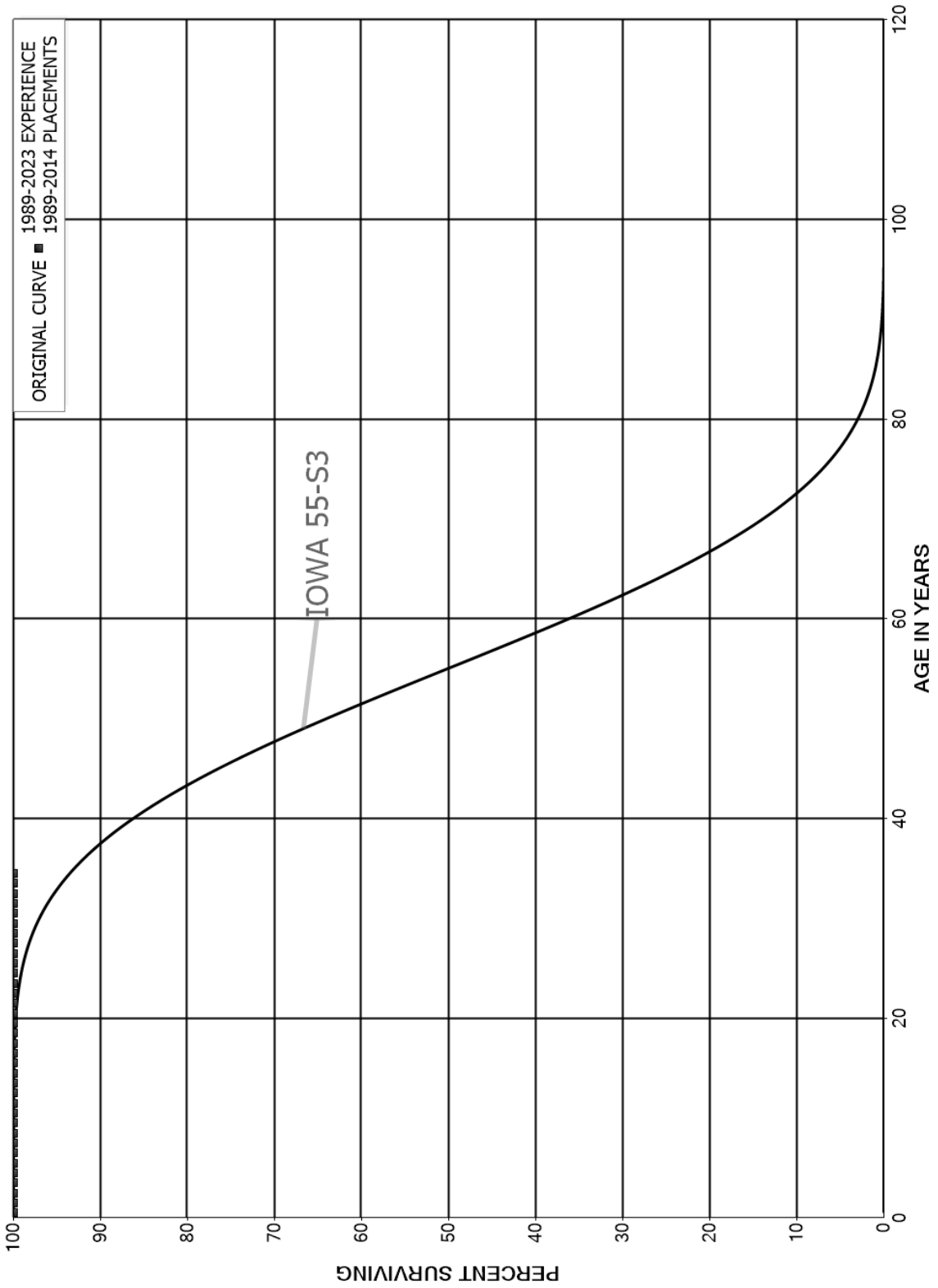
ACCOUNT 352.00 WELLS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2023 EXPERIENCE BAND 1989-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	64,838,832		0.0000	1.0000	100.00
0.5	57,556,369		0.0000	1.0000	100.00
1.5	52,423,569		0.0000	1.0000	100.00
2.5	48,356,358		0.0000	1.0000	100.00
3.5	43,804,325		0.0000	1.0000	100.00
4.5	40,316,037		0.0000	1.0000	100.00
5.5	36,987,527		0.0000	1.0000	100.00
6.5	36,987,527		0.0000	1.0000	100.00
7.5	36,987,527		0.0000	1.0000	100.00
8.5	36,987,527		0.0000	1.0000	100.00
9.5	36,987,527		0.0000	1.0000	100.00
10.5	36,987,527		0.0000	1.0000	100.00
11.5	36,970,027		0.0000	1.0000	100.00
12.5	36,970,027		0.0000	1.0000	100.00
13.5	36,970,027		0.0000	1.0000	100.00
14.5	36,138,659		0.0000	1.0000	100.00
15.5	36,138,659		0.0000	1.0000	100.00
16.5	27,363,189		0.0000	1.0000	100.00
17.5	27,363,189		0.0000	1.0000	100.00
18.5	23,510,122		0.0000	1.0000	100.00
19.5	18,383,091		0.0000	1.0000	100.00
20.5	18,338,288		0.0000	1.0000	100.00
21.5	18,338,288		0.0000	1.0000	100.00
22.5	18,138,203		0.0000	1.0000	100.00
23.5	18,138,203		0.0000	1.0000	100.00
24.5	18,138,203		0.0000	1.0000	100.00
25.5	11,810,679		0.0000	1.0000	100.00
26.5	11,810,679		0.0000	1.0000	100.00
27.5	11,810,679		0.0000	1.0000	100.00
28.5	11,810,679		0.0000	1.0000	100.00
29.5	11,808,321		0.0000	1.0000	100.00
30.5	11,625,429		0.0000	1.0000	100.00
31.5	11,474,852		0.0000	1.0000	100.00
32.5	9,469,844		0.0000	1.0000	100.00
33.5	8,933,762		0.0000	1.0000	100.00
34.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 352.10 STORAGE LEASEHOLDS AND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

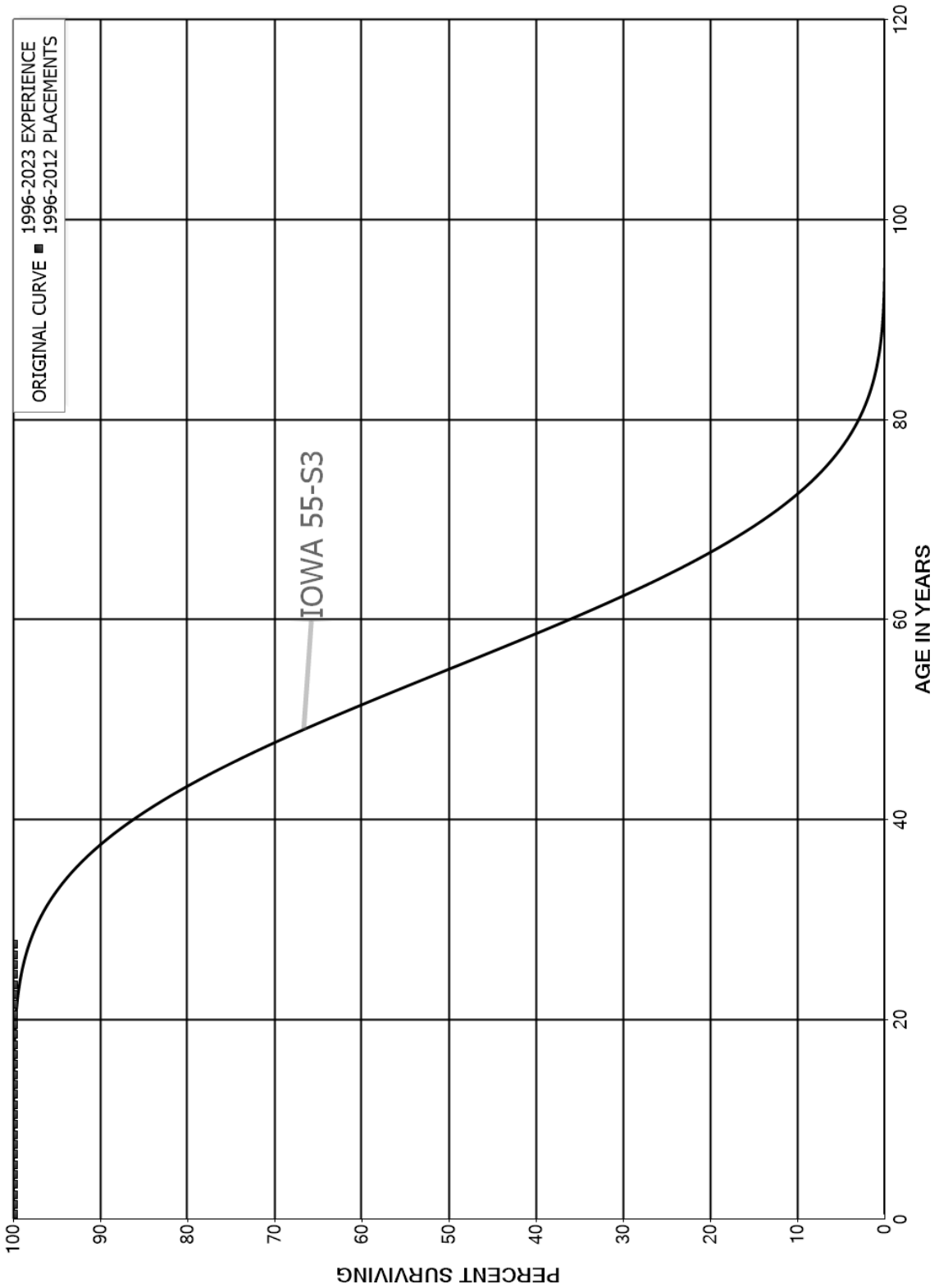
ACCOUNT 352.10 STORAGE LEASEHOLDS AND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2014 EXPERIENCE BAND 1989-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,939,513		0.0000	1.0000	100.00
0.5	3,939,512		0.0000	1.0000	100.00
1.5	3,939,512		0.0000	1.0000	100.00
2.5	3,939,512		0.0000	1.0000	100.00
3.5	3,939,512		0.0000	1.0000	100.00
4.5	3,939,512		0.0000	1.0000	100.00
5.5	3,939,512		0.0000	1.0000	100.00
6.5	3,939,512		0.0000	1.0000	100.00
7.5	3,939,512		0.0000	1.0000	100.00
8.5	3,939,512		0.0000	1.0000	100.00
9.5	3,539,512		0.0000	1.0000	100.00
10.5	3,539,512		0.0000	1.0000	100.00
11.5	3,539,512		0.0000	1.0000	100.00
12.5	3,539,512		0.0000	1.0000	100.00
13.5	3,539,512		0.0000	1.0000	100.00
14.5	3,539,512		0.0000	1.0000	100.00
15.5	3,539,512		0.0000	1.0000	100.00
16.5	3,539,512		0.0000	1.0000	100.00
17.5	3,539,512		0.0000	1.0000	100.00
18.5	3,539,512		0.0000	1.0000	100.00
19.5	3,538,491		0.0000	1.0000	100.00
20.5	3,538,491		0.0000	1.0000	100.00
21.5	3,535,500		0.0000	1.0000	100.00
22.5	3,535,500		0.0000	1.0000	100.00
23.5	3,535,500		0.0000	1.0000	100.00
24.5	3,530,407		0.0000	1.0000	100.00
25.5	3,038,080		0.0000	1.0000	100.00
26.5	1,448,101		0.0000	1.0000	100.00
27.5	1,210,801		0.0000	1.0000	100.00
28.5	1,210,801		0.0000	1.0000	100.00
29.5	1,210,801		0.0000	1.0000	100.00
30.5	1,210,800		0.0000	1.0000	100.00
31.5	1,210,800		0.0000	1.0000	100.00
32.5	1,210,800		0.0000	1.0000	100.00
33.5	1,210,800		0.0000	1.0000	100.00
34.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 352.20 RESERVOIRS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

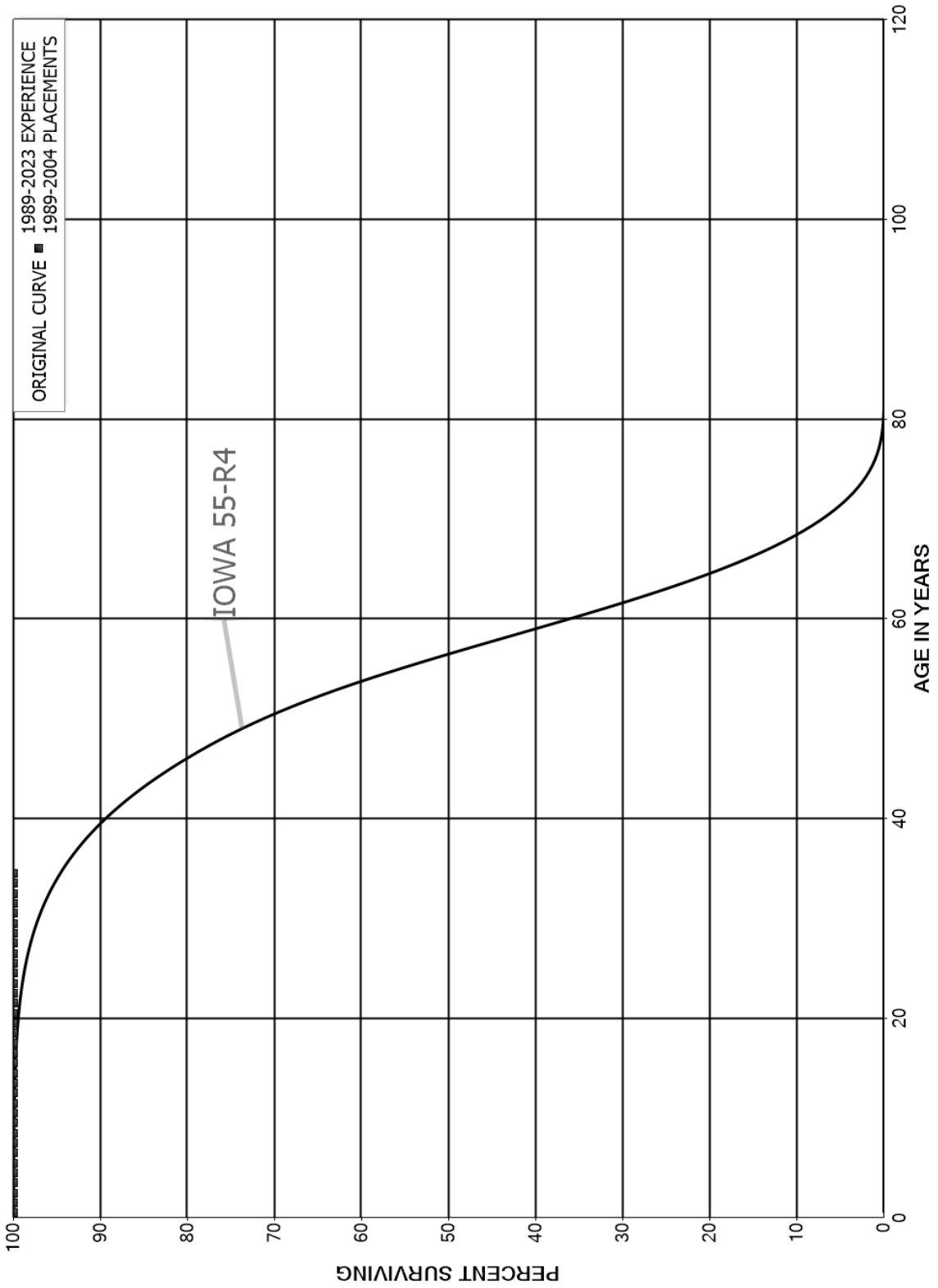
ACCOUNT 352.20 RESERVOIRS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1996-2012 EXPERIENCE BAND 1996-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	7,303,798		0.0000	1.0000	100.00
0.5	7,303,798		0.0000	1.0000	100.00
1.5	7,303,798		0.0000	1.0000	100.00
2.5	9,211,060		0.0000	1.0000	100.00
3.5	9,211,060		0.0000	1.0000	100.00
4.5	10,834,055		0.0000	1.0000	100.00
5.5	10,834,055		0.0000	1.0000	100.00
6.5	10,834,055		0.0000	1.0000	100.00
7.5	10,834,055		0.0000	1.0000	100.00
8.5	10,834,055		0.0000	1.0000	100.00
9.5	10,834,055		0.0000	1.0000	100.00
10.5	10,834,055		0.0000	1.0000	100.00
11.5	10,816,555		0.0000	1.0000	100.00
12.5	10,816,555		0.0000	1.0000	100.00
13.5	11,963,401		0.0000	1.0000	100.00
14.5	11,963,401		0.0000	1.0000	100.00
15.5	10,816,555		0.0000	1.0000	100.00
16.5	10,816,555		0.0000	1.0000	100.00
17.5	10,816,555		0.0000	1.0000	100.00
18.5	8,371,537		0.0000	1.0000	100.00
19.5	7,159,166		0.0000	1.0000	100.00
20.5	7,159,166		0.0000	1.0000	100.00
21.5	4,161,435		0.0000	1.0000	100.00
22.5	4,161,435		0.0000	1.0000	100.00
23.5	3,685,094		0.0000	1.0000	100.00
24.5	3,679,091		0.0000	1.0000	100.00
25.5	1,679,184		0.0000	1.0000	100.00
26.5	1,679,184		0.0000	1.0000	100.00
27.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 352.30 NONRECOVERABLE GAS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

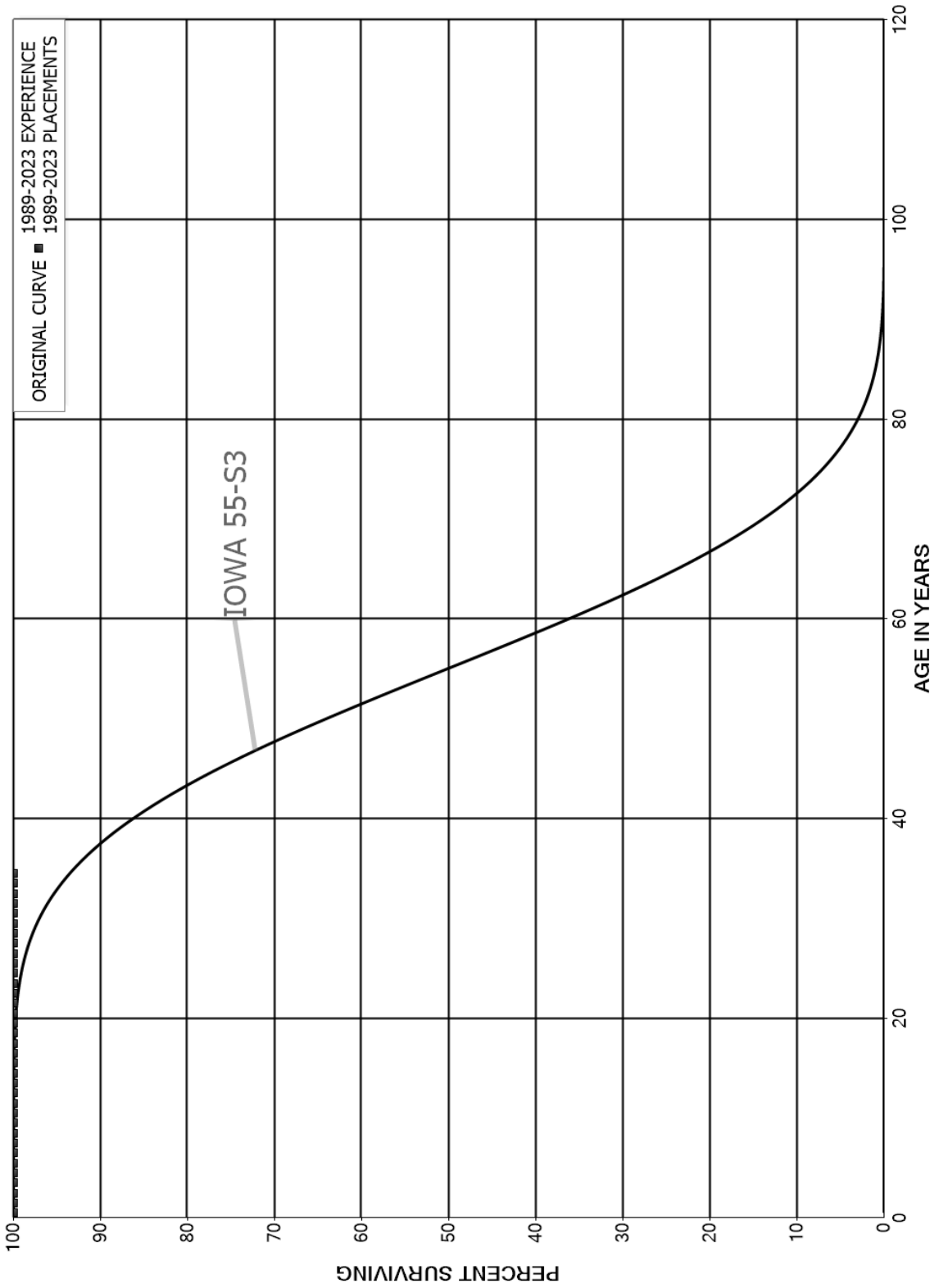
ACCOUNT 352.30 NONRECOVERABLE GAS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2004 EXPERIENCE BAND 1989-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,440,891		0.0000	1.0000	100.00
0.5	6,440,890		0.0000	1.0000	100.00
1.5	6,440,890		0.0000	1.0000	100.00
2.5	6,440,890		0.0000	1.0000	100.00
3.5	6,440,890		0.0000	1.0000	100.00
4.5	6,440,890		0.0000	1.0000	100.00
5.5	6,440,890		0.0000	1.0000	100.00
6.5	6,440,890		0.0000	1.0000	100.00
7.5	6,440,890		0.0000	1.0000	100.00
8.5	6,440,890		0.0000	1.0000	100.00
9.5	6,440,890		0.0000	1.0000	100.00
10.5	6,440,890		0.0000	1.0000	100.00
11.5	6,440,890		0.0000	1.0000	100.00
12.5	6,440,890		0.0000	1.0000	100.00
13.5	6,440,890		0.0000	1.0000	100.00
14.5	6,440,890		0.0000	1.0000	100.00
15.5	6,440,890		0.0000	1.0000	100.00
16.5	6,440,890		0.0000	1.0000	100.00
17.5	6,440,890		0.0000	1.0000	100.00
18.5	6,440,890		0.0000	1.0000	100.00
19.5	6,375,402		0.0000	1.0000	100.00
20.5	6,375,402		0.0000	1.0000	100.00
21.5	6,375,402		0.0000	1.0000	100.00
22.5	6,375,402		0.0000	1.0000	100.00
23.5	6,375,402		0.0000	1.0000	100.00
24.5	6,375,402		0.0000	1.0000	100.00
25.5	6,312,953		0.0000	1.0000	100.00
26.5	6,312,953		0.0000	1.0000	100.00
27.5	4,057,953		0.0000	1.0000	100.00
28.5	4,057,953		0.0000	1.0000	100.00
29.5	4,057,953		0.0000	1.0000	100.00
30.5	4,057,952		0.0000	1.0000	100.00
31.5	4,057,952		0.0000	1.0000	100.00
32.5	4,057,952		0.0000	1.0000	100.00
33.5	4,057,952		0.0000	1.0000	100.00
34.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 353.00 LINES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

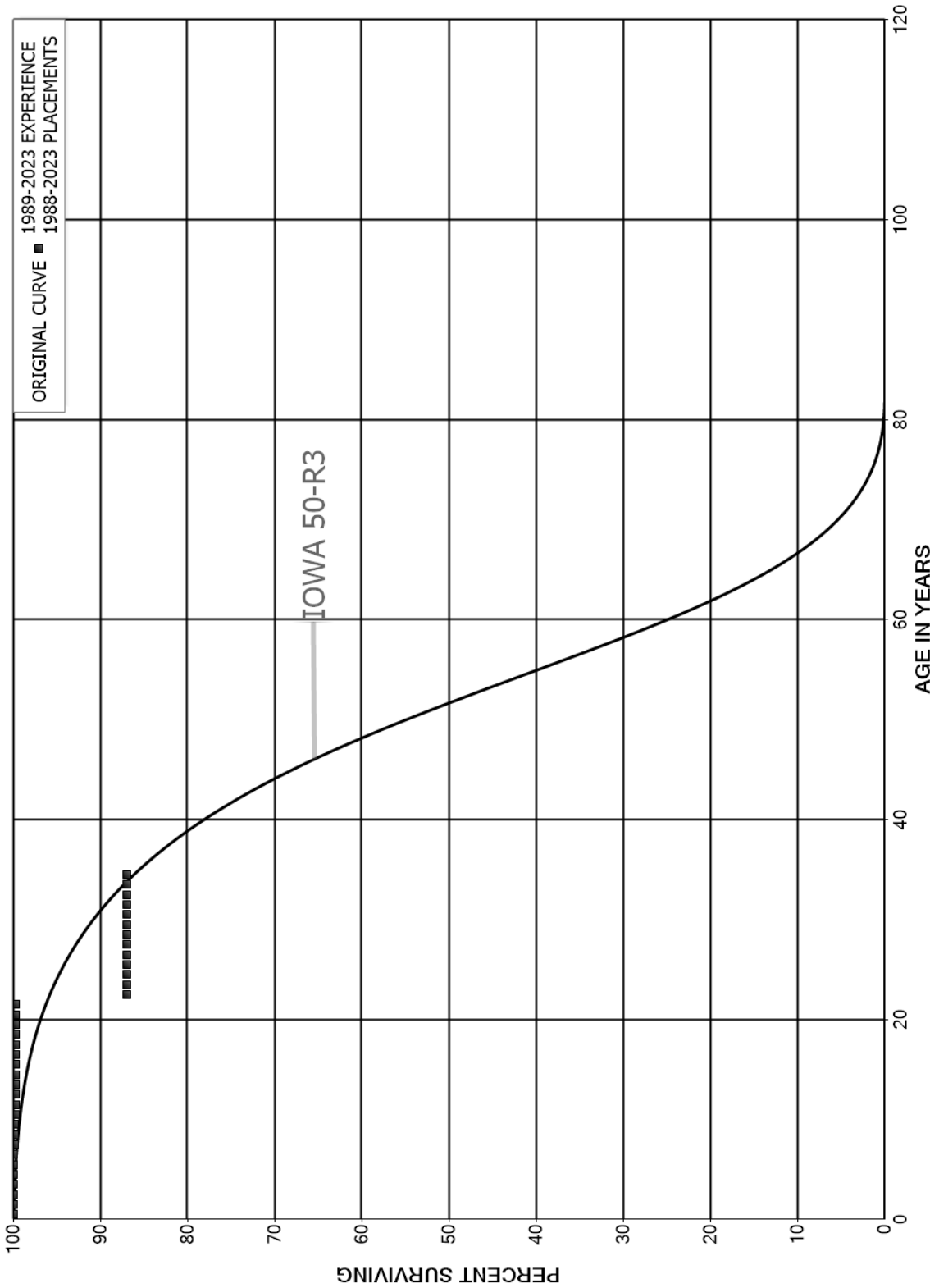
ACCOUNT 353.00 LINES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2023 EXPERIENCE BAND 1989-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	12,986,910		0.0000	1.0000	100.00
0.5	12,167,086		0.0000	1.0000	100.00
1.5	10,790,930		0.0000	1.0000	100.00
2.5	10,790,148		0.0000	1.0000	100.00
3.5	10,673,228		0.0000	1.0000	100.00
4.5	9,535,478		0.0000	1.0000	100.00
5.5	8,201,964		0.0000	1.0000	100.00
6.5	8,201,964		0.0000	1.0000	100.00
7.5	8,201,964		0.0000	1.0000	100.00
8.5	8,201,964		0.0000	1.0000	100.00
9.5	8,201,964		0.0000	1.0000	100.00
10.5	8,201,964		0.0000	1.0000	100.00
11.5	8,201,964		0.0000	1.0000	100.00
12.5	8,201,964		0.0000	1.0000	100.00
13.5	8,201,964		0.0000	1.0000	100.00
14.5	8,201,964		0.0000	1.0000	100.00
15.5	8,201,964		0.0000	1.0000	100.00
16.5	7,641,810		0.0000	1.0000	100.00
17.5	7,641,810		0.0000	1.0000	100.00
18.5	7,137,450		0.0000	1.0000	100.00
19.5	6,453,175		0.0000	1.0000	100.00
20.5	6,445,334		0.0000	1.0000	100.00
21.5	6,445,334		0.0000	1.0000	100.00
22.5	6,445,334		0.0000	1.0000	100.00
23.5	6,445,334		0.0000	1.0000	100.00
24.5	6,392,472		0.0000	1.0000	100.00
25.5	2,538,843		0.0000	1.0000	100.00
26.5	2,538,843		0.0000	1.0000	100.00
27.5	2,538,843		0.0000	1.0000	100.00
28.5	2,538,843		0.0000	1.0000	100.00
29.5	2,538,843		0.0000	1.0000	100.00
30.5	2,538,842		0.0000	1.0000	100.00
31.5	2,538,842		0.0000	1.0000	100.00
32.5	2,521,353		0.0000	1.0000	100.00
33.5	2,521,353		0.0000	1.0000	100.00
34.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNTS 354.10 THROUGH 354.60 COMPRESSOR STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

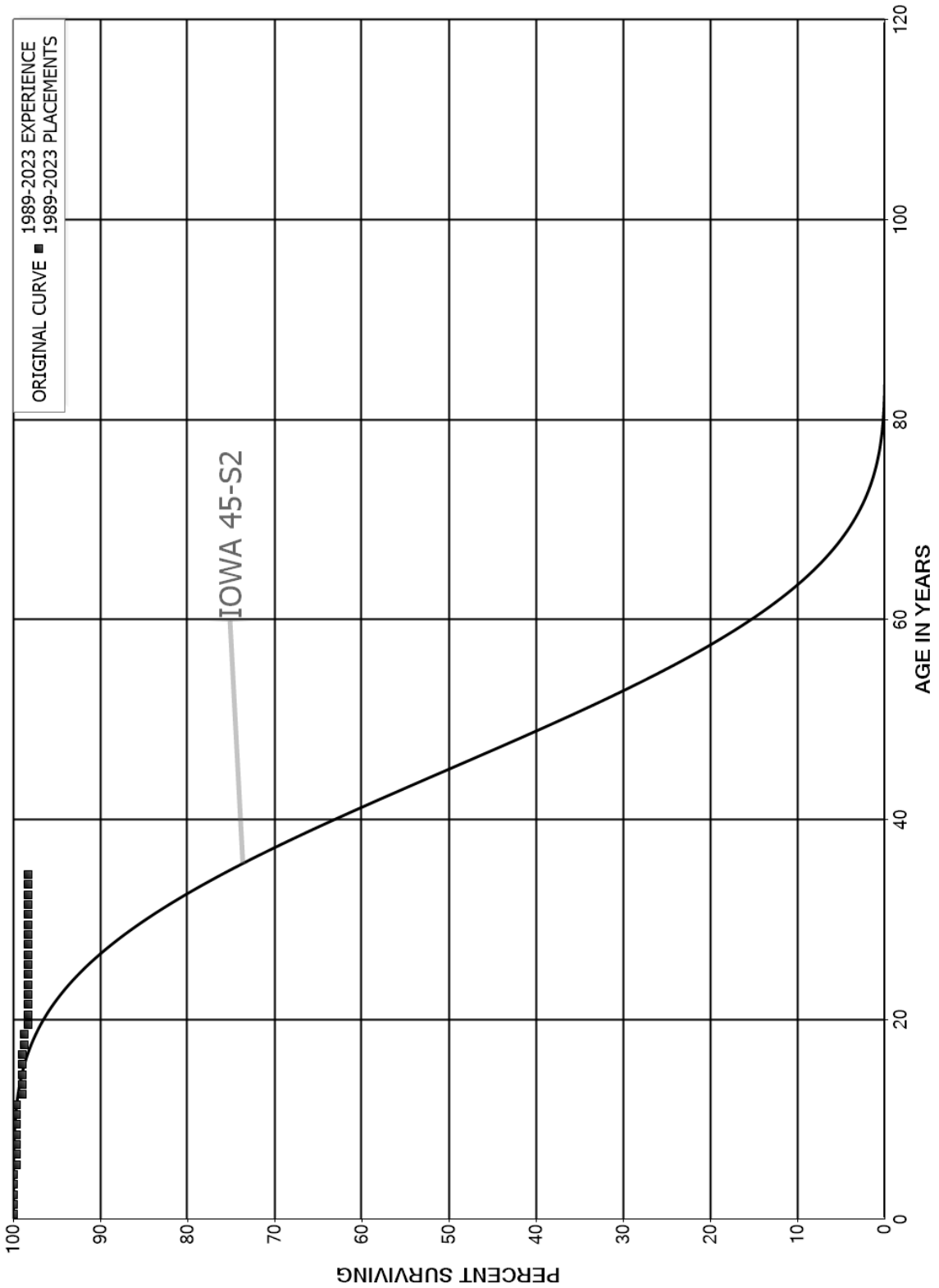
ACCOUNTS 354.10 THROUGH 354.60 COMPRESSOR STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1988-2023 EXPERIENCE BAND 1989-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	48,298,004		0.0000	1.0000	100.00
0.5	38,974,814		0.0000	1.0000	100.00
1.5	36,863,881	31,012	0.0008	0.9992	100.00
2.5	35,900,382		0.0000	1.0000	99.92
3.5	43,376,637		0.0000	1.0000	99.92
4.5	45,967,130		0.0000	1.0000	99.92
5.5	45,967,968		0.0000	1.0000	99.92
6.5	45,818,727	51,212	0.0011	0.9989	99.92
7.5	45,725,131		0.0000	1.0000	99.80
8.5	45,465,090		0.0000	1.0000	99.80
9.5	44,683,528	23,443	0.0005	0.9995	99.80
10.5	43,892,758		0.0000	1.0000	99.75
11.5	43,905,008		0.0000	1.0000	99.75
12.5	42,720,488		0.0000	1.0000	99.75
13.5	42,692,516		0.0000	1.0000	99.75
14.5	41,897,297		0.0000	1.0000	99.75
15.5	41,251,651		0.0000	1.0000	99.75
16.5	41,251,651		0.0000	1.0000	99.75
17.5	41,246,901		0.0000	1.0000	99.75
18.5	41,246,901		0.0000	1.0000	99.75
19.5	39,069,867		0.0000	1.0000	99.75
20.5	39,065,888		0.0000	1.0000	99.75
21.5	38,943,483	5,000,000	0.1284	0.8716	99.75
22.5	24,681,689		0.0000	1.0000	86.94
23.5	16,906,902		0.0000	1.0000	86.94
24.5	16,812,180		0.0000	1.0000	86.94
25.5	8,143,343		0.0000	1.0000	86.94
26.5	8,124,254		0.0000	1.0000	86.94
27.5	8,121,118		0.0000	1.0000	86.94
28.5	8,004,748		0.0000	1.0000	86.94
29.5	7,997,100		0.0000	1.0000	86.94
30.5	7,993,959		0.0000	1.0000	86.94
31.5	7,952,213		0.0000	1.0000	86.94
32.5	7,813,027		0.0000	1.0000	86.94
33.5	7,702,081		0.0000	1.0000	86.94
34.5					86.94

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 355.00 MEASURING AND REGULATING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

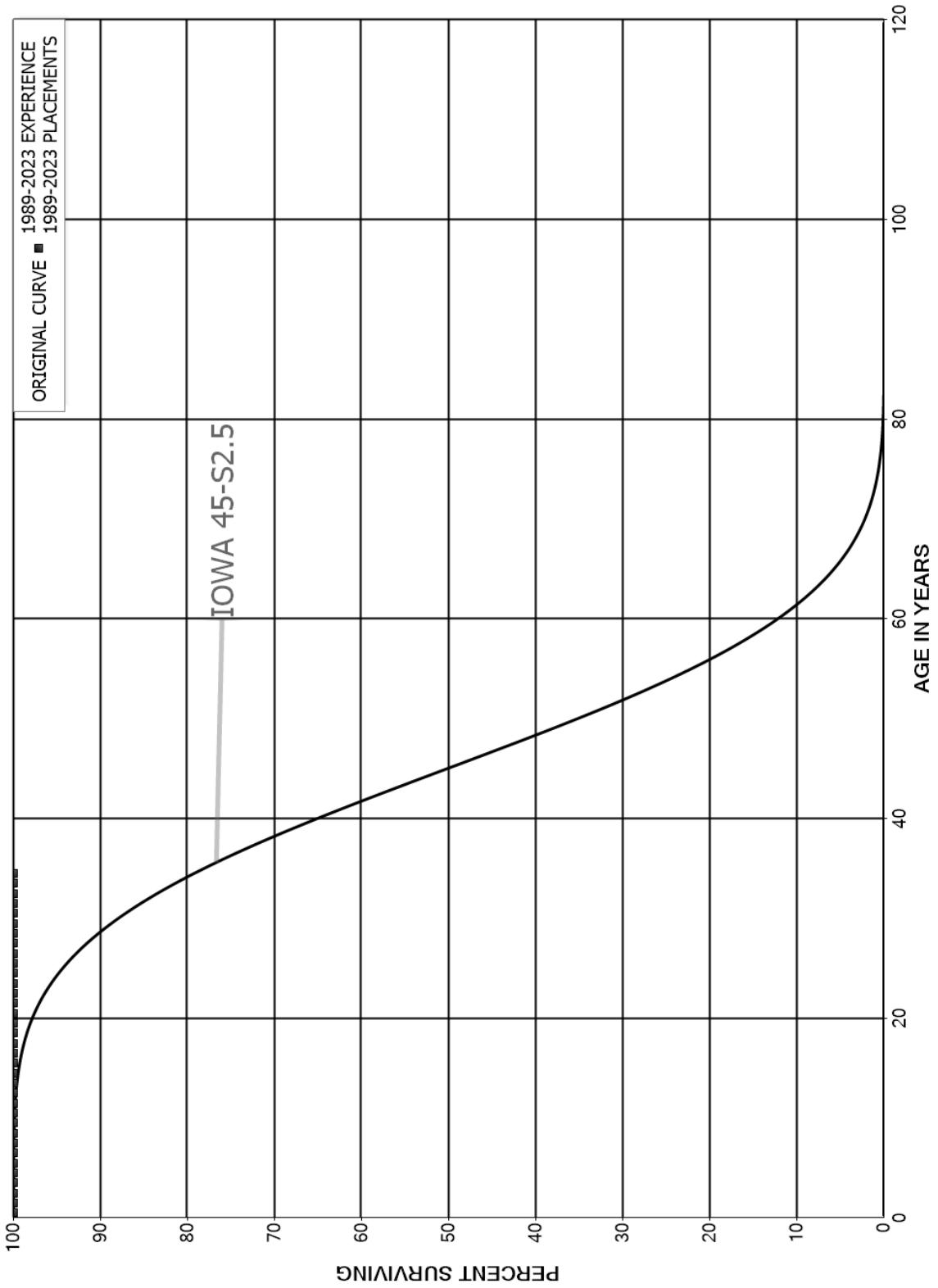
ACCOUNT 355.00 MEASURING AND REGULATING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2023 EXPERIENCE BAND 1989-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	39,987,117		0.0000	1.0000	100.00
0.5	36,702,177		0.0000	1.0000	100.00
1.5	27,546,415		0.0000	1.0000	100.00
2.5	18,161,888		0.0000	1.0000	100.00
3.5	16,698,104		0.0000	1.0000	100.00
4.5	17,326,031	58,779	0.0034	0.9966	100.00
5.5	16,417,180		0.0000	1.0000	99.66
6.5	16,292,883		0.0000	1.0000	99.66
7.5	16,168,075		0.0000	1.0000	99.66
8.5	16,158,003		0.0000	1.0000	99.66
9.5	16,158,003		0.0000	1.0000	99.66
10.5	16,086,849		0.0000	1.0000	99.66
11.5	16,069,349	122,683	0.0076	0.9924	99.66
12.5	15,511,149		0.0000	1.0000	98.90
13.5	15,462,884		0.0000	1.0000	98.90
14.5	14,075,689		0.0000	1.0000	98.90
15.5	14,310,699		0.0000	1.0000	98.90
16.5	9,699,149	15,249	0.0016	0.9984	98.90
17.5	9,540,770		0.0000	1.0000	98.74
18.5	7,749,151	32,310	0.0042	0.9958	98.74
19.5	6,886,213		0.0000	1.0000	98.33
20.5	6,886,213		0.0000	1.0000	98.33
21.5	6,688,016		0.0000	1.0000	98.33
22.5	6,639,166		0.0000	1.0000	98.33
23.5	4,935,004		0.0000	1.0000	98.33
24.5	4,696,363		0.0000	1.0000	98.33
25.5	3,606,243		0.0000	1.0000	98.33
26.5	3,606,243		0.0000	1.0000	98.33
27.5	3,590,871		0.0000	1.0000	98.33
28.5	3,581,013		0.0000	1.0000	98.33
29.5	3,580,978		0.0000	1.0000	98.33
30.5	3,579,193		0.0000	1.0000	98.33
31.5	3,561,374		0.0000	1.0000	98.33
32.5	3,539,964		0.0000	1.0000	98.33
33.5	3,473,015		0.0000	1.0000	98.33
34.5					98.33

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 356.00 PURIFICATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

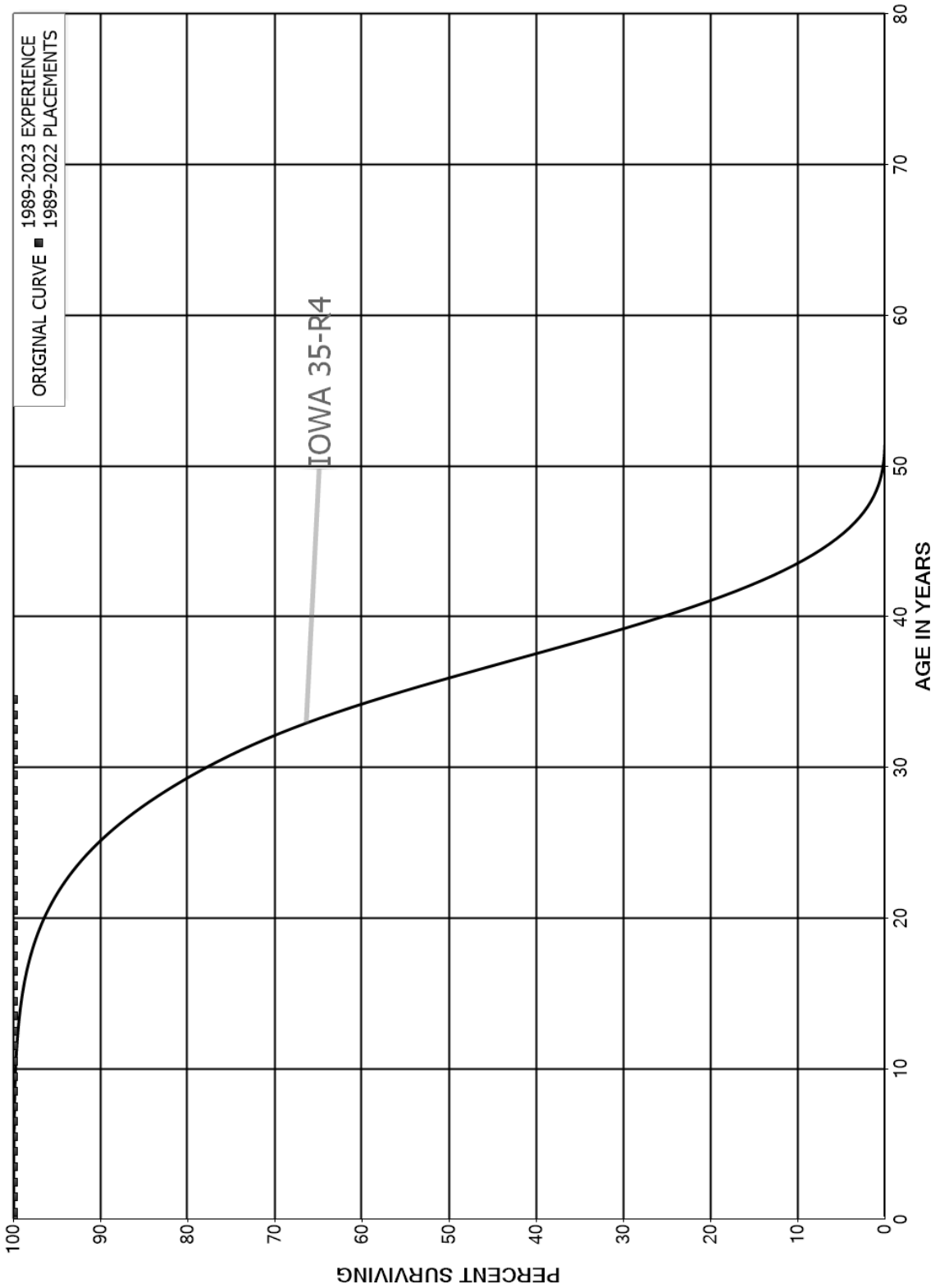
ACCOUNT 356.00 PURIFICATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2023 EXPERIENCE BAND 1989-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	28,955,345		0.0000	1.0000	100.00
0.5	28,777,466		0.0000	1.0000	100.00
1.5	28,542,130		0.0000	1.0000	100.00
2.5	28,555,651		0.0000	1.0000	100.00
3.5	363,765		0.0000	1.0000	100.00
4.5	363,765		0.0000	1.0000	100.00
5.5	297,363		0.0000	1.0000	100.00
6.5	297,363		0.0000	1.0000	100.00
7.5	297,363		0.0000	1.0000	100.00
8.5	297,363		0.0000	1.0000	100.00
9.5	297,363		0.0000	1.0000	100.00
10.5	297,363		0.0000	1.0000	100.00
11.5	297,363		0.0000	1.0000	100.00
12.5	297,363		0.0000	1.0000	100.00
13.5	297,363		0.0000	1.0000	100.00
14.5	297,363		0.0000	1.0000	100.00
15.5	297,363		0.0000	1.0000	100.00
16.5	297,363		0.0000	1.0000	100.00
17.5	297,363		0.0000	1.0000	100.00
18.5	297,363		0.0000	1.0000	100.00
19.5	297,363		0.0000	1.0000	100.00
20.5	297,363		0.0000	1.0000	100.00
21.5	297,363		0.0000	1.0000	100.00
22.5	297,363		0.0000	1.0000	100.00
23.5	297,363		0.0000	1.0000	100.00
24.5	297,363		0.0000	1.0000	100.00
25.5	294,282		0.0000	1.0000	100.00
26.5	294,282		0.0000	1.0000	100.00
27.5	245,456		0.0000	1.0000	100.00
28.5	171,575		0.0000	1.0000	100.00
29.5	171,575		0.0000	1.0000	100.00
30.5	168,697		0.0000	1.0000	100.00
31.5	152,757		0.0000	1.0000	100.00
32.5	152,757		0.0000	1.0000	100.00
33.5	139,942		0.0000	1.0000	100.00
34.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 357.00 OTHER EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

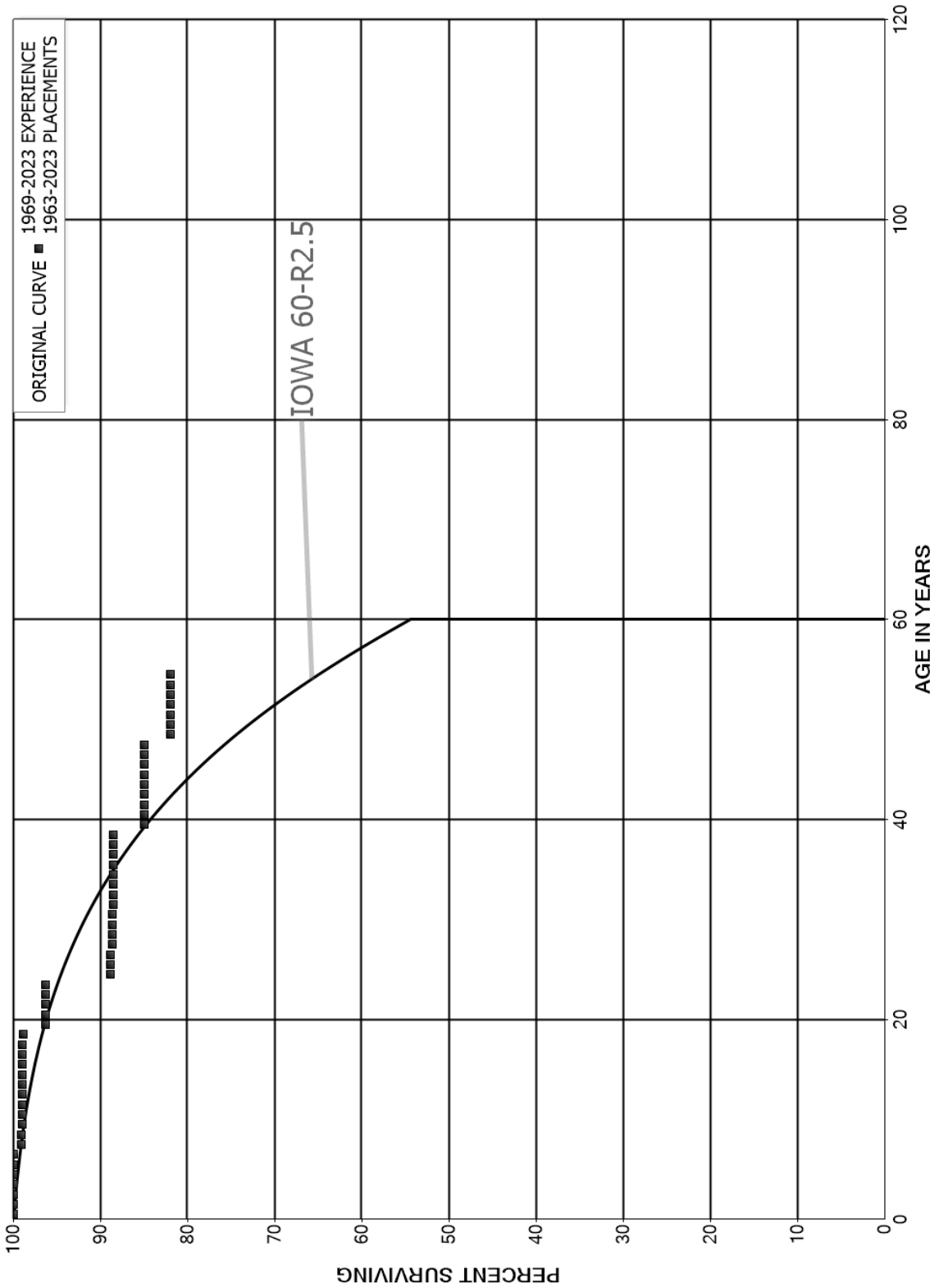
ACCOUNT 357.00 OTHER EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2022 EXPERIENCE BAND 1989-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,255,463		0.0000	1.0000	100.00
0.5	5,255,463		0.0000	1.0000	100.00
1.5	5,141,896		0.0000	1.0000	100.00
2.5	4,672,992		0.0000	1.0000	100.00
3.5	2,422,822		0.0000	1.0000	100.00
4.5	2,422,822		0.0000	1.0000	100.00
5.5	1,395,285		0.0000	1.0000	100.00
6.5	1,395,285		0.0000	1.0000	100.00
7.5	1,395,285		0.0000	1.0000	100.00
8.5	1,395,285		0.0000	1.0000	100.00
9.5	1,395,285		0.0000	1.0000	100.00
10.5	1,395,285		0.0000	1.0000	100.00
11.5	1,395,285		0.0000	1.0000	100.00
12.5	1,395,285		0.0000	1.0000	100.00
13.5	1,395,285		0.0000	1.0000	100.00
14.5	1,332,029		0.0000	1.0000	100.00
15.5	702,587		0.0000	1.0000	100.00
16.5	702,587		0.0000	1.0000	100.00
17.5	702,587		0.0000	1.0000	100.00
18.5	702,587		0.0000	1.0000	100.00
19.5	702,587		0.0000	1.0000	100.00
20.5	702,587		0.0000	1.0000	100.00
21.5	702,587		0.0000	1.0000	100.00
22.5	702,587		0.0000	1.0000	100.00
23.5	702,587		0.0000	1.0000	100.00
24.5	646,258		0.0000	1.0000	100.00
25.5	82,037		0.0000	1.0000	100.00
26.5	82,037		0.0000	1.0000	100.00
27.5	82,037		0.0000	1.0000	100.00
28.5	82,037		0.0000	1.0000	100.00
29.5	82,037		0.0000	1.0000	100.00
30.5	82,037		0.0000	1.0000	100.00
31.5	76,057		0.0000	1.0000	100.00
32.5	76,057		0.0000	1.0000	100.00
33.5	76,057		0.0000	1.0000	100.00
34.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1963-2023 EXPERIENCE BAND 1969-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	25,677,346	44	0.0000	1.0000	100.00
0.5	25,434,110		0.0000	1.0000	100.00
1.5	23,691,351		0.0000	1.0000	100.00
2.5	23,432,096		0.0000	1.0000	100.00
3.5	23,361,127		0.0000	1.0000	100.00
4.5	23,193,204	44	0.0000	1.0000	100.00
5.5	15,702,491		0.0000	1.0000	100.00
6.5	12,828,703	123,196	0.0096	0.9904	100.00
7.5	9,157,629		0.0000	1.0000	99.04
8.5	9,103,804	4,058	0.0004	0.9996	99.04
9.5	9,046,459		0.0000	1.0000	99.00
10.5	9,046,459		0.0000	1.0000	99.00
11.5	8,942,963		0.0000	1.0000	99.00
12.5	8,662,678		0.0000	1.0000	99.00
13.5	7,912,962	6,596	0.0008	0.9992	99.00
14.5	6,555,507		0.0000	1.0000	98.91
15.5	5,296,524		0.0000	1.0000	98.91
16.5	4,864,332		0.0000	1.0000	98.91
17.5	3,854,896	1,150	0.0003	0.9997	98.91
18.5	3,658,107	97,968	0.0268	0.9732	98.88
19.5	3,541,714		0.0000	1.0000	96.23
20.5	3,541,714		0.0000	1.0000	96.23
21.5	3,414,287		0.0000	1.0000	96.23
22.5	3,334,846		0.0000	1.0000	96.23
23.5	3,292,618	253,844	0.0771	0.9229	96.23
24.5	2,853,588		0.0000	1.0000	88.82
25.5	2,786,531		0.0000	1.0000	88.82
26.5	2,594,384	5,060	0.0020	0.9980	88.82
27.5	2,478,519	478	0.0002	0.9998	88.64
28.5	2,394,631		0.0000	1.0000	88.63
29.5	2,143,139		0.0000	1.0000	88.63
30.5	2,074,412	2,147	0.0010	0.9990	88.63
31.5	1,925,445	568	0.0003	0.9997	88.53
32.5	1,837,823		0.0000	1.0000	88.51
33.5	1,813,495		0.0000	1.0000	88.51
34.5	1,729,977		0.0000	1.0000	88.51
35.5	1,682,462		0.0000	1.0000	88.51
36.5	1,673,588		0.0000	1.0000	88.51
37.5	1,664,262		0.0000	1.0000	88.51
38.5	1,644,107	66,938	0.0407	0.9593	88.51

NORTHWEST NATURAL GAS COMPANY

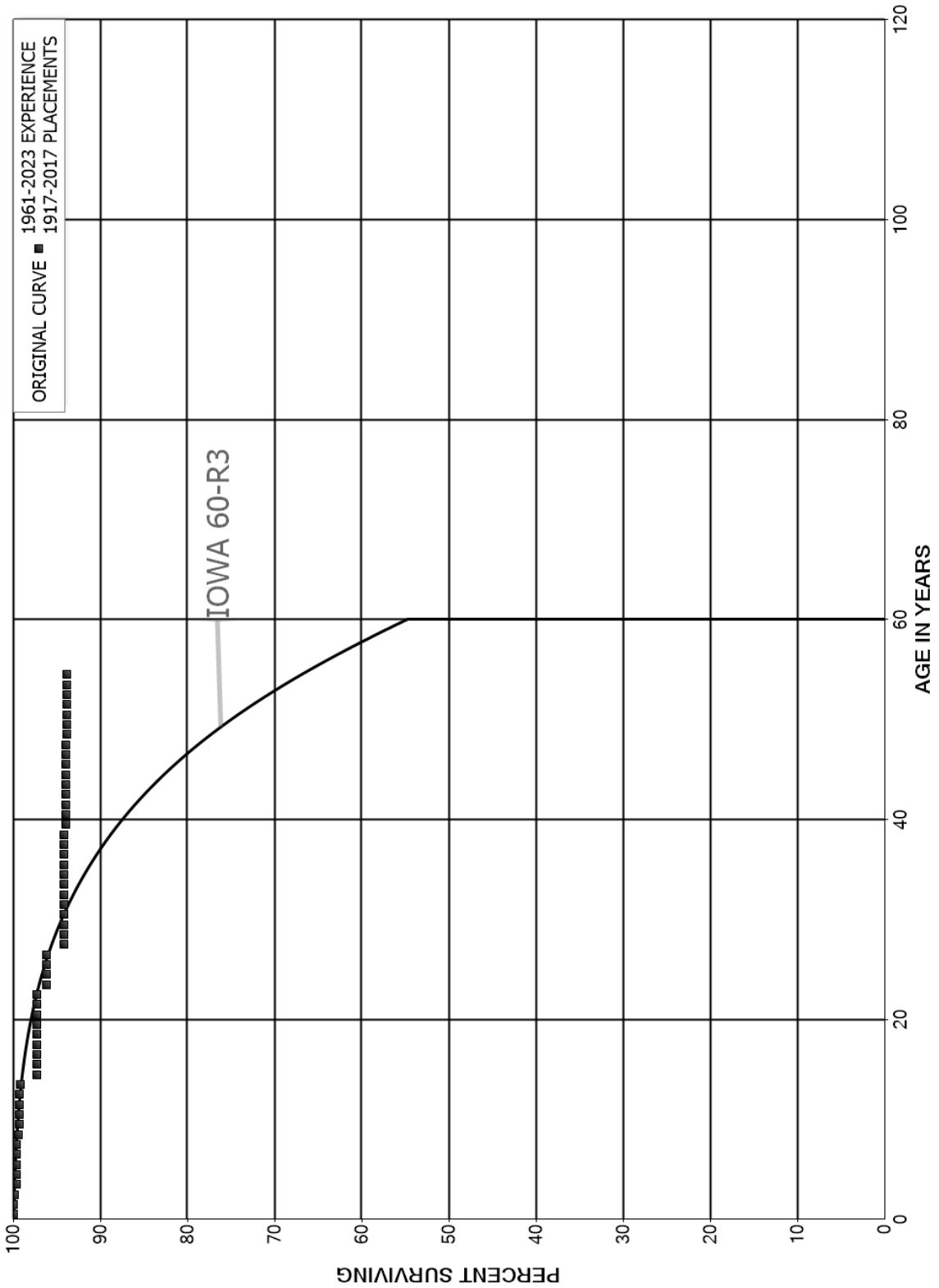
ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1963-2023 EXPERIENCE BAND 1969-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,576,899		0.0000	1.0000	84.90
40.5	1,576,899		0.0000	1.0000	84.90
41.5	1,516,207		0.0000	1.0000	84.90
42.5	1,515,190		0.0000	1.0000	84.90
43.5	1,515,190		0.0000	1.0000	84.90
44.5	1,499,105		0.0000	1.0000	84.90
45.5	1,457,539		0.0000	1.0000	84.90
46.5	746,366		0.0000	1.0000	84.90
47.5	731,809	25,020	0.0342	0.9658	84.90
48.5	697,146		0.0000	1.0000	82.00
49.5	91,537		0.0000	1.0000	82.00
50.5	91,537		0.0000	1.0000	82.00
51.5	91,537		0.0000	1.0000	82.00
52.5	91,537		0.0000	1.0000	82.00
53.5	65,448		0.0000	1.0000	82.00
54.5	6,036		0.0000	1.0000	82.00
55.5	5,509		0.0000	1.0000	82.00
56.5	5,509		0.0000	1.0000	82.00
57.5	5,509		0.0000	1.0000	82.00
58.5	4,009		0.0000	1.0000	82.00
59.5	4,009		0.0000	1.0000	82.00
60.5					82.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 362.00 GAS HOLDERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 362.00 GAS HOLDERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1917-2017 EXPERIENCE BAND 1961-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	10,693,529		0.0000	1.0000	100.00
0.5	10,766,444	954	0.0001	0.9999	100.00
1.5	10,725,963	20,788	0.0019	0.9981	99.99
2.5	10,731,567	24,257	0.0023	0.9977	99.80
3.5	10,732,521		0.0000	1.0000	99.57
4.5	10,732,344		0.0000	1.0000	99.57
5.5	10,735,297		0.0000	1.0000	99.57
6.5	10,360,610		0.0000	1.0000	99.57
7.5	8,673,677	12,049	0.0014	0.9986	99.57
8.5	8,575,271	11,416	0.0013	0.9987	99.43
9.5	8,571,828	472	0.0001	0.9999	99.30
10.5	8,572,007		0.0000	1.0000	99.30
11.5	8,549,518		0.0000	1.0000	99.30
12.5	8,549,518	8,994	0.0011	0.9989	99.30
13.5	9,300,870	174,892	0.0188	0.9812	99.19
14.5	8,812,224		0.0000	1.0000	97.33
15.5	8,812,224	2,066	0.0002	0.9998	97.33
16.5	8,810,257		0.0000	1.0000	97.30
17.5	8,442,780		0.0000	1.0000	97.30
18.5	8,442,780		0.0000	1.0000	97.30
19.5	8,442,780		0.0000	1.0000	97.30
20.5	8,442,780		0.0000	1.0000	97.30
21.5	8,442,709		0.0000	1.0000	97.30
22.5	8,442,031	96,759	0.0115	0.9885	97.30
23.5	8,345,123		0.0000	1.0000	96.19
24.5	8,345,123	1,431	0.0002	0.9998	96.19
25.5	8,345,123		0.0000	1.0000	96.17
26.5	8,345,123	174,892	0.0210	0.9790	96.17
27.5	8,028,102		0.0000	1.0000	94.16
28.5	8,027,148		0.0000	1.0000	94.16
29.5	7,954,233		0.0000	1.0000	94.16
30.5	7,932,289	1,200	0.0002	0.9998	94.16
31.5	7,931,089		0.0000	1.0000	94.14
32.5	7,930,072		0.0000	1.0000	94.14
33.5	7,930,072		0.0000	1.0000	94.14
34.5	7,922,701		0.0000	1.0000	94.14
35.5	7,931,283		0.0000	1.0000	94.14
36.5	7,931,283		0.0000	1.0000	94.14
37.5	7,931,283		0.0000	1.0000	94.14
38.5	7,311,305	18,053	0.0025	0.9975	94.14

NORTHWEST NATURAL GAS COMPANY

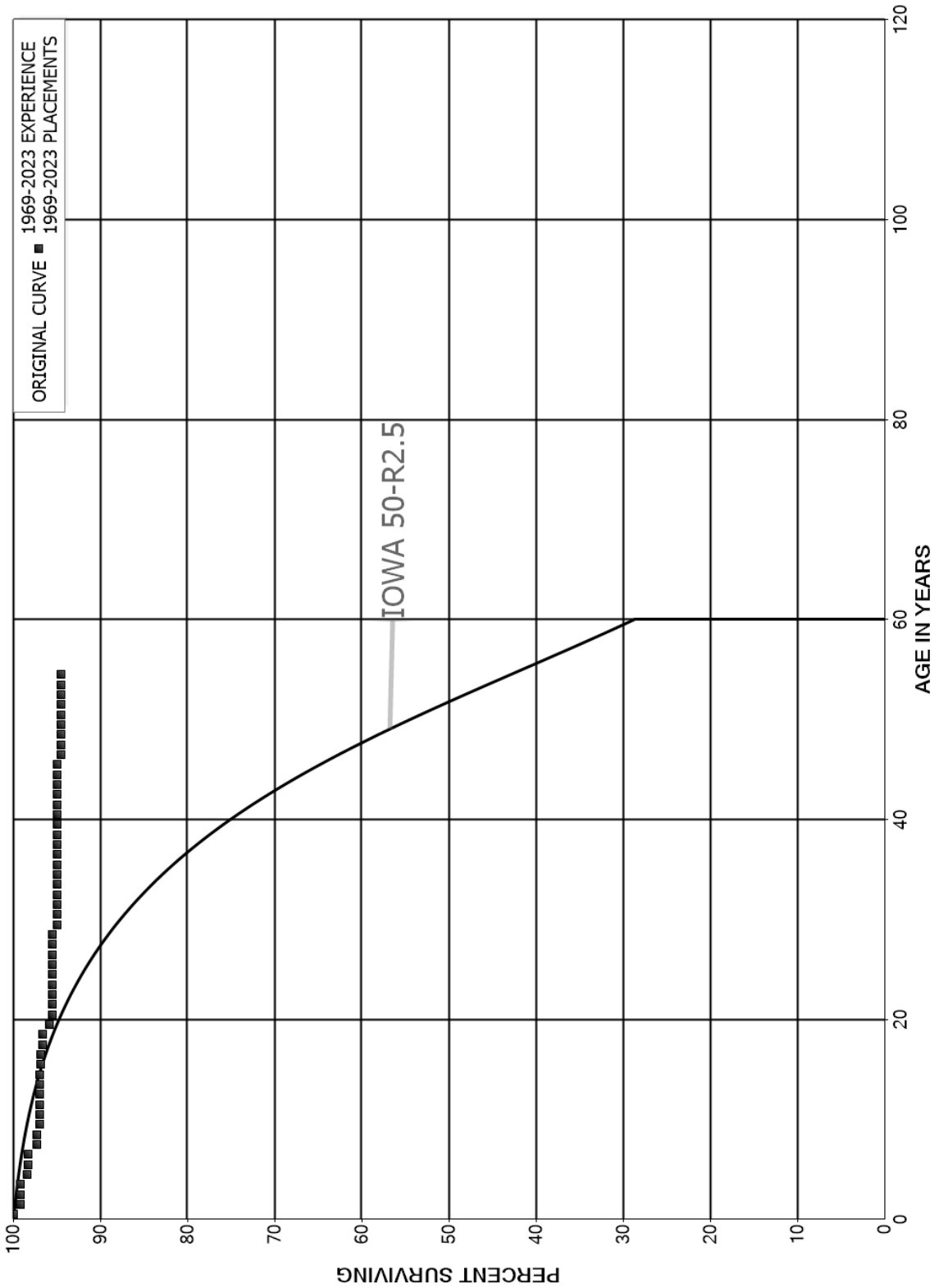
ACCOUNT 362.00 GAS HOLDERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1917-2017 EXPERIENCE BAND 1961-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	7,293,252		0.0000	1.0000	93.91
40.5	7,292,283		0.0000	1.0000	93.91
41.5	7,292,283		0.0000	1.0000	93.91
42.5	7,292,283		0.0000	1.0000	93.91
43.5	7,292,380		0.0000	1.0000	93.91
44.5	7,292,380		0.0000	1.0000	93.91
45.5	7,282,078		0.0000	1.0000	93.91
46.5	1,730,784		0.0000	1.0000	93.91
47.5	1,730,784	602	0.0003	0.9997	93.91
48.5	1,730,182		0.0000	1.0000	93.88
49.5	1,729,367		0.0000	1.0000	93.88
50.5	1,729,367		0.0000	1.0000	93.88
51.5	1,729,367		0.0000	1.0000	93.88
52.5	1,729,367		0.0000	1.0000	93.88
53.5	1,729,367		0.0000	1.0000	93.88
54.5	8,858		0.0000	1.0000	93.88
55.5	8,858		0.0000	1.0000	93.88
56.5	8,858		0.0000	1.0000	93.88
57.5	8,858		0.0000	1.0000	93.88
58.5	8,858		0.0000	1.0000	93.88
59.5	8,858		0.0000	1.0000	93.88
60.5	97		0.0000	1.0000	93.88
61.5	97		0.0000	1.0000	93.88
62.5	97		0.0000	1.0000	93.88
63.5	97		0.0000	1.0000	93.88
64.5	97		0.0000	1.0000	93.88
65.5	97		0.0000	1.0000	93.88
66.5	97		0.0000	1.0000	93.88
67.5	97		0.0000	1.0000	93.88
68.5					93.88

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 363.10 LIQUEFACTION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.10 LIQUEFACTION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2023 EXPERIENCE BAND 1969-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	27,179,866	28,598	0.0011	0.9989	100.00
0.5	27,060,071	199,635	0.0074	0.9926	99.89
1.5	20,823,516		0.0000	1.0000	99.16
2.5	19,870,112		0.0000	1.0000	99.16
3.5	19,793,952	146,338	0.0074	0.9926	99.16
4.5	19,417,376	18,698	0.0010	0.9990	98.42
5.5	14,548,542		0.0000	1.0000	98.33
6.5	10,875,424	114,090	0.0105	0.9895	98.33
7.5	10,358,546		0.0000	1.0000	97.30
8.5	10,304,721	34,692	0.0034	0.9966	97.30
9.5	9,758,855		0.0000	1.0000	96.97
10.5	9,758,855		0.0000	1.0000	96.97
11.5	9,685,872		0.0000	1.0000	96.97
12.5	9,685,872	434	0.0000	1.0000	96.97
13.5	9,685,438		0.0000	1.0000	96.97
14.5	9,615,025	13,425	0.0014	0.9986	96.97
15.5	9,539,222		0.0000	1.0000	96.83
16.5	9,495,419	18,523	0.0020	0.9980	96.83
17.5	9,321,042	3,226	0.0003	0.9997	96.64
18.5	9,269,484	74,502	0.0080	0.9920	96.61
19.5	8,899,934	34,032	0.0038	0.9962	95.83
20.5	8,740,379		0.0000	1.0000	95.47
21.5	8,665,232		0.0000	1.0000	95.47
22.5	8,199,959		0.0000	1.0000	95.47
23.5	8,111,837		0.0000	1.0000	95.47
24.5	7,783,304		0.0000	1.0000	95.47
25.5	7,234,849		0.0000	1.0000	95.47
26.5	6,950,150	399	0.0001	0.9999	95.47
27.5	6,756,916		0.0000	1.0000	95.46
28.5	6,754,705	35,128	0.0052	0.9948	95.46
29.5	6,702,869		0.0000	1.0000	94.96
30.5	6,686,673		0.0000	1.0000	94.96
31.5	6,605,144		0.0000	1.0000	94.96
32.5	6,501,938		0.0000	1.0000	94.96
33.5	6,412,166		0.0000	1.0000	94.96
34.5	6,390,407		0.0000	1.0000	94.96
35.5	6,390,407		0.0000	1.0000	94.96
36.5	6,313,086		0.0000	1.0000	94.96
37.5	6,298,223		0.0000	1.0000	94.96
38.5	6,286,698		0.0000	1.0000	94.96

NORTHWEST NATURAL GAS COMPANY

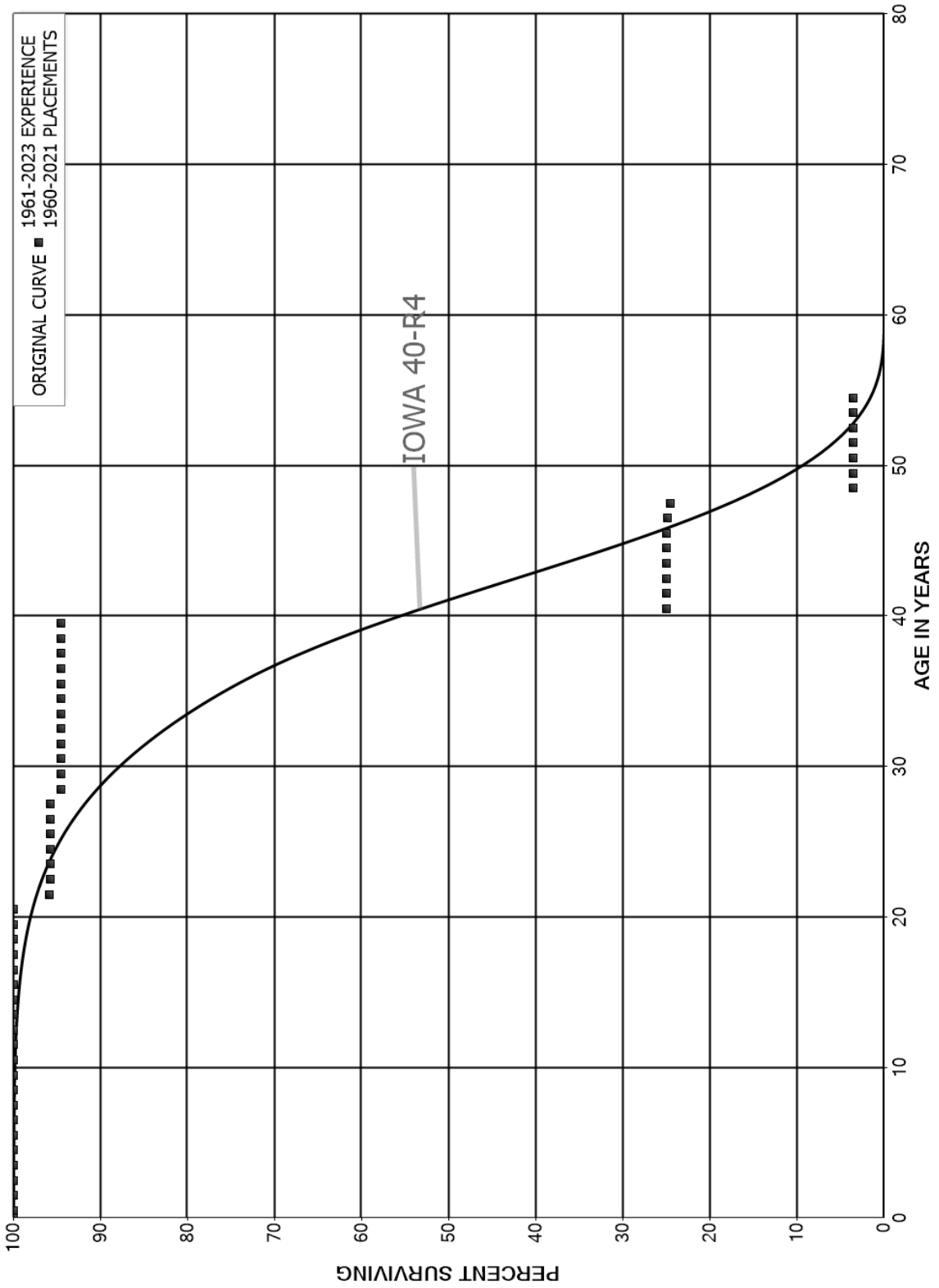
ACCOUNT 363.10 LIQUEFACTION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2023 EXPERIENCE BAND 1969-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	6,264,779		0.0000	1.0000	94.96
40.5	6,264,779		0.0000	1.0000	94.96
41.5	6,264,779		0.0000	1.0000	94.96
42.5	6,264,779		0.0000	1.0000	94.96
43.5	6,164,100		0.0000	1.0000	94.96
44.5	6,158,562		0.0000	1.0000	94.96
45.5	6,142,214	27,318	0.0044	0.9956	94.96
46.5	878,099		0.0000	1.0000	94.54
47.5	852,144		0.0000	1.0000	94.54
48.5	851,876		0.0000	1.0000	94.54
49.5	849,919		0.0000	1.0000	94.54
50.5	849,919		0.0000	1.0000	94.54
51.5	845,658		0.0000	1.0000	94.54
52.5	844,045		0.0000	1.0000	94.54
53.5	828,857		0.0000	1.0000	94.54
54.5					94.54

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 363.20 VAPORIZING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.20 VAPORIZING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1960-2021 EXPERIENCE BAND 1961-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	13,831,400		0.0000	1.0000	100.00
0.5	13,831,400	602	0.0000	1.0000	100.00
1.5	14,034,034		0.0000	1.0000	100.00
2.5	14,023,474	1,415	0.0001	0.9999	100.00
3.5	11,055,638		0.0000	1.0000	99.99
4.5	11,055,638		0.0000	1.0000	99.99
5.5	11,055,638		0.0000	1.0000	99.99
6.5	6,584,958	1,983	0.0003	0.9997	99.99
7.5	6,584,958		0.0000	1.0000	99.96
8.5	6,436,057	2,322	0.0004	0.9996	99.96
9.5	6,433,834		0.0000	1.0000	99.92
10.5	6,433,834		0.0000	1.0000	99.92
11.5	6,433,834		0.0000	1.0000	99.92
12.5	5,320,819		0.0000	1.0000	99.92
13.5	5,320,819		0.0000	1.0000	99.92
14.5	5,320,819		0.0000	1.0000	99.92
15.5	5,320,819		0.0000	1.0000	99.92
16.5	5,320,819		0.0000	1.0000	99.92
17.5	4,999,612		0.0000	1.0000	99.92
18.5	4,999,612		0.0000	1.0000	99.92
19.5	4,931,166		0.0000	1.0000	99.92
20.5	4,931,166	200,000	0.0406	0.9594	99.92
21.5	4,730,986	8,350	0.0018	0.9982	95.87
22.5	4,722,636		0.0000	1.0000	95.70
23.5	4,722,636	455	0.0001	0.9999	95.70
24.5	4,722,181	436	0.0001	0.9999	95.69
25.5	4,721,745		0.0000	1.0000	95.68
26.5	4,721,745	303	0.0001	0.9999	95.68
27.5	4,721,442	59,483	0.0126	0.9874	95.67
28.5	4,650,778		0.0000	1.0000	94.47
29.5	4,618,017		0.0000	1.0000	94.47
30.5	4,618,016		0.0000	1.0000	94.47
31.5	4,615,790		0.0000	1.0000	94.47
32.5	4,429,354		0.0000	1.0000	94.47
33.5	3,273,347		0.0000	1.0000	94.47
34.5	3,273,347		0.0000	1.0000	94.47
35.5	3,273,347		0.0000	1.0000	94.47
36.5	3,095,885		0.0000	1.0000	94.47
37.5	3,083,807		0.0000	1.0000	94.47
38.5	3,083,807		0.0000	1.0000	94.47

NORTHWEST NATURAL GAS COMPANY

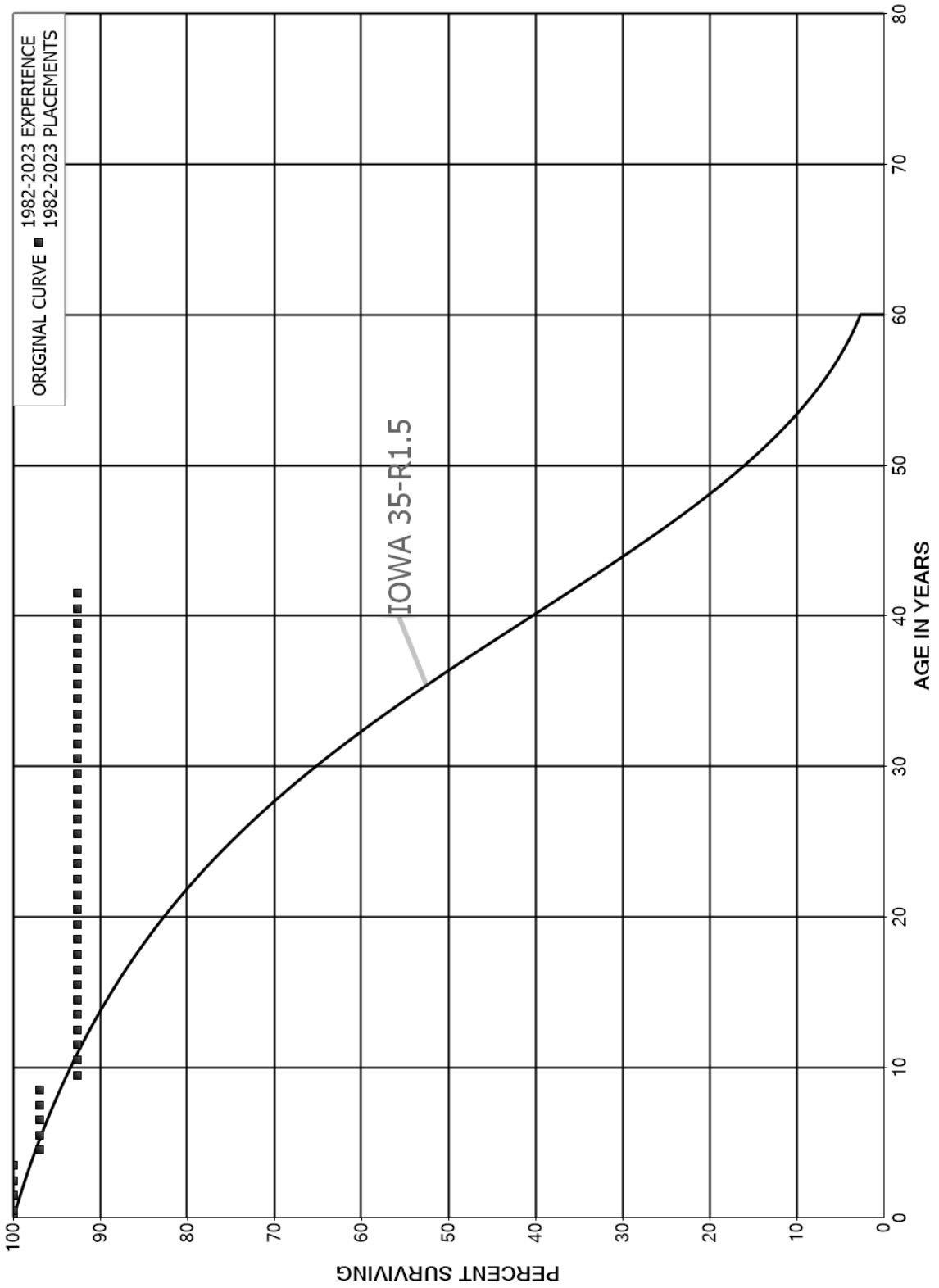
ACCOUNT 363.20 VAPORIZING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1960-2021 EXPERIENCE BAND 1961-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,083,807	2,269,514	0.7359	0.2641	94.47
40.5	814,293		0.0000	1.0000	24.94
41.5	814,293		0.0000	1.0000	24.94
42.5	814,293		0.0000	1.0000	24.94
43.5	814,293		0.0000	1.0000	24.94
44.5	814,293		0.0000	1.0000	24.94
45.5	814,293	4,062	0.0050	0.9950	24.94
46.5	749,406	9,122	0.0122	0.9878	24.82
47.5	353,620	303,259	0.8576	0.1424	24.52
48.5	50,092		0.0000	1.0000	3.49
49.5	47,833		0.0000	1.0000	3.49
50.5	34,582		0.0000	1.0000	3.49
51.5	32,214		0.0000	1.0000	3.49
52.5	18,960		0.0000	1.0000	3.49
53.5	18,960		0.0000	1.0000	3.49
54.5					3.49

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 363.30 COMPRESSOR EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.30 COMPRESSOR EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1982-2023 EXPERIENCE BAND 1982-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	9,311,101		0.0000	1.0000	100.00
0.5	6,207,702		0.0000	1.0000	100.00
1.5	5,980,975		0.0000	1.0000	100.00
2.5	5,160,185	273	0.0001	0.9999	100.00
3.5	5,038,729	151,425	0.0301	0.9699	99.99
4.5	4,887,304		0.0000	1.0000	96.99
5.5	4,630,707		0.0000	1.0000	96.99
6.5	4,132,901		0.0000	1.0000	96.99
7.5	1,865,931		0.0000	1.0000	96.99
8.5	1,865,931	84,841	0.0455	0.9545	96.99
9.5	395,261		0.0000	1.0000	92.58
10.5	395,261		0.0000	1.0000	92.58
11.5	395,261		0.0000	1.0000	92.58
12.5	395,261		0.0000	1.0000	92.58
13.5	395,261		0.0000	1.0000	92.58
14.5	395,261		0.0000	1.0000	92.58
15.5	343,850		0.0000	1.0000	92.58
16.5	343,850		0.0000	1.0000	92.58
17.5	343,850		0.0000	1.0000	92.58
18.5	327,070		0.0000	1.0000	92.58
19.5	327,070		0.0000	1.0000	92.58
20.5	148,568		0.0000	1.0000	92.58
21.5	148,568		0.0000	1.0000	92.58
22.5	148,568		0.0000	1.0000	92.58
23.5	148,568		0.0000	1.0000	92.58
24.5	148,568		0.0000	1.0000	92.58
25.5	148,568		0.0000	1.0000	92.58
26.5	127,741		0.0000	1.0000	92.58
27.5	108,320		0.0000	1.0000	92.58
28.5	108,320		0.0000	1.0000	92.58
29.5	108,320		0.0000	1.0000	92.58
30.5	108,320		0.0000	1.0000	92.58
31.5	108,320		0.0000	1.0000	92.58
32.5	108,320		0.0000	1.0000	92.58
33.5	108,320		0.0000	1.0000	92.58
34.5	108,320		0.0000	1.0000	92.58
35.5	108,320		0.0000	1.0000	92.58
36.5	108,320		0.0000	1.0000	92.58
37.5	86,804		0.0000	1.0000	92.58
38.5	86,804		0.0000	1.0000	92.58

NORTHWEST NATURAL GAS COMPANY

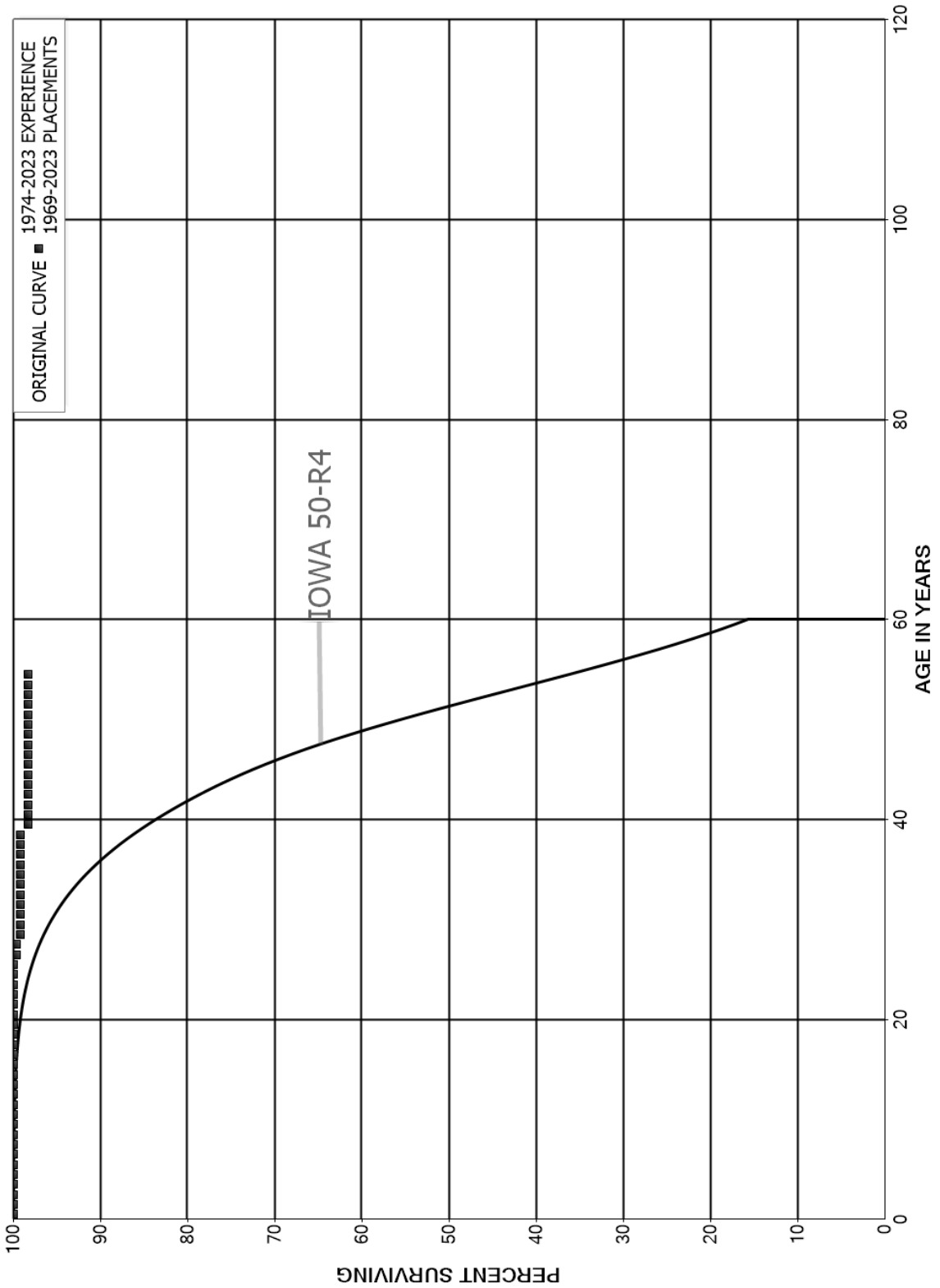
ACCOUNT 363.30 COMPRESSOR EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1982-2023 EXPERIENCE BAND 1982-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	86,804		0.0000	1.0000	92.58
40.5	85,687		0.0000	1.0000	92.58
41.5					92.58

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 363.40 MEASURING AND REGULATING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.40 MEASURING AND REGULATING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2023 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	22,645,250		0.0000	1.0000	100.00
0.5	19,061,727		0.0000	1.0000	100.00
1.5	13,805,464		0.0000	1.0000	100.00
2.5	13,447,703		0.0000	1.0000	100.00
3.5	12,989,084		0.0000	1.0000	100.00
4.5	13,333,771		0.0000	1.0000	100.00
5.5	12,752,913		0.0000	1.0000	100.00
6.5	1,362,034		0.0000	1.0000	100.00
7.5	1,362,034		0.0000	1.0000	100.00
8.5	1,362,034		0.0000	1.0000	100.00
9.5	1,002,125		0.0000	1.0000	100.00
10.5	850,563		0.0000	1.0000	100.00
11.5	850,563		0.0000	1.0000	100.00
12.5	850,563		0.0000	1.0000	100.00
13.5	850,563		0.0000	1.0000	100.00
14.5	682,272		0.0000	1.0000	100.00
15.5	682,272		0.0000	1.0000	100.00
16.5	682,272		0.0000	1.0000	100.00
17.5	653,998		0.0000	1.0000	100.00
18.5	653,998		0.0000	1.0000	100.00
19.5	653,998		0.0000	1.0000	100.00
20.5	653,998		0.0000	1.0000	100.00
21.5	636,675		0.0000	1.0000	100.00
22.5	636,675		0.0000	1.0000	100.00
23.5	636,675		0.0000	1.0000	100.00
24.5	636,675		0.0000	1.0000	100.00
25.5	636,675	2,647	0.0042	0.9958	100.00
26.5	634,028		0.0000	1.0000	99.58
27.5	634,028	2,566	0.0040	0.9960	99.58
28.5	631,462		0.0000	1.0000	99.18
29.5	631,462		0.0000	1.0000	99.18
30.5	631,462		0.0000	1.0000	99.18
31.5	628,091		0.0000	1.0000	99.18
32.5	607,580		0.0000	1.0000	99.18
33.5	560,097		0.0000	1.0000	99.18
34.5	555,322		0.0000	1.0000	99.18
35.5	545,620		0.0000	1.0000	99.18
36.5	545,620		0.0000	1.0000	99.18
37.5	545,620		0.0000	1.0000	99.18
38.5	541,958	4,721	0.0087	0.9913	99.18

NORTHWEST NATURAL GAS COMPANY

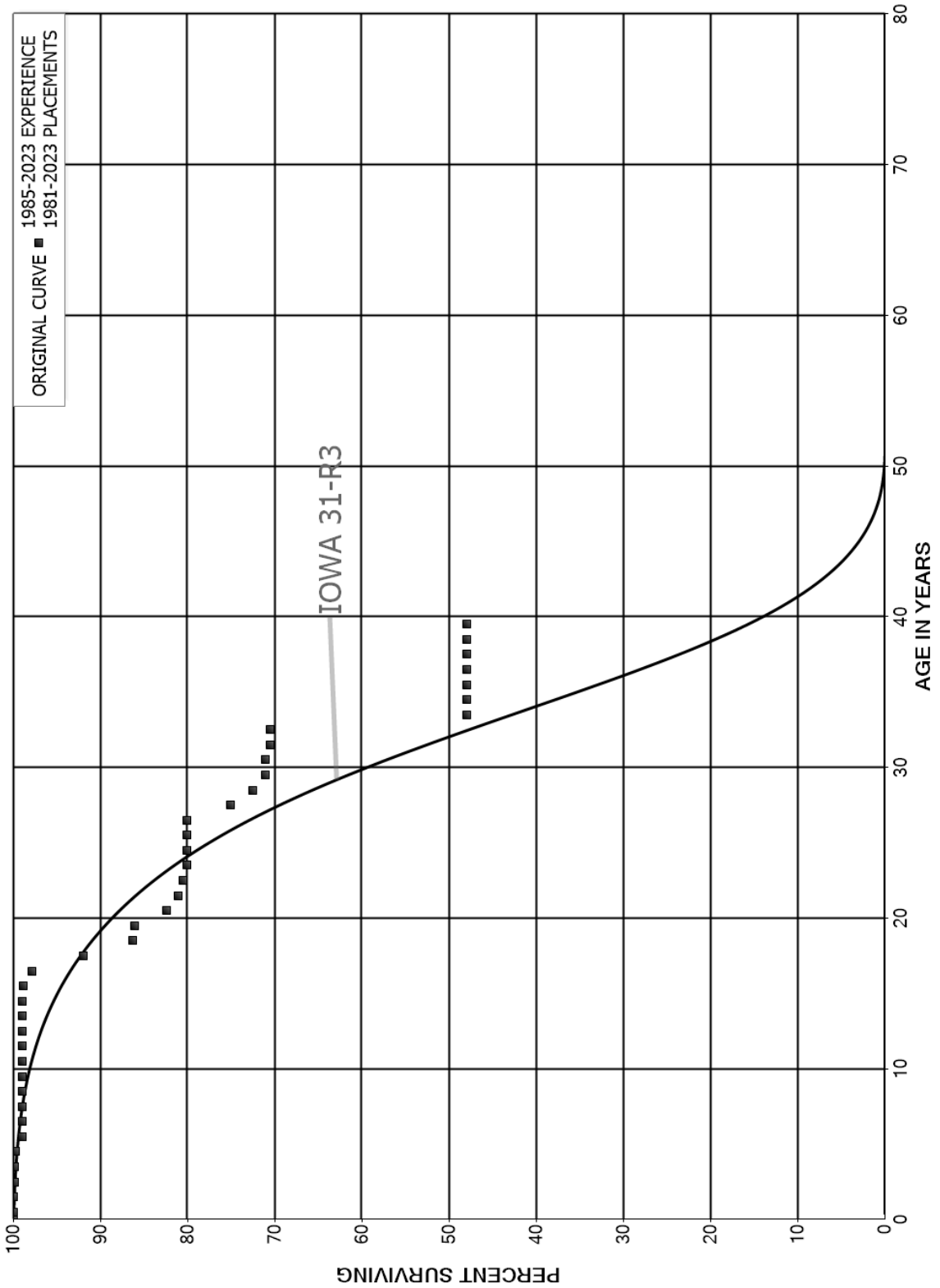
ACCOUNT 363.40 MEASURING AND REGULATING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2023 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	537,237		0.0000	1.0000	98.32
40.5	537,237		0.0000	1.0000	98.32
41.5	537,237		0.0000	1.0000	98.32
42.5	537,237		0.0000	1.0000	98.32
43.5	537,237		0.0000	1.0000	98.32
44.5	537,237		0.0000	1.0000	98.32
45.5	537,237		0.0000	1.0000	98.32
46.5	482,034		0.0000	1.0000	98.32
47.5	482,034		0.0000	1.0000	98.32
48.5	481,660		0.0000	1.0000	98.32
49.5	480,333		0.0000	1.0000	98.32
50.5	480,333		0.0000	1.0000	98.32
51.5	474,008		0.0000	1.0000	98.32
52.5	464,177		0.0000	1.0000	98.32
53.5	461,537		0.0000	1.0000	98.32
54.5					98.32

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 363.50 CNG REFUELING FACILITIES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.50 CNG REFUELING FACILITIES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1981-2023 EXPERIENCE BAND 1985-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,627,792		0.0000	1.0000	100.00
0.5	3,397,353	3,726	0.0011	0.9989	100.00
1.5	3,504,352	13	0.0000	1.0000	99.89
2.5	3,509,603	1,280	0.0004	0.9996	99.89
3.5	3,517,228	3,071	0.0009	0.9991	99.85
4.5	3,629,180	27,968	0.0077	0.9923	99.77
5.5	3,601,212		0.0000	1.0000	99.00
6.5	3,601,212		0.0000	1.0000	99.00
7.5	3,601,212		0.0000	1.0000	99.00
8.5	3,601,212		0.0000	1.0000	99.00
9.5	2,068,805		0.0000	1.0000	99.00
10.5	1,945,791		0.0000	1.0000	99.00
11.5	1,828,161		0.0000	1.0000	99.00
12.5	1,828,161		0.0000	1.0000	99.00
13.5	1,828,161	1,938	0.0011	0.9989	99.00
14.5	1,826,223	1,632	0.0009	0.9991	98.89
15.5	1,824,591	18,126	0.0099	0.9901	98.80
16.5	1,806,465	108,566	0.0601	0.9399	97.82
17.5	1,697,899	103,851	0.0612	0.9388	91.94
18.5	1,594,048	4,067	0.0026	0.9974	86.32
19.5	1,540,307	66,855	0.0434	0.9566	86.10
20.5	1,473,452	22,396	0.0152	0.9848	82.36
21.5	1,449,756	10,299	0.0071	0.9929	81.11
22.5	1,439,457	8,819	0.0061	0.9939	80.53
23.5	1,430,638		0.0000	1.0000	80.04
24.5	1,426,354		0.0000	1.0000	80.04
25.5	1,397,519		0.0000	1.0000	80.04
26.5	1,349,534	84,323	0.0625	0.9375	80.04
27.5	1,037,060	35,635	0.0344	0.9656	75.04
28.5	708,066	13,528	0.0191	0.9809	72.46
29.5	346,154	25	0.0001	0.9999	71.08
30.5	284,919	2,421	0.0085	0.9915	71.07
31.5	262,791		0.0000	1.0000	70.47
32.5	210,584	67,435	0.3202	0.6798	70.47
33.5	79,670		0.0000	1.0000	47.90
34.5	79,670		0.0000	1.0000	47.90
35.5	79,670		0.0000	1.0000	47.90
36.5	79,670		0.0000	1.0000	47.90
37.5	72,652		0.0000	1.0000	47.90
38.5	71,186		0.0000	1.0000	47.90

NORTHWEST NATURAL GAS COMPANY

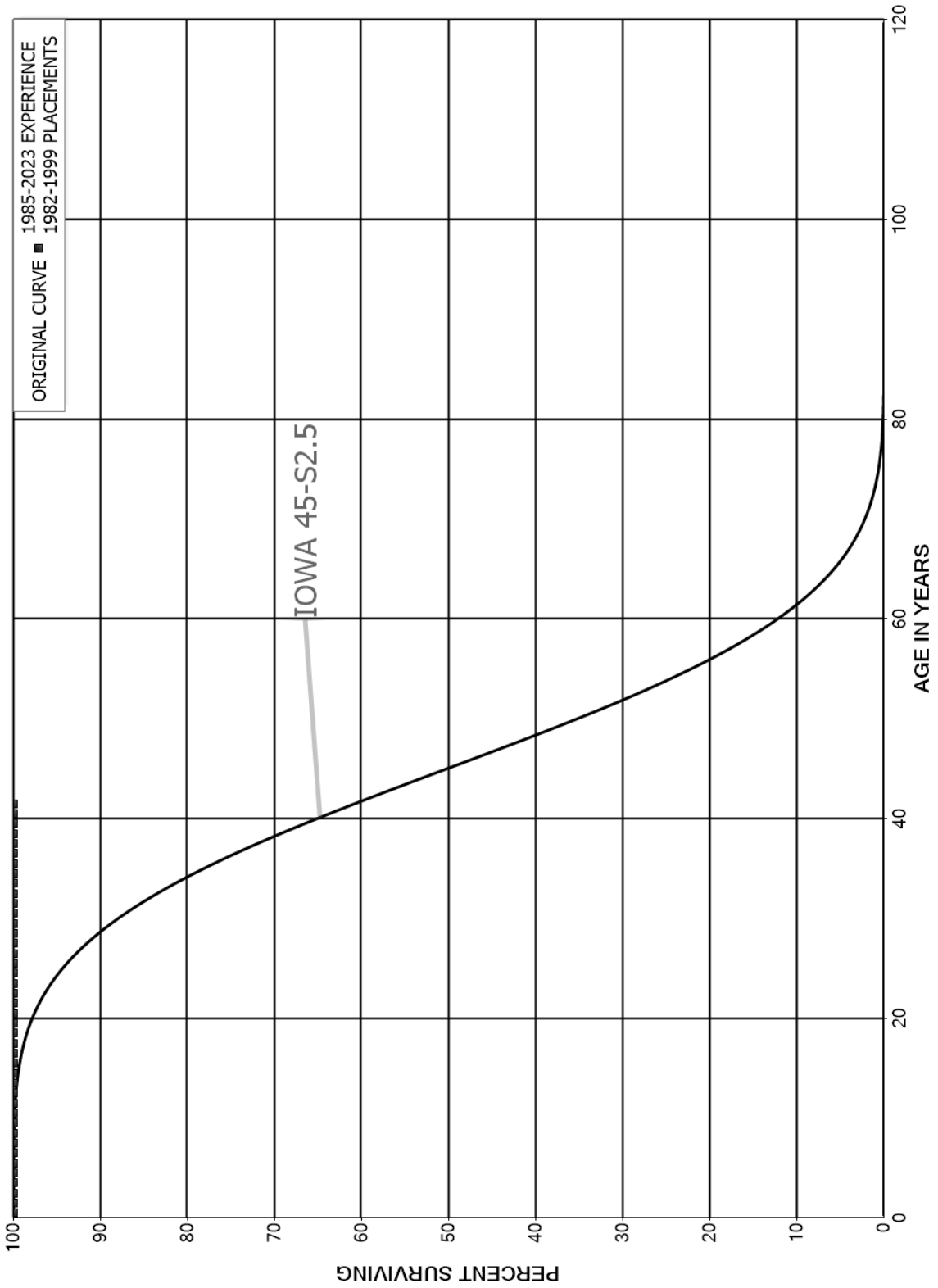
ACCOUNT 363.50 CNG REFUELING FACILITIES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1981-2023 EXPERIENCE BAND 1985-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	30,743		0.0000	1.0000	47.90
40.5	29,180		0.0000	1.0000	47.90
41.5	19,620		0.0000	1.0000	47.90
42.5					47.90

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 363.60 LNG REFUELING FACILITIES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.60 LNG REFUELING FACILITIES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1982-1999 EXPERIENCE BAND 1985-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	281,163		0.0000	1.0000	100.00
0.5	281,163		0.0000	1.0000	100.00
1.5	328,416		0.0000	1.0000	100.00
2.5	390,036		0.0000	1.0000	100.00
3.5	739,473		0.0000	1.0000	100.00
4.5	739,473		0.0000	1.0000	100.00
5.5	739,473		0.0000	1.0000	100.00
6.5	739,473		0.0000	1.0000	100.00
7.5	739,473		0.0000	1.0000	100.00
8.5	739,473		0.0000	1.0000	100.00
9.5	739,473		0.0000	1.0000	100.00
10.5	739,473		0.0000	1.0000	100.00
11.5	739,473		0.0000	1.0000	100.00
12.5	739,473		0.0000	1.0000	100.00
13.5	739,473		0.0000	1.0000	100.00
14.5	739,473		0.0000	1.0000	100.00
15.5	739,473		0.0000	1.0000	100.00
16.5	739,473		0.0000	1.0000	100.00
17.5	739,473		0.0000	1.0000	100.00
18.5	739,473		0.0000	1.0000	100.00
19.5	739,473		0.0000	1.0000	100.00
20.5	739,473		0.0000	1.0000	100.00
21.5	739,473		0.0000	1.0000	100.00
22.5	739,473		0.0000	1.0000	100.00
23.5	739,473		0.0000	1.0000	100.00
24.5	730,990		0.0000	1.0000	100.00
25.5	730,990		0.0000	1.0000	100.00
26.5	725,680		0.0000	1.0000	100.00
27.5	712,293		0.0000	1.0000	100.00
28.5	666,615		0.0000	1.0000	100.00
29.5	628,397		0.0000	1.0000	100.00
30.5	573,929		0.0000	1.0000	100.00
31.5	460,040		0.0000	1.0000	100.00
32.5	459,105		0.0000	1.0000	100.00
33.5	459,105		0.0000	1.0000	100.00
34.5	459,105		0.0000	1.0000	100.00
35.5	459,105		0.0000	1.0000	100.00
36.5	459,105		0.0000	1.0000	100.00
37.5	458,997		0.0000	1.0000	100.00
38.5	453,824		0.0000	1.0000	100.00

NORTHWEST NATURAL GAS COMPANY

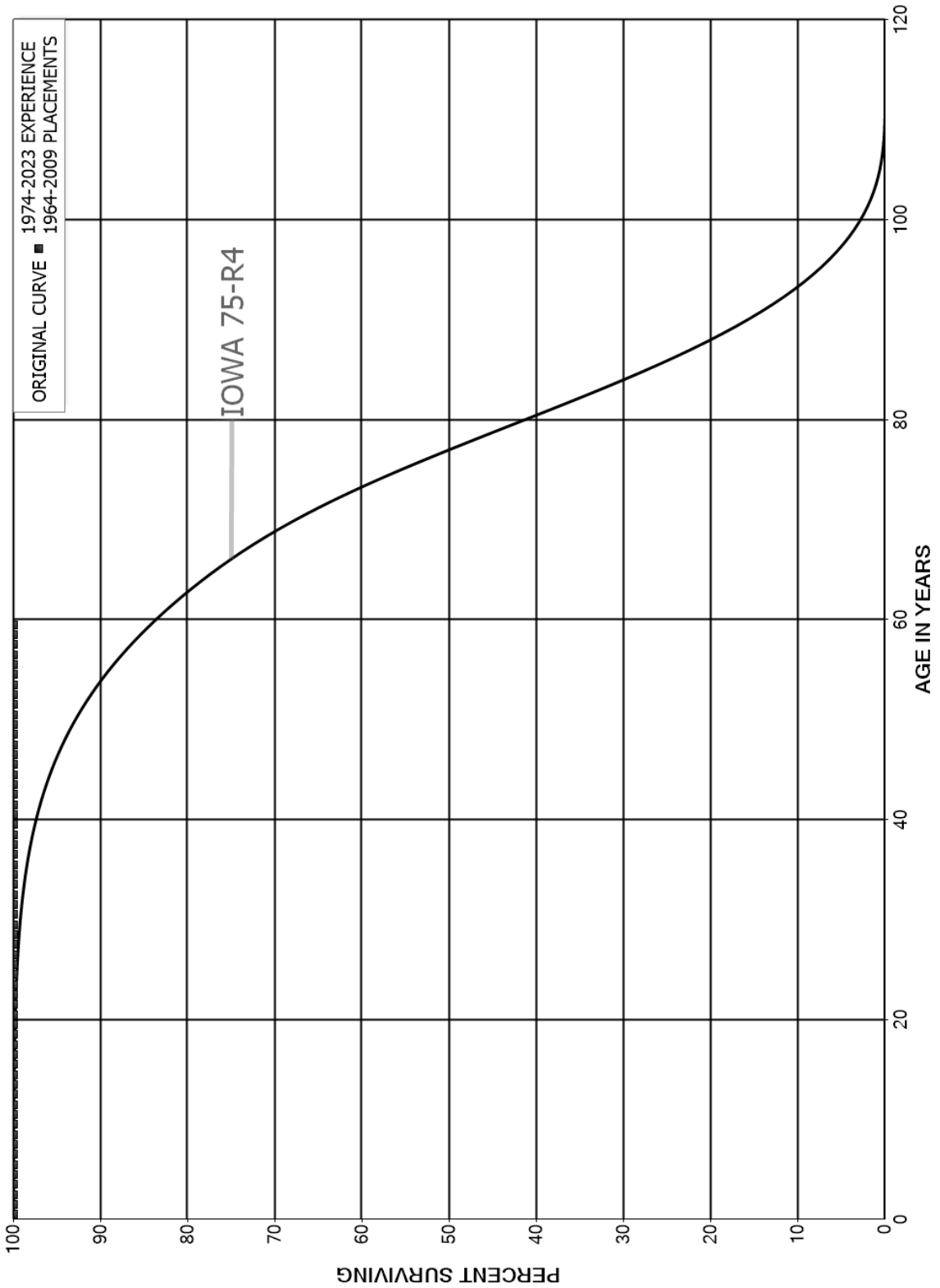
ACCOUNT 363.60 LNG REFUELING FACILITIES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1982-1999 EXPERIENCE BAND 1985-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	411,057		0.0000	1.0000	100.00
40.5	349,437		0.0000	1.0000	100.00
41.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 365.20 LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 365.20 LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1964-2009 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,770,969		0.0000	1.0000	100.00
0.5	5,375,541		0.0000	1.0000	100.00
1.5	5,279,074		0.0000	1.0000	100.00
2.5	5,310,109		0.0000	1.0000	100.00
3.5	5,310,109		0.0000	1.0000	100.00
4.5	5,310,109		0.0000	1.0000	100.00
5.5	5,286,730		0.0000	1.0000	100.00
6.5	5,446,043		0.0000	1.0000	100.00
7.5	5,579,754		0.0000	1.0000	100.00
8.5	6,153,400		0.0000	1.0000	100.00
9.5	6,361,083		0.0000	1.0000	100.00
10.5	6,455,177		0.0000	1.0000	100.00
11.5	6,455,177		0.0000	1.0000	100.00
12.5	6,455,177		0.0000	1.0000	100.00
13.5	6,455,177		0.0000	1.0000	100.00
14.5	6,270,968		0.0000	1.0000	100.00
15.5	6,270,968		0.0000	1.0000	100.00
16.5	6,270,968		0.0000	1.0000	100.00
17.5	6,270,968		0.0000	1.0000	100.00
18.5	6,270,968		0.0000	1.0000	100.00
19.5	4,195,148		0.0000	1.0000	100.00
20.5	3,013,374		0.0000	1.0000	100.00
21.5	2,617,946		0.0000	1.0000	100.00
22.5	2,617,946		0.0000	1.0000	100.00
23.5	2,617,946		0.0000	1.0000	100.00
24.5	2,617,946		0.0000	1.0000	100.00
25.5	2,617,946		0.0000	1.0000	100.00
26.5	2,617,946		0.0000	1.0000	100.00
27.5	2,617,946		0.0000	1.0000	100.00
28.5	2,617,946		0.0000	1.0000	100.00
29.5	2,617,946		0.0000	1.0000	100.00
30.5	2,617,946		0.0000	1.0000	100.00
31.5	2,604,197		0.0000	1.0000	100.00
32.5	2,461,137		0.0000	1.0000	100.00
33.5	2,060,125		0.0000	1.0000	100.00
34.5	1,244,309		0.0000	1.0000	100.00
35.5	1,244,309		0.0000	1.0000	100.00
36.5	1,244,309		0.0000	1.0000	100.00
37.5	1,244,309		0.0000	1.0000	100.00
38.5	1,244,309		0.0000	1.0000	100.00

NORTHWEST NATURAL GAS COMPANY

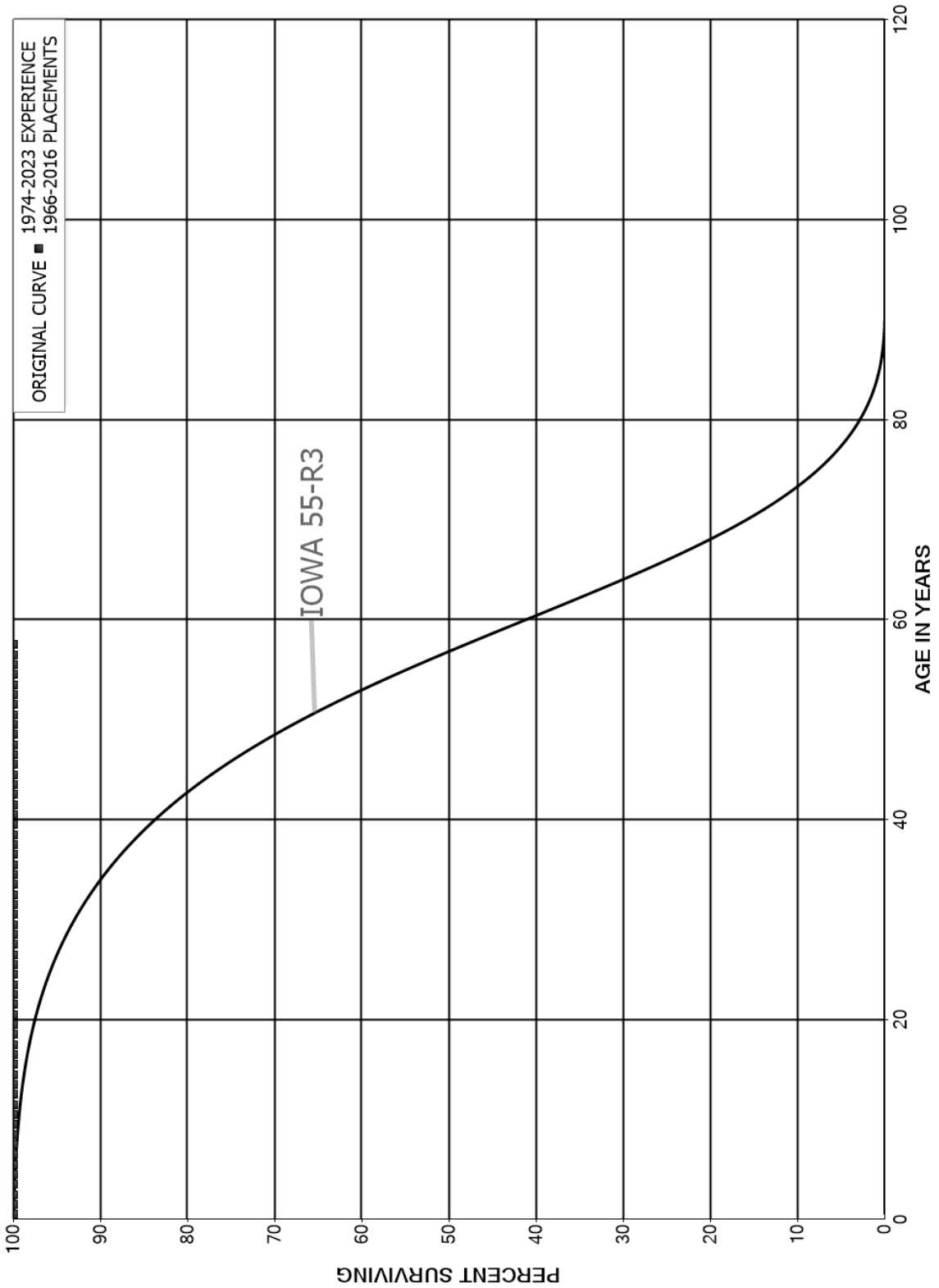
ACCOUNT 365.20 LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1964-2009 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,244,309		0.0000	1.0000	100.00
40.5	1,244,309		0.0000	1.0000	100.00
41.5	1,244,309		0.0000	1.0000	100.00
42.5	1,238,350		0.0000	1.0000	100.00
43.5	1,238,350		0.0000	1.0000	100.00
44.5	1,229,163		0.0000	1.0000	100.00
45.5	1,229,163		0.0000	1.0000	100.00
46.5	1,217,081		0.0000	1.0000	100.00
47.5	1,189,050		0.0000	1.0000	100.00
48.5	1,189,050		0.0000	1.0000	100.00
49.5	1,189,050		0.0000	1.0000	100.00
50.5	1,189,050		0.0000	1.0000	100.00
51.5	1,189,050		0.0000	1.0000	100.00
52.5	1,189,050		0.0000	1.0000	100.00
53.5	1,189,050		0.0000	1.0000	100.00
54.5	1,189,050		0.0000	1.0000	100.00
55.5	1,168,447		0.0000	1.0000	100.00
56.5	1,009,167		0.0000	1.0000	100.00
57.5	539,190		0.0000	1.0000	100.00
58.5	94,094		0.0000	1.0000	100.00
59.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 366.30 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 366.30 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2016 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,460,088		0.0000	1.0000	100.00
0.5	1,460,088		0.0000	1.0000	100.00
1.5	1,460,088		0.0000	1.0000	100.00
2.5	1,460,088		0.0000	1.0000	100.00
3.5	1,460,088		0.0000	1.0000	100.00
4.5	1,460,088		0.0000	1.0000	100.00
5.5	1,460,088		0.0000	1.0000	100.00
6.5	1,460,088		0.0000	1.0000	100.00
7.5	1,041,984		0.0000	1.0000	100.00
8.5	1,041,984		0.0000	1.0000	100.00
9.5	1,041,984		0.0000	1.0000	100.00
10.5	1,041,984		0.0000	1.0000	100.00
11.5	1,041,984		0.0000	1.0000	100.00
12.5	1,041,984		0.0000	1.0000	100.00
13.5	1,041,984		0.0000	1.0000	100.00
14.5	1,041,984		0.0000	1.0000	100.00
15.5	1,041,984		0.0000	1.0000	100.00
16.5	1,041,984		0.0000	1.0000	100.00
17.5	1,041,984		0.0000	1.0000	100.00
18.5	984,166		0.0000	1.0000	100.00
19.5	85,985		0.0000	1.0000	100.00
20.5	85,985		0.0000	1.0000	100.00
21.5	85,985		0.0000	1.0000	100.00
22.5	85,985		0.0000	1.0000	100.00
23.5	85,985		0.0000	1.0000	100.00
24.5	85,985		0.0000	1.0000	100.00
25.5	85,985		0.0000	1.0000	100.00
26.5	85,985		0.0000	1.0000	100.00
27.5	85,985		0.0000	1.0000	100.00
28.5	85,985		0.0000	1.0000	100.00
29.5	85,985		0.0000	1.0000	100.00
30.5	85,985		0.0000	1.0000	100.00
31.5	85,985		0.0000	1.0000	100.00
32.5	85,985		0.0000	1.0000	100.00
33.5	85,985		0.0000	1.0000	100.00
34.5	85,985		0.0000	1.0000	100.00
35.5	85,985		0.0000	1.0000	100.00
36.5	85,985		0.0000	1.0000	100.00
37.5	85,985		0.0000	1.0000	100.00
38.5	85,985		0.0000	1.0000	100.00

NORTHWEST NATURAL GAS COMPANY

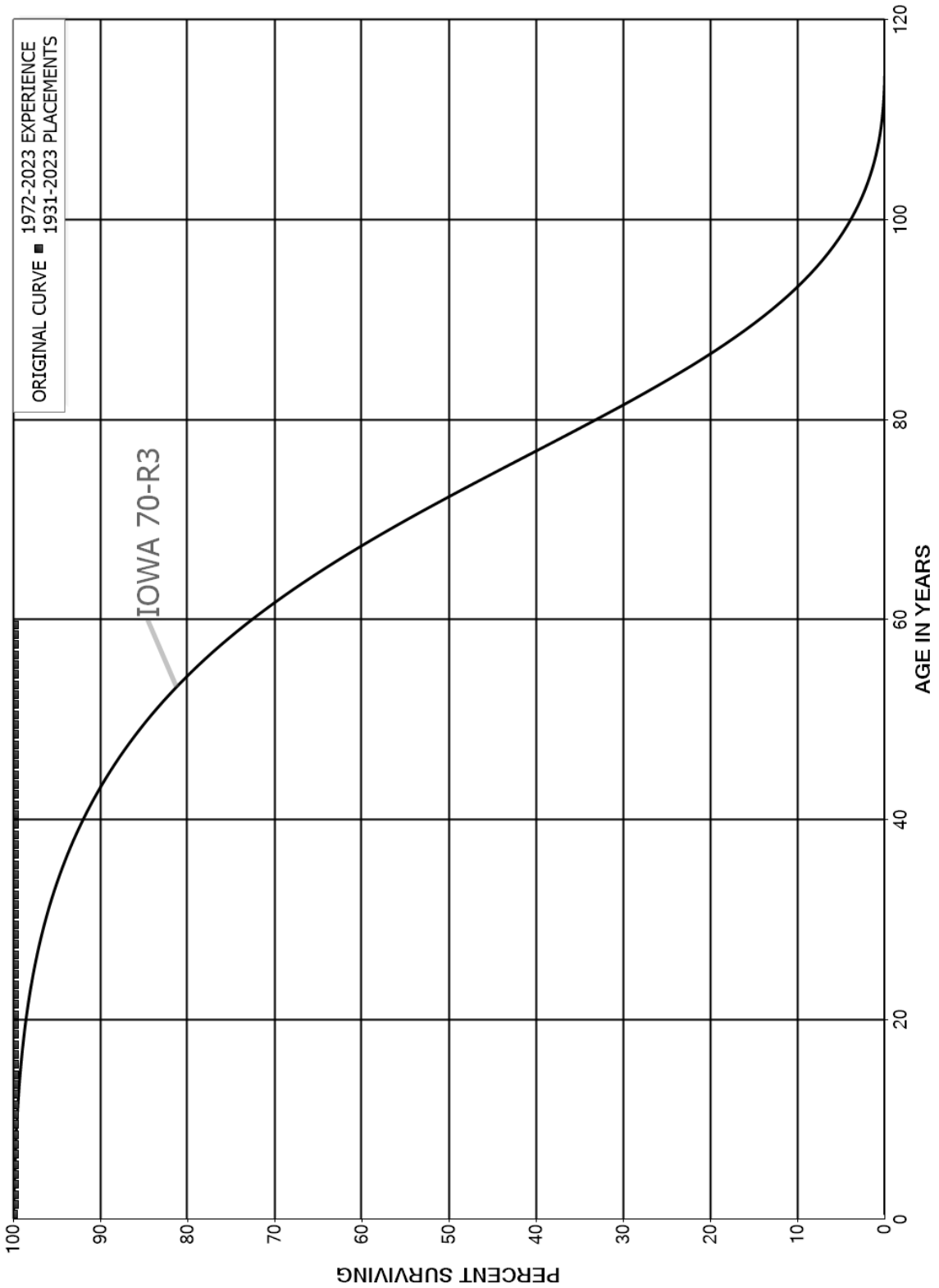
ACCOUNT 366.30 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2016 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	85,985		0.0000	1.0000	100.00
40.5	85,985		0.0000	1.0000	100.00
41.5	85,985		0.0000	1.0000	100.00
42.5	85,985		0.0000	1.0000	100.00
43.5	85,985		0.0000	1.0000	100.00
44.5	85,985		0.0000	1.0000	100.00
45.5	85,985		0.0000	1.0000	100.00
46.5	85,985		0.0000	1.0000	100.00
47.5	85,985		0.0000	1.0000	100.00
48.5	85,985		0.0000	1.0000	100.00
49.5	85,985		0.0000	1.0000	100.00
50.5	85,985		0.0000	1.0000	100.00
51.5	85,985		0.0000	1.0000	100.00
52.5	85,985		0.0000	1.0000	100.00
53.5	85,985		0.0000	1.0000	100.00
54.5	85,985		0.0000	1.0000	100.00
55.5	85,985		0.0000	1.0000	100.00
56.5	85,985		0.0000	1.0000	100.00
57.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNTS 367.00 THROUGH 367.26 MAINS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 367.00 THROUGH 367.26 MAINS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1931-2023 EXPERIENCE BAND 1972-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	311,329,776		0.0000	1.0000	100.00
0.5	316,548,454	532,003	0.0017	0.9983	100.00
1.5	343,813,389		0.0000	1.0000	99.83
2.5	338,009,566		0.0000	1.0000	99.83
3.5	327,984,914	38,942	0.0001	0.9999	99.83
4.5	319,300,797		0.0000	1.0000	99.82
5.5	308,104,740		0.0000	1.0000	99.82
6.5	307,461,718		0.0000	1.0000	99.82
7.5	302,877,415	1,086	0.0000	1.0000	99.82
8.5	297,252,260		0.0000	1.0000	99.82
9.5	279,211,651	1,086	0.0000	1.0000	99.82
10.5	230,288,244	16,355	0.0001	0.9999	99.82
11.5	198,868,205		0.0000	1.0000	99.81
12.5	190,822,564		0.0000	1.0000	99.81
13.5	171,475,182		0.0000	1.0000	99.81
14.5	166,874,669		0.0000	1.0000	99.81
15.5	166,874,669	2,603	0.0000	1.0000	99.81
16.5	166,806,129		0.0000	1.0000	99.81
17.5	166,808,732	541	0.0000	1.0000	99.81
18.5	166,793,797		0.0000	1.0000	99.81
19.5	128,793,642		0.0000	1.0000	99.81
20.5	61,949,897	1,756	0.0000	1.0000	99.81
21.5	61,692,549		0.0000	1.0000	99.81
22.5	61,155,910		0.0000	1.0000	99.81
23.5	61,091,777		0.0000	1.0000	99.81
24.5	27,575,643		0.0000	1.0000	99.81
25.5	27,575,643	481	0.0000	1.0000	99.81
26.5	27,575,162		0.0000	1.0000	99.81
27.5	27,575,162		0.0000	1.0000	99.81
28.5	27,573,648	388	0.0000	1.0000	99.81
29.5	27,440,689		0.0000	1.0000	99.80
30.5	27,295,904		0.0000	1.0000	99.80
31.5	27,295,904		0.0000	1.0000	99.80
32.5	27,292,423		0.0000	1.0000	99.80
33.5	26,995,509		0.0000	1.0000	99.80
34.5	10,178,290		0.0000	1.0000	99.80
35.5	10,178,290		0.0000	1.0000	99.80
36.5	10,178,290		0.0000	1.0000	99.80
37.5	10,160,853		0.0000	1.0000	99.80
38.5	10,131,532		0.0000	1.0000	99.80

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 367.00 THROUGH 367.26 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1931-2023 EXPERIENCE BAND 1972-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	10,131,532		0.0000	1.0000	99.80
40.5	10,131,532		0.0000	1.0000	99.80
41.5	9,969,318		0.0000	1.0000	99.80
42.5	9,458,671		0.0000	1.0000	99.80
43.5	9,424,544		0.0000	1.0000	99.80
44.5	9,424,544		0.0000	1.0000	99.80
45.5	9,411,932		0.0000	1.0000	99.80
46.5	9,406,964		0.0000	1.0000	99.80
47.5	8,179,539		0.0000	1.0000	99.80
48.5	8,179,539		0.0000	1.0000	99.80
49.5	8,179,539		0.0000	1.0000	99.80
50.5	8,179,539		0.0000	1.0000	99.80
51.5	8,160,658		0.0000	1.0000	99.80
52.5	8,161,199		0.0000	1.0000	99.80
53.5	8,161,199		0.0000	1.0000	99.80
54.5	8,144,175		0.0000	1.0000	99.80
55.5	8,139,304		0.0000	1.0000	99.80
56.5	8,041,218		0.0000	1.0000	99.80
57.5	4,791,489		0.0000	1.0000	99.80
58.5	632,284		0.0000	1.0000	99.80
59.5	541		0.0000	1.0000	99.80
60.5	541		0.0000	1.0000	99.80
61.5	541		0.0000	1.0000	99.80
62.5	541		0.0000	1.0000	99.80
63.5	541		0.0000	1.0000	99.80
64.5	541		0.0000	1.0000	99.80
65.5	541		0.0000	1.0000	99.80
66.5	541		0.0000	1.0000	99.80
67.5	541		0.0000	1.0000	99.80
68.5	541		0.0000	1.0000	99.80
69.5	541		0.0000	1.0000	99.80
70.5	541		0.0000	1.0000	99.80
71.5	541		0.0000	1.0000	99.80
72.5	541		0.0000	1.0000	99.80
73.5	541		0.0000	1.0000	99.80
74.5	541		0.0000	1.0000	99.80
75.5	541		0.0000	1.0000	99.80
76.5	541		0.0000	1.0000	99.80
77.5	541		0.0000	1.0000	99.80
78.5	541		0.0000	1.0000	99.80

NORTHWEST NATURAL GAS COMPANY

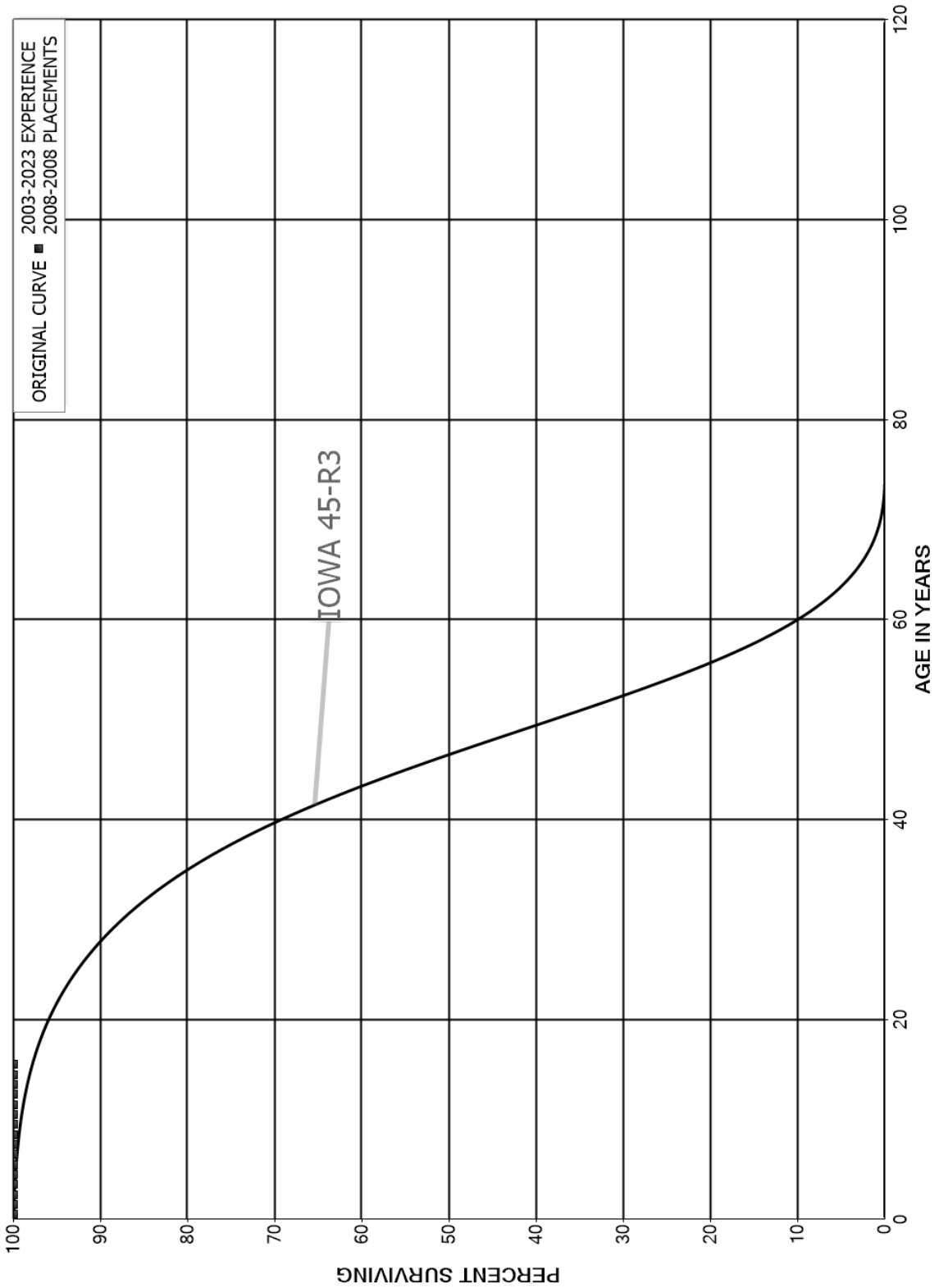
ACCOUNTS 367.00 THROUGH 367.26 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1931-2023 EXPERIENCE BAND 1972-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	541		0.0000	1.0000	99.80
80.5	541		0.0000	1.0000	99.80
81.5	541		0.0000	1.0000	99.80
82.5	541		0.0000	1.0000	99.80
83.5	541		0.0000	1.0000	99.80
84.5	541		0.0000	1.0000	99.80
85.5	541		0.0000	1.0000	99.80
86.5	541		0.0000	1.0000	99.80
87.5	541		0.0000	1.0000	99.80
88.5	541		0.0000	1.0000	99.80
89.5	541		0.0000	1.0000	99.80
90.5	541		0.0000	1.0000	99.80
91.5	541		0.0000	1.0000	99.80
92.5					99.80

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 368.00 COMPRESSOR STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

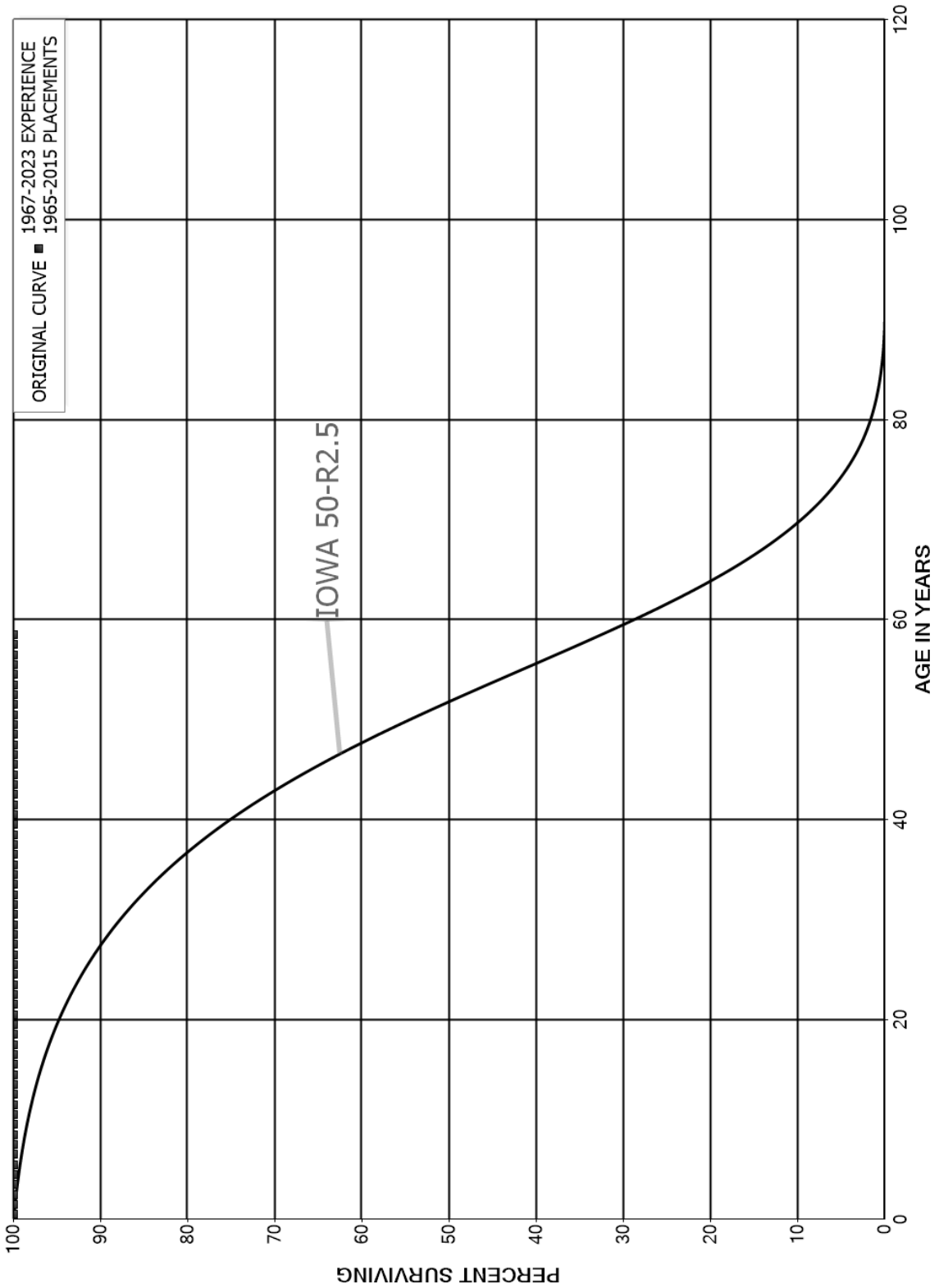
ACCOUNT 368.00 COMPRESSOR STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 2008-2008 EXPERIENCE BAND 2003-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	7,723,454		0.0000	1.0000	100.00
0.5	7,723,454		0.0000	1.0000	100.00
1.5	7,723,454		0.0000	1.0000	100.00
2.5	7,723,454		0.0000	1.0000	100.00
3.5	7,723,454		0.0000	1.0000	100.00
4.5	7,723,454		0.0000	1.0000	100.00
5.5	7,723,454		0.0000	1.0000	100.00
6.5	7,723,454		0.0000	1.0000	100.00
7.5	7,723,454		0.0000	1.0000	100.00
8.5	7,723,454		0.0000	1.0000	100.00
9.5	7,723,454		0.0000	1.0000	100.00
10.5	7,723,454		0.0000	1.0000	100.00
11.5	7,723,454		0.0000	1.0000	100.00
12.5	7,723,454		0.0000	1.0000	100.00
13.5	7,723,454		0.0000	1.0000	100.00
14.5	7,723,454		0.0000	1.0000	100.00
15.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 369.00 MEASURING AND REGULATING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 369.00 MEASURING AND REGULATING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1967-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,811,857		0.0000	1.0000	100.00
0.5	3,838,490	585	0.0002	0.9998	100.00
1.5	4,082,641		0.0000	1.0000	99.98
2.5	3,989,184		0.0000	1.0000	99.98
3.5	3,982,729		0.0000	1.0000	99.98
4.5	3,982,729		0.0000	1.0000	99.98
5.5	3,982,729		0.0000	1.0000	99.98
6.5	3,982,729		0.0000	1.0000	99.98
7.5	3,981,868	638	0.0002	0.9998	99.98
8.5	3,874,781		0.0000	1.0000	99.97
9.5	3,756,815		0.0000	1.0000	99.97
10.5	575,963		0.0000	1.0000	99.97
11.5	542,079		0.0000	1.0000	99.97
12.5	542,079		0.0000	1.0000	99.97
13.5	542,079		0.0000	1.0000	99.97
14.5	542,079		0.0000	1.0000	99.97
15.5	542,079		0.0000	1.0000	99.97
16.5	542,079		0.0000	1.0000	99.97
17.5	408,765		0.0000	1.0000	99.97
18.5	408,765		0.0000	1.0000	99.97
19.5	396,697		0.0000	1.0000	99.97
20.5	207,616		0.0000	1.0000	99.97
21.5	195,625		0.0000	1.0000	99.97
22.5	195,625		0.0000	1.0000	99.97
23.5	195,625		0.0000	1.0000	99.97
24.5	195,625		0.0000	1.0000	99.97
25.5	195,625		0.0000	1.0000	99.97
26.5	195,625		0.0000	1.0000	99.97
27.5	195,625		0.0000	1.0000	99.97
28.5	195,625		0.0000	1.0000	99.97
29.5	195,625		0.0000	1.0000	99.97
30.5	195,625		0.0000	1.0000	99.97
31.5	118,019		0.0000	1.0000	99.97
32.5	118,019		0.0000	1.0000	99.97
33.5	118,019		0.0000	1.0000	99.97
34.5	118,019		0.0000	1.0000	99.97
35.5	118,019		0.0000	1.0000	99.97
36.5	91,081		0.0000	1.0000	99.97
37.5	91,081		0.0000	1.0000	99.97
38.5	91,081		0.0000	1.0000	99.97

NORTHWEST NATURAL GAS COMPANY

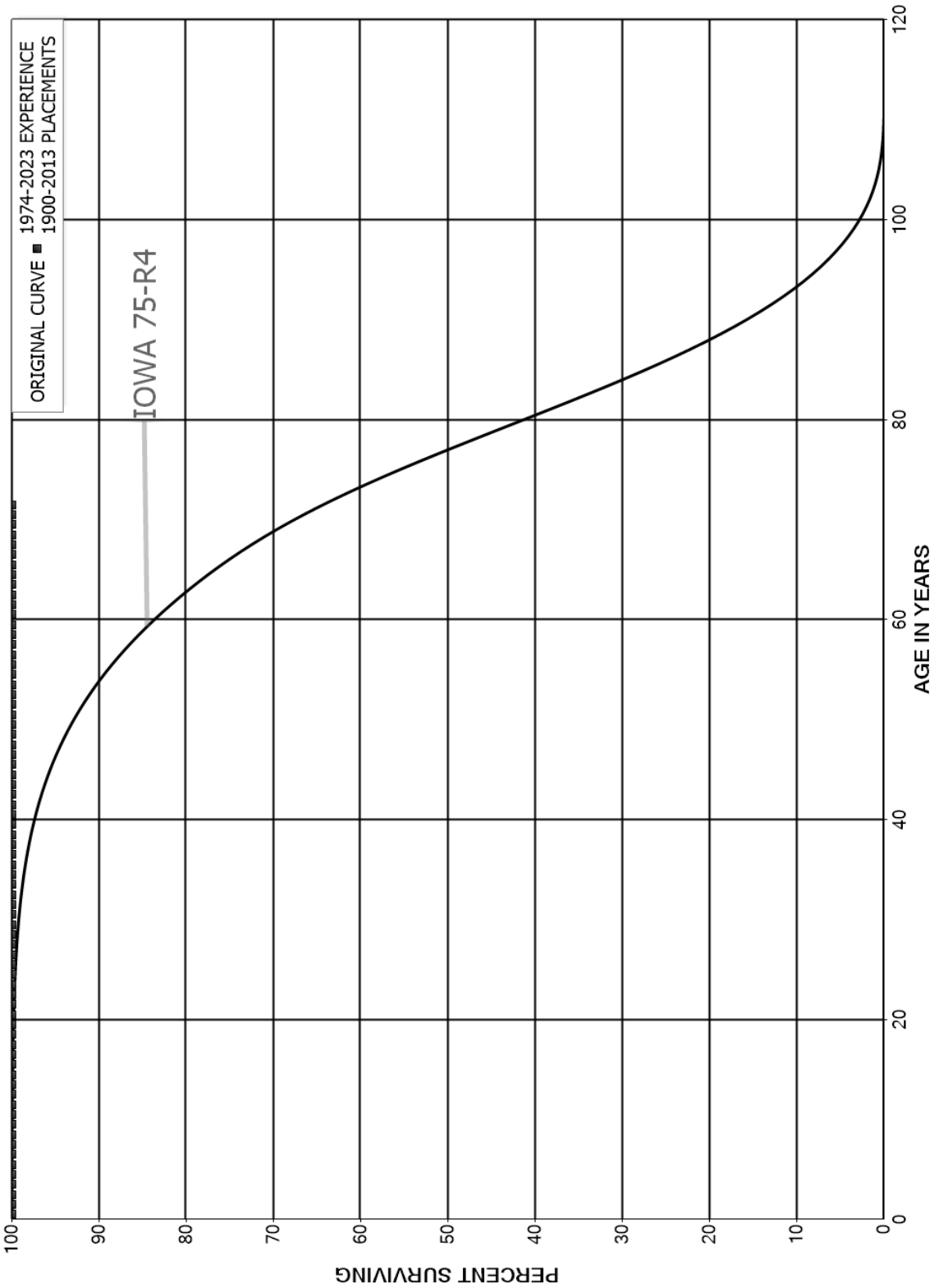
ACCOUNT 369.00 MEASURING AND REGULATING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1967-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	91,081		0.0000	1.0000	99.97
40.5	91,081		0.0000	1.0000	99.97
41.5	91,081		0.0000	1.0000	99.97
42.5	91,081		0.0000	1.0000	99.97
43.5	91,081		0.0000	1.0000	99.97
44.5	91,081		0.0000	1.0000	99.97
45.5	91,081		0.0000	1.0000	99.97
46.5	45,638		0.0000	1.0000	99.97
47.5	45,638		0.0000	1.0000	99.97
48.5	45,638		0.0000	1.0000	99.97
49.5	45,638		0.0000	1.0000	99.97
50.5	45,638		0.0000	1.0000	99.97
51.5	45,638		0.0000	1.0000	99.97
52.5	45,638		0.0000	1.0000	99.97
53.5	45,638		0.0000	1.0000	99.97
54.5	45,638		0.0000	1.0000	99.97
55.5	45,638		0.0000	1.0000	99.97
56.5	40,610		0.0000	1.0000	99.97
57.5	14,697		0.0000	1.0000	99.97
58.5					99.97

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 374.20 LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 374.20 LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2013 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,657,830		0.0000	1.0000	100.00
0.5	1,657,830		0.0000	1.0000	100.00
1.5	1,638,506		0.0000	1.0000	100.00
2.5	1,650,827		0.0000	1.0000	100.00
3.5	1,650,827		0.0000	1.0000	100.00
4.5	1,650,827		0.0000	1.0000	100.00
5.5	1,660,496		0.0000	1.0000	100.00
6.5	1,660,496		0.0000	1.0000	100.00
7.5	1,660,496		0.0000	1.0000	100.00
8.5	1,660,496		0.0000	1.0000	100.00
9.5	1,660,496		0.0000	1.0000	100.00
10.5	1,205,455		0.0000	1.0000	100.00
11.5	1,208,880		0.0000	1.0000	100.00
12.5	1,208,980		0.0000	1.0000	100.00
13.5	1,185,830		0.0000	1.0000	100.00
14.5	1,183,628		0.0000	1.0000	100.00
15.5	1,183,828		0.0000	1.0000	100.00
16.5	1,183,828		0.0000	1.0000	100.00
17.5	1,183,828		0.0000	1.0000	100.00
18.5	1,194,968		0.0000	1.0000	100.00
19.5	1,194,968		0.0000	1.0000	100.00
20.5	893,294		0.0000	1.0000	100.00
21.5	770,286		0.0000	1.0000	100.00
22.5	717,371		0.0000	1.0000	100.00
23.5	704,426		0.0000	1.0000	100.00
24.5	680,493		0.0000	1.0000	100.00
25.5	665,368		0.0000	1.0000	100.00
26.5	629,536		0.0000	1.0000	100.00
27.5	611,427		0.0000	1.0000	100.00
28.5	498,713		0.0000	1.0000	100.00
29.5	455,477		0.0000	1.0000	100.00
30.5	425,600		0.0000	1.0000	100.00
31.5	360,634		0.0000	1.0000	100.00
32.5	175,569		0.0000	1.0000	100.00
33.5	165,563		0.0000	1.0000	100.00
34.5	90,569		0.0000	1.0000	100.00
35.5	86,667		0.0000	1.0000	100.00
36.5	76,934		0.0000	1.0000	100.00
37.5	73,182		0.0000	1.0000	100.00
38.5	68,403		0.0000	1.0000	100.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 374.20 LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2013 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	67,639		0.0000	1.0000	100.00
40.5	67,387		0.0000	1.0000	100.00
41.5	66,348		0.0000	1.0000	100.00
42.5	57,628		0.0000	1.0000	100.00
43.5	56,063		0.0000	1.0000	100.00
44.5	54,474		0.0000	1.0000	100.00
45.5	47,629		0.0000	1.0000	100.00
46.5	37,352		0.0000	1.0000	100.00
47.5	36,548		0.0000	1.0000	100.00
48.5	32,908		0.0000	1.0000	100.00
49.5	29,604		0.0000	1.0000	100.00
50.5	29,604		0.0000	1.0000	100.00
51.5	29,604		0.0000	1.0000	100.00
52.5	27,097		0.0000	1.0000	100.00
53.5	27,097		0.0000	1.0000	100.00
54.5	27,097		0.0000	1.0000	100.00
55.5	17,428		0.0000	1.0000	100.00
56.5	17,428		0.0000	1.0000	100.00
57.5	17,428		0.0000	1.0000	100.00
58.5	17,428		0.0000	1.0000	100.00
59.5	16,678		0.0000	1.0000	100.00
60.5	13,253		0.0000	1.0000	100.00
61.5	13,153		0.0000	1.0000	100.00
62.5	13,153		0.0000	1.0000	100.00
63.5	12,953		0.0000	1.0000	100.00
64.5	12,953		0.0000	1.0000	100.00
65.5	12,953		0.0000	1.0000	100.00
66.5	12,953		0.0000	1.0000	100.00
67.5	1,813		0.0000	1.0000	100.00
68.5	1,813		0.0000	1.0000	100.00
69.5	1,813		0.0000	1.0000	100.00
70.5	1,813		0.0000	1.0000	100.00
71.5					100.00
72.5					
73.5	208,257		0.0000		
74.5	208,257		0.0000		
75.5	208,257		0.0000		
76.5	208,257		0.0000		
77.5	208,257		0.0000		
78.5	208,257		0.0000		

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 374.20 LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2013 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	208,257		0.0000		
80.5	208,257		0.0000		
81.5	208,257		0.0000		
82.5	208,257		0.0000		
83.5	208,257		0.0000		
84.5	208,257		0.0000		
85.5	208,257		0.0000		
86.5	208,257		0.0000		
87.5	208,257		0.0000		
88.5	208,257		0.0000		
89.5	208,257		0.0000		
90.5	208,257		0.0000		
91.5	208,257		0.0000		
92.5	208,257		0.0000		
93.5	208,257		0.0000		
94.5	208,257		0.0000		
95.5	208,257		0.0000		
96.5	208,257		0.0000		
97.5	208,257		0.0000		
98.5	208,257		0.0000		
99.5	208,257		0.0000		
100.5	208,257		0.0000		
101.5	208,257		0.0000		
102.5	208,257		0.0000		
103.5	208,257		0.0000		
104.5	208,257		0.0000		
105.5	208,257		0.0000		
106.5	208,257		0.0000		
107.5	208,257		0.0000		
108.5	208,257		0.0000		
109.5	208,257		0.0000		
110.5	208,257		0.0000		
111.5	208,257		0.0000		
112.5	208,257		0.0000		
113.5	208,257		0.0000		
114.5	208,257		0.0000		
115.5	208,257		0.0000		
116.5	208,257		0.0000		
117.5	208,257		0.0000		
118.5	208,257		0.0000		

NORTHWEST NATURAL GAS COMPANY

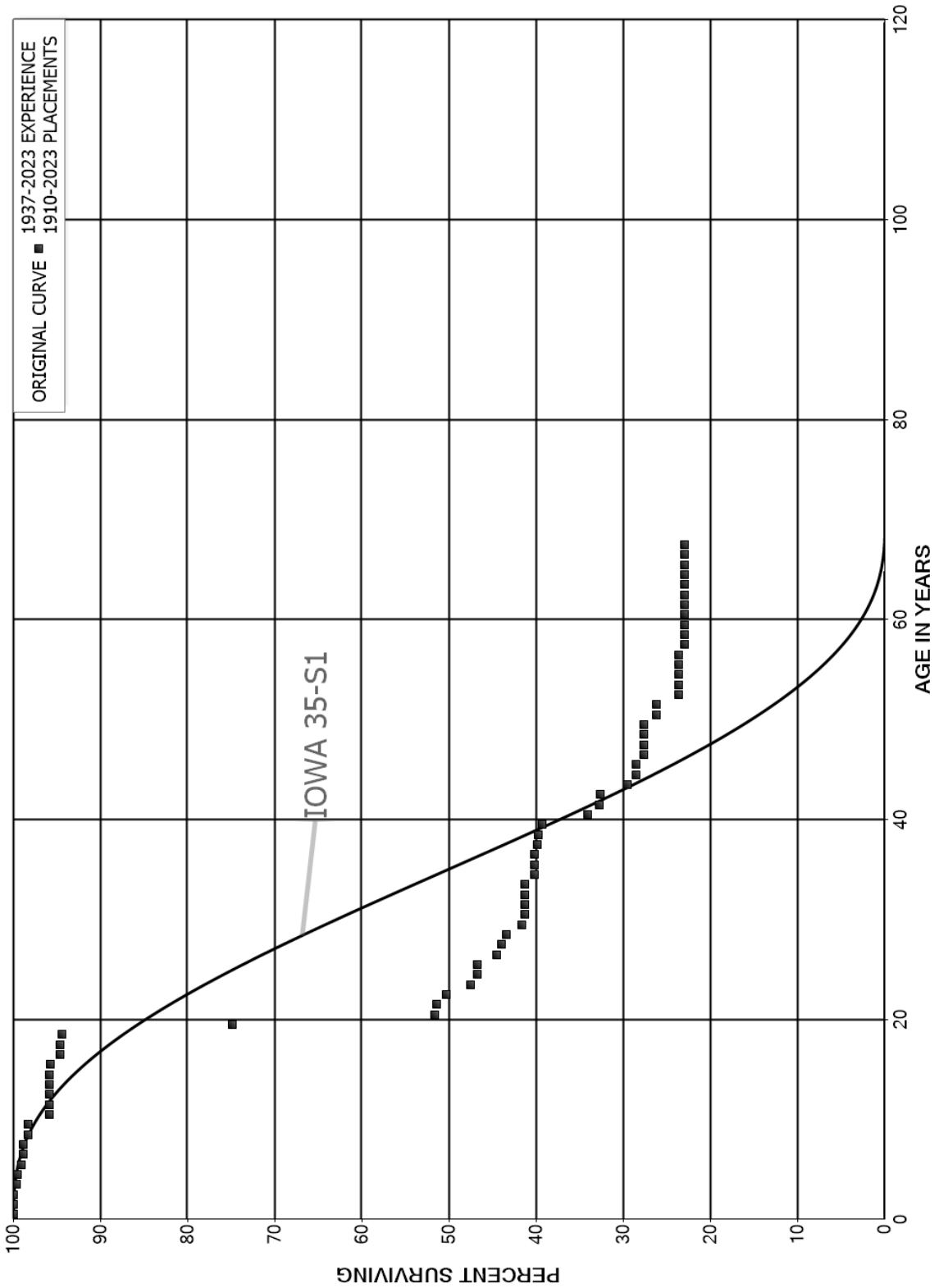
ACCOUNT 374.20 LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2013 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	208,257		0.0000		
120.5	208,257		0.0000		
121.5	208,257		0.0000		
122.5	208,257		0.0000		
123.5					

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 1937-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,616,189		0.0000	1.0000	100.00
0.5	1,574,618	119	0.0001	0.9999	100.00
1.5	1,548,149	582	0.0004	0.9996	99.99
2.5	1,548,149	5,004	0.0032	0.9968	99.95
3.5	1,548,149	2,755	0.0018	0.9982	99.63
4.5	1,548,149	5,302	0.0034	0.9966	99.45
5.5	1,464,971	3,403	0.0023	0.9977	99.11
6.5	1,464,971		0.0000	1.0000	98.88
7.5	108,808	611	0.0056	0.9944	98.88
8.5	108,808		0.0000	1.0000	98.33
9.5	110,952	2,752	0.0248	0.9752	98.33
10.5	110,952		0.0000	1.0000	95.89
11.5	110,952		0.0000	1.0000	95.89
12.5	110,952		0.0000	1.0000	95.89
13.5	110,952		0.0000	1.0000	95.89
14.5	110,952	170	0.0015	0.9985	95.89
15.5	99,983	1,206	0.0121	0.9879	95.74
16.5	99,983		0.0000	1.0000	94.59
17.5	99,983	167	0.0017	0.9983	94.59
18.5	99,983	20,760	0.2076	0.7924	94.43
19.5	99,553	30,809	0.3095	0.6905	74.82
20.5	99,553	506	0.0051	0.9949	51.67
21.5	99,553	2,221	0.0223	0.9777	51.40
22.5	99,553	5,411	0.0544	0.9456	50.26
23.5	99,403	1,664	0.0167	0.9833	47.53
24.5	99,403	118	0.0012	0.9988	46.73
25.5	99,403	4,717	0.0475	0.9525	46.67
26.5	99,403	1,209	0.0122	0.9878	44.46
27.5	99,403	1,250	0.0126	0.9874	43.92
28.5	99,403	4,092	0.0412	0.9588	43.37
29.5	95,587	588	0.0062	0.9938	41.58
30.5	93,092		0.0000	1.0000	41.33
31.5	93,092		0.0000	1.0000	41.33
32.5	93,092	23	0.0002	0.9998	41.33
33.5	67,622	1,870	0.0277	0.9723	41.32
34.5	65,874		0.0000	1.0000	40.17
35.5	65,874		0.0000	1.0000	40.17
36.5	65,874	639	0.0097	0.9903	40.17
37.5	65,874	150	0.0023	0.9977	39.78
38.5	65,874	588	0.0089	0.9911	39.69

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 1937-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	65,874	8,863	0.1345	0.8655	39.34
40.5	57,179	2,300	0.0402	0.9598	34.05
41.5	54,879	167	0.0030	0.9970	32.68
42.5	54,879	5,090	0.0927	0.9073	32.58
43.5	54,757	1,928	0.0352	0.9648	29.56
44.5	52,840		0.0000	1.0000	28.51
45.5	52,840	1,623	0.0307	0.9693	28.51
46.5	52,840	107	0.0020	0.9980	27.64
47.5	52,840	4	0.0001	0.9999	27.58
48.5	52,840		0.0000	1.0000	27.58
49.5	52,840	2,607	0.0493	0.9507	27.58
50.5	52,840		0.0000	1.0000	26.22
51.5	58,646	5,806	0.0990	0.9010	26.22
52.5	52,840		0.0000	1.0000	23.62
53.5	52,840		0.0000	1.0000	23.62
54.5	52,840		0.0000	1.0000	23.62
55.5	52,840		0.0000	1.0000	23.62
56.5	52,840	1,625	0.0308	0.9692	23.62
57.5	52,840		0.0000	1.0000	22.90
58.5	52,542		0.0000	1.0000	22.90
59.5	52,542		0.0000	1.0000	22.90
60.5	52,542		0.0000	1.0000	22.90
61.5	49,800		0.0000	1.0000	22.90
62.5	49,074		0.0000	1.0000	22.90
63.5	42,091		0.0000	1.0000	22.90
64.5	41,220		0.0000	1.0000	22.90
65.5	37,913		0.0000	1.0000	22.90
66.5	37,913		0.0000	1.0000	22.90
67.5	4,985		0.0000	1.0000	22.90
68.5	4,985		0.0000	1.0000	22.90
69.5	4,985		0.0000	1.0000	22.90
70.5	4,971		0.0000	1.0000	22.90
71.5	4,971		0.0000	1.0000	22.90
72.5	4,971		0.0000	1.0000	22.90
73.5	4,971		0.0000	1.0000	22.90
74.5	4,971		0.0000	1.0000	22.90
75.5	4,971		0.0000	1.0000	22.90
76.5	4,971		0.0000	1.0000	22.90
77.5	4,971		0.0000	1.0000	22.90
78.5	4,971		0.0000	1.0000	22.90

NORTHWEST NATURAL GAS COMPANY

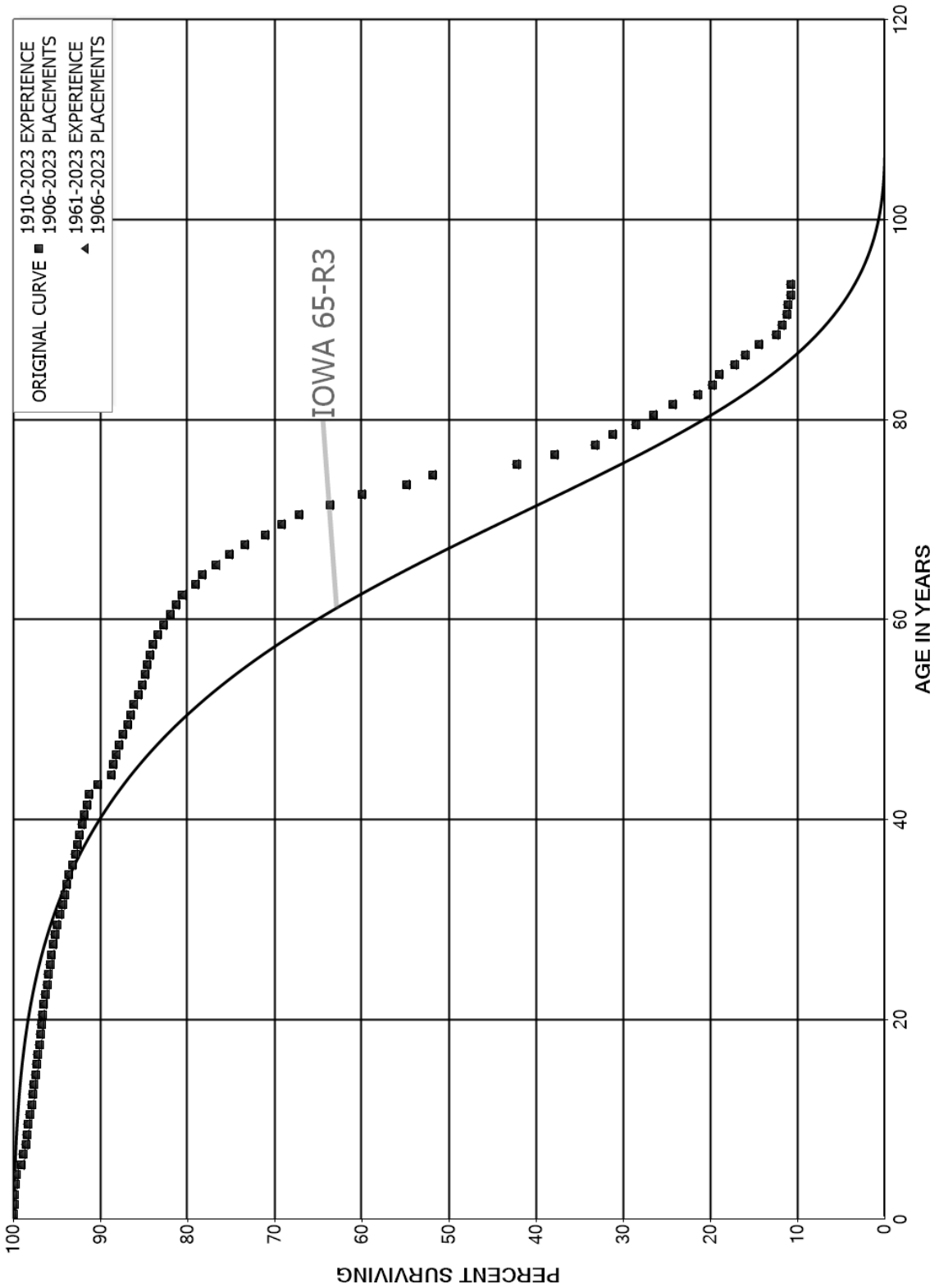
ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 1937-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	4,971		0.0000	1.0000	22.90
80.5	4,971		0.0000	1.0000	22.90
81.5	4,971		0.0000	1.0000	22.90
82.5	4,971		0.0000	1.0000	22.90
83.5	4,971		0.0000	1.0000	22.90
84.5	4,971		0.0000	1.0000	22.90
85.5	4,971		0.0000	1.0000	22.90
86.5	4,971		0.0000	1.0000	22.90
87.5	4,971		0.0000	1.0000	22.90
88.5	4,971		0.0000	1.0000	22.90
89.5	4,971		0.0000	1.0000	22.90
90.5	4,971		0.0000	1.0000	22.90
91.5	4,971		0.0000	1.0000	22.90
92.5	4,971		0.0000	1.0000	22.90
93.5	4,971		0.0000	1.0000	22.90
94.5	4,971		0.0000	1.0000	22.90
95.5	4,971		0.0000	1.0000	22.90
96.5	2,827		0.0000	1.0000	22.90
97.5	2,827		0.0000	1.0000	22.90
98.5	2,827		0.0000	1.0000	22.90
99.5	2,827		0.0000	1.0000	22.90
100.5	2,827		0.0000	1.0000	22.90
101.5	2,827		0.0000	1.0000	22.90
102.5	2,827		0.0000	1.0000	22.90
103.5	2,827		0.0000	1.0000	22.90
104.5	2,827		0.0000	1.0000	22.90
105.5	2,827		0.0000	1.0000	22.90
106.5	2,827		0.0000	1.0000	22.90
107.5	2,827		0.0000	1.0000	22.90
108.5	2,827		0.0000	1.0000	22.90
109.5	2,827		0.0000	1.0000	22.90
110.5					22.90

NORTHWEST NATURAL GAS COMPANY
ACCOUNTS 376.11 AND 376.12 MAINS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 376.11 AND 376.12 MAINS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1906-2023 EXPERIENCE BAND 1910-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,566,625,527	488,618	0.0003	0.9997	100.00
0.5	1,507,853,007	1,278,873	0.0008	0.9992	99.97
1.5	1,440,364,002	1,130,173	0.0008	0.9992	99.88
2.5	1,386,456,431	1,277,310	0.0009	0.9991	99.81
3.5	1,315,275,380	1,569,039	0.0012	0.9988	99.71
4.5	1,254,493,788	7,337,073	0.0058	0.9942	99.59
5.5	1,187,492,682	1,580,845	0.0013	0.9987	99.01
6.5	1,147,058,819	4,151,125	0.0036	0.9964	98.88
7.5	1,102,673,752	1,424,368	0.0013	0.9987	98.52
8.5	1,067,034,627	1,463,150	0.0014	0.9986	98.40
9.5	1,029,628,344	1,894,828	0.0018	0.9982	98.26
10.5	988,942,041	1,931,798	0.0020	0.9980	98.08
11.5	952,155,514	1,653,209	0.0017	0.9983	97.89
12.5	928,252,632	1,339,387	0.0014	0.9986	97.72
13.5	905,969,208	1,289,655	0.0014	0.9986	97.58
14.5	885,658,271	1,035,076	0.0012	0.9988	97.44
15.5	855,880,078	1,571,951	0.0018	0.9982	97.32
16.5	818,770,110	1,411,402	0.0017	0.9983	97.15
17.5	781,597,808	1,039,749	0.0013	0.9987	96.98
18.5	743,320,505	881,102	0.0012	0.9988	96.85
19.5	707,755,053	1,049,285	0.0015	0.9985	96.73
20.5	659,621,353	879,463	0.0013	0.9987	96.59
21.5	628,276,315	1,070,975	0.0017	0.9983	96.46
22.5	599,863,209	1,177,665	0.0020	0.9980	96.30
23.5	567,677,064	1,067,108	0.0019	0.9981	96.11
24.5	536,995,951	1,132,411	0.0021	0.9979	95.93
25.5	505,433,689	870,005	0.0017	0.9983	95.73
26.5	468,258,879	924,863	0.0020	0.9980	95.56
27.5	432,115,542	838,801	0.0019	0.9981	95.37
28.5	401,643,833	802,038	0.0020	0.9980	95.19
29.5	370,923,932	1,489,425	0.0040	0.9960	95.00
30.5	340,993,704	1,035,753	0.0030	0.9970	94.62
31.5	313,784,159	882,702	0.0028	0.9972	94.33
32.5	290,767,692	717,613	0.0025	0.9975	94.06
33.5	273,086,240	774,852	0.0028	0.9972	93.83
34.5	255,120,651	1,157,496	0.0045	0.9955	93.56
35.5	239,513,077	709,746	0.0030	0.9970	93.14
36.5	225,568,945	594,710	0.0026	0.9974	92.86
37.5	209,409,397	536,765	0.0026	0.9974	92.62
38.5	192,771,688	592,874	0.0031	0.9969	92.38

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 376.11 AND 376.12 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2023 EXPERIENCE BAND 1910-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	175,080,552	538,472	0.0031	0.9969	92.10
40.5	163,056,549	539,846	0.0033	0.9967	91.81
41.5	151,365,702	405,775	0.0027	0.9973	91.51
42.5	138,657,496	1,559,462	0.0112	0.9888	91.26
43.5	125,576,948	2,127,218	0.0169	0.9831	90.24
44.5	112,462,063	308,709	0.0027	0.9973	88.71
45.5	103,307,204	387,395	0.0037	0.9963	88.47
46.5	97,522,396	344,330	0.0035	0.9965	88.13
47.5	92,284,943	422,346	0.0046	0.9954	87.82
48.5	87,490,284	537,769	0.0061	0.9939	87.42
49.5	81,364,709	333,321	0.0041	0.9959	86.88
50.5	75,018,624	348,497	0.0046	0.9954	86.53
51.5	69,871,087	377,916	0.0054	0.9946	86.13
52.5	63,924,181	323,188	0.0051	0.9949	85.66
53.5	58,915,102	260,476	0.0044	0.9956	85.23
54.5	53,292,587	143,175	0.0027	0.9973	84.85
55.5	47,750,480	161,169	0.0034	0.9966	84.62
56.5	42,896,920	185,513	0.0043	0.9957	84.34
57.5	36,304,185	244,607	0.0067	0.9933	83.97
58.5	30,633,419	243,043	0.0079	0.9921	83.41
59.5	24,843,846	231,464	0.0093	0.9907	82.74
60.5	20,083,392	156,493	0.0078	0.9922	81.97
61.5	18,649,935	174,667	0.0094	0.9906	81.34
62.5	15,155,821	279,877	0.0185	0.9815	80.57
63.5	11,509,542	116,803	0.0101	0.9899	79.09
64.5	9,323,167	190,887	0.0205	0.9795	78.28
65.5	7,202,377	139,882	0.0194	0.9806	76.68
66.5	5,931,763	142,765	0.0241	0.9759	75.19
67.5	3,568,388	111,159	0.0312	0.9688	73.38
68.5	3,362,695	89,931	0.0267	0.9733	71.10
69.5	3,253,605	95,887	0.0295	0.9705	69.19
70.5	3,124,770	163,508	0.0523	0.9477	67.15
71.5	2,915,090	170,852	0.0586	0.9414	63.64
72.5	2,722,865	232,397	0.0854	0.9146	59.91
73.5	2,475,055	136,254	0.0551	0.9449	54.80
74.5	2,316,312	427,449	0.1845	0.8155	51.78
75.5	1,857,841	194,340	0.1046	0.8954	42.23
76.5	1,515,013	183,626	0.1212	0.8788	37.81
77.5	1,287,572	79,645	0.0619	0.9381	33.23
78.5	1,211,011	101,880	0.0841	0.9159	31.17

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 376.11 AND 376.12 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2023 EXPERIENCE BAND 1910-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	1,107,584	80,711	0.0729	0.9271	28.55
80.5	1,025,549	85,060	0.0829	0.9171	26.47
81.5	928,668	108,546	0.1169	0.8831	24.27
82.5	791,423	61,510	0.0777	0.9223	21.44
83.5	724,410	32,179	0.0444	0.9556	19.77
84.5	687,312	62,266	0.0906	0.9094	18.89
85.5	617,718	42,757	0.0692	0.9308	17.18
86.5	560,807	57,255	0.1021	0.8979	15.99
87.5	487,210	66,475	0.1364	0.8636	14.36
88.5	414,791	22,665	0.0546	0.9454	12.40
89.5	381,613	18,140	0.0475	0.9525	11.72
90.5	366,872	3,707	0.0101	0.9899	11.16
91.5	359,953	10,887	0.0302	0.9698	11.05
92.5	325,135	768	0.0024	0.9976	10.72
93.5	279,498	306	0.0011	0.9989	10.69
94.5	277,386	511	0.0018	0.9982	10.68
95.5	260,149	252	0.0010	0.9990	10.66
96.5	257,429	460	0.0018	0.9982	10.65
97.5	218,212	3,122	0.0143	0.9857	10.63
98.5	185,469	4,135	0.0223	0.9777	10.48
99.5	175,679	913	0.0052	0.9948	10.25
100.5	159,335	4,783	0.0300	0.9700	10.19
101.5	115,043	5,719	0.0497	0.9503	9.89
102.5	95,898	4,399	0.0459	0.9541	9.39
103.5	82,103	1,475	0.0180	0.9820	8.96
104.5	80,335	1,580	0.0197	0.9803	8.80
105.5	74,754	1,018	0.0136	0.9864	8.63
106.5	71,085	170	0.0024	0.9976	8.51
107.5	60,734		0.0000	1.0000	8.49
108.5	59,014		0.0000	1.0000	8.49
109.5	58,760	331	0.0056	0.9944	8.49
110.5	36,814	946	0.0257	0.9743	8.44
111.5	35,761		0.0000	1.0000	8.23
112.5	35,621		0.0000	1.0000	8.23
113.5	15,210		0.0000	1.0000	8.23
114.5	38		0.0000	1.0000	8.23
115.5	38		0.0000	1.0000	8.23
116.5	38		0.0000	1.0000	8.23
117.5					8.23

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 376.11 AND 376.12 MAINS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1906-2023 EXPERIENCE BAND 1961-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,542,371,840	488,618	0.0003	0.9997	100.00
0.5	1,487,853,380	1,278,873	0.0009	0.9991	99.97
1.5	1,423,481,430	1,130,173	0.0008	0.9992	99.88
2.5	1,372,839,774	1,277,310	0.0009	0.9991	99.80
3.5	1,304,005,748	1,569,039	0.0012	0.9988	99.71
4.5	1,247,479,914	7,337,073	0.0059	0.9941	99.59
5.5	1,180,750,457	1,580,845	0.0013	0.9987	99.00
6.5	1,140,492,105	4,151,125	0.0036	0.9964	98.87
7.5	1,096,323,094	1,424,368	0.0013	0.9987	98.51
8.5	1,060,925,395	1,463,150	0.0014	0.9986	98.38
9.5	1,023,664,394	1,894,828	0.0019	0.9981	98.25
10.5	983,089,808	1,931,798	0.0020	0.9980	98.07
11.5	946,392,271	1,653,209	0.0017	0.9983	97.87
12.5	922,632,182	1,339,387	0.0015	0.9985	97.70
13.5	900,713,646	1,289,655	0.0014	0.9986	97.56
14.5	880,518,587	1,035,076	0.0012	0.9988	97.42
15.5	850,771,917	1,571,726	0.0018	0.9982	97.31
16.5	813,698,854	1,411,402	0.0017	0.9983	97.13
17.5	776,554,820	1,039,749	0.0013	0.9987	96.96
18.5	738,298,128	881,102	0.0012	0.9988	96.83
19.5	702,766,395	1,049,285	0.0015	0.9985	96.71
20.5	654,661,028	879,463	0.0013	0.9987	96.57
21.5	623,345,517	1,070,975	0.0017	0.9983	96.44
22.5	594,966,736	1,177,665	0.0020	0.9980	96.27
23.5	562,809,299	1,067,108	0.0019	0.9981	96.08
24.5	532,149,506	1,132,411	0.0021	0.9979	95.90
25.5	500,604,960	870,005	0.0017	0.9983	95.70
26.5	463,473,072	924,863	0.0020	0.9980	95.53
27.5	427,338,847	838,801	0.0020	0.9980	95.34
28.5	396,944,671	802,038	0.0020	0.9980	95.15
29.5	366,367,048	1,489,425	0.0041	0.9959	94.96
30.5	336,572,587	1,035,753	0.0031	0.9969	94.57
31.5	309,451,587	882,702	0.0029	0.9971	94.28
32.5	286,578,630	717,613	0.0025	0.9975	94.01
33.5	269,055,733	774,852	0.0029	0.9971	93.78
34.5	251,363,846	1,157,496	0.0046	0.9954	93.51
35.5	236,278,706	709,746	0.0030	0.9970	93.08
36.5	222,564,078	594,710	0.0027	0.9973	92.80
37.5	206,675,537	536,765	0.0026	0.9974	92.55
38.5	190,428,731	592,874	0.0031	0.9969	92.31

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 376.11 AND 376.12 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2023 EXPERIENCE BAND 1961-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	172,895,368	538,472	0.0031	0.9969	92.02
40.5	160,969,028	539,846	0.0034	0.9966	91.74
41.5	149,332,444	405,775	0.0027	0.9973	91.43
42.5	136,683,247	1,559,462	0.0114	0.9886	91.18
43.5	123,616,969	2,127,218	0.0172	0.9828	90.14
44.5	110,554,052	308,709	0.0028	0.9972	88.59
45.5	101,534,154	387,395	0.0038	0.9962	88.34
46.5	95,805,024	344,330	0.0036	0.9964	88.00
47.5	90,678,769	422,346	0.0047	0.9953	87.69
48.5	86,144,169	537,769	0.0062	0.9938	87.28
49.5	80,537,765	333,321	0.0041	0.9959	86.73
50.5	75,018,624	348,497	0.0046	0.9954	86.38
51.5	69,871,087	377,916	0.0054	0.9946	85.97
52.5	63,924,181	323,188	0.0051	0.9949	85.51
53.5	58,915,102	260,476	0.0044	0.9956	85.08
54.5	53,292,587	143,175	0.0027	0.9973	84.70
55.5	47,750,480	161,169	0.0034	0.9966	84.47
56.5	42,896,920	185,513	0.0043	0.9957	84.19
57.5	36,304,185	244,607	0.0067	0.9933	83.82
58.5	30,633,419	243,043	0.0079	0.9921	83.26
59.5	24,843,846	231,464	0.0093	0.9907	82.60
60.5	20,083,392	156,493	0.0078	0.9922	81.83
61.5	18,649,935	174,667	0.0094	0.9906	81.19
62.5	15,155,821	279,877	0.0185	0.9815	80.43
63.5	11,509,542	116,803	0.0101	0.9899	78.95
64.5	9,323,167	190,887	0.0205	0.9795	78.14
65.5	7,202,377	139,882	0.0194	0.9806	76.54
66.5	5,931,763	142,765	0.0241	0.9759	75.06
67.5	3,568,388	111,159	0.0312	0.9688	73.25
68.5	3,362,695	89,931	0.0267	0.9733	70.97
69.5	3,253,605	95,887	0.0295	0.9705	69.07
70.5	3,124,770	163,508	0.0523	0.9477	67.04
71.5	2,915,090	170,852	0.0586	0.9414	63.53
72.5	2,722,865	232,397	0.0854	0.9146	59.81
73.5	2,475,055	136,254	0.0551	0.9449	54.70
74.5	2,316,312	427,449	0.1845	0.8155	51.69
75.5	1,857,841	194,340	0.1046	0.8954	42.15
76.5	1,515,013	183,626	0.1212	0.8788	37.74
77.5	1,287,572	79,645	0.0619	0.9381	33.17
78.5	1,211,011	101,880	0.0841	0.9159	31.12

NORTHWEST NATURAL GAS COMPANY

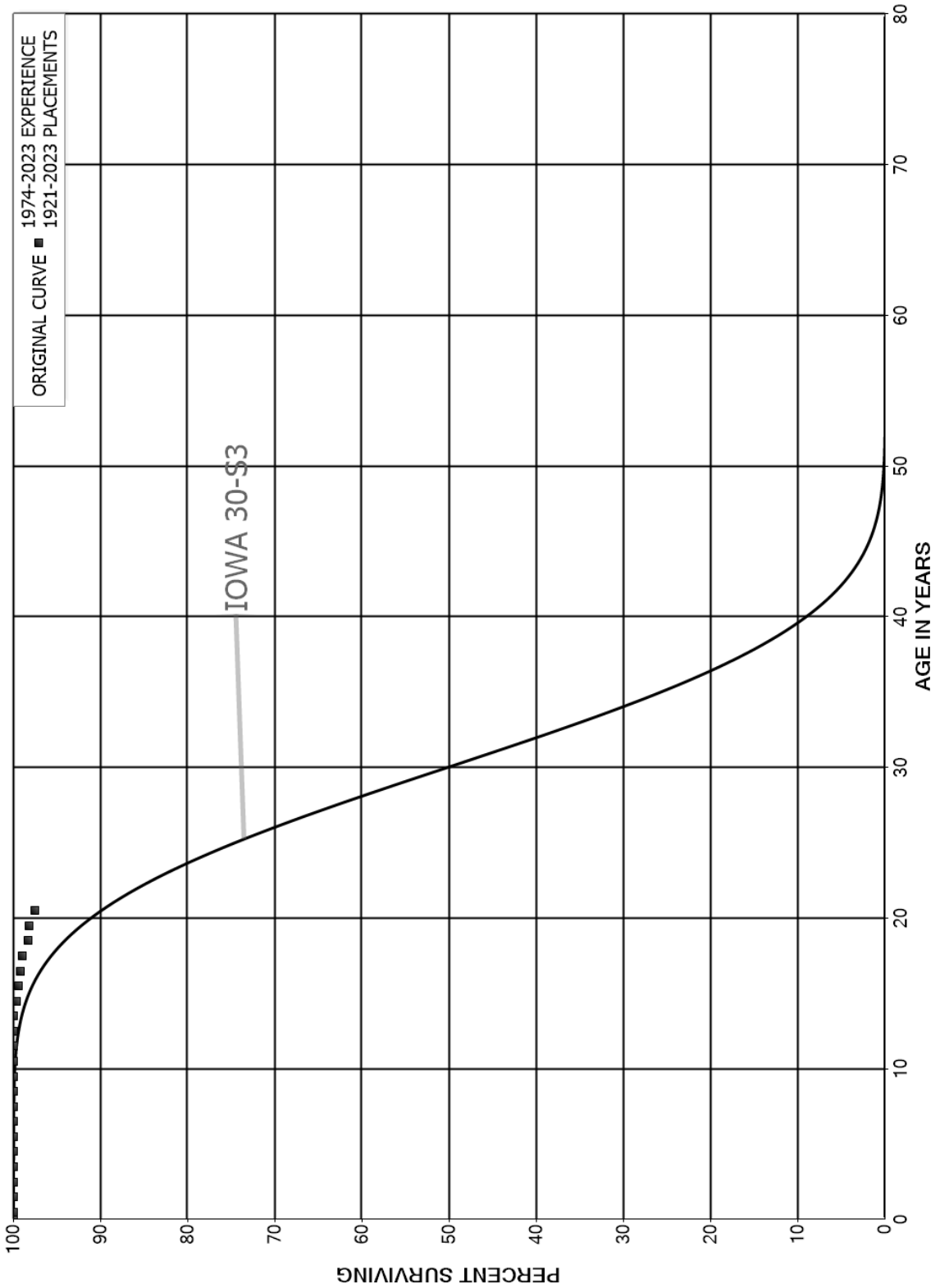
ACCOUNTS 376.11 AND 376.12 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2023 EXPERIENCE BAND 1961-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	1,107,584	80,711	0.0729	0.9271	28.50
80.5	1,025,549	85,060	0.0829	0.9171	26.42
81.5	928,668	108,546	0.1169	0.8831	24.23
82.5	791,423	61,510	0.0777	0.9223	21.40
83.5	724,410	32,179	0.0444	0.9556	19.73
84.5	687,312	62,266	0.0906	0.9094	18.86
85.5	617,718	42,757	0.0692	0.9308	17.15
86.5	560,807	57,255	0.1021	0.8979	15.96
87.5	487,210	66,475	0.1364	0.8636	14.33
88.5	414,791	22,665	0.0546	0.9454	12.38
89.5	381,613	18,140	0.0475	0.9525	11.70
90.5	366,872	3,707	0.0101	0.9899	11.14
91.5	359,953	10,887	0.0302	0.9698	11.03
92.5	325,135	768	0.0024	0.9976	10.70
93.5	279,498	306	0.0011	0.9989	10.67
94.5	277,386	511	0.0018	0.9982	10.66
95.5	260,149	252	0.0010	0.9990	10.64
96.5	257,429	460	0.0018	0.9982	10.63
97.5	218,212	3,122	0.0143	0.9857	10.61
98.5	185,469	4,135	0.0223	0.9777	10.46
99.5	175,679	913	0.0052	0.9948	10.23
100.5	159,335	4,783	0.0300	0.9700	10.17
101.5	115,043	5,719	0.0497	0.9503	9.87
102.5	95,898	4,399	0.0459	0.9541	9.38
103.5	82,103	1,475	0.0180	0.9820	8.95
104.5	80,335	1,580	0.0197	0.9803	8.79
105.5	74,754	1,018	0.0136	0.9864	8.61
106.5	71,085	170	0.0024	0.9976	8.50
107.5	60,734		0.0000	1.0000	8.48
108.5	59,014		0.0000	1.0000	8.48
109.5	58,760	331	0.0056	0.9944	8.48
110.5	36,814	946	0.0257	0.9743	8.43
111.5	35,761		0.0000	1.0000	8.21
112.5	35,621		0.0000	1.0000	8.21
113.5	15,210		0.0000	1.0000	8.21
114.5	38		0.0000	1.0000	8.21
115.5	38		0.0000	1.0000	8.21
116.5	38		0.0000	1.0000	8.21
117.5					8.21

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 377.00 COMPRESSOR STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 377.00 COMPRESSOR STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1921-2023 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,012,249		0.0000	1.0000	100.00
0.5	969,942		0.0000	1.0000	100.00
1.5	969,942		0.0000	1.0000	100.00
2.5	818,380		0.0000	1.0000	100.00
3.5	818,380		0.0000	1.0000	100.00
4.5	818,380		0.0000	1.0000	100.00
5.5	818,380		0.0000	1.0000	100.00
6.5	818,380		0.0000	1.0000	100.00
7.5	818,380		0.0000	1.0000	100.00
8.5	818,380		0.0000	1.0000	100.00
9.5	818,380		0.0000	1.0000	100.00
10.5	818,723		0.0000	1.0000	100.00
11.5	818,723	343	0.0004	0.9996	100.00
12.5	821,132		0.0000	1.0000	99.96
13.5	823,074	2,752	0.0033	0.9967	99.96
14.5	821,705	1,942	0.0024	0.9976	99.62
15.5	821,730	1,383	0.0017	0.9983	99.39
16.5	825,785	1,967	0.0024	0.9976	99.22
17.5	824,755	5,438	0.0066	0.9934	98.98
18.5	825,560	937	0.0011	0.9989	98.33
19.5	824,623	6,243	0.0076	0.9924	98.22
20.5					97.48
21.5					
22.5					
23.5	6,883		0.0000		
24.5	7,084	6,883	0.9716		
25.5	18,727	201	0.0107		
26.5	30,122	18,526	0.6150		
27.5	19,331	11,596	0.5999		
28.5	7,773	7,735	0.9951		
29.5	124,160	38	0.0003		
30.5	124,122	124,122	1.0000		
31.5					
32.5					
33.5					
34.5					
35.5	4,800		0.0000		
36.5	4,992	4,800	0.9615		
37.5	3,005	192	0.0639		
38.5	2,813	2,813	1.0000		

NORTHWEST NATURAL GAS COMPANY

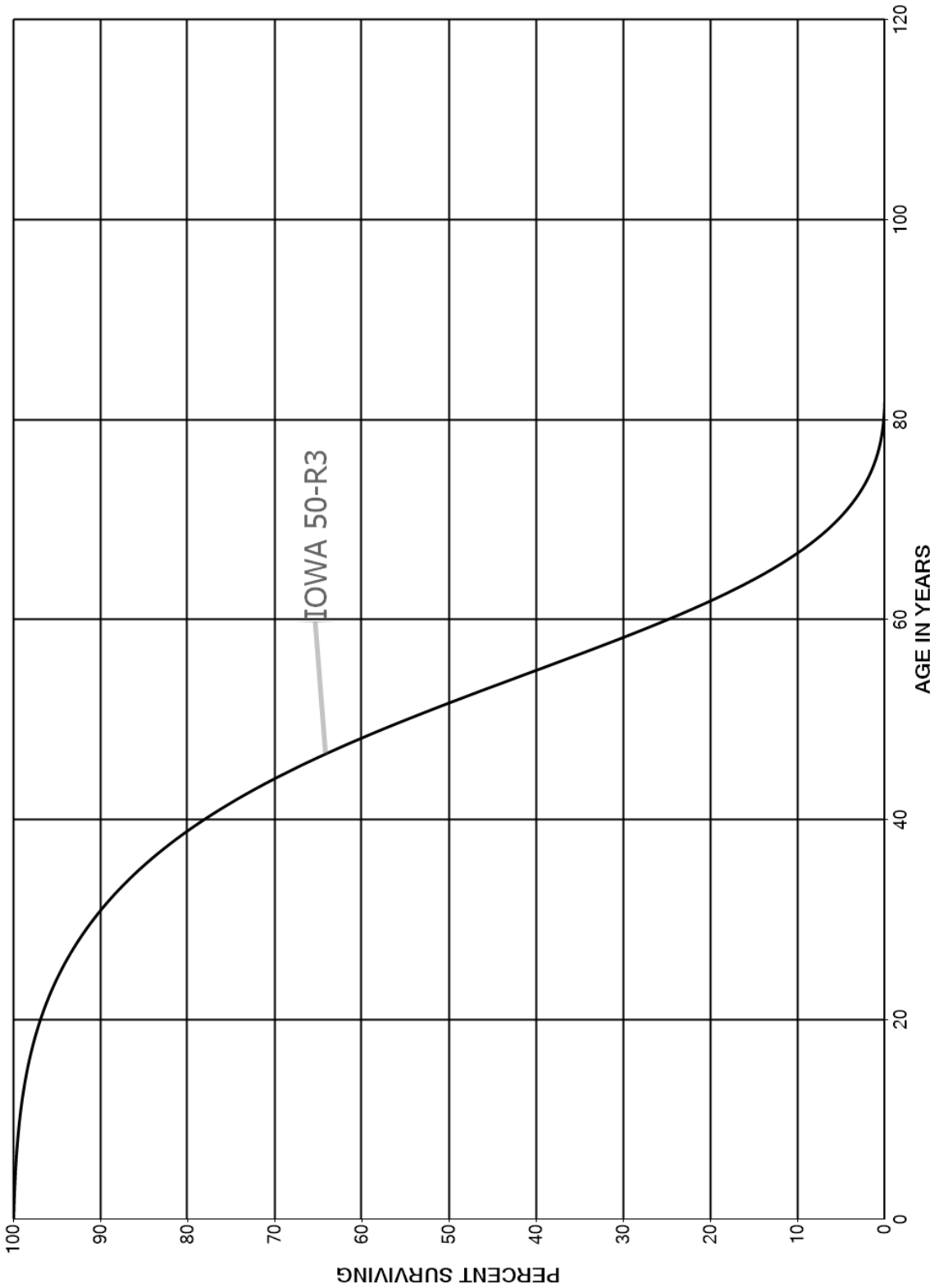
ACCOUNT 377.00 COMPRESSOR STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

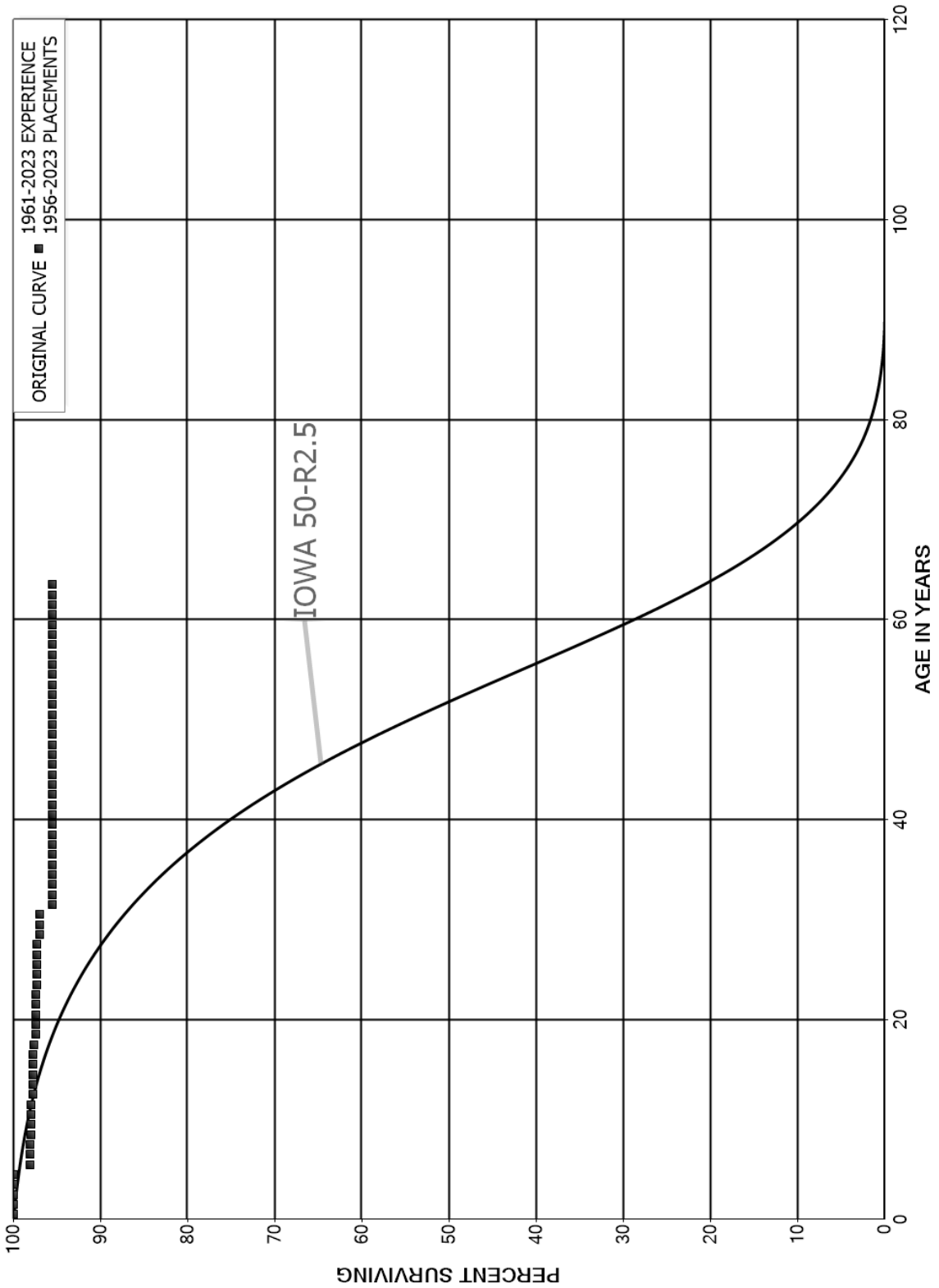
PLACEMENT BAND 1921-2023 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	80		0.0000		
40.5	80	80	1.0000		
41.5					
42.5					
43.5					
44.5					
45.5					
46.5	8,347		0.0000		
47.5	8,347	8,347	1.0000		
48.5	1,078		0.0000		
49.5	1,078	1,078	1.0000		
50.5					
51.5					
52.5	496		0.0000		
53.5	496	496	1.0000		
54.5					

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 378.00 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL
SMOOTH SURVIVOR CURVE



NORTHWEST NATURAL GAS COMPANY
ACCOUNT 379.00 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 379.00 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2023 EXPERIENCE BAND 1961-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	21,935,097	110	0.0000	1.0000	100.00
0.5	21,501,568	235	0.0000	1.0000	100.00
1.5	20,028,391	1,228	0.0001	0.9999	100.00
2.5	18,593,059	4,769	0.0003	0.9997	99.99
3.5	16,891,692	4,411	0.0003	0.9997	99.97
4.5	14,407,590	273,564	0.0190	0.9810	99.94
5.5	11,415,296	1,235	0.0001	0.9999	98.04
6.5	8,313,909	838	0.0001	0.9999	98.03
7.5	5,748,376	881	0.0002	0.9998	98.02
8.5	4,850,085	1,074	0.0002	0.9998	98.01
9.5	4,017,874	1,551	0.0004	0.9996	97.99
10.5	1,927,322		0.0000	1.0000	97.95
11.5	1,850,955	4,000	0.0022	0.9978	97.95
12.5	1,787,679		0.0000	1.0000	97.74
13.5	1,652,581		0.0000	1.0000	97.74
14.5	1,524,539		0.0000	1.0000	97.74
15.5	1,524,539		0.0000	1.0000	97.74
16.5	1,524,539	1,383	0.0009	0.9991	97.74
17.5	1,523,156	3,498	0.0023	0.9977	97.65
18.5	1,367,849		0.0000	1.0000	97.42
19.5	1,367,547		0.0000	1.0000	97.42
20.5	1,367,547	831	0.0006	0.9994	97.42
21.5	1,366,496	116	0.0001	0.9999	97.36
22.5	1,325,741	520	0.0004	0.9996	97.36
23.5	1,118,413		0.0000	1.0000	97.32
24.5	1,118,413		0.0000	1.0000	97.32
25.5	1,118,413		0.0000	1.0000	97.32
26.5	1,118,413		0.0000	1.0000	97.32
27.5	1,089,712	4,292	0.0039	0.9961	97.32
28.5	1,085,420		0.0000	1.0000	96.93
29.5	1,085,420		0.0000	1.0000	96.93
30.5	1,084,441	15,797	0.0146	0.9854	96.93
31.5	1,066,814		0.0000	1.0000	95.52
32.5	1,031,855		0.0000	1.0000	95.52
33.5	1,029,117		0.0000	1.0000	95.52
34.5	1,024,179		0.0000	1.0000	95.52
35.5	992,184		0.0000	1.0000	95.52
36.5	979,664		0.0000	1.0000	95.52
37.5	895,551		0.0000	1.0000	95.52
38.5	895,551		0.0000	1.0000	95.52

NORTHWEST NATURAL GAS COMPANY

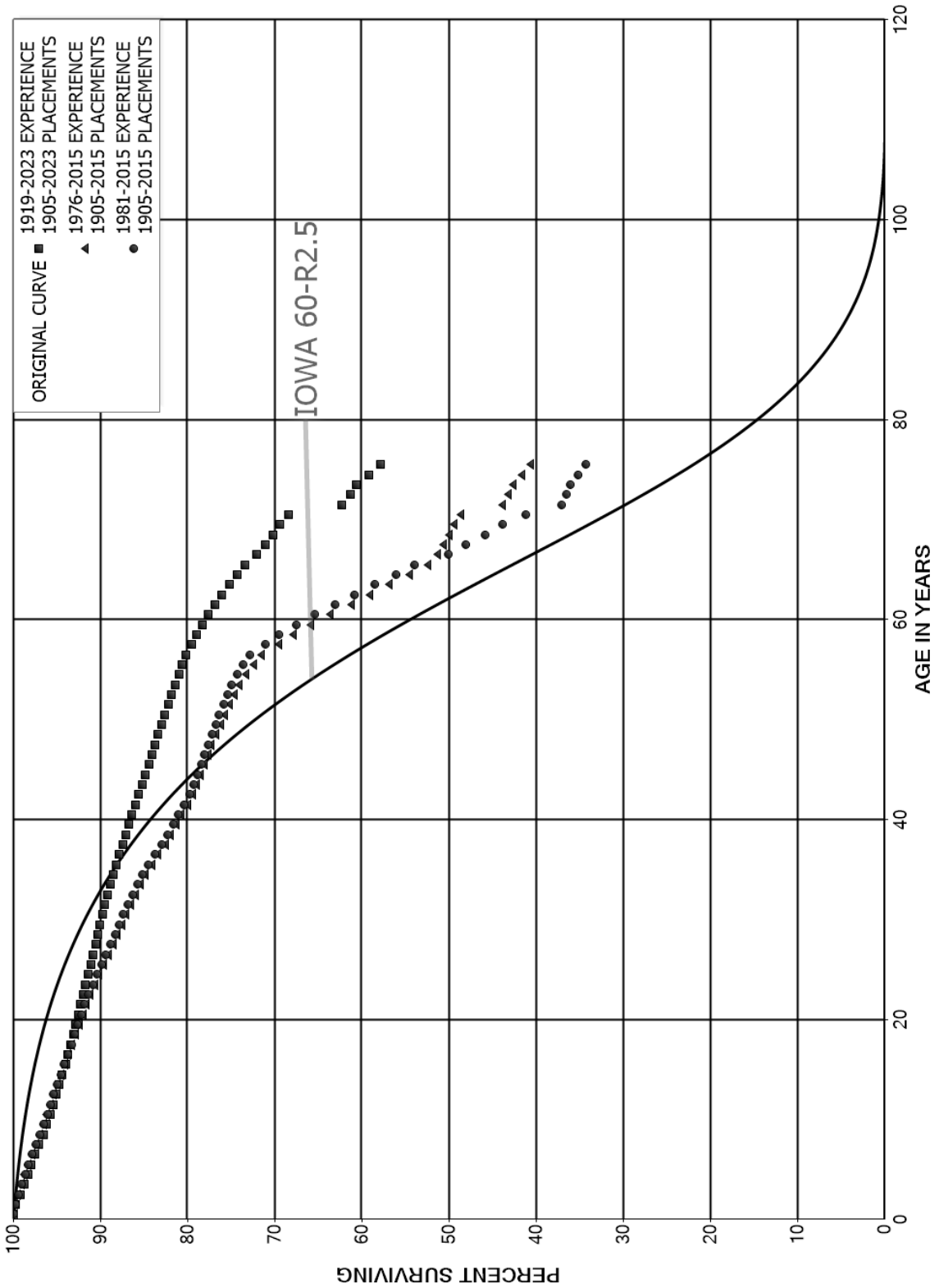
ACCOUNT 379.00 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-2023 EXPERIENCE BAND 1961-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	866,500		0.0000	1.0000	95.52
40.5	859,527		0.0000	1.0000	95.52
41.5	830,451		0.0000	1.0000	95.52
42.5	793,737		0.0000	1.0000	95.52
43.5	696,182		0.0000	1.0000	95.52
44.5	696,182		0.0000	1.0000	95.52
45.5	696,182		0.0000	1.0000	95.52
46.5	648,984		0.0000	1.0000	95.52
47.5	629,219		0.0000	1.0000	95.52
48.5	617,455		0.0000	1.0000	95.52
49.5	608,726		0.0000	1.0000	95.52
50.5	580,682		0.0000	1.0000	95.52
51.5	495,890		0.0000	1.0000	95.52
52.5	466,037		0.0000	1.0000	95.52
53.5	456,050		0.0000	1.0000	95.52
54.5	420,982		0.0000	1.0000	95.52
55.5	408,617		0.0000	1.0000	95.52
56.5	400,659		0.0000	1.0000	95.52
57.5	380,063		0.0000	1.0000	95.52
58.5	323,399		0.0000	1.0000	95.52
59.5	259,255		0.0000	1.0000	95.52
60.5	241,009		0.0000	1.0000	95.52
61.5	232,890		0.0000	1.0000	95.52
62.5	223,874		0.0000	1.0000	95.52
63.5	97,566		0.0000	1.0000	95.52
64.5	97,426		0.0000	1.0000	95.52
65.5	90,855		0.0000	1.0000	95.52
66.5	90,440		0.0000	1.0000	95.52
67.5					95.52

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 380.00 SERVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1905-2023 EXPERIENCE BAND 1919-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,071,935,044	1,042,465	0.0010	0.9990	100.00
0.5	1,024,432,762	2,348,906	0.0023	0.9977	99.90
1.5	981,212,325	4,568,417	0.0047	0.9953	99.67
2.5	932,992,695	4,342,737	0.0047	0.9953	99.21
3.5	890,168,864	3,689,532	0.0041	0.9959	98.75
4.5	847,557,834	3,365,978	0.0040	0.9960	98.34
5.5	810,714,221	3,634,585	0.0045	0.9955	97.95
6.5	775,307,803	3,867,851	0.0050	0.9950	97.51
7.5	742,295,182	3,610,865	0.0049	0.9951	97.02
8.5	713,806,792	2,973,769	0.0042	0.9958	96.55
9.5	683,891,469	2,644,703	0.0039	0.9961	96.15
10.5	656,782,462	2,412,969	0.0037	0.9963	95.78
11.5	636,163,883	2,276,060	0.0036	0.9964	95.42
12.5	617,840,941	2,261,124	0.0037	0.9963	95.08
13.5	605,102,265	2,522,848	0.0042	0.9958	94.74
14.5	582,901,137	2,094,086	0.0036	0.9964	94.34
15.5	561,300,730	1,927,742	0.0034	0.9966	94.00
16.5	539,591,542	1,802,999	0.0033	0.9967	93.68
17.5	515,211,854	1,577,710	0.0031	0.9969	93.37
18.5	492,079,828	1,557,474	0.0032	0.9968	93.08
19.5	467,010,641	1,407,269	0.0030	0.9970	92.78
20.5	440,456,833	1,240,691	0.0028	0.9972	92.51
21.5	415,073,197	1,147,094	0.0028	0.9972	92.24
22.5	390,910,953	1,344,230	0.0034	0.9966	91.99
23.5	366,779,400	1,069,049	0.0029	0.9971	91.67
24.5	339,590,484	1,145,411	0.0034	0.9966	91.41
25.5	314,521,556	974,845	0.0031	0.9969	91.10
26.5	288,702,622	844,854	0.0029	0.9971	90.82
27.5	264,970,453	806,619	0.0030	0.9970	90.55
28.5	244,034,441	695,856	0.0029	0.9971	90.27
29.5	221,540,066	656,325	0.0030	0.9970	90.02
30.5	199,472,386	608,915	0.0031	0.9969	89.75
31.5	179,602,086	611,957	0.0034	0.9966	89.48
32.5	160,407,653	560,116	0.0035	0.9965	89.17
33.5	142,783,859	517,171	0.0036	0.9964	88.86
34.5	127,301,271	525,792	0.0041	0.9959	88.54
35.5	115,416,970	513,449	0.0044	0.9956	88.17
36.5	104,843,853	497,945	0.0047	0.9953	87.78
37.5	94,680,461	365,423	0.0039	0.9961	87.36
38.5	84,283,555	331,118	0.0039	0.9961	87.03

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1905-2023 EXPERIENCE BAND 1919-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	75,672,762	264,550	0.0035	0.9965	86.68
40.5	68,973,892	319,288	0.0046	0.9954	86.38
41.5	62,821,116	265,074	0.0042	0.9958	85.98
42.5	55,286,386	297,340	0.0054	0.9946	85.62
43.5	47,940,334	199,379	0.0042	0.9958	85.16
44.5	42,061,498	182,879	0.0043	0.9957	84.80
45.5	37,288,922	167,822	0.0045	0.9955	84.44
46.5	33,923,653	132,593	0.0039	0.9961	84.06
47.5	31,101,110	133,939	0.0043	0.9957	83.73
48.5	28,817,519	139,440	0.0048	0.9952	83.37
49.5	26,340,722	114,287	0.0043	0.9957	82.96
50.5	23,558,731	112,133	0.0048	0.9952	82.60
51.5	20,922,828	98,874	0.0047	0.9953	82.21
52.5	18,566,445	85,635	0.0046	0.9954	81.82
53.5	16,494,680	88,128	0.0053	0.9947	81.44
54.5	14,449,858	78,961	0.0055	0.9945	81.01
55.5	12,677,145	68,011	0.0054	0.9946	80.57
56.5	11,015,252	89,897	0.0082	0.9918	80.13
57.5	9,346,785	68,019	0.0073	0.9927	79.48
58.5	7,920,229	67,299	0.0085	0.9915	78.90
59.5	6,702,979	51,179	0.0076	0.9924	78.23
60.5	5,707,911	55,641	0.0097	0.9903	77.63
61.5	4,871,433	48,915	0.0100	0.9900	76.88
62.5	4,095,848	47,336	0.0116	0.9884	76.10
63.5	3,419,366	43,691	0.0128	0.9872	75.23
64.5	3,108,567	36,786	0.0118	0.9882	74.26
65.5	3,033,059	55,106	0.0182	0.9818	73.39
66.5	2,774,139	36,273	0.0131	0.9869	72.05
67.5	2,516,291	32,839	0.0131	0.9869	71.11
68.5	2,468,359	29,497	0.0119	0.9881	70.18
69.5	2,425,416	33,744	0.0139	0.9861	69.34
70.5	2,312,532	206,564	0.0893	0.9107	68.38
71.5	2,092,827	33,791	0.0161	0.9839	62.27
72.5	2,007,939	22,736	0.0113	0.9887	61.27
73.5	1,964,340	45,426	0.0231	0.9769	60.57
74.5	1,894,971	41,322	0.0218	0.9782	59.17
75.5	428,582	14,122	0.0330	0.9670	57.88
76.5	378,922	17,652	0.0466	0.9534	55.97
77.5	314,346	11,374	0.0362	0.9638	53.37
78.5	280,533	8,791	0.0313	0.9687	51.43

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1905-2023 EXPERIENCE BAND 1919-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	253,766	6,055	0.0239	0.9761	49.82
80.5	242,558	6,563	0.0271	0.9729	48.63
81.5	214,036	6,898	0.0322	0.9678	47.32
82.5	192,310	6,847	0.0356	0.9644	45.79
83.5	172,665	3,716	0.0215	0.9785	44.16
84.5	150,642	3,809	0.0253	0.9747	43.21
85.5	132,410	3,930	0.0297	0.9703	42.12
86.5	119,967	2,471	0.0206	0.9794	40.87
87.5	111,701	1,298	0.0116	0.9884	40.03
88.5	107,133	1,377	0.0129	0.9871	39.56
89.5	102,538	809	0.0079	0.9921	39.05
90.5	99,370	17,363	0.1747	0.8253	38.75
91.5	74,566	3,756	0.0504	0.9496	31.98
92.5	58,925	1,691	0.0287	0.9713	30.36
93.5	52,665	2,161	0.0410	0.9590	29.49
94.5	46,458	4,384	0.0944	0.9056	28.28
95.5	39,313	1,449	0.0369	0.9631	25.61
96.5	37,720	625	0.0166	0.9834	24.67
97.5	32,522	423	0.0130	0.9870	24.26
98.5	24,243	428	0.0176	0.9824	23.95
99.5	18,386	570	0.0310	0.9690	23.52
100.5	16,521	489	0.0296	0.9704	22.79
101.5	15,286	447	0.0292	0.9708	22.12
102.5	14,923	256	0.0172	0.9828	21.47
103.5	12,205	328	0.0269	0.9731	21.11
104.5	9,639	239	0.0248	0.9752	20.54
105.5	7,736	109	0.0141	0.9859	20.03
106.5	7,627	321	0.0421	0.9579	19.75
107.5	7,306	104	0.0143	0.9857	18.92
108.5	7,194	95	0.0132	0.9868	18.65
109.5	6,937	95	0.0137	0.9863	18.40
110.5	6,818	29	0.0043	0.9957	18.15
111.5	5,683	38	0.0066	0.9934	18.07
112.5	5,646	0	0.0000	1.0000	17.95
113.5	2,838	22	0.0077	0.9923	17.95
114.5	2,763		0.0000	1.0000	17.81
115.5	1,588	19	0.0118	0.9882	17.81
116.5	1,569	45	0.0284	0.9716	17.60
117.5	1,392		0.0000	1.0000	17.10
118.5					17.10

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1905-2015 EXPERIENCE BAND 1976-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	719,096,775	568,357	0.0008	0.9992	100.00
0.5	693,643,292	1,319,582	0.0019	0.9981	99.92
1.5	667,462,905	2,325,246	0.0035	0.9965	99.73
2.5	643,364,245	2,426,756	0.0038	0.9962	99.38
3.5	625,125,686	2,497,748	0.0040	0.9960	99.01
4.5	609,123,532	2,472,689	0.0041	0.9959	98.61
5.5	598,723,462	2,659,992	0.0044	0.9956	98.21
6.5	578,494,534	2,715,397	0.0047	0.9953	97.78
7.5	557,994,341	2,676,125	0.0048	0.9952	97.32
8.5	537,545,260	2,410,751	0.0045	0.9955	96.85
9.5	514,495,328	2,077,535	0.0040	0.9960	96.42
10.5	492,436,156	1,938,105	0.0039	0.9961	96.03
11.5	468,676,863	1,885,282	0.0040	0.9960	95.65
12.5	442,867,326	1,821,114	0.0041	0.9959	95.26
13.5	418,275,210	2,121,702	0.0051	0.9949	94.87
14.5	394,205,527	1,696,741	0.0043	0.9957	94.39
15.5	370,573,726	1,634,305	0.0044	0.9956	93.99
16.5	343,550,694	1,579,612	0.0046	0.9954	93.57
17.5	318,443,478	1,352,378	0.0042	0.9958	93.14
18.5	292,656,096	1,372,112	0.0047	0.9953	92.74
19.5	268,738,218	1,226,661	0.0046	0.9954	92.31
20.5	247,325,684	1,104,720	0.0045	0.9955	91.89
21.5	224,300,630	1,026,199	0.0046	0.9954	91.48
22.5	201,968,171	1,221,880	0.0060	0.9940	91.06
23.5	181,633,202	924,927	0.0051	0.9949	90.51
24.5	162,206,271	1,038,777	0.0064	0.9936	90.05
25.5	144,233,499	849,065	0.0059	0.9941	89.47
26.5	128,475,042	722,228	0.0056	0.9944	88.94
27.5	116,388,458	688,326	0.0059	0.9941	88.44
28.5	105,767,470	602,401	0.0057	0.9943	87.92
29.5	95,638,161	545,296	0.0057	0.9943	87.42
30.5	85,040,072	514,671	0.0061	0.9939	86.92
31.5	76,220,574	508,309	0.0067	0.9933	86.40
32.5	69,258,973	453,214	0.0065	0.9935	85.82
33.5	62,967,415	423,259	0.0067	0.9933	85.26
34.5	55,241,506	444,813	0.0081	0.9919	84.69
35.5	47,620,517	420,601	0.0088	0.9912	84.00
36.5	41,432,905	414,302	0.0100	0.9900	83.26
37.5	36,357,672	284,751	0.0078	0.9922	82.43
38.5	32,805,062	256,538	0.0078	0.9922	81.78

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1905-2015 EXPERIENCE BAND 1976-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	29,832,670	197,897	0.0066	0.9934	81.14
40.5	27,443,601	250,055	0.0091	0.9909	80.61
41.5	24,781,775	185,983	0.0075	0.9925	79.87
42.5	21,867,977	128,482	0.0059	0.9941	79.27
43.5	19,177,416	103,663	0.0054	0.9946	78.81
44.5	16,786,612	95,564	0.0057	0.9943	78.38
45.5	14,669,601	72,396	0.0049	0.9951	77.93
46.5	12,638,806	69,320	0.0055	0.9945	77.55
47.5	10,847,116	74,557	0.0069	0.9931	77.12
48.5	9,176,584	60,559	0.0066	0.9934	76.59
49.5	7,523,018	41,650	0.0055	0.9945	76.09
50.5	6,134,297	48,594	0.0079	0.9921	75.67
51.5	4,955,088	37,454	0.0076	0.9924	75.07
52.5	3,986,339	29,080	0.0073	0.9927	74.50
53.5	3,188,815	33,901	0.0106	0.9894	73.96
54.5	2,435,730	28,099	0.0115	0.9885	73.17
55.5	1,793,195	23,591	0.0132	0.9868	72.33
56.5	1,508,170	40,874	0.0271	0.9729	71.37
57.5	1,421,983	34,434	0.0242	0.9758	69.44
58.5	1,200,808	36,150	0.0301	0.9699	67.76
59.5	955,749	32,807	0.0343	0.9657	65.72
60.5	927,214	35,142	0.0379	0.9621	63.46
61.5	894,281	31,566	0.0353	0.9647	61.06
62.5	801,115	30,164	0.0377	0.9623	58.90
63.5	781,043	31,842	0.0408	0.9592	56.68
64.5	737,356	27,775	0.0377	0.9623	54.37
65.5	2,392,368	50,900	0.0213	0.9787	52.33
66.5	2,314,924	32,520	0.0140	0.9860	51.21
67.5	2,264,280	29,278	0.0129	0.9871	50.49
68.5	2,197,548	26,661	0.0121	0.9879	49.84
69.5	2,122,871	30,528	0.0144	0.9856	49.24
70.5	2,071,068	203,366	0.0982	0.9018	48.53
71.5	1,848,813	30,648	0.0166	0.9834	43.76
72.5	1,812,315	21,566	0.0119	0.9881	43.04
73.5	1,768,069	44,121	0.0250	0.9750	42.52
74.5	1,708,247	40,134	0.0235	0.9765	41.46
75.5	246,980	13,166	0.0533	0.9467	40.49
76.5	214,880	16,696	0.0777	0.9223	38.33
77.5	183,078	10,462	0.0571	0.9429	35.35
78.5	163,392	7,944	0.0486	0.9514	33.33

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1905-2015 EXPERIENCE BAND 1976-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	148,900	5,202	0.0349	0.9651	31.71
80.5	135,883	5,854	0.0431	0.9569	30.60
81.5	126,087	6,306	0.0500	0.9500	29.29
82.5	116,236	6,129	0.0527	0.9473	27.82
83.5	101,396	2,918	0.0288	0.9712	26.35
84.5	85,647	2,997	0.0350	0.9650	25.60
85.5	78,080	3,258	0.0417	0.9583	24.70
86.5	70,775	1,731	0.0245	0.9755	23.67
87.5	66,283	865	0.0130	0.9870	23.09
88.5	68,138	540	0.0079	0.9921	22.79
89.5	63,091	457	0.0072	0.9928	22.61
90.5	54,906	17,083	0.3111	0.6889	22.44
91.5	31,736	3,288	0.1036	0.8964	15.46
92.5	27,236	1,630	0.0599	0.9401	13.86
93.5	24,244	1,781	0.0734	0.9266	13.03
94.5	22,463	4,059	0.1807	0.8193	12.07
95.5	15,942	1,251	0.0785	0.9215	9.89
96.5	12,453	452	0.0363	0.9637	9.11
97.5	10,337	298	0.0288	0.9712	8.78
98.5	9,751	184	0.0188	0.9812	8.53
99.5	9,567	308	0.0321	0.9679	8.37
100.5	9,224	411	0.0445	0.9555	8.10
101.5	7,840	191	0.0244	0.9756	7.74
102.5	7,697	130	0.0169	0.9831	7.55
103.5	5,978	60	0.0100	0.9900	7.42
104.5	5,918	98	0.0165	0.9835	7.35
105.5	3,013		0.0000	1.0000	7.23
106.5	2,960	37	0.0125	0.9875	7.23
107.5	1,748	29	0.0165	0.9835	7.14
108.5	1,719		0.0000	1.0000	7.02
109.5	1,586	42	0.0267	0.9733	7.02
110.5					6.83

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1905-2015 EXPERIENCE BAND 1981-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	686,602,942	542,260	0.0008	0.9992	100.00
0.5	668,187,342	1,198,907	0.0018	0.9982	99.92
1.5	647,207,319	2,207,430	0.0034	0.9966	99.74
2.5	625,622,703	2,316,964	0.0037	0.9963	99.40
3.5	608,456,016	2,372,717	0.0039	0.9961	99.03
4.5	592,797,930	2,362,113	0.0040	0.9960	98.65
5.5	582,396,162	2,553,511	0.0044	0.9956	98.25
6.5	562,477,048	2,590,122	0.0046	0.9954	97.82
7.5	543,019,857	2,562,331	0.0047	0.9953	97.37
8.5	523,620,964	2,283,982	0.0044	0.9956	96.91
9.5	501,463,771	1,941,815	0.0039	0.9961	96.49
10.5	480,425,163	1,811,030	0.0038	0.9962	96.12
11.5	457,681,082	1,780,290	0.0039	0.9961	95.75
12.5	432,681,533	1,704,342	0.0039	0.9961	95.38
13.5	408,990,101	2,020,634	0.0049	0.9951	95.01
14.5	386,058,077	1,590,604	0.0041	0.9959	94.54
15.5	363,367,593	1,537,152	0.0042	0.9958	94.15
16.5	337,367,298	1,481,259	0.0044	0.9956	93.75
17.5	313,320,573	1,247,938	0.0040	0.9960	93.34
18.5	288,386,285	1,253,541	0.0043	0.9957	92.97
19.5	265,215,598	1,120,376	0.0042	0.9958	92.56
20.5	244,766,074	998,169	0.0041	0.9959	92.17
21.5	222,582,263	944,564	0.0042	0.9958	91.80
22.5	200,626,816	1,165,841	0.0058	0.9942	91.41
23.5	180,781,649	883,816	0.0049	0.9951	90.87
24.5	161,703,056	1,014,244	0.0063	0.9937	90.43
25.5	143,778,265	831,854	0.0058	0.9942	89.86
26.5	128,004,451	709,855	0.0055	0.9945	89.34
27.5	116,042,901	674,775	0.0058	0.9942	88.85
28.5	105,368,368	590,960	0.0056	0.9944	88.33
29.5	95,219,974	528,938	0.0056	0.9944	87.84
30.5	84,657,724	501,044	0.0059	0.9941	87.35
31.5	75,867,986	493,394	0.0065	0.9935	86.83
32.5	68,947,897	439,817	0.0064	0.9936	86.27
33.5	62,734,300	415,526	0.0066	0.9934	85.72
34.5	55,080,825	439,451	0.0080	0.9920	85.15
35.5	47,479,873	416,417	0.0088	0.9912	84.47
36.5	41,296,661	409,003	0.0099	0.9901	83.73
37.5	36,210,560	280,506	0.0077	0.9923	82.90
38.5	32,667,662	251,837	0.0077	0.9923	82.26

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1905-2015 EXPERIENCE BAND 1981-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	29,709,946	194,129	0.0065	0.9935	81.62
40.5	27,330,959	246,768	0.0090	0.9910	81.09
41.5	24,687,054	183,530	0.0074	0.9926	80.36
42.5	21,791,058	125,974	0.0058	0.9942	79.76
43.5	19,101,966	101,311	0.0053	0.9947	79.30
44.5	16,689,351	93,191	0.0056	0.9944	78.88
45.5	14,564,135	68,550	0.0047	0.9953	78.44
46.5	12,499,424	64,199	0.0051	0.9949	78.07
47.5	10,684,886	69,133	0.0065	0.9935	77.67
48.5	8,992,785	52,655	0.0059	0.9941	77.16
49.5	7,342,051	34,146	0.0047	0.9953	76.71
50.5	5,926,026	40,529	0.0068	0.9932	76.36
51.5	4,739,823	28,844	0.0061	0.9939	75.83
52.5	3,769,650	21,572	0.0057	0.9943	75.37
53.5	2,975,750	25,547	0.0086	0.9914	74.94
54.5	2,234,831	21,145	0.0095	0.9905	74.30
55.5	1,618,723	16,832	0.0104	0.9896	73.59
56.5	1,372,115	34,170	0.0249	0.9751	72.83
57.5	1,321,330	29,062	0.0220	0.9780	71.02
58.5	1,120,211	30,889	0.0276	0.9724	69.45
59.5	895,884	29,028	0.0324	0.9676	67.54
60.5	869,361	31,128	0.0358	0.9642	65.35
61.5	836,293	29,542	0.0353	0.9647	63.01
62.5	725,188	27,505	0.0379	0.9621	60.78
63.5	701,399	28,590	0.0408	0.9592	58.48
64.5	626,729	23,899	0.0381	0.9619	56.10
65.5	598,637	42,722	0.0714	0.9286	53.96
66.5	542,061	22,547	0.0416	0.9584	50.11
67.5	517,559	23,303	0.0450	0.9550	48.02
68.5	473,800	21,434	0.0452	0.9548	45.86
69.5	438,965	26,494	0.0604	0.9396	43.78
70.5	2,067,501	203,366	0.0984	0.9016	41.14
71.5	1,845,299	30,648	0.0166	0.9834	37.10
72.5	1,809,976	21,566	0.0119	0.9881	36.48
73.5	1,765,730	44,121	0.0250	0.9750	36.04
74.5	1,706,098	40,134	0.0235	0.9765	35.14
75.5	246,980	13,166	0.0533	0.9467	34.32
76.5	214,880	16,696	0.0777	0.9223	32.49
77.5	183,078	10,462	0.0571	0.9429	29.96
78.5	163,392	7,944	0.0486	0.9514	28.25

NORTHWEST NATURAL GAS COMPANY

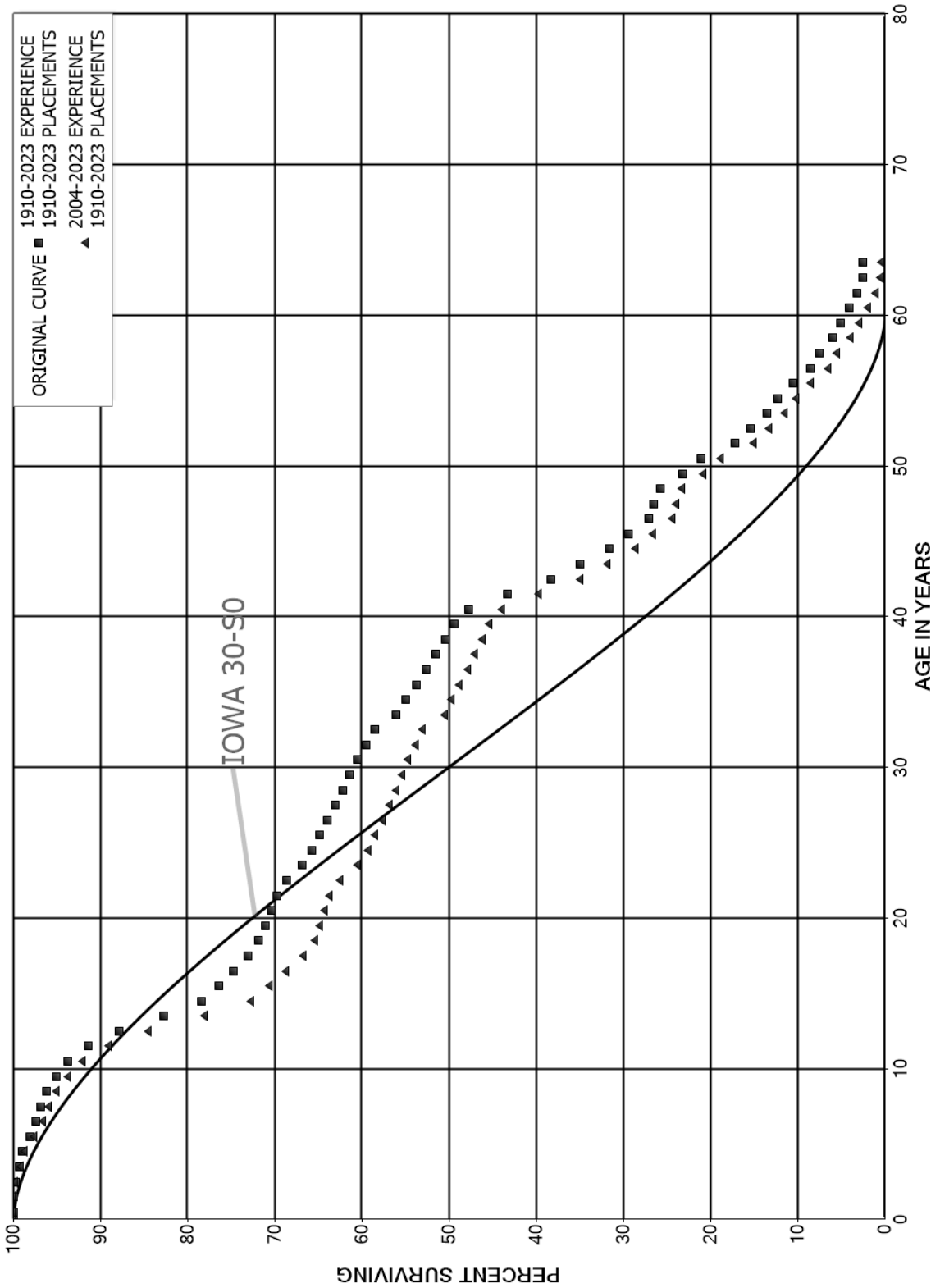
ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1905-2015 EXPERIENCE BAND 1981-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	148,900	5,202	0.0349	0.9651	26.88
80.5	135,883	5,854	0.0431	0.9569	25.94
81.5	126,087	6,306	0.0500	0.9500	24.82
82.5	116,236	6,129	0.0527	0.9473	23.58
83.5	101,396	2,918	0.0288	0.9712	22.34
84.5	85,647	2,997	0.0350	0.9650	21.69
85.5	78,080	3,258	0.0417	0.9583	20.93
86.5	70,775	1,731	0.0245	0.9755	20.06
87.5	66,283	865	0.0130	0.9870	19.57
88.5	68,138	540	0.0079	0.9921	19.31
89.5	63,091	457	0.0072	0.9928	19.16
90.5	54,906	17,083	0.3111	0.6889	19.02
91.5	31,736	3,288	0.1036	0.8964	13.10
92.5	27,236	1,630	0.0599	0.9401	11.75
93.5	24,244	1,781	0.0734	0.9266	11.04
94.5	22,463	4,059	0.1807	0.8193	10.23
95.5	15,942	1,251	0.0785	0.9215	8.38
96.5	12,453	452	0.0363	0.9637	7.73
97.5	10,337	298	0.0288	0.9712	7.44
98.5	9,751	184	0.0188	0.9812	7.23
99.5	9,567	308	0.0321	0.9679	7.09
100.5	9,224	411	0.0445	0.9555	6.87
101.5	7,840	191	0.0244	0.9756	6.56
102.5	7,697	130	0.0169	0.9831	6.40
103.5	5,978	60	0.0100	0.9900	6.29
104.5	5,918	98	0.0165	0.9835	6.23
105.5	3,013		0.0000	1.0000	6.13
106.5	2,960	37	0.0125	0.9875	6.13
107.5	1,748	29	0.0165	0.9835	6.05
108.5	1,719		0.0000	1.0000	5.95
109.5	1,586	42	0.0267	0.9733	5.95
110.5					5.79

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 381.00 METERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 1910-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	149,428,158	12,947	0.0001	0.9999	100.00
0.5	144,558,717	38,641	0.0003	0.9997	99.99
1.5	140,718,243	286,740	0.0020	0.9980	99.96
2.5	111,169,196	501,548	0.0045	0.9955	99.76
3.5	108,232,797	372,295	0.0034	0.9966	99.31
4.5	103,043,446	929,182	0.0090	0.9910	98.97
5.5	97,538,536	722,128	0.0074	0.9926	98.08
6.5	90,619,372	518,235	0.0057	0.9943	97.35
7.5	90,124,979	614,229	0.0068	0.9932	96.79
8.5	86,424,115	947,386	0.0110	0.9890	96.13
9.5	82,623,284	1,152,351	0.0139	0.9861	95.08
10.5	77,935,757	1,973,473	0.0253	0.9747	93.75
11.5	70,980,811	2,756,415	0.0388	0.9612	91.38
12.5	68,333,755	3,999,415	0.0585	0.9415	87.83
13.5	64,471,958	3,389,223	0.0526	0.9474	82.69
14.5	60,776,723	1,491,303	0.0245	0.9755	78.34
15.5	55,389,889	1,225,363	0.0221	0.9779	76.42
16.5	49,286,137	1,113,923	0.0226	0.9774	74.73
17.5	41,805,028	712,672	0.0170	0.9830	73.04
18.5	40,834,314	408,418	0.0100	0.9900	71.80
19.5	37,558,242	348,691	0.0093	0.9907	71.08
20.5	34,455,337	334,634	0.0097	0.9903	70.42
21.5	32,243,854	503,712	0.0156	0.9844	69.74
22.5	29,953,885	772,505	0.0258	0.9742	68.65
23.5	27,927,421	466,441	0.0167	0.9833	66.88
24.5	26,099,496	368,089	0.0141	0.9859	65.76
25.5	24,406,461	340,210	0.0139	0.9861	64.83
26.5	22,843,947	325,911	0.0143	0.9857	63.93
27.5	21,328,738	276,230	0.0130	0.9870	63.02
28.5	19,890,108	262,123	0.0132	0.9868	62.20
29.5	18,576,734	257,771	0.0139	0.9861	61.38
30.5	17,271,793	296,931	0.0172	0.9828	60.53
31.5	15,846,039	274,336	0.0173	0.9827	59.49
32.5	14,946,340	624,510	0.0418	0.9582	58.46
33.5	13,128,703	251,826	0.0192	0.9808	56.01
34.5	12,141,364	262,755	0.0216	0.9784	54.94
35.5	11,399,424	249,124	0.0219	0.9781	53.75
36.5	11,125,140	227,916	0.0205	0.9795	52.58
37.5	10,150,896	209,028	0.0206	0.9794	51.50
38.5	9,588,490	206,244	0.0215	0.9785	50.44

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 1910-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	9,148,552	311,607	0.0341	0.9659	49.35
40.5	8,786,349	802,075	0.0913	0.9087	47.67
41.5	8,021,426	923,765	0.1152	0.8848	43.32
42.5	7,131,457	626,284	0.0878	0.9122	38.33
43.5	6,540,908	631,063	0.0965	0.9035	34.97
44.5	5,932,081	410,645	0.0692	0.9308	31.59
45.5	5,542,802	432,447	0.0780	0.9220	29.41
46.5	5,129,086	116,672	0.0227	0.9773	27.11
47.5	5,031,421	144,653	0.0287	0.9713	26.49
48.5	4,904,365	484,255	0.0987	0.9013	25.73
49.5	4,435,341	411,437	0.0928	0.9072	23.19
50.5	4,035,514	742,192	0.1839	0.8161	21.04
51.5	3,305,065	340,874	0.1031	0.8969	17.17
52.5	2,971,449	359,925	0.1211	0.8789	15.40
53.5	2,614,668	248,151	0.0949	0.9051	13.53
54.5	2,369,222	335,434	0.1416	0.8584	12.25
55.5	2,036,143	384,334	0.1888	0.8112	10.52
56.5	1,657,897	200,168	0.1207	0.8793	8.53
57.5	1,459,377	291,512	0.1998	0.8002	7.50
58.5	1,169,340	193,116	0.1651	0.8349	6.00
59.5	977,179	187,455	0.1918	0.8082	5.01
60.5	790,331	174,158	0.2204	0.7796	4.05
61.5	616,249	119,367	0.1937	0.8063	3.16
62.5	497,009	7,787	0.0157	0.9843	2.55
63.5	489,281	684	0.0014	0.9986	2.51
64.5	488,597	14,217	0.0291	0.9709	2.50
65.5	474,415	21,788	0.0459	0.9541	2.43
66.5	452,627	19,625	0.0434	0.9566	2.32
67.5	433,002	955	0.0022	0.9978	2.22
68.5	432,123	341	0.0008	0.9992	2.21
69.5	431,817	566	0.0013	0.9987	2.21
70.5	431,251	12,934	0.0300	0.9700	2.21
71.5	418,317	138	0.0003	0.9997	2.14
72.5	404,592	168	0.0004	0.9996	2.14
73.5	404,424	2,962	0.0073	0.9927	2.14
74.5	401,462	173	0.0004	0.9996	2.12
75.5	131,182	1,350	0.0103	0.9897	2.12
76.5	129,832	1,838	0.0142	0.9858	2.10
77.5	127,994	649	0.0051	0.9949	2.07
78.5	127,345	8	0.0001	0.9999	2.06

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 1910-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	127,337	30	0.0002	0.9998	2.06
80.5	127,307	377	0.0030	0.9970	2.06
81.5	126,930	2,255	0.0178	0.9822	2.05
82.5	124,675		0.0000	1.0000	2.02
83.5	124,675	2,534	0.0203	0.9797	2.02
84.5	122,141		0.0000	1.0000	1.98
85.5	122,141		0.0000	1.0000	1.98
86.5	122,141		0.0000	1.0000	1.98
87.5	122,141		0.0000	1.0000	1.98
88.5	122,141		0.0000	1.0000	1.98
89.5	122,141	87	0.0007	0.9993	1.98
90.5	122,054	148	0.0012	0.9988	1.98
91.5	121,906	320	0.0026	0.9974	1.97
92.5	121,585	1,451	0.0119	0.9881	1.97
93.5	120,134	1,246	0.0104	0.9896	1.94
94.5	118,888	1,739	0.0146	0.9854	1.92
95.5	117,149	3,869	0.0330	0.9670	1.90
96.5	113,280	9,143	0.0807	0.9193	1.83
97.5	104,137	6,898	0.0662	0.9338	1.69
98.5	97,239	2,496	0.0257	0.9743	1.57
99.5	94,743	2,878	0.0304	0.9696	1.53
100.5	91,864	1,720	0.0187	0.9813	1.49
101.5	90,145	1,660	0.0184	0.9816	1.46
102.5	88,485	2,410	0.0272	0.9728	1.43
103.5	86,075	2,640	0.0307	0.9693	1.39
104.5	83,436	1,770	0.0212	0.9788	1.35
105.5	81,666	1,380	0.0169	0.9831	1.32
106.5	80,286	2,030	0.0253	0.9747	1.30
107.5	78,256	1,800	0.0230	0.9770	1.27
108.5	76,456	1,630	0.0213	0.9787	1.24
109.5	74,826	6,630	0.0886	0.9114	1.21
110.5	68,196	2,180	0.0320	0.9680	1.10
111.5	66,016	1,590	0.0241	0.9759	1.07
112.5	64,426	64,426	1.0000		1.04
113.5					

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 2004-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	107,226,344	76	0.0000	1.0000	100.00
0.5	106,202,970	21,898	0.0002	0.9998	100.00
1.5	104,435,115	268,352	0.0026	0.9974	99.98
2.5	76,931,232	476,124	0.0062	0.9938	99.72
3.5	75,637,222	334,825	0.0044	0.9956	99.11
4.5	72,215,678	862,715	0.0119	0.9881	98.67
5.5	68,324,379	688,269	0.0101	0.9899	97.49
6.5	63,401,496	453,238	0.0071	0.9929	96.51
7.5	64,480,550	551,029	0.0085	0.9915	95.82
8.5	62,298,076	884,427	0.0142	0.9858	95.00
9.5	59,742,491	1,069,422	0.0179	0.9821	93.65
10.5	56,465,285	1,847,270	0.0327	0.9673	91.97
11.5	50,884,506	2,586,072	0.0508	0.9492	88.96
12.5	49,497,743	3,805,234	0.0769	0.9231	84.44
13.5	46,950,305	3,198,204	0.0681	0.9319	77.95
14.5	44,188,877	1,307,134	0.0296	0.9704	72.64
15.5	39,518,396	1,074,609	0.0272	0.9728	70.49
16.5	33,862,944	963,233	0.0284	0.9716	68.57
17.5	27,309,121	535,508	0.0196	0.9804	66.62
18.5	27,126,843	238,226	0.0088	0.9912	65.32
19.5	24,420,312	224,263	0.0092	0.9908	64.74
20.5	21,664,331	182,813	0.0084	0.9916	64.15
21.5	20,343,417	371,575	0.0183	0.9817	63.61
22.5	19,213,560	630,497	0.0328	0.9672	62.45
23.5	17,967,240	356,400	0.0198	0.9802	60.40
24.5	16,892,186	243,933	0.0144	0.9856	59.20
25.5	15,699,043	216,313	0.0138	0.9862	58.34
26.5	14,628,396	216,629	0.0148	0.9852	57.54
27.5	13,510,255	167,645	0.0124	0.9876	56.69
28.5	12,323,498	155,555	0.0126	0.9874	55.98
29.5	11,787,370	145,521	0.0123	0.9877	55.28
30.5	11,084,371	187,496	0.0169	0.9831	54.60
31.5	10,549,200	132,332	0.0125	0.9875	53.67
32.5	10,358,507	513,676	0.0496	0.9504	53.00
33.5	9,068,859	134,452	0.0148	0.9852	50.37
34.5	8,559,817	159,779	0.0187	0.9813	49.62
35.5	8,286,583	160,875	0.0194	0.9806	48.70
36.5	8,499,660	139,438	0.0164	0.9836	47.75
37.5	7,942,258	145,828	0.0184	0.9816	46.97
38.5	7,826,422	139,021	0.0178	0.9822	46.11

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 2004-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	7,771,549	252,606	0.0325	0.9675	45.29
40.5	7,748,346	742,484	0.0958	0.9042	43.82
41.5	7,244,445	876,535	0.1210	0.8790	39.62
42.5	6,557,668	585,351	0.0893	0.9107	34.82
43.5	5,989,925	604,398	0.1009	0.8991	31.72
44.5	5,398,634	387,190	0.0717	0.9283	28.51
45.5	5,032,229	412,312	0.0819	0.9181	26.47
46.5	4,641,505	95,508	0.0206	0.9794	24.30
47.5	4,572,995	125,048	0.0273	0.9727	23.80
48.5	4,448,762	465,810	0.1047	0.8953	23.15
49.5	3,983,278	395,033	0.0992	0.9008	20.73
50.5	3,588,811	725,940	0.2023	0.7977	18.67
51.5	2,863,252	329,242	0.1150	0.8850	14.89
52.5	2,534,076	353,381	0.1395	0.8605	13.18
53.5	2,180,854	243,214	0.1115	0.8885	11.34
54.5	1,937,640	331,477	0.1711	0.8289	10.08
55.5	1,606,337	377,811	0.2352	0.7648	8.35
56.5	1,229,260	198,911	0.1618	0.8382	6.39
57.5	1,032,116	290,738	0.2817	0.7183	5.36
58.5	742,058	192,611	0.2596	0.7404	3.85
59.5	550,096	187,074	0.3401	0.6599	2.85
60.5	363,204	174,006	0.4791	0.5209	1.88
61.5	189,304	119,201	0.6297	0.3703	0.98
62.5	70,340	7,645	0.1087	0.8913	0.36
63.5	65,056	609	0.0094	0.9906	0.32
64.5	64,481	14,158	0.2196	0.7804	0.32
65.5	50,323	21,733	0.4319	0.5681	0.25
66.5	28,624	19,548	0.6829	0.3171	0.14
67.5	9,076	869	0.0957	0.9043	0.05
68.5	8,207	326	0.0397	0.9603	0.04
69.5	7,881	566	0.0718	0.9282	0.04
70.5	7,315	381	0.0521	0.9479	0.04
71.5	6,934	66	0.0095	0.9905	0.03
72.5	6,955	160	0.0230	0.9770	0.03
73.5	6,795		0.0000	1.0000	0.03
74.5	7,135	173	0.0242	0.9758	0.03
75.5	6,962	1,344	0.1930	0.8070	0.03
76.5	6,071	1,838	0.3028	0.6972	0.03
77.5	4,943	649	0.1313	0.8687	0.02
78.5	5,073	8	0.0016	0.9984	0.02

NORTHWEST NATURAL GAS COMPANY

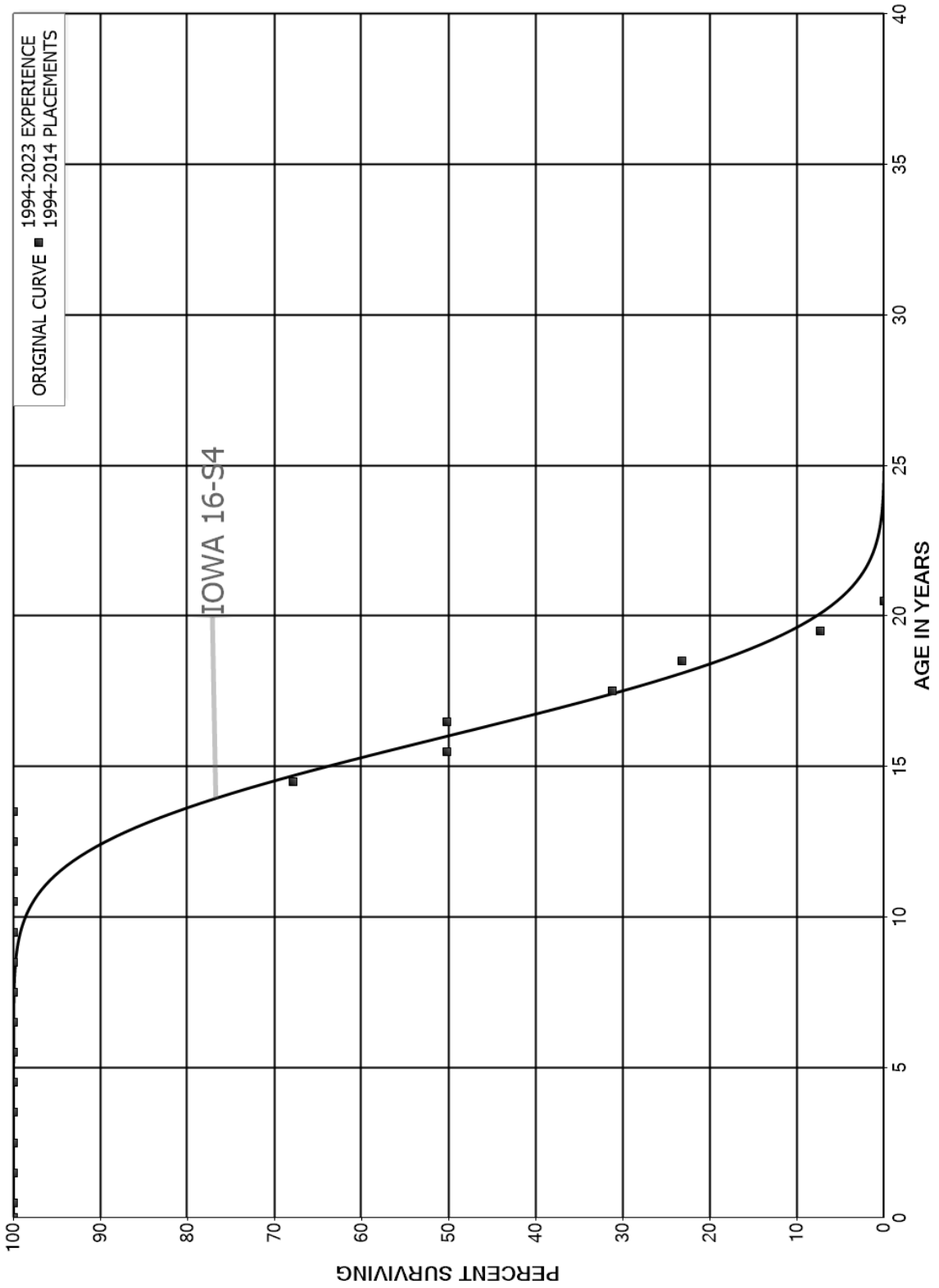
ACCOUNT 381.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 2004-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	5,533	30	0.0054	0.9946	0.02
80.5	5,919	377	0.0637	0.9363	0.02
81.5	5,542	2,255	0.4069	0.5931	0.01
82.5	3,287		0.0000	1.0000	0.01
83.5	3,326	34	0.0102	0.9898	0.01
84.5	3,292		0.0000	1.0000	0.01
85.5	3,313		0.0000	1.0000	0.01
86.5	3,313		0.0000	1.0000	0.01
87.5	3,313		0.0000	1.0000	0.01
88.5	3,370		0.0000	1.0000	0.01
89.5	3,399	87	0.0256	0.9744	0.01
90.5	3,312	148	0.0448	0.9552	0.01
91.5	3,164	320	0.1013	0.8987	0.01
92.5	2,843	1,451	0.5104	0.4896	0.01
93.5	120,134	1,246	0.0104	0.9896	0.00
94.5	118,888	1,739	0.0146	0.9854	0.00
95.5	117,149	3,869	0.0330	0.9670	0.00
96.5	113,280	9,143	0.0807	0.9193	0.00
97.5	104,137	6,898	0.0662	0.9338	0.00
98.5	97,239	2,496	0.0257	0.9743	0.00
99.5	94,743	2,878	0.0304	0.9696	0.00
100.5	91,864	1,720	0.0187	0.9813	0.00
101.5	90,145	1,660	0.0184	0.9816	0.00
102.5	88,485	2,410	0.0272	0.9728	0.00
103.5	86,075	2,640	0.0307	0.9693	0.00
104.5	83,436	1,770	0.0212	0.9788	0.00
105.5	81,666	1,380	0.0169	0.9831	0.00
106.5	80,286	2,030	0.0253	0.9747	0.00
107.5	78,256	1,800	0.0230	0.9770	0.00
108.5	76,456	1,630	0.0213	0.9787	0.00
109.5	74,826	6,630	0.0886	0.9114	0.00
110.5	68,196	2,180	0.0320	0.9680	0.00
111.5	66,016	1,590	0.0241	0.9759	0.00
112.5	64,426	64,426	1.0000		0.00
113.5					

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 381.10 METERS - ELECTRIC
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

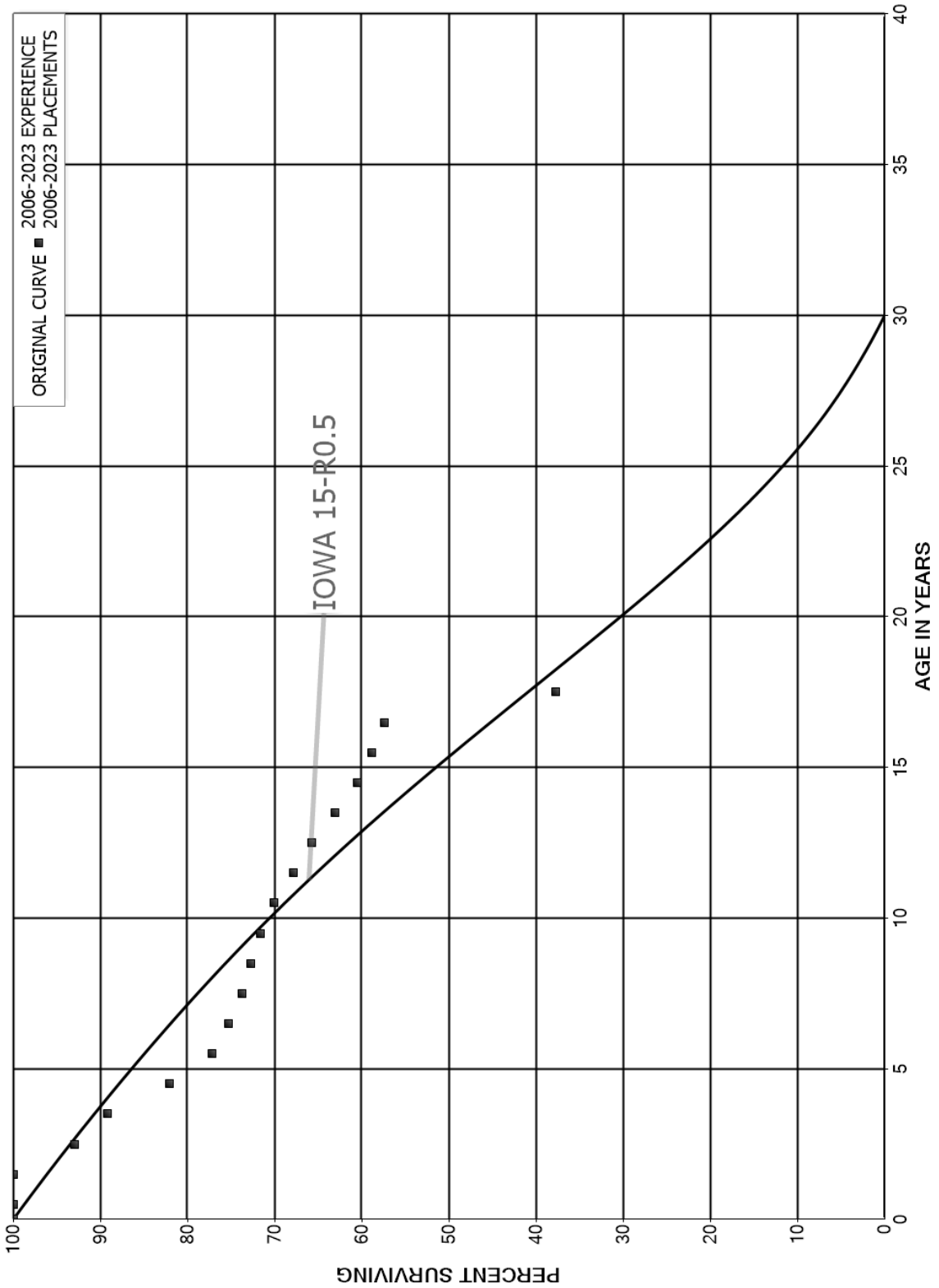
ACCOUNT 381.10 METERS - ELECTRIC

ORIGINAL LIFE TABLE

PLACEMENT BAND 1994-2014 EXPERIENCE BAND 1994-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,231,438		0.0000	1.0000	100.00
0.5	2,231,438		0.0000	1.0000	100.00
1.5	2,231,438		0.0000	1.0000	100.00
2.5	2,203,945		0.0000	1.0000	100.00
3.5	2,203,945		0.0000	1.0000	100.00
4.5	2,203,945		0.0000	1.0000	100.00
5.5	2,203,945		0.0000	1.0000	100.00
6.5	2,203,945		0.0000	1.0000	100.00
7.5	2,203,945		0.0000	1.0000	100.00
8.5	2,203,945		0.0000	1.0000	100.00
9.5	507,007		0.0000	1.0000	100.00
10.5	507,007		0.0000	1.0000	100.00
11.5	507,007		0.0000	1.0000	100.00
12.5	507,007		0.0000	1.0000	100.00
13.5	507,007	162,981	0.3215	0.6785	100.00
14.5	344,026	89,373	0.2598	0.7402	67.85
15.5	254,653		0.0000	1.0000	50.23
16.5	254,653	96,599	0.3793	0.6207	50.23
17.5	158,054	40,588	0.2568	0.7432	31.17
18.5	117,466	80,578	0.6860	0.3140	23.17
19.5	36,888	36,888	1.0000		7.28
20.5					

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 381.20 METERS - ERT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

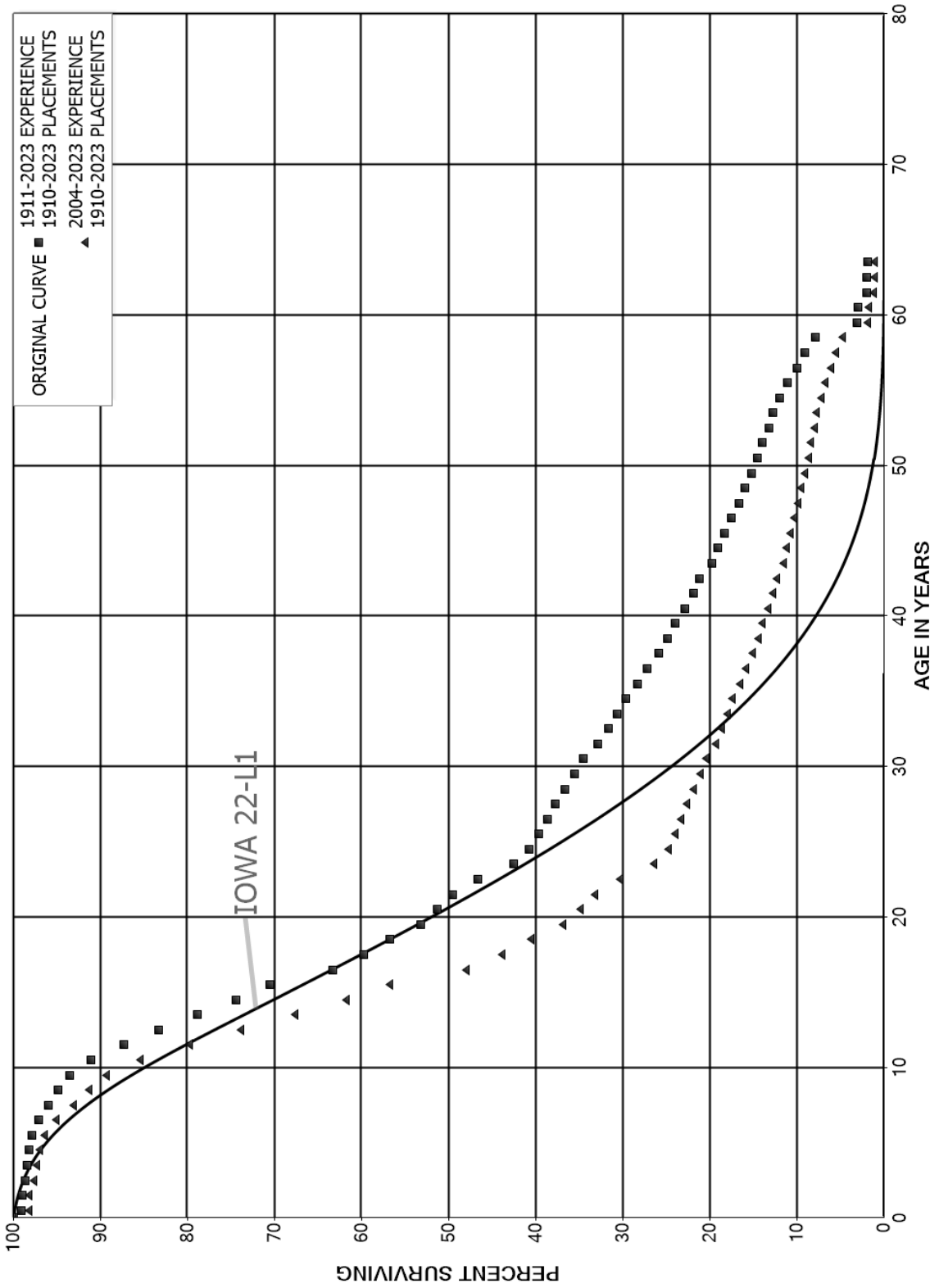
ACCOUNT 381.20 METERS - ERT

ORIGINAL LIFE TABLE

PLACEMENT BAND 2006-2023 EXPERIENCE BAND 2006-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	71,509,753		0.0000	1.0000	100.00
0.5	61,289,403	18,697	0.0003	0.9997	100.00
1.5	61,441,154	4,338,344	0.0706	0.9294	99.97
2.5	49,939,945	1,992,852	0.0399	0.9601	92.91
3.5	47,321,419	3,797,990	0.0803	0.9197	89.20
4.5	42,141,954	2,483,292	0.0589	0.9411	82.04
5.5	39,461,679	1,008,737	0.0256	0.9744	77.21
6.5	38,016,829	764,390	0.0201	0.9799	75.24
7.5	37,252,439	489,321	0.0131	0.9869	73.72
8.5	36,763,118	594,698	0.0162	0.9838	72.75
9.5	36,168,420	737,071	0.0204	0.9796	71.58
10.5	32,748,151	1,051,945	0.0321	0.9679	70.12
11.5	31,067,407	997,332	0.0321	0.9679	67.87
12.5	29,573,151	1,191,622	0.0403	0.9597	65.69
13.5	27,807,655	1,126,647	0.0405	0.9595	63.04
14.5	17,740,338	473,590	0.0267	0.9733	60.49
15.5	11,370,908	286,686	0.0252	0.9748	58.87
16.5	8,309,121	2,850,156	0.3430	0.6570	57.39
17.5					37.70

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 382.00 METER INSTALLATIONS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 1911-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	130,097,586	1,244,242	0.0096	0.9904	100.00
0.5	120,119,915	66,493	0.0006	0.9994	99.04
1.5	114,287,525	374,297	0.0033	0.9967	98.99
2.5	103,051,795	230,434	0.0022	0.9978	98.66
3.5	102,848,987	268,966	0.0026	0.9974	98.44
4.5	98,704,767	407,300	0.0041	0.9959	98.19
5.5	95,320,494	716,510	0.0075	0.9925	97.78
6.5	89,714,474	1,055,779	0.0118	0.9882	97.05
7.5	88,683,539	989,101	0.0112	0.9888	95.90
8.5	85,407,505	1,168,949	0.0137	0.9863	94.83
9.5	82,181,857	2,211,910	0.0269	0.9731	93.54
10.5	77,049,262	3,152,078	0.0409	0.9591	91.02
11.5	70,152,726	3,201,838	0.0456	0.9544	87.30
12.5	67,054,505	3,565,452	0.0532	0.9468	83.31
13.5	63,595,091	3,572,899	0.0562	0.9438	78.88
14.5	60,130,070	3,217,311	0.0535	0.9465	74.45
15.5	56,982,995	5,801,205	0.1018	0.8982	70.47
16.5	51,219,896	2,854,089	0.0557	0.9443	63.29
17.5	48,399,592	2,481,686	0.0513	0.9487	59.77
18.5	45,866,305	2,815,867	0.0614	0.9386	56.70
19.5	39,810,547	1,419,913	0.0357	0.9643	53.22
20.5	38,397,808	1,353,448	0.0352	0.9648	51.32
21.5	36,999,806	2,200,029	0.0595	0.9405	49.51
22.5	32,486,617	2,803,658	0.0863	0.9137	46.57
23.5	27,952,157	1,232,582	0.0441	0.9559	42.55
24.5	26,314,630	692,761	0.0263	0.9737	40.67
25.5	25,635,539	626,318	0.0244	0.9756	39.60
26.5	24,800,481	618,417	0.0249	0.9751	38.64
27.5	24,199,668	691,820	0.0286	0.9714	37.67
28.5	23,004,318	675,609	0.0294	0.9706	36.59
29.5	22,343,927	666,533	0.0298	0.9702	35.52
30.5	21,687,074	1,053,128	0.0486	0.9514	34.46
31.5	19,523,551	675,398	0.0346	0.9654	32.79
32.5	18,295,375	590,778	0.0323	0.9677	31.65
33.5	15,456,799	522,077	0.0338	0.9662	30.63
34.5	13,250,309	578,465	0.0437	0.9563	29.60
35.5	11,725,147	457,764	0.0390	0.9610	28.30
36.5	11,270,647	542,952	0.0482	0.9518	27.20
37.5	9,759,769	411,880	0.0422	0.9578	25.89
38.5	9,352,122	340,295	0.0364	0.9636	24.80

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 1911-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	9,018,072	411,969	0.0457	0.9543	23.89
40.5	8,209,803	332,397	0.0405	0.9595	22.80
41.5	7,439,093	255,579	0.0344	0.9656	21.88
42.5	6,360,546	415,268	0.0653	0.9347	21.13
43.5	5,341,268	187,867	0.0352	0.9648	19.75
44.5	5,163,701	214,981	0.0416	0.9584	19.05
45.5	4,464,102	192,565	0.0431	0.9569	18.26
46.5	4,283,800	205,285	0.0479	0.9521	17.47
47.5	3,877,241	156,261	0.0403	0.9597	16.64
48.5	3,727,191	178,630	0.0479	0.9521	15.96
49.5	3,402,782	156,447	0.0460	0.9540	15.20
50.5	2,980,282	119,208	0.0400	0.9600	14.50
51.5	2,225,409	111,775	0.0502	0.9498	13.92
52.5	2,062,785	78,270	0.0379	0.9621	13.22
53.5	1,796,531	110,494	0.0615	0.9385	12.72
54.5	1,687,927	121,785	0.0722	0.9278	11.94
55.5	1,283,244	131,348	0.1024	0.8976	11.08
56.5	842,799	79,013	0.0938	0.9062	9.94
57.5	658,047	86,719	0.1318	0.8682	9.01
58.5	456,831	275,319	0.6027	0.3973	7.82
59.5	168,378	10,272	0.0610	0.9390	3.11
60.5	158,278	52,494	0.3317	0.6683	2.92
61.5	105,952	2,285	0.0216	0.9784	1.95
62.5	103,690	3,218	0.0310	0.9690	1.91
63.5	97,640	4,967	0.0509	0.9491	1.85
64.5	79,765	86	0.0011	0.9989	1.76
65.5	61,565	14	0.0002	0.9998	1.75
66.5	24,110	29	0.0012	0.9988	1.75
67.5	17,941	66	0.0037	0.9963	1.75
68.5	17,889	14	0.0008	0.9992	1.74
69.5	17,882		0.0000	1.0000	1.74
70.5	17,882		0.0000	1.0000	1.74
71.5	17,882		0.0000	1.0000	1.74
72.5	17,882	7	0.0004	0.9996	1.74
73.5	17,875		0.0000	1.0000	1.74
74.5	17,875		0.0000	1.0000	1.74
75.5	17,875		0.0000	1.0000	1.74
76.5	17,875		0.0000	1.0000	1.74
77.5	17,875		0.0000	1.0000	1.74
78.5	17,875		0.0000	1.0000	1.74

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 1911-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	17,875		0.0000	1.0000	1.74
80.5	17,875		0.0000	1.0000	1.74
81.5	17,875		0.0000	1.0000	1.74
82.5	17,875		0.0000	1.0000	1.74
83.5	17,875		0.0000	1.0000	1.74
84.5	17,875		0.0000	1.0000	1.74
85.5	17,875		0.0000	1.0000	1.74
86.5	17,875		0.0000	1.0000	1.74
87.5	17,875		0.0000	1.0000	1.74
88.5	17,875		0.0000	1.0000	1.74
89.5	17,875	7	0.0004	0.9996	1.74
90.5	17,868		0.0000	1.0000	1.74
91.5	17,868		0.0000	1.0000	1.74
92.5	17,868		0.0000	1.0000	1.74
93.5	17,868	69	0.0039	0.9961	1.74
94.5	17,799	188	0.0105	0.9895	1.74
95.5	17,611	808	0.0459	0.9541	1.72
96.5	16,804	1,136	0.0676	0.9324	1.64
97.5	15,668		0.0000	1.0000	1.53
98.5	15,668	850	0.0542	0.9458	1.53
99.5	14,818	13,591	0.9172	0.0828	1.44
100.5	1,227	830	0.6762	0.3238	0.12
101.5	398	398	1.0000		0.04
102.5					

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 2004-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	62,899,572	1,232,304	0.0196	0.9804	100.00
0.5	58,766,611	13,012	0.0002	0.9998	98.04
1.5	55,713,012	289,945	0.0052	0.9948	98.02
2.5	47,480,726	179,790	0.0038	0.9962	97.51
3.5	49,945,555	182,860	0.0037	0.9963	97.14
4.5	48,632,884	272,204	0.0056	0.9944	96.78
5.5	48,532,757	654,595	0.0135	0.9865	96.24
6.5	46,383,648	972,881	0.0210	0.9790	94.94
7.5	48,830,635	907,712	0.0186	0.9814	92.95
8.5	48,231,718	1,090,095	0.0226	0.9774	91.23
9.5	47,569,561	2,093,357	0.0440	0.9560	89.16
10.5	44,863,445	2,959,877	0.0660	0.9340	85.24
11.5	40,506,233	3,002,892	0.0741	0.9259	79.62
12.5	39,898,577	3,356,486	0.0841	0.9159	73.71
13.5	39,042,564	3,390,303	0.0868	0.9132	67.51
14.5	37,802,516	3,071,325	0.0812	0.9188	61.65
15.5	36,245,289	5,661,834	0.1562	0.8438	56.64
16.5	31,549,119	2,719,185	0.0862	0.9138	47.79
17.5	30,584,734	2,319,568	0.0758	0.9242	43.67
18.5	29,243,340	2,639,132	0.0902	0.9098	40.36
19.5	24,097,792	1,288,029	0.0535	0.9465	36.72
20.5	23,417,195	1,167,044	0.0498	0.9502	34.76
21.5	23,196,777	2,023,688	0.0872	0.9128	33.02
22.5	20,421,288	2,638,565	0.1292	0.8708	30.14
23.5	17,404,905	1,073,042	0.0617	0.9383	26.25
24.5	16,817,910	550,224	0.0327	0.9673	24.63
25.5	17,195,323	479,320	0.0279	0.9721	23.82
26.5	16,933,673	504,344	0.0298	0.9702	23.16
27.5	16,800,627	567,703	0.0338	0.9662	22.47
28.5	15,841,311	531,480	0.0336	0.9664	21.71
29.5	16,008,772	532,610	0.0333	0.9667	20.98
30.5	16,072,309	886,919	0.0552	0.9448	20.28
31.5	14,948,680	535,078	0.0358	0.9642	19.17
32.5	14,360,838	472,086	0.0329	0.9671	18.48
33.5	12,005,094	399,256	0.0333	0.9667	17.87
34.5	10,168,171	487,761	0.0480	0.9520	17.28
35.5	9,197,363	382,263	0.0416	0.9584	16.45
36.5	9,263,432	473,749	0.0511	0.9489	15.77
37.5	8,198,105	359,611	0.0439	0.9561	14.96
38.5	8,222,345	299,806	0.0365	0.9635	14.30

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 2004-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	8,233,119	377,567	0.0459	0.9541	13.78
40.5	7,708,881	301,885	0.0392	0.9608	13.15
41.5	7,166,281	234,999	0.0328	0.9672	12.63
42.5	6,156,542	398,261	0.0647	0.9353	12.22
43.5	5,209,135	175,692	0.0337	0.9663	11.43
44.5	5,051,479	202,116	0.0400	0.9600	11.04
45.5	4,370,744	179,451	0.0411	0.9589	10.60
46.5	4,228,774	190,914	0.0451	0.9549	10.17
47.5	3,836,662	142,674	0.0372	0.9628	9.71
48.5	3,690,243	164,787	0.0447	0.9553	9.35
49.5	3,368,129	145,025	0.0431	0.9569	8.93
50.5	2,948,968	107,931	0.0366	0.9634	8.54
51.5	2,197,678	103,664	0.0472	0.9528	8.23
52.5	2,038,249	73,213	0.0359	0.9641	7.84
53.5	1,774,383	106,955	0.0603	0.9397	7.56
54.5	1,667,343	119,309	0.0716	0.9284	7.11
55.5	1,263,787	129,576	0.1025	0.8975	6.60
56.5	824,008	78,071	0.0947	0.9053	5.92
57.5	639,519	86,134	0.1347	0.8653	5.36
58.5	438,368	274,976	0.6273	0.3727	4.64
59.5	150,034	10,001	0.0667	0.9333	1.73
60.5	140,033	52,366	0.3740	0.6260	1.61
61.5	87,667	2,133	0.0243	0.9757	1.01
62.5	85,467	3,105	0.0363	0.9637	0.99
63.5	79,509	4,899	0.0616	0.9384	0.95
64.5	61,702		0.0000	1.0000	0.89
65.5	43,581		0.0000	1.0000	0.89
66.5	6,140		0.0000	1.0000	0.89
67.5					0.89
68.5					
69.5					
70.5					
71.5					
72.5					
73.5					
74.5					
75.5					
76.5					
77.5					
78.5					

NORTHWEST NATURAL GAS COMPANY

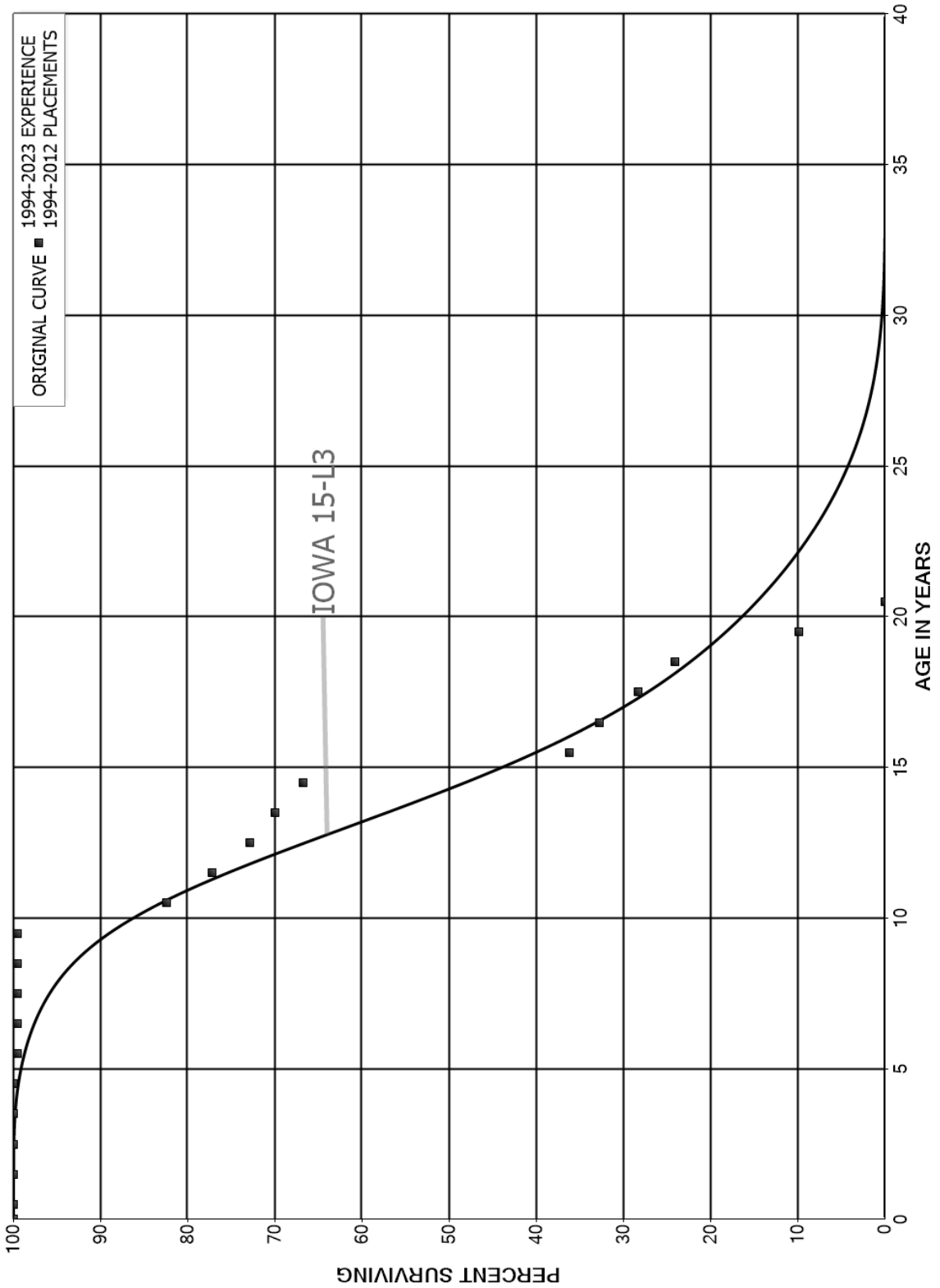
ACCOUNT 382.00 METER INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 2004-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5					
80.5	7		0.0000		
81.5	7		0.0000		
82.5	7		0.0000		
83.5	7		0.0000		
84.5	7		0.0000		
85.5	7		0.0000		
86.5	7		0.0000		
87.5	7		0.0000		
88.5	14		0.0000		
89.5	14	7	0.5000		
90.5	7		0.0000		
91.5	7		0.0000		
92.5	7		0.0000		
93.5	17,868	69	0.0039		
94.5	17,799	188	0.0105		
95.5	17,611	808	0.0459		
96.5	16,804	1,136	0.0676		
97.5	15,668		0.0000		
98.5	15,668	850	0.0542		
99.5	14,818	13,591	0.9172		
100.5	1,227	830	0.6762		
101.5	398	398	1.0000		
102.5					

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 382.10 METER INSTALLATIONS - ELECTRIC
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

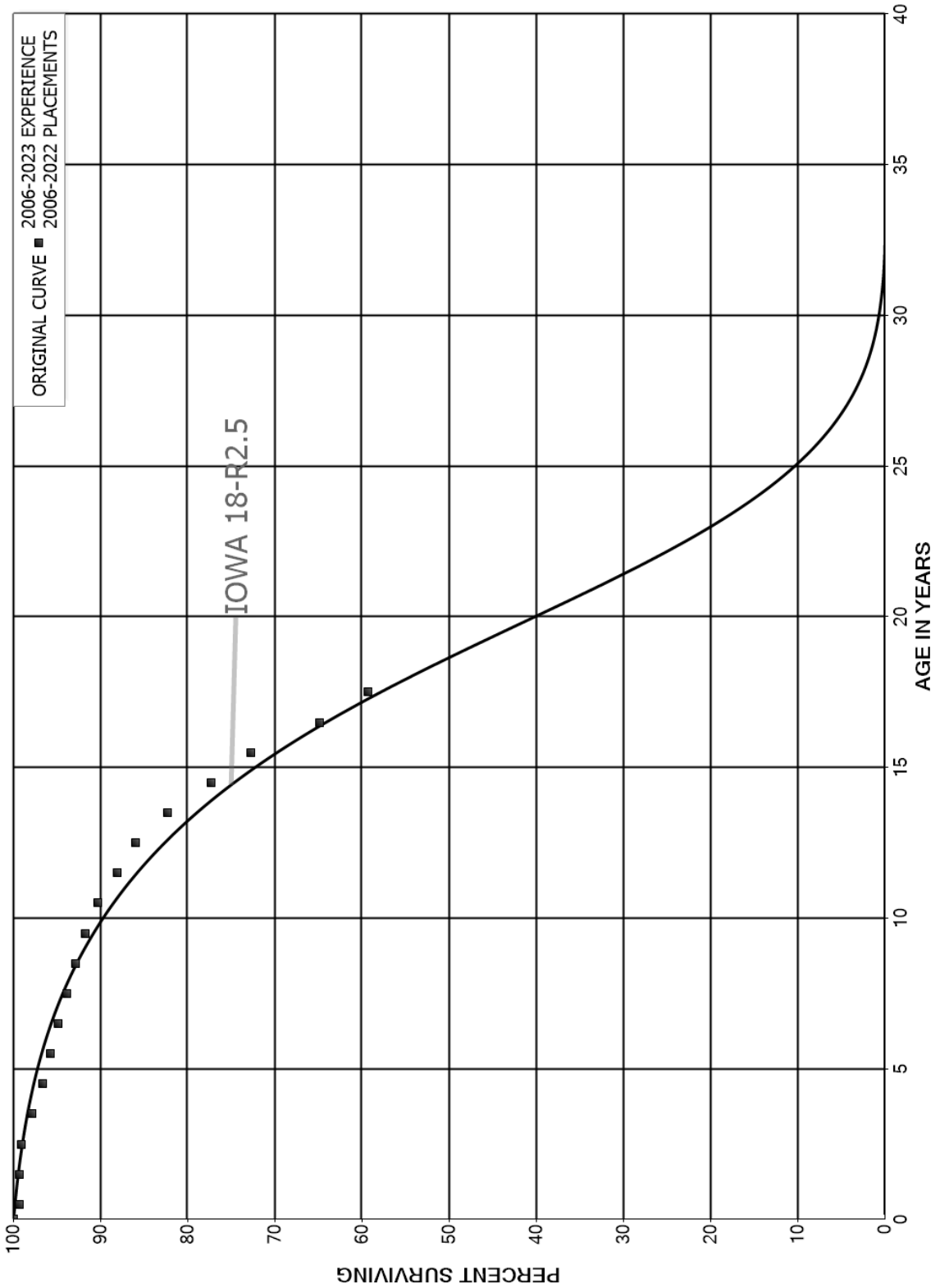
ACCOUNT 382.10 METER INSTALLATIONS - ELECTRIC

ORIGINAL LIFE TABLE

PLACEMENT BAND 1994-2012 EXPERIENCE BAND 1994-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	999,397		0.0000	1.0000	100.00
0.5	999,397		0.0000	1.0000	100.00
1.5	999,397		0.0000	1.0000	100.00
2.5	999,397		0.0000	1.0000	100.00
3.5	999,397		0.0000	1.0000	100.00
4.5	999,397	4,559	0.0046	0.9954	100.00
5.5	994,838		0.0000	1.0000	99.54
6.5	994,838		0.0000	1.0000	99.54
7.5	994,838		0.0000	1.0000	99.54
8.5	994,838		0.0000	1.0000	99.54
9.5	994,838	171,671	0.1726	0.8274	99.54
10.5	823,166	52,429	0.0637	0.9363	82.37
11.5	289,718	16,259	0.0561	0.9439	77.12
12.5	273,459	10,720	0.0392	0.9608	72.79
13.5	262,739	11,880	0.0452	0.9548	69.94
14.5	250,859	114,955	0.4582	0.5418	66.78
15.5	135,904	13,170	0.0969	0.9031	36.18
16.5	122,734	16,477	0.1342	0.8658	32.67
17.5	106,257	15,824	0.1489	0.8511	28.28
18.5	90,433	53,374	0.5902	0.4098	24.07
19.5	37,059	37,059	1.0000		9.86
20.5					

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 382.20 METER INSTALLATIONS - ERT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

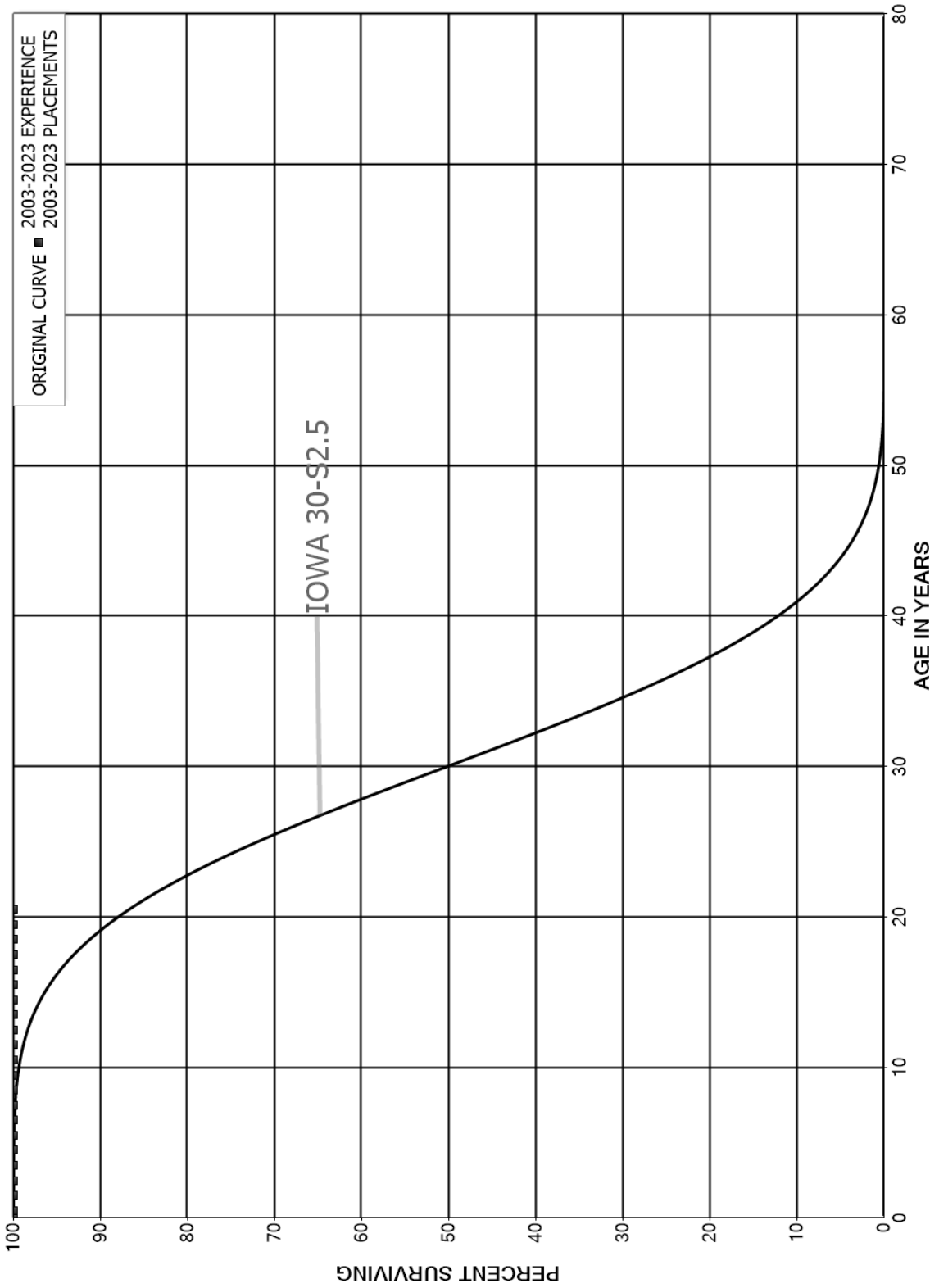
ACCOUNT 382.20 METER INSTALLATIONS - ERT

ORIGINAL LIFE TABLE

PLACEMENT BAND 2006-2022 EXPERIENCE BAND 2006-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	12,039,555	84,095	0.0070	0.9930	100.00
0.5	11,955,461	4,140	0.0003	0.9997	99.30
1.5	11,525,846	22,592	0.0020	0.9980	99.27
2.5	10,521,301	126,165	0.0120	0.9880	99.07
3.5	9,860,496	129,762	0.0132	0.9868	97.88
4.5	9,730,734	87,139	0.0090	0.9910	96.60
5.5	9,643,595	92,939	0.0096	0.9904	95.73
6.5	9,550,657	103,554	0.0108	0.9892	94.81
7.5	9,447,103	96,509	0.0102	0.9898	93.78
8.5	9,350,594	107,272	0.0115	0.9885	92.82
9.5	9,243,321	143,695	0.0155	0.9845	91.76
10.5	9,099,626	231,746	0.0255	0.9745	90.33
11.5	8,867,880	210,110	0.0237	0.9763	88.03
12.5	8,657,770	367,119	0.0424	0.9576	85.95
13.5	3,787,730	229,843	0.0607	0.9393	82.30
14.5	3,557,887	212,155	0.0596	0.9404	77.31
15.5	2,383,715	259,268	0.1088	0.8912	72.70
16.5	888,188	76,089	0.0857	0.9143	64.79
17.5					59.24

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 383.00 HOUSE REGULATORS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

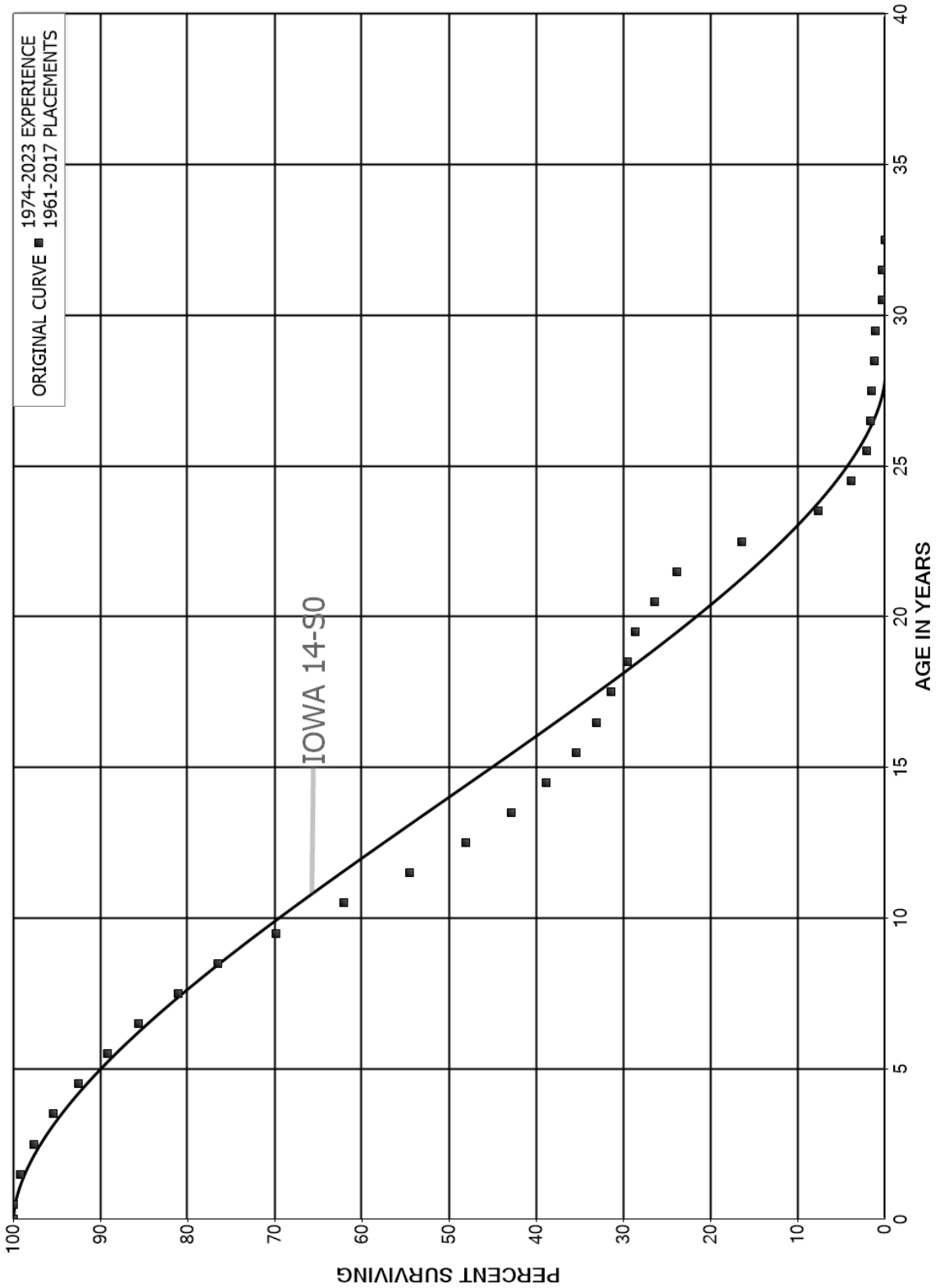
ACCOUNT 383.00 HOUSE REGULATORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 2003-2023 EXPERIENCE BAND 2003-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,244,767		0.0000	1.0000	100.00
0.5	2,822,905		0.0000	1.0000	100.00
1.5	2,679,970		0.0000	1.0000	100.00
2.5	2,553,748		0.0000	1.0000	100.00
3.5	2,419,709		0.0000	1.0000	100.00
4.5	2,199,701		0.0000	1.0000	100.00
5.5	1,877,440		0.0000	1.0000	100.00
6.5	1,678,311		0.0000	1.0000	100.00
7.5	1,495,492		0.0000	1.0000	100.00
8.5	1,280,026		0.0000	1.0000	100.00
9.5	1,115,746		0.0000	1.0000	100.00
10.5	775,208		0.0000	1.0000	100.00
11.5	619,596		0.0000	1.0000	100.00
12.5	569,858		0.0000	1.0000	100.00
13.5	487,625		0.0000	1.0000	100.00
14.5	451,511		0.0000	1.0000	100.00
15.5	369,806		0.0000	1.0000	100.00
16.5	263,639		0.0000	1.0000	100.00
17.5	163,930		0.0000	1.0000	100.00
18.5	52,920		0.0000	1.0000	100.00
19.5	1,945		0.0000	1.0000	100.00
20.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 386.00 OTHER PROPERTY ON CUSTOMERS' PREMISES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

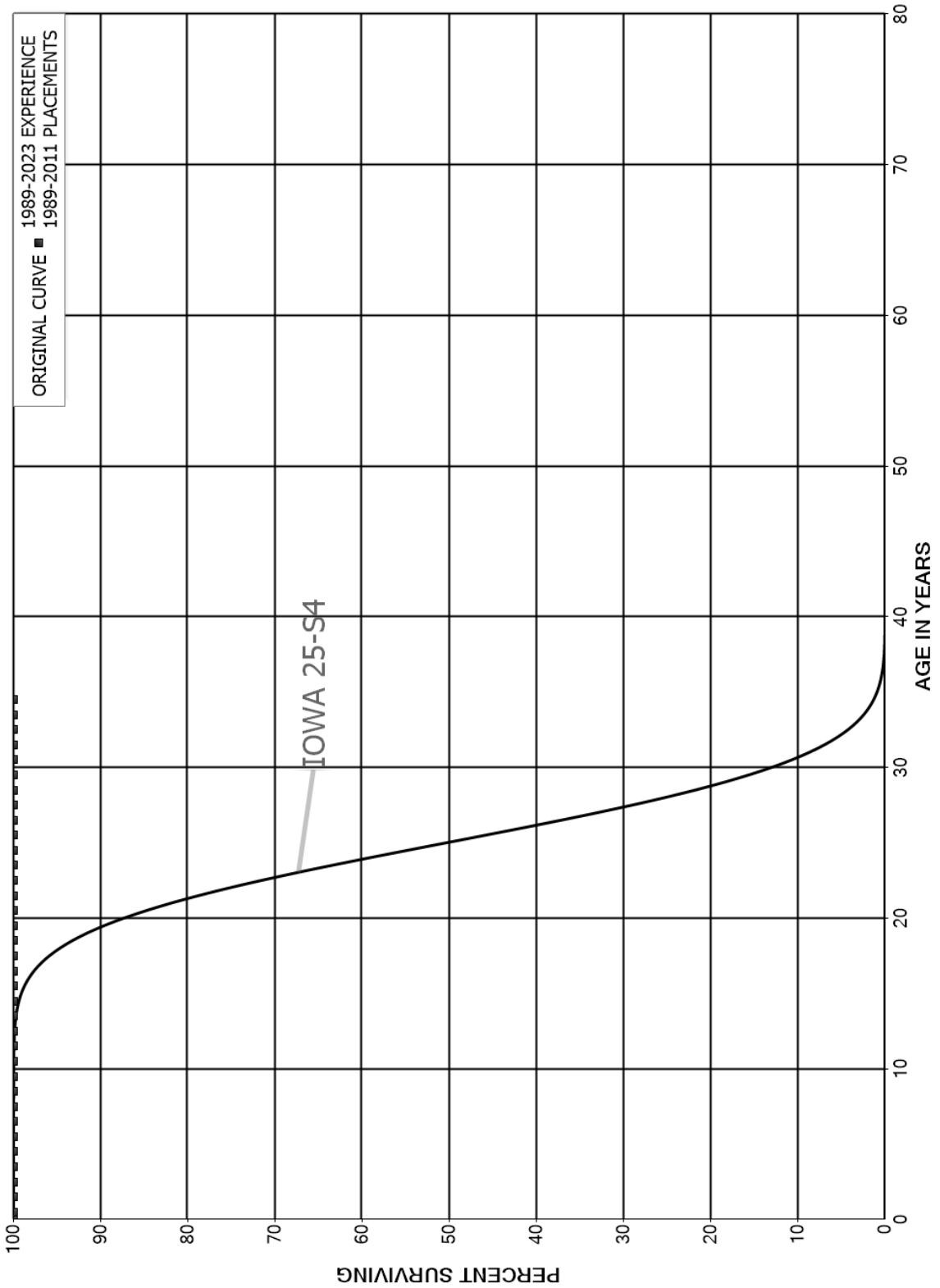
ACCOUNT 386.00 OTHER PROPERTY ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1961-2017 EXPERIENCE BAND 1974-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,442,554		0.0000	1.0000	100.00
0.5	2,043,820	17,133	0.0084	0.9916	100.00
1.5	2,911,018	45,588	0.0157	0.9843	99.16
2.5	3,930,713	90,018	0.0229	0.9771	97.61
3.5	5,088,205	152,426	0.0300	0.9700	95.37
4.5	6,142,351	224,679	0.0366	0.9634	92.52
5.5	7,031,760	281,453	0.0400	0.9600	89.13
6.5	6,777,605	355,326	0.0524	0.9476	85.56
7.5	7,568,373	425,239	0.0562	0.9438	81.08
8.5	8,085,694	711,200	0.0880	0.9120	76.52
9.5	8,043,360	891,675	0.1109	0.8891	69.79
10.5	7,630,732	922,861	0.1209	0.8791	62.06
11.5	6,973,764	826,393	0.1185	0.8815	54.55
12.5	6,219,017	674,073	0.1084	0.8916	48.09
13.5	5,544,944	528,050	0.0952	0.9048	42.87
14.5	5,016,894	437,695	0.0872	0.9128	38.79
15.5	4,579,199	303,909	0.0664	0.9336	35.41
16.5	4,275,290	217,796	0.0509	0.9491	33.06
17.5	4,057,494	242,066	0.0597	0.9403	31.37
18.5	3,815,428	116,881	0.0306	0.9694	29.50
19.5	3,698,547	285,152	0.0771	0.9229	28.60
20.5	3,413,395	337,691	0.0989	0.9011	26.39
21.5	3,075,704	950,161	0.3089	0.6911	23.78
22.5	2,125,543	1,146,559	0.5394	0.4606	16.43
23.5	978,984	479,837	0.4901	0.5099	7.57
24.5	499,147	226,905	0.4546	0.5454	3.86
25.5	272,242	66,375	0.2438	0.7562	2.11
26.5	205,867	14,758	0.0717	0.9283	1.59
27.5	191,109	38,572	0.2018	0.7982	1.48
28.5	152,537	11,751	0.0770	0.9230	1.18
29.5	140,786	97,214	0.6905	0.3095	1.09
30.5	43,572	11,751	0.2697	0.7303	0.34
31.5	31,821	31,821	1.0000		0.25
32.5					

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 387.10 OTHER EQUIPMENT - CATHODIC PROTECTION TESTING
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

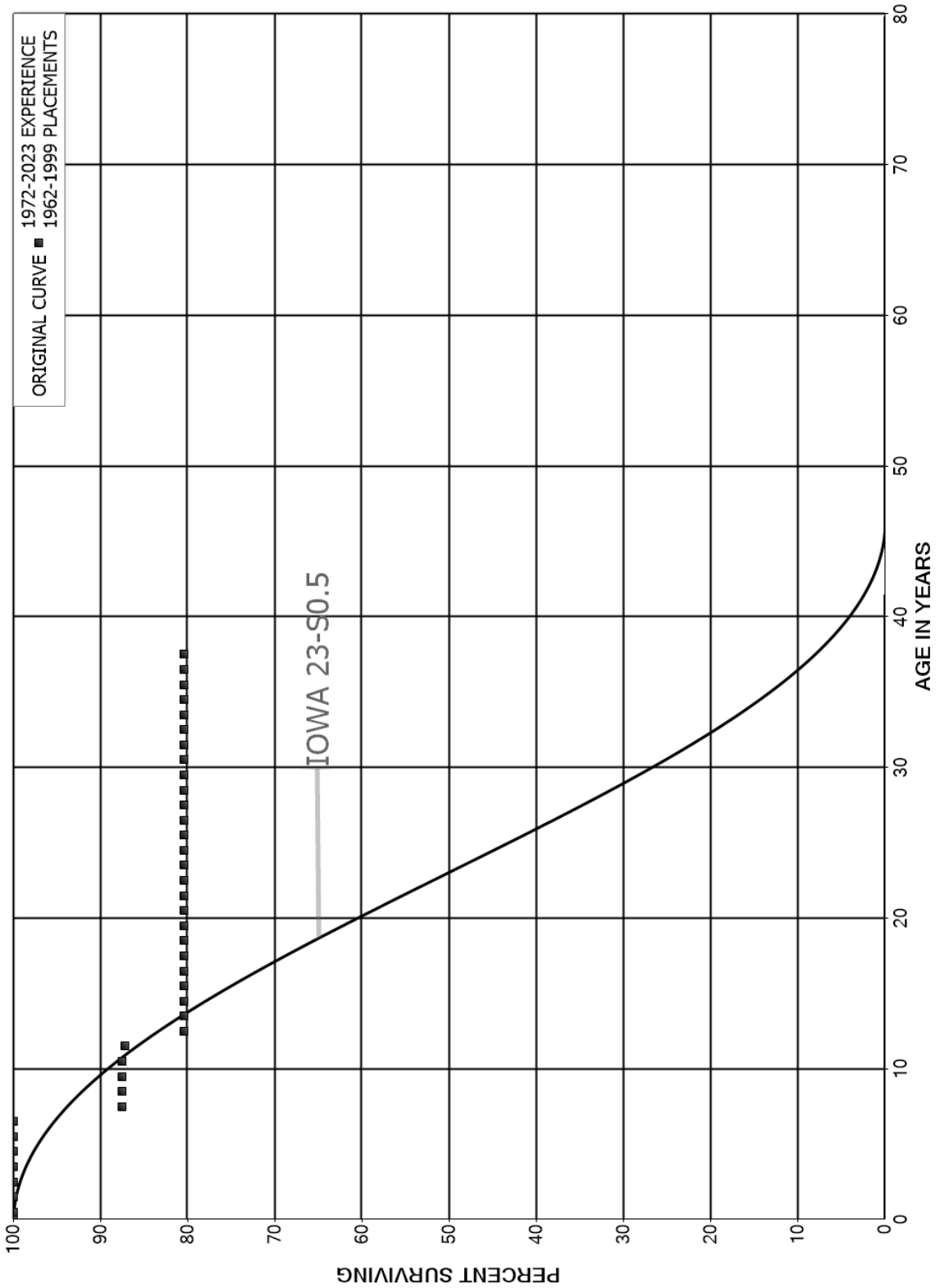
ACCOUNT 387.10 OTHER EQUIPMENT - CATHODIC PROTECTION TESTING

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2011 EXPERIENCE BAND 1989-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	173,859		0.0000	1.0000	100.00
0.5	173,859		0.0000	1.0000	100.00
1.5	173,859		0.0000	1.0000	100.00
2.5	173,859		0.0000	1.0000	100.00
3.5	173,859		0.0000	1.0000	100.00
4.5	173,859		0.0000	1.0000	100.00
5.5	173,859		0.0000	1.0000	100.00
6.5	173,859		0.0000	1.0000	100.00
7.5	173,859		0.0000	1.0000	100.00
8.5	173,859		0.0000	1.0000	100.00
9.5	173,859		0.0000	1.0000	100.00
10.5	173,859		0.0000	1.0000	100.00
11.5	173,859		0.0000	1.0000	100.00
12.5	138,950		0.0000	1.0000	100.00
13.5	138,950		0.0000	1.0000	100.00
14.5	138,950		0.0000	1.0000	100.00
15.5	138,950		0.0000	1.0000	100.00
16.5	138,950		0.0000	1.0000	100.00
17.5	138,950		0.0000	1.0000	100.00
18.5	129,084		0.0000	1.0000	100.00
19.5	129,084		0.0000	1.0000	100.00
20.5	129,084		0.0000	1.0000	100.00
21.5	129,084		0.0000	1.0000	100.00
22.5	129,084		0.0000	1.0000	100.00
23.5	129,084		0.0000	1.0000	100.00
24.5	129,084		0.0000	1.0000	100.00
25.5	129,084		0.0000	1.0000	100.00
26.5	129,084		0.0000	1.0000	100.00
27.5	129,084		0.0000	1.0000	100.00
28.5	129,084		0.0000	1.0000	100.00
29.5	129,084		0.0000	1.0000	100.00
30.5	129,084		0.0000	1.0000	100.00
31.5	46,148		0.0000	1.0000	100.00
32.5	27,929		0.0000	1.0000	100.00
33.5	18,825		0.0000	1.0000	100.00
34.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 387.20 OTHER EQUIPMENT - CALORIMETERS AT GATE STATION
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 387.20 OTHER EQUIPMENT - CALORIMETERS AT GATE STATION

ORIGINAL LIFE TABLE

PLACEMENT BAND 1962-1999 EXPERIENCE BAND 1972-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	107,454		0.0000	1.0000	100.00
0.5	107,454	25	0.0002	0.9998	100.00
1.5	107,454		0.0000	1.0000	99.98
2.5	107,454		0.0000	1.0000	99.98
3.5	107,454		0.0000	1.0000	99.98
4.5	107,454		0.0000	1.0000	99.98
5.5	107,454		0.0000	1.0000	99.98
6.5	107,454	13,401	0.1247	0.8753	99.98
7.5	107,824		0.0000	1.0000	87.51
8.5	115,988		0.0000	1.0000	87.51
9.5	116,853		0.0000	1.0000	87.51
10.5	104,958	370	0.0035	0.9965	87.51
11.5	104,588	8,164	0.0781	0.9219	87.20
12.5	96,424		0.0000	1.0000	80.39
13.5	96,424		0.0000	1.0000	80.39
14.5	96,424		0.0000	1.0000	80.39
15.5	96,424		0.0000	1.0000	80.39
16.5	96,424		0.0000	1.0000	80.39
17.5	96,424		0.0000	1.0000	80.39
18.5	96,424		0.0000	1.0000	80.39
19.5	96,424		0.0000	1.0000	80.39
20.5	96,424		0.0000	1.0000	80.39
21.5	96,424		0.0000	1.0000	80.39
22.5	96,424		0.0000	1.0000	80.39
23.5	96,424		0.0000	1.0000	80.39
24.5	93,709		0.0000	1.0000	80.39
25.5	89,269		0.0000	1.0000	80.39
26.5	76,317		0.0000	1.0000	80.39
27.5	73,945		0.0000	1.0000	80.39
28.5	71,691		0.0000	1.0000	80.39
29.5	64,033		0.0000	1.0000	80.39
30.5	59,167		0.0000	1.0000	80.39
31.5	59,167		0.0000	1.0000	80.39
32.5	37,876		0.0000	1.0000	80.39
33.5	37,624		0.0000	1.0000	80.39
34.5	37,624		0.0000	1.0000	80.39
35.5	37,624		0.0000	1.0000	80.39
36.5	37,624		0.0000	1.0000	80.39
37.5	11,859		0.0000	1.0000	80.39
38.5	11,859		0.0000	1.0000	80.39

NORTHWEST NATURAL GAS COMPANY

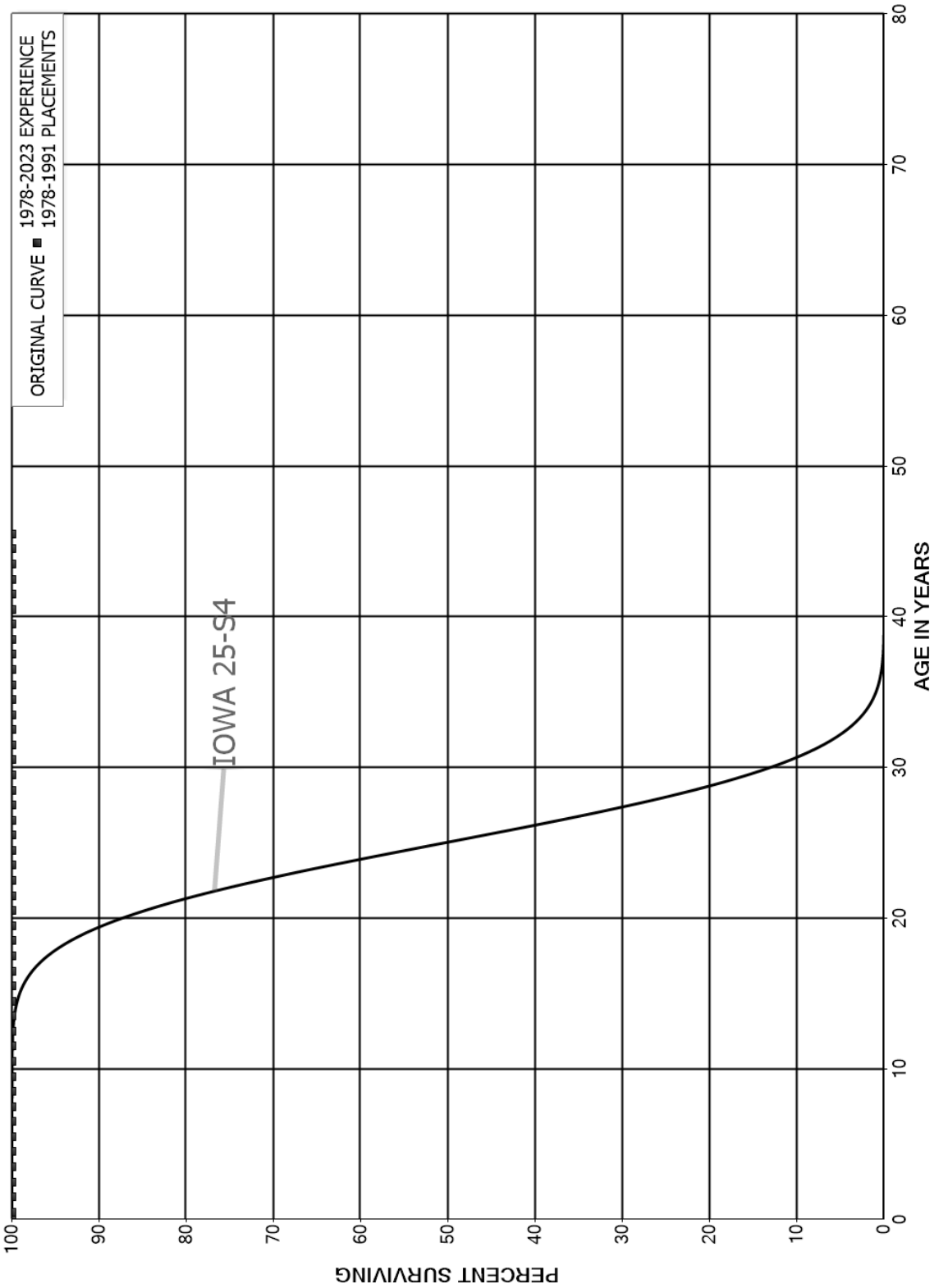
ACCOUNT 387.20 OTHER EQUIPMENT - CALORIMETERS AT GATE STATION

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1962-1999 EXPERIENCE BAND 1972-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	11,859		0.0000	1.0000	80.39
40.5	11,859		0.0000	1.0000	80.39
41.5	11,859		0.0000	1.0000	80.39
42.5	11,859		0.0000	1.0000	80.39
43.5	11,859		0.0000	1.0000	80.39
44.5	11,859		0.0000	1.0000	80.39
45.5	11,859		0.0000	1.0000	80.39
46.5	11,859		0.0000	1.0000	80.39
47.5	11,859		0.0000	1.0000	80.39
48.5	11,859		0.0000	1.0000	80.39
49.5	11,859		0.0000	1.0000	80.39
50.5	11,859		0.0000	1.0000	80.39
51.5	865		0.0000	1.0000	80.39
52.5	865		0.0000	1.0000	80.39
53.5	865		0.0000	1.0000	80.39
54.5	865		0.0000	1.0000	80.39
55.5	865		0.0000	1.0000	80.39
56.5	865		0.0000	1.0000	80.39
57.5	865		0.0000	1.0000	80.39
58.5	865		0.0000	1.0000	80.39
59.5	865		0.0000	1.0000	80.39
60.5	865		0.0000	1.0000	80.39
61.5					80.39

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 387.30 OTHER EQUIPMENT - METER TESTING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 387.30 OTHER EQUIPMENT - METER TESTING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1978-1991 EXPERIENCE BAND 1978-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	60,776		0.0000	1.0000	100.00
0.5	60,776		0.0000	1.0000	100.00
1.5	60,776		0.0000	1.0000	100.00
2.5	60,776		0.0000	1.0000	100.00
3.5	60,776		0.0000	1.0000	100.00
4.5	60,776		0.0000	1.0000	100.00
5.5	60,776		0.0000	1.0000	100.00
6.5	60,776		0.0000	1.0000	100.00
7.5	60,776		0.0000	1.0000	100.00
8.5	60,776		0.0000	1.0000	100.00
9.5	60,776		0.0000	1.0000	100.00
10.5	72,671		0.0000	1.0000	100.00
11.5	72,671		0.0000	1.0000	100.00
12.5	72,671		0.0000	1.0000	100.00
13.5	72,671		0.0000	1.0000	100.00
14.5	72,671		0.0000	1.0000	100.00
15.5	72,671		0.0000	1.0000	100.00
16.5	72,671		0.0000	1.0000	100.00
17.5	72,671		0.0000	1.0000	100.00
18.5	72,671		0.0000	1.0000	100.00
19.5	72,671		0.0000	1.0000	100.00
20.5	72,671		0.0000	1.0000	100.00
21.5	72,671		0.0000	1.0000	100.00
22.5	72,671		0.0000	1.0000	100.00
23.5	72,671		0.0000	1.0000	100.00
24.5	72,671		0.0000	1.0000	100.00
25.5	72,671		0.0000	1.0000	100.00
26.5	72,671		0.0000	1.0000	100.00
27.5	72,671		0.0000	1.0000	100.00
28.5	72,671		0.0000	1.0000	100.00
29.5	72,671		0.0000	1.0000	100.00
30.5	72,671		0.0000	1.0000	100.00
31.5	72,671		0.0000	1.0000	100.00
32.5	60,776		0.0000	1.0000	100.00
33.5	60,170		0.0000	1.0000	100.00
34.5	60,170		0.0000	1.0000	100.00
35.5	60,170		0.0000	1.0000	100.00
36.5	58,537		0.0000	1.0000	100.00
37.5	57,190		0.0000	1.0000	100.00
38.5	16,792		0.0000	1.0000	100.00

NORTHWEST NATURAL GAS COMPANY

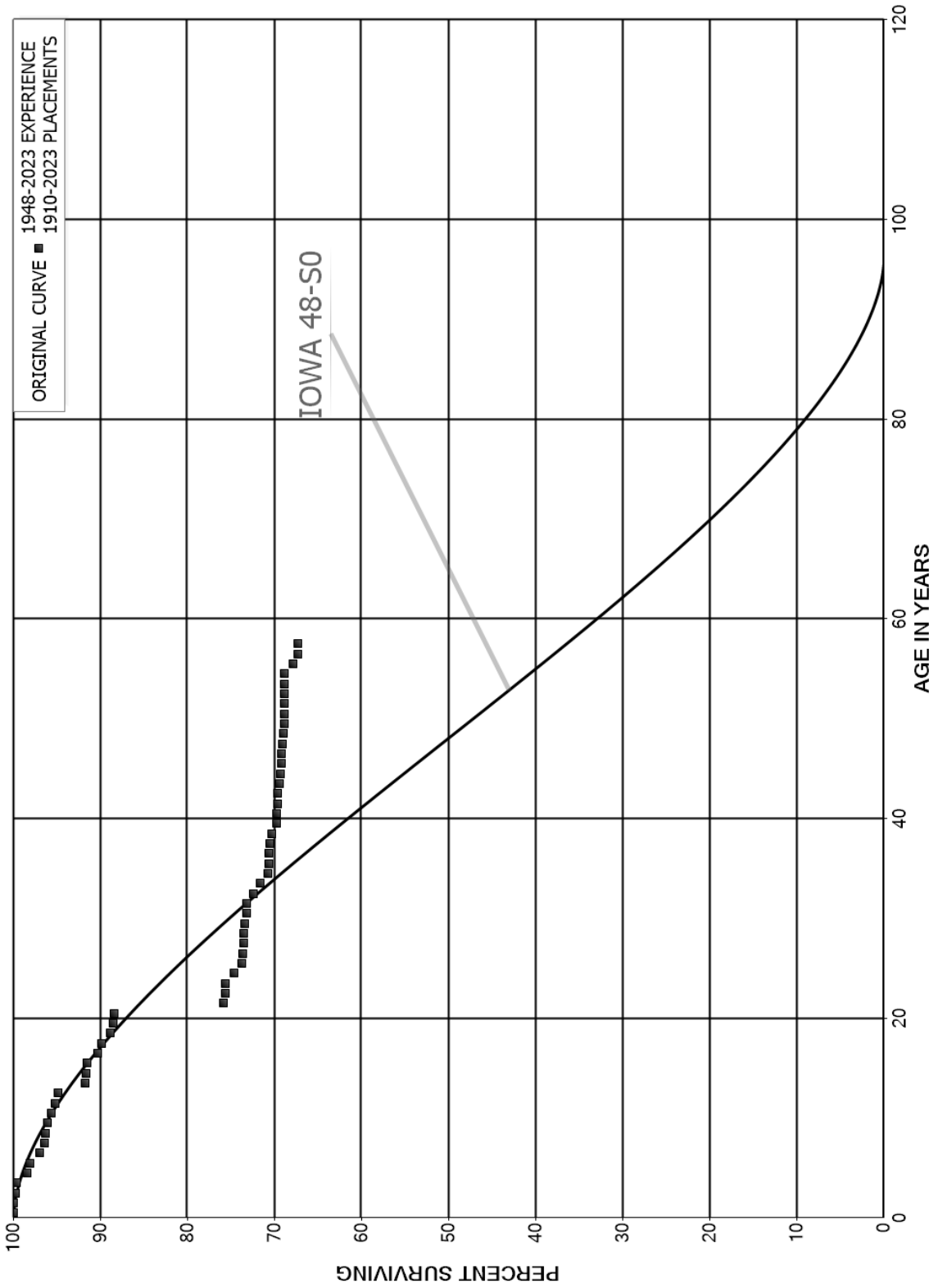
ACCOUNT 387.30 OTHER EQUIPMENT - METER TESTING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1978-1991 EXPERIENCE BAND 1978-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	15,567		0.0000	1.0000	100.00
40.5	15,567		0.0000	1.0000	100.00
41.5	15,567		0.0000	1.0000	100.00
42.5	15,567		0.0000	1.0000	100.00
43.5	15,567		0.0000	1.0000	100.00
44.5	6,819		0.0000	1.0000	100.00
45.5					100.00

NORTHWEST NATURAL GAS COMPANY
ACCOUNTS 390.00 AND 390.10 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 390.00 AND 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 1948-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	185,507,854	39,299	0.0002	0.9998	100.00
0.5	174,467,479	63,712	0.0004	0.9996	99.98
1.5	147,249,495	278,632	0.0019	0.9981	99.94
2.5	111,216,870	192,359	0.0017	0.9983	99.75
3.5	109,531,844	1,337,593	0.0122	0.9878	99.58
4.5	104,970,230	300,827	0.0029	0.9971	98.36
5.5	92,754,025	1,097,379	0.0118	0.9882	98.08
6.5	90,954,613	475,026	0.0052	0.9948	96.92
7.5	86,655,231	126,822	0.0015	0.9985	96.42
8.5	84,369,484	163,031	0.0019	0.9981	96.27
9.5	73,684,194	393,305	0.0053	0.9947	96.09
10.5	39,359,139	154,142	0.0039	0.9961	95.58
11.5	30,336,991	99,411	0.0033	0.9967	95.20
12.5	26,296,254	873,148	0.0332	0.9668	94.89
13.5	24,644,700	38,768	0.0016	0.9984	91.74
14.5	23,891,392	24,337	0.0010	0.9990	91.59
15.5	23,549,321	317,423	0.0135	0.9865	91.50
16.5	22,787,234	100,550	0.0044	0.9956	90.27
17.5	20,868,782	246,103	0.0118	0.9882	89.87
18.5	19,253,697	69,123	0.0036	0.9964	88.81
19.5	14,642,704	23,841	0.0016	0.9984	88.49
20.5	12,979,613	1,843,884	0.1421	0.8579	88.35
21.5	10,603,372	27,089	0.0026	0.9974	75.80
22.5	9,716,130	4	0.0000	1.0000	75.60
23.5	9,310,212	118,594	0.0127	0.9873	75.60
24.5	8,764,638	110,670	0.0126	0.9874	74.64
25.5	8,165,699	11,605	0.0014	0.9986	73.70
26.5	7,805,416	9,618	0.0012	0.9988	73.59
27.5	7,699,600	3,094	0.0004	0.9996	73.50
28.5	7,666,084	2,415	0.0003	0.9997	73.47
29.5	7,650,338	27,872	0.0036	0.9964	73.45
30.5	7,473,141	6,135	0.0008	0.9992	73.18
31.5	7,212,551	70,812	0.0098	0.9902	73.12
32.5	7,010,712	74,315	0.0106	0.9894	72.40
33.5	6,766,260	84,148	0.0124	0.9876	71.64
34.5	6,520,415	7,153	0.0011	0.9989	70.75
35.5	6,435,276	5,915	0.0009	0.9991	70.67
36.5	6,319,990	6,901	0.0011	0.9989	70.60
37.5	6,133,575	18,930	0.0031	0.9969	70.53
38.5	6,047,497	53,995	0.0089	0.9911	70.31

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 390.00 AND 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 1948-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	5,847,725	710	0.0001	0.9999	69.68
40.5	5,557,270	3,798	0.0007	0.9993	69.67
41.5	5,299,850	3,567	0.0007	0.9993	69.62
42.5	4,935,188	9,794	0.0020	0.9980	69.58
43.5	4,835,673	12,969	0.0027	0.9973	69.44
44.5	4,788,883	8,014	0.0017	0.9983	69.25
45.5	3,982,147	786	0.0002	0.9998	69.14
46.5	2,901,848	4,086	0.0014	0.9986	69.12
47.5	2,226,866	622	0.0003	0.9997	69.03
48.5	2,191,007	3,943	0.0018	0.9982	69.01
49.5	1,777,154	450	0.0003	0.9997	68.88
50.5	1,545,146	28	0.0000	1.0000	68.87
51.5	1,463,047		0.0000	1.0000	68.86
52.5	1,440,548		0.0000	1.0000	68.86
53.5	1,428,160	418	0.0003	0.9997	68.86
54.5	1,403,802	20,908	0.0149	0.9851	68.84
55.5	1,328,620	10,091	0.0076	0.9924	67.82
56.5	1,295,002	558	0.0004	0.9996	67.30
57.5	642,291	3,476	0.0054	0.9946	67.27
58.5	369,608		0.0000	1.0000	66.91
59.5	239,103	435	0.0018	0.9982	66.91
60.5	231,368		0.0000	1.0000	66.79
61.5	226,079		0.0000	1.0000	66.79
62.5	219,077		0.0000	1.0000	66.79
63.5	216,762		0.0000	1.0000	66.79
64.5	264,704	38,544	0.1456	0.8544	66.79
65.5	223,904	9,030	0.0403	0.9597	57.06
66.5	211,055		0.0000	1.0000	54.76
67.5	164,997		0.0000	1.0000	54.76
68.5	147,143	8,917	0.0606	0.9394	54.76
69.5	138,163		0.0000	1.0000	51.44
70.5	126,631		0.0000	1.0000	51.44
71.5	97,411		0.0000	1.0000	51.44
72.5	87,330		0.0000	1.0000	51.44
73.5	87,082		0.0000	1.0000	51.44
74.5	78,739		0.0000	1.0000	51.44
75.5	75,677		0.0000	1.0000	51.44
76.5	68,896		0.0000	1.0000	51.44
77.5	68,703		0.0000	1.0000	51.44
78.5	67,941		0.0000	1.0000	51.44

NORTHWEST NATURAL GAS COMPANY

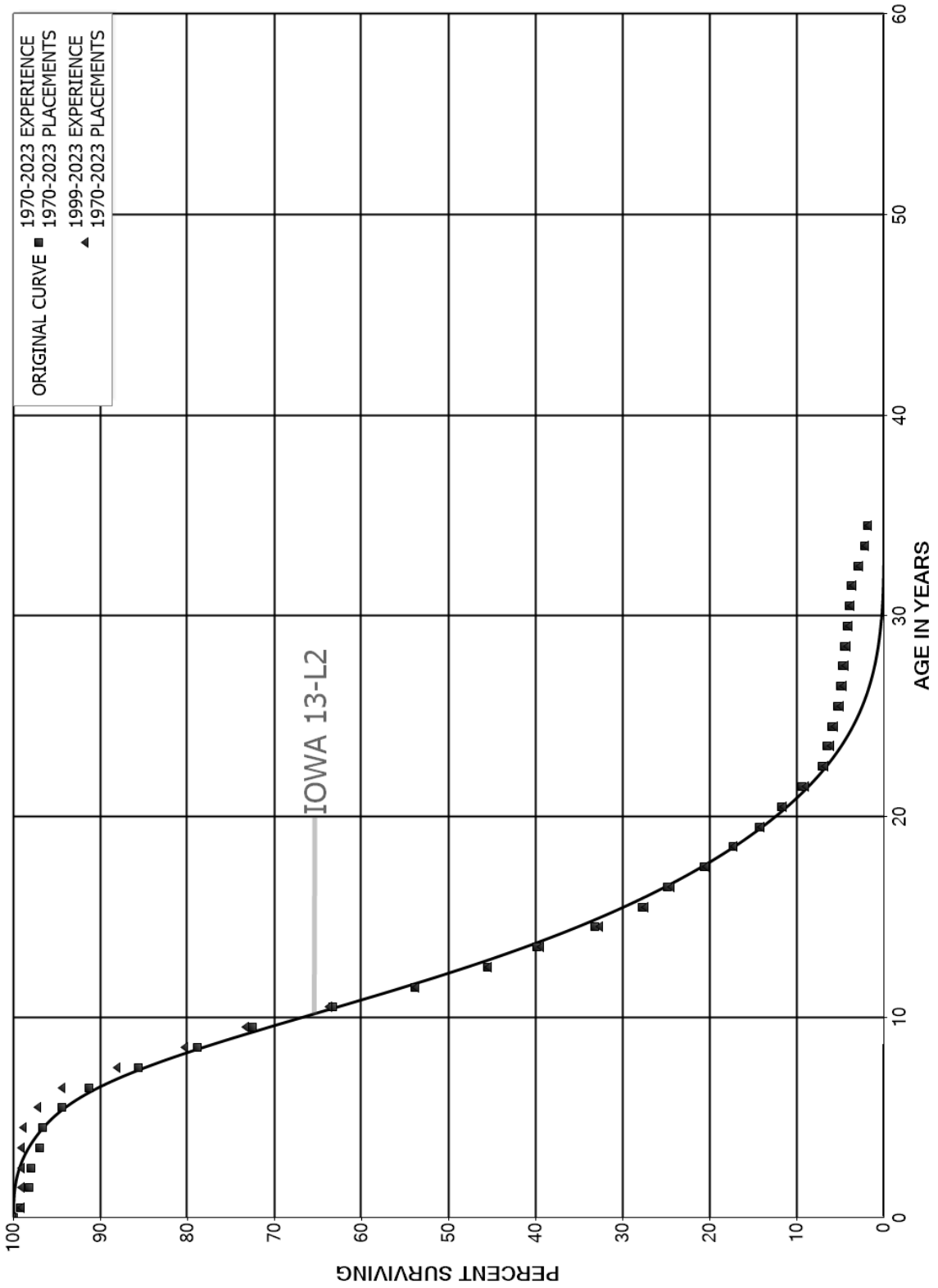
ACCOUNTS 390.00 AND 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2023 EXPERIENCE BAND 1948-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	67,910		0.0000	1.0000	51.44
80.5	64,852		0.0000	1.0000	51.44
81.5	64,341		0.0000	1.0000	51.44
82.5	62,997		0.0000	1.0000	51.44
83.5	62,902		0.0000	1.0000	51.44
84.5	62,795		0.0000	1.0000	51.44
85.5	61,850	416	0.0067	0.9933	51.44
86.5	61,198		0.0000	1.0000	51.10
87.5	61,165		0.0000	1.0000	51.10
88.5	61,165		0.0000	1.0000	51.10
89.5	61,165		0.0000	1.0000	51.10
90.5	61,165		0.0000	1.0000	51.10
91.5	61,165	4,535	0.0741	0.9259	51.10
92.5	56,630		0.0000	1.0000	47.31
93.5	56,453		0.0000	1.0000	47.31
94.5	56,453	5,153	0.0913	0.9087	47.31
95.5	51,300		0.0000	1.0000	42.99
96.5	50,755		0.0000	1.0000	42.99
97.5	50,755		0.0000	1.0000	42.99
98.5	50,663		0.0000	1.0000	42.99
99.5	50,652		0.0000	1.0000	42.99
100.5	50,585		0.0000	1.0000	42.99
101.5	50,075		0.0000	1.0000	42.99
102.5	50,075		0.0000	1.0000	42.99
103.5	49,651		0.0000	1.0000	42.99
104.5	49,651		0.0000	1.0000	42.99
105.5	49,651		0.0000	1.0000	42.99
106.5	49,651		0.0000	1.0000	42.99
107.5	49,651		0.0000	1.0000	42.99
108.5	49,479		0.0000	1.0000	42.99
109.5	49,479		0.0000	1.0000	42.99
110.5					42.99

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 392.00 TRANSPORTATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1970-2023 EXPERIENCE BAND 1970-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	103,000,891	810,292	0.0079	0.9921	100.00
0.5	101,168,447	1,043,743	0.0103	0.9897	99.21
1.5	97,763,703	277,244	0.0028	0.9972	98.19
2.5	93,409,406	913,832	0.0098	0.9902	97.91
3.5	87,539,201	295,923	0.0034	0.9966	96.95
4.5	79,760,292	1,864,246	0.0234	0.9766	96.63
5.5	51,640,698	1,679,914	0.0325	0.9675	94.37
6.5	49,790,256	3,081,630	0.0619	0.9381	91.30
7.5	46,517,221	3,726,898	0.0801	0.9199	85.65
8.5	42,567,044	3,415,602	0.0802	0.9198	78.78
9.5	37,075,615	4,714,481	0.1272	0.8728	72.46
10.5	28,544,623	4,248,575	0.1488	0.8512	63.25
11.5	21,358,720	3,296,502	0.1543	0.8457	53.83
12.5	17,333,847	2,181,678	0.1259	0.8741	45.53
13.5	13,505,141	2,237,165	0.1657	0.8343	39.80
14.5	10,983,785	1,824,552	0.1661	0.8339	33.20
15.5	8,613,411	895,995	0.1040	0.8960	27.69
16.5	7,468,788	1,277,769	0.1711	0.8289	24.81
17.5	6,129,743	972,045	0.1586	0.8414	20.56
18.5	5,092,789	895,469	0.1758	0.8242	17.30
19.5	3,851,531	670,605	0.1741	0.8259	14.26
20.5	2,966,297	613,790	0.2069	0.7931	11.78
21.5	2,270,208	553,251	0.2437	0.7563	9.34
22.5	1,649,730	137,289	0.0832	0.9168	7.06
23.5	1,489,505	113,735	0.0764	0.9236	6.48
24.5	1,235,428	146,339	0.1185	0.8815	5.98
25.5	971,230	70,523	0.0726	0.9274	5.27
26.5	865,547	34,821	0.0402	0.9598	4.89
27.5	741,361	30,978	0.0418	0.9582	4.69
28.5	579,963	42,868	0.0739	0.9261	4.50
29.5	414,518	19,394	0.0468	0.9532	4.17
30.5	399,466	20,433	0.0512	0.9488	3.97
31.5	379,033	86,154	0.2273	0.7727	3.77
32.5	283,033	73,243	0.2588	0.7412	2.91
33.5	209,790	32,157	0.1533	0.8467	2.16
34.5	147,565	6,956	0.0471	0.9529	1.83
35.5	140,028	12,235	0.0874	0.9126	1.74
36.5	127,793		0.0000	1.0000	1.59
37.5	127,793	9,128	0.0714	0.9286	1.59
38.5	118,665	9,517	0.0802	0.9198	1.48

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1970-2023 EXPERIENCE BAND 1970-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	106,804	3,518	0.0329	0.9671	1.36
40.5	75,940		0.0000	1.0000	1.31
41.5	75,940		0.0000	1.0000	1.31
42.5	75,940		0.0000	1.0000	1.31
43.5	75,940		0.0000	1.0000	1.31
44.5	75,940		0.0000	1.0000	1.31
45.5	75,940		0.0000	1.0000	1.31
46.5	75,940		0.0000	1.0000	1.31
47.5	69,477		0.0000	1.0000	1.31
48.5	69,477		0.0000	1.0000	1.31
49.5	69,477		0.0000	1.0000	1.31
50.5	69,477		0.0000	1.0000	1.31
51.5					1.31

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1970-2023 EXPERIENCE BAND 1999-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	79,345,235	810,292	0.0102	0.9898	100.00
0.5	79,846,496		0.0000	1.0000	98.98
1.5	80,046,168	21,443	0.0003	0.9997	98.98
2.5	78,316,136	43,927	0.0006	0.9994	98.95
3.5	75,002,739	104,526	0.0014	0.9986	98.90
4.5	69,518,649	1,190,138	0.0171	0.9829	98.76
5.5	43,748,678	1,275,411	0.0292	0.9708	97.07
6.5	42,861,155	2,841,718	0.0663	0.9337	94.24
7.5	40,951,949	3,621,172	0.0884	0.9116	87.99
8.5	38,042,090	3,311,277	0.0870	0.9130	80.21
9.5	33,370,336	4,389,400	0.1315	0.8685	73.23
10.5	25,660,027	4,032,763	0.1572	0.8428	63.60
11.5	19,103,052	2,954,460	0.1547	0.8453	53.60
12.5	15,423,125	2,068,291	0.1341	0.8659	45.31
13.5	12,200,248	2,099,737	0.1721	0.8279	39.23
14.5	10,023,164	1,615,406	0.1612	0.8388	32.48
15.5	7,968,568	855,914	0.1074	0.8926	27.25
16.5	6,964,791	1,162,181	0.1669	0.8331	24.32
17.5	5,791,366	922,320	0.1593	0.8407	20.26
18.5	4,881,498	895,469	0.1834	0.8166	17.04
19.5	3,660,170	670,605	0.1832	0.8168	13.91
20.5	2,802,334	613,790	0.2190	0.7810	11.36
21.5	2,131,096	553,251	0.2596	0.7404	8.87
22.5	1,517,081	137,289	0.0905	0.9095	6.57
23.5	1,356,856	100,018	0.0737	0.9263	5.98
24.5	1,146,564	143,962	0.1256	0.8744	5.53
25.5	884,743	70,523	0.0797	0.9203	4.84
26.5	851,350	34,821	0.0409	0.9591	4.45
27.5	731,844	30,978	0.0423	0.9577	4.27
28.5	579,963	42,868	0.0739	0.9261	4.09
29.5	414,518	19,394	0.0468	0.9532	3.79
30.5	399,466	20,433	0.0512	0.9488	3.61
31.5	379,033	86,154	0.2273	0.7727	3.43
32.5	283,033	73,243	0.2588	0.7412	2.65
33.5	209,790	32,157	0.1533	0.8467	1.96
34.5	147,565	6,956	0.0471	0.9529	1.66
35.5	140,028	12,235	0.0874	0.9126	1.58
36.5	127,793		0.0000	1.0000	1.45
37.5	127,793	9,128	0.0714	0.9286	1.45
38.5	118,665	9,517	0.0802	0.9198	1.34

NORTHWEST NATURAL GAS COMPANY

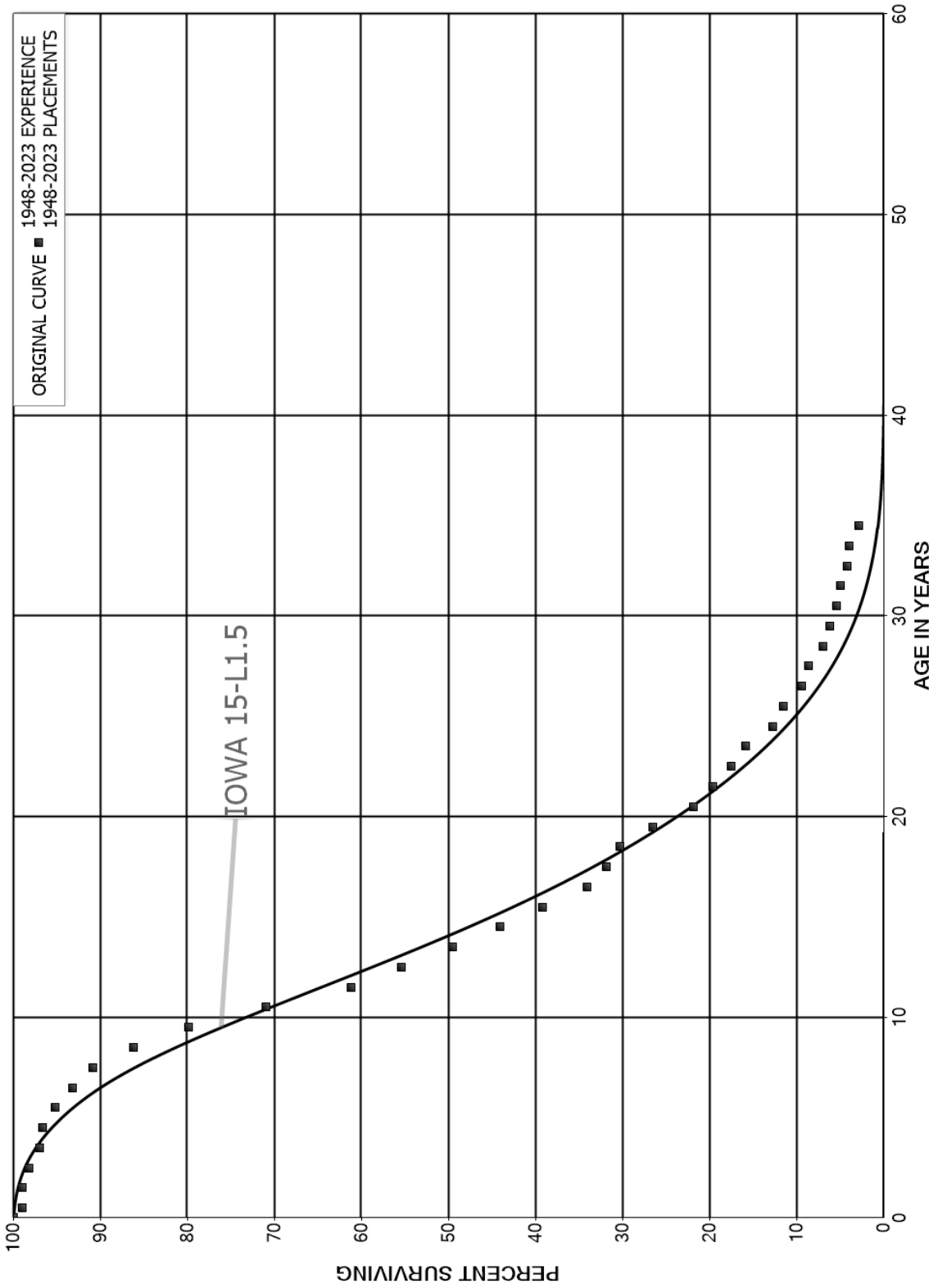
ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1970-2023 EXPERIENCE BAND 1999-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	106,804	3,518	0.0329	0.9671	1.23
40.5	75,940		0.0000	1.0000	1.19
41.5	75,940		0.0000	1.0000	1.19
42.5	75,940		0.0000	1.0000	1.19
43.5	75,940		0.0000	1.0000	1.19
44.5	75,940		0.0000	1.0000	1.19
45.5	75,940		0.0000	1.0000	1.19
46.5	75,940		0.0000	1.0000	1.19
47.5	69,477		0.0000	1.0000	1.19
48.5	69,477		0.0000	1.0000	1.19
49.5	69,477		0.0000	1.0000	1.19
50.5	69,477		0.0000	1.0000	1.19
51.5					1.19

NORTHWEST NATURAL GAS COMPANY
ACCOUNT 396.00 POWER OPERATED EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHWEST NATURAL GAS COMPANY

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1948-2023 EXPERIENCE BAND 1948-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	26,880,447	288,089	0.0107	0.9893	100.00
0.5	25,281,767		0.0000	1.0000	98.93
1.5	24,324,429	187,123	0.0077	0.9923	98.93
2.5	21,978,096	268,514	0.0122	0.9878	98.17
3.5	19,960,191	66,342	0.0033	0.9967	96.97
4.5	18,122,706	268,368	0.0148	0.9852	96.65
5.5	12,034,695	252,087	0.0209	0.9791	95.21
6.5	11,866,127	297,998	0.0251	0.9749	93.22
7.5	11,594,547	594,677	0.0513	0.9487	90.88
8.5	10,998,956	807,883	0.0735	0.9265	86.22
9.5	9,881,042	1,108,142	0.1121	0.8879	79.89
10.5	8,567,207	1,177,004	0.1374	0.8626	70.93
11.5	7,047,484	666,155	0.0945	0.9055	61.18
12.5	5,690,217	606,769	0.1066	0.8934	55.40
13.5	4,918,015	543,883	0.1106	0.8894	49.49
14.5	4,335,258	481,182	0.1110	0.8890	44.02
15.5	3,783,300	488,233	0.1290	0.8710	39.13
16.5	3,255,980	211,609	0.0650	0.9350	34.08
17.5	2,763,336	139,493	0.0505	0.9495	31.87
18.5	2,124,170	262,192	0.1234	0.8766	30.26
19.5	1,803,679	318,213	0.1764	0.8236	26.52
20.5	1,387,483	143,146	0.1032	0.8968	21.84
21.5	1,144,741	122,544	0.1070	0.8930	19.59
22.5	1,022,197	97,196	0.0951	0.9049	17.49
23.5	925,001	180,554	0.1952	0.8048	15.83
24.5	697,695	68,335	0.0979	0.9021	12.74
25.5	579,885	105,633	0.1822	0.8178	11.49
26.5	456,931	40,160	0.0879	0.9121	9.40
27.5	409,809	77,980	0.1903	0.8097	8.57
28.5	319,621	34,938	0.1093	0.8907	6.94
29.5	306,400	41,139	0.1343	0.8657	6.18
30.5	260,912	19,501	0.0747	0.9253	5.35
31.5	241,411	37,953	0.1572	0.8428	4.95
32.5	193,616	12,255	0.0633	0.9367	4.17
33.5	181,362	49,370	0.2722	0.7278	3.91
34.5	117,331		0.0000	1.0000	2.85
35.5	117,331		0.0000	1.0000	2.85
36.5	117,331		0.0000	1.0000	2.85
37.5	117,331		0.0000	1.0000	2.85
38.5	54,944		0.0000	1.0000	2.85

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1948-2023 EXPERIENCE BAND 1948-2023

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	54,944		0.0000	1.0000	2.85
40.5	54,944		0.0000	1.0000	2.85
41.5	30,054		0.0000	1.0000	2.85
42.5	30,054	20,334	0.6766	0.3234	2.85
43.5	1,025		0.0000	1.0000	0.92
44.5	1,025		0.0000	1.0000	0.92
45.5	1,025		0.0000	1.0000	0.92
46.5	1,025		0.0000	1.0000	0.92
47.5	1,025	1,025	1.0000		0.92
48.5					

PART VIII. NET SALVAGE STATISTICS

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 376.11 AND 376.12 MAINS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993	1,431,992	226,683	16		0	226,683-	16-
1994	1,342,378	503,908	38		0	503,908-	38-
1995	344,510	450,493	131		0	450,493-	131-
1996	1,098,128	507,451	46		0	507,451-	46-
1997	1,806,918	503,848	28		0	503,848-	28-
1998	1,534,412	584,938	38		0	584,938-	38-
1999	1,902,441	652,267	34	15-	0	652,282-	34-
2000	1,690,556	86,394	5		0	86,394-	5-
2001	2,229,849	807,009	36		0	807,009-	36-
2002	1,765,905	59,291	3	53,763-	3-	113,054-	6-
2003	978,308	1,219,533	125	3,457	0	1,216,076-	124-
2004	1,104,995	1,369,122	124		0	1,369,122-	124-
2005	1,600,635	1,206,093	75		0	1,206,093-	75-
2006	3,661,277	1,273,053	35		0	1,273,053-	35-
2007	1,377,807	1,317,655	96		0	1,317,655-	96-
2008	794,472	1,177,857	148		0	1,177,857-	148-
2009	985,969	1,375,758	140	31,298	3	1,344,460-	136-
2010	874,891	2,057,941	235	72,780	8	1,985,161-	227-
2011	1,100,014	2,172,997	198	50,054	5	2,122,943-	193-
2012	4,007,215	1,968,930	49	33,775	1	1,935,155-	48-
2013	910,088	1,829,071	201	41,432	5	1,787,639-	196-
2014	3,674,656	2,600,318	71	44,128	1	2,556,190-	70-
2015	839,793	2,844,855	339	20,544	2	2,824,311-	336-
2016	1,258,301	2,367,778	188	18,016	1	2,349,762-	187-
2017	393,185	1,743,030	443	36,627	9	1,706,403-	434-
2018	583,585	2,079,219	356	77,396	13	2,001,823-	343-
2019	495,564	993,867	201	94,181	19	899,686-	182-
2020	89,443	214,670	240	73,714	82	140,956-	158-
2021	391,433	2,570,854	657	130,472	33	2,440,382-	623-
2022	635,695	2,694,366	424	32,232	5	2,662,134-	419-
2023	1,636,252		0	60,650	4	60,650	4
TOTAL	42,540,667	39,459,249	93	766,978	2	38,692,271-	91-
THREE-YEAR MOVING AVERAGES							
93-95	1,039,627	393,695	38		0	393,695-	38-
94-96	928,339	487,284	52		0	487,284-	52-
95-97	1,083,185	487,264	45		0	487,264-	45-
96-98	1,479,819	532,079	36		0	532,079-	36-
97-99	1,747,924	580,351	33	5-	0	580,356-	33-
98-00	1,709,136	441,200	26	5-	0	441,205-	26-

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 376.11 AND 376.12 MAINS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
99-01	1,940,949	515,223	27	5-	0	515,228-	27-
00-02	1,895,437	317,565	17	17,921-	1-	335,486-	18-
01-03	1,658,021	695,278	42	16,769-	1-	712,046-	43-
02-04	1,283,069	882,649	69	16,769-	1-	899,417-	70-
03-05	1,227,979	1,264,916	103	1,152	0	1,263,764-	103-
04-06	2,122,302	1,282,756	60		0	1,282,756-	60-
05-07	2,213,240	1,265,600	57		0	1,265,600-	57-
06-08	1,944,519	1,256,188	65		0	1,256,188-	65-
07-09	1,052,749	1,290,423	123	10,433	1	1,279,991-	122-
08-10	885,111	1,537,185	174	34,693	4	1,502,493-	170-
09-11	986,958	1,868,899	189	51,377	5	1,817,521-	184-
10-12	1,994,040	2,066,623	104	52,203	3	2,014,420-	101-
11-13	2,005,772	1,990,333	99	41,754	2	1,948,579-	97-
12-14	2,863,986	2,132,773	74	39,778	1	2,092,995-	73-
13-15	1,808,179	2,424,748	134	35,368	2	2,389,380-	132-
14-16	1,924,250	2,604,317	135	27,563	1	2,576,754-	134-
15-17	830,426	2,318,554	279	25,062	3	2,293,492-	276-
16-18	745,024	2,063,342	277	44,013	6	2,019,329-	271-
17-19	490,778	1,605,372	327	69,401	14	1,535,971-	313-
18-20	389,531	1,095,919	281	81,764	21	1,014,155-	260-
19-21	325,480	1,259,797	387	99,456	31	1,160,341-	357-
20-22	372,190	1,826,630	491	78,806	21	1,747,824-	470-
21-23	887,793	1,755,073	198	74,451	8	1,680,622-	189-
FIVE-YEAR AVERAGE							
19-23	649,677	1,294,751	199	78,250	12	1,216,502-	187-

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993	2,841,387	396,430	14		0	396,430-	14-
1994	2,500,176	663,273	27		0	663,273-	27-
1995	2,342,406	748,847	32		0	748,847-	32-
1996	2,230,345	741,543	33		0	741,543-	33-
1997	1,902,901	771,714	41		0	771,714-	41-
1998	1,960,026	842,083	43		0	842,083-	43-
1999	1,994,257	896,403	45	105-	0	896,508-	45-
2000	1,617,520	35,662	2		0	35,662-	2-
2001	1,390,478	876,280	63		0	876,280-	63-
2002	1,276,053	52,935	4	108,373-	8-	161,308-	13-
2003	1,166,885	923,195	79	133	0	923,062-	79-
2004	1,204,971	1,334,747	111		0	1,334,747-	111-
2005	1,698,676	1,075,509	63		0	1,075,509-	63-
2006	1,337,959	1,267,508	95		0	1,267,508-	95-
2007	1,674,091	2,072,481	124		0	2,072,481-	124-
2008	986,328	2,488,358	252		0	2,488,358-	252-
2009	430,790	465,616	108		0	465,616-	108-
2010	496,643	1,318,460	265		0	1,318,460-	265-
2011	489,210	1,171,358	239		0	1,171,358-	239-
2012	689,693	2,784,271	404		0	2,784,271-	404-
2013	1,699,245	2,306,446	136		0	2,306,446-	136-
2014	1,630,916	2,933,879	180		0	2,933,879-	180-
2015	1,293,428	2,577,664	199		0	2,577,664-	199-
2016	2,214,181	5,577,376	252		0	5,577,376-	252-
2017	1,162,235	1,248,131	107		0	1,248,131-	107-
2018	1,714,774	2,079,495	121		0	2,079,495-	121-
2019	1,477,866	2,552,534	173		0	2,552,534-	173-
2020	135,451	195,198	144		0	195,198-	144-
2021	1,352,193	7,221,715	534		0	7,221,715-	534-
2022	2,709,157	4,137,277	153		0	4,137,277-	153-
2023	2,523,393		0		0		0
TOTAL	48,143,634	51,756,388	108	108,345-	0	51,864,733-	108-
THREE-YEAR MOVING AVERAGES							
93-95	2,561,323	602,850	24		0	602,850-	24-
94-96	2,357,642	717,888	30		0	717,888-	30-
95-97	2,158,551	754,035	35		0	754,035-	35-
96-98	2,031,091	785,113	39		0	785,113-	39-
97-99	1,952,395	836,733	43	35-	0	836,768-	43-
98-00	1,857,268	591,383	32	35-	0	591,418-	32-

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
99-01	1,667,418	602,782	36	35-	0	602,817-	36-
00-02	1,428,017	321,626	23	36,124-	3-	357,750-	25-
01-03	1,277,805	617,470	48	36,080-	3-	653,550-	51-
02-04	1,215,970	770,292	63	36,080-	3-	806,372-	66-
03-05	1,356,844	1,111,150	82	44	0	1,111,106-	82-
04-06	1,413,869	1,225,921	87		0	1,225,921-	87-
05-07	1,570,242	1,471,833	94		0	1,471,833-	94-
06-08	1,332,793	1,942,782	146		0	1,942,782-	146-
07-09	1,030,403	1,675,485	163		0	1,675,485-	163-
08-10	637,920	1,424,145	223		0	1,424,145-	223-
09-11	472,214	985,145	209		0	985,145-	209-
10-12	558,515	1,758,030	315		0	1,758,030-	315-
11-13	959,383	2,087,358	218		0	2,087,358-	218-
12-14	1,339,951	2,674,865	200		0	2,674,865-	200-
13-15	1,541,196	2,605,996	169		0	2,605,996-	169-
14-16	1,712,842	3,696,306	216		0	3,696,306-	216-
15-17	1,556,615	3,134,390	201		0	3,134,390-	201-
16-18	1,697,063	2,968,334	175		0	2,968,334-	175-
17-19	1,451,625	1,960,053	135		0	1,960,053-	135-
18-20	1,109,364	1,609,076	145		0	1,609,076-	145-
19-21	988,503	3,323,149	336		0	3,323,149-	336-
20-22	1,398,934	3,851,397	275		0	3,851,397-	275-
21-23	2,194,914	3,786,331	173		0	3,786,331-	173-
FIVE-YEAR AVERAGE							
19-23	1,639,612	2,821,345	172		0	2,821,345-	172-

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993	35,525		0		0		0
1994	75,695		0	25	0	25	0
1995	109,668		0	220	0	220	0
1996	169,183		0	158	0	158	0
1997	187,776		0	6,160	3	6,160	3
1998	234,076		0	16,920	7	16,920	7
1999	237,115		0	6,900	3	6,900	3
2000	182,134		0	1,936	1	1,936	1
2001	147,077		0		0		0
2002	205,198		0		0		0
2003	323,750		0		0		0
2004	293,768		0		0		0
2005	316,926		0		0		0
2006	517,442		0		0		0
2007	865,099		0		0		0
2008	679,498		0		0		0
2009	2,445,908		0		0		0
2010	832,853		0		0		0
2011	387,538		0		0		0
2012	442,790		0		0		0
2013	822,151		0		0		0
2014	839,332		0		0		0
2015	1,126,709		0		0		0
2016	1,315,911		0		0		0
2017	696,854		0		0		0
2018	1,576,280		0		0		0
2019	1,729,669		0		0		0
2020	4,769,124		0	43,305	1	43,305	1
2021	5,165,289		0	70,297	1	70,297	1
2022	2,543,509		0	11,177	0	11,177	0
2023	7,065,967		0		0		0
TOTAL	36,339,814		0	157,098	0	157,098	0
THREE-YEAR MOVING AVERAGES							
93-95	73,629		0	82	0	82	0
94-96	118,182		0	134	0	134	0
95-97	155,542		0	2,179	1	2,179	1
96-98	197,012		0	7,746	4	7,746	4
97-99	219,656		0	9,993	5	9,993	5
98-00	217,775		0	8,585	4	8,585	4

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
99-01	188,775		0	2,945	2	2,945	2
00-02	178,136		0	645	0	645	0
01-03	225,342		0		0		0
02-04	274,239		0		0		0
03-05	311,481		0		0		0
04-06	376,045		0		0		0
05-07	566,489		0		0		0
06-08	687,346		0		0		0
07-09	1,330,168		0		0		0
08-10	1,319,420		0		0		0
09-11	1,222,100		0		0		0
10-12	554,394		0		0		0
11-13	550,826		0		0		0
12-14	701,424		0		0		0
13-15	929,397		0		0		0
14-16	1,093,984		0		0		0
15-17	1,046,491		0		0		0
16-18	1,196,348		0		0		0
17-19	1,334,268		0		0		0
18-20	2,691,691		0	14,435	1	14,435	1
19-21	3,888,027		0	37,867	1	37,867	1
20-22	4,159,307		0	41,593	1	41,593	1
21-23	4,924,922		0	27,158	1	27,158	1
FIVE-YEAR AVERAGE							
19-23	4,254,712		0	24,956	1	24,956	1

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.10 METERS - ELECTRIC

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2014	507,007		0		0		0
2015							
2016							
2017							
2018							
2019							
2020							
2021							
2022							
2023							
TOTAL	507,007		0		0		0
THREE-YEAR MOVING AVERAGES							
14-16	169,002		0		0		0
15-17							
16-18							
17-19							
18-20							
19-21							
20-22							
21-23							
FIVE-YEAR AVERAGE							
19-23							

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.20 METERS - ERT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2010	631,904		0		0		0
2011	272,574		0		0		0
2012	479,487		0		0		0
2013	500,211		0		0		0
2014	422,728		0		0		0
2015	607,184		0		0		0
2016	552,861		0		0		0
2017	403,962		0		0		0
2018	1,074,843		0		0		0
2019	4,021,547		0		0		0
2020	4,090,445		0		0		0
2021	3,274,304		0		0		0
2022	5,021,163		0		0		0
2023	2,850,156		0		0		0
TOTAL	24,203,369		0		0		0
THREE-YEAR MOVING AVERAGES							
10-12	461,322		0		0		0
11-13	417,424		0		0		0
12-14	467,475		0		0		0
13-15	510,041		0		0		0
14-16	527,591		0		0		0
15-17	521,336		0		0		0
16-18	677,222		0		0		0
17-19	1,833,451		0		0		0
18-20	3,062,278		0		0		0
19-21	3,795,432		0		0		0
20-22	4,128,637		0		0		0
21-23	3,715,208		0		0		0
FIVE-YEAR AVERAGE							
19-23	3,851,523		0		0		0

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993	46,518	2,598	6		0	2,598-	6-
1994	96,011	9,377	10	1,694	2	7,683-	8-
1995	131,729	3,165	2		0	3,165-	2-
1996	238,906	303	0		0	303-	0
1997	191,607	1,715	1		0	1,715-	1-
1998	328,975	596	0		0	596-	0
1999	370,161	8,471	2	290	0	8,181-	2-
2000	278,986		0	6,715	2	6,715	2
2001	242,395	6,349	3		0	6,349-	3-
2002	329,497	1,602	0		0	1,602-	0
2003	514,135	19,994	4		0	19,994-	4-
2004	480,981	4,365	1		0	4,365-	1-
2005	516,182		0		0		0
2006	813,246		0		0		0
2007	1,549,221		0		0		0
2008	1,077,855		0		0		0
2009	10,496,732		0		0		0
2010	3,633,211		0		0		0
2011	1,646,617		0		0		0
2012	1,809,044		0		0		0
2013	2,227,911		0		0		0
2014	3,182,624		0		0		0
2015	3,438,321		0		0		0
2016	2,975,570		0		0		0
2017	1,694,704		0		0		0
2018	2,778,764		0		0		0
2019	2,692,778		0		0		0
2020	5,030,201		0		0		0
2021	2,322,890		0		0		0
2022	2,969,507		0		0		0
2023	4,862,972		0		0		0
TOTAL	58,968,251	58,535	0	8,699	0	49,836-	0
THREE-YEAR MOVING AVERAGES							
93-95	91,419	5,047	6	565	1	4,482-	5-
94-96	155,549	4,282	3	565	0	3,717-	2-
95-97	187,414	1,728	1		0	1,728-	1-
96-98	253,163	871	0		0	871-	0
97-99	296,914	3,594	1	97	0	3,497-	1-
98-00	326,041	3,022	1	2,335	1	687-	0

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
99-01	297,181	4,940	2	2,335	1	2,605-	1-
00-02	283,626	2,650	1	2,238	1	412-	0
01-03	362,009	9,315	3		0	9,315-	3-
02-04	441,538	8,654	2		0	8,654-	2-
03-05	503,766	8,120	2		0	8,120-	2-
04-06	603,470	1,455	0		0	1,455-	0
05-07	959,550		0		0		0
06-08	1,146,774		0		0		0
07-09	4,374,603		0		0		0
08-10	5,069,266		0		0		0
09-11	5,258,853		0		0		0
10-12	2,362,957		0		0		0
11-13	1,894,524		0		0		0
12-14	2,406,526		0		0		0
13-15	2,949,619		0		0		0
14-16	3,198,838		0		0		0
15-17	2,702,865		0		0		0
16-18	2,483,013		0		0		0
17-19	2,388,749		0		0		0
18-20	3,500,581		0		0		0
19-21	3,348,623		0		0		0
20-22	3,440,866		0		0		0
21-23	3,385,123		0		0		0
FIVE-YEAR AVERAGE							
19-23	3,575,670		0		0		0

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.10 METER INSTALLATIONS - ELECTRIC

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2014	518,377		0		0		0
2015							
2016							
2017							
2018							
2019							
2020							
2021							
2022							
2023							
TOTAL	518,377		0		0		0
THREE-YEAR MOVING AVERAGES							
14-16	172,792		0		0		0
15-17							
16-18							
17-19							
18-20							
19-21							
20-22							
21-23							
FIVE-YEAR AVERAGE							
19-23							

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.20 METER INSTALLATIONS - ERT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2010	116,947		0		0		0
2011	52,987		0		0		0
2012	94,349		0		0		0
2013	101,403		0		0		0
2014	99,995		0		0		0
2015	113,714		0		0		0
2016	103,020		0		0		0
2017	74,826		0		0		0
2018	125,764		0		0		0
2019	197,054		0		0		0
2020	377,910		0		0		0
2021	321,469		0		0		0
2022	257,923		0		0		0
2023	547,368		0		0		0
TOTAL	2,584,729		0		0		0
THREE-YEAR MOVING AVERAGES							
10-12	88,094		0		0		0
11-13	82,913		0		0		0
12-14	98,582		0		0		0
13-15	105,037		0		0		0
14-16	105,576		0		0		0
15-17	97,187		0		0		0
16-18	101,203		0		0		0
17-19	132,548		0		0		0
18-20	233,576		0		0		0
19-21	298,811		0		0		0
20-22	319,101		0		0		0
21-23	375,587		0		0		0
FIVE-YEAR AVERAGE							
19-23	340,345		0		0		0

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 390.00 AND 390.10 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993		12,158				12,158-	
1994	723	155,281		50	7	155,231-	
1995		12,056				12,056-	
1996	374,465		0		0		0
1997	43,454	6,063	14		0	6,063-	14-
1998							
1999							
2000	125,000		0		0		0
2001	728,234		0		0		0
2002							
2003	6,013		0		0		0
2004							
2005	8,335		0		0		0
2006							
2007							
2008							
2009	2,852		0		0		0
2010							
2011							
2012	10,603		0		0		0
2013	649,588		0		0		0
2014	57,511		0		0		0
2015							
2016							
2017							
2018							
2019							
2020	231,371		0		0		0
2021	1,132,240		0		0		0
2022							
2023							
TOTAL	3,370,388	185,558	6	50	0	185,508-	6-
THREE-YEAR MOVING AVERAGES							
93-95	241	59,832		17	7	59,815-	
94-96	125,063	55,779	45	17	0	55,762-	45-
95-97	139,306	6,040	4		0	6,040-	4-
96-98	139,306	2,021	1		0	2,021-	1-
97-99	14,485	2,021	14		0	2,021-	14-
98-00	41,667		0		0		0

NORTHWEST NATURAL GAS COMPANY

ACCOUNTS 390.00 AND 390.10 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES							
99-01	284,411		0		0		0
00-02	284,411		0		0		0
01-03	244,749		0		0		0
02-04	2,004		0		0		0
03-05	4,783		0		0		0
04-06	2,778		0		0		0
05-07	2,778		0		0		0
06-08							
07-09	951		0		0		0
08-10	951		0		0		0
09-11	951		0		0		0
10-12	3,534		0		0		0
11-13	220,064		0		0		0
12-14	239,234		0		0		0
13-15	235,700		0		0		0
14-16	19,170		0		0		0
15-17							
16-18							
17-19							
18-20	77,124		0		0		0
19-21	454,537		0		0		0
20-22	454,537		0		0		0
21-23	377,413		0		0		0
FIVE-YEAR AVERAGE							
19-23	272,722		0		0		0

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1996	3,663,578		0		0		0
1997	1,147,124		0		0		0
1998	643,102		0	194,772	30	194,772	30
1999	1,082,085		0	254,777	24	254,777	24
2000	785,471		0	152,200	19	152,200	19
2001	755,493		0	272,108	36	272,108	36
2002	1,093,048		0	277,660	25	277,660	25
2003	1,374,444		0	282,314	21	282,314	21
2004	1,197,018		0	346,555	29	346,555	29
2005	2,326,071		0	242,308	10	242,308	10
2006	1,212,955		0	218,615	18	218,615	18
2007	1,390,528		0	198,400	14	198,400	14
2008	1,213,420		0	132,689	11	132,689	11
2009	1,806,465		0	116,482	6	116,482	6
2010	2,718,582		0	206,572	8	206,572	8
2011	2,232,500		0	154,173	7	154,173	7
2012	1,908,460		0	240,524	13	240,524	13
2013	1,815,857		0	150,375	8	150,375	8
2014	943,871		0	83,811	9	83,811	9
2015	1,390,921		0	234,987	17	234,987	17
2016	2,350,445		0	328,690	14	328,690	14
2017	1,737,627		0	223,715	13	223,715	13
2018	1,541,208		0	251,821	16	251,821	16
2019	2,256,423		0	342,064	15	342,064	15
2020	1,534,186		0	350,318	23	350,318	23
2021	2,179,673		0	440,019	20	440,019	20
2022	2,112,903		0	481,303	23	481,303	23
2023	1,013,642		0	262,602	26	262,602	26
TOTAL	45,427,101		0	6,439,854	14	6,439,854	14
THREE-YEAR MOVING AVERAGES							
96-98	1,817,935		0	64,924	4	64,924	4
97-99	957,437		0	149,850	16	149,850	16
98-00	836,886		0	200,583	24	200,583	24
99-01	874,350		0	226,362	26	226,362	26
00-02	878,004		0	233,989	27	233,989	27
01-03	1,074,329		0	277,361	26	277,361	26
02-04	1,221,503		0	302,176	25	302,176	25
03-05	1,632,511		0	290,392	18	290,392	18
04-06	1,578,681		0	269,159	17	269,159	17

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES							
05-07	1,643,185		0	219,775	13	219,775	13
06-08	1,272,301		0	183,235	14	183,235	14
07-09	1,470,138		0	149,190	10	149,190	10
08-10	1,912,822		0	151,914	8	151,914	8
09-11	2,252,516		0	159,076	7	159,076	7
10-12	2,286,514		0	200,423	9	200,423	9
11-13	1,985,606		0	181,691	9	181,691	9
12-14	1,556,063		0	158,237	10	158,237	10
13-15	1,383,550		0	156,391	11	156,391	11
14-16	1,561,746		0	215,829	14	215,829	14
15-17	1,826,331		0	262,464	14	262,464	14
16-18	1,876,427		0	268,075	14	268,075	14
17-19	1,845,086		0	272,533	15	272,533	15
18-20	1,777,272		0	314,734	18	314,734	18
19-21	1,990,094		0	377,467	19	377,467	19
20-22	1,942,254		0	423,880	22	423,880	22
21-23	1,768,739		0	394,641	22	394,641	22
FIVE-YEAR AVERAGE							
19-23	1,819,365		0	375,261	21	375,261	21

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1995	520,485		0		0		0
1996	75,190		0		0		0
1997	30,348		0		0		0
1998	63,975		0	19,797	31	19,797	31
1999	10,223		0	10,646	104	10,646	104
2000	104,702		0	26,730	26	26,730	26
2001	189,458		0	14,283	8	14,283	8
2002	190,349		0	29,311	15	29,311	15
2003	102,476		0	16,777	16	16,777	16
2004	302,574		0	14,825	5	14,825	5
2005	872,364		0	186,761	21	186,761	21
2006	504,138		0	20,352	4	20,352	4
2007	251,001		0	59,528	24	59,528	24
2008	114,341		0	15,286	13	15,286	13
2009	139,361		0	4,647	3	4,647	3
2010	240,789		0	46,089	19	46,089	19
2011	498,971		0	119,294	24	119,294	24
2012	365,158		0	92,512	25	92,512	25
2013	502,213		0	214,520	43	214,520	43
2014	255,426		0	38,520	15	38,520	15
2015	581,404		0	150,376	26	150,376	26
2016	710,358		0	170,180	24	170,180	24
2017	441,739		0	129,938	29	129,938	29
2018	549,609		0	136,469	25	136,469	25
2019	598,755		0	202,211	34	202,211	34
2020	204,308		0	34,185	17	34,185	17
2021	935,455		0	339,759	36	339,759	36
2022	730,921		0	316,493	43	316,493	43
2023	661,295		0	403,147	61	403,147	61
TOTAL	10,747,387		0	2,812,636	26	2,812,636	26
THREE-YEAR MOVING AVERAGES							
95-97	208,674		0		0		0
96-98	56,504		0	6,599	12	6,599	12
97-99	34,849		0	10,148	29	10,148	29
98-00	59,633		0	19,058	32	19,058	32
99-01	101,461		0	17,220	17	17,220	17
00-02	161,503		0	23,441	15	23,441	15
01-03	160,761		0	20,124	13	20,124	13
02-04	198,466		0	20,304	10	20,304	10

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES							
03-05	425,805		0	72,788	17	72,788	17
04-06	559,692		0	73,979	13	73,979	13
05-07	542,501		0	88,880	16	88,880	16
06-08	289,827		0	31,722	11	31,722	11
07-09	168,235		0	26,487	16	26,487	16
08-10	164,830		0	22,007	13	22,007	13
09-11	293,040		0	56,677	19	56,677	19
10-12	368,306		0	85,965	23	85,965	23
11-13	455,447		0	142,109	31	142,109	31
12-14	374,266		0	115,184	31	115,184	31
13-15	446,348		0	134,472	30	134,472	30
14-16	515,729		0	119,692	23	119,692	23
15-17	577,834		0	150,165	26	150,165	26
16-18	567,235		0	145,529	26	145,529	26
17-19	530,034		0	156,206	29	156,206	29
18-20	450,891		0	124,288	28	124,288	28
19-21	579,506		0	192,052	33	192,052	33
20-22	623,561		0	230,146	37	230,146	37
21-23	775,890		0	353,133	46	353,133	46
FIVE-YEAR AVERAGE							
19-23	626,147		0	259,159	41	259,159	41

PART IX. DETAILED DEPRECIATION CALCULATIONS

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 303.10 MISCELLANEOUS INTANGIBLE PLANT - SOFTWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2000	502,539.37	502,539	502,539			
2001	558,085.41	558,085	558,085			
2002	459,910.17	459,910	459,910			
2003	2,307,822.96	2,307,823	2,307,823			
2005	885,137.94	885,138	885,138			
2006	379,424.15	379,424	379,424			
2007	905,024.86	905,025	905,025			
2008	195,433.83	195,434	195,434			
2009	691,265.93	668,226	415,957	275,309	0.50	275,309
2013	5,127,530.65	3,589,271	2,234,249	2,893,282	4.50	642,952
2014	2,852,281.63	1,806,436	1,124,470	1,727,812	5.50	314,148
2015	5,990,559.80	3,394,671	2,113,114	3,877,446	6.50	596,530
2016	1,565,025.78	782,513	487,098	1,077,928	7.50	143,724
2017	5,367,950.67	2,326,094	1,447,946	3,920,005	8.50	461,177
2018	11,968,877.76	4,388,628	2,731,832	9,237,046	9.50	972,321
2019	7,863,607.95	2,359,082	1,468,481	6,395,127	10.50	609,060
2020	41,394,131.14	9,658,493	6,012,216	35,381,915	11.50	3,076,688
2021	8,025,999.41	1,337,693	832,687	7,193,312	12.50	575,465
2022	15,225,935.26	1,522,594	947,784	14,278,151	13.50	1,057,641
2023	15,784,388.35	526,094	327,483	15,456,905	14.50	1,065,993
	128,050,933.02	38,553,173	26,336,695	101,714,238		9,791,008

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.4 7.65

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 303.11 MISCELLANEOUS INTANGIBLE PLANT - HORIZON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2022	46,726,994.21	7,009,049	4,141,642	42,585,352	8.50	5,010,041
	46,726,994.21	7,009,049	4,141,642	42,585,352		5,010,041
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					8.5	10.72

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 303.12 MISCELLANEOUS INTANGIBLE PLANT - SECURITY DIRECTIVE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2022	22,009,118.33	3,301,368	1,783,632	20,225,486	8.50	2,379,469
2023	233,045.18	11,652	6,295	226,750	9.50	23,868
	22,242,163.51	3,313,020	1,789,927	20,452,237		2,403,337

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.5 10.81

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 303.20 MISCELLANEOUS INTANGIBLE PLANT - CUSTOMER INFORMATION SYSTEM

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
1995	639,469.00	639,469	639,469			
1996	369,842.00	369,842	369,842			
1997	27,346,787.00	27,346,787	27,346,787			
1998	450,570.00	450,570	450,570			
1999	150,721.00	150,721	150,721			
2004	415,255.38	415,255	415,255			
2005	468,752.58	468,753	468,753			
2006	448,313.73	448,314	448,314			
2007	415,837.92	415,838	415,838			
2008	190,259.31	190,259	190,259			
2013	1,267,786.82	887,451	1,267,787			
2014	246,002.37	155,801	235,203	10,799	5.50	1,963
	32,409,597.11	31,939,060	32,398,798	10,799		1,963

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.5 0.01

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 303.30 MISCELLANEOUS INTANGIBLE PLANT - INDUSTRIAL AND COMMERCIAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
1998	1,427,352.00	1,427,352	1,427,352			
1999	2,707,150.00	2,707,150	2,707,150			
2000	12,449.00	12,449	12,449			
	4,146,951.00	4,146,951	4,146,951			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 303.40 MISCELLANEOUS INTANGIBLE PLANT - CRMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2020	2,757,525.21	1,930,268	2,500,610	256,915	1.50	171,277
2021	7,406,959.82	3,703,480	4,797,759	2,609,201	2.50	1,043,680
2022	4,001,784.79	1,200,535	1,555,261	2,446,524	3.50	699,007
2023	19,041,697.58	1,904,170	2,466,801	16,574,897	4.50	3,683,310
	33,207,967.40	8,738,453	11,320,431	21,887,536		5,597,274
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					3.9	16.86

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 303.71 MISCELLANEOUS INTANGIBLE PLANT - CLOUD-BASED SOFTWARE HORIZON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2022	24,096,593.68	3,614,489	3,203,067	20,893,527	8.50	2,458,062
	24,096,593.68	3,614,489	3,203,067	20,893,527		2,458,062

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.5 10.20

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 303.72 MISCELLANEOUS INTANGIBLE PLANT - CLOUD-BASED SOFTWARE TSA SECURITY DIRECTIVE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2022	3,134,883.06	940,465		3,134,883	3.50	895,681
2023	23,000.05	2,300		23,000	4.50	5,111
	3,157,883.11	942,765		3,157,883		900,792
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					3.5	28.53

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 305.11 STRUCTURES AND IMPROVEMENTS - GAS PRODUCTION

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-S1						
NET SALVAGE PERCENT.. -5						
1963	8,320.00	7,528	8,736			
	8,320.00	7,528	8,736			
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					0.0	0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 305.17 STRUCTURES AND IMPROVEMENTS - MIXING STATION

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-S1						
NET SALVAGE PERCENT.. -5						
1956	44,564.00	42,780	46,792			
1958	2,023.00	1,911	4,454	2,330-		
	46,587.00	44,691	51,246	2,330-		
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					0.0	0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 305.50 STRUCTURES AND IMPROVEMENTS - OTHER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-S1						
NET SALVAGE PERCENT.. -5						
1984	13,156.00	9,307	13,814			
	13,156.00	9,307	13,814			
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					0.0	0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 311.70 LIQUEFIED PETROLEUM GAS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 18-L0.5						
NET SALVAGE PERCENT.. -5						
1963	403.00	370	423			
1964	224.00	204	235			
1973	3,406.00	2,875	7,408	3,832-		
	4,033.00	3,449	8,066	3,831-		
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					0.0	0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 311.80 LIQUEFIED PETROLEUM GAS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 18-L0.5						
NET SALVAGE PERCENT.. -5						
1975	4,209.00	3,501	6,585	2,166-		
	4,209.00	3,501	6,585	2,166-		
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					0.0	0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 318.30 LIGHT OIL REFINING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S2.5						
NET SALVAGE PERCENT.. -5						
1926	6,740.00	7,077	7,077			
1941	65,282.00	66,475	68,546			
1943	3,000.00	3,028	3,150			
1947	11,000.00	10,911	11,550			
1950	14,536.00	14,228	15,263			
1951	28,111.00	27,391	29,517			
1952	15,110.00	14,656	15,866			
1953	1.00	1	1			
1956	163.00	155	171			
1957	953.00	903	1,000			
	144,896.00	144,825	152,141			
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					0.0	0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 318.50 TAR PROCESSING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S2.5						
NET SALVAGE PERCENT.. -5						
1913	4,028.00	4,229	4,229			
1923	8,294.00	8,709	8,709			
1940	23,539.00	24,068	24,716			
1943	48,609.00	49,066	51,039			
1944	8,137.00	8,179	8,544			
1947	46,907.00	46,527	49,252			
1948	6,861.00	6,775	7,204			
1949	591.00	581	621			
1952	264.00	256	277			
1953	89,945.00	86,845	94,442			
1954	4,566.00	4,388	4,794			
1955	1,810.00	1,732	1,902			
	243,551.00	241,355	255,729			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 319.00 GAS MIXING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R0.5						
NET SALVAGE PERCENT.. -5						
1956	145,043.00	152,295	152,295			
1957	15,520.00	16,296	16,296			
1958	5,736.00	6,023	6,023			
1959	217.00	228	228			
1960	277.00	291	291			
1962	1,667.00	1,750	1,750			
1964	921.00	959	967			
1967	89.00	88	93			
1980	12,421.00	9,960	13,042			
1981	3,557.00	2,802	3,735			
	185,448.00	190,692	194,720			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 350.20 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. 0						
1989	40,841.00	19,662	20,150	20,691	36.30	570
1993	5,264.00	2,255	2,311	2,953	40.01	74
1994	400.00	166	170	230	40.95	6
1997	185.00	69	71	114	43.81	3
1998	628.00	226	232	396	44.78	9
2001	3,804.00	1,213	1,243	2,561	47.68	54
2007	58,502.94	13,731	14,072	44,431	53.57	829
	109,624.94	37,322	38,249	71,376		1,545

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 46.2 1.41

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 351.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R4						
NET SALVAGE PERCENT.. 0						
1989	2,101,010.00	1,165,703	1,287,980	813,030	26.71	30,439
1990	45,791.00	24,735	27,330	18,461	27.59	669
1991	275,498.00	144,774	159,960	115,538	28.47	4,058
1992	41,905.00	21,400	23,645	18,260	29.36	622
1993	3,226.00	1,598	1,766	1,460	30.27	48
1994	13,262.00	6,370	7,038	6,224	31.18	200
1995	35,648.00	16,576	18,315	17,333	32.10	540
1998	2,475,159.00	1,035,433	1,144,045	1,331,114	34.90	38,141
1999	4,963.00	1,998	2,208	2,755	35.85	77
2000	32,811.00	12,687	14,018	18,793	36.80	511
2001	884,241.00	327,762	362,143	522,098	37.76	13,827
2002	242,899.00	86,149	95,186	147,713	38.72	3,815
2003	16,898.54	5,720	6,320	10,579	39.69	267
2004	74,234.66	23,928	26,438	47,797	40.66	1,176
2005	123.98	38	42	82	41.64	2
2008	290,921.56	74,767	82,610	208,312	44.58	4,673
2009	3,834.31	922	1,019	2,815	45.57	62
2010	12,998.94	2,912	3,217	9,782	46.56	210
2012	159,638.62	30,491	33,689	125,950	48.54	2,595
2014	426,776.29	67,431	74,504	352,272	50.52	6,973
2015	66,404.73	9,385	10,369	56,036	51.52	1,088
2017	173,824.60	18,803	20,775	153,050	53.51	2,860
2018	1,252,081.82	114,565	126,583	1,125,499	54.51	20,648
2021	285,370.88	11,891	13,138	272,233	57.50	4,734
2022	232,028.00	5,801	6,410	225,618	58.50	3,857
2023	5,403,375.84	45,010	49,731	5,353,645	59.50	89,977
	14,554,925.77	3,256,849	3,598,479	10,956,447		232,069

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 47.2 1.59

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 352.00 WELLS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-S4						
NET SALVAGE PERCENT.. 0						
1989	8,933,762.00	6,037,436	6,331,890	2,601,872	16.21	160,510
1990	536,082.00	353,171	370,396	165,686	17.06	9,712
1991	2,005,008.00	1,286,012	1,348,732	656,276	17.93	36,602
1992	150,577.00	93,900	98,480	52,097	18.82	2,768
1993	182,892.00	110,686	116,084	66,808	19.74	3,384
1994	2,358.00	1,383	1,450	908	20.67	44
1998	6,327,524.00	3,221,975	3,379,115	2,948,409	24.54	120,147
2001	200,085.00	89,998	94,387	105,698	27.51	3,842
2003	44,802.88	18,369	19,265	25,538	29.50	866
2004	5,127,030.63	1,999,542	2,097,062	3,029,969	30.50	99,343
2005	3,853,067.17	1,425,635	1,495,165	2,357,902	31.50	74,854
2007	8,775,470.65	2,895,905	3,037,143	5,738,328	33.50	171,293
2009	831,368.14	241,097	252,856	578,512	35.50	16,296
2012	17,500.00	4,025	4,221	13,279	38.50	345
2018	3,328,509.28	366,136	383,993	2,944,516	44.50	66,169
2019	3,488,288.60	313,946	329,258	3,159,031	45.50	69,429
2020	4,552,032.47	318,642	334,182	4,217,850	46.50	90,706
2021	4,166,820.20	208,341	218,502	3,948,318	47.50	83,122
2022	5,132,799.55	153,984	161,494	4,971,306	48.50	102,501
2023	5,371,642.43	53,716	56,336	5,315,306	49.50	107,380
	63,027,620.00	19,193,899	20,130,011	42,897,609		1,219,313

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.2 1.93

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 352.10 STORAGE LEASEHOLDS AND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-S3						
NET SALVAGE PERCENT.. 0						
1989	1,210,800.00	720,317	784,140	426,660	22.28	19,150
1993	1.00	1	1			
1996	237,300.00	116,192	126,487	110,813	28.07	3,948
1997	1,589,979.00	752,489	819,163	770,816	28.97	26,607
1998	492,327.00	224,861	244,785	247,542	29.88	8,285
1999	5,093.00	2,241	2,440	2,653	30.80	86
2002	2,991.00	1,162	1,265	1,726	33.64	51
2004	1,020.52	360	392	629	35.58	18
2014	400,000.00	69,092	75,213	324,787	45.50	7,138
	3,939,511.52	1,886,715	2,053,886	1,885,626		65,283

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 28.9 1.66

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 352.20 RESERVOIRS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-S3						
NET SALVAGE PERCENT.. 0						
1996	1,679,184.00	822,196	853,296	825,888	28.07	29,422
1998	1,999,907.00	913,418	947,969	1,051,938	29.88	35,205
1999	6,003.00	2,641	2,741	3,262	30.80	106
2000	476,341.00	201,449	209,069	267,272	31.74	8,421
2002	2,997,731.00	1,164,199	1,208,235	1,789,496	33.64	53,195
2004	1,212,371.25	428,076	444,268	768,103	35.58	21,588
2005	2,445,017.29	819,741	850,749	1,594,268	36.56	43,607
2012	17,500.00	3,659	3,797	13,703	43.50	315
	10,834,054.54	4,355,379	4,520,124	6,313,931		191,859

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 32.9 1.77

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 352.30 NONRECOVERABLE GAS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R4						
NET SALVAGE PERCENT.. 0						
1989	4,057,952.00	2,431,809	2,751,847	1,306,105	22.04	59,261
1993	1.00	1	1			
1996	2,255,000.00	1,100,440	1,245,264	1,009,736	28.16	35,857
1998	62,449.00	28,386	32,122	30,327	30.00	1,011
2004	65,487.82	22,980	26,004	39,484	35.70	1,106
	6,440,889.82	3,583,616	4,055,238	2,385,652		97,235

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 24.5 1.51

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 353.00 LINES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-S3						
NET SALVAGE PERCENT.. -15						
1989	2,521,353.00	1,724,975	1,762,844	1,136,712	22.28	51,019
1991	17,489.00	11,395	11,645	8,467	23.84	355
1993	1.00	1	1			
1998	3,853,629.00	2,024,078	2,068,513	2,363,160	29.88	79,088
1999	52,862.00	26,748	27,335	33,456	30.80	1,086
2003	7,841.06	3,343	3,416	5,601	34.61	162
2004	684,275.05	277,852	283,952	502,964	35.58	14,136
2005	504,360.29	194,461	198,730	381,284	36.56	10,429
2007	560,153.49	192,899	197,134	447,043	38.53	11,602
2018	1,333,513.81	153,354	156,721	1,376,820	49.50	27,815
2019	1,137,750.13	107,054	109,404	1,199,009	50.50	23,743
2020	116,919.92	8,557	8,745	125,713	51.50	2,441
2021	782.00	41	42	857	52.50	16
2022	1,344,670.40	42,170	43,096	1,503,275	53.50	28,099
2023	819,822.92	8,570	8,758	934,038	54.50	17,138
	12,955,423.07	4,775,498	4,880,336	10,018,401		267,129

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.5 2.06

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 354.10 COMPRESSOR STATION EQUIPMENT - TURBINE 1

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. -10						
1989	3,547,382.00	2,381,074	2,779,504	1,122,616	19.49	57,600
1990	110,946.00	72,687	84,850	37,191	20.22	1,839
1991	139,186.00	88,893	103,768	49,337	20.97	2,353
1992	41,746.00	25,973	30,319	15,602	21.72	718
1993	3,141.00	1,901	2,219	1,236	22.49	55
1994	7,648.00	4,499	5,252	3,161	23.26	136
1995	116,370.00	66,436	77,553	50,454	24.05	2,098
1996	3,136.00	1,735	2,025	1,425	24.85	57
1997	19,089.09	10,222	11,932	9,066	25.66	353
1998	166,055.57	85,924	100,302	82,359	26.48	3,110
2023	3,730,531.56	40,215	46,944	4,056,641	49.51	81,936
	7,885,231.22	2,779,559	3,244,668	5,429,086		150,255
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					36.1	1.91

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 354.20 COMPRESSOR STATION EQUIPMENT - TURBINE 2

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. -10						
1989	4,154,699.00	2,788,717	3,255,359	1,314,810	19.49	67,461
	4,154,699.00	2,788,717	3,255,359	1,314,810		67,461
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					19.5	1.62

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 354.30 COMPRESSOR STATION EQUIPMENT - TURBINE 3

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. -10						
1998	8,502,780.91	4,399,679	5,135,886	4,217,173	26.48	159,259
1999	94,722.00	47,283	55,195	48,999	27.31	1,794
2000	3,218,557.00	1,547,160	1,806,049	1,734,364	28.15	61,612
2001	1,699,551.00	785,193	916,581	952,925	29.00	32,859
2002	122,405.06	54,235	63,310	71,336	29.86	2,389
2008	131,264.60	42,769	49,926	94,465	35.19	2,684
2009	69,541.41	21,250	24,806	51,690	36.11	1,431
2010	20,130.52	5,744	6,705	15,439	37.03	417
2014	781,561.86	158,532	185,059	674,659	40.78	16,544
2023	6,443,741.67	69,464	81,088	7,007,028	49.51	141,528
	21,084,256.03	7,131,309	8,324,605	14,868,077		420,517

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.4 1.99

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 354.40 COMPRESSOR STATION EQUIPMENT - TURBINE 4

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. -10						
2000	4,556,230.32	2,190,180	2,556,667	2,455,186	28.15	87,218
2001	6,176,092.83	2,853,355	3,330,812	3,462,890	29.00	119,410
2004	2,147,487.86	869,303	1,014,765	1,347,472	31.60	42,642
2012	17,500.00	4,277	4,993	14,257	38.89	367
2013	767,326.56	171,513	200,213	643,846	39.84	16,161
2022	2,731,916.61	88,951	103,835	2,901,273	48.52	59,795
	16,396,554.18	6,177,579	7,211,285	10,824,925		325,593
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					33.2	1.99

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 354.50 COMPRESSOR STATION EQUIPMENT - TURBINE 5

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. -10						
2001	1,386,150.00	640,401	747,561	777,204	29.00	26,800
2003	3,978.82	1,687	1,969	2,408	30.73	78
2004	29,546.20	11,960	13,961	18,540	31.60	587
2011	1,167,361.91	309,211	360,952	923,146	37.96	24,319
2016	42,248.74	6,794	7,931	38,543	42.69	903
2017	145,612.11	20,310	23,709	136,464	43.66	3,126
2020	779,535.40	58,824	68,667	788,822	46.57	16,938
2022	185,043.79	6,025	7,033	196,515	48.52	4,050
	3,739,476.97	1,055,212	1,231,783	2,881,642		76,801

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.5 2.05

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 354.60 COMPRESSOR STATION EQUIPMENT - TURBINE 6

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. -10						
2015	260,041.78	47,255	55,162	230,884	41.74	5,531
	260,041.78	47,255	55,162	230,884		5,531
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					41.7	2.13

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 355.00 MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S2						
NET SALVAGE PERCENT.. -10						
1989	3,473,015.20	2,439,043	2,570,462	1,249,855	16.27	76,820
1990	66,949.00	46,117	48,602	25,042	16.82	1,489
1991	21,410.00	14,455	15,234	8,317	17.38	479
1992	17,819.00	11,778	12,413	7,188	17.96	400
1993	1,785.00	1,154	1,216	748	18.56	40
1994	35.00	22	23	16	19.18	1
1995	9,858.00	6,068	6,395	4,449	19.82	224
1996	15,372.00	9,214	9,710	7,199	20.48	352
1998	1,090,120.00	616,881	650,119	549,013	21.85	25,126
1999	238,641.00	130,843	137,893	124,612	22.57	5,521
2000	1,704,161.55	903,959	952,666	921,912	23.30	39,567
2001	48,850.00	25,005	26,352	27,383	24.06	1,138
2002	198,196.98	97,671	102,934	115,083	24.84	4,633
2003	0.07					
2004	830,627.56	376,641	396,935	516,755	26.45	19,537
2005	1,791,619.55	775,621	817,412	1,153,370	27.29	42,263
2006	143,130.10	58,953	62,129	95,314	28.15	3,386
2007	4,611,549.49	1,801,368	1,898,428	3,174,276	29.02	109,382
2008	207,002.45	76,356	80,470	147,233	29.91	4,923
2009	993,447.65	344,350	362,904	729,888	30.82	23,682
2011	435,517.72	131,160	138,227	340,842	32.68	10,430
2012	17,500.00	4,864	5,126	14,124	33.63	420
2013	71,153.62	18,106	19,082	59,187	34.59	1,711
2015	10,072.05	2,083	2,195	8,884	36.54	243
2016	124,808.02	22,820	24,050	113,239	37.52	3,018
2017	124,297.12	19,719	20,781	115,946	38.51	3,011
2018	369,594.51	49,600	52,273	354,281	39.51	8,967
2019	76,345.99	8,398	8,850	75,131	40.50	1,855
2020	1,857,532.18	158,927	167,490	1,875,795	41.50	45,200
2021	9,662,801.94	590,552	622,372	10,006,710	42.50	235,452
2022	9,155,761.89	335,678	353,765	9,717,573	43.50	223,392
2023	2,105,592.36	25,732	27,119	2,289,033	44.50	51,439
	39,474,567.00	9,103,138	9,593,627	33,828,397		944,101

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.8 2.39

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 356.00 PURIFICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S2.5						
NET SALVAGE PERCENT.. -5						
1989	139,942.00	97,731	71,371	75,568	15.07	5,014
1990	12,815.00	8,773	6,407	7,049	15.66	450
1992	15,940.00	10,459	7,638	9,099	16.88	539
1993	2,878.00	1,845	1,347	1,675	17.53	96
1995	73,881.00	45,011	32,871	44,704	18.89	2,367
1996	48,826.00	28,926	21,124	30,143	19.61	1,537
1998	3,081.00	1,718	1,255	1,980	21.10	94
2018	66,401.79	8,521	6,223	63,499	39.50	1,608
2020	28,191,885.97	2,302,403	1,681,396	27,920,084	41.50	672,773
2022	235,336.24	8,236	6,015	241,088	43.50	5,542
2023	177,877.51	2,075	1,515	185,256	44.50	4,163
	28,968,864.51	2,515,698	1,837,162	28,580,146		694,183
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					41.2	2.40

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 357.00 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R4						
NET SALVAGE PERCENT.. 0						
1989	76,057.00	64,410	74,516	1,541	5.36	288
1992	5,980.00	4,779	5,529	451	7.03	64
1998	564,221.00	383,670	443,871	120,350	11.20	10,746
1999	56,329.00	37,064	42,880	13,449	11.97	1,124
2008	629,441.85	273,895	316,872	312,570	19.77	15,810
2009	63,256.08	25,827	29,879	33,377	20.71	1,612
2018	1,027,537.43	161,180	186,471	841,066	29.51	28,501
2020	2,250,170.09	224,364	259,568	1,990,602	31.51	63,174
2021	475,212.76	33,944	39,270	435,943	32.50	13,414
2022	113,567.00	4,867	5,631	107,936	33.50	3,222
	5,261,772.21	1,214,000	1,404,487	3,857,285		137,955

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 28.0 2.62

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
LINNTON						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2036						
NET SALVAGE PERCENT.. -5						
1969	59,412.00	50,994	51,870	10,513	10.13	1,038
1970	26,089.00	22,296	22,679	4,715	10.25	460
1974	183.00	154	157	36	10.68	3
1975	8,525.00	7,123	7,245	1,706	10.77	158
1976	14,557.00	12,105	12,313	2,972	10.86	274
1978	9,671.00	7,960	8,097	2,058	11.04	186
1981	1,017.00	824	838	230	11.26	20
1982	46,738.00	37,632	38,278	10,797	11.33	953
1985	20,155.00	15,929	16,203	4,960	11.51	431
1986	6,343.00	4,980	5,066	1,595	11.56	138
1987	6,731.00	5,248	5,338	1,729	11.61	149
1988	30,340.00	23,481	23,884	7,973	11.66	684
1991	27,819.00	21,018	21,379	7,831	11.79	664
1992	4,998.00	3,743	3,807	1,441	11.83	122
1993	42,483.00	31,514	32,055	12,552	11.87	1,057
1994	37,310.00	27,412	27,883	11,293	11.90	949
1995	45,530.00	33,107	33,676	14,131	11.93	1,184
1996	20,875.00	15,007	15,265	6,654	11.97	556
1997	22,876.00	16,259	16,538	7,482	11.99	624
2000	10,951.00	7,475	7,603	3,895	12.08	322
2001	30,731.00	20,661	21,016	11,252	12.10	930
2002	60,440.00	39,976	40,662	22,800	12.12	1,881
2004	6,103.00	3,888	3,955	2,453	12.17	202
2005	185,610.40	115,870	117,860	77,031	12.18	6,324
2006	961,819.17	586,950	597,029	412,881	12.20	33,843
2007	432,192.31	257,224	261,641	192,161	12.22	15,725
2008	892,383.17	516,588	525,459	411,544	12.24	33,623
2009	1,097,712.30	616,755	627,346	525,252	12.25	42,878
2010	113,303.89	61,521	62,577	56,392	12.27	4,596
2011	221,064.76	115,632	117,618	114,500	12.28	9,324
2012	71,983.47	36,073	36,692	38,890	12.30	3,162
2015	53,824.55	22,787	23,178	33,337	12.33	2,704
2016	484,828.69	190,189	193,455	315,615	12.34	25,577
2017	14,238.78	5,098	5,186	9,765	12.35	791
2018	5,604,150.24	1,791,493	1,822,256	4,062,102	12.36	328,649
2020	43,051.42	9,852	10,021	35,183	12.38	2,842

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
LINNTON						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2036						
NET SALVAGE PERCENT.. -5						
2021	86,705.20	15,082	15,341	75,699	12.39	6,110
2022	1,452,034.00	163,670	166,480	1,358,155	12.39	109,617
2023	244,182.54	9,938	10,109	246,283	12.40	19,862
	12,498,961.89	4,923,508	5,008,053	8,115,857		658,612
NEWPORT						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -5						
1965	1,500.00	1,246	1,357	218	12.21	18
1974	605,426.00	473,334	515,399	120,299	14.27	8,430
1977	711,173.00	543,725	592,045	154,686	14.86	10,410
1978	31,895.00	24,198	26,348	7,141	15.04	475
1979	16,085.00	12,106	13,182	3,707	15.22	244
1982	13,954.00	10,245	11,155	3,496	15.70	223
1984	270.00	195	212	71	15.98	4
1986	2,983.00	2,112	2,300	832	16.24	51
1987	2,143.00	1,503	1,637	614	16.35	38
1988	17,175.00	11,921	12,980	5,053	16.47	307
1989	83,518.00	57,353	62,450	25,244	16.58	1,523
1990	24,328.00	16,525	17,994	7,551	16.68	453
1991	59,235.00	39,785	43,321	18,876	16.77	1,126
1992	141,822.00	94,098	102,460	46,453	16.87	2,754
1993	26,244.00	17,200	18,729	8,828	16.95	521
1994	214,182.00	138,483	150,790	74,101	17.04	4,349
1995	37,880.00	24,165	26,313	13,461	17.11	787
1996	89,930.00	56,528	61,552	32,875	17.19	1,912
1997	169,271.00	104,764	114,074	63,660	17.26	3,688
1998	67,057.09	40,829	44,457	25,953	17.33	1,498
1999	164,083.00	98,200	106,927	65,360	17.39	3,758
2000	31,277.00	18,380	20,013	12,827	17.45	735
2001	48,710.00	28,064	30,558	20,587	17.51	1,176
2002	66,987.31	37,781	41,139	29,198	17.57	1,662
2003	0.04		0			
2004	12,320.82	6,633	7,222	5,714	17.67	323
2005	10,028.06	5,257	5,724	4,805	17.72	271
2006	47,617.22	24,275	26,432	23,566	17.76	1,327
2008	366,599.53	175,247	190,821	194,108	17.84	10,880

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
NEWPORT						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -5						
2009	253,147.32	116,587	126,948	138,857	17.88	7,766
2010	636,411.98	281,326	306,327	361,905	17.92	20,196
2011	60,719.61	25,659	27,939	35,816	17.95	1,995
2012	31,512.46	12,654	13,779	19,310	17.99	1,073
2014	53,287.83	18,931	20,613	35,339	18.05	1,958
2016	3,063,049.39	925,237	1,007,462	2,208,740	18.10	122,030
2017	2,859,549.08	777,925	847,058	2,155,468	18.13	118,890
2018	1,907,457.63	457,927	498,622	1,504,208	18.15	82,876
2019	167,922.77	34,437	37,497	138,822	18.17	7,640
2020	27,918.13	4,651	5,064	24,250	18.19	1,333
2021	71,870.99	8,949	9,744	65,720	18.21	3,609
	12,196,541.26	4,728,435	5,148,646	7,657,722		428,309
OTHER						
SURVIVOR CURVE.. IOWA 60-R2.5						
NET SALVAGE PERCENT.. -5						
1963	4,009.00	3,220	3,659	550	14.11	39
1968	527.00	401	456	98	16.55	6
1975	1,118.00	772	877	297	20.54	14
1999	21,103.00	8,095	9,199	12,959	38.08	340
	26,757.00	12,488	14,191	13,904		399
	24,722,260.15	9,664,431	10,170,890	15,787,483		1,087,320
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					14.5	4.40

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 362.00 GAS HOLDERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
LINNTON						
INTERIM SURVIVOR CURVE.. IOWA 60-R3						
PROBABLE RETIREMENT YEAR.. 6-2036						
NET SALVAGE PERCENT.. -20						
1969	1,720,509.00	1,705,967	1,680,444	384,167	9.83	39,081
1974	815.00	789	777	201	10.53	19
1983	969.00	892	879	284	11.40	25
1991	1,017.00	883	870	351	11.85	30
1993	18,991.00	16,194	15,952	6,837	11.93	573
2006	362,872.63	254,245	250,441	185,006	12.28	15,066
2009	488,646.40	315,183	310,468	275,908	12.33	22,377
2015	53,824.55	26,127	25,736	38,853	12.41	3,131
2016	1,686,933.32	758,999	747,644	1,276,676	12.42	102,792
2017	221,486.45	90,941	89,580	176,203	12.42	14,187
	4,556,064.35	3,170,220	3,122,790	2,344,487		197,281
NEWPORT						
INTERIM SURVIVOR CURVE.. IOWA 60-R3						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -20						
1977	5,551,294.00	4,918,558	6,156,563	504,990	14.60	34,588
1978	10,302.00	9,054	11,333	1,030	14.82	70
1994	72,915.00	54,346	68,025	19,473	17.16	1,135
1996	138,492.00	100,284	125,526	40,665	17.33	2,347
2006	900.36	528	661	420	17.93	23
2017	153,200.46	47,874	59,924	123,917	18.29	6,775
	5,927,103.82	5,130,644	6,422,031	690,494		44,938
OTHER						
SURVIVOR CURVE.. IOWA 60-R3						
NET SALVAGE PERCENT.. -20						
2003	1,600.14	624	1,312	608	40.51	15
	1,600.14	624	1,312	608		15
	10,484,768.31	8,301,488	9,546,133	3,035,589		242,234
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					12.5	2.31

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.10 LIQUEFACTION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
LINNTON						
INTERIM SURVIVOR CURVE.. IOWA 50-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2036						
NET SALVAGE PERCENT.. -5						
1969	828,857.00	728,737	870,300			
1970	15,188.00	13,287	15,947			
1971	1,613.00	1,404	1,694			
1972	4,261.00	3,688	4,474			
1974	1,957.00	1,675	2,055			
1975	268.00	228	281			
1976	25,955.00	21,957	27,104	149	9.26	16
1980	100,679.00	83,068	102,540	3,173	9.92	320
1986	715.00	566	699	52	10.73	5
1987	68,778.00	53,990	66,646	5,571	10.84	514
1990	86,886.00	66,527	82,122	9,109	11.14	818
1991	51,422.00	39,018	48,164	5,829	11.23	519
1992	77,450.00	58,224	71,872	9,450	11.31	836
1994	15,589.00	11,487	14,180	2,189	11.46	191
1995	2,211.00	1,612	1,990	332	11.52	29
1996	6,143.00	4,428	5,466	984	11.59	85
1997	132,937.00	94,701	116,900	22,684	11.64	1,949
1998	157,516.00	110,774	136,741	28,651	11.70	2,449
1999	78,997.00	54,811	67,659	15,288	11.75	1,301
2000	88,122.00	60,264	74,391	18,138	11.80	1,537
2001	284,485.00	191,511	236,403	62,306	11.85	5,258
2002	44,801.00	29,665	36,619	10,422	11.89	877
2003	131,666.14	85,640	105,715	32,534	11.93	2,727
2004	219,028.75	139,722	172,474	57,506	11.97	4,804
2005	46,627.74	29,138	35,968	12,991	12.00	1,083
2006	127,298.03	77,726	95,946	37,717	12.04	3,133
2007	8,445.29	5,029	6,208	2,660	12.07	220
2009	70,412.91	39,560	48,833	25,100	12.13	2,069
2012	72,983.52	36,594	45,172	31,461	12.20	2,579
2015	53,824.55	22,799	28,143	28,372	12.26	2,314
2016	402,787.76	157,951	194,977	227,951	12.28	18,563
2017	111,506.66	39,864	49,209	67,873	12.30	5,518
2019	55,575.58	15,373	18,977	39,378	12.33	3,194
2020	75,214.89	17,217	21,253	57,723	12.34	4,678
2021	461,522.51	80,492	99,360	385,238	12.35	31,193
	3,911,724.33	2,378,727	2,906,482	1,200,829		98,779

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.10 LIQUEFACTION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
NEWPORT						
INTERIM SURVIVOR CURVE.. IOWA 50-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -5						
1977	5,236,797.00	4,175,830	4,395,745	1,102,892	11.74	93,943
1978	16,348.00	12,910	13,590	3,576	12.05	297
1979	5,538.00	4,331	4,559	1,256	12.35	102
1984	21,919.00	16,276	17,133	5,882	13.77	427
1985	11,525.00	8,464	8,910	3,192	14.03	228
1986	14,148.00	10,271	10,812	4,043	14.29	283
1987	8,543.00	6,131	6,454	2,516	14.53	173
1989	21,759.00	15,245	16,048	6,799	14.98	454
1990	2,886.00	1,997	2,102	928	15.19	61
1991	51,784.00	35,368	37,231	17,143	15.39	1,114
1992	4,079.00	2,749	2,894	1,389	15.58	89
1993	16,196.00	10,770	11,337	5,669	15.75	360
1994	1,119.00	733	772	403	15.92	25
1996	186,692.00	118,692	124,943	71,084	16.23	4,380
1997	151,762.28	94,925	99,924	59,426	16.37	3,630
1998	390,938.46	240,397	253,057	157,428	16.50	9,541
1999	249,536.00	150,686	158,622	103,391	16.63	6,217
2001	180,788.00	104,935	110,461	79,366	16.86	4,707
2002	30,345.79	17,242	18,150	13,713	16.96	809
2004	76,018.79	41,160	43,328	36,492	17.16	2,127
2005	1,705.00	899	946	844	17.24	49
2006	28,555.27	14,628	15,398	14,585	17.33	842
2007	35,357.72	17,562	18,487	18,639	17.40	1,071
2008	62,378.35	29,930	31,506	33,991	17.48	1,945
2014	356,850.62	127,163	133,860	240,833	17.83	13,507
2017	3,561,611.76	970,749	1,021,872	2,717,820	17.97	151,242
2018	4,848,560.74	1,164,258	1,225,572	3,865,417	18.01	214,626
2019	174,662.05	35,828	37,715	145,680	18.04	8,075
2021	221,992.66	27,675	29,132	203,960	18.11	11,262
2022	6,620,268.05	517,801	545,070	6,406,211	18.14	353,154
2023	109,895.48	3,031	3,191	112,200	18.16	6,178
	22,700,560.02	7,978,636	8,398,821	15,436,767		890,918
	26,612,284.35	10,357,363	11,305,303	16,637,596		989,697
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					16.8	3.72

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.20 VAPORIZING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
LINNTON						
INTERIM SURVIVOR CURVE.. IOWA 40-R4						
PROBABLE RETIREMENT YEAR.. 6-2036						
NET SALVAGE PERCENT.. -5						
1969	18,960.00	19,216	19,438	470	1.39	338
1971	13,254.00	13,263	13,416	500	1.88	266
1972	2,368.00	2,354	2,381	105	2.13	49
1973	13,251.00	13,082	13,233	680	2.39	285
1974	2,259.00	2,214	2,240	132	2.66	50
1975	269.00	262	265	17	2.93	6
1976	386,664.00	373,416	377,731	28,266	3.21	8,806
1986	12,078.00	10,517	10,639	2,043	6.79	301
1987	177,462.00	152,273	154,033	32,302	7.25	4,455
1990	1,140,108.00	934,622	945,423	251,691	8.58	29,335
1991	181,570.00	146,592	148,286	42,362	8.98	4,717
1993	1.00	1	1			
1994	32,761.00	25,280	25,572	8,827	10.01	882
1995	11,181.00	8,500	8,598	3,142	10.29	305
2006	321,206.91	199,163	201,465	135,803	12.01	11,307
2015	53,824.46	22,958	23,223	33,292	12.41	2,683
2017	2,091,400.63	752,471	761,167	1,434,804	12.45	115,245
	4,458,618.00	2,676,184	2,707,111	1,974,438		179,030
NEWPORT						
INTERIM SURVIVOR CURVE.. IOWA 40-R4						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -5						
1977	60,825.00	58,294	42,719	21,147	3.49	6,059
1990	15,899.00	12,698	9,305	7,389	9.55	774
1991	4,866.00	3,805	2,788	2,321	10.17	228
1992	2,226.00	1,703	1,248	1,089	10.79	101
2002	180.00	108	79	110	15.80	7
2004	68,445.68	38,694	28,356	43,512	16.41	2,652
2011	1,113,015.02	481,397	352,780	815,886	17.76	45,940
2015	95,076.50	31,802	23,305	76,525	18.14	4,219

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.20 VAPORIZING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
NEWPORT						
INTERIM SURVIVOR CURVE.. IOWA 40-R4						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -5						
2017	2,379,279.54	655,089	480,065	2,018,178	18.26	110,525
2020	2,967,835.97	498,721	365,475	2,750,753	18.37	149,742
2021	10,560.25	1,326	972	10,117	18.40	550
	6,718,208.96	1,783,637	1,307,093	5,747,026		320,797
	11,176,826.96	4,459,821	4,014,204	7,721,464		499,827
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					15.4	4.47

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.30 COMPRESSOR EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
LINNTON						
INTERIM SURVIVOR CURVE.. IOWA 35-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2036						
NET SALVAGE PERCENT.. -5						
1982	85,687.00	70,801	79,182	10,789	7.37	1,464
1983	1,117.00	915	1,023	150	7.58	20
1986	21,516.00	17,164	19,196	3,396	8.19	415
1996	19,421.00	13,896	15,541	4,851	9.98	486
2008	51,410.22	29,245	32,707	21,274	11.30	1,883
2022	233,035.00	25,805	28,860	215,827	11.96	18,046
2023	950,567.29	37,648	42,105	955,991	11.99	79,732
	1,362,753.51	195,474	218,613	1,212,278		102,046
NEWPORT						
INTERIM SURVIVOR CURVE.. IOWA 35-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -5						
1997	20,827.00	13,239	19,854	2,014	13.03	155
2003	178,502.00	99,048	148,539	38,888	14.58	2,667
2005	16,780.44	8,804	13,203	4,416	15.01	294
2014	1,385,829.26	484,453	726,516	728,604	16.45	44,292
2016	2,266,969.59	672,916	1,009,148	1,371,171	16.67	82,254
2017	497,806.37	133,115	199,628	323,069	16.77	19,265
2018	256,596.34	60,478	90,697	178,730	16.86	10,601
2020	121,183.04	19,799	29,692	97,550	17.04	5,725
2021	820,790.65	100,558	150,803	711,027	17.11	41,556
2022	13,113.00	1,010	1,515	12,254	17.19	713
2023	2,152,831.40	58,682	88,003	2,172,470	17.26	125,867
	7,731,229.09	1,652,102	2,477,597	5,640,194		333,389
	9,093,982.60	1,847,576	2,696,210	6,852,472		435,435
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					15.7	4.79

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.40 MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
LINNTON						
INTERIM SURVIVOR CURVE.. IOWA 50-R4						
PROBABLE RETIREMENT YEAR.. 6-2036						
NET SALVAGE PERCENT.. -5						
1969	461,537.00	432,513	345,073	139,541	5.37	25,985
1970	2,640.00	2,457	1,960	812	5.67	143
1971	9,831.00	9,085	7,248	3,074	5.98	514
1972	6,325.00	5,803	4,630	2,011	6.29	320
1974	1,327.00	1,198	956	438	6.96	63
1975	374.00	335	267	125	7.30	17
1985	3,662.00	2,986	2,382	1,463	10.38	141
1988	3,818.00	3,031	2,418	1,591	10.92	146
1990	33,747.00	26,288	20,973	14,461	11.21	1,290
2002	17,323.00	11,578	9,237	8,952	12.18	735
2006	28,273.59	17,383	13,869	15,819	12.33	1,283
2009	168,291.28	95,165	75,926	100,780	12.39	8,134
2013	151,561.74	72,733	58,029	101,111	12.45	8,121
2014	359,909.59	163,387	130,355	247,550	12.46	19,868
2017	1,203,718.97	432,407	344,988	918,917	12.48	73,631
2018	426,268.10	136,915	109,235	338,346	12.48	27,111
2020	366,277.42	84,183	67,164	317,427	12.49	25,414
2021	330,436.66	57,866	46,167	300,791	12.49	24,083
2022	1,919,653.00	216,116	172,424	1,843,211	12.49	147,575
2023	2,387,812.46	96,502	76,992	2,430,211	12.49	194,573
	7,882,786.81	1,867,931	1,490,295	6,786,631		559,147
NEWPORT						
INTERIM SURVIVOR CURVE.. IOWA 50-R4						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -5						
1977	55,203.00	47,540	16,142	41,821	8.97	4,662
1988	5,884.00	4,329	1,470	4,708	14.31	329
1989	4,775.00	3,462	1,176	3,838	14.68	261
1990	13,736.00	9,811	3,331	11,091	15.02	738
1991	20,511.00	14,429	4,899	16,637	15.34	1,085
1992	3,371.00	2,336	793	2,746	15.63	176
2017	10,187,159.88	2,787,940	946,648	9,749,870	18.41	529,596
2018	154,590.07	37,322	12,673	149,647	18.42	8,124
2019	116,849.50	24,024	8,157	114,535	18.44	6,211
2020	101,306.78	16,961	5,759	100,613	18.45	5,453

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.40 MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
NEWPORT						
INTERIM SURVIVOR CURVE.. IOWA 50-R4						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. -5						
2021	188,716.81	23,634	8,025	190,128	18.46	10,299
2022	3,336,609.95	263,143	89,351	3,414,090	18.47	184,845
2023	1,195,710.81	33,095	11,237	1,244,259	18.47	67,366
	15,384,423.80	3,268,026	1,109,662	15,043,983		819,145
	23,267,210.61	5,135,957	2,599,957	21,830,614		1,378,292
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					15.8	5.92

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.50 CNG REFUELING FACILITIES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 31-R3						
NET SALVAGE PERCENT.. -5						
1981	19,620.00	18,973	20,601			
1982	9,560.00	9,160	10,038			
1983	1,563.00	1,484	1,641			
1984	40,443.00	38,041	42,465			
1985	1,466.00	1,365	1,539			
1986	7,018.00	6,466	7,369			
1990	63,479.00	55,537	64,168	2,485	5.17	481
1991	52,207.00	44,950	51,936	2,881	5.58	516
1992	19,707.00	16,674	19,265	1,427	6.02	237
1993	61,210.00	50,815	58,713	5,558	6.49	856
1994	348,384.00	283,322	327,355	38,448	6.99	5,500
1995	293,359.00	233,306	269,566	38,461	7.52	5,114
1996	228,151.00	177,041	204,556	35,003	8.09	4,327
1997	47,984.57	36,276	41,914	8,470	8.68	976
1998	28,835.82	21,204	24,499	5,779	9.29	622
1999	4,283.40	3,057	3,532	966	9.93	97
2002	1,300.00	836	966	399	12.01	33
2004	49,674.00	29,461	34,040	18,118	13.49	1,343
2012	117,630.32	43,349	50,086	73,426	20.12	3,649
2013	123,013.59	41,624	48,093	81,071	21.01	3,859
2014	1,532,406.79	471,284	544,530	1,064,497	21.92	48,563
2023	230,439.48	3,825	4,419	237,542	30.51	7,786
	3,281,734.97	1,588,050	1,831,291	1,614,531		83,959

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 19.2 2.56

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 363.60 LNG REFUELING FACILITIES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S2.5						
NET SALVAGE PERCENT.. -5						
1982	349,437.00	272,573	366,909			
1983	61,620.00	47,433	64,701			
1984	42,767.00	32,452	44,905			
1985	5,173.00	3,867	5,432			
1986	108.00	79	113			
1991	935.00	627	918	64	16.26	4
1992	113,889.00	74,727	109,363	10,220	16.88	605
1993	54,468.00	34,912	51,094	6,097	17.53	348
1994	38,218.00	23,899	34,976	5,153	18.20	283
1995	45,678.00	27,828	40,727	7,235	18.89	383
1996	13,387.00	7,931	11,607	2,449	19.61	125
1997	5,310.00	3,055	4,471	1,104	20.34	54
1999	8,483.00	4,576	6,697	2,210	21.88	101
	739,473.00	533,959	741,913	34,534		1,903

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.1 0.26

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 365.20 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1964	94,094.00	68,451	71,319	22,775	20.44	1,114
1965	445,096.00	319,579	332,971	112,125	21.15	5,301
1966	469,977.00	332,871	346,819	123,158	21.88	5,629
1967	159,280.00	111,262	115,924	43,356	22.61	1,918
1968	20,603.00	14,186	14,780	5,823	23.36	249
1976	28,031.00	16,938	17,648	10,383	29.68	350
1977	12,082.00	7,167	7,467	4,615	30.51	151
1979	9,187.00	5,241	5,461	3,726	32.21	116
1981	5,959.00	3,262	3,399	2,560	33.94	75
1989	815,816.00	368,096	383,521	432,295	41.16	10,503
1990	401,012.00	175,912	183,283	217,729	42.10	5,172
1991	143,060.00	60,962	63,517	79,543	43.04	1,848
1992	13,749.00	5,687	5,925	7,824	43.98	178
2002	395,428.00	112,618	117,337	278,091	53.64	5,184
2003	1,181,773.75	321,123	334,579	847,195	54.62	15,511
2004	2,075,820.15	536,952	559,453	1,516,367	55.60	27,273
2009	184,208.96	35,492	36,979	147,230	60.55	2,432
	6,455,176.86	2,495,799	2,600,382	3,854,795		83,004

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 46.4 1.29

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 366.30 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
NET SALVAGE PERCENT.. 0						
1966	85,985.00	70,383	75,892	10,093	9.98	1,011
2004	898,180.86	302,283	325,944	572,237	36.49	15,682
2005	57,818.26	18,512	19,961	37,857	37.39	1,012
2016	504,088.49	66,998	72,242	431,846	47.69	9,055
	1,546,072.61	458,176	494,039	1,052,034		26,760

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 39.3 1.73

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 367.00 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. -40						
1931	541.00	688	703	54	6.43	8
1964	631,743.00	634,400	647,969	236,471	19.79	11,949
1965	4,159,205.00	4,125,108	4,213,338	1,609,549	20.41	78,861
1966	3,249,729.00	3,182,778	3,250,853	1,298,768	21.03	61,758
1967	98,086.00	94,810	96,838	40,482	21.67	1,868
1968	4,871.00	4,645	4,744	2,075	22.32	93
1969	17,024.00	16,009	16,351	7,483	22.98	326
1972	18,881.00	16,985	17,348	9,085	25.02	363
1976	1,227,425.00	1,034,233	1,056,354	662,041	27.87	23,755
1977	4,968.00	4,113	4,201	2,754	28.61	96
1978	12,612.00	10,253	10,472	7,185	29.35	245
1980	34,127.00	26,708	27,279	20,499	30.87	664
1981	510,647.00	391,768	400,147	314,759	31.64	9,948
1982	162,214.00	121,921	124,529	102,571	32.42	3,164
1985	29,321.00	20,648	21,090	19,959	34.79	574
1986	17,437.00	11,997	12,254	12,158	35.60	342
1989	522,156.00	333,447	340,579	390,439	38.07	10,256
1990	139,805.00	86,930	88,789	106,938	38.91	2,748
1991	940.00	569	581	735	39.75	18
1993	136,072.00	77,669	79,330	111,171	41.46	2,681
1994	132,571.00	73,392	74,962	110,637	42.32	2,614
1995	1,514.00	812	829	1,291	43.19	30
2001	536,035.70	230,065	234,986	515,464	48.54	10,619
2002	255,592.00	105,048	107,295	250,534	49.45	5,066
2003	145,757.63	57,253	58,478	145,583	50.36	2,891
2004	102,958.14	38,528	39,352	104,789	51.29	2,043
2007	65,936.81	20,994	21,443	70,869	54.08	1,310
2009	4,600,512.66	1,291,815	1,319,445	5,121,273	55.96	91,517
2010	19,347,382.59	5,065,145	5,173,481	21,912,855	56.91	385,044
2011	8,045,641.26	1,953,498	1,995,280	9,268,618	57.86	160,190
2012	31,403,683.70	7,028,270	7,178,594	36,786,563	58.81	625,515
2013	48,073,769.43	9,835,701	10,046,072	57,257,205	59.77	957,959
2014	17,931,560.05	3,324,547	3,395,654	21,708,530	60.73	357,460
2015	5,312,454.39	881,857	900,719	6,536,717	61.70	105,944
2016	4,539,331.08	665,439	679,672	5,675,392	62.67	90,560
2017	3,119,026.03	396,753	405,239	3,961,397	63.64	62,247
2018	14,893,908.12	1,605,563	1,639,903	19,211,568	64.61	297,347
2019	9,883,982.95	871,767	890,413	12,947,163	65.59	197,395
2020	9,993,194.34	687,492	702,196	13,288,276	66.56	199,644

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 367.00 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. -40						
2021	5,441,231.52	267,687	273,412	7,344,312	67.54	108,740
2022	25,260,061.74	747,597	763,587	34,600,499	68.52	504,969
2023	23,827,440.16	233,509	238,504	33,119,912	69.51	476,477
	243,891,349.30	45,578,411	46,553,265	294,894,624		4,855,298
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					60.7	1.99

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 367.21 MAINS - NORTH MIST

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. -40						
1989	1,430,448.00	913,478	1,153,074	849,553	38.07	22,316
1990	81,695.00	50,798	64,122	50,251	38.91	1,291
1991	2,019.00	1,221	1,541	1,286	39.75	32
2004	181.00	68	86	167	51.29	3
2013	480,239.39	98,255	124,026	548,309	59.77	9,174
	1,994,582.39	1,063,820	1,342,849	1,449,566		32,816

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 44.2 1.65

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 367.22 MAINS - SOUTH MIST

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. -40						
1989	14,864,615.00	9,492,484	12,088,213	8,722,248	38.07	229,111
1990	75,414.00	46,892	59,715	45,865	38.91	1,179
1991	522.00	316	402	329	39.75	8
1993	8,713.00	4,973	6,333	5,865	41.46	141
	14,949,264.00	9,544,665	12,154,663	8,774,307		230,439

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.1 1.54

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 367.23 MAINS - SOUTH MIST

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. -40						
1999	33,516,134.00	15,598,476	17,448,553	29,474,035	46.73	630,730
2000	64,133.00	28,693	32,096	57,690	47.63	1,211
2001	603.00	259	290	554	48.54	11
2003	382,180.95	150,120	167,925	367,128	50.36	7,290
2013	918,290.41	187,879	210,163	1,075,444	59.77	17,993
	34,881,341.36	15,965,427	17,859,027	30,974,851		657,235
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					47.1	1.88

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 367.24 MAINS - 11.7M S MIST

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. -40						
2003	17,466,181.89	6,860,681	7,804,954	16,647,701	50.36	330,574
	17,466,181.89	6,860,681	7,804,954	16,647,701		330,574
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					50.4	1.89

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 367.25 MAINS - 12M NORTH S MIST

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. -40						
2003	10,767,917.66	4,229,617	4,746,732	10,328,353	50.36	205,090
2004	7,746,047.21	2,898,617	3,253,003	7,591,463	51.29	148,011
2005	16,294.30	5,797	6,506	16,306	52.21	312
2013	83,391.98	17,062	19,148	97,601	59.77	1,633
	18,613,651.15	7,151,093	8,025,389	18,033,723		355,046
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					50.8	1.91

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 367.26 MAINS - 38M NORTH S MIST

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. -40						
2003	38,081,707.37	14,958,418	16,867,772	36,446,618	50.36	723,722
2004	30,150,968.21	11,282,673	12,722,839	29,488,516	51.29	574,937
	68,232,675.58	26,241,091	29,590,611	65,935,135		1,298,659
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					50.8	1.90

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 368.00 COMPRESSOR STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R3						
NET SALVAGE PERCENT.. -5						
2008	7,723,454.21	2,654,524	3,373,630	4,735,997	30.27	156,458
	7,723,454.21	2,654,524	3,373,630	4,735,997		156,458
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					30.3	2.03

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 369.00 MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R2.5						
NET SALVAGE PERCENT.. -10						
1965	14,697.00	13,367	16,167			
1966	25,913.00	23,379	28,504			
1967	5,028.00	4,499	5,531			
1977	45,443.00	36,331	49,987			
1987	26,938.00	17,998	29,632			
1992	77,606.00	45,910	85,367			
2002	11,991.00	5,054	10,877	2,313	30.84	75
2003	189,080.78	76,290	164,187	43,802	31.66	1,384
2004	12,068.68	4,649	10,005	3,271	32.49	101
2006	133,313.77	46,399	99,857	46,788	34.18	1,369
2012	33,883.82	7,894	16,989	20,283	39.41	515
2013	3,180,851.99	678,794	1,460,865	2,038,072	40.30	50,573
2014	106,367.62	20,593	44,319	72,685	41.20	1,764
2015	106,367.62	18,463	39,735	77,269	42.11	1,835
	3,969,550.28	999,620	2,062,022	2,304,483		57,616

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 40.0 1.45

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 374.20 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1900	208,257.00	208,257	208,257			
1952	1,813.00	1,505	1,813			
1956	11,140.00	8,902	11,140			
1960	200.00	153	200			
1962	100.00	75	100			
1963	3,425.00	2,524	3,425			
1964	750.00	546	750			
1968	9,669.00	6,657	9,669			
1971	2,507.00	1,650	2,507			
1974	3,304.00	2,069	3,304			
1975	3,640.00	2,240	3,640			
1976	804.00	486	804			
1977	10,277.00	6,096	10,277			
1978	6,845.00	3,984	6,845			
1979	1,589.00	907	1,589			
1980	1,565.00	875	1,565			
1981	8,720.00	4,774	8,720			
1982	1,039.00	557	1,039			
1983	252.00	132	252			
1984	764.00	391	764			
1985	4,779.00	2,390	4,779			
1986	3,752.00	1,831	3,752			
1987	9,733.00	4,630	9,733			
1988	3,902.00	1,808	3,902			
1989	74,994.00	33,837	74,994			
1990	10,006.00	4,389	10,006			
1991	185,065.00	78,862	185,065			
1992	64,966.00	26,870	64,966			
1993	29,877.00	11,979	29,877			
1994	43,236.00	16,787	43,236			
1995	112,714.00	42,321	112,714			
1996	18,109.00	6,568	18,109			
1997	35,832.00	12,532	35,832			
1998	15,125.00	5,096	15,125			
1999	23,933.00	7,751	23,933			
2000	14,758.00	4,589	14,758			
2001	52,915.00	15,762	52,915			
2002	123,008.00	35,033	123,008			
2003	301,674.10	81,974	301,674			

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 374.20 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
2009	2,201.96	424	1,988	214	60.55	4
2010	23,150.32	4,155	19,485	3,665	61.54	60
2013	455,790.26	63,688	298,660	157,130	64.52	2,435
	1,886,180.64	716,056	1,725,171	161,010		2,499
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					64.4	0.13

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-S1						
NET SALVAGE PERCENT.. 0						
1913	2,827.00	2,827	2,827			
1927	2,144.00	2,144	2,144			
1953	14.00	14	14			
1956	32,928.00	32,298	21,328	11,600	0.67	11,600
1958	3,307.00	3,194	2,109	1,198	1.20	998
1959	871.00	834	551	320	1.47	218
1960	6,983.00	6,634	4,381	2,602	1.75	1,487
1961	726.00	684	452	274	2.02	136
1962	2,742.00	2,561	1,691	1,051	2.31	455
1965	298.00	271	179	119	3.16	38
1990	25,470.00	16,832	11,115	14,355	11.87	1,209
1993	1,907.00	1,187	784	1,123	13.21	85
2016	1,356,163.12	275,884	182,177	1,173,986	27.88	42,109
2018	83,178.16	12,667	8,365	74,813	29.67	2,522
2022	26,468.45	1,127	744	25,724	33.51	768
2023	41,571.59	594	392	41,180	34.50	1,194
	1,587,598.32	359,752	239,253	1,348,345		62,819

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 21.5 3.96

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 376.11 MAINS - HP 4" AND LESS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -65						
1906	38.00	63	63			
1910	1,486.00	2,452	2,452			
1911	33.00	54	54			
1912	33.00	54	54			
1913	846.84	1,397	1,397			
1914	389.00	640	642			
1915	258.22	423	426			
1916	203.00	332	335			
1917	91.00	148	150			
1918	420.08	682	693			
1919	2,922.01	4,727	4,821			
1920	530.00	854	874			
1921	1,394.00	2,239	2,300			
1922	3,143.77	5,028	5,187			
1923	824.00	1,313	1,360			
1924	92.28	146	152			
1925	10,444.49	16,510	17,233			
1926	3,628.84	5,713	5,988			
1927	3,028.90	4,749	4,982	16	3.23	5
1928	3,793.38	5,923	6,213	46	3.49	13
1929	598.77	931	977	11	3.74	3
1930	2,212.07	3,425	3,593	57	4.00	14
1931	736.11	1,135	1,191	24	4.26	6
1932	1,984.41	3,047	3,196	78	4.52	17
1933	404.00	618	648	19	4.78	4
1934	1,805.82	2,749	2,884	96	5.03	19
1935	105.33	160	168	6	5.29	1
1936	4,979.21	7,514	7,882	334	5.55	60
1937	1,098.10	1,650	1,731	81	5.81	14
1938	6.66	10	10	1	6.07	
1939	832.67	1,240	1,301	73	6.33	12
1940	4,948.84	7,336	7,695	471	6.60	71
1941	2,439.72	3,600	3,776	250	6.87	36
1942	9,590.13	14,085	14,775	1,049	7.14	147
1943	988.17	1,444	1,515	115	7.43	15
1944	2,042.04	2,970	3,115	254	7.71	33
1945	1,205.00	1,743	1,828	160	8.01	20
1946	23,985.29	34,516	36,206	3,370	8.31	406
1947	16,463.98	23,559	24,713	2,453	8.63	284
1948	545.40	776	814	86	8.95	10
1949	16,924.00	23,934	25,106	2,819	9.29	303
1950	17,887.98	25,142	26,373	3,142	9.63	326

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 376.11 MAINS - HP 4" AND LESS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -65						
1951	21,257.02	29,684	31,137	3,937	9.99	394
1952	18,288.79	25,367	26,609	3,568	10.36	344
1953	24,932.17	34,335	36,016	5,122	10.75	476
1954	14,568.02	19,914	20,889	3,148	11.15	282
1955	12,004.04	16,284	17,081	2,726	11.56	236
1956	244,057.60	328,414	344,494	58,201	11.99	4,854
1957	593,138.46	791,526	830,282	148,396	12.43	11,939
1958	525,092.37	694,725	728,741	137,661	12.88	10,688
1959	767,318.21	1,006,049	1,055,309	210,766	13.35	15,788
1960	997,185.67	1,295,027	1,358,437	286,919	13.84	20,731
1961	1,278,561.62	1,644,538	1,725,061	384,566	14.33	26,836
1962	4,974.67	6,333	6,643	1,565	14.85	105
1963	1,774,985.03	2,235,730	2,345,200	583,525	15.38	37,941
1964	2,841,770.78	3,540,511	3,713,868	975,054	15.92	61,247
1965	2,924,595.24	3,602,104	3,778,477	1,047,105	16.48	63,538
1966	3,645,285.91	4,437,000	4,654,253	1,360,469	17.05	79,793
1967	2,832,847.54	3,406,416	3,573,207	1,100,991	17.63	62,450
1968	3,032,314.73	3,600,088	3,776,362	1,226,957	18.23	67,304
1969	3,382,225.91	3,963,115	4,157,165	1,423,508	18.84	75,558
1970	3,057,816.01	3,534,906	3,707,989	1,337,407	19.46	68,726
1971	2,881,102.38	3,283,796	3,444,583	1,309,236	20.10	65,136
1972	2,913,836.19	3,273,026	3,433,286	1,374,544	20.75	66,243
1973	3,621,686.77	4,007,480	4,203,702	1,772,081	21.41	82,769
1974	2,977,758.19	3,244,302	3,403,156	1,510,145	22.08	68,394
1975	2,899,842.46	3,109,363	3,261,609	1,523,131	22.76	66,921
1976	3,803,064.00	4,011,204	4,207,608	2,067,448	23.45	88,164
1977	4,317,582.98	4,476,088	4,695,255	2,428,757	24.16	100,528
1978	6,036,665.11	6,149,412	6,450,511	3,509,986	24.87	141,133
1979	8,192,701.66	8,196,073	8,597,385	4,920,573	25.59	192,285
1980	8,529,471.79	8,372,683	8,782,642	5,290,986	26.33	200,949
1981	7,528,900.44	7,249,134	7,604,080	4,818,606	27.07	178,005
1982	7,008,142.49	6,614,285	6,938,146	4,625,289	27.82	166,258
1983	7,262,725.74	6,714,473	7,043,240	4,940,257	28.58	172,857
1984	9,837,418.10	8,902,460	9,338,359	6,893,381	29.35	234,868
1985	10,754,786.17	9,519,696	9,985,817	7,759,580	30.13	257,537
1986	10,465,733.32	9,056,617	9,500,064	7,768,396	30.91	251,323
1987	9,525,867.89	8,049,811	8,443,961	7,273,721	31.71	229,383
1988	9,712,002.05	8,009,998	8,402,199	7,622,604	32.51	234,470
1989	12,191,490.44	9,804,116	10,284,164	9,831,795	33.32	295,072
1990	12,991,704.53	10,177,318	10,675,639	10,760,673	34.14	315,193
1991	14,453,865.99	11,021,759	11,561,427	12,287,452	34.96	351,472
1992	17,006,491.30	12,605,713	13,222,938	14,837,773	35.80	414,463

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 376.11 MAINS - HP 4" AND LESS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -65						
1993	18,884,846.19	13,595,418	14,261,102	16,898,894	36.64	461,214
1994	20,593,727.69	14,381,208	15,085,368	18,894,283	37.49	503,982
1995	17,276,820.25	11,692,045	12,264,533	16,242,220	38.34	423,636
1996	16,693,187.22	10,928,537	11,463,641	16,080,118	39.21	410,102
1997	16,885,115.54	10,681,136	11,204,126	16,656,315	40.08	415,577
1998	18,874,654.18	11,522,976	12,087,186	19,055,993	40.95	465,348
1999	17,866,098.27	10,508,106	11,022,624	18,456,438	41.83	441,225
2000	16,422,214.70	9,287,920	9,742,692	17,353,962	42.72	406,226
2001	13,932,933.38	7,561,654	7,931,902	15,057,438	43.62	345,196
2002	12,921,435.37	6,717,622	7,046,543	14,273,825	44.52	320,616
2003	17,175,512.92	8,532,486	8,950,269	19,389,327	45.43	426,796
2004	16,298,243.59	7,720,185	8,098,195	18,793,907	46.34	405,566
2005	12,917,775.85	5,817,107	6,101,935	15,212,395	47.26	321,887
2006	16,079,402.14	6,865,430	7,201,588	19,329,426	48.18	401,192
2007	14,617,482.51	5,896,093	6,184,789	17,934,057	49.11	365,181
2008	8,414,054.06	3,193,134	3,349,482	10,533,707	50.05	210,464
2009	14,503,392.86	5,158,001	5,410,557	18,520,041	50.99	363,209
2010	4,338,858.45	1,439,555	1,510,041	5,649,075	51.93	108,782
2011	11,457,173.05	3,524,902	3,697,495	15,206,841	52.88	287,573
2012	17,083,653.84	4,844,113	5,081,299	23,106,730	53.83	429,254
2013	13,349,582.09	3,463,275	3,632,850	18,393,960	54.78	335,779
2014	14,720,206.95	3,460,117	3,629,538	20,658,803	55.74	370,628
2015	17,344,181.40	3,649,927	3,828,642	24,789,257	56.71	437,123
2016	21,703,509.94	4,038,383	4,236,118	31,574,673	57.67	547,506
2017	18,914,211.66	3,053,747	3,203,270	28,005,179	58.64	477,578
2018	22,768,384.04	3,115,125	3,267,654	34,300,180	59.61	575,410
2019	23,831,785.80	2,668,028	2,798,665	36,523,782	60.59	602,802
2020	19,749,843.71	1,724,517	1,808,956	30,778,286	61.56	499,972
2021	23,896,951.31	1,492,424	1,565,499	37,864,471	62.54	605,444
2022	21,464,946.66	806,449	845,935	34,571,227	63.52	544,257
2023	29,038,170.24	361,264	378,953	47,534,028	64.51	736,847
	733,069,799.15	377,976,788	396,483,311	813,081,858		18,030,844

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 45.1 2.46

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 376.12 MAINS - HP 4" AND OVER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -65						
1909	15,171.92	25,034	25,034			
1910	18,924.68	31,226	31,226			
1911	107.55	177	177			
1912	73.85	122	122			
1913	20,767.30	34,266	34,266			
1915	4,079.00	6,685	6,252	478	0.44	478
1916	10,173.75	16,632	15,555	1,232	0.60	1,232
1917	2,712.00	4,418	4,132	343	0.82	343
1918	4,687.00	7,610	7,117	617	1.04	593
1919	80.00	129	121	11	1.27	9
1920	9,605.00	15,480	14,478	1,370	1.51	907
1921	15,536.41	24,949	23,334	2,301	1.74	1,322
1922	37,159.00	59,435	55,587	5,725	1.99	2,877
1923	17,836.00	28,420	26,580	2,849	2.23	1,278
1924	5,562.00	8,827	8,256	921	2.48	371
1925	19,177.00	30,313	28,351	3,291	2.73	1,205
1926	36,316.09	57,174	53,473	6,449	2.98	2,164
1927	10,785.00	16,911	15,816	1,979	3.23	613
1928	13,629.16	21,281	19,903	2,585	3.49	741
1929	512.68	797	745	101	3.74	27
1930	56,369.00	87,285	81,635	11,374	4.00	2,844
1931	22,611.66	34,864	32,607	4,702	4.26	1,104
1932	220.60	339	317	47	4.52	10
1934	8,805.18	13,404	12,536	1,993	5.03	396
1935	5,966.83	9,044	8,459	1,386	5.29	262
1937	13,738.29	20,642	19,306	3,362	5.81	579
1939	5,571.02	8,297	7,760	1,432	6.33	226
1940	204.00	302	282	55	6.60	8
1941	2,385.00	3,519	3,291	644	6.87	94
1942	1,951.00	2,866	2,680	539	7.14	75
1945	4,704.00	6,805	6,364	1,398	8.01	175
1946	10,534.00	15,159	14,178	3,203	8.31	385
1947	133,674.27	191,278	178,896	41,667	8.63	4,828
1948	30,663.40	43,628	40,804	9,791	8.95	1,094
1949	5,025.44	7,107	6,647	1,645	9.29	177
1952	27,604.00	38,287	35,808	9,739	10.36	940
1953	8,981.10	12,368	11,567	3,252	10.75	303
1954	14,182.88	19,387	18,132	5,270	11.15	473
1955	83,723.80	113,575	106,223	31,921	11.56	2,761
1956	1,977,027.61	2,660,369	2,488,148	773,948	11.99	64,549
1957	537,549.99	717,345	670,907	216,050	12.43	17,381
1958	1,404,634.80	1,858,406	1,738,101	579,546	12.88	44,996

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 376.12 MAINS - HP 4" AND OVER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -65						
1959	1,333,005.20	1,747,734	1,634,593	564,866	13.35	42,312
1960	2,410,450.29	3,130,408	2,927,759	1,049,484	13.84	75,830
1961	2,065,022.94	2,656,117	2,484,172	923,116	14.33	64,418
1962	1,298,743.16	1,653,353	1,546,322	596,604	14.85	40,175
1963	2,811,692.92	3,541,544	3,312,280	1,327,013	15.38	86,282
1964	2,776,712.70	3,459,456	3,235,506	1,346,070	15.92	84,552
1965	2,559,514.74	3,152,449	2,948,373	1,274,826	16.48	77,356
1966	2,794,751.75	3,401,740	3,181,526	1,429,814	17.05	83,860
1967	1,920,831.87	2,309,744	2,160,221	1,009,152	17.63	57,241
1968	2,430,351.86	2,885,413	2,698,624	1,311,457	18.23	71,939
1969	2,044,666.70	2,395,833	2,240,737	1,132,963	18.84	60,136
1970	1,760,487.46	2,035,164	1,903,416	1,001,388	19.46	51,459
1971	2,739,194.38	3,122,053	2,919,945	1,599,726	20.10	79,588
1972	1,979,812.94	2,223,865	2,079,902	1,186,789	20.75	57,195
1973	2,348,449.39	2,598,613	2,430,390	1,444,551	21.41	67,471
1974	2,675,203.26	2,914,665	2,725,982	1,688,103	22.08	76,454
1975	1,602,030.21	1,717,781	1,606,579	1,036,771	22.76	45,552
1976	1,156,683.17	1,219,988	1,141,011	767,516	23.45	32,730
1977	1,168,399.94	1,211,294	1,132,880	794,980	24.16	32,905
1978	2,901,294.41	2,955,482	2,764,157	2,022,979	24.87	81,342
1979	2,901,671.84	2,902,866	2,714,947	2,072,812	25.59	81,001
1980	3,064,189.87	3,007,864	2,813,148	2,242,765	26.33	85,179
1981	4,847,160.57	4,667,045	4,364,921	3,632,894	27.07	134,204
1982	4,260,449.08	4,021,012	3,760,709	3,269,032	27.82	117,507
1983	4,289,416.52	3,965,615	3,708,899	3,368,638	28.58	117,867
1984	7,345,237.69	6,647,139	6,216,833	5,902,809	29.35	201,118
1985	5,441,494.56	4,816,588	4,504,783	4,473,683	30.13	148,479
1986	5,289,026.00	4,576,906	4,280,617	4,446,276	30.91	143,846
1987	3,764,429.16	3,181,121	2,975,189	3,236,119	31.71	102,054
1988	5,178,448.93	4,270,939	3,994,457	4,549,984	32.51	139,956
1989	5,078,987.18	4,084,405	3,819,999	4,560,330	33.32	136,865
1990	4,039,562.73	3,164,474	2,959,620	3,705,659	34.14	108,543
1991	7,798,905.92	5,947,036	5,562,051	7,306,144	34.96	208,986
1992	9,217,025.14	6,831,931	6,389,662	8,818,429	35.80	246,325
1993	9,743,044.14	7,014,130	6,560,066	9,515,957	36.64	259,715
1994	9,348,646.75	6,528,436	6,105,814	9,319,453	37.49	248,585
1995	12,319,839.38	8,337,421	7,797,693	12,530,042	38.34	326,814
1996	18,556,097.27	12,148,129	11,361,713	19,255,847	39.21	491,095
1997	19,387,197.32	12,263,895	11,469,984	20,518,892	40.08	511,948
1998	11,658,055.35	7,117,243	6,656,504	12,579,287	40.95	307,186
1999	11,780,404.27	6,928,751	6,480,214	12,957,453	41.83	309,765
2000	14,910,274.76	8,432,812	7,886,909	16,715,044	42.72	391,270

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 376.12 MAINS - HP 4" AND OVER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -65						
2001	13,447,850.32	7,298,390	6,825,924	15,363,029	43.62	352,201
2002	17,591,699.95	9,145,608	8,553,562	20,472,743	44.52	459,855
2003	29,998,069.85	14,902,501	13,937,779	35,559,036	45.43	782,721
2004	18,467,612.49	8,747,776	8,181,484	22,290,077	46.34	481,012
2005	24,461,006.29	11,015,231	10,302,153	30,058,507	47.26	636,024
2006	19,828,057.91	8,465,996	7,917,945	24,798,351	48.18	514,702
2007	21,085,887.60	8,505,183	7,954,595	26,837,120	49.11	546,470
2008	20,547,899.75	7,797,928	7,293,125	26,610,910	50.05	531,687
2009	4,701,878.38	1,672,181	1,563,931	6,194,168	50.99	121,478
2010	16,753,080.67	5,558,371	5,198,547	22,444,036	51.93	432,198
2011	10,916,634.19	3,358,601	3,141,180	14,871,266	52.88	281,227
2012	18,088,541.14	5,129,051	4,797,019	25,049,074	53.83	465,337
2013	25,619,210.27	6,646,379	6,216,122	36,055,575	54.78	658,189
2014	21,483,638.29	5,049,923	4,723,013	30,724,990	55.74	551,220
2015	17,138,799.86	3,606,706	3,373,224	24,905,796	56.71	439,178
2016	18,898,388.94	3,516,433	3,288,794	27,893,548	57.67	483,675
2017	20,107,462.58	3,246,400	3,036,242	30,141,071	58.64	514,002
2018	36,968,771.74	5,057,993	4,730,561	56,267,912	59.61	943,934
2019	34,459,044.69	3,857,776	3,608,041	53,249,383	60.59	878,848
2020	50,453,856.41	4,405,530	4,120,335	79,128,528	61.56	1,285,389
2021	28,864,939.34	1,802,688	1,685,990	45,941,160	62.54	734,588
2022	52,157,427.85	1,959,581	1,832,726	84,227,030	63.52	1,325,992
2023	29,742,883.10	370,031	346,077	48,729,680	64.51	755,382
	779,378,528.59	318,558,873	297,942,649	988,031,923		20,420,234

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 48.4 2.62

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 377.00 COMPRESSOR STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-S3						
NET SALVAGE PERCENT.. -5						
2003	818,380.00	546,231	718,571	140,728	10.93	12,875
2023	42,306.82	741	975	43,447	29.50	1,473
	860,686.82	546,972	719,546	184,175		14,348

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.8 1.67

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 378.00 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. -25						
1949	13,147.00	15,638	14,988	1,446	2.42	598
1950	2,585.00	3,058	2,931	300	2.68	112
1952	3,901.00	4,565	4,375	501	3.19	157
1953	7,573.00	8,813	8,447	1,019	3.45	295
1954	3,935.00	4,554	4,365	554	3.71	149
1955	13,406.00	15,430	14,789	1,968	3.96	497
1956	48,458.00	55,460	53,154	7,418	4.22	1,758
1957	30,840.00	35,096	33,637	4,913	4.48	1,097
1958	42,875.00	48,513	46,496	7,098	4.74	1,497
1959	36,309.00	40,848	39,150	6,236	5.00	1,247
1960	107,203.00	119,880	114,896	19,108	5.27	3,626
1961	66,657.00	74,073	70,994	12,327	5.55	2,221
1962	43,697.00	48,252	46,246	8,375	5.83	1,437
1963	66,875.00	73,345	70,296	13,298	6.13	2,169
1964	82,595.00	89,967	86,227	17,017	6.43	2,647
1965	155,371.00	167,995	161,011	33,203	6.75	4,919
1966	167,417.00	179,638	172,170	37,101	7.08	5,240
1967	95,011.00	101,139	96,934	21,830	7.42	2,942
1968	116,937.00	123,398	118,268	27,903	7.79	3,582
1969	103,704.00	108,474	103,964	25,666	8.16	3,145
1970	44,816.00	46,429	44,499	11,521	8.56	1,346
1971	104,156.00	106,838	102,396	27,799	8.97	3,099
1972	154,237.00	156,551	150,043	42,753	9.40	4,548
1973	127,698.00	128,177	122,848	36,774	9.85	3,733
1974	68,713.00	68,163	65,329	20,562	10.32	1,992
1975	47,726.00	46,760	44,816	14,842	10.81	1,373
1976	46,498.00	44,964	43,095	15,028	11.32	1,328
1977	209,427.00	199,741	191,437	70,347	11.85	5,936
1978	42,548.00	40,006	38,343	14,842	12.39	1,198
1979	159,252.00	147,467	141,336	57,729	12.96	4,454
1980	159,436.00	145,326	139,284	60,011	13.54	4,432
1981	122,295.00	109,637	105,079	47,790	14.14	3,380
1982	246,534.00	217,258	208,226	99,942	14.75	6,776
1983	244,704.00	211,730	202,928	102,952	15.39	6,690
1984	596,419.00	506,509	485,452	260,072	16.03	16,224
1985	270,231.00	224,967	215,615	122,174	16.70	7,316
1986	371,597.00	303,037	290,439	174,057	17.38	10,015
1987	307,786.00	245,690	235,476	149,256	18.07	8,260
1988	269,971.00	210,780	202,017	135,447	18.77	7,216
1989	300,385.00	229,119	219,594	155,887	19.49	7,998
1990	242,524.00	180,559	173,053	130,102	20.22	6,434
1991	539,949.00	391,868	375,577	299,359	20.97	14,276

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 378.00 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
NET SALVAGE PERCENT.. -25						
1992	464,086.00	328,109	314,469	265,638	21.72	12,230
1993	273,224.00	187,910	180,098	161,432	22.49	7,178
1994	575,924.00	385,005	368,999	350,906	23.26	15,086
1995	674,159.00	437,361	419,179	423,520	24.05	17,610
1996	1,135,006.00	713,635	683,968	734,790	24.85	29,569
1997	864,430.00	526,006	504,139	576,398	25.66	22,463
1998	600,436.00	353,056	338,379	412,166	26.48	15,565
1999	781,675.00	443,405	424,972	552,122	27.31	20,217
2000	942,827.00	515,019	493,608	684,926	28.15	24,331
2001	85,371.00	44,820	42,957	63,757	29.00	2,199
2002	729,133.00	367,118	351,856	559,560	29.86	18,739
2003	572,105.94	275,612	264,154	450,978	30.73	14,675
2004	933,123.87	429,237	411,393	755,012	31.60	23,893
2005	448,837.66	196,479	188,311	372,736	32.49	11,472
2006	341,438.24	141,868	135,970	290,828	33.38	8,713
2007	921,693.36	362,225	347,166	804,951	34.28	23,482
2008	1,038,546.13	384,522	368,536	929,647	35.19	26,418
2009	1,015,593.77	352,665	338,004	931,488	36.11	25,796
2010	1,776,089.88	575,897	551,956	1,668,156	37.03	45,049
2011	1,339,039.11	403,051	386,295	1,287,504	37.96	33,917
2012	1,530,066.81	424,976	407,309	1,505,275	38.89	38,706
2013	4,230,410.08	1,074,524	1,029,853	4,258,160	39.84	106,882
2014	3,336,812.27	769,135	737,160	3,433,855	40.78	84,204
2015	810,260.45	167,319	160,363	852,463	41.74	20,423
2016	1,873,752.16	342,428	328,193	2,013,997	42.69	47,177
2017	845,963.08	134,085	128,511	928,943	43.66	21,277
2018	2,723,320.39	366,287	351,059	3,053,091	44.62	68,424
2019	1,166,726.01	128,632	123,284	1,335,124	45.59	29,285
2020	2,955,890.46	253,468	242,931	3,451,932	46.57	74,124
2021	4,744,766.72	291,803	279,672	5,651,286	47.54	118,874
2022	4,199,464.10	155,380	148,921	5,100,409	48.52	105,120
2023	5,382,235.81	65,932	63,191	6,664,604	49.51	134,611
	55,197,805.30	16,876,681	16,175,076	52,822,181		1,415,068

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.3 2.56

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 379.00 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R2.5						
NET SALVAGE PERCENT.. -25						
1956	90,440.00	99,054	111,948	1,102	6.19	178
1957	415.00	452	511	8	6.44	1
1958	6,571.00	7,115	8,041	173	6.69	26
1959	140.00	151	171	4	6.94	1
1960	126,308.00	135,150	152,742	5,143	7.20	714
1961	9,016.00	9,586	10,834	436	7.47	58
1962	8,119.00	8,576	9,692	457	7.75	59
1963	18,246.00	19,140	21,631	1,176	8.04	146
1964	64,144.00	66,806	75,502	4,678	8.34	561
1965	56,664.00	58,562	66,185	4,645	8.66	536
1966	20,596.00	21,116	23,865	1,880	8.99	209
1967	7,958.00	8,091	9,144	804	9.33	86
1968	12,365.00	12,464	14,086	1,370	9.68	142
1969	35,068.00	35,015	39,573	4,262	10.06	424
1970	9,987.00	9,875	11,160	1,324	10.45	127
1971	29,853.00	29,219	33,022	4,294	10.85	396
1972	84,792.00	82,079	92,763	13,227	11.28	1,173
1973	28,044.00	26,838	30,332	4,723	11.72	403
1974	8,729.00	8,253	9,327	1,584	12.18	130
1975	11,764.00	10,982	12,412	2,293	12.66	181
1976	19,765.00	18,209	20,579	4,127	13.15	314
1977	47,198.00	42,879	48,461	10,536	13.66	771
1980	97,555.00	84,653	95,672	26,272	15.29	1,718
1981	36,714.00	31,326	35,404	10,488	15.87	661
1982	29,076.00	24,380	27,554	8,791	16.46	534
1983	6,973.00	5,741	6,488	2,228	17.07	131
1984	29,051.00	23,466	26,521	9,793	17.69	554
1986	84,113.00	65,251	73,745	31,396	18.97	1,655
1987	12,520.00	9,506	10,743	4,907	19.63	250
1988	31,995.00	23,756	26,848	13,146	20.30	648
1989	4,938.00	3,581	4,047	2,126	20.99	101
1990	2,738.00	1,939	2,191	1,232	21.68	57
1991	34,959.00	24,130	27,271	16,428	22.39	734
1992	1,830.00	1,230	1,390	898	23.11	39
1993	979.00	640	723	501	23.84	21
1996	28,701.00	17,156	19,389	16,487	26.09	632
2000	206,808.00	107,437	121,422	137,088	29.22	4,692
2001	40,639.00	20,299	22,941	27,858	30.02	928
2002	220.00	105	119	156	30.84	5
2004	302.39	132	149	229	32.49	7
2005	155,306.30	64,724	73,149	120,984	33.33	3,630
2009	128,042.07	42,382	47,899	112,154	36.76	3,051

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 379.00 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R2.5						
NET SALVAGE PERCENT.. -25						
2010	135,098.10	41,745	47,179	121,694	37.64	3,233
2011	59,276.55	17,012	19,226	54,870	38.52	1,424
2012	76,366.14	20,218	22,850	72,608	39.41	1,842
2013	2,090,302.12	506,898	572,881	2,039,997	40.30	50,620
2014	832,210.86	183,086	206,918	833,346	41.20	20,227
2015	898,196.35	177,169	200,231	922,514	42.11	21,907
2016	2,565,294.90	447,644	505,914	2,700,705	43.02	62,778
2017	3,101,387.30	470,636	531,899	3,344,835	43.93	76,140
2018	2,742,492.22	352,410	398,284	3,029,831	44.86	67,540
2019	2,555,967.51	269,655	304,756	2,890,203	45.78	63,132
2020	1,699,020.09	139,744	157,935	1,965,840	46.71	42,086
2021	1,485,514.96	87,274	98,635	1,758,259	47.65	36,899
2022	1,556,236.99	54,857	61,998	1,883,298	48.59	38,759
2023	575,634.87	6,764	7,644	711,900	49.53	14,373
	22,002,640.72	4,036,558	4,561,996	22,941,305		527,644

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 43.5 2.40

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R2.5						
NET SALVAGE PERCENT.. -100						
1905	1,391.60	2,783	2,783			
1906	133.00	266	266			
1908	1,175.00	2,350	2,350			
1909	53.00	106	106			
1910	2,807.67	5,615	5,615			
1912	1,105.60	2,209	1,965	246	0.05	246
1913	23.55	47	47			
1914	162.68	323	287	38	0.50	38
1915	7.13	14	14			
1918	1,664.41	3,244	2,885	444	1.53	290
1919	2,237.74	4,341	3,861	614	1.80	341
1920	2,462.15	4,755	4,229	695	2.06	337
1922	784.36	1,500	1,334	235	2.61	90
1923	1,329.26	2,530	2,250	409	2.89	142
1924	5,429.79	10,288	9,150	1,710	3.16	541
1925	7,855.78	14,813	13,174	2,538	3.43	740
1926	4,572.61	8,584	7,634	1,511	3.68	411
1927	143.38	268	238	49	3.93	12
1928	2,761.01	5,139	4,571	951	4.16	229
1929	4,046.62	7,501	6,671	1,422	4.39	324
1930	4,569.31	8,436	7,503	1,636	4.61	355
1931	12,003.10	22,074	19,632	4,374	4.83	906
1932	7,584.75	13,893	12,356	2,814	5.05	557
1933	2,493.26	4,549	4,046	941	5.27	179
1934	3,282.62	5,965	5,305	1,260	5.49	230
1935	6,951.46	12,582	11,190	2,713	5.70	476
1936	5,794.24	10,443	9,288	2,300	5.93	388
1937	8,513.81	15,282	13,591	3,437	6.15	559
1938	14,421.81	25,777	22,925	5,919	6.38	928
1939	18,307.17	32,581	28,977	7,637	6.61	1,155
1940	12,799.11	22,680	20,171	5,427	6.84	793
1941	14,827.40	26,161	23,267	6,388	7.07	904
1942	21,958.54	38,567	34,301	9,616	7.31	1,315
1943	5,153.61	9,010	8,013	2,294	7.55	304
1944	17,975.09	31,277	27,817	8,133	7.80	1,043
1945	22,439.61	38,858	34,559	10,320	8.05	1,282
1946	46,923.71	80,866	71,920	21,927	8.30	2,642
1947	35,538.09	60,936	54,195	16,881	8.56	1,972
1948	17,532.31	29,904	26,596	8,469	8.83	959
1949	23,943.43	40,616	36,123	11,764	9.11	1,291
1950	20,894.57	35,249	31,350	10,439	9.39	1,112
1951	51,399.21	86,214	76,677	26,121	9.68	2,698

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R2.5						
NET SALVAGE PERCENT.. -100						
1952	13,269.00	22,124	19,677	6,861	9.98	687
1953	79,139.83	131,135	116,628	41,652	10.29	4,048
1954	13,446.55	22,133	19,685	7,208	10.62	679
1955	15,093.90	24,679	21,949	8,239	10.95	752
1956	221,575.10	359,692	319,901	123,249	11.30	10,907
1957	203,812.98	328,412	292,082	115,544	11.66	9,909
1958	52,344.56	83,699	74,440	30,249	12.03	2,514
1959	272,343.76	431,937	384,154	160,534	12.42	12,925
1960	637,907.60	1,003,212	892,232	383,583	12.82	29,921
1961	736,450.20	1,148,126	1,021,115	451,785	13.23	34,149
1962	790,177.35	1,220,555	1,085,532	494,823	13.66	36,224
1963	965,559.79	1,476,978	1,313,588	617,532	14.11	43,766
1964	1,170,024.72	1,771,815	1,575,809	764,240	14.57	52,453
1965	1,375,130.50	2,060,853	1,832,873	917,388	15.04	60,997
1966	1,600,778.68	2,372,898	2,110,398	1,091,159	15.53	70,261
1967	1,616,651.67	2,369,462	2,107,342	1,125,961	16.03	70,241
1968	1,734,520.55	2,512,175	2,234,268	1,234,773	16.55	74,609
1969	1,983,691.64	2,837,988	2,524,038	1,443,345	17.08	84,505
1970	2,011,627.70	2,841,746	2,527,380	1,495,875	17.62	84,896
1971	2,288,127.76	3,189,650	2,836,797	1,739,459	18.18	95,680
1972	2,548,857.67	3,504,679	3,116,977	1,980,738	18.75	105,639
1973	2,690,625.00	3,646,712	3,243,297	2,137,953	19.34	110,546
1974	2,363,496.47	3,156,828	2,807,606	1,919,387	19.93	96,306
1975	2,175,749.27	2,861,850	2,545,260	1,806,239	20.54	87,938
1976	2,721,892.66	3,523,926	3,134,094	2,309,691	21.16	109,154
1977	3,238,863.82	4,125,211	3,668,863	2,808,865	21.79	128,906
1978	4,629,171.95	5,795,723	5,154,576	4,103,768	22.44	182,877
1979	5,715,434.75	7,031,928	6,254,027	5,176,842	23.09	224,203
1980	7,091,607.53	8,566,662	7,618,982	6,564,233	23.76	276,272
1981	7,308,099.46	8,664,921	7,706,371	6,909,828	24.43	282,842
1982	5,871,755.83	6,828,852	6,073,416	5,670,096	25.11	225,810
1983	6,470,655.60	7,374,347	6,558,566	6,382,745	25.81	247,297
1984	8,325,450.62	9,294,034	8,265,889	8,385,012	26.51	316,296
1985	10,073,836.79	11,004,055	9,786,740	10,360,934	27.23	380,497
1986	9,697,299.86	10,360,013	9,213,945	10,180,655	27.95	364,245
1987	10,092,908.49	10,536,996	9,371,349	10,814,468	28.68	377,074
1988	11,434,661.42	11,655,808	10,366,393	12,502,930	29.42	424,981
1989	14,999,373.70	14,914,477	13,264,575	16,734,172	30.17	554,663
1990	17,100,936.34	16,576,622	14,742,846	19,459,027	30.92	629,335
1991	18,624,738.10	17,575,420	15,631,153	21,618,323	31.69	682,181
1992	19,308,800.39	17,725,479	15,764,612	22,852,989	32.46	704,035
1993	21,437,043.97	19,121,843	17,006,504	25,867,584	33.24	778,206

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 380.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R2.5						
NET SALVAGE PERCENT.. -100						
1994	21,915,889.32	18,971,709	16,872,979	26,958,800	34.03	792,207
1995	20,261,057.71	17,005,916	15,124,650	25,397,465	34.82	729,393
1996	23,000,337.75	18,684,094	16,617,181	29,383,494	35.63	824,684
1997	24,980,949.77	19,618,539	17,448,253	32,513,647	36.44	892,252
1998	24,130,332.60	18,298,996	16,274,684	31,985,981	37.25	858,684
1999	26,245,913.14	19,176,839	17,055,416	35,436,410	38.08	930,578
2000	23,039,621.17	16,196,854	14,405,090	31,674,152	38.91	814,036
2001	23,097,804.98	15,598,872	13,873,259	32,322,351	39.74	813,346
2002	24,210,624.47	15,664,274	13,931,426	34,489,823	40.59	849,712
2003	25,248,075.87	15,619,975	13,892,027	36,604,125	41.44	883,304
2004	23,605,715.78	13,927,372	12,386,667	34,824,765	42.30	823,280
2005	21,657,966.12	12,157,483	10,812,571	32,503,361	43.16	753,090
2006	22,726,940.84	12,098,460	10,760,077	34,693,805	44.03	787,958
2007	19,937,470.02	10,035,326	8,925,176	30,949,764	44.90	689,304
2008	19,728,466.64	9,351,293	8,316,814	31,140,119	45.78	680,212
2009	19,837,820.54	8,814,737	7,839,614	31,836,027	46.67	682,152
2010	10,668,894.37	4,423,964	3,934,566	17,403,223	47.56	365,921
2011	16,262,664.87	6,261,126	5,568,494	26,956,836	48.45	556,385
2012	18,402,748.98	6,532,976	5,810,271	30,995,227	49.35	628,069
2013	24,607,791.19	7,989,165	7,105,370	42,110,212	50.26	837,847
2014	27,142,637.04	7,989,164	7,105,369	47,179,905	51.17	922,023
2015	26,835,791.62	7,084,649	6,300,915	47,370,668	52.08	909,575
2016	29,409,238.23	6,862,352	6,103,210	52,715,266	53.00	994,628
2017	32,009,705.80	6,487,087	5,769,458	58,249,954	53.92	1,080,303
2018	33,746,195.09	5,792,872	5,152,040	62,340,350	54.85	1,136,561
2019	39,217,130.97	5,529,615	4,917,906	73,516,356	55.77	1,318,206
2020	38,744,563.58	4,248,729	3,778,716	73,710,411	56.71	1,299,778
2021	43,903,666.35	3,453,462	3,071,425	84,735,908	57.64	1,470,089
2022	40,867,962.24	1,934,689	1,720,666	80,015,258	58.58	1,365,914
2023	46,499,651.41	728,185	647,630	92,351,673	59.53	1,551,347
	1,004,062,014.54	547,323,025	486,777,081	1,521,346,948		35,336,053
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					43.1	3.52

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-S0						
NET SALVAGE PERCENT.. 0						
1983	74,388.86	55,891	32,221	42,168	7.46	5,653
1984	253,176.22	186,761	107,667	145,509	7.87	18,489
1985	362,639.61	262,551	151,360	211,280	8.28	25,517
1986	758,418.15	538,477	310,430	447,988	8.70	51,493
1987	31,272.11	21,776	12,554	18,718	9.11	2,055
1988	483,011.11	329,414	189,906	293,105	9.54	30,724
1989	738,750.11	493,485	284,493	454,257	9.96	45,608
1990	1,194,883.79	781,060	450,279	744,605	10.39	71,666
1991	628,996.42	402,136	231,830	397,166	10.82	36,707
1992	1,134,824.80	708,891	408,674	726,151	11.26	64,489
1993	1,054,102.00	643,002	370,689	683,413	11.70	58,411
1994	1,059,351.95	630,314	363,374	695,978	12.15	57,282
1995	1,179,089.23	683,872	394,250	784,839	12.60	62,289
1996	1,251,072.12	706,443	407,262	843,810	13.06	64,610
1997	1,304,342.29	716,514	413,068	891,274	13.52	65,923
1998	1,403,612.34	749,066	431,834	971,778	13.99	69,462
1999	1,440,722.63	745,819	429,963	1,010,760	14.47	69,852
2000	1,273,954.67	639,105	368,442	905,513	14.95	60,569
2001	1,801,510.85	874,327	504,047	1,297,464	15.44	84,033
2002	1,899,162.31	890,707	513,490	1,385,672	15.93	86,985
2003	2,772,798.89	1,253,305	722,527	2,050,272	16.44	124,712
2004	2,883,270.72	1,254,223	723,056	2,160,215	16.95	127,446
2005	294,931.04	123,184	71,015	223,916	17.47	12,817
2006	6,419,429.38	2,567,772	1,480,313	4,939,116	18.00	274,395
2007	4,956,971.23	1,893,563	1,091,634	3,865,337	18.54	208,486
2008	3,992,437.41	1,451,930	837,033	3,155,404	19.09	165,291
2009	439,742.81	151,711	87,461	352,282	19.65	17,928
2011	1,979.67	606	349	1,631	20.81	78
2012	5,048,717.03	1,445,599	833,384	4,215,333	21.41	196,886
2013	3,580,551.06	951,245	548,390	3,032,161	22.03	137,638
2014	2,878,498.88	704,282	406,017	2,472,482	22.66	109,112
2015	3,100,226.68	690,327	397,971	2,702,256	23.32	115,877
2017	6,206,258.51	1,100,556	634,467	5,571,792	24.68	225,761
2018	4,603,849.83	705,908	406,954	4,196,896	25.40	165,232
2019	4,830,668.54	619,920	357,382	4,473,287	26.15	171,063
2020	2,443,899.74	250,084	144,173	2,299,727	26.93	85,396

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-S0						
NET SALVAGE PERCENT.. 0						
2021	29,266,678.83	2,204,659	1,270,979	27,995,700	27.74	1,009,218
2022	3,176,439.41	148,244	85,463	3,090,976	28.60	108,076
2023	5,320,335.97	85,125	49,074	5,271,262	29.52	178,566
	111,544,967.20	28,661,854	16,523,475	95,021,492		4,465,795
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					21.3	4.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.10 METERS - ELECTRIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 16-S4						
NET SALVAGE PERCENT.. 0						
2014	1,696,938.46	1,001,194	1,461,577	235,361	6.56	35,878
	1,696,938.46	1,001,194	1,461,577	235,361		35,878
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					6.6	2.11

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 381.20 METERS - ERT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-R0.5						
NET SALVAGE PERCENT.. 0						
2006	5,458,965.42	3,522,834	3,389,719	2,069,246	5.32	388,956
2007	2,775,100.71	1,707,603	1,643,079	1,132,022	5.77	196,191
2008	5,895,840.23	3,443,171	3,313,066	2,582,774	6.24	413,906
2009	8,940,669.43	4,935,250	4,748,765	4,191,904	6.72	623,795
2010	573,874.12	298,030	286,769	287,105	7.21	39,820
2011	496,924.53	241,172	232,059	264,866	7.72	34,309
2012	628,798.68	282,959	272,267	356,532	8.25	43,216
2013	2,683,198.53	1,110,844	1,068,869	1,614,330	8.79	183,655
2016	0.22					
2017	436,112.85	114,262	109,944	326,169	11.07	29,464
2018	196,983.35	43,862	42,205	154,778	11.66	13,274
2019	1,381,474.71	252,354	242,818	1,138,657	12.26	92,876
2020	625,674.35	89,265	85,892	539,782	12.86	41,974
2021	6,206,202.29	637,191	613,114	5,593,088	13.46	415,534
2022	1,575,712.33	97,694	94,003	1,481,709	14.07	105,310
2023	10,220,349.25	211,255	203,272	10,017,077	14.69	681,898
	48,095,881.00	16,987,746	16,345,841	31,750,040		3,304,178

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.6 6.87

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 22-L1						
NET SALVAGE PERCENT.. 0						
1956	6,139.96	5,978	947	5,193	0.58	5,193
1957	37,441.00	36,199	5,733	31,708	0.73	31,708
1958	18,120.95	17,388	2,754	15,367	0.89	15,367
1959	12,907.89	12,292	1,947	10,961	1.05	10,439
1960	2,852.25	2,697	427	2,425	1.20	2,021
1961	67.51	63	10	58	1.37	42
1964	13,358.16	12,229	1,937	11,421	1.86	6,140
1965	115,016.15	104,404	16,535	98,481	2.03	48,513
1966	106,417.43	95,776	15,169	91,248	2.20	41,476
1967	310,202.72	276,785	43,837	266,366	2.37	112,391
1968	284,247.80	251,431	39,821	244,427	2.54	96,231
1969	84.19	74	12	72	2.72	26
1970	190,653.07	165,521	26,215	164,438	2.90	56,703
1971	55,765.60	47,958	7,595	48,171	3.08	15,640
1972	643,358.09	548,025	86,795	556,563	3.26	170,725
1973	274,135.99	231,146	36,608	237,528	3.45	68,849
1974	157,327.24	131,297	20,795	136,532	3.64	37,509
1975	5,896.92	4,870	771	5,126	3.83	1,338
1976	214,833.34	175,577	27,808	187,025	4.02	46,524
1978	497,135.03	397,256	62,917	434,218	4.42	98,239
1979	1,074.42	849	134	940	4.62	203
1980	617,641.05	482,038	76,344	541,297	4.83	112,070
1981	836,033.76	644,507	102,076	733,958	5.04	145,627
1982	451,748.29	343,943	54,473	397,275	5.25	75,671
1983	406,120.94	305,143	48,328	357,793	5.47	65,410
1984	1,174.82	871	138	1,037	5.69	182
1985	918.50	672	106	812	5.91	137
1986	973,603.35	701,880	111,162	862,441	6.14	140,463
1988	951,407.38	665,557	105,410	845,997	6.61	127,987
1989	1,689,773.02	1,163,645	184,296	1,505,477	6.85	219,778
1990	2,254,008.05	1,527,609	241,940	2,012,068	7.09	283,790
1991	560,680.72	373,615	59,172	501,509	7.34	68,325
1992	1,118,793.09	732,306	115,981	1,002,812	7.60	131,949
1995	524,285.28	324,344	51,369	472,916	8.39	56,367
1997	225,924.86	134,014	21,225	204,700	8.95	22,872
1999	418,560.11	237,056	37,544	381,016	9.54	39,939
2000	1,744,045.82	963,986	152,674	1,591,372	9.84	161,725
2001	2,319,307.03	1,249,272	197,857	2,121,450	10.15	209,010
2002	56,913.36	29,854	4,728	52,185	10.46	4,989
2003	1,106.41	564	89	1,017	10.78	94
2004	3,248,185.58	1,607,852	254,649	2,993,537	11.11	269,445
2005	76,055.16	36,472	5,776	70,279	11.45	6,138

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.00 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 22-L1						
NET SALVAGE PERCENT.. 0						
2007	19,007.75	8,510	1,348	17,660	12.15	1,453
2012	3,799,338.70	1,367,762	216,624	3,582,715	14.08	254,454
2013	2,965,328.90	1,008,212	159,679	2,805,650	14.52	193,227
2014	2,081,456.95	662,278	104,890	1,976,567	15.00	131,771
2015	2,307,252.64	679,601	107,634	2,199,619	15.52	141,728
2017	4,914,628.61	1,181,722	187,159	4,727,470	16.71	282,913
2018	3,018,469.43	632,520	100,177	2,918,292	17.39	167,814
2019	3,928,587.83	692,846	109,732	3,818,856	18.12	210,754
2021	10,884,896.25	1,118,205	177,099	10,707,797	19.74	542,442
2022	5,372,545.91	337,020	53,376	5,319,170	20.62	257,962
2023	6,479,431.73	138,401	21,920	6,457,512	21.53	299,931
	67,194,266.99	21,870,092	3,463,742	63,730,525		5,491,694
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					11.6	8.17

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.10 METER INSTALLATIONS - ELECTRIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-L3						
NET SALVAGE PERCENT.. 0						
2012	481,019.77	308,492	298,351	182,669	5.38	33,953
	481,019.77	308,492	298,351	182,669		33,953

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.4 7.06

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 382.20 METER INSTALLATIONS - ERT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 18-R2.5						
NET SALVAGE PERCENT.. 0						
2006	812,099.60	607,272	693,187	118,913	4.54	26,192
2007	1,236,258.68	890,106	1,016,036	220,223	5.04	43,695
2008	962,016.51	662,724	756,484	205,533	5.60	36,702
2010	4,502,920.97	2,794,333	3,189,668	1,313,253	6.83	192,277
2020	534,640.00	96,235	109,850	424,790	14.76	28,780
2021	981,953.28	127,104	145,086	836,867	15.67	53,406
2022	425,475.14	33,327	38,042	387,433	16.59	23,353
	9,455,364.18	5,211,101	5,948,353	3,507,011		404,405

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.7 4.28

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 383.00 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-S2.5						
NET SALVAGE PERCENT.. 0						
2003	1,944.74	1,194	1,007	938	11.58	81
2004	50,974.78	30,160	25,424	25,551	12.25	2,086
2005	111,010.40	63,091	53,184	57,826	12.95	4,465
2006	99,709.20	54,209	45,697	54,012	13.69	3,945
2007	106,166.87	54,994	46,359	59,808	14.46	4,136
2008	81,705.03	40,144	33,840	47,865	15.26	3,137
2009	36,113.86	16,745	14,116	21,998	16.09	1,367
2010	82,233.28	35,771	30,154	52,079	16.95	3,073
2011	49,737.69	20,177	17,009	32,729	17.83	1,836
2012	155,612.57	58,406	49,235	106,378	18.74	5,677
2013	340,537.54	117,373	98,942	241,596	19.66	12,289
2014	169,400.03	53,022	44,696	124,704	20.61	6,051
2015	215,465.95	60,546	51,039	164,427	21.57	7,623
2016	177,698.56	44,188	37,249	140,450	22.54	6,231
2017	199,129.42	43,012	36,258	162,871	23.52	6,925
2018	322,261.36	58,974	49,714	272,547	24.51	11,120
2019	220,007.55	33,001	27,819	192,189	25.50	7,537
2020	134,038.69	15,638	13,182	120,857	26.50	4,561
2021	126,222.41	10,518	8,866	117,356	27.50	4,267
2022	142,935.10	7,147	6,025	136,910	28.50	4,804
2023	421,861.93	7,032	5,928	415,934	29.50	14,099
	3,244,766.96	825,342	695,743	2,549,024		115,310

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 22.1 3.55

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 386.00 OTHER PROPERTY ON CUSTOMERS' PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 14-S0						
NET SALVAGE PERCENT.. 0						
2017	1,162,110.41	388,482	753,163	408,947	9.32	43,878
	1,162,110.41	388,482	753,163	408,947		43,878
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					9.3	3.78

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 387.10 OTHER EQUIPMENT - CATHODIC PROTECTION TESTING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-S4						
NET SALVAGE PERCENT.. 0						
1989	18,825.00	17,861	18,574	251	1.28	196
1990	9,104.00	8,583	8,925	179	1.43	125
1991	18,219.00	17,060	17,741	478	1.59	301
1992	82,936.00	77,064	80,138	2,798	1.77	1,581
2005	9,866.13	7,060	7,342	2,524	7.11	355
2011	34,908.85	17,440	18,135	16,774	12.51	1,341
	173,858.98	145,068	150,855	23,004		3,899

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.9 2.24

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 387.20 OTHER EQUIPMENT - CALORIMETERS AT GATE STATION

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 23-S0.5						
NET SALVAGE PERCENT.. 0						
1962	865.00	865	865			
1972	10,994.00	10,994	10,994			
1986	25,765.00	22,505	25,765			
1990	252.00	205	252			
1991	21,291.00	17,014	21,291			
1993	4,866.00	3,736	4,866			
1994	7,658.00	5,760	7,658			
1995	2,254.00	1,659	2,254			
1996	2,372.00	1,707	2,372			
1997	12,952.00	9,100	12,952			
1998	4,440.00	3,042	4,440			
1999	2,715.00	1,813	2,715			
	96,424.00	78,400	96,424			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 387.30 OTHER EQUIPMENT - METER TESTING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-S4						
NET SALVAGE PERCENT.. 0						
1978	6,819.00	6,819	6,819			
1979	8,748.00	8,748	8,748			
1984	1,225.00	1,192	1,225			
1985	40,398.00	39,121	40,398			
1986	1,347.00	1,299	1,347			
1987	1,633.00	1,566	1,633			
1990	606.00	571	606			
1991	11,895.00	11,138	11,895			
	72,671.00	70,454	72,671			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. -5						
1913	49,479.00	51,953	51,953			
1915	172.00	181	181			
1920	424.00	445	445			
1922	510.00	536	536			
1923	67.00	70	70			
1924	11.00	12	12			
1925	92.00	97	97			
1927	545.00	572	572			
1930	177.00	182	186			
1936	33.00	32	35			
1937	236.00	230	248			
1938	945.00	912	992			
1939	107.00	102	112			
1940	95.00	90	100			
1941	1,344.00	1,264	1,411			
1942	511.00	476	537			
1943	3,058.00	2,825	3,211			
1944	31.00	28	32	1	6.15	
1945	762.00	691	789	11	6.53	2
1946	193.00	173	197	6	6.92	1
1947	6,781.00	6,036	6,889	231	7.31	32
1948	3,062.00	2,700	3,082	133	7.69	17
1949	8,343.00	7,286	8,316	444	8.08	55
1950	248.00	214	244	16	8.47	2
1951	10,081.00	8,631	9,851	734	8.86	83
1952	29,220.00	24,762	28,261	2,420	9.26	261
1953	11,532.00	9,674	11,041	1,068	9.65	111
1954	63.00	52	59	7	10.05	1
1955	17,854.00	14,665	16,737	2,010	10.45	192
1956	46,058.00	37,429	42,718	5,643	10.85	520
1957	3,819.00	3,070	3,504	506	11.25	45
1958	2,256.00	1,793	2,046	323	11.66	28
1959	1,537.00	1,208	1,379	235	12.06	19
1960	2,315.00	1,799	2,053	378	12.47	30
1961	7,174.00	5,511	6,290	1,243	12.88	97
1962	5,289.00	4,016	4,584	969	13.29	73
1963	7,300.00	5,476	6,250	1,415	13.71	103
1964	130,505.00	96,720	110,388	26,642	14.12	1,887
1965	269,207.00	197,042	224,886	57,781	14.54	3,974
1966	652,577.00	471,648	538,297	146,909	14.96	9,820
1967	28,680.00	20,465	23,357	6,757	15.38	439
1968	58,260.00	41,024	46,821	14,352	15.81	908

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. -5						
1969	24,007.00	16,679	19,036	6,171	16.24	380
1970	16,934.00	11,606	13,246	4,535	16.67	272
1971	22,591.00	15,270	17,428	6,293	17.10	368
1972	82,143.00	54,733	62,467	23,783	17.54	1,356
1973	232,553.00	152,715	174,295	69,886	17.98	3,887
1974	410,099.00	265,360	302,858	127,746	18.42	6,935
1975	35,275.00	22,485	25,662	11,377	18.86	603
1976	674,980.00	423,614	483,476	225,253	19.31	11,665
1977	71,654.00	44,264	50,519	24,718	19.76	1,251
1978	794,352.00	482,893	551,131	282,939	20.21	14,000
1979	34,675.00	20,730	23,659	12,750	20.67	617
1980	90,623.00	53,266	60,793	34,361	21.13	1,626
1981	357,050.00	206,275	235,424	139,478	21.59	6,460
1982	254,992.00	144,693	165,140	102,602	22.06	4,651
1983	29,883.00	16,649	19,002	12,375	22.53	549
1984	23,017.00	12,582	14,360	9,808	23.01	426
1985	50,285.00	26,960	30,770	22,029	23.49	938
1986	104,994.00	55,190	62,989	47,255	23.97	1,971
1987	70,133.00	36,114	41,217	32,423	24.46	1,326
1988	73,630.00	37,126	42,372	34,940	24.95	1,400
1989	92,458.00	45,608	52,053	45,028	25.45	1,769
1990	164,888.00	79,534	90,773	82,359	25.95	3,174
1991	128,634.00	60,639	69,208	65,858	26.45	2,490
1992	247,197.00	113,772	129,849	129,708	26.96	4,811
1993	153,692.00	68,988	78,737	82,640	27.48	3,007
1995	18,867.50	8,036	9,172	10,639	28.53	373
1996	88,757.78	36,755	41,949	51,247	29.07	1,763
1997	208,311.11	83,799	95,641	123,086	29.61	4,157
1998	372,706.61	145,450	166,004	225,338	30.16	7,471
1999	394,922.00	149,368	170,475	244,193	30.71	7,952
2000	181,017.49	66,246	75,607	114,461	31.27	3,660
2001	409,332.12	144,700	165,148	264,651	31.84	8,312
2002	196,636.83	67,016	76,486	129,983	32.42	4,009
2003	902,838.01	296,244	338,107	609,873	33.00	18,481
2004	4,167,289.98	1,312,696	1,498,195	2,877,459	33.60	85,639
2005	1,213,206.76	366,237	417,991	855,876	34.20	25,026
2006	1,174,466.05	338,868	386,754	846,435	34.81	24,316
2007	88,023.67	24,185	27,603	64,822	35.44	1,829
2008	240,284.56	62,706	71,567	180,732	36.07	5,011
2009	661,837.93	163,454	186,552	508,378	36.71	13,848
2010	716,899.25	166,703	190,260	562,484	37.37	15,052
2011	3,586,892.63	781,494	891,928	2,874,309	38.04	75,560

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. -5						
2012	8,807,856.10	1,787,964	2,040,624	7,207,625	38.72	186,147
2013	15,918,360.62	2,987,677	3,409,871	13,304,408	39.42	337,504
2014	9,852,047.32	1,696,109	1,935,789	8,408,861	40.13	209,541
2015	2,147,511.53	335,414	382,812	1,872,075	40.86	45,817
2016	895,762.62	125,206	142,899	797,652	41.61	19,170
2017	539,011.32	66,263	75,627	490,335	42.38	11,570
2018	11,924,207.41	1,259,804	1,437,829	11,082,589	43.17	256,720
2019	2,733,856.88	240,409	274,382	2,596,168	43.98	59,031
2020	1,032,966.80	72,084	82,270	1,002,345	44.81	22,369
2021	35,763,860.80	1,814,891	2,071,356	35,480,698	45.68	776,723
2022	26,269,561.86	821,699	937,815	26,645,225	46.57	572,154
2023	10,939,676.00	117,279	133,852	11,352,808	47.51	238,956
	147,048,661.54	19,028,593	21,709,798	132,691,297		3,132,793
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					42.4	2.13

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVMENTS - SOURCE CONTROL PLANT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 48-S0						
NET SALVAGE PERCENT.. -5						
2013	17,923,230.89	3,363,966	6,238,535	12,580,857	39.42	319,149
2014	667,063.96	114,840	212,973	487,444	40.13	12,147
2016	3,119,876.16	436,084	808,725	2,467,145	41.61	59,292
2017	216,141.91	26,571	49,276	177,673	42.38	4,192
2019	507,450.98	44,624	82,756	450,068	43.98	10,233
2022	599,800.97	18,761	34,793	594,998	46.57	12,776
	23,033,564.87	4,004,846	7,427,058	16,758,185		417,789
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					40.1	1.81

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 391.10 OFFICE FURNITURE AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
2002	150,625.11	150,625	150,625			
	150,625.11	150,625	150,625			
AMORTIZED						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	900,507.14	877,994	864,690	35,817	0.50	35,817
2005	156,461.63	144,727	142,534	13,928	1.50	9,285
2006	86,514.39	75,700	74,553	11,961	2.50	4,784
2007	161,293.83	133,067	131,051	30,243	3.50	8,641
2008	262,606.27	203,520	200,436	62,170	4.50	13,816
2009	16,197.81	11,743	11,565	4,633	5.50	842
2010	610,092.81	411,813	405,573	204,520	6.50	31,465
2012	915,653.06	526,501	518,523	397,130	8.50	46,721
2013	1,290,726.41	677,631	667,363	623,363	9.50	65,617
2014	1,073,795.73	510,053	502,325	571,471	10.50	54,426
2015	526,655.66	223,829	220,437	306,218	11.50	26,628
2016	228,667.97	85,750	84,451	144,217	12.50	11,537
2017	614,673.90	199,769	196,742	417,932	13.50	30,958
2018	357,096.50	98,202	96,714	260,382	14.50	17,957
2019	221,915.36	49,931	49,174	172,741	15.50	11,145
2020	8,934,077.08	1,563,463	1,539,773	7,394,304	16.50	448,140
2021	917,853.23	114,732	112,994	804,860	17.50	45,992
2022	217,497.71	16,312	16,065	201,433	18.50	10,888
2023	597,503.02	14,938	14,712	582,791	19.50	29,887
	18,089,789.51	5,939,675	5,849,675	12,240,115		904,546
	18,240,414.62	6,090,300	6,000,300	12,240,115		904,546

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.5 4.96

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 391.20 OFFICE FURNITURE AND EQUIPMENT - COMPUTERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
2016	0.14					
	0.14					
AMORTIZED						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2019	16,124,026.13	14,511,624	13,482,131	2,641,895	0.50	2,641,895
2020	15,425,944.20	10,798,161	10,032,111	5,393,833	1.50	3,595,889
2021	2,202,453.81	1,101,227	1,023,103	1,179,351	2.50	471,740
2022	4,769,443.93	1,430,833	1,329,326	3,440,118	3.50	982,891
2023	6,527,786.84	652,779	606,469	5,921,318	4.50	1,315,848
	45,049,654.91	28,494,624	26,473,140	18,576,515		9,008,263
	45,049,655.05	28,494,624	26,473,140	18,576,515		9,008,263

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.1 20.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 391.21 OFFICE FURNITURE AND EQUIPMENT - COMPUTERS HORIZON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2022	2,190,419.85	328,563	328,563	1,861,857	8.50	219,042
	2,190,419.85	328,563	328,563	1,861,857		219,042

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.5 10.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 391.22 OFFICE FURNITURE AND EQUIPMENT - COMPUTERS TSA SECUIRTY DIRECTIVE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2022	9,135,002.99	1,370,250	1,370,250	7,764,753	8.50	913,500
2023	6,165.45	308	308	5,857	9.50	617
	9,141,168.44	1,370,558	1,370,558	7,770,610		914,117

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.5 10.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 13-L2						
NET SALVAGE PERCENT.. +15						
1972	69,477.00	59,055	59,055			
1976	6,463.00	5,494	5,494			
1983	27,346.00	23,244	23,244			
1984	2,344.00	1,992	1,992			
1991	9,846.00	7,848	8,369			
1994	122,576.04	93,450	104,190			
1995	130,420.96	97,811	110,858			
1996	89,364.25	65,909	75,960			
1997	35,160.27	25,472	29,886			
1998	117,858.83	83,843	100,180			
1999	137,426.00	95,966	115,777	1,035	2.32	446
2000	22,937.00	15,702	18,943	553	2.53	219
2001	52,722.00	35,334	42,628	2,186	2.75	795
2002	27,181.78	17,808	21,484	1,621	2.98	544
2003	196,904.50	126,042	152,062	15,307	3.21	4,769
2004	340,901.61	212,868	256,812	32,954	3.45	9,552
2005	69,026.34	41,973	50,638	8,034	3.70	2,171
2006	50,063.92	29,624	35,739	6,815	3.95	1,725
2007	143,928.24	82,814	99,910	22,429	4.20	5,340
2008	344,618.82	192,654	232,425	60,501	4.45	13,596
2009	16,819.11	9,128	11,012	3,284	4.70	699
2010	1,369,865.78	721,919	870,949	293,437	4.94	59,400
2011	514,464.34	263,050	317,353	119,942	5.18	23,155
2012	2,546,339.20	1,260,345	1,520,526	643,862	5.43	118,575
2013	3,587,968.55	1,712,570	2,066,106	983,667	5.70	172,573
2014	1,422,283.20	650,035	784,226	424,715	6.01	70,668
2016	2,522.59	1,016	1,226	918	6.84	134
2018	26,230,797.15	8,438,211	10,180,162	12,116,016	8.08	1,499,507
2019	7,424,678.82	2,014,653	2,430,550	3,880,427	8.85	438,466
2020	4,979,112.48	1,077,614	1,300,072	2,932,174	9.69	302,598
2021	4,077,052.92	645,102	778,274	2,687,221	10.58	253,991
2022	2,309,617.01	223,507	269,647	1,693,527	11.52	147,008
2023	1,022,542.64	33,428	40,329	828,832	12.50	66,307
	57,500,630.35	18,365,481	22,116,078	26,759,458		3,192,238

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.4 5.55

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 393.00 STORES EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1931	410.00	410	410			
1949	142.00	142	142			
1950	555.00	555	555			
1951	854.00	854	854			
1953	319.00	319	319			
1956	5,263.00	5,263	5,263			
1957	4,077.00	4,077	4,077			
1959	2,143.00	2,143	2,143			
1960	4,411.00	4,411	4,411			
1961	7,017.00	7,017	7,017			
1962	1,425.00	1,425	1,425			
1963	6,629.00	6,629	6,629			
1964	7,252.00	7,252	7,252			
1965	912.00	912	912			
1966	22,261.00	22,261	22,261			
1967	2,462.00	2,462	2,462			
1968	5,254.00	5,254	5,254			
1969	2,624.00	2,624	2,624			
1970	3,287.00	3,287	3,287			
1971	2,696.00	2,696	2,696			
1972	1,500.00	1,500	1,500			
1974	2,858.00	2,858	2,858			
1975	135.00	135	135			
1976	9,518.00	9,518	9,518			
1977	2,502.00	2,502	2,502			
1978	2,983.00	2,983	2,983			
1979	6,192.00	6,192	6,192			
1980	4,499.00	4,499	4,499			
1982	3,276.00	3,276	3,276			
1984	1,936.00	1,936	1,936			
1985	2,099.00	2,099	2,099			
1986	1,915.00	1,915	1,915			
	119,406.00	119,406	119,406			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 394.00 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 25-SQUARE						
NET SALVAGE PERCENT.. 0						
2000	533,048.95	501,066	501,066	31,983	1.50	21,322
2001	494,438.80	444,995	444,995	49,444	2.50	19,778
2002	479,727.82	412,566	412,566	67,162	3.50	19,189
2003	546,830.13	448,401	448,401	98,429	4.50	21,873
2004	857,542.25	668,883	668,883	188,659	5.50	34,302
2005	731,631.02	541,407	541,407	190,224	6.50	29,265
2006	382,098.07	267,469	267,469	114,629	7.50	15,284
2007	212,322.56	140,133	140,133	72,190	8.50	8,493
2008	419,885.67	260,329	260,329	159,557	9.50	16,795
2009	236,537.99	137,192	137,192	99,346	10.50	9,462
2010	79,462.62	42,910	42,910	36,553	11.50	3,179
2011	286,576.95	143,288	143,288	143,289	12.50	11,463
2012	1,673,154.33	769,651	769,651	903,503	13.50	66,926
2013	944,985.54	396,894	396,894	548,092	14.50	37,799
2014	431,652.65	164,028	164,028	267,625	15.50	17,266
2015	360,232.86	122,479	122,479	237,754	16.50	14,409
2016	1,360,659.75	408,198	408,198	952,462	17.50	54,426
2017	1,829,211.61	475,595	475,595	1,353,617	18.50	73,168
2018	1,359,422.40	299,073	299,073	1,060,349	19.50	54,377
2019	1,205,137.21	216,925	216,925	988,212	20.50	48,205
2020	2,501,680.54	350,235	350,235	2,151,446	21.50	100,067
2021	1,157,247.24	115,725	115,725	1,041,522	22.50	46,290
2022	606,696.19	36,402	36,402	570,294	23.50	24,268
2023	5,202,485.46	104,050	104,050	5,098,435	24.50	208,099
	23,892,668.61	7,467,894	7,467,894	16,424,775		955,705

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 17.2 4.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-L1.5						
NET SALVAGE PERCENT.. +20						
1985	62,386.85	44,685	42,031	7,878	1.57	5,018
1989	14,660.73	10,040	9,444	2,285	2.16	1,058
1991	9,842.00	6,567	6,177	1,697	2.49	682
1995	12,208.00	7,670	7,214	2,552	3.22	793
1996	6,962.00	4,303	4,047	1,523	3.41	447
1998	55,390.23	32,998	31,038	13,274	3.83	3,466
1999	17,877.00	10,440	9,820	4,482	4.05	1,107
2002	74,959.64	40,938	38,507	21,461	4.76	4,509
2003	62,542.82	33,323	31,344	18,690	5.01	3,731
2004	58,270.22	30,269	28,471	18,145	5.26	3,450
2005	501,185.16	253,399	238,350	162,598	5.52	29,456
2006	279,938.87	137,656	129,481	94,470	5.78	16,344
2007	11,235.18	5,369	5,050	3,938	6.04	652
2008	38,685.54	17,929	16,864	14,084	6.31	2,232
2010	126,667.32	55,058	51,788	49,546	6.85	7,233
2011	702,206.22	294,365	276,883	284,882	7.14	39,899
2012	307,231.72	123,711	116,364	129,421	7.45	17,372
2013	114,245.00	43,931	41,322	50,074	7.79	6,428
2014	63,570.81	23,123	21,750	29,107	8.18	3,558
2018	5,792,891.03	1,439,742	1,354,239	3,280,074	10.34	317,222
2019	1,761,607.76	370,177	348,193	1,061,093	11.06	95,940
2020	1,698,007.01	286,175	269,180	1,089,226	11.84	91,995
2021	2,159,211.03	267,172	251,305	1,476,064	12.68	116,409
2022	1,008,720.99	76,929	72,360	734,617	13.57	54,135
2023	1,309,883.06	33,533	31,542	1,016,364	14.52	69,998
	16,250,386.19	3,649,502	3,432,764	9,567,545		893,134

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.7 5.50

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 397.00 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2013	49,718.14	34,803	34,803	14,915	4.50	3,314
	49,718.14	34,803	34,803	14,915		3,314

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.5 6.67

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 397.10 COMMUNICATION EQUIPMENT - MOBILE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2018	55,474.85	30,511	30,511	24,964	4.50	5,548
2019	4,161,405.21	1,872,632	1,872,632	2,288,773	5.50	416,141
2020	40,009.64	14,003	14,003	26,007	6.50	4,001
2021	29,219.34	7,305	7,305	21,914	7.50	2,922
2023	1,054,670.22	52,734	52,734	1,001,936	9.50	105,467
	5,340,779.26	1,977,185	1,977,185	3,363,594		534,079

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.3 10.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 397.20 COMMUNICATION EQUIPMENT - NON-MOBILE AND TELEMETER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2013	9,957.65	6,970	6,970	2,988	4.50	664
	9,957.65	6,970	6,970	2,988		664

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.5 6.67

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 397.30 COMMUNICATION EQUIPMENT - TELEMETER OTHER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
2007	53,241.79	53,242	53,242			
	53,241.79	53,242	53,242			
AMORTIZED						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2009	47,988.32	46,389	46,211	1,778	0.50	1,778
2010	188,278.98	169,451	168,800	19,479	1.50	12,986
2011	562,402.09	468,667	466,865	95,537	2.50	38,215
2012	264,234.41	202,581	201,802	62,432	3.50	17,838
2013	135,620.33	94,934	94,569	41,051	4.50	9,122
2014	386,407.83	244,724	243,783	142,625	5.50	25,932
2015	2,309.81	1,309	1,304	1,006	6.50	155
2018	94,316.84	34,583	34,450	59,867	9.50	6,302
2019	436,457.88	130,937	130,434	306,024	10.50	29,145
2020	4,370,817.24	1,019,843	1,015,923	3,354,895	11.50	291,730
2021	2,379,868.92	396,653	395,128	1,984,741	12.50	158,779
2022	2,884,116.73	288,412	287,303	2,596,813	13.50	192,357
2023	2,211,539.37	73,711	73,428	2,138,112	14.50	147,456
	13,964,358.75	3,172,194	3,160,000	10,804,359		931,795
	14,017,600.54	3,225,436	3,213,242	10,804,359		931,795

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.6 6.65

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 397.40 COMMUNICATION EQUIPMENT - TELEMETER MICROWAVE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
2007	61,119.78	61,120	61,120			
	61,119.78	61,120	61,120			
AMORTIZED						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2010	71,274.98	64,147	64,147	7,128	1.50	4,752
2011	44,683.87	37,236	37,236	7,448	2.50	2,979
2013	177,219.97	124,054	124,054	53,166	4.50	11,815
2014	371,736.68	235,432	235,432	136,305	5.50	24,783
2015	76,277.45	43,224	43,224	33,053	6.50	5,085
2017	1,206,002.15	522,597	522,597	683,405	8.50	80,401
2019	2,763,921.53	829,176	829,176	1,934,746	10.50	184,262
2020	861,088.57	200,918	200,918	660,171	11.50	57,406
2022	336,271.84	33,627	33,627	302,645	13.50	22,418
2023	1,100,802.00	36,690	36,690	1,064,112	14.50	73,387
	7,009,279.04	2,127,101	2,127,101	4,882,178		467,288
	7,070,398.82	2,188,221	2,188,221	4,882,178		467,288

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.4 6.61

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 397.50 COMMUNICATION EQUIPMENT - TELEPHONE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2014	246,231.06	233,920	223,836	22,395	0.50	22,395
2015	94,440.13	80,274	76,814	17,626	1.50	11,751
	340,671.19	314,194	300,650	40,021		34,146

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.2 10.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 398.10 MISCELLANEOUS EQUIPMENT - PRINT SHOP

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2010	4,359.31	3,923	3,923	436	1.50	291
	4,359.31	3,923	3,923	436		291
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					1.5	6.67

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 398.20 MISCELLANEOUS EQUIPMENT - KITCHEN

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2010	12,812.44	11,531	11,531	1,281	1.50	854
2020	16,052.40	3,746	3,746	12,306	11.50	1,070
	28,864.84	15,277	15,277	13,588		1,924
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					7.1	6.67

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 398.30 MISCELLANEOUS EQUIPMENT - JANITORIAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1947	889.00	889	889			
1958	3,088.00	3,088	3,088			
1960	20.00	20	20			
1962	1,248.00	1,248	1,248			
1963	801.00	801	801			
1964	1,355.00	1,355	1,355			
1965	1,157.00	1,157	1,157			
1966	1,108.00	1,108	1,108			
1967	1,659.00	1,659	1,659			
1968	1,108.00	1,108	1,108			
1969	1,653.00	1,653	1,653			
1970	255.00	255	255			
1976	266.00	266	266			
1992	266.00	266	266			
	14,873.00	14,873	14,873			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 398.40 MISCELLANEOUS EQUIPMENT - LEASED BUILDINGS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1969	605.00	605	605			
1985	4,788.00	4,788	4,788			
1986	4,455.00	4,455	4,455			
1987	272.00	272	272			
	10,120.00	10,120	10,120			
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					0.0	0.00

NORTHWEST NATURAL GAS COMPANY

ACCOUNT 398.50 MISCELLANEOUS EQUIPMENT - OTHER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1958	299.00	299	299			
1961	486.00	486	486			
1962	5,361.00	5,361	5,361			
1964	972.00	972	972			
1965	410.00	410	410			
1966	864.00	864	864			
1971	267.00	267	267			
1976	1,127.00	1,127	1,127			
1977	12,091.00	12,091	12,091			
1978	741.00	741	741			
1985	262.00	262	262			
1986	5,000.00	5,000	5,000			
1987	1,831.00	1,831	1,831			
1988	814.00	814	814			
1989	7,330.00	7,330	7,330			
1990	765.00	765	765			
1991	5,587.00	5,587	5,587			
1992	8,257.00	8,257	8,257			
1993	14,275.00	14,275	14,275			
	66,739.00	66,739	66,739			
AMORTIZED						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2022	243.22	18	12	231	18.50	12
	243.22	18	12	231		12
	66,982.22	66,757	66,751	231		12

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 19.2 0.02

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Direct Testimony of Holly J. Braun

THERMAL ENERGY NETWORKS

Exh. HJB-1CT

REDACTED VERSION

August 29, 2025

DIRECT TESTIMONY OF HOLLY J. BRAUN

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position at Northwest Natural Gas Company ("NW Natural" or "the Company").

A. My name is Holly J. Braun. I am a Business Development Consultant at NW Natural.

Q. Please describe your education and employment background.

A. I received a Bachelor of Business Administration from Lipscomb University with a concentration in Professional Accounting in 2001. I served as an auditor with Ernst & Young for two years; also obtaining my Certification of Public Accounting. I then developed and managed the Sarbanes-Oxley compliance program at NW Natural from 2003-2008. At this point, I moved into the Environmental Policy and Sustainability Department, shaping energy policy and managing efficiency programs until 2018 when I became an internal Innovation Consultant identifying technologies to decarbonize thermal energy delivery.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain NW Natural's Thermal Energy Network ("TEN") pilot project in Vancouver, including how the Company proposes to recover the costs of the project. As further explained in my testimony, NW Natural is seeking several different funding sources for this project, including an investment tax credit, an energy savings credit from the local electric utility, a grant from the Washington State Department of Commerce, as well as cost recovery through customer rates.

In this proceeding, NW Natural is seeking Commission approval to include a portion of the project's costs as provisional capital that will be recovered from natural gas customers at the beginning of the second rate year (August 1, 2027). NW Natural

is also seeking the Commission's approval of how it proposes to allocate costs between its natural gas customers and the customer that will be served by the TEN with the understanding that the Company will file the special contract for service to the TEN customer closer to project operation.

Q. Please summarize your testimony.

A. My testimony first describes TENs at a high-level, including how they work and why they are so efficient. I also describe the regulatory framework for TENs development in Washington, explaining how NW Natural is seeking to take advantage of a recently passed law—HB 2131—to build the Vancouver TEN project. Next, I explain the Vancouver TEN project, describing how it was selected and potential expansion opportunities. Finally, as referenced above, I explain how NW Natural proposes to recover the cost of the project through a combination of an investment tax credit, an energy savings credit from the local electric utility, contributions from TEN and natural gas customers, and a grant from the Washington State Department of Commerce that the Company is currently pursuing.

II. BACKGROUND

Q. What is a TEN?

A. Thermal Energy Networks (TENs) connect multiple buildings through a loop of underground pipes carrying water. This water exchanges heat with the earth through geothermal boreholes or wells. Each building connects to the TEN using a ground source heat pump, which provides heating, cooling, and hot water. The heat pump works by transferring heat from the underground loop into a building during the cold winter months and removing heat from the building into the loop during the summer.

Q. Is a TEN more efficient than air-source heat pumps?

A. Yes. Unlike the TEN, an air source heat pump uses outside air to heat and cool a building. However, in winter, for example, an air source heat pump becomes less efficient and effective at heating a building as the surface temperature drops. This decline in efficiency and effectiveness is because an air source heat pump pulls heat from outdoor air and there is less heat available in colder air. As a result, air source heat pumps are typically paired with back-up electric resistance heating for colder weather, which is very inefficient during the coldest times of the year. Likewise, in summer an air source heat pump rejects heat into hotter air, reducing its comparative efficiency.

TENs, on the other hand, use geothermal energy to heat and cool a building. Unlike air source heat pumps, TENs' efficiency and effectiveness does not depend on air temperatures that rise and fall dramatically with the seasons. Instead, TENs use the energy under the earth's surface, where the temperature remains about 55 degrees Fahrenheit year-round. This lack of temperature fluctuation, as well as water serving as the energy transfer medium (as opposed to air), makes TENs much more efficient than air source heat pumps. Water is 800 times denser than air, making it a more potent energy-transfer medium than air. The TEN system is designed to achieve a maximum coefficient of performance (COP) of approximately 6.0, which significantly outperforms conventional air source heat pumps. This higher performance translates into greater system-level energy efficiency.

Q. Why is NW Natural interested in developing a TEN pilot project?

A. NW Natural is committed to helping Washington transition to a low carbon future. The Company believes that TENs are a promising technology that may ultimately be an effective emissions reduction solution because they provide extremely efficient heating and cooling, including domestic water heating.

Q. Please briefly explain the regulatory framework for TENs in Washington.

A. In 2024, the Washington legislature passed HB 2131 (codified as RCW 80.28.450-480; RCW 43.31.033). HB 2131 permits natural gas utilities, such as NW Natural, to construct TENs to meet the heating and cooling needs of their customers. As a first step in the TENs regulatory process, NW Natural notified the Commission that it intended to develop the Vancouver TEN pilot project as required by RCW 80.28.460(2)(a) on June 5, 2025. On June 26, 2025, the Commission acknowledged that NW Natural complied with the notification requirements under that provision, giving the Company priority to develop the Vancouver TEN pilot project. See Exh. HJB-2.

The next step in the regulatory process is "submit[ting] the project for review and validation of costs assessments to the [C]ommission."[1] NW Natural submitted this project for Commission review on July 29, 2025.[2] As of the date of this testimony, this filing is pending before the Commission in docket UG-250458. HB 2131 lists the factors that the Commission must consider for approval, such as being able to fully

[1] RCW 80.28.450.

[2] *See* Exhs. HJB-3C through HJB-8C for the complete filing. These attachments are in the same order as they were presented for the July 29, 2025 filing and do not necessarily reflect the order that they are mentioned in this testimony.

meet the space heating of customers served by the TEN, as well as other policy and societal objectives.[3] HB 2131 also makes TEN pilot projects eligible for grants from the Washington State Department of Commerce to offset the cost of the TEN based on "the difference between the gas company's lowest reasonable cost resources under its current business practices and the costs of building and operating the thermal energy network pilot project," as determined by the Commission through the review and validation process outlined above.

The Commission's review and validation process in docket UG-250458, however, is not a cost recovery proceeding and does not ensure that NW Natural can recover the cost of the project from customers. Instead, per RCW 80.28.450, NW Natural is seeking to recover "the costs of building and operating the project from ratepayers in [this] rate case filing before the [C]ommission."

Q. You state that the Commission is in the process of reviewing and validating the Company's cost assessment of the Vancouver TEN project in docket UG-250458. Since this assessment is not complete, why is NW Natural seeking cost recovery in this proceeding?

A. NW Natural is seeking cost recovery in this proceeding because it expects the Vancouver TEN project to enter rates beginning in the second year of the multi-year rate plan (August 1, 2027). Although it is filing this testimony before the Commission has completed its review and validation of the Company's cost assessment of the Vancouver TEN project in docket UG-250458, NW Natural is nonetheless seeking cost

[3] *See* RCW 80.28.460 for the complete list of factors.

recovery for this project because it falls within the proposed multi-year rate plan. The Company has not filed a general rate case in Washington since 2020, and the timing of this rate case is not based on the in-service date of the Vancouver TEN project.

NW Natural is also taking this opportunity to continue the dialogue about this project with an emphasis on cost recovery and cost allocation. In the Company's July 29, 2025 filing seeking the Commission's review and validation of its cost assessments, the Company noted the importance of such a dialogue.[4] Since the time the Company began seriously pursuing this project, the amount of Washington State Department of Commerce grant funding available has been reduced from $25 million to $4.8 million for all TENs pilot projects.[5] This reduction is a material change that will affect the amount that utility customers must pay for TENs pilot projects. The Company views this proceeding as an opportunity to continue discussions on TENs development and cost recovery in the light of these funding cuts.

Q. Has NW Natural forecasted the amount of a grant that it may receive from the Washington State Department of Commerce to offset the cost of the project?

A. No. Since NW Natural is currently engaged in the review and validation process, it has not included a potential grant as an offset to the amount that must be recovered from customers. However, the Company is pursuing such a grant and will update the project's revenue requirement to reflect any grant that it subsequently receives.

[4] Exh. HJB-3, para. 3 and 76.

[5] Exh. HJB-3, para. 3 and 76.

III. VANCOUVER TEN PROJECT

Q. Please describe the Vancouver TEN project.

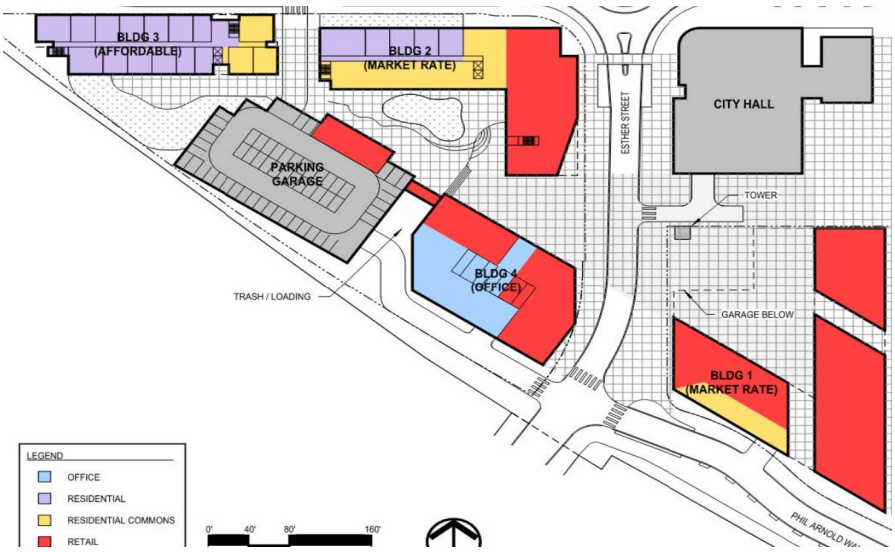
A. NW Natural selected a new construction site where the TEN will supply 100 percent of the heating and cooling plus domestic hot water to three new buildings planned for construction in Vancouver's Waterfront Gateway district, as well as the existing Vancouver City Hall. The TEN design is based on the developer site plan as of March 2025. Vancouver's existing City Hall, located across from Building 1, consists of 124,000 square feet of office space. Building 1, located on Esther Street and Phil Arnold Way, is currently planned to provide approximately 185 units of market-rate housing and 16,000 square feet of retail space. Building 2, located on the southwest corner of Esther and 6th Streets, is currently planned to provide approximately 155 units of market-rate housing and 8,800 square feet of retail space. Building 4,[6] located across the street from Building 1 and adjacent to Building 2, was originally planned as office space as depicted in Figure 1 but is currently planned as an additional 90 units of market-rate housing and 4,000 square feet of retail space. Building construction is expected to begin in late 2026. The total conditioned square footage is expected to be approximately 430,000.

Because the new buildings are still in the planning stage and have not yet been permitted, NW Natural recognizes the actual building sizes and use may change. Any such changes will be incorporated into the next stage of the Company's TEN design

[6] Building 3, to the far west side of the development, was originally in scope as affordable housing, but was on a separate track with its own developer, architect and funding and was further in development than the TEN pilot could accommodate; therefore, Building 3 is not in scope for this pilot.

work but will not fundamentally change the network. Figure 1, below, shows a map of the project area.

Figure 1



Q. Before developing the Vancouver TEN project, did NW Natural seek to learn from other utilities that have already developed these networks?

A. Yes. NW Natural has been tracking the progress of TENs since the first utility-operated TEN began development outside of Boston in 2021. By actively learning from this project, as well as other TEN projects proposed by various utilities since that time, NW Natural began development of its own pilot project that meets the swift timelines outlined in HB 2131 where TENs are scheduled to be placed in service prior to December 5, 2026.[7] Specifically, NW Natural learned that focusing on new construction for an initial pilot—as opposed to retrofitting existing buildings—is faster, more economical and easier to complete. Second, NW Natural learned the importance

[7] NW Natural also notes that HB 2131 allows utilities to petition the Commission for extensions to this deadline.

of having a local community champion that can help pull the pilot project forward. Finally, NW Natural learned that load diversity is key to optimizing thermal energy assets.

Q. How did NW Natural incorporate these lessons in selecting the downtown Vancouver site for its TENs pilot project?

A. First, based on the experience from other TENs projects across the country, NW Natural decided to focus on new construction. With new construction, there are fewer decisionmakers (i.e., a handful of developers can decide to install TENs in their new residential housing, as opposed to existing construction where that decision must be made by a multitude of individual property owners). Given the accelerated timeframe of HB 2131, where TENs are scheduled to be placed in service prior to December 5, 2026, reducing the number of decisionmakers can speed up the project and allow NW Natural to connect more customers than if the Company focused on retrofitting existing construction.

Second, new construction provides the cost and construction efficiency of utilizing trenches already open for other utilities rather than digging up paved streets.

Third, as stated above, NW Natural also learned from other utilities that have successfully completed a TEN that a community champion is critical to the success of any TENs project. In this regard, NW Natural is very appreciative to the City of Vancouver, which reached out to the Company upon passage of HB 2131, eager to partner with NW Natural to develop TENs in the city. With the City, NW Natural explored multiple sites but ultimately chose this project due to the load diversity, development timeline, and the nature of building use.

Fourth, the Vancouver TEN pilot project allows for increased efficiency as a result of thermal energy load diversity, which is another important lesson that the Company has incorporated from other TENs projects across the country. The proposed NW Natural pilot project includes multi-family residential buildings, City Hall, and commercial space. With these buildings connected to the TEN, load sharing occurs when there are simultaneous heating and cooling loads. The heat pumps in heating mode extract heat from the ambient temperature loop ("ATL") while the heat pumps in cooling mode reject heat to the ATL. The rejected heat is balanced by the extracted heat so that thermal energy sources are not needed to meet these loads.

Finally, although not directly related to what NW Natural learned from other utilities, NW Natural was also attracted to the project site due to the public nature of this development, specifically the plaza and adjacent farmers' market in downtown Vancouver. At this location, there is ample opportunity to educate and engage the public via active and passive methods regarding the TEN development and its superior energy efficiency and energy optimization compared to alternatives.

Q. Please explain the equity considerations that went into selecting the Vancouver TEN pilot project.

A. The Vancouver TEN pilot project is designed not only to deliver high-efficiency, non-combustion heating and cooling, but also to generate benefits that extend beyond individual customers to the broader community. While the initial buildings to be served are market-rate residential and commercial properties, the project is sited within census tract 042400, an area that scores among the most impacted in the state across all metrics

of the Washington Environmental Health Disparities Map.[8] This includes scores of 10 out of 10 for overall environmental health disparities and health disparities, and 9 out of 10 for diesel pollution and disproportionate impact, social vulnerability, and lead exposure risk. Locating the state's first utility-led thermal energy network in such a high-need area reflects NW Natural's commitment to equitable infrastructure investment and ensures that the pilot aligns with Washington's climate justice objectives.

Compared to all-electric air source heat pumps that these new buildings would likely use due to current Washington building codes, the project represents a replicable model for reducing system-wide emissions. Based on modeling by Salas O'Brien, the TEN configuration is expected to achieve a 36 percent reduction in greenhouse gas emissions compared to a fully electric business-as-usual scenario which already included a ground source heat pump system serving City Hall.[9]

Finally, NW Natural will leverage its existing community engagement infrastructure to guide future community benefit strategies related to the TEN pilot. This includes engagement with NW Natural's Community and Equity Advisory Group ("CEAG") and Community Affairs Manager ("CAM") team during project implementation, utilizing them as existing forums for meaningful participation by community stakeholders in future decisions about expansion, workforce development, and public benefit.

[8] Washington Environmental Health Disparities Map | Washington State Department of Health.

[9] Confidential Exh. HJB-7C.

Q. Has NW Natural received support from the local community for its Vancouver TEN pilot project?

A. Yes. The City of Vancouver has stated that the Vancouver TEN pilot project is "an innovative, sustainable infrastructure investment that aligns with the City's goals for climate action, energy resilience, equitable community development, and reducing the costs to deliver new housing," and that "[i]n addition to its environmental benefits, the thermal energy network pilot will support local economic development, create living wage jobs, and improve energy equity by delivering affordable and sustainable thermal services to a diverse set of users, including housing, municipal buildings, and small businesses."[10]

Clark Public Utilities, the electric utility for Vancouver (and all of Clark County), states that its "initial analysis indicates the NW Natural TEN project would have both an energy and capacity value for the utility and would be a benefit to the community," and that "projects like NW Natural's TEN pilot will be a key component to the successful approach needed to achieve Washington's carbon reduction goals."[11]

Finally, the developer of the new buildings that will be served by the project, Lincoln Property Company ("Lincoln"), states that the Vancouver TEN pilot "will not only provide immediate environmental and operational benefits but also set a precedent for smart energy infrastructure development in the region."[12] Specifically, Lincoln "encourages stakeholders to move forward with this transformative initiative, which

[10] Exh. HJB-4.

[11] Exh. HJB-4.

[12] Exh. HJB-4.

will serve as a model for future sustainable urban energy development and contribute to the long-term success of the Vancouver area."[13]

All three letters of support are attached to this testimony. *See* Exh. HJB-4.

Q. Did NW Natural consider alternative sites for its TENs pilot project?

A. Yes. NW Natural considered several new construction sites for its TENs pilot project. However, these sites all had limitations compared to the Vancouver TEN site that the Company ultimately selected. One site was too far along in development to pause for the development of a TENs design and exposure to regulatory uncertainty. Conversely, another site was not far enough in development, meaning that NW Natural could meet the timeline anticipated in HB 2131 for the deployment of its pilot project. Another site lacked load diversity and would primarily be used during business hours, which would sub-optimize thermal assets.

Q. Will the Vancouver pilot project be able to fully meet the heating and cooling needs of all the buildings that are connected to the project?

A. Yes. As designed, the pilot will deliver thermal service to an estimated 430 new market-rate multi-family units, 36,800 square feet of retail commercial space, and Vancouver's City Hall.[14] These buildings, located within a couple of city blocks, represent a cross-section of residential, commercial, and public-sector customers, enabling the pilot to test and refine a scalable service model across multiple customer classes.

[13] Exh. HJB-4.

[14] Confidential Exh. HJB-3C, para. 18.

Q. Please describe the design of the TEN.

A. To support both near-term delivery of heating and cooling to the buildings that will be served by the pilot project, as well as potential expansion in the future, NW Natural will implement what it has named the Street Loop system. This design was chosen after detailed evaluation of three design options due to its balanced construction profile, streamlined integration within the public right-of-way, and, critically, its positioning for future expansion.

The Street Loop will be installed in a configuration that allows new buildings to connect over time, unlocking a broader impact beyond the initial pilot footprint. Each building will be equipped with a distributed heat pump system calibrated to meet peak winter heating and summer cooling conditions as determined by energy modeling during the design phase. Year-round capacity will be achieved through geothermal resource sizing and loop flow design, without the inclusion of thermal energy storage. Thermal energy storage is not included in the design because the open-loop geothermal system, supported by a high-yield aquifer, is capable of directly meeting peak capacity demands.

The TEN pilot is designed as a distributed ATL system. Based on the preferred Street Loop design, the ATL will consist of a closed loop buried pipe system circulating water with a small amount of chemical treatment that inhibits corrosion and bacteria growth. The TEN will circulate ambient temperature fluid through a central pipe loop, driven by a primary pump station that distributes energy throughout the network to heat pumps located within each building. Each building connected to the loop will be equipped with a dedicated energy transfer station, which will include circulation pumps

and a heat exchanger that pulls geothermal fluid from the ATL to deliver energy to the building. As the heat pumps within each building extract heat from or reject heat to the ATL, the ATL will balance the needed energy flow to satisfy each heat pump's needs.

The ATL will be designed to operate within a moderate temperature range and serve as a shared thermal reservoir, allowing buildings to either extract or reject heat depending on their individual heating and cooling needs. Each building connected to the TEN is intended to use decentralized, high-efficiency ground source heat pumps, specifically:

- Ground source heat pumps will be installed at the building level, downstream of each energy transfer station.
- Each energy transfer station will transfer thermal energy from the ATL to the building's internal distribution pipe system, which will then supply thermal energy to the ground source heat pumps.
- The ATL supply water temperature differential from one energy source to the next energy source will not be more than 10°F at design conditions. This design limit ensures consistent operational efficiency for all heat pumps connected to the system while allowing sufficient margin for capacity and flow control across the network.
- This decentralized ground source heat pump architecture will ensure that the TEN system is modular and demand-responsive, allowing each building to independently control indoor temperatures without relying on centralized delivery of conditioned air or hot/chilled water.

A dedicated backup heating system is not required for the initial pilot due to the system's built-in redundancies and the reliability of the thermal resource. The design includes dual-pump redundancy (N+1), dual extraction wells and thermal load balancing across buildings and energy transfer station units. These features, coupled with the consistent production capacity of the open-loop geothermal source, will allow the system to meet heating needs without additional backup. Backup power may be considered in future system expansions, but it is not included in the scope of this pilot due to the expected reliability of the current configuration.

By maintaining ownership of the thermal energy assets, NW Natural will apply its utility-standard operations and maintenance protocols to ensure consistent year-round performance. NW Natural's experience in maintaining energy infrastructure, combined with dual-pump redundancy, Supervisory Control and Data Acquisition ("SCADA")-monitored controls, and the high-capacity geothermal resource will enable the TEN system to deliver uninterrupted space conditioning and water heating across seasonal and peak load conditions. Figure 2, below, shows the design of the Street Loop.

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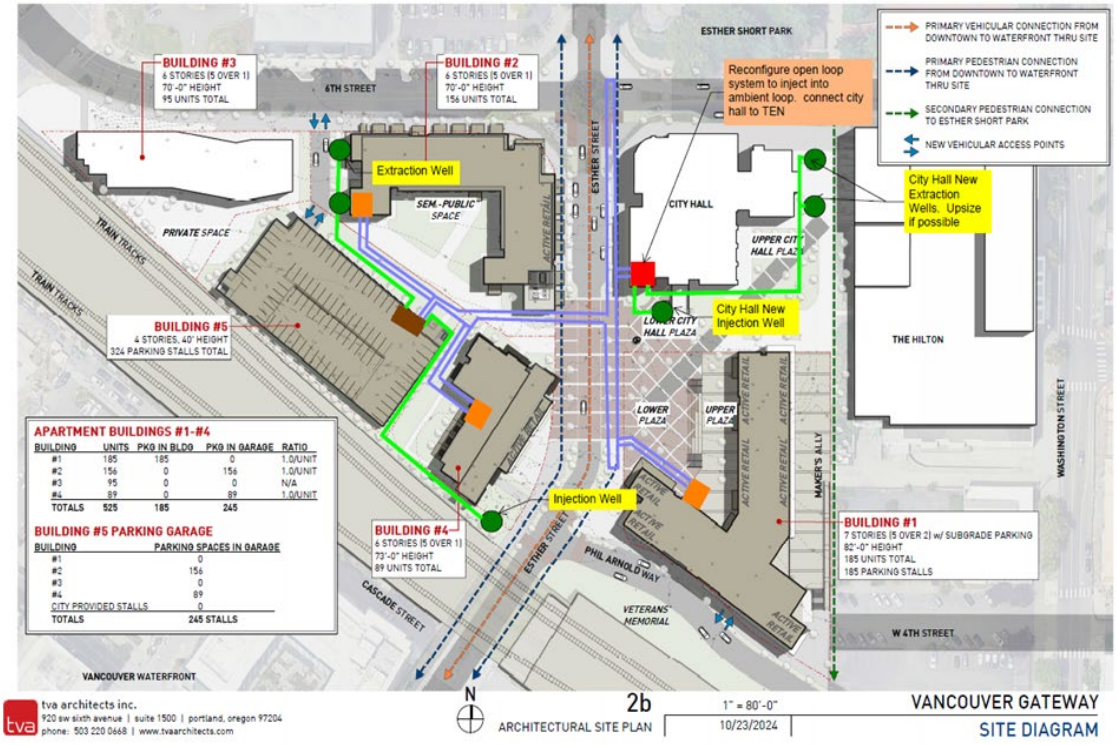
Figure 2



Q. Please explain the potential for the Vancouver TEN pilot project to be expanded in the future.

A. NW Natural's project team has identified logical future expansion targets to occur after completion of the pilot, including Esther Short Commons, a nearby affordable housing complex operated by the Vancouver Housing Authority. Built in 2004, Esther Short Commons would greatly benefit from the energy savings that a TEN connection would provide and may be able to receive government funding to retrofit the complex to be compatible with a TEN connection. Other potential future network extension connections include downtown civic buildings, condominiums, small business offices, future mixed-use development sites, and a senior housing facility that could further expand the pilot's long-term public value and benefit disadvantaged and historically

underserved community members. By concentrating service among a densely clustered customer base in downtown Vancouver and building in future growth capacity, NW Natural will establish a flexible, high-impact model that can be expanded in the future.

Q. Please explain how NW Natural will ensure the safe and reliable operation of the Vancouver TEN pilot project.

A. NW Natural will maintain high standards of infrastructure safety and reliability through engineered design features, operational oversight, and integration with existing utility-wide safety systems. The TEN pilot will be monitored and controlled through a centralized SCADA platform, enabling real-time control, monitoring, and metering of the ATL, open loop wells, and energy transfer stations. Redundant equipment will be incorporated into the system to ensure uninterrupted service in the event of equipment failure.

Each building's energy transfer station will be equipped with safety measures, including valves that can isolate the ATL from each building. System maintenance protocols will be adapted from NW Natural's utility-standard operations and maintenance procedures to ensure consistent performance and regulatory compliance. The ambient loop will be filled with water and treated with corrosion inhibitors and biocides. Air separators and automatic feed stations will maintain system pressure and prevent cavitation, which is critical for ensuring long-term reliability and system health.

Pump station enclosures are under evaluation, with above-grade, below-grade and in-building options under consideration. Regardless of final placement, the infrastructure will be subject to NW Natural's enterprise-wide physical and

cybersecurity protocols, including adherence to Transportation Security Administration ("TSA") Pipeline Security Guidelines. All buried piping will be installed with tracer wire and location tape to support long-term asset tracking and prevent excavation damage. The high-density polyethylene ("HDPE") piping selected for the system carries a 50-year warranty.

In addition, NW Natural will leverage internal safety systems and initiatives, including its Journey to Zero Safety Initiative (focused on reducing workplace injuries), the Pipeline Safety Management System (a voluntary safety framework that exceeds regulatory standards), and the Enterprise Safety Management and Reporting System (used to log field observations and track hazards in real time).

Finally, NW Natural will continue to track and learn from sibling utilities' operational protocols and experience through the Utility Networked Geothermal Collaborative – a group of 29 gas utilities in various stages of TEN development. As I have said above, learning from other utilities' experiences has been critical in developing the Company's Vancouver TEN project. NW Natural's experience in Vancouver will likewise benefit TENs operations throughout North America and beyond.

Q. How will NW Natural evaluate the success of the Vancouver pilot project?

A. As part of its July 29, 2025 filing seeking the Commission's review and validation of the project's costs, NW Natural is proposing a number of metrics intended to help NW Natural monitor the performance of the TEN pilot project and better understand how to operate and maintain future TEN projects. Proposed metrics are focused on measuring technical performance, safety and reliability performance, financial

performance, customer experience, and societal impacts. The information gathered through these metrics is expected to aid the Commission in adopting rules governing thermal energy networks. See Exh. HJB-5 for proposed metrics.

Q. When will the Vancouver pilot project enter service?

A. NW Natural currently plans to deploy this project within 30 months of June 6, 2024 (December 5, 2026) as specified in HB 2131, but will seek extensions from the Commission as appropriate, necessary, and authorized under RCW 80.28.460(2)(a). NW Natural notes that the construction of the new buildings will not be complete at this time. Therefore, the Vancouver TEN pilot project is scheduled to be finished prior to the completion of the new buildings. Given this difference in timelines, NW Natural does not anticipate the project entering rates until the second rate year (August 1, 2027). NW Natural is proposing to begin cost recovery at this time, as explained in the next section.

IV. COST RECOVERY

Q. What is your current cost estimate for the Vancouver TEN pilot project?

A. NW Natural currently estimates that the Vancouver TEN pilot project will cost approximately $12.8 million in total. The total cost that NW Natural is seeking to recover from customers, however, is lowered by an investment tax credit that NW Natural anticipates will be available for utility-scale geothermal projects,[15] as well as an energy savings credit that NW Natural anticipates it will receive from Clark Public Utilities via the Bonneville Power Administration due to the high efficiency of the TEN

[15] This investment tax credit was not impacted by recent changes to federal tax law.

as compared to other electric alternatives. Taken together, these credits reduce the overall cost of the project from $12.8 million to $9.2 million.

Importantly, however, NW Natural is unable to estimate the amount of grant funding that it may receive from the Washington Department of Commerce to offset the cost of the project. When the amount of grant funding becomes known, NW Natural will lower the project's capital investment by that amount, ensuring that customers receive the full benefit of this grant.

Q. Please describe how the cost estimate for the project was developed.

A. NW Natural contracted with Salas O'Brien to provide engineering services through schematic design of a TEN to support the Vancouver TEN pilot project. Salas O'Brien has extensive experience designing TEN projects across North America. Salas O'Brien completed the Basis of Design Report and the Energy Report that were used to develop a schematic design of the Street Loop system that is referenced in Figure 2 above.[16]

In developing this design, the team of NW Natural, City of Vancouver and the developer of the new buildings that will be served by the project—Lincoln Property Company—met at least semi-weekly from December 2024 through June 2025 to understand the site's thermal needs, limitations, feasibility of various loop options and available thermal resources. This resulted in a schematic design supported by all entities and serves as the basis for the detailed cost estimates provided by JLD Cost Consulting. NW Natural has included this cost estimate as confidential Exh. HJB-8C.

[16] Exh. HJB-6; Confidential Exh. HJB-7C.

Schematic design represents approximately 30 percent design completeness. The 30 percent design includes cost contingencies to provide a conservative estimate. The amount of these cost contingencies will be reduced over time as NW Natural moves towards 100 percent design. Figure 3 below reflects a high-level cost summary; a detailed estimate is available in confidential Exh. HJB-8C.

Figure 3

TEN Component	**Schematic Design cost estimate**
Open Loop	[redacted]
Pump house and Energy transfer stations	[redacted]
Vault	[redacted]
Heat pumps	[redacted]
SCADA Control System	[redacted]
Contingency	[redacted]
Insurance	[redacted]
Taxes/Fees	[redacted]
Other (Indirect, Misc. Electrical, , etc.)	[redacted]
Total	**$12,800,000**

NW Natural notes that the costs of the heat pumps are not included in the estimate prepared by the Company's consultant, but are necessary for the project. The Company

estimated the cost of the heat pumps based on a similar project by the building developer, Lincoln Property Company. Also, NW Natural estimates approximately $61,000 of O&M costs each year. A major driver of these costs is electrical power to operate the project.

As stated above, the cost of the project is reduced from $12.8 million to $9.2 million due to the utility-scale geothermal investment tax credit and the energy savings credit that NW Natural expects to receive from Clark Public Utilities via the Bonneville Power Administration. Any grant that NW Natural subsequently receives from the Washington State Department of Commerce would further lower the cost of the project.

Q. Why is NW Natural using schematic design to develop its revenue requirement in this proceeding?

A. NW Natural decided to use schematic design to develop its revenue requirement in this proceeding for three reasons. First, given the multi-year nature of rate cases in Washington and the fact that the project will not enter rates until the second rate year, schematic design is the best information that the Company has available.

Second, utilizing the schematic design and including the project in a multi-year rate proceeding gives NW Natural the opportunity to share the project with the Commission and parties to help inform discussions about TENs projects more generally, including rate design. By doing so, NW Natural is seeking to have open dialogue about TENs projects, especially in light of reduced funding for Washington State Department of Commerce grants to offset the cost of the project. NW Natural understands that the $25 million originally envisioned for such grants statewide is now $4.8 million.

Finally, NW Natural serves a relatively small number of customers in the state, making this pilot project a major investment in its Washington service territory, meaning that the Company must seek prompt recovery of the project's costs.

Q. How does NW Natural propose to recover the costs of the Vancouver TEN pilot project?

A. Given the current estimate of the project (currently $9.2 million after applying the investment tax credit and the energy savings credit) and its limited scope (three new buildings in downtown Vancouver in addition to City Hall), the TEN customer cannot be expected to pay the entire cost of the project. Put simply, the amount would be too great for the TEN customer to bear for heating and cooling compared to any other alternative technology (air-source heat pumps, for example).

Again, NW Natural recognizes that HB 2131 includes the opportunity to receive grants from the Washington State Department of Commerce to offset the cost of TENs pilot projects. NW Natural is vigorously pursuing such a grant. The Company also recognizes that it has not included an estimate of the grant amount that it may receive to offset the cost of the project. However, as referenced above, the amount available for these grants has been significantly reduced. This reduction is a material change that affects how we are approaching cost recovery. Specifically, NW Natural cannot rely on receiving a Washington State Department of Commerce grant that would reduce the project's capital investment to such an extent that spreading the project's remaining costs to natural gas customers would be unnecessary.

Due to these factors, NW Natural is seeking to recover the cost of the project from both the TEN customer and its natural gas customers. As such, NW Natural is

seeking to merge the rate base of its Vancouver TEN pilot project with its natural gas rate base as permitted in RCW 80.28.480. This rate base merger is solely intended as a way to allocate costs of the TENs project to the Company's natural gas customers in light of reduced state funding. The rate base merger is in the public interest because it enables the development of TENs, whose development the state is seeking to facilitate through HB 2131 as a way to help it achieve its climate goals.

Q. How much would the TEN customer pay for the pilot project?

A. Of the project's estimated annual revenue requirement of $1.4 million for the first year in service, NW Natural proposes to allocate approximately $86,000 to the new buildings that will be constructed as part of the development (i.e., excluding City Hall). This amount, in aggregate, represents what the TEN customer would have paid had air-source heat pumps been installed in lieu of TENs. In developing the amount that the TEN customer would have paid for air-source heat pumps, NW Natural relied on the energy modeling performed by its consultant, Salas O'Brien, which calculated this cost in sufficiently granular terms, as shown in Figure 13 of the Energy Report that it prepared for this project.[17]

Although NW Natural recognizes this is a relatively small amount of the project's revenue requirement, it nonetheless believes this is the maximum amount that can be spread to the TEN customer for three reasons. First, due to Washington's current building codes for new construction, air-source heat pumps represent the intended heating and cooling technology that would have been installed had TENs not been

[17] *See* confidential Exh. HJB-7C.

developed. It would be unreasonable to expect the TEN customer to pay more for heating and cooling relative to established and known alternatives, like air-source heat pumps. Second, using natural gas equipment as a baseline in lieu of air-source heat pumps, even if permissible under the Washington building codes, would lead to the TEN customer paying less than their fair share because natural gas alternatives do not provide cooling, whereas TENs do. Finally, this project is a pilot and having an established methodology to estimate the cost of other methods of heating and cooling is helpful in determining how TENs should expand.

Q. Does NW Natural plan on allocating any of the project's costs to City Hall?

A. No. City Hall already uses geothermal energy to provide heating and cooling to the building. Although this system's pumps only provide service to City Hall and is not a network connected to other buildings, they do utilize two supply wells and one injection well. To facilitate the development of the new buildings that will be served by the Vancouver TEN project, the City of Vancouver must move these wells at its own expense. These new wells, built and paid for by the City of Vancouver, will be incorporated into the TEN, helping to provide heating and cooling, not only to City Hall, but to the rest of the buildings served by the network as well.

Also, not specifically allocating costs to the City of Vancouver is consistent with the Company's approach of allocating costs based on how buildings would have been heated and cooled in the lieu of TENs. In this case, the City of Vancouver would have relied on its own supply and injection wells to heat and cool City Hall and would be responsible for these costs. NW Natural believes it would be unreasonable to request the City of Vancouver to pay more for heating and cooling relative to the status quo

alternative, especially because these supply and injection wells are being relied upon to support the TEN. NW Natural also notes that the City of Vancouver would continue to be responsible for operations and maintenance costs of these wells, including the cost of power to operate them.

Q. Excluding City Hall, how does NW Natural plan to spread costs to the TEN customer?

A. NW Natural plans to enter into a special contract with the owner of the new buildings that will be served by the TEN pursuant to WAC 480-80-143. NW Natural intends to file this contract with the Commission prior to the Vancouver TEN pilot project entering service. Although NW Natural has not fully developed the terms of the special contract, it currently plans to install a Btu meter at the energy transfer station for each building, which will measure that building's energy consumption, including heating, cooling, and hot water. NW Natural expects that the building owner would then allocate these heating and cooling costs to each building's tenants.

Q. Why does the Company believe a special contract is appropriate in this instance?

A. NW Natural believes a special contract is appropriate given the unique nature of the Vancouver TEN pilot project. Namely, it is the first TEN developed under HB 2131 in the state, it is the Company's first non-gas project, and it is relatively limited in scope. As such, a special contract is appropriate because the TEN "[p]rovide[s] for utility services not specifically addressed in the gas, electric, or water company's existing tariffs."[18] Therefore, the Company believes it is appropriate to develop a

[18] WAC 480-80-143(1)(b).

special contract that will permit it to serve these new buildings. The other alternative would be a whole new tariff that would stand alongside the Company's existing natural gas tariff. While such a TEN tariff may be warranted in the future as this network expands, NW Natural does not believe that it currently makes sense to develop such a tariff for a pilot project, especially because such a tariff would only serve a single customer (i.e., the owner of the three new buildings).

Q. Special contracts are subject to the requirements in WAC 480-80-143. WAC 480-80-143(5)(c) requires the Company to "[d]emonstrate, at a minimum, that the contract charges recover all costs resulting from providing the service during its term." How does the Company plan to address that requirement?

A. NW Natural plans to file an exemption from this requirement in accordance with WAC 480-80-015. Such an exemption is in the public interest because it is necessary to facilitate the development of TENs, especially in light of reduced state funding. NW Natural believes that TENs are a promising technology that may help the state transition to a low carbon future. The Company is seeking to maximize the opportunity presented in HB 2131 to develop these networks. The Company also does not think it is in anyone's interest to develop TENs cost recovery mechanisms, such as a standalone tariff, that are inefficient and unnecessary for a pilot project, although the Company will consider developing such a tariff in the future if TENs expand.

Q. How much would natural gas customers pay for the Vancouver TEN pilot project?

A. NW Natural currently expects its existing natural gas customers to initially pay approximately $1.3 million in the first year of service. This amount represents the

remainder of the project costs that are not paid for by the TEN customer. Importantly, this amount may be reduced as more becomes known about the project. For instance, any Washington State Department of Commerce grant that NW Natural receives would directly offset the costs that natural gas customers would pay for the project.

Natural gas customers receiving the full benefit of any Washington State Department of Commerce grant is reasonable because the amount that the customer served by the TEN will pay is already set by the estimated cost-of-service of alternative technology (air-source heat pumps) and because natural gas customers will not be directly served by the project. Also, NW Natural's current estimate includes a contingency of [redacted] because it is based on schematic design representing approximately 30 percent design completeness. As the project is further developed, these contingencies may prove unnecessary, reducing the cost of the project and, therefore, the cost allocated to natural gas customers. As with the treatment of the Washington State Department of Commerce grants, any reduction of costs would be reflected in the cost that natural gas customers would otherwise pay because the cost contribution of the TEN customer is already set.

Although NW Natural realizes that this treatment also means that natural gas customers would be responsible for any costs in excess of NW Natural's cost estimate, the Company nonetheless believes this is not likely to occur and that natural gas customers benefit from TENs development. As stated above, NW Natural's estimate is conservative. It does not take into consideration any Washington State Department of Commerce grants and includes a sizable contingency. This conservative estimate reduces the possibility that natural gas customers would bear costs in excess of what

the Company has estimated above. Also, natural gas customers will benefit from the Vancouver TEN pilot project, even though they will not be directly served by the project. As NW Natural gains experience with TENs, it can evaluate whether the technology is a decarbonization solution that can help meet the Company's obligations under the Climate Commitment Act. Finally, NW Natural does not believe that the pilot project would be viable without this level of support from its natural gas customers. Again, it would be unreasonable to ask the TEN customer to pay more for heating and cooling relative to air-sourced heat pumps or, in the case of City Hall, its existing geothermal system.

Q. How does NW Natural plan to spread costs of the pilot to its natural gas customers?

A. NW Natural plans to include the portion of costs that it is allocating to natural gas customers through base rates starting in the second rate year (August 1, 2027).

Q. Will there be an opportunity to review costs for prudency after the Vancouver TEN pilot project is in-service?

A. Yes. The Vancouver TEN pilot project will be part of the portfolio of provisional capital adjustments that are expected to go into service during the second year of the Company's proposed multi-year rate plan. As explained in the Direct Testimony of Kyle T. Walker (Exh. KTW-1T), NW Natural is proposing an annual retrospective review process for all provisional capital investments. NW Natural will file a report for utility plant, including the Vancouver TEN project, that was placed into service during the rate year, within three months following the end of that rate year. This filing gives parties the opportunity to review evidence and conduct discovery.

Q. Given this subsequent filing, what is NW Natural seeking here?

A. NW Natural is seeking to add the cost of a portion of the TEN project to rates paid by natural gas customers as provisional capital, subject to the review process above, into rates starting in the second rate year (August 1, 2027). NW Natural is also seeking Commission approval of its approach to allocating the project's costs between the customer that will be served by the TEN and its natural gas customers with the understanding that the Company will file the special contract for TEN's service closer to project operation.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

V. LIST OF EXHIBITS

Exh. HJB-2	TEN Acknowledgement Letter
Exh. HJB-3C	Vancouver TEN Petition (Confidential and Redacted)
Exh. HJB-4	Letters of Support
Exh. HJB-5	Pilot Metrics
Exh. HJB-6	Basis of Design Report
Exh. HJB-7C	Energy Report (Confidential and Redacted)
Exh. HJB-8C	Cost Estimate Report (Confidential and Redacted)

*Please note that Exhs. HJB-4, HJB-5, HJB-6, HJB-7C, and HJB-8C were originally attached to the Vancouver TEN petition filed in docket UG-250458. The Vancouver TEN petition is attached to this testimony as confidential Exh. HJB-3C.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Holly J. Braun

THERMAL ENERGY NETWORKS

Exh. HJB-2

August 29, 2025

Service Date: June 26, 2025

STATE OF WASHINGTON

UTILITIES AND TRANSPORTATION COMMISSION

621 Woodland Square Loop S.E. ● Lacey, Washington 98503

P.O. Box 47250 ● Olympia, Washington 98504-7250

(360) 664-1160 ● TTY 1-800-833-6384 or 711

June 26, 2025

Ryan Sigurdson
Northwest Natural Gas Company d/b/a NW Natural
Rates & Regulatory Affairs
250 SW Taylor Street
Portland, Oregon 97204
ryan.sigurdson@nwnatural.com
efiling@nwnatural.com

To All Interested Parties:

In 2024, Washington state passed legislation to promote thermal energy networks.[1] Part of that legislation allows existing natural gas companies to pursue thermal energy pilot projects within their service territories on the condition that those companies timely notify the Washington Utilities and Transportation Commission (Commission) in writing of their intent to do so.[2]

The Commission hereby acknowledges that Northwest Natural Gas Company d/b/a NW Natural's June 5, 2025, filing in Docket UG-250458 complies with the notification requirements in RCW 80.28.460(2)(a).

Per RCW 80.28.460(2)(a), Northwest Natural Gas Company d/b/a NW Natural currently has priority to develop a pilot project at three new building sites located in downtown Vancouver, Washington, as designated in filing UG-250458.

Sincerely,

Jeff Killip
Executive Director and Secretary

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[1] HB 2131 (2023) later codified as RCW 80.28.450-480

[2] RCW 80.28.460(2)(a) reads, "A gas company has priority for developing thermal energy pilot projects in the gas company's service territory, but the gas company must announce in writing to the commission its intention to deploy a pilot project in a specific location within 12 months of June 6, 2024."

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Holly J. Braun

THERMAL ENERGY NETWORKS

Exh. HJB-3C

REDACTED VERSION

August 29, 2025

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of NORTHWEST NATURAL GAS COMPANY DBA NW NATURAL Vancouver Thermal Energy Pilot Project	 DOCKET NO. UG-250458 PETITION

I. INTRODUCTION

1 Pursuant to RCW 80.28.450 and 80.28.460, Northwest Natural Gas Company ("NW Natural" or the "Company") petitions the Washington Utilities and Transportation Commission (the "Commission") for an order acknowledging the Company's proposed thermal energy network ("TEN") pilot project in Vancouver, Washington. Specifically, NW Natural is "submit[ing] the project for review and validation of costs assessments to the [C]omission per RCW 80.28.450.

2 Pursuant to RCW 80.28.470(2), NW Natural is also petitioning the Commission to use an alternative process from what is specified in RCW 80.28.470(1) to estimate the cost to deploy a thermal energy network pilot project. Specifically, NW Natural is petitioning the Commission to use its current estimate, based on schematic design, as permitted by RCW 80.28.470(2). NW Natural proposes that this estimate be used by the Department of Commerce to calculate any potential grant award under RCW 43.31.033(4). This process is an alternative to RCW 80.28.470(1), which would appear to require NW Natural to first fully design the project and complete a request-for-proposals to finalize construction costs. The RCW

80.28.470(1) process creates additional risk, expense and an elongated time horizon, making it a much more difficult pathway to pursuing and completing a TENs pilot project.

3 Finally, NW Natural is seeking to use the alternative process as specified in RCW 80.28.470(2) in order to facilitate an open dialogue about this project. NW Natural understands that Department of Commerce grant funding available for all TENs pilot projects has been reduced from $25 million to $4.8 million since the time the Company began seriously pursuing this project. This reduction is a material change that will affect the amount that utility customers must pay for TENs pilot projects. Although NW Natural is not seeking cost recovery in this proceeding, it nonetheless views this filing as a way to begin discussions of how TENs development should proceed in light of these funding cuts. The Company would like to facilitate an open dialogue between itself, the Commission, and any other interested entities about the benefits, costs, and trade-offs of the project, knowing that the all-in costs will likely be higher than originally anticipated as a result of the limited grant funding available. NW Natural understands that the Commission has previously acknowledged that the Company as complied with the notification requirements in accordance with RCW 80.28.460(2), giving NW Natural priority to develop the TEN pilot project, but this acknowledgement did not discuss or evaluate the merits of the project. NW Natural looks forward to substantive discussions regarding the project, which will fully meet the heating and cooling needs for a mix of residential, commercial, and office space in downtown Vancouver and, if successful, can be expanded to other buildings.

4 In support of this Petition, NW Natural states as follows:

II. NAME OF PETITIONER

5 NW Natural is in the business of furnishing natural gas service within the State of Washington as a public service company and is subject to the regulatory authority of the Commission as to its rates, service, facilities, and practices. Its full name and mailing address for the purposes of this proceeding are:

Northwest Natural Gas Company
c/o Zachary Kravitz
Vice President of Regulatory Affairs and Resource Planning
250 SW Taylor Street
Portland, OR 97204-3038

6 The name and address of the Company's attorney for purposes of this proceeding are:

Ryan Sigurdson
Regulatory Attorney (WSBA #39733)
250 SW Taylor Street
Portland, OR 97204-3038

III. SUPPORT FOR PETITION

A. Legal Authority

7 In 2024, the Washington legislature passed House Bill 2131 ("HB 2131") (codified as RCW 80.28.450-480; RCW 43.31.033). HB 2131 permits natural gas utilities, such as NW Natural, to construct TENs to meet the heating and cooling needs of their customers. As stated above, however, prior to constructing such a network, NW Natural must "submit the project for review and validation of costs assessments to the [C]ommission."[1] As part of its review, the Commission must consider a number of factors concerning the project, such as being able to fully meet the space heating of customers served by the TEN, as well as other policy and societal objectives, in addition to a number of factors that the Commission may consider.[2]

[1] RCW 80.28.450.
[2] RCW 80.28.460.

Importantly, as stated above, this Petition is not seeking cost recovery of NW Natural's TEN pilot project. Instead, per RCW 80.28.450, NW Natural will seek to recover "the costs of building and operating the project from ratepayers in a rate case filing before the [C]ommission" after seeking the Commission's approval in this proceeding.

8 HB 2131 also makes TEN pilot projects eligible for grants from the Department of Commerce to offset the cost of the TEN.[3] The maximum amount of this grant "the difference between the gas company's lowest reasonable cost resources under its current business practices and the costs of building and operating the thermal energy network pilot project," as determined by the Commission.[4] In deciding to award a grant, the Department of Commerce must consider the information that NW Natural provides in this Petition, as well as the Commission's "findings and conclusions . . . regarding the pilot project."[5] NW Natural has provided a copy of this Petition to the Department of Commerce.

B. Background

9 NW Natural has been tracking the progress of TENs since the first utility-operated TEN began development outside of Boston in 2021. By actively learning from this project, as well as other TEN projects proposed by various utilities since that time, NW Natural began development of its own pilot project that meets the swift timelines outlined in HB 2131. Specifically, NW Natural has learned that focusing on new construction for an initial pilot—as opposed to retrofitting existing buildings—is faster and easier to complete. Second, NW Natural learned the importance of having a local community champion that can help pull the pilot project

[3] RCW 43.31.033.
[4] *Id.*
[5] *Id.*

forward. Finally, NW Natural learned that load diversity is key to optimizing thermal energy assets.

10 Applying these learnings to the TENs development in its service territory, NW Natural selected a new construction site where the TEN will supply 100 percent of the heating and cooling plus domestic hot water to three new buildings planned for construction in Vancouver's Waterfront Gateway district, as well as the existing Vancouver City Hall. The TEN design is based on the developer site plan as of March 2025. Vancouver's existing City Hall, located across from Building 1, consists of 124,000 square feet of office space. Building 1, located on Esther Street and Phil Arnold Way, is currently planned to provide approximately 185 units of market-rate housing and 16,000 square feet of retail space. Building 2, located on the southwest corner of Esther and 6th Streets, is currently planned to provide approximately 155 units of market-rate housing and 8,800 square feet of retail space. Building 4,[6] located across the street from Building 1 and adjacent to Building 2, was originally planned as office space as depicted in Figure 1 below but is currently planned as an additional 90 units of market-rate housing and 4,000 square feet of retail space. Building construction is expected to begin in late 2026. The total conditioned square footage is expected to be approximately 430,000.

11 Because the new buildings are still in the planning stage and have not yet been permitted, NW Natural recognizes the actual building sizes and use may change. Any such changes will be incorporated into the next stage of TEN design work but will not fundamentally change the network. Figure 1, below, shows a map of the project area.

[6] Building 3, to the far west side of the development, was originally in scope as affordable housing, but was on a separate track with its own developer, architect and funding and was further in development than the TEN pilot could accommodate; therefore, Building 3 is not in scope for this pilot.

Figure 1

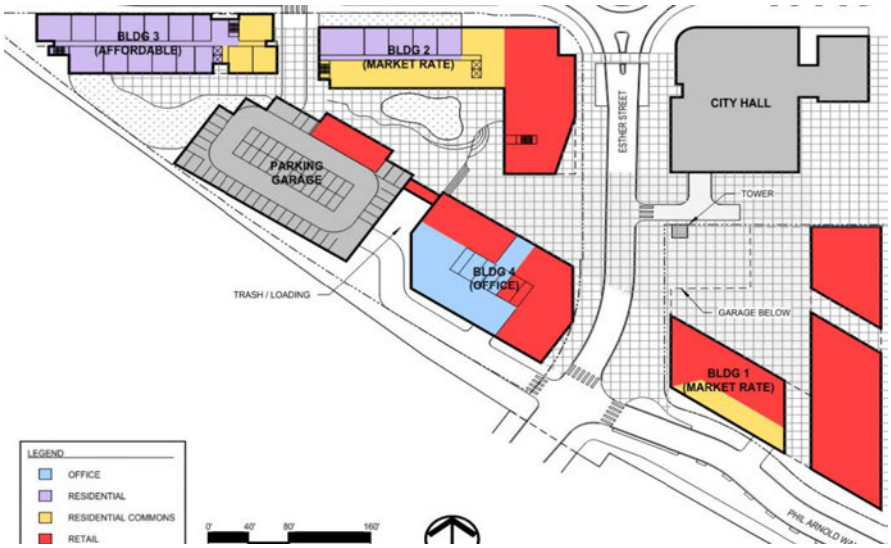

Figure 1: Waterfront Gateway site map

12 NW Natural selected this project for five reasons. First, based on its learnings from other TENs projects across the country, NW Natural decided to focus on new construction. With new construction, there are fewer decisionmakers (i.e., a handful of developers can decide to install TENs in their new residential housing, as opposed to existing construction where that decision must be made by a multitude of individual property owners). Given the accelerated timeframe of HB 2131, where TENs are scheduled to be placed in service prior to December 5, 2026, reducing the number of decisionmakers can speed up the project and allow us to connect more customers than if we focused on retrofitting existing construction.

13 Second, new construction provides the cost and construction efficiency of utilizing trenches already open for other utilities rather than digging up paved streets.

14 Third, as stated above, NW Natural also learned from other utilities that have successfully completed a TEN that a community champion is critical to the success of any TENs project. In this regard, NW Natural is very appreciative to the City of Vancouver, who reached out to

the Company upon passage of HB 2131, eager to partner with NW Natural to develop TENs in the city. With the City, NW Natural explored multiple sites but ultimately chose this project due to the load diversity, development timeline, and nature of building use.[7]

15 Fourth, the Vancouver TENs pilot project allows for increased efficiency as a result of thermal energy load diversity, which is another important learning that the Company has incorporated from other TENs projects across the country. The proposed NW Natural pilot project includes multi-family residential buildings, City Hall, and commercial space. With these buildings connected to the TEN, load sharing occurs when there are simultaneous heating and cooling loads. The heat pumps in heating mode extract heat from the ambient temperature loop ("ATL") while the heat pumps in cooling mode reject heat to the ATL. The rejected heat is balanced by the extracted heat such that the thermal energy sources do not need to meet the entire thermal energy demand.

16 Fifth, due to the public nature of this development, specifically the plaza and adjacent farmers' market in downtown Vancouver, there is ample opportunity to educate and engage the public via active and passive methods regarding the TEN development and its superior energy efficiency and energy optimization compared to alternatives.

C. Statutory Criteria that the Commission Must Consider

RCW 80.28.460(2) – Intention to Deploy a Pilot Project

17 Per RCW 80.28.460(2)(a), NW Natural has already received priority to develop a TEN pilot in downtown Vancouver. The Company plans to deploy this project within 30 months of June

[7] Other sites assessed faced the following limitations: one site was too far along in design to pause for development of a TEN design, one was not far enough along for the Company to meet the timeline dictated in HB 2131, and one site lacked load diversity and would primarily be used only during business hours and would, therefore, sub-optimize thermal assets.

6, 2024 (December 5, 2026) in order to maintain this priority, but will seek extensions as appropriate and necessary.

RCW 80.28.460(3)(a) -- The number and type of customers served, including the percent of low-income customers served.

18 While this development will target occupants seeking market-rate housing, the site was selected for its ability to connect a diverse, high-density mix of customers within a compact, infrastructure-ready footprint. The pilot will deliver thermal service to an estimated 430 new market-rate multifamily units, 36,800 square feet of retail commercial space, and Vancouver's City Hall. These buildings, located within a couple of city blocks, represent a cross-section of residential, commercial, and public-sector customers, enabling the pilot to test and refine a scalable service model across multiple customer classes.

19 To support both near-term delivery and long-term growth, NW Natural will implement what it has named the Street Loop system. This design was chosen after detailed evaluation of three total design options due to its balanced construction profile, streamlined integration within the public right-of-way, and, critically, its positioning for future customer expansion. The Street Loop will be installed in a configuration that allows new buildings to connect over time, unlocking a broader impact beyond the initial pilot footprint.

20 As explained above, Building 3, which is currently planned to be affordable housing, was originally planned to be served by the TEN pilot, it was on a separate track with its own developer and was further in development than the TEN pilot could accommodate. However, NW Natural's project team has identified logical future expansion targets to occur after completion of the pilot, including Esther Short Commons, a nearby affordable housing complex operated by the Vancouver Housing Authority. Built in 2004, Esther Short Commons

would greatly benefit from the energy savings such a TEN connection would provide and may be able to receive government funding to retrofit the complex to be compatible with a TEN connection. Other potential future network extension connections include civic buildings, condominiums, and small business office options in downtown, future mixed-use development sites, and a senior housing facility could further expand the pilot's long-term public value and benefit disadvantaged and historically underserved community members.

21 By concentrating service among a densely clustered customer base and building in future growth capacity, NW Natural will establish a flexible, high-impact model that can be expanded in the future.

22 Figure 2, below, shows the design of the Street Loop that will serve the TENs pilot project.

Figure 2

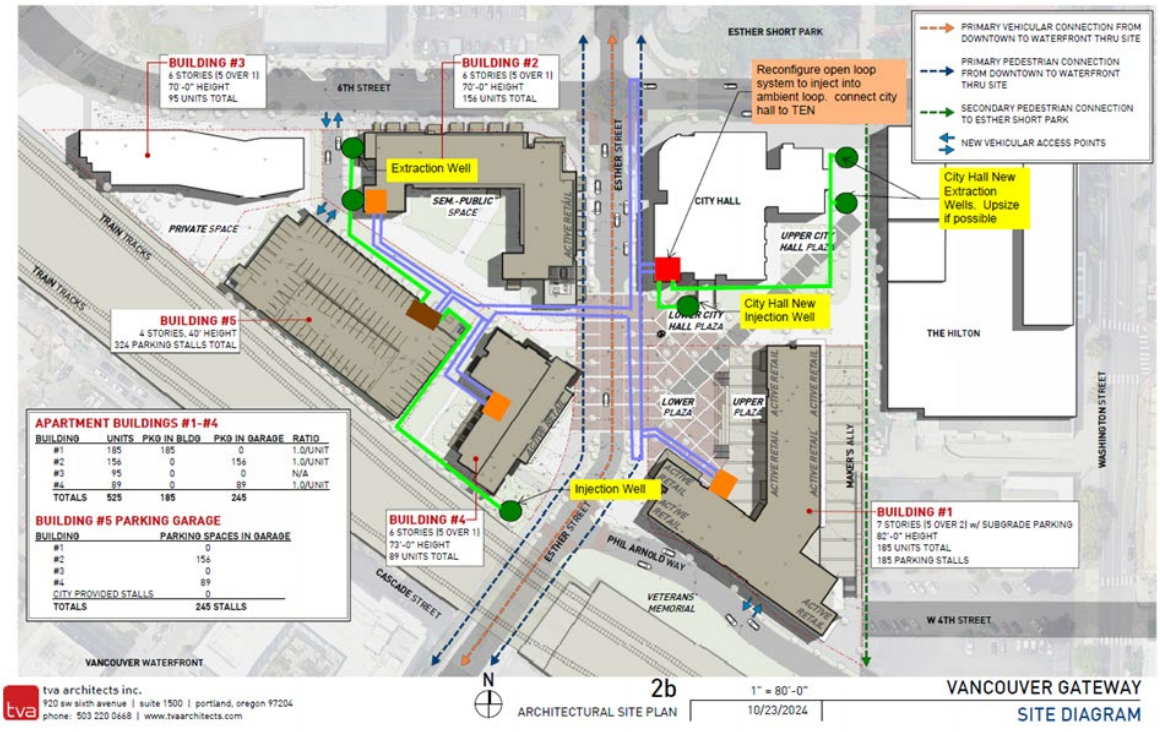

Figure 2 2: Street Loop TEN Design

RCW 80.28.460(3)(b) -- The use of the existing natural gas workforce and other labor considerations, such as efforts to transition the natural gas workforce to thermal energy work, training, recruiting, job creation and retention, payment of prevailing wages, and state-registered apprenticeship utilization.

23 NW Natural has a long-standing commitment to a collaborative and transparent relationship with its union partners. With over half of its workforce unionized for nearly a century, the Company maintains a strong partnership with its union partners, built on mutual respect and shared goals. NW Natural recognizes the union as a key stakeholder in cultivating a workplace where employees feel valued, supported, and empowered. This commitment is reflected in its collective bargaining agreement, which ensures fair wages, competitive benefits, and a safe, inclusive work environment.

24 NW Natural will use the pilot as an opportunity to evaluate how its existing utility workforce can support the delivery of thermal energy systems. As part of this effort, the Company will assess the potential to leverage internal personnel, in partnership with labor, including construction technicians, pipeline maintenance crews, and customer operations staff, to support pilot operations and maintenance.

25 To guide this evaluation, NW Natural will analyze and identify where existing capabilities align with the technical requirements of ambient loop systems and ground-source heat pump technologies. This analysis will also help pinpoint retraining and upskilling opportunities in geothermal system operation, loop maintenance, and system controls.

26 Prior to completion of the pilot project, NW Natural will assess the extent to which operations and maintenance could be delivered by internal staff or through contract services. This assessment will inform future workforce planning and labor engagement. Once the staffing

model is finalized and the broader scope of the workforce needs are defined, NW Natural may pursue formal support from workforce development partners and seek alignment on such items as prevailing wage and jurisdictional scopes of work.

27 Looking ahead, NW Natural will use the pilot to inform potential future workforce development strategies that support utility-led thermal infrastructure at scale. This may include exploring partnerships with technical colleges, trade schools, and/or workforce development organizations. The Company will evaluate outreach strategies to connect with historically underrepresented workers, such as through community-based organizations in Clark County, as it considers expansion into nearby disadvantaged census tracts, consistent with the Washington Environmental Health Disparities Map.

28 This pilot will serve as a platform for designing a replicable, equity-driven utility workforce model that honors NW Natural's workforce commitments while preparing for increasing decarbonization measures in the future.

RCW 80.28.460(3)(c) -- The ability to maintain infrastructure safety and reliability.

29 NW Natural will maintain high standards of infrastructure safety and reliability through engineered design features, operational oversight, and integration with existing utility-wide safety systems. The TEN pilot will be monitored and controlled through a centralized Supervisory Control and Data Acquisition ("SCADA") platform, enabling real-time control, monitoring, and metering of the ambient temperature loop (ATL), open loop wells, and energy transfer station ("ETS") system. Redundant assets will be incorporated into the system to ensure uninterrupted service in the event of equipment failure.

30 Each building's ETS will be equipped with safety measures, including valves that can isolate the ATL from each building. System maintenance protocols will be adapted from NW Natural's utility-standard operations and maintenance procedures to ensure consistent performance and regulatory compliance. The ambient loop will be filled with water and treated with corrosion inhibitors and biocides. Air separators and automatic feed stations will maintain system pressure and prevent cavitation, which is critical for ensuring long-term reliability and system health.

31 Pump station enclosures are under evaluation, with both above-grade and below-grade options under consideration. Regardless of final placement, the infrastructure will be subject to NW Natural's enterprise-wide physical and cybersecurity protocols, including adherence to Transportation Security Administration (TSA) Pipeline Security Guidelines. All buried piping will be installed with tracer wire and location tape to support long-term asset tracking and prevent excavation damage. The high-density polyethylene (HDPE) piping selected for the system carries a 50-year warranty.

32 In addition, NW Natural will leverage internal safety systems and initiatives, including its Journey to Zero Safety Initiative (focused on reducing workplace injuries), the Pipeline Safety Management System (a voluntary safety framework that exceeds regulatory standards), and the Enterprise Safety Management and Reporting System (used to log field observations and track hazards in real time).

33 The metrics NW Natural intends to track safety and reliability:

1. Number of workforce safety incidents
2. TENs system up-time
3. Cause of TEN shutdowns (planned/unplanned)

4. Duration of shutdowns (planned/unplanned)

RCW 80.28.460(3)(d) -- The ability to meet 100 percent of the pilot project customers' demand for space heating.

34 NW Natural has designed the TEN to meet 100 percent of the space heating demand for all connected buildings, including residential units, commercial tenants, and Vancouver City Hall. Each building will be equipped with a distributed heat pump system calibrated to meet peak winter heating conditions as defined through energy modeling during the design phase.

35 Year-round heating capacity will be achieved through geothermal resource sizing and loop flow design, without the inclusion of thermal energy storage ("TES"). TES is not included in the design because the open-loop geothermal system, supported by a high-yield aquifer, is capable of directly meeting peak capacity demands. Additionally, since the majority of electrical load in the system comes from in-unit heat pumps on the customer side, utility-side TES would not enable meaningful load shifting or generate cost or operational benefits. As a result, TES would increase capital cost without delivering corresponding value to the system.

36 By maintaining ownership of the thermal energy assets, NW Natural will apply its utility-standard operations and maintenance protocols to ensure consistent year-round performance. NW Natural's experience in maintaining such infrastructure, combined with dual-pump redundancy, SCADA-monitored controls, and the high-capacity geothermal resource will enable the TEN system to deliver uninterrupted space heating across seasonal and peak load conditions.

RCW 80.28.460(3)(e) -- Whether the pilot project creates benefits to customers, communities, and society at large including, but not limited to, public health benefits such as improved air quality in areas with disproportionate environmental or public health burdens and disadvantaged communities as identified by the environmental health disparities map described in RCW 43.70.815, and increased affordability of thermal energy options;

Equity Benefits Per the WA Environmental Health Disparities Map

37 The Vancouver TENs pilot project is designed not only to deliver high-efficiency, non-combustion heating and cooling, but also to generate benefits that extend beyond individual customers to the broader community. While the initial buildings to be served are market-rate residential and commercial properties, the project is sited within census tract 042400, an area that scores among the most impacted in the state across all metrics of the Washington Environmental Health Disparities Map. This includes scores of 10 out of 10 for overall environmental health disparities and health disparities, and 9 out of 10 for diesel pollution and disproportionate impact, social vulnerability, and lead exposure risk. Locating the state's first utility-led thermal energy network in such a high-need area reflects NW Natural's commitment to equitable infrastructure investment and ensures that the pilot aligns with Washington's climate justice objectives.

Public Health Benefits, Specifically Emissions Reductions

38 Compared to all-electric air source heat pumps that these new buildings would likely use due to current Washington building codes, the project represents a replicable model for reducing system-wide emissions. Based on modeling by Salas O'Brien, the TEN configuration is expected to achieve a 36 percent reduction in greenhouse gas emissions compared to a fully

electric business-as-usual scenario which already included a ground source heat pump system serving City Hall.[8]

Affordability Programs and Propose Customer Affordability Strategies

39 Although the initial buildings served by the pilot are market-rate, NW Natural is actively working to ensure that the TEN customers will not pay more for thermal service under the TEN model than they would under a standard business-as-usual scenario using code-compliant electric equipment for both heating and cooling.

40 While final rates and incentives will depend on several outstanding variables, including final equipment cost inputs and grant award size, NW Natural's intent is to develop a rate that is cost-competitive with baseline equipment, ensuring that early adopters of this clean thermal infrastructure do not face cost burdens relative to standard practice.

41 As part of future exploration, NW Natural may evaluate the viability of options such as:

- Partnering with local housing agencies to pre-screen public housing eligibility for future TEN nodes or rate tiers,
- Offering income-qualified bill discounts or enrollment support in partnership with community-based organizations,
- Structuring future rates to support energy-burdened customers, should subsequent phases include connections to affordable housing or community-serving facilities.

[8] NW Natural notes that calculating a specific amount of greenhouse gas reductions depends on the emissions factor used and that stakeholders can disagree about what this factor should be (i.e., the emissions intensity of the incremental electric generation to serve additional load). To hopefully avoid such disagreements in this filing, NW Natural has presented a relative reduction of 36 percent in greenhouse gas emissions that is not dependent on a certain emissions factor.

Anchoring Broader Community Benefits in NW Natural's Existing Programs and Partnerships

42 NW Natural will leverage its existing community engagement infrastructure to guide future community benefit strategies related to the TEN pilot. This includes engagement with NW Natural's Community and Equity Advisory Group ("CEAG") and Community Affairs Manager (CAM) team during project implementation, utilizing them as existing forums for meaningful participation by community stakeholders in future decisions about expansion, workforce development, and public benefit.

43 These structures provide a strong foundation for integrating equity and community perspectives into long-term thermal energy planning. As part of the broader community value proposition, NW Natural will also draw upon:

- Its track record of philanthropic support, with over 380 nonprofits served, and deep partnerships with workforce equity organizations such as Constructing Hope and the Urban League;
- Internal programs that support career pathway development for underrepresented workers, which can be adapted to support a new class of clean energy and thermal infrastructure jobs;
- The positioning of this pilot as a bridge between NW Natural's equity commitments and Washington's climate justice mandates, even if the first phase does not directly serve equity-prioritized customers.

This engagement will support NW Natural's goal of ensuring that the TEN pilot not only delivers clean energy to its initial customers, but also sets the stage for equitable, community-centered expansion in future phases.

RCW 80.28.460(3)(f) -- Coordination with any electric utility providing electrical service to areas served by the pilot project;

44 NW Natural initiated discussions with Clark Public Utilities ("CPU"), the local electric utility, to explore how the Vancouver TENs pilot project could deliver measurable electric load and capacity savings. These conversations focused on helping CPU evaluate the pilot's potential to reduce peak electricity demand and overall system usage, particularly by using highly efficient ground-source heat pumps that displace less efficient electric alternatives. The TEN design results in meaningful grid savings and NW Natural and CPU are now assessing how these energy and capacity benefits might translate into an incentive structure to support the pilot. This collaboration reflects the type of joint planning between gas and electric utilities encouraged by Washington State House Bill 1514, which promotes coordinated investment and resource optimization across utility systems. While the pilot is not designed as a grid-responsive resource in the traditional demand response sense, it is expected to provide consistent peak load reduction that aligns with CPU's broader goals of improving grid efficiency and affordability. As part of this project, NW Natural will continue to coordinate with CPU by sharing key TEN technical system, energy consumption, and power demand data that can inform CPU's grid system planning, reliability, and peak demand reduction efforts. CPU has provided a letter of support for the Vancouver TENs pilot project, included in Attachment 1.

45 In parallel, NW Natural is actively coordinating with peer natural gas utilities across Washington to support shared learning and system-wide scalability of thermal energy networks. Lessons from the Vancouver TENs pilot will be disseminated through structured engagement with our peer utilities.

RCW 80.28.460(3)(g) -- Whether the pilot project furthers the climate justice mandates of chapter 70A.02 RCW and the emissions reduction mandates of chapter 70A.45 RCW;

46 The Vancouver TEN pilot supports the climate justice mandates of RCW 70A.02 and the emissions reduction goals of RCW 70A.45 by investing in non-combustion thermal infrastructure that is located on-site in an area with high environmental health disparities. As stated above, the project site, located in census tract 042400, scores a 10 out of 10 in overall Environmental Health Disparities on the Washington Environmental Health Disparities Map. It also ranks 9 out of 10 in diesel pollution and disproportionate impact, 9 out of 10 in social vulnerability, 9 out of 10 in lead exposure risk, and 10 out of 10 in health disparities. These indicators confirm the community's disproportionate exposure to environmental burdens and health risks, positioning the pilot to deliver meaningful, place-based emissions benefits.

47 Although the pilot will initially serve market-rate buildings, the ambient loop has been designed to accommodate future expansion to nearby affordable housing and public-serving facilities as explained above. NW Natural will use equity screening tools, including the RCW 70A.02 criteria and Environmental Health Disparities Map, to inform future decisions on node siting, community partnerships, and workforce engagement.

48 NW Natural already maintains a strong foundation in equitable workforce practices and will leverage these efforts in support of the TEN pilot project. The Company partners with community-based organizations such as the Urban League, Women in Trades, Constructing Hope, and Incight to attract candidates from historically underrepresented populations. These partnerships include hosting job fairs, posting job openings on targeted hiring platforms, avoiding exclusionary language, and continuously refining hiring processes to minimize bias.

NW Natural's Communications team amplifies these efforts through social media outreach to broaden engagement.

49 NW Natural also operates two pre-apprenticeship internship programs, one for Construction and one for Customer Field Service, that provide year-long, paid on-the-job training for diverse candidates. These programs prepare participants for full-time employment with the company and include structured advancement and mentorship. Building on these initiatives, NW Natural's Organizational Effectiveness team supports a range of belonging-focused programs, including Employee Resource Groups (ERGs) and mentoring. Together, these existing initiatives will be leveraged to support inclusive workforce engagement as the TEN pilot advances.

50 To align with State requirements for procedural justice, NW Natural intends to implement community engagement strategies that center meaningful participation by overburdened and vulnerable populations. Engagement activities will be shaped by best practices described in RCW 70A.02.050, which outlines standards for equitable communication and inclusive decision-making. NW Natural will also leverage its CEAG to convene structured meetings and share project updates, ensuring transparency and accountability as the pilot progresses.

51 Regarding the emissions reduction goals of RCW 70A.45, emissions modeling conducted by Salas O'Brien estimates that the TEN pilot will achieve a 36 percent reduction in Scope 2 greenhouse gas emissions relative to a fully electric air-source heat pump ("ASHP") scenario as explained above. Even though the comparison excludes natural gas, it nonetheless demonstrates the significant emissions reduction potential of the TEN model, especially considering that City Hall already has a ground source heat pump. These findings reinforce

the pilot's role as a replicable decarbonization strategy that can contribute to the state's long-term emissions reduction targets.

RCW 80.28.460(3)(h) -- Whether the pilot project advances financial and technical approaches to equitable and affordable building electrification

52 The Vancouver TEN pilot will advance affordable building decarbonization by introducing a centralized, utility-managed thermal energy system that leverages a shared ambient loop and a centralized open-loop geothermal energy source. While each building, and each unit, will maintain its own HVAC equipment, the system design avoids reliance on less efficient, standalone ASHPs. This configuration will reduce total system energy consumption, improve overall efficiency, and enable more elegant mechanical system design compared to conventional approaches. More importantly, by offering a scalable model for efficient, decarbonized building operations in new developments, the TEN pilot provides a replicable pathway to support financially and technically viable decarbonization.

53 The TEN system is designed to achieve a maximum coefficient of performance (COP) of approximately 6.0, which significantly outperforms conventional ASHPs. This higher performance translates into greater system-level energy efficiency. By replacing distributed electric resistance or ASHP systems with centralized infrastructure, the system can also reduce total electric demand and reduce the cost of electrical infrastructure directly serving each new building. Because NW Natural will own and maintain the thermal infrastructure, building owners can reduce their investment and management of the system compared to individual HVAC systems, further reducing financial burdens. Combined with grant-funded capital costs

and a system-wide cost recovery approach, this model offers a clean, affordable solution for decarbonization that aligns with Washington's climate and equity goals.

54 As a utility-led initiative, the pilot will benefit from centralized ownership, planning, and administration, setting it apart from developer- or customer-owned systems. NW Natural's approach will enable coordinated long-term infrastructure planning, transparent rate setting, and future access to utility-administered incentives. By distributing infrastructure and operational costs across a broader customer base, the utility model further mitigates financial risks for individual property owners and tenants while ensuring professional, consistent service delivery. These advantages position the TEN as an equitable platform for future decarbonization efforts.

55 While the initial pilot will serve market-rate mixed-use buildings, NW Natural has accounted for future expansion to community-serving facilities, including affordable housing, and other civic buildings. The ambient loop layout and system capacity have been designed to accommodate these connections in later phases, helping advance broader equity goals.

56 In parallel, the pilot will generate insights to inform future cost allocation and rate design strategies. NW Natural will assess usage data and cost recovery mechanisms with an eye toward energy efficiency incentives and affordability pathways for income-qualified customers in future expansion areas. Rate development and equity considerations will be guided by pilot results and ongoing coordination with regulatory agencies.

57 Ultimately, the Vancouver TENs pilot project is slated to demonstrate how centralized thermal energy infrastructure can support efforts to overcome technical, financial, and logistical barriers to decarbonization in dense, mixed-use contexts. NW Natural intends to share lessons

learned with peer utilities, local sustainability offices, the Commission, and the Department of Commerce to support broader decarbonization efforts statewide.

RCW 80.28.460(3)(i) -- Whether the pilot project will develop information useful for the commission's adoption of rules governing thermal energy networks

58 NW Natural will publish a public-facing final report and include a dedicated Technology and Knowledge Transfer (TKT) task to document lessons learned throughout the pilot. These deliverables will be designed to generate actionable insights for Commission rulemaking process on utility-led thermal energy networks.

59 To support this, NW Natural will conduct structured consultations with key stakeholders, such as the Commission, Department of Commerce, labor representatives, technical experts, and community partners, at major project milestones. These check-ins will be used to review project activities, gather feedback, and identify rulemaking-relevant takeaways in areas such as: rate design and customer billing transparency; interconnection practices and safety protocols; labor and workforce development alignment; and community engagement strategies. This approach will allow for meaningful stakeholder input and knowledge sharing, and it will enable NW Natural to align pilot findings with future regulatory design efforts across the state.

60 Further, NW Natural is proposing a number of metrics intended to help NW Natural monitor the performance of the TEN pilot project and better understand how to operate and maintain future TEN projects. Proposed metrics are focused on measuring technical performance, safety and reliability performance, financial performance, customer experience, and societal impacts. The information gathered through these metrics is expected to aid the commission in adopting rules governing thermal energy networks. See Attachment 2 for proposed metrics.

RCW 80.28.460(3)(j) -- Enrollment in an electric utility demand response program;

61 NW Natural has been in close coordination with CPU; at this time, there is not a demand response program offered by the local utility but as that changes, NW Natural will help facilitate enrollment of the TENs customers.

RCW 80.28.460(3)(k) -- The potential to enable gas pipeline decommissioning and its potential to supplant the need for gas pipeline replacement and the need to spend on gas pipeline replacement programs.

62 Although the TEN will primarily serve new construction that will not require conventional natural gas service for space heating or domestic water heating, the project represents a meaningful opportunity to explore how utility-owned thermal energy networks can be planned and deployed as alternatives to traditional natural gas service. Through this project, NW Natural will generate lessons about utility coordination, infrastructure scoping, and long-term planning that could inform approaches to expanding TENs in the future.

RCW 80.28.460(3)(l) -- Whether the thermal energy network is a distributed system that uses ambient temperature fluid and high-efficiency heat pump equipment in each building in the network.

63 The TEN pilot is designed as a distributed ambient loop system. Based on the preferred Street Loop design, the ATL will consist of a closed loop buried pipe system circulating water with a small amount of chemical treatment that inhibits corrosion and bacteria growth.

64 The thermal energy network will circulate ambient temperature fluid through a central ambient temperature loop, driven by a primary pump station that distributes energy throughout the network to heat pumps located within each building. Each building connected to the loop will

be equipped with a dedicated energy transfer station (ETS), which includes circulation pumps and a heat exchanger that pulls geothermal fluid from the ATL to deliver energy to the building. As the heat pumps within each building extract heat from or reject heat to the ATL, the ATL will balance needed energy flow to satisfy each heat pump's needs.

65 The ATL will be designed to operate within a moderate temperature range and serve as a shared thermal reservoir, allowing buildings to either extract or reject heat depending on their individual heating and cooling needs.

66 Each building connected to the TEN is intended to use decentralized, high-efficiency GSHPs, specifically:

- GSHPs will be installed at the building level, downstream of each ETS.
- Each ETS will transfer thermal energy from the ATL to the building's internal distribution loop, which will then supply thermal energy to the GSHPs.
- The ATL supply water temperature differential from one energy source to the next energy source shall not be more than 10°F at design conditions. This design limit ensures consistent operational efficiency for all heat pumps connected to the system while allowing sufficient margin for capacity and flow control across the network.

This decentralized GSHP architecture will ensure that the TEN system is modular and demand-responsive, allowing each building to independently control indoor temperatures without relying on centralized delivery of conditioned air or hot/chilled water.

D. Statutory Criteria that the Commission May Consider

RCW 80.28.460(4)(a) -- Greenhouse gas emissions reductions;

67 As stated above, the TEN pilot is projected to achieve a 36 percent reduction in carbon emissions compared to a business-as-usual (BAU) scenario using conventional fully electric heating systems.

RCW 80.28.460(4)((b) -- The use of waste heat, ground-source heat, geothermal resources, or other nonfossil fuel and noncombustion sources, and the use of electric heat pumps;

68 The pilot project will rely primarily on an open-loop geothermal well field as its source of thermal energy. Through a centralized ambient temperature loop, geothermal energy will be circulated between connected buildings, where distributed ground-source heat pumps located in each building will extract or reject heat based on individual load conditions. The system will be fully electric. No backup will be required to meet end-use needs under the current system design.

RCW 80.28.460(4)(c) -- The ability to provide the pilot project customers' hot water demands.

69 Domestic hot water ("DHW") for all connected buildings will be supplied through building-level heat pump water heaters connected to the ambient temperature loop. The system has been sized to account for DHW demand based on occupancy type and usage estimates developed during the modeling phase. This design ensures year-round delivery of 100 percent of DHW needs without reliance on gas or electric resistance heating.

RCW 80.28.460(4)(d) -- The ability to provide the pilot project customers' cooling demand.

70 Cooling for all connected buildings will be delivered through the same systems used for heating. These systems are capable of extracting heat from indoor spaces and rejecting it to

the ambient loop. The loop is designed to maintain thermal balance and accommodate concurrent heating and cooling demands across a diverse mix of building types. System modeling has included detailed cooling load calculations based on expected summer temperatures, building envelope performance, and internal heat gains.

RCW 80.28.460(4)(e) -- The consideration of options to provide thermal energy storage.

71 TES is not included in the design because the open-loop geothermal system, supported by a high-yield aquifer, is capable of directly meeting peak capacity demands. Additionally, since the majority of electrical load in the system comes from in-unit heat pumps on the customer side, utility-side TES would not enable meaningful load shifting or generate cost or operational benefits. As a result, TES would increase capital cost without delivering corresponding value to the system.

72 A dedicated backup heating system is not required for the initial pilot due to the system's built-in redundancies and the reliability of the thermal resource. The design includes dual-pump redundancy (N+1) and thermal load balancing across buildings and ETS units. These features, coupled with the consistent production capacity of the open-loop geothermal source, will allow the system to meet heating needs without additional backup. Backup power may be considered in future system expansions, but it is not included in the scope of this pilot due to the expected reliability of the current configuration.

RCW 80.28.460(6) – Performance Metrics

73 See Attachment 2, as well as our explanation above regarding how we satisfy the requirements of RCW 80.28.460(3)(i).

RCW 80.28.470 – The Cost of the Project

74 Pursuant to RCW 80.28.470(2), NW Natural is petitioning the Commission to use an alternative process from what is specified in RCW 80.28.470(1) to estimate the cost to deploy a thermal energy network pilot project. RCW 80.28.470(1) appears to require NW Natural to first fully design the project and then submit a request-for-proposals to finalize construction costs. RCW 80.28.470(2), however, permits NW Natural to petition the Commission to use an alternative process. Specifically, NW Natural is petitioning the Commission to use its current design estimate to move forward with the project that is based on the schematic design of the Vancouver TENs pilot project provided by Salas O'Brien. As mentioned above, NW Natural contracted with Salas O'Brien to provide the schematic design of a TEN to support the Vancouver TENs pilot project. Salas O'Brien has extensive experience designing TEN projects across North America. Please see Attachment 3, Basis of Design Report and Confidential Attachment 4, the Energy Report. Both of these reports were completed by Salas O'Brien as part of our design work for the project.

75 The team of NW Natural, City of Vancouver and the developer of the new buildings that will be served by the project—Lincoln Property Company—met at least semi-weekly from December 2024 through June 2025 to understand the site's thermal needs, limitations, feasibility of various loop options and available thermal resources. This resulted in a schematic design supported by all entities and serves as the basis for the detailed cost estimates provided by JLD Cost Consulting. NW Natural has included this cost estimate as Confidential Attachment 5.

76 Schematic design represents approximately 30 percent design completeness. NW Natural decided to use 30 percent design as an alternative to the process contemplated in RCW

80.28.470(1) for four reasons. First, it gives NW Natural the opportunity to share the project with the Commission and interested entities for discussion at a much earlier stage than would otherwise be possible if the Company had waited until design was complete. By doing so, NW Natural is seeking to have open dialogue about TENs projects, especially in light of reduced funding available for Department of Commerce grants to offset the cost of the project. NW Natural understands that the $25 million originally envisioned for such grants statewide is now $4.8 million. This reduction in funding is a material change that will almost certainly increase costs to utility customers, although NW Natural notes that utility scale geothermal tax credits remain available despite recent changes to federal tax law. NW Natural currently anticipates that this tax credit will be available for this project.

77 Second, it would cost approximately $440,000 to develop the final design in addition to approximately $230,000 that NW Natural has already spent on the project. Although NW Natural is committed to the TENs project, the Company and our customers should not incur additional costs in developing the project without some assurance of Commission support, especially given the substantial reduction in state grants that are available for these pilot projects. NW Natural understands that the Commission's approval of cost recovery is not guaranteed even if the Commission grants NW Natural's petitions in this filing. However, under HB 2131 the Commission has considerable discretion to approve or reject a TENs pilot project with no clear legal standard to apply to such projects. Given this considerable uncertainty, the Company is seeking some initial discussions and feedback that it should continue to invest in this project.

78 Third, 30 percent design completeness allows NW Natural to move faster than it otherwise could in constructing the Vancouver TENs pilot project. If NW Natural had to wait until design

was complete and a request-for-proposals conducted, then the Company would have to pause the project and wait for Commission approval, even though all the necessary steps have been taken to begin construction. This delay may mean not meeting the December 2026 deadline set by the bill. On the other hand, the 30 percent design completeness is a natural point to pause and consider if the Company should continue to pursue project. In short, a company, even if it was not Commission-jurisdictional, would likely pause the project at this point and consider whether it should go forward.

79 Finally, NW Natural serves a relatively small number of customers in the state, making this pilot project a major investment in its Washington service territory. As such, the Company is seeking input from the Commission as soon as practicable on this TENs pilot project, especially due to cuts in the amount of grant finding available from the Department of Commerce, increasing the cost of the project to the Company's customers.

80 The 30 percent design includes cost contingencies to provide a conservative (worst case) estimate. The amount of these cost contingencies will be reduced over time as NW Natural moves towards 100 percent design. Figure 3 below reflects a high-level cost summary; a detailed estimate is available in Confidential Attachment 5.

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Figure 3

TEN Component	**Schematic Design cost estimate**
Open Loop	[redacted]
Pump house and ETS	[redacted]
Vault	[redacted]
Heat pumps	[redacted]
SCADA Control System	[redacted]
Contingency	[redacted]
Insurance	[redacted]
Taxes/Fees	[redacted]
Other (Indirect, Misc. Electrical, , etc.)	[redacted]
Total	**$12,800,000**

NW Natural notes that the cost of the heat pumps are not included in the estimate prepared by our consultant, but are necessary for the project. The Company estimated the cost of the heat pumps based on a similar project by the building developer, Lincoln Property Company. Also, the cost, above, does not reflect the benefits of the utility-scale geothermal tax credit or any energy efficiency credits that may be available through CPU. NW Natural, however, is pursuing these avenues to lower the overall cost of the project.

81 RCW 80.28.470(1) also requires NW Natural to compare the cost of the TENs pilot project to the "lowest reasonable cost alternative resource for heating services under the gas company's

current business practices." NW Natural is not seeking an alternative process for this calculation. Instead, it estimates the cost of extending gas service to these buildings in downtown Vancouver to be approximately $38,000.

82 If the Commissions approves the alternative process to estimate the cost of the Vancouver TENs pilot project, NW Natural will complete design work and issue a Request for Proposals for TEN construction based on construction documents and the final drawings and specifications.

IV. CONCLUSION

83 NW Natural appreciates the work of the Commission, Staff, and interested parties for their work to date on TENs. In support of the project, NW Natural has secured letters of support from the City of Vancouver, Clark Public Utilities, and Lincoln Property Company. These letters of support are attached to this filing as Attachment 1. In accordance with RCW 80.28.450, RCW 80.28.460 RCW, 80.28.470(2), NW Natural respectfully requests that the Commission review and validate the costs assessments of its Vancouver TENs pilot project, including the alternative process used to develop this cost estimate.

Dated this 29th day of July 2025.

Respectfully Submitted,

NORTHWEST NATURAL GAS COMPANY

/s/Ryan Sigurdson
Ryan Sigurdson
Regulatory Attorney (WSBA #39733)
250 SW Taylor Street
Portland, OR 97204-3038
Phone: 503.610.7570
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BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Holly J. Braun

THERMAL ENERGY NETWORKS

Exh. HJB-4

August 29, 2025

Clark Public Utilities
Customer-owned, customer-focused

Commissioners
Nancy E. Barnes
Sherry S. Erickson
Jane A. Van Dyke

Chief Executive Officer/ General Manager
Lena Wittler

June 30, 2025

The Honorable Brian Rybarik, Chair
The Honorable Ann Rendahl, Commissioner
The Honorable Milt Doumit, Commissioner
Washington Utilities and Transportation Commission
621 Woodland Square Loop SE
Lacey, WA 98503
Re: NW Natural's Thermal Energy Network Pilot Project

Dear Chair Rybarik and Commissioners,

Clark Public Utilities supports NW Natural's application for a proposed Thermal Energy Network (TEN) pilot project. The project team at NW Natural contacted Clark Public Utilities during the initial planning and design phase of this TEN project and we have been coordinating and researching the potential value of this project for the electric grid in Clark County for the last several months.

Our initial analysis indicates the NW Natural TEN project would have both an energy and capacity value for the utility and would be a benefit to the community. We have identified a process to measure and report energy efficiency savings this project may provide. We also concluded TEN projects have potential to provide capacity value to the electric utility; when measured against the baseline technologies that would be providing space and water conditioning, a TEN achieves much lower peak demand during both the summer and winter seasons. Clark Public Utilities does not currently have programs that provide incentives for the reduced demand TEN projects provide but the potential capacity benefit of this NW Natural pilot has been a catalyst to explore options for a future incentive program design.

Clark Public Utilities recognizes both the challenges we face as Washington decarbonizes not just the electric sector but the entire state-wide economy, and the benefits the clean energy future will bring our state. We believe projects like NW Natural's TEN pilot will be a key component to the successful approach needed to achieve Washington's carbon reduction goals. For that reason, combined with the value streams we have identified, we strongly support NW Natural's TEN grant application.

Sincerely,

Matt Babbitts
Clark Public Utilities

CITY OF Vancouver WASHINGTON

July 2, 2025
Washington Utilities and Transportation Commission
621 Woodland Square Loop SE
Lacey, WA 98503

Subject: Letter of Support for NW Natural Thermal Energy Network Pilot in Vancouver, WA

Dear Grant Review Panel,

On behalf of the City of Vancouver, I am writing to express our strong support for NW Natural's thermal energy network pilot. This initiative represents an innovative, sustainable infrastructure investment that aligns with the City's goals for climate action, energy resilience, equitable community development, and reducing the costs to deliver new housing.

As municipalities across the country face growing challenges related to climate change, energy affordability, and aging infrastructure, the deployment of thermal energy networks offers an exciting solution that, though new to the City of Vancouver, has proven scalable and successful elsewhere in similar applications. The proposed project will utilize ground sourced heat recovery to provide low-carbon heating and cooling for the City's Waterfront Gateway mixed use redevelopment and adjacent City Hall. After completion of the thermal energy network pilot and construction of the redevelopment site, it is expected to serve over 300 residential units, 35,000 sf of retail, and 200,000 sf of office. This will significantly reduce greenhouse gas emissions with a modeled 36% energy savings compared to a conventional heating and cooling system. This significant energy savings is expected to bring down operating costs and enhance the reliability of energy services for the development while lowering the initial cost of construction for the residential development by eliminating their need to include building mechanical equipment in their scope.

The City of Vancouver recognizes the importance of innovative energy solutions in meeting our climate and sustainability targets as highlighted by the City's Climate Action Framework and ongoing Green Building Policy development. The thermal energy network pilot directly supports these efforts and demonstrates a model of public-private collaboration with the potential to be replicated regionally.

In addition to its environmental benefits, the thermal energy network pilot will support local economic development, create living wage jobs, and improve energy equity by delivering affordable and sustainable thermal services to a diverse set of users, including housing, municipal buildings, and small businesses.

We are proud to partner with NW Natural in advancing this exciting initiative, and we are committed to supporting the successful development, implementation, and long-term viability of the thermal energy network pilot.

Thank you for your consideration of this important project.

Sincerely,

Anne McEnerny-Ogle
Mayor
City of Vancouver, Washington

Lincoln

Lincoln Property Company
720 Third Avenue | Suite 1410
Seattle, WA 98104

T 509.389.3406
nwillard@lpc.com

June 30, 2025

The Honorable Brian Rybarik, Chair
The Honorable Ann Rendahl, Commissioner
The Honorable Milt Doumit, Commissioner
Washington Utilities and Transportation Commission
621 Woodland Square Loop SE
Lacey, WA 98503

Re: NW Natural's Thermal Energy Network Pilot Project

Dear Chair Rybarik and Commissioners

Lincoln Property Company is pleased to offer our full support for NW Natural's proposal to develop a brand-new Thermal Energy Network (TEN) in Vancouver, Washington.

The proposed TEN aligns with Lincoln's core values and offers an innovative approach to providing reliable, low-carbon thermal energy to the growing Vancouver community. This TEN will not only provide immediate environmental and operational benefits but also set a precedent for smart energy infrastructure development in the region. We believe this project will build the State of Washington's sustainability legacy, becoming a powerful example of interdisciplinary collaboration and innovation.

As a company with a long-standing commitment to sustainable and resilient development, Lincoln has experience with carbon and energy management in new construction projects regionally and nationally. We support transitioning to thermal energy networks as an essential aspect of future-proofing our built environments—and thereby our communities—and we are eager to contribute our expertise to this forward-thinking initiative.

This project has the potential to be a landmark case study for future new construction, and we are eager to support NW Natural's leadership in advancing clean energy solutions. We encourage local stakeholders to move forward with this transformative initiative, which will serve as a model for future sustainable urban energy systems and contribute to the long-term success of the Vancouver area.

Sincerely,

Alex Aigner

Alex Aigner
Executive Vice President, Pacific Northwest

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Holly J. Braun

THERMAL ENERGY NETWORKS

Exh. HJB-5

August 29, 2025

Vancouver Waterfront Gateway TENs Pilot Metrics

Per RCW 80.28.460(6), these performance metrics "are intended to help inform the commission's rule making and rate making and specifically to help inform any future standardized metrics that the commission may adopt for thermal energy network pilot projects," and, as such, are not intended to be ongoing reporting requirements.

Technical Metrics

Metrics	Data Collected	Unit of Measurement	Comments
1. Load Profiles of Customer Equipment	Building number/occupancy/use/sq. ft.	Various	HB 2131 (3a)
	Nameplate capacity of space conditioning and DHW equipment	BTU/h	HB 2131 (4c, 4d)
	Electricity consumption of space conditioning and DHW equipment	kWh	HB2131 (3f) - provided by electric utility serving TEN pilot
	Thermal energy consumption building side of ETS(s)	BTU/h	HB 2131 (3d,3l, 4c,4d)
2. Load Profiles of Thermal Source(s)	Thermal energy consumption of GLHX	BTU/h	
	Electricity consumption of open loop well/circulation pump(s) and ancillary equipment	kWh	HB2131 (3f) - provided by electric utility serving TEN pilot
	Electricity consumption of GLHX ancillary equipment	kWh	HB2131 (3f) - provided by electric utility serving TEN pilot
3. Energy Input/Output of Thermal Energy Network (TEN)	Hours of system operation to provide heating	Hours	HB2131 (3d)
	Hours of system operation to provide cooling	Hours	HB2131 (4d)
	Electricity consumption of ATL pumps and ancillary equipment	kWh	HB2131 (3f) - provided by electric utility serving TEN pilot

Financial Metrics

Metric	Utility-Side	Equipment	Labor	Comments
1. Capital Expenditures (Utility-Side)	Design	X	X	HB2131 (3h)
	Electrical	X	X	HB2131 (3h)
	Equipment and facilities	X	X	HB2131 (3h)
	Property/permitting	X	X	HB2131 (3h)
	Metering	X	X	HB2131 (3h)
	Software	X	X	HB2131 (3h)
	Other	X	X	HB2131 (3h)
2. Operating Expenditures (Utility + Customer Building-Side)	Electricity	X	N/A	HB2131 (3h)
	Equipment and facilities maintenance	N/A	X	HB2131 (3h)
	Equipment and facilities labor	X	X	HB2131 (3h)
	Other	X	X	HB2131 (3h)

Vancouver Waterfront Gateway TENs Pilot Metrics

Customer Metrics

Metric	Data Collected	Unit of Measurement	Comments
1. Customer Satisfaction with TEN Service	Customer-experience survey results	Customer count by satisfaction level	HB2131 (3e)
	Number of customers served	Number	HB2131 (3a)

Safety & Reliability Metrics

Metric	Data Collected	Unit of Measurement	Comments
1. Safety	Workforce safety incidents	Number	HB2131 (3c)
2. Reliability	TEN system up-time	Percent	HB2131 (3c)
	Cause of TEN shutdowns (planned/unplanned)	Description	HB2131 (3c)
	Duration of shutdowns (planned/unplanned)	Hour	HB2131 (3c)

Vancouver Waterfront Gateway TENs Pilot Metrics

Societal Metrics

Metric	Data collected	Unit of Measurement	Comments
1. Greenhouse Gas Emissions Reductions	Carbon emissions reductions	TBD	HB2131 (4a)
2. Aggregate Electric Demand Reductions	Buildings enrolled in electric demand response program	Number	HB2131 (3j)
	TEN electric demand (utility owned)	kW	HB2131 (3f) – provided by electric utility serving TEN pilot
	TEN electric consumption (utility owned)	kWh	HB2131 (3f) – provided by electric utility serving TEN pilot
3. System Efficiency: COP	TEN electric demand (utility owned)	kW	HB2131 (3f) – provided by electric utility serving TEN pilot
	Space conditioning and DHW output (Customer-side)	kWh	HB2131 (3f) – provided by electric utility serving TEN pilot
4. Number of jobs created (temporary and permanent)	Number of jobs during design, construction, and operation of the pilot project (union/non-union) including use of existing workforce	Number	HB 2131 (3a, 3b)

ACRONYMS & ABBREVIATIONS

ASHP – Air Source Heat Pumps

ATL – Ambient Temperature Loop

BAU – Business as Usual

DHW – Domestic Hot Water

ETS – Energy Transfer Station

GLHX – Ground Loop Heat Exchange/Exchanger

PUD – Public Utility District

TEN – Thermal Energy Network

WSHPs – Water Source Heat Pumps, also known as ground source heat pumps

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Holly J. Braun

THERMAL ENERGY NETWORKS

Exh. HJB-6

August 29, 2025

Salas O'Brien

TEN Pilot Project
Basis of Design Report
NW Natural – Waterfront Gateway

Prepared for: NW Natural

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May 13, 2025

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ACRONYMS & ABBREVIATIONS

ASHP – Air Source Heat Pumps
ATL – Ambient Temperature Loop
DHW – Domestic Hot Water
ETS – Energy Transfer Station
GLHX – Ground Loop Heat Exchange/Exchanger
GLD – Ground Loop Design, software for GLHX modeling
HDPE – High Density Polyethylene
SCADA – Supervisory Control and Data Acquisition
TEN – Thermal Energy Network
TRNSYS – Transient System Simulation, software for modeling ambient loop TENs
WET – Wastewater Energy Transfer, also known as sewage heat exchange, sewage heat recovery, wastewater heat recovery, etc.
WSHPs – Water Source Heat Pumps, also known as ground source heat pumps

THERMAL ENERGY NETWORK DESIGN

OVERVIEW

The recommended ambient thermal loop (ATL) location is a variation of the “Street Loop” option as presented in the pre-design report. The ATL will be routed in the right-of-way adjacent to the street with run-outs to each of the buildings.

Due to the significant available thermal production from an open loop geothermal system at this site, it is recommended that the City Hall open loop geothermal system be connected to the TEN system and an additional set of extraction and injection wells be installed on the west side of the site.

The ATL and the Open Loop Geothermal will need a pump station(s). The Open Loop Geothermal pump station is planned to be located in the parking garage. The 30% design shows two options for the ALT pump station. Option A is a vault located in the plaza on the East side of the site. Option B is for the ALT pump station to be located adjacent to the Open Loop pump station in the parking garage.

Each building will need an Energy Transfer Station (ETS) to separate the fluid in the TENs system from the fluid in the building system and to transfer heat between the systems. The exact location of the ETS in the new construction buildings will need to be coordinated with their building design team. They are currently shown near the planned mechanical rooms.

CIVIL

Project Design Parameters

The proposed civil/site systems will be designed in accordance with standard engineering practice and current code requirements.

Site Clearing/Demolition

- Prior to any excavation, erosion control measures will be installed to prevent the transmission of sediment laden runoff from the construction area.
- Where applicable, topsoil will be stripped and stockpiled with appropriate erosion controls applied to all disturbed areas.
- Clear and grub area within limits of the project including removal of trees, bushes, shrubs, stumps, fencing and other incidental materials not required for use on the site.
- Areas that will be left disturbed and exposed for a significant period of time shall be seeded for protection.
- Traffic control, signage, and barriers will be needed throughout the project for staging, phasing and protection of the public from construction activities.
- Conduct demolition in a manner that will prevent damage to adjacent structures, utilities, site improvements, and other facilities to remain. Surfaces to be demolished shall be clearly defined with perimeter saw cuts. All demolished materials must be properly handled and disposed of offsite.
- Remove all site improvements as required to allow installation of new utilities.
- Protect all existing site improvements and utilities that are to remain during all construction activities.

Site Earthwork

Provide excavation and backfill for utilities and surface restoration including temporary excavation and support as required per jurisdictional standards and specifications.

Site Grading, Excavation & Disposal

Prepare subgrades for walks, pavements, turf, and grasses. Provide proof-rolling of subgrades as well as any necessary dewatering systems.

Provide stockpiling of all suitable onsite materials required for reuse. The project area may contain polluted or contaminated soils. Soil testing will be conducted via geoenvironmental investigations. Monitoring of soils during excavation may be required. Polluted and contaminated soils shall be disposed of legally with all required permitting and manifests.

All hazardous waste removal shall be performed by a licensed Hazardous Waste Contractor. Include all necessary permitting and manifests required for the removal of hazardous waste.

Borrow Fill

Provide clean imported materials for sub-base and base courses for concrete and bituminous walks and pavements.

Provide clean imported material for subsurface utility trench bedding and backfill.

Site Dewatering

Provide all necessary dewatering systems to maintain a dry work area. Dewatering systems shall be designed and installed by licensed professionals in Washington State experienced with these systems.

Site Shoring

Provide all necessary temporary excavation support and protection to allow construction of proposed structures, improvements, and utilities. Temporary excavation support and protection systems shall be designed and installed by licensed professionals experienced with these systems.

Erosion and Sediment Control

The project will require a permit from US EPA for a Stormwater Permit for Construction Activity prior to the planned commencement of construction. This permit includes requirements for a Stormwater Pollution Prevention Plan (SWPPP) prior to the commencement of construction and Plan Implementation Inspections during construction performed by a qualified person. The permittee shall provide all necessary “Qualified Inspectors” and “Qualified Professionals” as defined in the permit regulations.

Erosion and sediment control measures will consist of, but shall not be limited to, inlet protection, silt fence, compost filter socks, construction entrances, sediment control ponds, etc.

The installation and maintenance of all erosion and sedimentation control measures shall be in accordance with the SWPPP provided with the Stormwater Permit mentioned above.

Utilities Trenching

Place and compact backfill in excavations on subgrades free of mud, frost, snow, or ice. Individual compacted layers shall be compacted to minimum dry densities as follows:

- Under Equipment Pads, Structures, and Pavements (Other Than Stone Base): 95 percent.
- Under and Around Utilities (Other Than Stone): 95 percent.
- Under Walkways: 95 percent.
- Under Lawn or Unpaved Areas: 90 percent.

Site Surface Improvements

- Bituminous Pavement
  - Bituminous concrete paving that is removed to allow for the installation of proposed utility shall be reinstalled to match existing conditions.

- Roadway Paving and Surfacing
  - The bituminous concrete paving section will consist of no less than 7.2” of asphalt over 8 inches of aggregate base material., specifically hot mix asphalt Class ½” PG 58H-22 constructed in accordance with Section 5-04 of the WSDOT Standard Specifications.
- Painted Lines and Markings
  - Pavement markings shall comply with the City of Vancouver. Washington standards and Specifications.
- Pedestrian Paving
  - Sidewalks removed to allow for the installation of proposed utility and surface improvements will be reinstalled to match existing conditions.
- ADA Site Elements
  - ADA ramps, signage, and striping removed to allow for the installation of proposed utility and surface improvements will be reinstalled to match existing conditions.
- Sidewalks
  - Concrete sidewalks will consist of 4-inch-thick, normal weight concrete with 3,000 psi (CL 3000) minimum, 28-day compressive strength, maximum 3-1/2” slump. Concrete sidewalks will be installed over 3” gravel base material.
- Curbing
  - Site curbing removed to allow for the installation of proposed utility will be reinstalled to match existing conditions. Site curbing will consist of precast concrete curbing or cast-in-place curbing to match existing conditions.
  - Precast concrete curbing will be 6 inches wide by 18 inches minimum depth, and curbing will extend 6 inches above adjacent roadway surfaces.
- Retaining Walls
  - Site retaining walls removed to allow for the installation of proposed geothermal system will be reinstalled to match existing conditions. Site retaining walls will consist of reinforced, cast-in-place retaining walls to match existing conditions.

Planting

Planting beds removed to allow for the installation of proposed utility and surface improvements will be replaced in kind to match existing conditions and plant species. All other disturbed softscape areas of the site will be lawn seed mixes or sod.

STRUCTURAL

Existing (City Hall)

Utility penetrations shall be cored through any existing concrete foundation walls at each building entry point. Existing walls shall be scanned prior to coring in order to locate the position of existing reinforcing steel. Avoid coring through or within 2 inches of existing reinforcing steel. Since adjustments to the location of the cores may be required after scanning, coordination with the exterior utility layout will be critical to ensure proper alignment. The coring process shall employ diamond-tipped core drills mounted on stable rigs or to the exterior face of the foundation walls. Provide a clear distance between adjacent cores and existing wall penetrations of one core diameter. Notify engineer of record if existing reinforcing steel cannot be avoided or if minimum spacing between cores cannot be maintained and allow for additional design team review and directives prior to coring. Exterior wall waterproofing shall be repaired to match the existing conditions.

New Construction

Penetration for new construction will be coordinated during design.

MECHANICAL

Operational Narrative

The Thermal Energy Network (TEN) system will likely have an open loop geothermal system. An open loop geothermal system is connected to an ambient temperature loop (ATL) pipe through a set of heat exchangers that distributes energy throughout the community to the heat pumps located within each building. Each of the open loop wells will be served by its own heat exchanger and pump station that includes (2) heat exchangers and (2) pumps. The heat exchangers are designed to provide approximately 75% of the maximum flow from the open loop wells and the pumps are sized to be fully redundant. The pumps are included to circulate the geothermal fluid through the heat exchangers to transfer heat to/from the ATL as needed. Refer to the Pump Infrastructure section in this narrative for additional information regarding equipment requirements associated with the ATL pump station.

Each of the buildings will be served by a dedicated Energy Transfer Station (ETS) which includes circulation pumps and a heat exchanger that pulls fluid from the ATL to deliver energy to the building. As the heat pumps within each building extract heat from or reject heat to the ATL, the ATL pumps speed up to provide more flow, and the thermal asset pumps speed up to transfer more heat to/from the ATL to satisfy each heat pump’s needs.

Each building will be equipped with isolation valves and a bypass line that will facilitate phasing and construction timing by allowing the isolation of each building from the ATL. Refer to flow diagrams on mechanical plans for additional information. Each building’s ETS heat exchanger will isolate the ATL from the building and provide a demarcation between Utility infrastructure and building systems. This also allows each building to connect without shutting down the ATL.

The ATL will be filled with 100% water solution with a small amount of chemical treatment that inhibits corrosion and bacteria growth. Since the ATL is a closed loop, it does not need significant fluid/water once it is filled and operational, however as any air is removed via the air elimination system or as fluid is lost due to expansion and pressure relief, a small amount of fluid will be added via automatic feed stations to maintain the pressure, thus keeping the pumps primed and operating. The system operating pressure will be confirmed during a later phase, however, is expected to be below 100 PSI.

A SCADA control system will be provided to control, monitor, and meter the ATL, open loop wells, and ETS systems.

Operational Parameters

The following presents the basis of design for the geothermal system:

- Outdoor Air Design Conditions:
  - Vancouver, WA
    - Summer: 87.7°F DB, 66.1°F MCWB (ASHRAE 1.0%)
    - Winter: 24.4°F DB (ASHRAE 99.6%)
- Delivery supply water temperatures:
  - 32°F minimum heating mode supply water temperature to the building side of the ETS.
  - 93°F maximum cooling mode supply water temperature to the building side of the ETS.
  - 3°F approach temperature on the ETS.
  - The ATL supply water temperature differential from one energy source to the next energy source shall not be more than 10°F (at design conditions). This will provide a consistent operational efficiency for all heat pumps served by the ATL system.
- Operational system pressure shall be designed to maintain minimum suction pressure at each pump to prevent pump cavitation and to limit pressure to within piping and component pressure ratings.
- ATL flow rate shall be designed to maintain the specified maximum temperature differentials between the energy source input manifolds. The heat exchanger flow rates shall be designed at 3GPM/Ton of capacity required.
- Pipe sizing Requirements:
  - The ATL pipe size will be standard pipe sizes based upon required flow. Flow rates to achieve proper temperature differences and pressure drop shall be primary design criteria for pipe sizing.

Infrastructure Piping and Materials

- Piping Materials:
  - All ATL piping shall be constructed of HDPE.
    - All pipe and heat fused materials shall be manufactured from a virgin polyethylene extrusion compound material. Pipe shall be manufactured to outside diameters, wall thicknesses and respective tolerances as specified in ASTM D-3035, D-2447, or F-714.

  - The material shall be PE4710 HDPE with minimum cell classification 445474C, with a UV stabilizer of C, D, or E as specified in ASTM D3350 and is listed by the Plastic Pipe Institute in PPI TR-4 with HDB ratings of 1600 psi at 73°F (23°C) and 1000psi at 140°F (60°C).
  - All PE4710 HDPE pipe shall have DR rating based on determined system pressures.
- High Density Polyethylene (HDPE) Pipe Fittings:
  - Pipe fittings shall be of the same material designation as detailed above and shall meet the requirements of ASTM D2683 (for socket fusion) or ASTM D3261 (for butt/saddle fusion). Each fitting shall be identified with the manufacturer's name, nominal size, pressure rating, relevant ASTM standard(s) and date of manufacture.
  - All piping shall be hydrostatically pressure tested to ASTM standards before burial and follow PPI and manufacturer pressure testing guidelines for HDPE pipe.
- A minimum 50-year limited warranty will be specified for HDPE piping.
- All pipe and fitting joining methods shall be either butt, socket, or saddle type heat fusion processes. No mechanical joints shall be allowed underground unless located within a sub-surface vault.
- Transitions from HDPE to pump volutes, valves, etc. shall be 4 or 6 bolt flanged ductile cast iron back up rings with HDPE fitting type connection for any below ground connections and flanged schedule 40 steel for any above grade connections.
- Where possible, ATL and geothermal piping will have a minimum 3’, 360° clearance around the pipe from any other infrastructure running parallel to this service. If the geothermal piping is run parallel (within 3’ distance) with either water or sewer lines for more than 3’, then the geothermal infrastructure piping shall be insulated with 1” thickness EPDM insulation for the entire length the piping is running with the other infrastructure. Buried insulation shall be protected with HDPE jacket and sealed to prevent water intrusion.
- All ATL and geothermal piping shall have a minimum 1’, 360° clearance around the pipe from any other infrastructure crossing perpendicular to this service.
- Tracer wire shall be installed on all non-metallic pipes with fiber tape placed at 10’ intervals. All tracer wire and location tape shall conform to all local and provincial regulations and standards. All tracer wire termination points will at their respective manifold or ETS. The maximum distance between termination points is not to exceed 500’. Tracer wire termination points will not be placed above ground in pedestals.

PUMP INFRASTRUCTURE

Structural

New mechanical equipment shall be placed on new concrete housekeeping pads in existing utility rooms. Housekeeping pads shall be pinned to the existing slabs with #4 dowels spaced at 18 inches on center around the perimeter edge of the housekeeping pad. Dowels shall be drilled and installed with epoxy adhesive 3 inches into the existing slab-on-grade. Pads shall be reinforced with #4 reinforcing bars spaced at 12 inches on center in each direction. Concrete for new housekeeping pads shall have a minimum 28-day compressive strength of 4,000 psi.

Mechanical

The pump stations are intended to locate all the equipment required to operate the ATL and all of the thermal resources, including ground loop heat exchanger(s). The equipment requirements for each pump station are listed below. Refer for schedules on drawings for pump sizes and operational requirements.

Pump Station Equipment

- ATL Pump Station
  - Option A – Below Grade Vault
    - Vehicle load rated precast concrete vault located near city hall. Refer to drawings for approximate location and more information.
  - Option B – Above Grade
    - Located within future parking garage in the same location as open loop pump stations. Refer to drawings for approximate location and more information.
  - 2 Pumps (N+1 redundancy) utilizing ECM/VFD control.
  - Air-Dirt Separator.
  - Expansion Tank.
  - Makeup water connection and meter.
- Open Loop Pump Stations – Located to be determined.
  - 2 Pumps (N+1 redundancy) utilizing ECM/VFD control.
  - Open Loop, stainless steel, double wall Heat Exchanger
- Energy Transfer Stations (ETS) – Located in Buildings 1, 2, 4 and City Hall.
  - Plate and Frame Heat Exchanger with a 3°F approach temperature.
  - Source / ATL Side of HX
    - 2 Pumps (N+1 redundancy) utilizing ECM/VFD control.
    - 2 Pipes entering/exiting the structure.
    - 1 Energy Monitoring Station. Includes 1 display/BTU meter, 1 flow meter, 1 supply temperature sensor, and 1 return temperature sensor.
  - Load / Building Loop Side of Heat Exchanger (All components on this side of HX shall be provided by the mechanical contractor responsible for the building side system.)
    - 2 Pumps (N+1 redundancy) utilizing ECM/VFD control.
    - 1 supply temperature sensor, and 1 return temperature sensor.
    - Air- Separator
    - Expansion Tank
    - Glycol Feed System

SCADA CONTROL SYSTEM

- Control instrumentation for the ATL, Open Loop Geothermal, and ETS systems will be provided and will include but not limited to on/off and modulating controls, actuators, water pressure switches, differential pressure transduces and transmitters, temperature and pressure sensors/transmitters, electromagnetic water flow meters, BTU energy meters, current transducers, temperature control panels, and low-voltage power supplies.

- Automatic temperature control devices and instrumentation will be provided with a complete interface to a SCADA system with overall system architecture and communications protocol to be determined upon further review and discussion. As a minimum, TEN will operate independently of the connected buildings to provide source water based on building demand feedback temperature and flow rate monitoring. All TEN equipment will be monitored, controlled, alarmed, and trended via the SCADA. The system will include a web-based operator interface. Heating and cooling energy transfer to/from the geothermal ground source heat exchangers will be monitored and trended using electromagnetic flow meters, temperature transmitters, and BTU energy meters.
- System shall include the following:
    - ATL
        - Leaving and Entering Water Temperature at every source connection
        - ATL flow rate
        - ATL pump speed
    - ETS
        - Leaving and Entering Water Temperature at the source and load side of the ETS
        - Source side pump speed
        - Source side flow rate
        - Source side BTU metering
    - Open Loop Geothermal
        - Water Temperature at each well
        - Flow rate
        - Pump speed
        - BTU metering

OPEN LOOP GEOTHERMAL

Hydrogeologic Conditions

The aquifer selected for the open loop system is the Unconsolidated Sedimentary Aquifer (USA). The USA is assumed to extend from ~30 ft to ~100 ft below ground, to be confirmed by the test drilling program.

The USA is capable of sustainable yields of more than 2000 GPM to/from a single well. A single supply and injection well completed in the USA is sufficient to satisfy 100% of the total heating and cooling requirements of the Thermal Energy Network (including the City Hall).

The groundwater is assumed to flow toward the Columbia River in a south southwest (SSW) direction.

Well Details

- Well Layout:
    - The intention is to maximize efficiency of the supply wells by limiting the effect of drawdown on an adjacent supply well (or wells). It also prevents, or limits, the effect of the injection temperature on the ambient temperature near the supply wells.

  - Generally, supply wells are located up-gradient of the groundwater flow direction and / or injection wells are located down-gradient of the supply wells.
- Well Spacing:
  - Spacing between adjacent supply wells and adjacent injection wells (if more than one is required) is based on the aquifer characteristics.
  - Spacing between a supply well and its nearest injection well are based on aquifer characteristics, the temperature of the groundwater being injected, and the flow rate going into the well. Higher temperature difference and flow will result in the need for greater spacing.
- Well Depths:
  - All wells will extend to the bottom of the USA. The grain size analysis will inform whether the depth can be decreased.
- Well Capacities:
  - The capacity of an open loop well will depend on the depth of the well, diameter of the well screen, slot size of the well screen, and requirements of the TEN.
  - Well details are to be confirmed by the test drilling program.

Operational Parameters

- The open loop geothermal system will constitute a non-consumptive use of groundwater.
- The ambient groundwater temperature is assumed to be ~52°F.
- The typical temperature drop across a HX in an open loop system for heating is ≤12°F, to ensure freeze protection of the returning water. The typical temperature rise for cooling is ≤25°F, to maintain energy efficiency of the heat pump. The resulting HX leaving water temperatures are a minimum of 40°F and maximum of 77°F.
-
- Redundancy:
  - A fully redundant well is optional, to be confirmed by the owner.

Submersible Pumps for Open Loop Wells

The supply wells will be equipped with a submersible pump. The size of the pump is based on the flow requirements for satisfying the loads of the TEN and the pressure head requirements (friction losses and pumping elevation lift).

Typically, a pump control panel with Variable Frequency Drive (VFD) will be utilized and is supplied by the manufacturer of the submersible pump.

ELECTRICAL

- All applicable national, state, local and jurisdictional codes shall be followed for the installation.
- The new Electrical Systems will be designed in accordance with the requirements of the following codes and standards.
  - 2021 Washington State Building Code.
  - 2021 International Building code

    - 2020 National Electrical Code
    - NFPA 72, National Fire Alarm code
    - Clark Public Utility material and installation specs.
    - City of Vancouver
- Power for City Hall Open Loop Pump Station and Transfer Station to be powered via a 225,3P,4W Panelboard fed via the existing building service distribution. Provide separate sub-meter as required.
- Power for Building One Transfer Station to be powered via the building service via a dedicated 225A,3P,4W panel and sub-meter.
- Power for Building Two Transfer Station to be powered via the building service via a dedicated 225A,3P,4W panel and sub-meter.
- Power for Building Four Transfer Station to be powered via the building service via a dedicated 225A,3P,4W panel and sub-meter.
- Power for Building Five Open Loop Pump Station via the building service via a dedicated 225A,3P,4W panel and sub-meter..
- Power to ATL Pump Station Vault (option A) shall be fed via an underground duct bank to a pad mounted transformer feeding a pedestal mounted meter cabinet and 225A, 3P, 4W panelboard for power to pumps. Option B 1 Pump House to be fed via an underground duct bank to a pad mounted transformer and metering feeding a 225A, 3P, 4W panelboard for power to pumps

APPENDICES

- 30% Design Drawings
- Energy Report
- Closed Loop Analysis Report
- Open Loop Geothermal Feasibility Study (for reference)
- Wastewater Energy Transfer (WET) Concept (for reference)

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Holly J. Braun

THERMAL ENERGY NETWORKS

Exh. HJB-7C

REDACTED VERSION

August 29, 2025

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY (PAGES 1-59)
UNDER WAC 480-07-160 AND HAS BEEN REDACTED.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Holly J. Braun

THERMAL ENERGY NETWORKS

Exh. HJB-8C

REDACTED VERSION

August 29, 2025

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY (PAGES 1-36)
UNDER WAC 480-07-160 AND HAS BEEN REDACTED.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Direct Testimony of Robert J. Wyman

EMBEDDED COST OF SERVICE MODEL AND RATE DESIGN/SPREAD

Exh. RJW-1T

August 29, 2025

DIRECT TESTIMONY OF ROBERT J. WYMAN

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position with Northwest Natural Gas Company dba NW Natural ("NW Natural" or the "Company").

A. My name is Robert J. Wyman. My current position is Senior Rates and Regulatory Economist for NW Natural. I am responsible for economic analysis, short-term load forecasting of residential and commercial rate classes, cost of service, and rate spread and rate design. I have been a witness and supported witnesses and created technical work papers for multiple rate and advice proceedings filed with the Washington and Oregon utility commissions on behalf of NW Natural.

Q. Please summarize your educational background and business experience.

A. I hold a Bachelor of Science in Economics from the Robert D. Clark Honors College at the University of Oregon and a Master of Arts in Applied Economics from the University of Michigan. Prior to attending graduate school I was employed by ECONorthwest, an economics consultancy, and worked in the firm's economic development and transportation practice area. I was responsible for the technical analysis on and consultation for dozens of projects, largely in the Pacific Northwest and Western states. I joined NW Natural in 2016 as a Rates and Regulatory Analyst. I have nearly 20 years of professional experience including 8 years of consulting with a focus on public finance and policy, urban economics, and financial feasibility (benefit-cost) analysis as well as nearly 10 years as an analyst and economist in the energy industry with a focus on load forecasting, cost of service, and rate spread and rate design.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the methodology for NW Natural's weather normalized use-per-customer ("UPC") forecast for the Residential and Commercial firm sales rate classes, present the Embedded Cost of Service Study ("EmCOSS") and the daily reading data sampled load study, and describe the Company's rate spread and rate design proposal for each year in the multi-year rate plan ("MYRP").[1] At the end of this testimony, I describe how the rate spread proposal will allocate incremental revenue requirement to each NW Natural Washington Tariff rate schedule ("RS"), excluding RS 4, RS 10, RS 43, and special contract schedules. Separately, I propose tariff changes for RS 10 Charges for Special Metering Equipment, Rental Meters, and Metering Services ("RS 10 Metering Services").

Q. Please summarize your testimony.

A. My testimony is made up of five distinct sections: (1) The Company's UPC weather normalizing methodology; (2) the EmCOSS methodology and a summary of results; (3) proposed changes to rate design as well as the rate spread proposal to be applied to the proposed incremental revenue requirement for this proceeding; (4) revenue and bill impacts for sales firm rate schedules; and (5) the Company's RS 10 Metering Services proposal. First, I will detail the UPC weather normalizing methodology (which creates what is referred to here as the "Normal UPCs") and explain how it is used in conjunction with the Company's customer forecast to create short-term weather

[1] The MYRP consists of the following three years: Rate Year 1, from August 1, 2026, through July 31, 2027 ("RY1"); Rate Year 2, from August 1, 2027, through July 31, 2028 ("RY2"); and Rate Year Three, from August 1, 2028, through July 31, 2029.

normalized volumes for the Residential and Commercial rate classes. The normalized values are used to support the determination of the proposed revenue requirement presented in Exh. KTW-1T. Second, I will outline NW Natural's EmCOSS methodology and will show the embedded cost inputs by capital investment and operations expense categories, on a rate schedule basis. Third, I present and discuss proposed rate design changes. Then, I will show how the Company proposes to spread the incremental revenue requirement across rate schedules. Finally, I will present the revenue and bill impacts associated with the Company's proposal.

My testimony explains how the Normal UPCs were derived using an autoregressive model specification to interpret the relationship between temperature and commodity usage to create weather normalized revenues for the Residential and Commercial firm sales service rate classes for the test year of April 1, 2024, through March 31, 2025 ("Test Year"). I will also explain how the Company derived Test Year revenues for the Industrial and Commercial interruptible sales and transportation service rate classes.

This testimony also explains how the EmCOSS is used to assign incremental revenue requirement to rate schedules based on "cost causality" (i.e., how much of the capital investment costs and operations and maintenance ("O&M") expenses required to serve the Company's customers can be attributable to each rate schedule). The EmCOSS filed with this case indicates that the Large Commercial, Industrial, and Transportation rate schedule classes are paying more than their determined cost of service under present rates, which is consistent with past rate case results. The study also indicates that RS 1 General Sales Service (Residential) ("RS 1 Residential"), RS

2 Residential Sales Service ("RS 2 Residential"), and RS 27 Residential Heating Dry-Out Service ("RS 27 Dry-Out") rate schedules are paying less than their determined cost of service, a result that is consistent with the results from the Company's last rate case, Docket UG-200994. Also consistent is the finding that RS 3 Basic Firm Sales Service Non-Residential (Commercial) ("RS 3 General Commercial") is overpaying its cost to serve, albeit to a lesser extent than indicated in Docket UG-200994. The largest difference is the finding that RS 1 Commercial General Sales Service ("RS 1 Commercial") is paying well below its cost of service (compared to the finding it was paying just above its cost of service in Docket UG-200994). In my testimony, I discuss the reasoning for these shifts in EmCOSS-indicated determined cost of service relative to parity.

I also present the Company's rate design proposal. The Company proposes to increase the monthly fixed charges for RS 1 Residential, RS 1 Commercial, and RS 2 Residential. I discuss and analyze the Company's proposal and conclude that its monthly fixed charge proposal would help to smooth customer bills across the entire year, resulting in lower winter bills at a time when a customer's bill (in addition to other energy bills) is highest, as well as promote rate equity for the residential rate class.

Then, I describe the methodology by which NW Natural proposes to spread the incremental revenue requirement presented in Exh. KTW-1T for each year in the MYRP. The Company proposes to spread incremental revenue requirement in such a manner that is responsive to the results of the EmCOSS, with small deviations for RS 2 Residential and RS 3 General Commercial which I discuss in testimony. I describe the following multi-step rate spread proposal for all rate schedules in full later in my

testimony. First, for RS 1 Residential, RS 1 Commercial, and RS 27 Dry-Out, NW Natural proposes to use a separate cap for each rate schedule that moves its relative position closer to parity with respect to the EmCOSS results, because these schedules are paying less than their cost to serve at current rates. The Company proposes a cap for RS 2 Residential that allocates slightly less than the average revenue increase (but slightly higher than the average margin increase) to minimize rate impacts even though this schedule is paying less than its cost to serve at current rates, and a cap for RS 3 General Commercial that allocates slightly more than the average margin increase to this schedule although the EmCOSS indicates this schedule is paying just above its cost to serve at present rates. Second, the Company proposes to apply an equal percent of incremental margin allocation to all rate schedules with an EmCOSS-indicated parity ratio of 1.20 and lower plus rate schedules RS 41 Non-Residential Sales and Transportation Service and RS 42 Large Volume Non-Residential Sales and Transportation Service (collectively, RS 41/RS 42 Commercial Sales Firm).[2] This step reflects the EmCOSS study results, which indicate that while these schedules are overpaying their cost to serve at present rates, they are not overpaying at the same relative level as those with parity ratios over 1.20, or those with industrial interruptible and/or transportation service. Third, the Company proposes to apply a floor based on equal percent of margin increase of the remaining incremental revenue requirement to the remaining rate schedules in the RS 41/42 Commercial Sales Firm rate classes, which is less than the overall margin increase.

[2] A ratio of 1.00 indicates rate parity, and a ratio above and below 1.00 indicates a rate schedule is overpaying and underpaying its EmCOSS-indicated cost of service, respectively.

As a result of this multi-step proposal, the RS 1 Residential, RS 1 Commercial, RS 2 Residential, RS 3 General Commercial, and RS 27 Dry-Out rate schedules will receive a revenue requirement spread slightly greater than an equal percent of margin share calculated across all rate schedules, with the greatest relative increase being applied to RS 27 Dry-Out at a percentage double that of an equal percent of margin share. The rate schedules with a parity ratio below 1.20 plus RS 41/42 Commercial Sales Firm will receive a revenue spread equal to that of an equal percent of revenue share. The remaining rate schedules (including those with industrial interruptible and/or transportation service) will receive a spread less than an equal percent of revenue share, a lower rate relative to other rate schedules in the RS 41/42 Commercial Sales Firm rate classes. The Company's proposal equitably distributes the incremental revenue requirement such that the rate classes are moved closer to or retain margin parity based on their EmCOSS-indicated cost causation, except for RS 2 Residential and RS 3 General Commercial which, respectively, are allocated amounts just below and just above the amounts meant to roughly retain their indicated parities. The proposal described above is an incremental approach; it moves most rate classes closer to (or retains) parity but does so in a manner that works to minimize rate impacts. It does this by balancing the impact on residential customers while taking incremental steps towards the EmCOSS-indicated parity for larger volume customers who are farthest from parity.

Next, I show the proposed spread of incremental revenue requirement for each sales firm service rate schedule and the corresponding average monthly bill impact.

The final section of this testimony discusses proposed tariff changes to Rate Schedule 10 – Charges for Special Metering Equipment, Rental Meters, and Metering Services, which are presented on proposed Sheets 110.1 and 110.2 filed with this proceeding.

Q. Are you introducing any exhibits with your testimony?

A. Yes. I am sponsoring Exhs. RJW-2 through RJW-19C. Exhs. RJW-2 through RJW-4 support the Company's weather normalized use per customer analysis. Exhs. RJW-5 through RJW-7 support the Company's load study in compliance with WAC 480-85 (Natural Gas Cost of Service). Exhs. RJW-8 through RJW-11 support the Company's embedded cost of service study. Exh. RJW-12 is the Company's embedded cost of service study results and revenue requirement allocation by rate schedule, including the natural gas cost of service template in compliance with WAC 480-85-040(1). Exh. RJW-13 is an alternate embedded cost of service study using the results of the load study, which is being provided to ensure compliance with WAC 480-85-060(2). Due to the Company's findings discussed in the load study in Exh. RJW-5, the Company does not adopt the results of the alternative EmCOSS presented in Exh. RJW-13 for this case and, instead, adopts the results of the EmCOSS presented in Exh. RJW-12 for this case. Exhs. RJW-14 through RJW-16 support the tables found in this testimony. Exh. RJW-17 presents the rate spread allocation proposal methodology. Exh. RJW-18 indicates the incremental revenue requirement allocation by rate schedule, the bill impact and rate increase by rate schedule, as well as the proposed billing determinants by rate schedule and rate block. Exh. RJW-19C shows the Rate Schedule 10 determination of cost of service for metering equipment and metering services.

II. WEATHER NORMALIZED LOAD

Q. What is the Test Year customer and weather normalized load?

A. The Test Year customers and normalized volumes are calculated separately. The weather normalized volumes are a short-term load adjustment with respect to the effects of weather that is built using the following steps:

1. Weather data are collected to produce a 30-year historical benchmark for normal weather.
2. Actual weather data are paired with actual load data on a billing cycle and rate schedule basis. The paired data are used in a statistical regression analysis, as described below, to produce weather normalized UPCs for the Residential and Commercial rate classes for the Test Year period (i.e., the Normal UPCs) as well as every year of the MYRP.
3. For these rate classes, the Normal UPCs are multiplied by customer forecast to derive the normalized load for the Test Year, the Pro Forma Period (i.e., April 1, 2025 through July 31, 2026), and each year of the MYRP.

The weather normalized load is used to calculate revenues at existing rates in the proposed revenue requirement presented in Exh. KTW-2. In addition to being a revenue requirement input, the Normal UPCs are also used to create the design day load factor, which is an important input to the EmCOSS.

Q. Please describe the customer forecast methodology.

A. For the Residential and Commercial firm sales service rate classes, Pro Forma Period and MYRP forecasted customer counts were developed by adding new customers to the existing customer base. Customer attrition, or loss of customers, was deducted from

the existing customer base. New customers, which are largely driven by new premises served on the system, are based on historical regional business and employment growth trends, housing starts forecasts, housing permitting activity, as well as other economic factors. The customer growth forecast used for purposes of developing additional volumes and revenues is the same forecast used for producing incremental capital expenditures that make up gross plant in the MYRP rate base.

Q. Please describe how the Normal UPCs were derived.

A. The Normal UPCs represent weather normalized usage for the Residential and Commercial firm sales service rate classes on a per customer basis. The normalizing analysis relies on the relationship between weather (including temperature, which is translated into heating degree days, or "HDDs," as well as other variables such as solar radiation and wind speed) and load demand by rate schedule and time of year (measured in daily increments),[3] as well as economic factors which I describe in greater detail below. To develop the Normal UPCs, I:

- Collected daily high and low temperature data observed in Vancouver (National Oceanic and Atmospheric Administration "NOAA" Station 94298 -- Vancouver Pearson Airport) and The Dalles (Bureau of Reclamation automated agricultural weather station network "AgriMet" station HOXO) for the period June 1, 1995,

[3] A heating degree day is a unit of measurement that is calculated by subtracting the average temperature for a day from a base set point temperature, where the average temperature is lower than the base set point temperature. Heating degree days are additive in that the sum of the daily heating degree days over the course of the month is taken to represent that month's weather. Where the average temperature is higher than the base set point temperature, zero (rather than negative) heating degree days are recorded. Heating degree days are a common unit of measurement that allows for an analysis of increasing load demand as a function of increasingly colder weather.

through May 31, 2025, for two purposes. The first purpose was to have recent actual weather data to statistically analyze against recent actual usage, and the second purpose was to produce a 30-year historical benchmark for normal weather. Where gaps in the data are present, I used NOAA Station 356751 (Portland International Airport) to estimate, using a simple linear regression, normal degree days at Station 94298 to estimate the relationship between temperature readings at like stations.

- Matched actual therm usage and actual HDDs for the period of January 2012 through May 2025. As part of this process, I used load data on a billing cycle basis and matched actual weather observations with the days between cycle meter read dates. This process ensures actual usage recorded for each billing period is appropriately matched to the observed weather for the same period. I then created a weighting of the number of days, customers, and HDDs associated with each billing cycle for each schedule in the Residential and Commercial customer classes. I used a 59-degree Fahrenheit base for residential schedules and a 58-degree Fahrenheit base for Commercial schedules as temperature set points to convert temperature observations to HDDs.[4]

[4] The set point is estimated to be the temperature at which customers begin to use energy for heating purposes. To estimate the relationship between space heating load and temperature, choosing the set point that provides an approximation as to what ambient temperature customers begin to use space heating is important. The Company used the 59-degree Fahrenheit base for Residential schedules and 58-degree Fahrenheit base for Commercial schedules as its temperature set points for HDDs because these values produce a linear relationship between therm load and HDDs within the Company's service territory (i.e., these set points achieve the an optimal linear function at approximately the point where there is a heating load response to average ambient outside temperature). I use the set points to linearize the relationship so that I can use a simplified time series model specification to derive weather normalized load by month and rate schedule.

- Aggregated the cycle-based therm usage as well as the days, customers, and HDDs weights by month. I used these monthly aggregates to regress therm use per premise per day against HDDs per day (as well as additional weather and economic variables), using a type of econometric time series model specification which I describe in greater detail below. I created a model estimation for every firm sales service schedule in the Residential and Commercial customer classes (including two models for the Residential customer class based on connection date: Premises connected prior to July 1, 2023 and premises connected on and after that date). For each model, I tested four categories of coefficients that explain usage per customer per day as a function of: (1) weather, including heating usage per HDD per day; (2) base usage by month; (3) non-weather factors that account for the shift in energy usage patterns after the COVID-19 pandemic, as well as energy efficiency from ongoing demand side management and macroeconomic indicators such as industrial production and gross domestic product; and (4) temporal effects on usage from prior periods.
- Developed normal daily HDDs using daily HDD values derived from the benchmark 30-year weather data set.
- Used the econometrically estimated coefficients to build the weather normalized Normal UPCs on a daily basis using the 30-year HDD benchmark.

The above-referenced methodology is consistent with the methodology I applied in NW Natural's most recent general rate case, Docket UG-200994.

Q. Please describe the specification for the weather normalization model.

A. I used an Autoregressive Integrated Moving Average ("ARIMA") time series model to estimate weather normalized load per customer per day as the weighted function of the number of days, customers, and HDDs associated with each billing cycle in the model period. An ARIMA model is a type of time series model specification for data observations that occur across equal intervals of time. The model is used to help forecast future values in the series by each value against a chosen number of lagged values (the autoregressive term); lags of moving averages may be chosen as well. ARIMA models are denoted as ARIMA(p,d,q) where p is the number of time lags in the autoregressive term; d indicates the number of times the independent variables are differenced; and q is the number of lags of moving averages. Together, these terms help fit the time series model by accounting for different temporal effects on usage that are associated with prior periods.

Q. Has the Company used the ARIMA model specification for its weather normalized load forecast in prior rate case filings?

A. Yes. I used an ARIMA time series model to calculate the Normal UPCs for the Company's prior Washington general rate case, Docket UG-200994.

Q. Please describe the changes in the Normal UPCs analysis methodology from NW Natural's latest rate case, Docket UG-200994.

A. I used consistent data collection, actual weather, load data alignment, and weighting methods to prepare the Normal UPCs. Similarly, I used an ARIMA time series model specification to produce the final Normal UPCs regression coefficients. I made

multiple modifications to the ARIMA model specification and indicator variable selection process for this proceeding. In summary, I:

1. Used a Stata module called "arimaauto" to recommend an algorithmically parameterized ARIMA model specification for each rate schedule in the Normal UPCs analysis. This command uses a Stata-adjusted Hyndman-Khandakar algorithm. I used the output of arimaauto as baseline model specification and note deviations from its recommendation later in this testimony.
2. Included non-linear weather terms, such as a squared HDD term for multiple rate schedules.
3. Included macroeconomic variables such as the consumer price index or an industrial production index (for large volume rate schedules) as well as a variable to control for the structural economic and social impacts related to the COVID-19 global pandemic (such as the continued prevalence of remote work).
4. Included additional weather variables beyond HDDs such as wind chill and solar radiation as a proxy for observed weather in the analysis.
5. Used, for some rate schedules, multiplicative seasonal components to the ARIMA model in the form of ARIMA(p,d,q)*(P,D,Q)s where s indicates the number of lagged multiplicative seasonal autoregressive P and moving average Q terms, seasonally differenced D times. Where applied, the seasonal differencing parameters account for the seasonal variation in rate class usage instead of the monthly indicator variables which are removed from the model specification.

Below, I describe in greater detail my selection process for each firm sales service rate schedule in the Normal UPCs analysis.

Q. Why did the Company make these changes to the Normal UPCs analysis for this proceeding?

A. Many of these changes are in response to recommendations the Company has received in Oregon general rate case proceedings and for which I concluded increased model estimation efficacy. After implementing these changes, I tested for and found improvements to model estimating performance and fit, which produce better test statistics (such as the Durbin-Watson test statistic). Further, I evaluated the changes based on ease of replicability, as well as performance against out-of-sample backcast testing conducted across varying historical data vintages, and comparison of mean absolute percentage error across forecasted model results.

Q. Please describe the weather variables included in the Normal UPCs analysis in this case.

A. I evaluated the estimation effectiveness of employing weather variables beyond HDDs which are a standard measure of weather in load forecasting analyses, including the explanatory variables: effective temperature, precipitation, solar radiation, wind speed, and wind chill. The data used to create these variables are sourced from a third-party and are employed in the Company's Integrated Resource Plan ("IRP") long-term resource planning forecast models.[5] The use of multiple variables that measure weather are meant to control for the fact that day-of ambient temperature is not the only factor that can influence heat loss. Using day-before HDDs, for instance, can help model how

[5] See, for instance, discussion of daily demand drivers in *Northwest Natural Gas Company's 2022 Integrated Resource Plan*, Docket UG-210094, at 97-100 (Sept. 23, 2022). The Company sources hourly weather data for various airports throughout its service territory to be used in its IRP models from an IBM business partner called DAI Source.

heat loss in a building from one cold weather day prior can impact natural gas consumption the following day. Using a wind chill factor can help model how wind speed can contribute to indoor cooling. I have found that including such observations can make small improvements to model estimation.

The effective temperature is an equal weighted measure of the prior day and current day temperature, converted into HDDs, which works to control for heat loss that may occur on a specific calendar day because of weather observed the prior day. The wind chill value is calculated based on a relationship between wind speed and the difference between a temperature set point and observed temperature for that day.[6] The set point in this case is the temperature cut-off where any value higher produces no wind chill effect (e.g., the temperature point at which combined wind speed and temperature does not create wind chill impacts). This set point was determined in the cited study to be 14 degrees Celsius, or about 57.2 degrees Fahrenheit.[7]

Using the effective temperature as well as historical snowfall data from NOAA, I created a "snow factor" variable for modeling the Commercial rate class schedules in this proceeding. I calculated the factor by multiplying the effective temperature by a binary indicator of whether snow was present on a given day or not so that the combination of colder weather in addition to the presence of snow is weighted heavier compared to warmer weather that precedes snow melt. I found that this factor did not improve the forecasting ability of the Residential rate class model, but it did so for the

[6] Yabsley, Warren and Shirley Coleman. *Using Data Analytics for Business Decisions in the UK Energy Sector – a Case Study Integrating Gas Demand with Weather Data.* International Journal of Oil, Gas and Coal Technology. May 2, 2019. Vol. 21, No. 1, pages 109-129.

[7] *Id*.

Commercial rate class schedules; therefore, I only included it in the models for the Commercial rate class schedules.

Q. Please describe how HDDs are included in multiple explanatory variables within the Normal UPCs analysis using interaction effects.

A. The Normal UPCs analysis includes explanatory variables that have interactive effects between the additional weather variables and effective temperature HDDs, in addition to the standard HDD variable. Variables with interactive effects recognize that demand can be different on a cold rainy day relative to a warmer rainy day, or that wind chill has a larger impact on demand as temperatures decrease. Using the effective temperature, as noted above, helps to control for temperature observed in the prior day and can help explain how, for instance, a cold rainy day yesterday could result in heat loss that impacts how long it will take a furnace to reach desired temperature on the thermostat today.

Q. Please describe how the Normal UPCs analysis controls for monthly fixed effects and weekend days.

A. For this proceeding, I use monthly fixed effects to control for seasonality for the Residential rate class while including one variable for number of weekend days per month to model how base load consumption patterns vary by month based on number of non-standard working days, especially as it relates to residential demand (e.g., number of days in a given month more likely to be spent at home using natural gas for non-heating related uses such as cooking and heating water for showers and laundry). For the Commercial rate class, I removed the monthly fixed effects from the model and instead used the ARIMA(p,d,q)*(P,D,Q)s multiplicative seasonal model specification

to account for seasonal variation in usage, but did use the weekend days variable to control for days that, depending on the business sector, commercial customers could be closed or operating for fewer hours.

Q. Please explain how the Company treats the constant term in its Normal UPCs analysis.

A. For the Residential rate class, I chose to drop the constant term so that the Normal UPCs model produces one base load coefficient associated with each of the 12 months of the year. This makes building the weather normalized UPC values on a daily and monthly basis straightforward, because each model coefficient can be matched to a specific period (month) within the year. Alternatively, if I were to retain the constant term, I would have to choose one or more months to drop, in which case the constant term coefficient would instead take on the base load attributes of the dropped variable(s). For the Commercial rate class, I retained the constant term because the ARIMA(p,d,q)*(P,D,Q)s multiplicative seasonal model specification accounts for the seasonality leaving the constant term to pick up the base load attributes.

Q. Please describe how the Normal UPCs estimates demand-side management ("DSM") savings.

A. For this Normal UPCs analysis, I have created a DSM variable and use the forecasting power of the ARIMA model specification to control for DSM savings in the Test Year rather than use a post-estimation adjustment based on anticipated programmatic savings. I used historical savings based on energy efficiency measures deployed since 2012, broken down by heating and non-heating related savings based on savings measure type, as reported by the Energy Trust of Oregon. I then converted these

savings into a savings per premise per day explanatory variable to appropriately align with the dependent variable – demand per premise per day. While the model may not anticipate all programmatic savings, it now uses historical actual savings to inform short-term forecasted savings without having to rely on post-estimation demand adjustments.

Q. Please describe how the Normal UPCs analysis estimates macroeconomic effects.

A. I have included an indicator variable that controls for behavioral changes that impact natural gas demand since the COVID-19 pandemic statewide stay-at-home order was issued for Washington in March 2020. This variable is meant to capture longer-term post-pandemic changes to consumption patterns, especially patterns that influence residential and commercial demand such as higher rates of working from home. Additionally, for the Commercial rate classes, I have added a variable from the Oregon Office of Economic Analysis ("OEA") that indexes United States industrial production as a proxy measure of the year-over-year performance of the macro economy, as well as the Consumer Price Index ("CPI") for All Urban Consumers in the Western United States also provided by the OEA as a macroeconomic signal of changes to inflation, pricing, and purchasing power.

Q. Please describe the Company's ARIMA model specification selection process.

A. I used the Stata arimaauto module to auto-parameterize, in ARIMA(p,d,q) or ARIMA(p,d,q)*(P,D,Q)s terms, every rate schedule modeled for the Normal UPCs analysis. I did not, however, select the arimaauto model parameters for all schedules but rather used the module as a starting point for model specification evaluation. I compared the auto-parameterized models against models with slightly different terms,

relying foremost on Durbin-Watson test statistics, r-squared values, and root mean squared error results to assess model efficacy and choose appropriate ARIMA *p* and *q* terms.[8] I relied on the Augmented Dickey-Fuller test to determine the appropriateness of differencing load data variables with the ARIMA *d* term to ensure model stationarity. Further, I plotted model residuals to check for non-uniformity. I consulted the Akaike Information Criterion ("AIC") and the Bayesian Information Criterion ("BIC") metrics to evaluate the performance of models under varying *p* and *q* term specifications against one another.[9] Finally, I performed "backcast" tests as I describe below, to assess the forecasting abilities of the auto-parameterized models against non-auto-parameterized models. Again, this process is consistent with the methodology applied in Docket UG-200994.

Q. Please describe the issue of non-stationarity and how it could impact the Normal UPCs model.

A. Non-stationarity in the Normal UPCs model variables can occur when their statistical properties vary over time. A utility's customer count is an example, for instance, because it generally increases over time but not at a constant rate. New customers spurred by housing construction are more likely to start service in summer months than winter months. As such, the Normal UPCs model could contain non-stationary inputs,

[8] The Durbin-Watson test statistic, which is a test for autocorrelation, takes a value from 0 to 4. A value of 2 indicates no autocorrelation. A value less than 2 indicates positive autocorrelation, and a value greater than 2 indicates negative autocorrelation.

[9] When comparing models with the same variables but different *p* or *q* terms, in general the model with the lower AIC and BIC metric is preferable.

which is why using the Augmented Dickey-Fuller test is helpful for determining whether the *d* differencing term is necessary.

Q. Please summarize the explanatory variable selection process.

A. I also relied on Durbin-Watson test statistics, r-squared values, and mean squared errors, as well as AIC/BIC metrics, to assess the choice of observed weather variables, monthly indicator variables, weekend days variable, weather-temperature interaction term variables and COVID-19, macroeconomic, and DSM variables to optimize model estimation.

Q. Did the Company perform a "backcast" test to assist in the model optimization process?

A. Yes. A backcast test evaluates how well a model can estimate actual known out-of-sample values using historical (actual) data. I performed an analysis using three backcast tests of varying data vintages to compare model forecast performance against actual load data for the Residential rate schedules. Models are evaluated against each other by calculating and comparing mean absolute percent error ("MAPE") value to test model accuracy and performance. I selected the model specifications with the lowest MAPE for the Normal UPCs analysis.

Q. Does the ARIMA model perform better at weather normalizing load compared to other types of models?

A. Yes. I found that the ARIMA model outperforms both simple linear regression and vector autoregressive models when compared against the model test statistics and metrics as well as backcast tests as discussed above.

Q. How are the results of the ARIMA model interpreted and evaluated?

A. The final output of the ARIMA models is an estimation of weather normalized use per customer per day for each evaluated rate schedule (the dependent variable). The monthly indicator variables (or, in the absence of these variables, the constant term) represent customer baseload demand. The customer heat load use coefficient is expressed as incremental demand per HDD per customer. The additional weather variables and interaction terms are similarly expressed as incremental demand per unit (e.g., inch of precipitation, degree of wind chill or effective temperature HDD) per customer. The macroeconomic and DSM variables represent structural customer baseload demand that cannot be accounted for based on weather or time of year. After running the ARIMA models to produce these coefficients, I used statistical software to evaluate the model estimation output against the 30-year daily normal HDD values to derive a normalized use per customer per day by month.[10] The additional weather variables were also evaluated against historical daily normal values. The model output incorporated the effects of the ARIMA autoregressive and moving average terms on base and heat load use into the use per customer estimation. I repeated this process for every firm sales rate schedule in the Residential and Commercial customer classes.

Q. Please describe the model specification for each firm sales rate schedule modeled in the Normal UPCs analysis.

A. Below, I describe the model specification for each rate schedule in the Normal UPCs analysis.

[10] I used the Stata statistical software package and developed use per customer estimations based on model results using the "predict" command after running the ARIMA model.

1. RS 1 General Sales Service (Residential)

For RS 1 General Sales Service (Residential) ("RS 1 Residential"), I included monthly fixed effects to control for seasonality and a squared HDD term to control for non-linear effects of weather. I used the same ARIMA model specification that I developed for RS 2 Residential, which I describe below, to maintain consistency across the Residential class models – and also because this model specification produced more optimal test statistics compared to models with different specifications.[11] The arimaauto auto-parameterization module suggested a non-differenced specification of ARIMA(2,0,2)(0,0,0)[2] or a one order differenced specification of ARIMA(1,1,0). After testing for model fit and estimating performance, I chose the non-differenced ARIMA(2,0,2)(0,0,0)[2] specification. The model is as follows, where *m* is month and *y* is year:

$$\frac{R1\ UPC}{Day}m,y = \beta_1\frac{R1\ HDD}{Day} + \beta_2\left(\frac{R1\ HDD}{Day}\right)^2 + \beta_3\frac{WindChill * EffectiveTemp}{Day} + \beta_4\frac{SolarRadiation}{Day} + \beta_5 Jan_{=1} \ldots$$
$$+ \beta_{16}Dec_{=1} + \beta_{17}SinceCovidMnths_{=1} + \beta_{18}WeekendDays + ARIMA(2,0,2)(0,0,0)_{[2]}$$

This model produces a normalized UPC value of 175.3 therms annually. This value, which is about 74 percent lower than the RS 2 Residential UPC, is expected because this sales service schedule does not allow primary space heating systems or water heating appliances and is limited to lower-usage appliances such as cooktops and fireplace inserts with a nameplate rating below 20,000 BTUs.

[11] I use the word "optimal" here and elsewhere in this testimony instead of adjectives such as "larger" or "smaller" because not every test statistic is evaluated based on magnitude. The Durbin-Watson test statistic for autocorrelation, for instance, takes a value from 0 to 4. The optimal value, which indicates no autocorrelation, is 2.

2. RS 2 Residential Sales Service

I included monthly fixed effects to control for seasonality and a squared HDD term to control for non-linear effects of weather for the RS 2 Residential model. I tested and then excluded weather terms that did not produce meaningful coefficients based on estimated p-values. I included weather variables with interaction effects (with effective HDDs) that were statistically significant. The arimaauto auto-parameterization module suggested a non-differenced specification of ARIMA(2,0,2)(0,0,0)$_{[2]}$ or a one order differenced specification of ARIMA(1,1,0). I found, however, that a specification of ARIMA(2,0,2)(0,0,0)$_{[2]}$ produces optimal test statistics and better backcast predictive fit compared to these other specifications. The model is as follows, where *m* is month and *y* is year:

$$\frac{R2\ UPC}{Day}m,y = \beta_1\frac{R2\ HDD}{Day} + \beta_2\left(\frac{R2\ HDD}{Day}\right)^2 + \beta_3\frac{WindChill * EffectiveTemp}{Day} + \beta_4\frac{SolarRadiation}{Day} + \beta_5 Jan_{=1} \ldots$$
$$+ \beta_{16}Dec_{=1} + \beta_{17}SinceCovidMnths_{=1} + \beta_{18}WeekendDays + ARIMA(2,0,2)(0,0,0)_{[2]}$$

This model produces a normalized UPC value of 662.3 therms annually. The model produces a UPC about 2.3 percent lower compared to the model specification used in UG-200994.

3. RS 1 General Sales Service (Commercial)

For RS 1 General Sales Service (Commercial) ("RS 1 Commercial"), I used a simplified model with only an explanatory variable to control for seasonality for non-winter months (with the constant term representing the remaining months). RS 1 Commercial excludes primary space and water heating equipment and has a low number of customers, which drove poorer estimation results for more complex models with more variables. The arimaauto auto-parameterization module suggested a non-

differenced specification of ARIMA(1,0,0)(0,0,0)[2] which I chose for this model. The model is as follows:

$$\frac{C1\ UPC}{Day}m,y = \beta_1\frac{C1\ HDD}{Day} + \beta_2 NonWinterMos_{=1} + \beta_3 Constant + ARIMA(1,0,0)(0,0,0)_{[2]}$$

This model produces a normalized UPC value of 654.4 therms annually. RS 1 Commercial is a low-usage rate schedule with the same service parameters and allowable equipment as RS 1 Residential. Therefore, as expected, the RS 1 Commercial UPC estimated for this proceeding is 79 percent lower than the RS 3 Commercial UPC.

4. RS 3 Basic Firm Sales Non-Residential Service - Commercial

For the RS 3 Basic Firm Sales Non-Residential Service – Commercial ("RS 3 General Commercial") model specification, I removed the monthly fixed effects and instead controlled for seasonality in the ARIMA specification, included a squared HDD term to control for non-linear effects of weather. I tested, and then excluded, weather terms that did not produce meaningful coefficients based on estimated p-values. The arimaauto auto-parameterization module suggested a non-differenced specification of ARIMA(2,0,2)(0,0,0)[2] or a one order differenced specification of ARIMA(2,1,2). I found, for this proceeding, that the differenced specification with the same order of multiplicative seasonal ARIMA periods of ARIMA(2,0,2)(2,1,2)[12] produces optimal test statistics compared to other specifications. The model is as follows:

$$\frac{C3\ UPC}{Day}m,y = \beta_1\frac{C3\ HDD}{Day} + \beta_2\left(\frac{C3\ HDD}{Day}\right)^2 + \beta_3\frac{WindChill * EffectiveTemp}{Day} + \beta_4\frac{SolarRadiation}{Day}$$
$$+ \beta_5 SinceCovidMnths_{=1} + \beta_6\frac{SnowFactor}{Day} + \beta_7 WeekendDays + \beta_8 CPIWest$$
$$+ \beta_9\frac{CommercialDSM}{Day} + \beta_{10} Constant + ARIMA(2,0,2)(2,1,2)_{[12]}$$

This model produces a normalized UPC value of 3,155.2 therms annually. The model produces a UPC about 10.9 percent higher compared to the UG-200994 model, which is attributable to both estimated increases in actual per customer demand as well as to the new model specification.

5. RS 27 Residential Heating Dry-Out Service

For the RS 27 Residential Heating Dry-Out Service ("RS 27 Dry-Out") model specification, I included monthly fixed effects and excluded weather terms because they did not have a statistically significant effect on model estimation. The arimaauto auto-parameterization module suggested a non-differenced specification of ARIMA(2,0,2)(0,0,0)[2] or a one order differenced specification of ARIMA(2,1,2). I found that the arimaauto recommended non-differenced model specification produces optimal test statistics and better backcast predictive fit compared to these other specifications. The model is as follows:

$$\frac{R27\ UPC}{Day}m,y = \beta_1 \frac{R27\ HDD}{Day} + \beta_2 NonWinterMnths_{=1} + \beta_3 Constant + ARIMA(2,0,2)$$

This model produces a normalized UPC value of 525.9 therms annually, which is 11.8 percent lower than the UPC value estimated for UG-200994.

6. RS 41 Non-Residential Firm Sales Service - Commercial

For the RS 41 Non-Residential Firm Sales Service – Commercial ("RS 41 Commercial Firm Sales") model specification, I included no monthly fixed effects and instead control for seasonality in the ARIMA specification and excluded all weather terms because they did not produce meaningful coefficients. The arimaauto auto-parameterization module suggested a non-differenced specification of ARIMA(1,0,0)(0,0,0)[2] or a one order differenced specification of

ARIMA(1,1,0)(0,0,0)[2]. For this proceeding, I chose a model specification of ARIMA(1,0,1)(1,1,1)[12], which produces more optimal test statistics. The model is as follows:

$$\frac{C41\ UPC}{Day}m, y = \beta_1 \frac{C41\ HDD}{Day} + \beta_2 WeekendDays_{=1} + \beta_3 IndustrialProductionIndex + ARIMA(1,0,1)(1,1,1)_{[12]}$$

This model produces a normalized UPC value of 41,096.8 therms annually, which is 1.4 percent lower than the UPC value estimated for UG-200994.

7. RS 42 Large Volume Non-Residential Firm Sales Service - Commercial

For RS 42 Large Volume Non-Residential Firm Sales Service – Commercial ("RS 42 Large Volume Commercial Firm Sales"), I used the same model specification as RS 41 Commercial Firm Sales. The arimaauto auto-parameterization module suggested a non-differenced specification of ARIMA(1,0,0) or a one order differenced specification of ARIMA(1,1,0). This model specification is ARIMA(1,0,1)(1,1,1)[12] and is the same specification I used for RS 41 Commercial Firm Sales. The model is as follows:

$$\frac{C42\ UPC}{Day}m, y = \beta_1 \frac{C42\ HDD}{Day} + \beta_2 WeekendDays_{=1} + \beta_3 IndustrialProductionIndex + ARIMA(1,0,1)(1,1,1)_{[12]}$$

This model produces a normalized UPC value of 246,137.6 therms annually, which is 69.5 percent higher than the UPC value estimated for UG-200994. The large change in UPC can be explained by changes to the composition of customers on this rate schedule: Compared to UG-200994, the number of customers increased from five to nine. Given the low customer count, as well as the high usage variability between large volume customers, a small number of customers can more easily drive changes of a larger magnitude to the UPC on rate schedules such as RS 42 Large Volume Commercial Firm Sales.

Q. Have you calculated UPCs for the subset of residential premises taking service on RS 2 Residential that represent new service connections ("New Premises UPC")?

A. Yes. The Company has noticed a decrease in average normalized usage for new residential premises over the past few years, and therefore the anticipated UPC for new service connections is lower than existing service connections. In response to this observation, for this proceeding I have calculated an additional UPC for new connection customers taking service on RS 2 Residential, which is used to build the Company's proposed revenues beginning at the Pro Forma Period and extending through the MYRP period. This New Premises UPC, which I estimate is about 334.0 therms annually, is meant to better estimate revenues that new customers will generate for the purpose of developing the Company's revenue requirement for this proceeding. This analysis is presented in Exh. RJW-4.

Q. Please describe the New Premises UPC data collection and estimation parameters.

A. I queried the Company's Customer Information System ("CIS") for new premises that have been connected to the Company's system beginning July 1, 2023, and associated installed equipment. Due to the short timeframe as well as the fact there is generally a delay between service initialization at new premises and observable therm load, I did not use an ARIMA model to estimate the New Premises UPC. Instead, I used assumed therm usage by equipment type for each premises to develop an expected therm load by premises. I then averaged these expected loads across the 1,799 premises in my query to calculate the estimated New Premises UPC.

Q. Why is there generally a delay between service initialization at new premises and observable therm load?

A. The initialization of service may not coincide with the installation of all appliances, and there may be a gap between when the premise is completed, is placed on the market and sold, and when a new household fully moves in; due to these reasons, there could be multiple billing periods between when a service is initialized and when it begins to produce data adequate for establishing a normalized annual use. For some new construction premises, a developer may opt for dry-out service and therefore the premise will be on RS 27 Dry-Out for several months prior to it being ready for habitation, at which point it is placed on RS 2 Residential service. Due to this gap between service initialization and full habitation, using an ARIMA model on usage of premises connected beginning July 2023 would not produce an accurate weather normalized UPC estimation. After more years of data are collected, however, it is probable that the New Premises UPC can be calculated using an ARIMA model specification.

Q. Please summarize the results of the Normal UPCs analysis.

A. The Normal UPCs analysis methodology changes, which I described earlier, result in improved test statistics and predictive capabilities, as well as interpretability. The chosen ARIMA model specifications produce a weather-normalized Test Year UPC of 653.6 therms annually for the Residential class (including RS 1 and RS 2 Residential), and 3,794.3 therms annually for the Commercial Firm Sales schedules combined.

Q. How are the customer forecast and Normal UPCs used to create Test Year volumes that generate revenues at existing rates for the proposed revenue requirement?

A. The Company calculates Residential and Commercial Firm Sales class Test Year monthly volumes by multiplying the weather normalized UPCs for each residential and commercial firm sales rate schedule by monthly end-of-period customer counts.

Q. How are normalized Test Year volumes built for the Industrial Sales as well as the Commercial and Industrial Transportation classes?

A. Normalized Test Year volumes for the Industrial Sales as well as the Commercial and Industrial Transportation classes are developed using a customer-specific methodology ("Industrial Forecast"). This customer-specific Industrial Forecast begins with a recent 12-month period of actual usage and customers and is then adjusted by the Company's large customer and major accounts subject matter experts for changes in projected load usage, and customer additions, losses, and rate schedule changes that arise from the service election period.

Q. Where are the Test Year volumes used to build the revenues for the revenue requirement presented?

A. The derivation of Test Year revenues from the customer and volume forecasts is presented in a summary by customer class in Exh. KTW-4.

Q. What are the Company's other uses for the Normal UPCs?

A. The Company uses the Normal UPCs to develop the design day load factor for the EmCOSS, as discussed below. The Normal UPCs are also used to estimate throughput volumes for the Company's annual purchased gas adjustment ("PGA"). The

methodology for calculating the Normal UPCs is consistent between the PGAs and rate case filings.

III. EMBEDDED COST OF SERVICE STUDY

A. Embedded Cost of Service Regulatory Considerations

Q. Has the Commission stated its preference for cost of service study methodology?

A. Yes. The Commission, in General Order No. R-599 (Docket UG-170003), issued on July 7, 2020, adopted WAC 480-85. These rules establish minimum filing requirements – including data inputs, methodologies, presentation of results – for any cost of service study filed with the Commission, and specifically direct utilities to calculate cost of service using an embedded cost method. The Commission states that its preference for the embedded cost methodology is based on long-standing precedent and stakeholder compromise.[12]

Q. Does the Company's EmCOSS meet the requirements of WAC 480-85?

A. Yes, the Company's cost of service study presented in this filing meets all necessary requirements. In the Company's prior rate case proceeding, Docket UG-200994, it requested and received an exemption to WAC 480-85-050(1), which specifies that the usage data employed in any cost of service study must come from advanced metering technology that provides, at a minimum, daily natural gas usage readings. If these data are not available, the utility may conduct a "load study," defined as a study of daily

[12] *See*: *In the Matter of Amending WAC 480-07-510 and Adopting Chapter 480-85 WAC Relating to Cost of Service Studies for Electric and Natural Gas Investor-Owned Utilities*, Dockets UE-170002 and UG-170003, General Order R-599, at 11 (Jul. 7, 2020); and WAC 480-85-060.

usage data to produce rate class load profiles using a subset of sampled customers.[13] At the time of the Company's last filing, the Company did not have advanced metering infrastructure ("AMI") described in WAC 480-85-050(1)(a) or other advanced metering technology such as automated meter reading ("AMR") with daily read capabilities as indicated in WAC 480-85-050(1)(c) to comply with this requirement. The Company submitted for an exemption of WAC 480-85-050(1) which was granted in UG-200925, Order 01.

Q. Does the Company have the daily meter reading capabilities deployed such that it can satisfy the requirements of WAC 480-85-050 in this filing?

A. Yes. While the Company is still in the process of installing additional new AMR encoder receiver transmitters ("ERT") that have daily read capabilities described in WAC 480-85-050(1)(b) for all customers across its Washington service territory, it does have daily read capabilities across a subset of customers with sufficient consistent daily data representative of all its customer classes for a minimum of twelve months. Therefore, the Company has developed a load study using daily data from a sampling of customers with daily read capable meters which is presented in Exh. RJW-5. Exh. RJW-6 and Exh. RJW-7 present the load study sampling and regression methodology, respectively.

[13] See WAC 480-85-030(5) (defining "load study" as "a statistical analysis of load data collected from sampled customers to estimate the load profiles of customer classes over a minimum twelve-month period.").

Q. Is the Company working to deploy daily read capabilities for all customers such that it can satisfy these requirements without the need for a load study?

A. Yes. The Company has an on-going system-wide Meter Modernization Program effort described in further detail in Exh. JSK-1T, aimed at replacing end-of-life ERTs. As part of this effort, older meter families are replaced with daily read-capable sets. While these devices are expected to be fully installed across the Company's Washington service territory by the end of 2027, the Company anticipates it would not have a minimum 12 months of daily meter read data to collect from these upgraded meter sets until the end of 2028 at the earliest.

Q. Does the EmCOSS methodology follow the same cost of service methodology presented in the Company's last rate case?

A. Yes. This is the Company's second EmCOSS that follows the cost of service study methodology adopted under General Order No. R-599 and described at WAC 480-85-060.

B. Embedded Cost of Service Study Purpose and Principles

Q. What purpose does a cost of service study serve?

A. The overall objective of a cost of service study, including an embedded cost study, is to apportion the incremental revenue requirement to rate schedules based on each schedule's specific cost to serve (this is true of other types of cost of service studies, such as those based on long run marginal costs). Whereas a long run cost of service study evaluates the marginal (incremental) costs borne by each rate schedule with the addition of one new customer, the embedded cost of service study presented below is based on historical Test Year installed costs (e.g., gross plant and the accumulated

depreciation on those capital assets) of assets in-service and expenses (e.g., for operations, maintenance, taxes) associated with the on-going provision of utility service.[14] By analyzing how the customers that make up each rate schedule contribute to these embedded capital costs and on-going expenses, the EmCOSS methodology works to apportion a utility's storage, transmission, and distribution costs, as well as operating expenses (i.e., all of the components of revenue requirement) based on cost causation.[15] As a general rule, cost causation is an influential factor in parties' discussions on how to allocate costs to specific rate schedules for rate spread; therefore, it serves the utility well to understand the engineering and economic cost differences between customer classes and/or rate schedules.

Q. Please describe the economic principles that underlie a cost of service study.

A. Embedded cost studies (and cost of service studies in general) allocate costs based on cost causation to identify how the incremental revenue requirement should be allocated to rate schedules in order to move closer to *Pareto Optimality*.[16] The reasonable allocation of costs is determined by understanding the specific customer characteristics associated with each class and rate schedule in order to equitably allocate costs.

[14] In practice, a cost of service study can and usually does apportion costs using both an embedded and incremental approach, depending on the type of cost. For instance, an embedded cost study may apportion Test Year customer service costs across all rate schedules, but allocate these costs to specific schedules based on the incremental costs of an additional customer.

[15] For gas utilities that produce energy, an embedded cost of service model can similarly apportion commodity production costs based on cost causation.

[16] *Pareto Optimality* is a state of allocation equilibrium where participants cannot be made collectively or individually better off given a change in cost or price, without also making other participants worse off. Cost of service studies generally measure the relationship between current utility rates and pareto optimal rates, on a rate class or rate schedule basis, as a "parity ratio" where a value of 1.00 indicates customers in that group are paying no more and no less than their full cost to serve. A change to the rate that results in deviation from 1.00 would signal either cost subsidization (greater than 1.00) or cost subsidy (less than 1.00).

Characteristics can include peak day demand and average usage characteristics, service type (firm vs. interruptible, sales vs. transportation), customer service needs, and average mains and service lines costs. A cost of service study works to identify not only how each characteristic of a rate class contributes to overall costs, but how these characteristics contribute to the utility's fixed and variable costs.

Economists have derived the principles of "subsidy-free prices" and "stand-alone costs" ("SAC") as a means for achieving *Pareto Optimality*. Subsidy-free pricing is achieved when the price of a good or service charged to a group of customers exceeds its marginal cost ("MC") but is less than the cost these customers otherwise would have incurred individually (e.g., the SAC). Prices set at a subsidy-free level provide customers economies of scale given that all customers are paying a portion of the fixed system costs where (Price > MC) while achieving equitable cost sharing of common costs. While the sharing of fixed and other common system costs is the most equitable outcome for customers, local distribution companies must be aware that price does not exceed the SAC to serve customers because customers would in theory be unwilling to take service (and/or would move to the next best economic alternative) if prices exceed SAC. Therefore, the level of price is key to ensuring customer equity is achieved between rate classes/schedules with common utility costs fairly identified and allocated.

Q. Please describe the specific purpose of the EmCOSS methodology presented in this testimony.

A. The EmCOSS methodology presented in this testimony is an economics exercise that evaluates how much of the Company's embedded capital investment and carrying

costs, and operations and other expenses required to serve its customers, can be directly and indirectly attributable to each rate schedule. The costs and expenses that form a basis for the EmCOSS follow the Company's Test Year for the 12 months ended March 31, 2025.

The EmCOSS follows three main steps: (1) functionalization; (2) classification, and (3) allocation. Functionalization places costs that make up the revenue requirement into categories based on broad utility functions and, following the approved methodologies prescribed in Table 3 of WAC 480-85-060(3), is based on Federal Energy Regulatory Commission ("FERC") Uniform System of Account categorization. The functionalization of embedded costs is informed by the makeup of the Company's capital investments and operating expenses in the Test Year revenue requirement of this proceeding. The second step, classification, further splits the functional costs into three characteristics related to their marginal cost characteristic: (a) demand costs are closely related to plant in-service, are generally fixed, but are influenced by design day peak demand and average throughput; (b) energy costs are variable and are directly related to therms consumed; and (c) customer costs can be fixed or variable and related to the number of customers taking service. Allocation, the final step, can assign cost items through indirect or direct assignment. Every functionalized and classified cost item is assigned to individual rate schedules through allocation methods that follow Table 4 of WAC 480-85-060(3). Some cost items are allocated based on direct assignment to specific rate schedules, however, and I describe below how these costs are directly assigned and allocated through the results of "special studies."

After allocating all revenue requirement cost elements, the EmCOSS calculates the relative ratio of revenue to incremental costs for each rate schedule at present rates. This ratio is used to understand cross-subsidies between rate schedules at current rates and can be used by the Company to inform its rate spread and rate design proposals.

Q. What costs does the EmCOSS directly assign through special studies?

A. I directly assigned costs for the following items based on studies conducted using Company data such as job orders, engineering and other Geographic Information Systems ("GIS") data, accounting data, and billing and usage data:

- Distribution mains
- Service lines
- Meter sets and regulators
- Certain customer accounts services

Note that for some costs, such as distribution mains, I directly assign only a portion of the total costs; the remainder is assigned per WAC 480-85-060(1)(d) and Table 4 of WAC 480-85-060(3). I describe each of these studies in detail below.

Q. Please explain how the EmCOSS is presented with this rate case.

A. The full Excel-based EmCOSS model is submitted in its entirety as an exhibit accompanying this rate case. Each of the special studies is similarly submitted as exhibits; the output from each study is summarized in a tab in the EmCOSS, with an index identifying the external spreadsheet file(s). The natural gas cost of service template sponsored in Exh. RJW-12, which cross-references the revenue requirement results and summarizes the EmCOSS outputs, is also located within the EmCOSS model exhibit in compliance with WAC 480-85-040(1).

C. NW Natural's EmCOSS Inputs and Methodology

Q. Have you prepared a cost of service study for this proceeding?

A. Yes. Exh. RJW-12 presents the results of NW Natural's embedded cost of service study, the EmCOSS. The exhibit includes the natural gas cost of service template and shows the indicated EmCOSS summary results and the EmCOSS-indicated spread of NW Natural's proposed revenue requirement by rate schedule. Exh. RJW-8 through RJW-11 are inputs that support the Company's EmCOSS.

Q. Does your EmCOSS methodology differ from the methodology used in the Company's last rate case filing, UG-200994?

A. No. The Company's EmCOSS methodology generally follows that of its last rate case filing, Docket UG-200994. As I describe below, I used a five-year coincident peak value to derive the load factor for the large volume rate schedules, where previously I had used non-coincident peaks for these schedules. For all other rate schedules, I used a coincident peak in UG-200994 as well as this proceeding.

Q. How is your discussion of the EmCOSS methodology organized?

A. The individual EmCOSS inputs and methodology discussion sections are organized as follows:

1. Design Day Load Factor
2. Functionalized Plant Investment Costs
3. Operations and Maintenance (O&M) Expense
4. EmCOSS Insights and Outcomes

1. Design Day Load Factor

Q. What is the design day load factor?

A. The load factor is a ratio measure of each rate schedule's contribution to the design day peak load. For purposes of the EmCOSS, I consider design day load on a Washington basis and attributable to Washington customers only. While load could potentially peak for other reasons on other systems, load peaks for NW Natural are a matter of space heating requirements and are therefore directly related to weather.

Q. How is the design day load factor value interpreted?

A. The design day load factor is the ratio of normalized average usage to the estimated design day peak usage, expressed as a percentage. A low load factor ratio indicates that a rate schedule has high peaking load relative to normalized average usage (i.e., it indicates the rate schedule has high weather sensitivity as load peaks during cold weather events). A high load factor indicates less weather sensitivity and more predicable base load usage throughout the year. Residential rate schedules, which use gas most significantly for heating purposes, are expected to have lower load factors relative to Industrial rate schedules that are more heavily comprised of processing load customers that use gas for purposes not tied directly to weather, such as the manufacturing of goods.

Q. How does the EmCOSS use the design day load factor?

A. The load factor is the basis for the design day (peak) and annual throughput (average) allocator that the EmCOSS uses to allocate (in full or in part) distribution mains and assets, system core mains, and transmission main investment to each rate schedule. The "Design Day Peak and Average Allocator" is a weighted ratio of each rate

schedule's contribution to the load factor-derived peak day deliveries and average throughput. Rate schedules with lower load factor ratios require more excess system capacity investment to meet design day load relative to higher load factor schedules, assuming equivalent annual load, and are therefore allocated more of these investment costs relative to higher load factor schedules.

Q. How is the design day load factor calculated for the EmCOSS?

A. The design day load factor for each rate schedule was estimated using the Normal UPCs for the Residential and Commercial sales customer classes, and the Company's Industrial Forecast for the remaining schedules. The design day load factor is calculated in Exh. RJW-11.

The ARIMA-based Normal UPC analysis described earlier in this testimony produced base and heat load coefficients for each rate schedule in the Residential and Commercial sales customer classes. I used statistical software that estimated these coefficients to model the normalized load numerator for the load factor ratio using the historical 30-year HDD average. As part of its resource planning processes, the Company has estimated an 11-degree Fahrenheit design day temperature, which I converted to HDDs. Using the Normal UPC-derived heating coefficients, I then estimated the design day load factor denominator.[17] For the rate schedules included in the Normal UPC analysis, this process creates a load factor based on coincident peak.

[17] For NW Natural's 2022 IRP, the Company used a probabilistic planning standard to forecast peak load as function several key drivers. This planning standard sets a daily resource capacity requirement such that the Company would be 99 percent certain it would be capable of meeting load going into any winter. Using this methodology, the Company has calculated an average system weighted temperature around this planning standard of roughly 11-degrees Fahrenheit.

Large Commercial interruptible and transportation service and Industrial schedules in rate classes RS 41 and RS 42 are not included in the Normal UPC analysis, as well as RS 3 Industrial. Customers in these classes were not included in the Normal UPC analysis because the Company maintains a separate customer-specific Industrial Forecast for these customers that is routinely updated by its subject matter experts. The Industrial Forecast volumes are the basis for the normalized load numerator for the load factor ratio. For the denominator, I queried historical load data by month and by day (where available) for all customers in these rate classes for each of the peak days on the Company's Washington system beginning January 2021 through May 2025 (resulting in five peak days). I calculated a maximum daily delivery volume ("MDDV") for each customer by peak day and aggregated these volumes by rate schedule. Then, I averaged each year's peak day MDDV value to derive a five-year coincident peak value for each large volume Commercial and Industrial service rate schedule in RS 41 and RS 42, as well as RS 3 Industrial (excluding Commercial Sales Firm service schedules, which are included in the Normal UPC analysis). This five-year coincident peak value is the basis for the design day load factor denominator; consistent with the Normal UPC analysis rate schedules, this design day load factor calculation is based on coincident peak. For the large volume Commercial and Industrial customers, coincident peak recognizes that depending on sector (such as agriculture or food processing), peak usage may not be tied to winter design day demands but rather the time of year processing or manufacturing occurs.

Q. How did you calculate the coincident peak for situations where the numerator is larger than the denominator?

A. I capped the coincident peak load factors at one hundred percent such that it at least reflects each rate schedule's annual average throughput contribution. Doing so is reasonable because for the rate schedules where this applies, their average winter sales are larger than or nearly equal to their average summer sales.

Q. What were the results of the design day load factor analysis?

A. I estimate an overall load factor for Washington rate schedules of 30.5 percent, with a firm load factor of 28.6 percent and a transportation load factor of 98.1 percent. The RS 2 Residential load factor is about 24.5 percent, meaning normal load for this schedule is a little less than one-quarter of its design day load. The RS 3 Commercial load factor is about 29.4 percent, while the Large Commercial rate schedules have estimated load factors ranging from 32.5 percent to 100.0 percent; the Industrial rate schedules have estimated load factors ranging from 55.5 percent to 100.0 percent.

Q. What were the results of the Company's load study analysis?

A. As I noted earlier, the Company also conducted a load study as defined by WAC 480-85-030(5). The load study data collection, sampling methodology, regression estimation techniques, and conclusions are presented in Exh. RJW-5, Exh. RJW-6, and Exh. RJW-7. The load study evaluates customer load profiles and calculates alternative design day load factors using sampled load data at daily granularity. The load study concludes that the design day load factors developed using the Normal UPC analysis described above produce usage estimations with better performance and fit of actual usage.

Q. Does the Company use the results of the design day load factor analysis or the results of the load study for its EmCOSS?

A. For the purposes of the EmCOSS for this proceeding, the Company uses the design day load factor analysis results developed using the Normal UPC analysis as the allocation method for distribution mains, transmission mains, and distribution assets as described in Table 4 of WAC 480-85-060(3) for the reasons discussed above and in the load study (Exh. RJW-5). The EmCOSS that the Company has used for this proceeding is presented in Exh. RJW-12. An alternative EmCOSS using the load study results is presented in Exh. RJW-13, to ensure compliance with WAC 480-85-060(2). Due to the Company's findings discussed in the load study in Exh. RJW-5, the Company does not adopt the results of the alternative EmCOSS presented in Exh. RJW-13 for this case and, instead, adopts the results of the EmCOSS presented in Exh. RJW-12 for this case.

Q. Does the Company rely solely on the peak and average methodology for allocation of capacity costs in the EmCOSS?

A. No. On its own, the Design Day Peak and Average Allocator does not fully capture the entirety of the system's cost causation among all rate schedules, which is why I also employ "average and excess" and "winter to summer average excess" allocation methodologies in my EmCOSS as is specified under the allocation method for Storage in Table 4 of WAC 480-85-060(3). While cost causation for some investments such as a portion of distribution mains and transmission mains are determined based on demand throughput based on a rate schedule's contribution to capacity needs (e.g., peak and average methodology), it also follows that cost causation for some investments, such as underground storage, are better allocated based on a rate schedule's contribution to

capacity demands at peak times (e.g., winter to summer average excess). The Company uses both methodologies to balance the assignment of cost causation among disparate investment categories from high volume to lower volume, but peakier, customer classes.

2. Functionalized Plant Investment Costs

Q. Please outline the specific components of functionalized plant investment costs evaluated in your study.

A. The functionalized incremental plant cost categories evaluated in this study include:

a) Distribution mains and assets, which are required for various purposes over time as the system grows, including mains to serve new customers and mains installed for safety and reliability purposes. The EmCOSS directly allocates a portion of these mains costs, based on an analysis of average installation cost per foot and length by rate schedule. The remainder of distribution mains costs are allocated based on the peak and average allocator. Distribution mains are designated in the Company's plant accounting records as those less than four inches in diameter, and those four inches or greater.

b) Unattributable system core mains, which are the balance of mains not attributable to distribution mains. System core mains, for the purpose of this EmCOSS, constitute the distribution pipeline that transport gas from the interstate pipeline to delivery points on the Company's system (e.g., gate stations) and interconnect with smaller diameter mains used to serve areas with customers such as neighborhoods, commercial strips, or industrial districts.

c) Transmission mains, which constitutes the pipeline that transports gas from the interstate pipeline to delivery points on the Company's system.

d) Distribution Assets, which are miscellaneous plant assets needed to support distribution functions.

e) Storage, which includes the costs associated with underground storage, is a primarily winter peaking resource.

f) Service lines, which includes costs associated with the piping and trenching from meter set to distribution main, and distribution main tie-in.

g) Meter set and regulator assemblies, which includes the cost of the meter and regulator, as well as the pipe fittings, bracket assemblies labor, and shop time required for assembly.

h) Administrative & General and Intangible Plant includes many of the assets used to serve all customers such as computers and software, as well as communications equipment.

i) Land and Structures are the physical assets the Company uses for its operations.

a. Distribution Mains and Assets

Q. Did you conduct a special study to directly assign distribution mains costs to individual rate schedules?

A. Yes, I directly assigned a portion of distribution mains costs using a special study which is presented in Exh. RJW-8. Costs not directly assigned are allocated based on the design day peak and average allocator.

Q. What were the inputs used to calculate the directly allocated distribution mains costs?

A. The main extension costs were evaluated using ten calendar years (2015 – 2024) of historical accounting data of Washington main extension job orders. The accounting data include the total cost (excluding construction overhead) and footage installed per job, pipe size and material, and are delineated by service type (conversion vs new construction), and market segment. The market segments analyzed are as follow:

- Residential-single family new construction ("Residential New")
- Residential-single family conversion ("Residential Conversion")
- Commercial / Industrial ("Com/Ind")

In addition to the ten years of job orders data, I used a main extension forecast that is produced annually by the Company's Business Analytics team, for 2024 through the Test Year. This forecast uses three categories of extensions: Commercial mains, Residential mains, and system expansion main extensions. The third category is overwhelmingly made up of new construction residential connections. The forecast is expressed in terms of mains footage and cost per foot.

Neither the main extension jobs order data nor the forecast includes a rate schedule breakout. I delineate by market segment, however, based on several factors, including location of the main extension, pipe size, and the type of customers most likely to take service on the extension.

Q. How were the directly allocated distribution mains costs calculated?

A. I used the main extension jobs order data to calculate the 10-year average cost per foot and median main length installed by market segment. Additionally, I used the same

dataset to calculate the 10-year average cost per foot and median main length installed by pipe size (less than four inches, or greater than or equal to four inches) and material (polyethylene or wrapped steel). The average cost of main extension is based on accounting data that are expressed in nominal dollars. Therefore, for purposes of the Test Year, I escalated the nominal main extension costs per foot to forecasted Test Year values using an inflation index that I equally weighted using two data sources ("Inflation Index").[18] The escalated values were used to create the median Test Year cost per foot input for the EmCOSS.

Q. How did you assign the median distribution main extension *cost per foot* for each market segment and pipe size to a rate schedule?

A. I used a weighting methodology that employs three inputs: (1) the Company's main extension forecast, weighted using a ratio of incremental customers added by way of conversion off existing main and those added through system expansion; (2) the job orders data by market segment; and (3) the job orders data by pipe size. For every rate schedule, I used a 50-50 weighting ("Segment Weight") to assign costs based on the forecast and the 10-year actual median cost per foot by market segment. For the Commercial and Industrial rate schedules, I further assigned costs by pipe size and type. I used pipe sizes and type for the large customer schedules as a method for further weighting main costs across schedules with wide variations in customer sizes, loads, and physical location off-main.

[18] I equally weighted inflation forecasts from two sources: (1) The Company's real long-term discount rate assumption used by its Strategic Planning Team for IRP development; (2) Oregon Economic and Revenue Forecast, Table Other Economic Indicators: CPI Urban Consumers. Page 45 (Exh. TFD-3, page 49), May 2025.

I assigned the Residential Conversion market segment to RS 2 Residential, the Residential New market segment to RS 27 Dry-Out, and the Com/Ind market segment to both RS 3 Commercial and RS 3 Industrial customers. Due to the large number of RS 3 Commercial customers on the system, I used Company GIS data to query a randomized sample of these customers to estimate the pipe size of the mains that customers in this rate class have been connected to historically. Using these GIS data, I calculated the ratio of customers connected to mains of less than four inches and greater than or equal to four inches and used this ratio to assign costs once the Segment Weight had been applied. The RS 3 Industrial mains costs were assigned similarly.

For the RS 41 and RS 42 rate classes, I applied the same Com/Ind Segment Weight as used for the RS 3 rate class. Mains costs were further delineated by rate schedule using the historical GIS pipe size data. For these larger schedules, I categorized mains connections by both pipe size and material due to the large variations in mains sizes and types that serve these customers.

Q. How did you assign the median distribution main extension *length* for each market segment and pipe size to a rate schedule?

A. I used a similar methodology as described above to calculate the median main extension length (in feet) for each schedule. For RS 2 Residential and RS 27 Dry-Out, I used the Company's main extension and customers forecasts. For the Commercial and Industrial schedules, I used 10-year average installed feet of mains by pipe size and material type to estimate main extension lengths for three categories: Small Com/Ind, Large Commercial, and Large Com/Ind.

Q. How were the directly allocable distribution mains costs calculated and allocated?

A. First, I estimated the feet of Washington mains on the Company's system not attributable to main extensions serving customers. I used feet of mains reported in the Company's FERC Distribution Report as a basis for total mains footage, categorized by pipe size.[19] Next, I used the historical GIS pipe size data to estimate what percentage of customers in each rate schedule are connected to distribution mains of less than four inches and equal to or greater than four inches. Using the distribution main extension median installed feet described above, I calculated the feet attributable to these customer classes by pipe diameter category. The remaining feet were classified as system core (unattributable) mains. I used an average cost of installed mains, weighted by pipe material, to get an estimated cost per foot. I then allocated these attributable mains to rate schedules based on share of overall attributable costs.

b. System Core Mains

Q. How did you calculate the share of distribution mains to classify as system core mains?

A. The remainder of the feet of mains reported on the FERC Distribution Report and not determined to be directly allocable distribution mains above (the unattributable portion) was classified as system core mains.

[19] The FERC Distribution Report is created annually by the NW Natural Engineering Department. It is used by the Plant Accounting team to validate that the feet of mains reported in the Company's asset management accounting databases is correct.

Q. How did you assign the system core mains costs to each rate schedule?

A. I used a peak and average method for distributing the system core mains costs to the rate schedules based on two allocations: Total average throughput and peak firm demand. The total throughput allocator is based on the design day load factor (i.e., the "average") and distributes costs across all schedules. The firm demand allocator is based on one minus the design day load factor (i.e., the "peak") and similarly distributes costs across all rate schedules. This cost assignment follows the allocation methodology for Distribution Mains in Table 4 of WAC 480-85-060(3).

Q. Does the system core mains allocation make an adjustment for interruptible peak day deliveries?

A. No. The system core mains allocation follows the coincident peak load factors, which assign no peak firm design day demands to the interruptible rate schedules following application of the peak and average methodology.

c. Transmission Mains

Q. How were the transmission mains costs allocated?

A. Transmission mains costs were allocated using the design day peak and average allocator based on the Washington system load factor per Table 4 of WAC 480-85-060(3).

d. Distribution Assets

Q. How were the distribution asset costs allocated?

A. Distribution asset costs were allocated using the design day peak and average allocator based on the Washington system load factor also per Table 4 of WAC 480-85-060(3).

e. Gas Storage

Q. How were underground gas storage costs allocated?

A. Underground gas storage plant costs were allocated to sales customers only, using a ratio based on Test Year average winter sales that exceed Test Year average summer sales as described in Table 4 of WAC 480-85-060(3). This measure allocates costs based on contribution to average peak loads compared to a period of average base loads.

Q. Were any underground storage costs classified as balancing and allocated to the Transportation class?

A. No. The EmCOSS does not classify any storage costs as balancing for allocation to the Transportation class. NW Natural generally will utilize the interstate pipeline for daily and/or monthly system balancing, not underground storage assets. However, it is possible that our underground storage assets could be utilized for balancing all customer classes, including Transportation. Any underground storage costs that could potentially be allocated to the Transportation class would be negligible.

f. Service Lines

Q. How were service line installation costs and average footage installed by rate schedule determined through your special study?

A. The calculation of average services cost per foot and the average footage installed was derived using ten years of historical accounting data of Washington services job orders (2015 – 2024) for customer service installations by market segment and are presented in Exh. RJW-8. These data are very similar to those of the Washington mains orders; the orders include the total cost (excluding construction overhead), footage installed

per job, and pipe size and material. The important distinction is that the services orders are associated with customers on specific rate schedules.

Services costs for RS 2 Residential, RS 3 Commercial, and RS 27 Dry-Out were calculated using a ten-year average of job costs per foot. Due to the small job sample size for the Commercial and Industrial schedules in the RS 41 and RS 42 classes, I used historical data to calculate a weighted median cost per foot. Using a GIS data query for services connection footage by rate schedule historically, I estimated services cost by customer per rate schedule by multiplying the average footage by average cost per foot. I used the Inflation Index to inflate nominal dollars to Test Year values.

Q. Did the Company update its Service Line Cost Allocator?

A. Yes. In Docket UG-200994, I applied a separate allocation for rate schedules in the RS 41 and RS 42 rate classes based on the overall embedded services plant cost in the Test Year. For this proceeding, I have applied a consistent allocation of embedded costs on a per service basis to all rate schedules that is informed by the results of my special study (through the *Line-1* allocator). Thereby, I have removed the effects of the *Line-2* allocator from the study.

g. Meter Sets and Regulators

Q. Please outline how your special study calculated costs for meter sets and regulators.

A. I ran a customer query out of NW Natural's CIS that included each actively billed customer's meter set model number and delivery pressure. A summary of this CIS data provided the counts of meter set models by rate schedule. NW Natural's Engineering Department maintains an engineering cost memo that provides the assembly and capital

cost for each assembled meter set (by meter model number) with regulator. I calculated weighted-average cost using the costs from the engineering cost guide and meter counts by rate schedule to derive the capital investment cost by customer by rate schedule. The results of this analysis are presented in Exh. RJW-9.

Q. How were meters and regulators plant investment costs allocated to rate schedules?

A. I converted the average meter cost per customer per rate schedule to share of overall meter and regulator costs using customer count as a weight.

h. General and Intangible Plant

Q. How was general plant allocated to rate schedules?

A. I used a common allocator that was built using three factors: (1) net allocated plant balances for the storage, distribution, and transmission functions; (2) total O&M expense allocation; and (3) customer count. I created the common allocator using an equal weight of each of these three factors. These factors together represent a mix of each rate schedule's share of overall utility capital investments and operating expenses, accounting for the relationship between costs and customer count.

Q. How was intangible plant allocated to rate schedules?

A. I similarly used the common allocator to allocate intangible plant, as I considered these common costs. I examined the intangible plant assets at the materiality threshold of 0.5 percent per Table 4 of WAC 480-85-060(3) and found no items directly allocable to specific rate classes or schedules.

Q. Were any of the Company's plant balances not covered in Table 3 of WAC 480-85-060(3)? How were these accounts allocated?

A. Yes, FERC Accounts 363.5 (CNG Refueling Facilities) and 363.6 (LNG Refueling Facilities) are not included in Table 3 of WAC 480-85-060(3). I used the common allocator to allocate these plant balances to the rate schedules because the benefits associated with these facilities are not limited to any customer class.

i. Land and Structures

Q. How were land and structures allocated?

A. I allocated the general land and structures plant balances (FERC Accounts 389 and 390) based on functionalized storage, transmission, and distribution plant. For land and structures attributable to certain functions, I allocated the balance based on plant associated with that function only (e.g., storage related land and structures are allocated based on storage plant).

3. Operations and Maintenance (O&M) Expenses

Q. Please describe the categories of O&M expenses evaluated in the EmCOSS.

A. Below, I describe how I allocate O&M expenses in the EmCOSS. O&M expenses are associated in EmCOSS with capital investments as well as common costs. O&M expenses associated with capital investments are the on-going O&M expenses required to keep plant assets operational and efficient. The expenses are associated with the assets: gas storage, transmission, and distribution. Common O&M expenses are associated with common cost items required to keep the entire system running, such as administrative and office expenses, wages and salaries, and customer service and billing. The two major categories of common O&M expenses that I evaluated in the

EmCOSS were: (a) Customer Service and Billing; and (b) Administrative and General. I explain how these expenses were allocated to the rate schedules below.

a. Customer Service and Billing

Q. What are the categories of customer service and billing O&M expenses that were evaluated in the EmCOSS?

A. The EmCOSS includes a special study based on the following categories of O&M customer service-related expenses for direct allocation and presented in Exh. RJW-10:

- Gas Scheduling, which includes departments that schedule underground storage injections/withdrawals, as well as control the distribution system's daily operations.
- Gas Planning, which are operations that include, short- and long-term gas acquisitions, planning, and analysis (e.g., gas purchasing and hedging activities).
- Major Accounts Services, which is the team that interacts primarily with large commercial and industrial customers through the service election process, coordinates billing and addresses billing issues, as well as coordinates new large customer acquisitions.
- Accounts Services, including billing, payment processing, metering, collections, and construction field services.

Q. How were gas planning and gas scheduling costs evaluated and assigned to each rate schedule?

A. The gas scheduling and gas planning cost centers were evaluated using the O&M budget cost center for the Gas Scheduling and Planning Department. Cost categories include total salaries, administrative costs, and FTE counts for each cost center. These

values are used to evaluate per customer costs for the EmCOSS, based on average hours spent on each customer at a calculated average labor rate.

The gas scheduling cost center was broken out into two functions: gas storage operations and gas control operations. Costs associated with gas storage operations were allocated to firm sales rate schedules only. Gas control operations costs were allocated to all schedules based on three factors: (1) service type (sales firm, sales interruptible, or transportation); (2) normalized annual throughput; and (3) the amount of time gas management staff estimate they spend working with customers of each service type.

The gas planning cost center was allocated to all service types based on the amount of time gas management staff estimate they spend working with customers of each service type. Costs are largely allocated to sales customers since little staff time is devoted to transportation customers that are responsible for procuring their own gas commodity.

Once costs were assigned to each service type, they were directly allocated to each rate schedule based on weighted customer counts within that service type.

Q. How did you evaluate Major Accounts Services costs?

A. Major Accounts Services costs were allocated only to the large RS 41 and RS 42 Commercial and Industrial rate classes, as well as RS 3 Industrial. Costs were further allocated to sales and transportation rate schedules based on reported staff time spent interfacing with each service type.

Q. How were all other Accounts Services costs evaluated?

A. For all other Accounts Services costs, NW Natural conducted a "Meter-to-Cash" study, that evaluated the incremental costs associated with providing these services to customers. The study evaluated the following cost center groups in the Company that directly serve customers:

- Accounts Services (meter reading scheduling, payment processing, collections)
- Contact Center (customer call center)
- Resource Management Center (field services scheduling/dispatch)
- Construction Field Services (field technicians and field scheduling)
- Office Services (bill printing)
- Treasury (costs that pertain only to payment processing)
- Information Technology (costs related to computer support for processes that support meter reading, payments, and Company website)

Q. What is the purpose of the Meter-to-Cash study?

A. The Meter-to-Cash study was first developed by the Company in 2015. It was developed to estimate the incremental costs of customer additions associated with the Accounts Services functions listed above. The 2015 analysis was developed over several months, through meetings with managers and subject matter experts associated with each of the Accounts Services functions. These meetings helped to determine what individual cost centers and expense items should be associated with each activity, as well as what costs and activities are associated with three categories of rate schedules: Residential, Small Commercial, and Large Commercial / Industrial. Data were collected after these informational interviews were complete. Costs that are not

directly tied to customer count were not included in the Meter-to-Cash study (e.g., software upgrade costs are not necessarily correlated to customer additions and are therefore not included).

Q. Has the Meter-to-Cash study been updated?

A. Yes. The Meter-to-Cash study was updated in 2023, and again in 2024, to reflect current operations and Accounts Services functions. Updates are developed with input from subject matter experts across the Company, using similar methodology as the initial 2015 study. The updated study is the basis for incremental Accounts Services costs for the EmCOSS.

Q. What data were collected and what criteria were used for its inclusion in the Meter-to-Cash study?

A. Incremental O&M cost estimates in the Meter-to-Cash study were based on data collected from the Company's engineering, accounting, and customer contact teams. Data were vetted with the help of supervisors and managers of these teams as well as individual cost centers. The expenses identified as part of the Meter-to-Cash process were identified by cost center and were determined to be appropriate for inclusion in this incremental cost study based on the following criteria: If it were determined an additional forecasted customer would make a direct cost change within the cost center associated with these groups, and this direct cost was measurable, the cost would be included. Costs that are not tied to functions provided by the cost centers listed above for the direct service of customers were not included in the Meter-to-Cash study.

Q. How were the incremental Meter-to-Cash costs allocated to the rate schedules for the EmCOSS?

A. After identifying the incremental costs, the EmCOSS breaks out each cost center's budget into five categories:

1. Meter Reading
2. Billing
3. Payment Processing
4. Collections (costs that pertain to payment processing)
5. Other Activities

Within each category of budget, costs are evaluated as payroll versus non-payroll. An incremental cost per customer was derived by taking the above categories and apportioning the cost into the three broad categories of rate schedules. I weighted these class-based average costs by rate schedule customer count to create an indirect allocator for customer service and billing O&M expenses.

Q. Did you directly allocate any additional customer services-related O&M expenses?

A. Yes. I examined the Company's Washington-allocated O&M expenses by type and cost center. Any costs identified as relating specifically to Residential, Residential and Commercial, or Commercial and/or Industrial classes were directly allocated to rate schedules as appropriate based on weighted customer count.

b. Administrative and General Expenses

Q. How did you allocate administrative and general O&M expenses?

A. The administrative and general O&M expenses allocation follows Table 4 of WAC 480-85-060(3) where specified. For expenses not noted in the table, I used the common allocator, except for FERC Account 921. This account represents general payroll; I allocated most of these costs based on the customer-weighted customer services cost allocator described above. I identified a portion of FERC 921 expenses as directly attributable to specific rate classes and allocated these costs as such.

4. EmCOSS Insights and Outcomes

Q. Upon what basis is revenue at current rates compared against revenue with the proposed incremental revenue requirement at the first MYRP rate effective date?

A. The EmCOSS compares the ratio of adjusted Test Year Revenues at Current Rates against the EmCOSS based Total Revenue Requirement at Unity, the difference being the proposed margin increase at the first MYRP rate effective date (i.e., August 1, 2026). This ratio is used to derive the Revenue-to-Cost Ratio at Present Rates, and then the Parity Ratio at Present Rates, which indicates each rate schedule's position relative to cost parity (i.e., the point that the schedule is neither over- nor under-paying its EmCOSS determined cost of service). Refer to the EmCOSS study results, Exh. RJW-12.

Q. What do the results of the EmCOSS indicate?

A. The EmCOSS-indicated Parity Ratio at Present Rates for each rate schedule is illustrated in Table 1 below. A parity ratio below the value of 1.00 indicates that customers on a given schedule are underpaying their EmCOSS determined cost of

service. A value over 1.00 indicates that customers on a given rate schedule are paying more than their cost of service at present rates. Per Table 1 below, the results of the EmCOSS indicate that the RS 1 Residential and RS 1 Commercial General Sales Service ("RS 1 Residential" and "RS 1 Commercial") rate schedules are paying well below their full cost of service at present rates. RS 2 Residential and RS 27 Dry-Out rate schedules are also paying less than their full cost of service at present rates while the remaining rate schedules are paying more than their cost to serve (with RS 3 General Commercial paying just slightly above the determined cost of service).

Table 1
EmCOSS Parity Ratio at Present Rates, by Rate Schedule

RATE SCHEDULE	01 R	02 R	27 C	01 C	03 C	03 I	41 CSF	42 CSF
EmCOSS Determined Parity Ratio	**0.51**	**0.95**	**0.74**	**0.50**	**1.06**	**1.02**	**1.33**	**1.35**
RATE SCHEDULE	42 CSI	41 ISF	42 ISF	42 ISI	41 CTF 41 ITF	42 CTF	42 ITF	42 CTI 42 ITI
EmCOSS Determined Parity Ratio	**1.11**	**1.39**	**1.42**	**1.81**	**1.49**	**1.25**	**1.43**	**3.12**

The class-wide EmCOSS-indicated parity ratios are as follow: 0.94 for the Residential rate schedules; 1.05 for the Small Commercial schedules; 1.31 for Large Commercial Sales schedules; and 1.58 for the Industrial and Transportation schedules.

Q. How do these results compare with the Company's last filed EmCOSS?

A. This EmCOSS and the Company's last study, filed with Docket UG-200994, both indicate that the RS 41 and RS 42 rate classes are paying more than their determined cost of service under present rates. Both studies also indicate that RS 1 Residential, RS 2 Residential, and RS 27 Dry-Out customers are paying less than their determined

cost of service. Also consistent is the finding that RS 3 Commercial is overpaying its cost to serve, albeit to a lesser extent than indicated in the prior rate case. The largest difference is the finding that RS 1 Commercial is paying well below its cost of service (compared to the finding it was paying just above its cost of service in UG-200994). The RS 2 Residential parity ratio is slightly higher than the UG-200994 indicated ratio (while still underpaying the determined cost of service, the EmCOSS indicates the gap has narrowed). Based on the data and methods used to calculate incremental cost for this EmCOSS, as described earlier in this testimony, I find that RS 1 Residential and RS 1 Commercial customers have the lowest Relative Revenue-to-Cost Ratio at the Company's current rates.

Q. What factors must be considered when comparing the results of the EmCOSS across multiple proceedings?

A. Direct comparison of parity ratios across proceedings is not straightforward due to changes in investment mix, customer makeup and service elections, and changes to overall throughput and design day demand.

Q. Why does the EmCOSS now indicate the RS 1 Residential customers are paying well below their cost to serve?

A. As noted earlier, the RS 1 Residential tariff does not allow primary space heating systems or water heating appliances and is limited to lower-usage appliances such as cooktops and fireplace inserts. Since the Company's last filed EmCOSS, the Company has realized a higher growth rate of new premises on RS 1 Residential that are lower-usage. Therefore, the customer makeup has changed (the customer count on this rate schedule has increased roughly 20 percent since just January 2023) as well as estimated

load factor. Because these customers are low using (the Normalized UPC is 74 percent lower than that of RS 2 Residential), the EmCOSS credits them with lower fixed cost recovery compared to higher using schedules with similar a load factors (such as RS 2 Residential).

Q. Was the Company required to conduct any economic feasibility studies for its Washington special contract customers since its last general rate case filing?

A. Yes. In resolution of the Company's 2019 Washington general rate case, Docket UG-181053, the Company agreed in settlement to conduct an updated economic feasibility study for its Washington special contracts within three years of November 1, 2019. As noted in final Commission Order 06 of that docket, the Company "has been unable to locate the original study, and that the relevant contract has been effective on a month-to-month basis for the past 20 years." Per the settlement, the Company agreed to conduct the study with the purpose of verifying that the special contract rates continue to be fair, just, and reasonable.[20]

Q. Did the Company conduct an economic feasibility study for its special contract customers?

A. Yes. The Company conducted an economic feasibility study prior to November 2022 for the one customer taking service under a special contract in the Company's Washington service territory as of October 2022. The purpose of the economic feasibility study was to reexamine the economics of the agreement between NW Natural and the special contract customer by estimating the cost that the customer

[20] See: *Washington Utilities and Transportation Commission, Complainant, v. Northwest Natural Gas d/b/a NW Natural, Respondent,* Docket UG-181053, Order 06, at 29-30 (Oct. 21, 2019).

would likely incur at the time of the study if it were to bypass the Company's system and directly interconnect to Northwest Pipeline.

Q. What was the result of the Company's economic feasibility study?

A. The study concluded that the cost of bypassing the Company's system would be uneconomic for the special contract customer, and the Company recommended eliminating the special contract service. The customer is no longer taking service under the special contract and is currently taking large volume industrial transportation firm service.

IV. RATE DESIGN & RATE SPREAD

Q. What is the purpose of the rate design and rate spread section of your testimony?

A. The purpose of this section of my testimony is to:

- Discuss the Company's approach to rate design for this proceeding;
- Summarize NW Natural's incremental revenue requirement request;
- Discuss the results of the EmCOSS and how it relates to rate spread;
- Describe the methodology for how the Company proposes to spread incremental revenue; and
- Show the revenue requirement spread by rate schedule and the corresponding average bill impact.

1. Rate Design

Q. Is the Company proposing any rate design changes in this proceeding?

A. Yes. The Company is proposing the following changes to fixed cost rate design in this proceeding for Rate Year 1 (RY1), Rate Year 2 (RY2), and Rate Year 3 (RY3):

- Increase the RS 1 Residential fixed monthly charge from $5.50 to $8.00 in RY1.

- Increase the RS 1 Commercial fixed monthly charge from $7.00 to $10.00 in RY1.
- Increase the RS 1 Residential fixed monthly charge from $8.00 to $10.00 in RY2.
- Increase the RS 2 Residential fixed monthly charge from $8.00 to $10.00 in RY2.

Q. Why is the Company proposing to increase the fixed monthly charge for these rate schedules?

A. The fixed monthly charge is one element the Company uses to collect a portion of the fixed cost component of its overall authorized revenue requirement for these rate schedules. These fixed costs (such as meters, services, and billing) are incurred solely because of the existence of customers connected to the system and are not related to usage demands. The other piece is the volumetric rate, which is used to collect the remainder of the fixed cost component as well as the variable component of the overall authorized revenue requirement. In fact, a significant portion of the Company's fixed costs are collected on the volumetric rate. Table 2 below shows the EmCOSS-indicated fixed monthly charge compared to the existing fixed monthly charge for each rate schedule in the Company's proposal.

Table 2
EmCOSS-Indicated Fixed Charges

Rate Schedule	EmCOSS-Indicated Fixed Charge	Existing Fixed Charge	Ratio Existing to Indicated Fixed Charge	RY1 Proposed Fixed Charge	RY2 Proposed Fixed Charge	RY3 Proposed Fixed Charge	Ratio Proposed to Indicated Fixed Charge
	$	$	%	$	$	$	%
RS 1 Residential	$ 33.85	$ 5.50	16.2%	$ 8.00	$ 10.00	$ 10.00	29.5%
RS 1 Commercial	$ 67.09	$ 7.00	10.4%	$ 10.00	$ 10.00	$ 10.00	14.9%
RS 2 Residential	$ 30.87	$ 8.00	25.9%	$ 8.00	$ 10.00	$ 10.00	32.4%

Note: The data in Table 2 is presented in Exh. RJW-14.

The existing fixed monthly charge for RS 1 Residential is under one-fifth of the EmCOSS-indicated fixed monthly charge at the proposed rates in this proceeding. For

RS 2 Residential, it is just over one-quarter of the EmCOSS-indicated fixed charge. For RS 1 Commercial, it is less than one-tenth. The Company's proposal, as shown in Table 2 above, makes meaningful – but incremental – progress towards closing the gap between current fixed cost recovery on a per customer basis and that customer's full fixed cost responsibility. At RY2, the ratio of proposed to EmCOSS-indicated fixed monthly charge would be nearly the same for RS 1 and RS 2 Residential (at just under one-third). Although the RS 1 Commercial ratio at RY2 is lower compared to the residential rate schedules, the fixed charge rate is equal to that of RS 1 Residential which has the same tariff service parameters (e.g., notably, limited to equipment that does not qualify as primary space heating systems).

Q. How does the Company's rate design proposal constitute sound rate design?

A. As shown in Table 2 above, the Company's proposal much more closely aligns fixed cost recovery across the entire residential rate class compared to existing rates (as a ratio of the proposed fixed charge monthly rate to the EmCOSS-indicated rate). It also aligns (on a dollar basis) fixed recovery for like schedules (RS 1 Residential and RS 1 Commercial) that have the same service parameters under a single tariff. As I explain further below, the Company's rate design promotes rate equity through a fair apportionment of revenue requirement between the fixed and volumetric charges that reduces subsidization flowing from higher usage customers to lower usage customers. The Company's proposal is responsive to the principle of fairness presented as "Attributes of a Sound Rate Structure" developed by James C. Bonbright ("Bonbright Principles"). The sixth principle seeks to avoid "arbitrariness and capriciousness" while attaining equity in three dimensions: "(1) Horizonal (i.e., equals treated equally);

(2) vertical (i.e., unequals treated unequally); and (3) anonymous (i.e., no ratepayer's demands can be diverted away uneconomically from an incumbent by a potential entrant)."[21] The Company's proposal avoids arbitrariness in the fixed price signal between residential customers on RS 1 Residential and RS 2 Residential, while apportioning volumetric rates that reduce the gap in cost recovery between higher usage and lower usage customers on an intra-class basis (and that are responsive to the EmCOSS-indicated results that show RS 1 Residential customers pay well below their cost of service compared to RS 2 Residential customers). The proposal also treats customers under the same service provisions (RS 1 Residential and RS 1 Commercial) more equally on an intra-class basis while still recognizing differing costs of service across premises types through the volumetric rate (residential vs commercial).

Q. How do the Company's existing fixed monthly charges for these rate schedules compare to peer utilities?

A. Table 3 below shows a comparison of the Company's existing fixed monthly charge, and its proposal compared to peer natural gas utilities in Washington for residential customers:

[21] See: Bonbright, James C., Albert L. Danielsen, David R. Kamerschen. *Principles of Public Utility Rates* (Second Edition, 1988). Public Utilities Reports, pages 383-384.

Table 3
Fixed Monthly Charges for
Residential Customers,
Comparison of Peer Utility Residential Rate Tariffs

Residential Rate Tariffs	Fixed charge Residential	
Puget Sound Energy (NG)	$14.00	
Avista (NG)	$10.50	
NW Natural (RS 1 Residential Proposed)	$10.00	*At Rate Year 2*
NW Natural (RS 2 Residential Proposed)	$10.00	*At Rate Year 2*
NW Natural (RS 2 Residential Existing)	$8.00	
Cascade Gas	$5.50	*Increasing to $6.00 March 2026*
NW Natural (RS 1 Residential Existing)	$5.50	

Note: The data in Table 3 is presented in Exh. RJW-14.

As Table 3 above indicates, the Company's RS 1 Residential fixed monthly charge will be the lowest of all peer utilities' residential fixed charge rates after March 2026, while the Company's RS 2 Residential fixed monthly charge would be the second lowest. The Company's proposed fixed charges for both RS 1 and RS 2 Residential at RY3 continue to maintain the second lowest residential fixed charge rates of peer natural gas utilities in Washington but places it nearly in line with that of the second highest (Avista).

Table 4 below shows a comparison of the Company's existing fixed monthly charge, and its proposal compared to peer natural gas utilities in Washington for general service commercial customers:

Table 4
Fixed Monthly Charges for
General Service Commercial Customers,
Comparison of Peer Utility Commercial Rate Tariffs

General Commercial Rate Tariffs	Fixed charge Commercial	
Puget Sound Energy (NG)	$50.56	*Increasing to $65.72 January 2026*
NW Natural (RS 3 Commercial Existing)	$22.00	
Cascade Gas	$20.00	*Increasing to $25.50 March 2026*
Avista (NG)	$10.50	
NW Natural (RS 1 Commercial Proposed)	$10.00	*At Rate Year 1*
NW Natural (RS 1 Commercial Existing)	$7.00	

Note: The data in Table 4 is presented in Exh. RJW-14.

Table 4 above indicates that the Company's RS 1 Commercial fixed monthly charge is currently the lowest fixed monthly charge compared to general commercial service fixed charges for peer natural gas utilities in Washington (there are no comparable low-usage commercial rate schedules). The Company's proposal will maintain this ranking, but it will more closely align with the general commercial fixed charge of Avista.

Q. In general, can increasing the monthly fixed charge be beneficial for customers?

A. Yes. When more fixed costs are collected through a higher monthly fixed charge, less of the revenue requirement is collected through the volumetric rate. This works to smooth the Company's bills across the entire year, resulting in lower winter bills at a time when customer's other energy bills may be increasing as well. Since NW Natural is a single-peaking utility, higher monthly fixed charges put a greater share of cost recovery on bills when they are the lowest: During the summer months. The outcome for customers are more predictable, and flatter, bills throughout the entire year. Finally, for residential customers enrolled in the bill discount program, the discount is applied by the same discount percentage on both the fixed monthly and volumetric charge rates.[22]

[22] The percentage of the bill that is discounted includes both the fixed and volumetric portions of the bill. For instance, a $50.00 RS 2 Residential bill discounted at the current Tier 1 level (40%) is $30.00 regardless of whether the fixed charge is $8.00 or $10.00.

Q. Does the Company have evidence that at least some residential customers prefer smoother bills throughout the entire year?

A. Yes. The Company's Equal Pay plan, which spreads bills evenly throughout the entire year, is in practicality an individualized 100 percent monthly fixed charge. As of August 2025, roughly 12 percent of the Company's Washington residential customers (taking service on both RS 1 and RS 2 Residential, totaling almost 11,000 customers) have opted into paying a fixed bill through the Equal Pay plan, including just over 1,000 customers (accounting for 9.3 percent of customers on the Equal Pay plan) that are also enrolled in the bill discount program.

Q. Can increasing the monthly fixed charge promote rate equity for residential customers?

A. Yes. As I noted above, a substantial portion of RS 1 and RS 2 Residential fixed costs are collected on the volumetric rate. The amount that is collected on the volumetric rate varies based on weather (for heating load) but also varies based on the number and type of appliances that a customer has installed, as well as housing characteristics: square footage, tightness of building envelope, and age of home which influences standards and materials used in its construction. Fewer fixed costs are collected from lower usage residential customers compared to higher usage residential customers. Lower monthly fixed charges cause greater upward pressure on the volumetric rate, thereby causing intra-class subsidization that flows from the higher usage customers to the lower usage customers.

In the absence of fixed monthly charge increases, both external and internal policies can also influence how much of the cost burden falls on higher using customers

compared to lower using customers. Establishing higher monthly fixed charges helps to equalize the contribution each customer within a class makes towards recovery of the fixed costs attributable to that rate schedule, reducing the gap between customers that are paying too much and those that are paying too little. For instance, as I discussed earlier, the anticipated UPC for new service connections is lower than existing service connections. This means that customers in newer premises will pay less of their fixed costs through the volumetric rate compared to existing customers resulting in rate inequity. Further, as the Company explores further conservation and new appliance mixes in residences like hybrid systems, such a rate design could be key to fairness between residential customers with varying usages. A higher monthly fixed charge, which produces downward pressure on the volumetric charge, mitigates a cross-subsidy that benefits lower usage customers and promotes rate equity for higher usage customers.

Q. Have you examined how the Company's RS 1 Residential monthly fixed charge proposal would impact individual customers on a monthly basis, including those customers currently enrolled in the bill discount program?

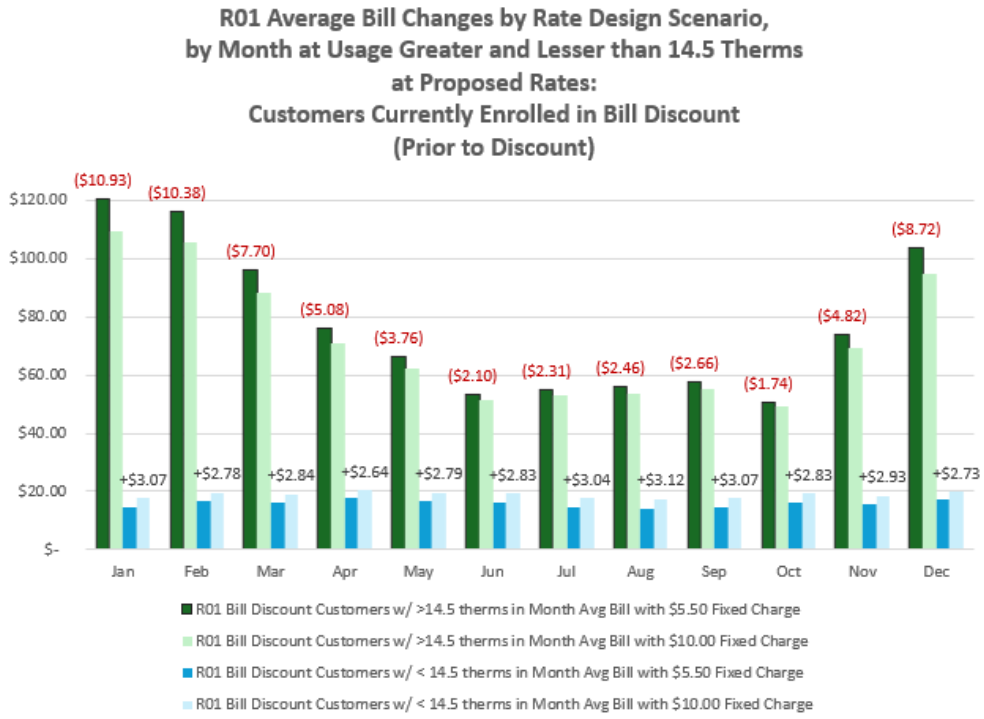
A. Yes. I examined bills issued in 2024 for RS 1 Residential premises that had a bill for every month in the year (thereby excluding premises that either moved onto or off the schedule during the year) and currently have active accounts. My analysis follows premises, so customer accounts that move into or out of a premises on RS 1 Residential service are still counted provided that premises had twelve months of bills. I made a comparison of the Company's proposed RS 1 Residential RY2 rates in this proceeding with the $10.00 fixed monthly charge against the rates the Company would have

proposed for RY2 with the current $5.50 fixed monthly charge. In the $10.00 scenario, the proposed volumetric billing rate is $2.02861 per therm; under a $5.50 scenario, the volumetric billing rate would be $2.33820 per therm. Given this difference in volumetric rate, I calculate that a customer would pay *less* under the $10.00 fixed charge scenario if they used greater than 14.5 therms in a month. Across all months for all RS 1 Residential customers, I found that the average bill would be 63 cents higher per month under the Company's proposal. The average bill would be $3.46 and $2.90 lower in the months of January and February, however, and $2.11 lower in December when bills are their highest. Across all months, the bill increase equates to less than the $4.50 fixed charge increase on 75.2 percent of bills, with the remaining 24.8 percent of bills getting a $4.50 increase due to zero reported usage (from $3.68 to $8.18 on a total bill basis after Schedule 308 credits have been applied).

Q. What did you find when you examined how the Company's RS 1 Residential monthly fixed charge proposal would impact customers currently enrolled in the bill discount program?

A. I examined the impacts of the Company's RS 1 Residential proposal on customers that are currently enrolled in Schedule L (Residential Bill Discount Program). I found that the average bill across all months would be 34 cents lower under the Company's proposal before any Schedule L discounts have been applied. Table 5 below shows average bill changes comparing the Company's $10.00 fixed charge proposal against the status quo ($5.50) for customers currently enrolled in the bill discount program using greater or lesser than 14.5 therms (the breakeven level of usage) by month prior to Schedule L discounts.

Table 5



Note: The data in Table 5 is presented in Exh. RJW-15.

Table 5 above shows that RS 1 Residential customers enrolled in the bill discount program that use greater than 14.5 therms in the months of January and February will realize bills that are on average $10.93 and $10.38 lower, respectively, under the Company's proposal compared to the status quo at proposed rates in this proceeding. Just over 60 percent of all RS 1 Residential customers enrolled in the bill discount program would realize lower bills in each of these two months under the Company's proposal. For the remainder that would receive higher bills, those amounts would average $3.07 and $2.78 in January and February, respectively. The average total bill would be $17.56 and $19.43 in January and February for these customers, compared to a total average bill of $109.31 and $105.67 in the same months for customers that use greater than 14.5 therms. Therefore, although the cohort of

customers that use less than 14.5 therms would realize higher on average bills in these months, those bills are over 80 percent lower compared to the average bills for customers that use greater than 14.5 therms. These figures are prior to the application of any Schedule L bill discounts.

Table 6 below presents the average bill comparison between the Company's $10.00 proposal and the $5.50 fixed charge status quo as shown above in Table 5, but with the Schedule L bill discounts applied across each income tier. The bill discount is applied on the entire bill (both fixed and volumetric charges), therefore, the difference in average bills under both scenarios is lower when the Schedule L bill discount is steeper for customers using both greater or lesser than 54.1 therms.

Table 6
RS 1 Residential Bill Discount Enrolled Customer
Average Bill Changes:
Proposed Fixed Charge Compared to Status Quo
at RY2 Proposed Rates
by Month by Usage Category
by Schedule L Bill Discount Tier

	Avg RY2 Bill at $5.50 Fixed Charge *Prior to Discount*	Avg RY2 Bill Difference at $10.00 Fixed Charge Based on Usage Above/Below Breakeven Amount									
		Usage Greater than 14.5 therms					Usage Less than 14.5 therms				
		Share	Tier 0	Tier 1	Tier 2	Tier 3	Share	Tier 0	Tier 1	Tier 2	Tier 3
		%	80%	40%	20%	15%	%	80%	40%	20%	15%
Jan	$ 81.79	64.2%	$ (2.19)	$ (6.56)	$ (8.75)	$ (9.29)	35.8%	$ 0.61	$ 1.84	$ 2.45	$ 2.61
Feb	$ 75.99	59.7%	$ (2.08)	$ (6.23)	$ (8.30)	$ (8.82)	40.3%	$ 0.56	$ 1.67	$ 2.23	$ 2.37
Mar	$ 57.80	52.2%	$ (1.54)	$ (4.62)	$ (6.16)	$ (6.55)	47.8%	$ 0.57	$ 1.71	$ 2.27	$ 2.42
Apr	$ 38.58	35.8%	$ (1.02)	$ (3.05)	$ (4.06)	$ (4.31)	64.2%	$ 0.53	$ 1.59	$ 2.12	$ 2.25
May	$ 33.60	34.3%	$ (0.75)	$ (2.26)	$ (3.01)	$ (3.20)	65.7%	$ 0.56	$ 1.67	$ 2.23	$ 2.37
Jun	$ 24.09	20.9%	$ (0.42)	$ (1.26)	$ (1.68)	$ (1.78)	79.1%	$ 0.57	$ 1.70	$ 2.26	$ 2.40
Jul	$ 17.44	6.0%	$ (0.46)	$ (1.39)	$ (1.85)	$ (1.96)	94.0%	$ 0.61	$ 1.83	$ 2.43	$ 2.59
Aug	$ 15.98	4.5%	$ (0.49)	$ (1.47)	$ (1.96)	$ (2.09)	95.5%	$ 0.62	$ 1.87	$ 2.50	$ 2.65
Sep	$ 16.39	4.5%	$ (0.53)	$ (1.60)	$ (2.13)	$ (2.26)	95.5%	$ 0.61	$ 1.84	$ 2.46	$ 2.61
Oct	$ 20.44	11.9%	$ (0.35)	$ (1.04)	$ (1.39)	$ (1.48)	88.1%	$ 0.57	$ 1.70	$ 2.26	$ 2.40
Nov	$ 35.42	32.8%	$ (0.96)	$ (2.89)	$ (3.86)	$ (4.10)	67.2%	$ 0.59	$ 1.76	$ 2.34	$ 2.49
Dec	$ 66.08	56.7%	$ (1.74)	$ (5.23)	$ (6.97)	$ (7.41)	43.3%	$ 0.55	$ 1.64	$ 2.18	$ 2.32

Note: The data in Table 6 is presented in Exh. RJW-15.

The first column of Table 6 above shows the RY2 average bill at the current $5.50 monthly fixed charge for enrolled bill discount customers, prior to Schedule L bill discounts. The remaining columns show the difference in average bill for each bill

discount tier based on whether a RS 1 Residential customer uses above or below the breakeven amount (14.5 therms), and the percentage of customers in each usage category. Table 6 above indicates that for the roughly 64.2 and 59.7 percent of all RS 1 Residential customers enrolled in the bill discount program that use greater than 14.5 therms in January and February, respectively, their bills will be lower by an amount that more than offsets the higher bills for the minority of customers in those months. For Tier 0 customers that are in the 35.8 and 40.3 percent share of all customers that use less than 14.5 therms in these two months, their average bills will be just about 61 (January) and 56 (February) cents higher under the Company's proposal. In low usage months such as August where only about 4.5 percent of RS 1 Residential customers use greater than 14.5 therms, bills would similarly be just about 62 cents higher for Tier 0 customers at a time of the year usage (and total bills) are at their lowest. As indicated in Table 6 above, August average bills ($15.98) are about 80.5 percent lower than January bills ($81.79) prior to bill discounts.

Q. Have you examined how the Company's RS 2 Residential monthly fixed charge proposal would impact individual customers on a monthly basis, including those customers currently enrolled in the bill discount program?

A. Yes. Consistent with my RS 1 Residential analysis, I examined bills issued in 2024 for RS 2 Residential premises that had a bill for every month in the year (thereby excluding premises that either moved onto or off the schedule during the year) and currently have active accounts. This analysis also follows premises, so customer accounts that move into or out of a premises on RS 2 Residential service are still counted provided that premises had twelve months of bills. I made a comparison of the Company's proposed

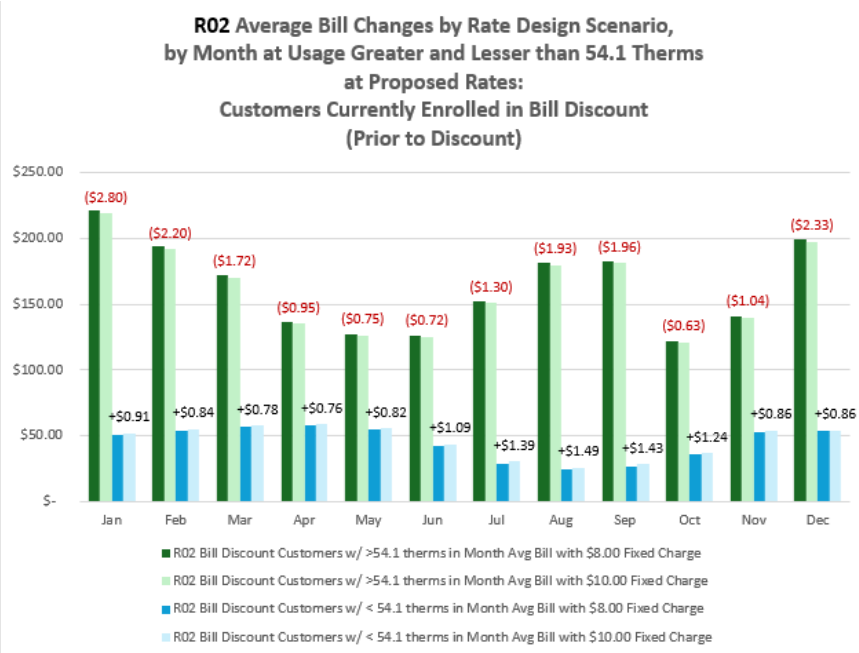
RS 2 Residential RY2 rates in this proceeding with the $10.00 fixed monthly charge against the rates the Company would have proposed for RY2 with the current $8.00 fixed monthly charge. In the $10.00 scenario, the proposed volumetric billing rate is $1.66276 per therm; under a $8.00 scenario, the volumetric billing rate would be $1.69970 per therm. Given this difference in volumetric rate, a customer would pay *less* under the $10.00 fixed charge if they used greater than 54.1 therms in a month. Across all months for all RS 2 Residential customers, I found that the average bill would be just 7 cents higher per month under the Company's proposal. The average bill would be $2.22 and $1.59 lower in the months of January and February, however, and $1.62 lower in December when bills are their highest. Across all months, the bill increase equates to less than the $2.00 fixed charge increase on 97.3 percent of bills, with the remaining 2.7 percent of bills getting a $2.00 increase due to zero reported usage (from $0.61 to $2.61 on a total bill basis after Schedule 308 credits have been applied).

Q. What did you find when you examined how the Company's RS 2 Residential monthly fixed charge proposal would impact customers currently enrolled in the bill discount program?

A. I examined the impacts of the Company's RS 2 Residential proposal on customers that are currently enrolled in Schedule L (Residential Bill Discount Program). I found that the average bill across all months would be 2 cents lower under the Company's proposal before any Schedule L discounts have been applied. Table 7 below shows average bill changes comparing the Company's $10.00 fixed charge proposal against the status quo ($8.00) for customers currently enrolled in the bill discount program

using greater or lesser than 54.1 therms by month (the breakeven level of usage) by month prior to Schedule L discounts.

Table 7



Note: The data in Table 7 is presented in Exh. RJW-16.

Table 7 above shows that RS 2 Residential customers enrolled in the bill discount program that use greater than 54.1 therms in the months of January and February will realize bills that are on average $2.80 and $2.20 lower, respectively, under the Company's proposal compared to the status quo at proposed rates in this proceeding. Of all RS 2 Residential customers enrolled in the bill discount program, roughly 85 percent would realize lower bills in each of these two months under the Company's proposal. For the remaining 15 percent that would receive higher bills, those amounts would average $0.91 and $0.84 in January and February, respectively. The average total bill would be $51.80 and $54.88 in January and February for these 15 percent of customers, compared to a total average bill of $218.81 and $191.85 in the

same months for customers that use greater than 54.1 therms. Therefore, although the cohort of customers that use less than 54.1 therms would realize higher on average bills in these months, those bills are over 70 percent lower compared to the average bills for customers that use greater than 54.1 therms. These figures are prior to the application of any Schedule L bill discounts.

Table 8 below presents the average bill comparison between the Company's $10.00 proposal and the $8.00 fixed charge status quo as shown above in Table 7 above, but with Schedule L bill discounts applied across each income tier. The bill discount is applied on the entire bill (both fixed and volumetric charges), therefore, the difference in average bills under both scenarios is lower when the Schedule L bill discount is steeper for customers using both greater or lesser than 54.1 therms.

Table 8
RS 2 Residential Bill Discount Enrolled Customer
Average Bill Changes:
Proposed Fixed Charge Compared to Status Quo
at RY2 Proposed Rates,
by Month by Usage Category
by Schedule L Bill Discount Tier

	Avg RY2 Bill at $8.00 Fixed Charge *Prior to Discount*	Avg RY2 Bill Difference at $10.00 Fixed Charge Based on Usage Above/Below Breakeven Amount									
		Usage Greater than 54.1 therms					Usage Less than 54.1 therms				
		Share	Tier 0	Tier 1	Tier 2	Tier 3	Share	Tier 0	Tier 1	Tier 2	Tier 3
		%	80%	40%	20%	15%	%	80%	40%	20%	15%
Jan	$ 198.82	86.6%	$ (0.56)	$ (1.68)	$ (2.24)	$ (2.38)	13.4%	$ 0.18	$ 0.54	$ 0.73	$ 0.77
Feb	$ 170.75	83.4%	$ (0.44)	$ (1.32)	$ (1.76)	$ (1.87)	16.6%	$ 0.17	$ 0.50	$ 0.67	$ 0.71
Mar	$ 146.10	77.8%	$ (0.34)	$ (1.03)	$ (1.37)	$ (1.46)	22.2%	$ 0.16	$ 0.47	$ 0.62	$ 0.66
Apr	$ 96.13	48.6%	$ (0.19)	$ (0.57)	$ (0.76)	$ (0.81)	51.4%	$ 0.15	$ 0.45	$ 0.60	$ 0.64
May	$ 73.59	26.1%	$ (0.15)	$ (0.45)	$ (0.60)	$ (0.63)	73.9%	$ 0.16	$ 0.49	$ 0.66	$ 0.70
Jun	$ 47.65	6.4%	$ (0.14)	$ (0.43)	$ (0.57)	$ (0.61)	93.6%	$ 0.22	$ 0.66	$ 0.87	$ 0.93
Jul	$ 29.92	0.9%	$ (0.26)	$ (0.78)	$ (1.04)	$ (1.10)	99.1%	$ 0.28	$ 0.83	$ 1.11	$ 1.18
Aug	$ 25.12	0.5%	$ (0.39)	$ (1.16)	$ (1.55)	$ (1.64)	99.5%	$ 0.30	$ 0.89	$ 1.19	$ 1.26
Sep	$ 27.75	0.7%	$ (0.39)	$ (1.18)	$ (1.57)	$ (1.67)	99.3%	$ 0.29	$ 0.86	$ 1.15	$ 1.22
Oct	$ 38.57	3.6%	$ (0.13)	$ (0.38)	$ (0.51)	$ (0.54)	96.4%	$ 0.25	$ 0.75	$ 0.99	$ 1.06
Nov	$ 91.05	43.3%	$ (0.21)	$ (0.63)	$ (0.84)	$ (0.89)	56.7%	$ 0.17	$ 0.52	$ 0.69	$ 0.73
Dec	$ 174.70	82.9%	$ (0.47)	$ (1.40)	$ (1.86)	$ (1.98)	17.1%	$ 0.17	$ 0.52	$ 0.69	$ 0.73

Note: The data in Table 8 is presented in Exh. RJW-16.

The first column of Table 8 above shows the RY2 average bill at the current $8.00 monthly fixed charge for enrolled bill discount customers, prior to Schedule L bill discounts. The remaining columns show the difference in average bill for each bill discount tier based on whether a RS 2 Residential customer uses above or below the breakeven amount (54.1 therms), and the percentage of customers in each usage category. Table 8 above indicates that for the roughly 86.6 and 83.4 percent of all RS 2 Residential customers enrolled in the bill discount program that use greater than 54.1 therms in January and February, respectively, their bills will be lower by an amount that more than offsets the higher bills for the minority of customers in those months (for instance, the table shows Tier 3 bills being $2.38 lower for the higher using customers but higher by a lesser amount, $0.77, for lower using customers in January). For Tier 0 customers that are in the 13.4 and 16.6 percent share of all customers that use less than 54.1 therms in these two months, their average bills will be just about 18 (January) and 17 (February) cents higher under the Company's proposal. In low usage months such as August where only about 0.5 percent of RS 2 Residential customers use greater than 54.1 therms, bills would be just about 30 cents higher for Tier 0 customers that use less than 54.1 therms at a time of the year usage (and total bills) are at their lowest. As indicated in Table 8 above, August average bills ($25.12) are about 87.4 percent lower than January bills ($198.82) prior to bill discounts.

Q. Based on your analysis of impacts of the Company's monthly fixed charge proposal on RS 1 and RS 2 Residential customer bills, including those customers currently enrolled in the bill discount program, what do you conclude?

A. I find that the Company's RS 1 and RS 2 Residential monthly fixed charge proposals, as compared to retaining the existing monthly fixed charges, would result in lower winter bills for a majority of customers (including a majority of customers enrolled in the bill discount program) at the time of year bills are at their highest. For the minority of customers that would realize higher winter bills, (1) their overall bills are already lower than that of the majority because they are lower using customers; and (2) the amount by which the minority would realize higher bills, the majority would realize lower bills by an even greater amount. The Company's proposal would instead result in slightly higher summer bills for a majority of customers (including a majority of customers enrolled in the bill discount program) at the time of year bills are at their lowest (for instance, average bills are over 87.4 percent lower in August for RS 2 Residential). All else equal, the Company's proposal provides rate relief to those customers that have the highest bills (e.g., the highest users) at a time of year their bills are highest. This includes 86.6 percent of RS 2 Residential customers enrolled in the bill discount program in the month of January. It provides this relief by equitably shifting some fixed cost recovery to just lower using customers in the winter months and to most customers in the summer months. Yet, the higher summer bills are more than offset by the lower winter bills (for instance, as shown in Table 8 above, an average RS 2 Residential August bill would be higher by $1.49, but an average January bill would be lower by $2.80). As demonstrated by the analysis above, the Company's RS

1 and RS 2 Residential monthly fixed charge proposals would align fixed cost recovery fairly and equitably for all customers including those enrolled in the bill discount program.

Q. Do you believe that the higher monthly fixed charges proposed by the Company would minimize the conservation price signal through the volumetric charge?

A. No. The Company adds an adjustment to the volumetric billing rate of every customer's bill for recovery of costs associated with the Washington Climate Commitment Act ("CCA") for every therm of usage. Regardless of the monthly fixed charge, all customers will continue to see the same usage-based price signal on every therm, which avoids disincentivizing conservation because customers can continue to lower their bills by lowering their usage.

2. Rate Spread

Q. What is NW Natural's total incremental revenue requirement?

A. NW Natural has filed for an incremental revenue requirement of $25.6 million for RY1, $8.6 million for RY2, and $8.3 million in RY3 in this case. See Exh. KTW-1T.

Q. Is any of the incremental revenue requirement in the MYRP attributable to special contract customers?

A. No. The special contract customers are not allocated any of the incremental revenue requirement given they are under fixed cost contracts. Further, there are currently no special contract customers in the Company's Washington service territory.

Q. How does the EmCOSS relate to rate spread?

A. The EmCOSS provides the embedded capital investment and O&M costs, by functional category, and gives insights into cost causation across customer classes. In theory,

spreading the incremental revenue requirement such that all schedules have a Parity Ratio at Present Rates of 1.00 would align all customers to their indicated level of cost causation. In practice, rate spread (and rate design) tends to deviate from this strict application of cost study results, given such a change in the short-run would violate principles of acceptable rate impacts and smoothing, neither of which violations would be in the Company's or the customer's interests. It is also important to balance the interests of rate equity with rate volatility. The EmCOSS does, however, provide a baseline for incremental revenue requirement allocation by rate schedule.

Q. What are NW Natural's thoughts on using the EmCOSS results to spread revenue requirement?

A. NW Natural values the EmCOSS outputs as a baseline for understanding the basis of cost causality among the rate classes. Of course, as stated above, there are other important factors that should be considered, most importantly the idea that equitable distribution of the rate spread should be balanced with customer rate impacts. If the Company were to spread revenue requirement across rate schedules strictly in a way that results in each rate schedule paying its share of its embedded costs (i.e., if all schedules were suddenly brought to parity with their indicated cost causality), such a shift would result in substantially higher rates for many customers and perhaps inadvertently trigger rate volatility. The Company does not have a rigid standard for what constitutes unacceptable rate impacts, but rather analyzes its EmCOSS results on a case-by-case basis in conjunction with regulatory precedent, principles, and the specific nature of the rate increase in the rate case.

Table 9 below shows the amount of incremental revenue requirement that would need to be spread to each rate schedule in order to put each class in line with paying its embedded costs per the results of this EmCOSS. The sum total of the amounts in Table 9 equals the full incremental RY1 revenue requirement in this case of $25.6 million. The values in this table (Total Net Income Deficiency (Sufficiency)) are derived in Exh. RJW-12 at Row 22 of tab, "E Summary of Results."

Table 9
EmCOSS Indicated Total Incremental
Revenue Requirement Deficiency (Sufficiency),
by Rate Schedule

RATE SCHEDULE	01 R	02 R	27 R	01 C	03 C	03 I	41 CSF	42 CSF
EmCOSS Determined Target Revenue	$803,302	$22,031,975	$138,144	$50,652	$4,066,841	$43,387	($299,192)	($158,230)
RATE SCHEDULE	**42 CSI**	**41 ISF**	**42 ISF**	**42 ISI**	**41 CTF 41 ITF**	**42 CTF**	**42 ITF**	**42 CTI 42 ITI**
EmCOSS Determined Target Revenue	$69,351	($111,354)	($174,639)	($43,830)	($33,725)	($2,876)	($138,627)	($683,436)

As seen in Table 9 above, RS 2 Residential customers would bear the largest share of the incremental revenue requirement increase, followed by RS 3 Commercial customers if the Company were to adhere strictly to the indicated EmCOSS results. On a percent of total revenue basis, the indicated increase would be 29.7 percent and 16.1 percent for the RS 2 Residential and RS 3 General Commercial rate schedules, respectively. On a percentage basis, RS 1 Residential and RS 1 Commercial would see the largest increases at 139.1 percent and 144.5 percent, respectively. The customers within the RS 41 and RS 42 rate classes would all realize rate reductions under such a scenario, the one exception being RS 42 Commercial Sales Interruptible.

NW Natural believes that the factors of fairness and minimizing rate impact weigh in favor of not realigning rates completely to their indicated cost causality based on the results of the EmCOSS in this rate case, which would require higher rate increases for some schedules while others receive decreases. A strict application of the EmCOSS results across all rate schedules would not be consistent with fundamental principles of rate design and rate structure, such as the third Bonbright Principle: "Stability and predictability of the rates themselves, with a minimum of unexpected changes that are seriously adverse to utility customers and with a sense of historical continuity."[23]

The Company understands that rate design principles, such as the Bonbright Principles, taken together, can be overlapping in nature and they do not offer any rules of priority. Ratemaking consists of finding a reasonable balance between these guidelines, where strict application of economic principles of optimum pricing may yield to regulatory, historical, and social factors.

Q. Please describe the Company's rate spread proposal.

A. The Company proposes to spread incremental revenue requirement in such a manner that is responsive to the results of the EmCOSS. I describe the Company's rate spread methodology in detail below. First, for RS 1 Residential, RS 1 Commercial, and RS 27 Dry-Out, I propose to use a separate cap for each rate schedule that moves each of these schedule's relative position closer to parity with respect to the EmCOSS results, because these schedules are paying less than their cost to serve at current rates. For RS

[23] *Id*. at 383.

2 Residential, which is also paying less than its cost to serve at current rates, I propose a cap that moves the schedule closer to revenue parity but is just lower than margin parity in the interest of balancing a lower rate increase with fairness for other rate classes. I propose a cap for RS 3 General Commercial that allocates slightly more than the average margin increase to this schedule. Second, I propose to apply an increase equal to the amount to retain revenue parity to all rate schedules with an EmCOSS-indicated parity ratio at 1.20 and lower plus RS 41/42 Commercial Sales Firm to recognize that while these schedules are overpaying their cost to serve at present rates, they are not overpaying at the same relative level as the remaining rate schedules. Third, the remaining revenue requirement is allocated to all remaining rate schedules using the same revenue floor, also in recognition of the EmCOSS results. As a result of the application of the floor, the relative position to revenue parity of the applicable rate schedules with respect to the overall indicated EmCOSS results will decrease, reflecting the fact that these classes are paying more than their cost to serve at current rates. This final step essentially allocates the remaining revenue requirement on an equal percent of margin basis among the remaining rate schedules, which include all industrial sales interruptible rate schedules, as well as all commercial and industrial transportation firm and transportation interruptible rate schedules in the RS 41/42 rate classes.

The Company's proposal equitably distributes the incremental revenue requirement such that the rate classes are moved closer to or retain margin parity based on their EmCOSS-indicated cost causation, except for RS 2 Residential and RS 3 General Commercial which are allocated amounts just below and just above the

amounts meant to roughly retain their indicated parities. The proposal described above is an incremental approach; it moves most rate classes closer to (or retains) parity but does so in a manner that works to minimize rate shock. It does this by balancing the impact to residential customers while taking incremental steps towards the EmCOSS-indicated parity for larger volume customers who are farthest from parity.

Q. Please describe the methodology NW Natural proposes to use to spread the $25.6 million RY1 incremental revenue requirement.

A. NW Natural proposes a multi-step process for spreading the $25.6 million RY1 incremental revenue requirement:

1. Apply a cap equal to 1.25 times the overall incremental revenue increase of 22.8 percent to RS 1 Residential and RS 1 Commercial. This cap is equal to a 28.5 percent revenue increase.
2. Apply a cap equal to 0.99 times the overall incremental margin increase of 39.5 percent to RS 2 Residential. This cap is equal to a 23.0 percent revenue increase, just above the overall incremental revenue increase of 22.8 percent proposed for this case.
3. Apply a cap equal to 1.10 times the overall incremental margin increase of 39.5 percent to RS 3 General Commercial. This cap is equal to a 24.2 percent revenue increase.
4. Apply a cap equal to 2.00 times the overall incremental margin increase of 22.8 percent to RS 27 Dry-Out. This cap is equal to a 45.6 percent revenue increase.
5. Apply an equal percent of incremental margin allocation equal to a 39.5 margin increase to all rate schedules with an EmCOSS-indicated parity ratio at 1.20 and

lower plus RS 41/42 Commercial Sales Firm. Depending on rate schedule, this equates to revenue increases below the overall incremental revenue increase of 22.8 percent ranging from 14.5 percent to 21.2 percent.

6. Apply a floor based on equal percent of margin increase of the remaining incremental revenue requirement to the remaining rate schedules in the RS 41/42 rate classes. This step results in the same proposed margin increase for each of these schedules (27.4 percent) which is less than the overall margin increase of 39.5 percent, and revenue increases ranging from 10.6 percent to 27.4 percent. The effect of this step would be the same as applying a floor equal to 0.69 times the overall incremental margin increase in this case.

Q. Do you present this rate spread methodology in an exhibit to this testimony?

A. Yes. I present this rate spread allocation proposal methodology in Exh. RJW-17.

Q. Please describe how this rate spread proposal impacts each rate class relative to an equal percent of margin spread.

A. RS 1 Residential, RS 1 Commercial, RS 2 Residential, RS 3 General Commercial, and RS 27 Dry-Out will receive a revenue spread greater than an equal percent of margin share calculated across all rate schedules. RS 27 Dry-Out will receive the highest relative increase, at a percentage double that of an equal percent of margin share. The rate schedules with a parity ratio below 1.20 plus RS 41/42 Commercial Sales Firm will receive a revenue spread equal to that of an equal percent of revenue share. The remaining rate schedules (including those with industrial interruptible and/or transportation service), as indicated above, will receive a spread less than an equal

percent of revenue share, a lower rate relative to other rate schedules in the RS 41/42 rate classes.

Q. How does this rate spread proposal impact the EmCOSS-indicated parity ratios?

A. This rate proposal moves the parity ratio for nearly every rate schedule closer to unity (e.g., to a value of 1.0). The Parity Ratio at Proposed Rates is presented in Exh. RJW-12 at Row 36 of tab, "E Summary of Results."

Q. Are there any components of the $25.6 million revenue requirement that are already included, but are removed and spread separately?

A. Yes. We must first remove the temporary plant excess deferred income taxes ("EDIT") amortization credit of $530 thousand from the $25.6 million incremental revenue requirement in RY1 in order to calculate a billing adjustment for Schedule 305. After RY1, this amount is embedded in rates and there are no further adjustments necessary for RY2 or RY3.

Q. Please explain how NW Natural proposes to spread the plant EDIT amortization credit.

A. The Company proposes to spread the plant EDIT credit to all rate schedules using the same rate spread methodology as described above.

Q. Are there any additional proposed rates that you spread after the base revenue requirement of $25.6 million has been applied in RY1?

A. Yes. The Company proposes to spread the proposed Meter Modernization Program deferral on an equal percent of margin basis to all rate schedules after the proposed $25.6 million incremental revenue requirement has been spread for RY1 as described above. Similarly, the Company proposes to spread the COVID-19 and Transportation

Security Administration ("TSA") O&M Startup deferrals in the same manner. Each deferral is described in greater detail in Exh. KTW-1T.

Q. How does the Company propose to spread its incremental RY2 and RY3 revenue requirement?

A. The Company proposes to spread the incremental RY2 ($8.6 million) and RY3 ($8.3 million) revenue requirement in the same manner as RY1 as described above.

Q. Are there any additional proposed rates that you spread after the base revenue requirement has been applied in RY2 and RY3?

A. Yes. The Company also proposes to spread the additional rates noted above based on an equal percent of margin basis to all rate schedules after the proposed incremental revenue requirements have been spread for RY2 and RY3 as described above. Additionally, in RY3, the Company proposes the TSA Cost of Service deferral.

Q. What is the effect of the Company's fixed monthly charge proposal, as described earlier, on the rate spread methodology?

A. The Company's fixed monthly charge proposals are revenue neutral, meaning that once the incremental revenue requirement to be spread is determined the fixed charge proposal only impacts how revenues are assigned for calculation of the fixed and volumetric billing determinants.

Q. Do you present the proposed rate spread allocations in an exhibit to this testimony?

A. Yes. I present the proposed rate spread allocations and calculated billing determinants in Exh. RJW-18.

V. RESULTS AND BILL IMPACTS

Q. What is the rate impact to firm sales customers for the revenue requirement components?

A. Table 10 below shows the combined incremental revenue requirement of $25.6 million net of the $530 thousand plant EDIT credit (i.e., margin revenues only) with an average bill increase presented in this case for firm sales customers. These impacts are also presented in Exh. RJW-18, in the tab "Rate Impacts – Revenue Requirement Only."

Table 10
Incremental Revenue Requirement (Margin Revenues)
and Average Bill Increase,
Firm Sales Customers Only

	Rate Year One		Rate Year Two		Rate Year Three	
Rate Schedule	Revenue Req. Increase	Pct. Increase to Avg. Cust. Bill*	Revenue Req. Increase	Pct. Increase to Avg. Cust. Bill*	Revenue Req. Increase	Pct. Increase to Avg. Cust. Bill*
01 R	$ 164,292	25.9%	$ 54,539	6.8%	$ 49,858	5.8%
02 R	$ 17,050,169	21.5%	$ 5,778,671	5.9%	$ 5,501,608	4.6%
27	$ 95,340	36.9%	$ 19,088	5.4%	$ 18,804	5.0%
01 C	$ 9,999	25.6%	$ 3,169	6.4%	$ 3,122	6.0%
03 C	$ 6,131,413	22.7%	$ 1,923,010	5.8%	$ 1,894,435	5.3%
03 I	$ 45,088	21.5%	$ 15,156	6.0%	$ 14,930	4.9%
41 C Firm Sales	$ 777,441	20.9%	$ 261,344	5.8%	$ 257,440	5.4%
41 I Firm Sales	$ 119,329	14.3%	$ 53,288	5.6%	$ 52,496	4.6%
42 C Firm Sales	$ 259,563	20.9%	$ 87,249	5.8%	$ 85,950	5.4%
42 I Firm Sales	$ 138,242	18.0%	$ 61,739	6.8%	$ 60,811	5.5%
Total All Schedules**	**$ 25,557,678**		**$ 8,591,020**		**$ 8,268,228**	

* The average customer bill impact figure calculation excludes pipeline capacity charges for RS 41 and RS 42 rate classes, and thus the rate impacts for these schedules are overstated.
** The proposed margin revenue increase is based on volumetric billing rates rounded to the fifth decimal as necessitated by the Company's tariff. Therefore, there may be a small discrepancy with the indicated revenue requirement presented in Exh. KTW-1T. The total represents all rate schedules, not just the ones presented in Table 10 above.

Q. What is the rate impact to firm sales customers for all of the rate components presented in this case combined?

A. Table 11 below shows the combined incremental revenue requirement (total revenues combined) and average bill increase of all the rate components presented in this case for firm sales customers. This table includes the incremental revenue requirement shown in Table 10 above combined with the impacts of the proposed deferrals as identified earlier. These impacts are also presented in Exh. RJW-18, in the tab "Rate Impacts – Combined."

Table 11
Combined Incremental Revenue Requirement (All Revenues)
and Average Bill Increase for all Rate Components,
Firm Sales Customers Only

	Rate Year One		Rate Year Two		Rate Year Three	
Rate Schedule	**Revenue Req. Increase**	**Pct. Increase to Avg. Cust. Bill***	**Revenue Req. Increase**	**Pct. Increase to Avg. Cust. Bill***	**Revenue Req. Increase**	**Pct. Increase to Avg. Cust. Bill***
01 R	$ 166,395	26.3%	$ 56,312	6.8%	$ 55,974	6.3%
02 R	$ 17,248,023	21.8%	$ 5,977,444	5.2%	$ 6,154,177	5.0%
27	$ 95,821	37.1%	$ 19,723	5.4%	$ 20,936	5.4%
01 C	$ 10,110	25.9%	$ 3,271	6.4%	$ 3,476	6.5%
03 C	$ 6,195,208	23.0%	$ 1,986,780	5.8%	$ 2,110,586	5.7%
03 I	$ 45,604	21.8%	$ 15,657	5.5%	$ 16,590	5.3%
41 C Firm Sales	$ 786,354	21.1%	$ 269,997	5.8%	$ 286,128	5.8%
41 I Firm Sales	$ 121,315	14.5%	$ 55,059	5.1%	$ 58,239	5.0%
42 C Firm Sales	$ 262,532	21.2%	$ 90,426	5.8%	$ 94,780	5.8%
42 I Firm Sales	$ 140,540	18.3%	$ 64,161	6.3%	$ 66,895	5.9%
Total All Schedules**	**$ 25,851,105**		**$ 8,884,182**		**$ 9,232,823**	

* The average customer bill impact figure calculation excludes pipeline capacity charges for RS 41 and RS 42 rate classes, and thus the rate impacts for these schedules are overstated.
** The proposed revenue increase is based on volumetric billing rates rounded to the fifth decimal as necessitated by the Company's tariff. Therefore, there may be a small discrepancy with the indicated revenue requirement presented in Exh. KTW-1T. The total represents all rate schedules, not just the ones presented in Table 11 above.

Q. Does your testimony present the revenue and rate changes applicable to all other rate schedules as well?

A. Yes. Exh. RJW-18 shows the derivation of the revenue increases and average bill impacts by rate schedule for the revenue requirement effects and for the combined rate components shown in Table 10 and Table 11 above. Exh. RJW-18 also contains the volumetric rate increases by rate schedule and block, as well as the proposed billing determinants in the tab, "Proposed Rates - Combined."

V. SCHEDULE 10 TARIFF UPDATE

Q. What does the Company propose with regards to tariff Schedule 10?

A. Yes. The Company requests revisions to tariff Rate Schedule 10 – Charges for Special Metering Equipment, Rental Meters, and Metering Services (referred to here as RS 10 Metering Services, or "Schedule 10") to replace the existing meter rental rates for diaphragm and rotary meters with a descriptive formula that defines the calculation of the rental meter rate based on the cost of meter requested.[24]

Q. What is tariff Schedule 10?

A. Schedule 10 is an optional tariff schedule that enables customers to rent meters and metering services based on a monthly charge currently specified in the tariff for both diaphragm and rotary meters. Schedule 10 includes the terms and conditions of meter rental, as well as rates for various rotary and diaphragm meter sizes. Customers taking service under Schedule 10 enter into a rental meter agreement with the Company.

[24] This excludes diaphragm and rotary meters listed on Sheet 110.1 where monthly charges have been retained under service agreements prior to April 27, 2018, based on meter type and installation date.

Q. Why is the Company proposing revisions to Schedule 10?

A. Currently, Schedule 10 includes two tables of meters (one for diaphragm meters and one for rotary meters) delineated by size and capacity with a corresponding monthly charge rate on Sheet 110.1. The meters found on these tables, however, may not always match the Company's inventory in stock because meter inventory and their related costs can change periodically. NW Natural's Engineering department conducts research and testing on various meters and determines the meters that should be included in NW Natural's meter inventory. Instead of filing frequent tariff changes to keep up with the meters that are in inventory (especially where inventory changes do not align with general rate case proceedings), NW Natural proposes that it would be more efficient to include a cost of service formula in the tariff rather than list specific rates based on meters that may or may not be in inventory. The formula, an explanation of how to use it to calculate the monthly meter rental rate, and any necessary definitions would be included in the Schedule 10 tariff. Under the Company's proposal, customers taking service under Schedule 10 will enter into a rental meter agreement with the Company that will reflect the meter rental rate as calculated in the formula found in the tariff.

Q. How will the Company communicate the Schedule 10 monthly meter rental rates to customers?

A. The Company proposes to replace the current rates listed in the Schedule 10 tariff for diaphragm and rotary meters on Sheet 110.1 with a descriptive formula that will calculate the rate applied to rental meters regardless of size. NW Natural will continue the practice of consulting with customers choosing to rent supplementary meters

regarding available meters that meet their service requirements prior to entering into a rental agreement that will include the rental meter charge as determined by the formula. Thereafter, it is expected that rental meter charges will be updated when the Company's authorized cost of capital changes, typically with each general rate case effective date.

Q. Please describe the proposed Schedule 10 formula.

A. The Schedule 10 formula is the same as the one that is currently used to calculate the monthly meter rental rates, which in summary is the net present value of the cost of service of the meter divided by 12. The cost to serve is generally comprised of the cost of the rental meter and other costs customarily related to the revenue requirement of utility investment, including, but not limited to, depreciation expense, return on investment, income taxes, property and other taxes, operating maintenance costs, and revenue-sensitive costs. The cost of the meters available for rental is inclusive of an Encoder Receiver Transmitter (ERT), if necessary, as well as required fittings and components (e.g., swivel, gasket, flange) which can vary by meter type and size. An additional description of the components of the meter rental rate formula is found on proposed Sheets 110.1 and 110.2 filed with this proceeding.

Q. How many meters are currently being rented under Schedule 10?

A. As of November 2024, there were 28 diaphragm and rotary meters of the types listed on Sheet 110.1 being rented to customers in Washington under Schedule 10, of which 10 are meters of the types listed and installed under prior service agreements prior to the date indicated on Sheet 110.1).

Q. Is the Company proposing any other changes to Schedule 10?

A. Yes. The Company is proposing to increase the Administrative Set-Up / Consultation and Technical Assistance Fees found on Sheet 110.2 from $100.00 to $145.00. These new rates are based on updated current labor rates for customer field service ("CFS") technicians inclusive of payroll overhead and vehicle costs using an assumption that these tasks require one and a half hours to complete on average. This calculation is presented in confidential Exh. RJW-19C.

Q. What service do the CFS technicians provide associated with these fees?

A. Company technicians at the CFS 4 level, which is classified as a Major Account Services Field Technician, complete meter rental service requests for customers. For Administrative Set-up/Consultation calls, CFS 4 Technicians will work with the customer to determine appropriate meter volume, location, type and model, and will work with the Company's meter shop on design specific to the customer's premises. The technician will also help the customer, if requested, complete a rental application. This work is completed for both rotary and diaphragm rental meters.

Further, CFS 4 Technicians complete Technical Assistance calls for rental meters. Rotary meters require more technical work, including assembly and reading calibration and care for moving parts (e.g., are properly oiled), during set-up compared to diaphragm meters.

Q. Why does the Company believe its Schedule 10 fee proposal is reasonable?

A. These fees have been included in the Schedule 10 tariff since at least 2004. The Schedule 10 tariff effective July 1, 2004 (with Advice No. WUTC 04-1), did not include an Administrative Set-Up/Consultation Fee, but did include two Technical

Assistance Charges: A Technical Assistance Charge (Rotary meters only) of $200, as well as a Technical Assistance Charge (Diaphragm meters) of $100. Under the current Schedule 10 tariff, the $200 Technical Assistance Charge (Rotary meters only) is set to $100 and an additional (and complementary) Administrative Set-Up/Consultation Fee (All meters) of $100 was designated. Per the Special Provisions on Sheet 110.2 of the Schedule 10 tariff, the Administrative Set-Up/Consultation Fee is incurred for each rental meter (rotary and diaphragm), meaning that the total cost incurred for delivery of each rental rotary meter has remained $200 since 2004.

Using 2004, when Advice No. WUTC 04-1 became effective, as a comparison baseline means that the Company's proposal (a 45 percent increase) is less than the increase in average consumer prices (69.0 percent) and average nominal wages (85.7 percent) from then until now.[25]

Q. Where are the proposed changes to Schedule 10 presented?

A. The proposed changes to the Schedule 10 tariff are presented on proposed Sheets 110.1 and 110.2 filed with this proceeding.

Q. Do the Company's proposed changes to Schedule 10 impact any other rate schedules?

A. No. The purpose of these changes is to continue to align the costs borne by customers using services under Schedule 10 to those customers only.

[25] The comparison figures were derived from the Federal Reserve Economic Database, series CPIAUCSL (Consumer Price Index for All Urban Consumers: All Items in U.S. City Average) and LES1252881500Q (Employed full time: Median usual weekly nominal earnings: wage and salary workers: 16 years and over).

Q. Does this conclude your Direct Testimony?

A. Yes.

VI. LIST OF EXHIBITS

Exh. RJW-2	Normal Weather Model
Exh. RJW-3	Normal UPC Model
Exh. RJW-4	New Premises UPC Model
Exh. RJW-5	Load Study
Exh. RJW-6	Load Study Sampling Methodology
Exh. RJW-7	Load Study Regression Analysis and Model Verification
Exh. RJW-8	Mains and Services Special Study for EmCOSS
Exh. RJW-9	Meters Cost Special Study for EmCOSS
Exh. RJW-10	Account Services Cost Special Study for EmCOSS
Exh. RJW-11	Design Day Load Factor Derivation for EmCOSS
Exh. RJW-12	Embedded Cost of Service Study (EmCOSS) – Primary Model Using Normal UPC Results
Exh. RJW-13	Embedded Cost of Service Study (EmCOSS) – Alternate Model Using Load Study Results
Exh. RJW-14	Fixed Charge Peer Comparison

Exh. RJW-15	RS 1 Residential Fixed Charge Proposal Analysis
Exh. RJW-16	RS 2 Residential Fixed Charge Proposal Analysis
Exh. RJW-17	Rate Spread Proposal Methodology
Exh. RJW-18	Rate Spread and Rate Allocation Model
Exh. RJW-19C	RS Schedule 10 Determination of Cost of Service (Confidential and Redacted)

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Robert J. Wyman

EMBEDDED COST OF SERVICE MODEL AND RATE DESIGN/SPREAD

Exh. RJW-5

August 29, 2025

Introduction

Washington Administrative Code ("WAC") 480-85-050 requires a utility to meet certain requirements for customer usage data granularity in its embedded cost of service Study ("EmCOSS") model, which includes inputs from advanced metering technology such as automated meter reading ("AMR") or a load study. For utilities with AMR capabilities, data from these meters may be used in the EmCOSS if the granularity of the data meets or exceeds the WAC requirement for daily meter data for a natural gas utility. If a utility does not have the technology to meet this daily meter data requirement, it must conduct a load study to inform its EmCOSS inputs. NW Natural falls into the latter category and has therefore developed this load study.

Per WAC 480-85-030(5), a load study is a "statistical analysis of load data collected from sampled customers to estimate the load profiles of customer classes over a minimum twelve-month period." For natural gas utilities, the load data must be collected at a daily granularity.

This document discusses the Company's sampling methodology, regression estimation techniques, and supporting documentation it used to develop its load study for UG-250610. The purpose of this load study is to derive a design day load factor using sampling of daily meter reading data for each of the Company's Washington rate schedules. The design day load factor is the ratio of normalized average usage to the estimated design day peak usage, expressed as a percentage. A low load factor ratio indicates that a rate schedule has high peaking load relative to normalized average usage (i.e., it indicates the rate schedule has high weather sensitivity as load peaks during cold weather events). A high load factor indicates less weather sensitivity and more predicable base load usage throughout the year. The load factor is the basis for the design day (peak) and annual throughput (average) allocator that the EmCOSS uses to allocate (in full or in part) distribution mains and assets, system core mains, and transmission main investment to each rate schedule. The results of this load study, therefore, aim to assign the relative cost to serve each rate schedule or class within the EmCOSS based on their contribution to peak demand.

Finally, this document presents the results of the load study and compares those results to the Company's design day load factor analysis as presented in Exh. RJW-1T.

AMR Deployment

NW Natural does not currently have AMR daily meter reading technology with daily read capabilities deployed throughout its entire service area but is in the process of a Meter Modernization Program that includes the expansion of daily meter reading abilities through AMR throughout the Company's Washington service territory. This process includes encoder receiver transmitter ("ERT") installation required for daily usage data. As described in greater detail in the Direct Testimony of Joe S. Karney, Exh. JSK-1T, ERT deployment implementation is based on geography and age of the meter. Through this process, the Company's customers in Clark County were forecasted to have full ERT installation by June of 2025, while the Company's customers in Klickitat and Skamania Counties in the Columbia River Gorge are forecasted to have ERT changes completed by the end of 2027. Therefore, because the Company does not currently have full coverage of daily reading capable meters for all customers across all rate schedules, it must use sampled daily read data from meters that do have this capability.

Per WAC 480-85-050 requirements, this load study requires at least twelve months' worth of daily meter readings from the sampled premises. Accordingly, the daily meter read capable premises selected in the sampling methodology, described in detail below, will show fewer premises with daily metering capability than the rollout of the Meter Modernization Program would suggest at the time of this filing because newly ERT capable meters will not be eligible for the load study for at least twelve months after being set.

Tables 1 through 3 below show the percentage of meters with daily meter reading capabilities, by county and sales firm rate schedule, as of January 1, 2025. Note that this is a point-in-time status of proportion of premises with daily metering capability and does not necessarily represent the number of premises used in this load study (especially applicable for rate schedules that show one hundred percent coverage).

Table 1
Clark County Sales Firm Premises
with Daily Metering Capability

Clark			
Rate Schedule	Total Meters	Daily Meters	% with Daily
C01	35	29	83%
C03	6,797	5,096	75%
C41SF	91	83	91%
C42SF	8	8	100%
I03	18	17	94%
I41SF	17	17	100%
I42SF	8	8	100%
R01	1,906	1,702	89%
R02	87,481	45,209	52%
R03	42	29	69%
R27	375	375	100%
Total	96,786	52,581	54%

Table 2
Klickitat County Sales Firm Premises
with Daily Metering Capability

Klickitat			
Rate Schedule	Total Meters	Daily Meters	% with Daily
C01	2	1	50%
C03	166	140	84%
C41SF	1	1	100%
I03	1	1	100%
I41SF	2	2	100%
R01	48	35	73%
R02	1,434	838	58%
R03	3	3	100%
R27	1	1	100%
Total	1,659	1,023	62%

Table 3
Skamania County Sales Firm Premises
with Daily Metering Capability

Skamania			
Rate Schedule	Total Meters	Daily Meters	% with Daily
C03	48	43	90%
R01	14	10	71%
R02	514	267	52%
R03	1	1	100%
Total	577	321	56%

Service Territory and Customer Characteristics

NW Natural serves customers in the SW region of Washington covering Clark, Klickitat, and Skamania counties. The Clark and Skamania County service area is more suburban and located within the Portland-Vancouver metro area while Klickitat County is more rural and is located at the eastern end of the Columbia River Gorge.

This service territory includes two primary National Oceanic and Atmospheric Administration ("NOAA") weather zones: Vancouver station and The Dalles. Observed weather data as presented in Exh. RJW-2 shows Vancouver experiences warmer winters and cooler summers with more rainfall year-round relative to The Dalles region in the Columbia River Gorge. The weather variation experienced by NW Natural's customers across its Washington service territory is an important variable when considering how to design the load study sampling methodology.

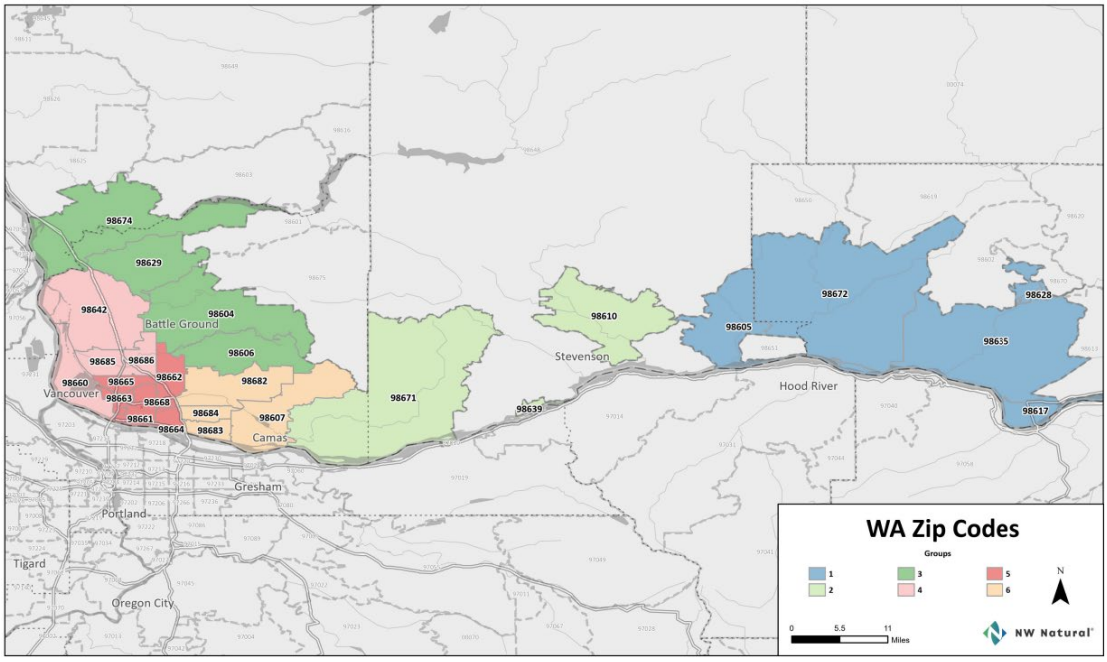
Premises Sampling Methodology

To ensure a representative sample of premises with sufficient daily read data, the Company considered how its Meter Modernization Program is being deployed as well as the temperature variability of its Washington service territory relative to where premises with twelve months of daily metering capable technology are available. Given AMR meters are being deployed in a geographically batched approach, if the Company were to simply use a sample size from the entire population of customers with daily metering capabilities, the load study sample would be biased to the premises located in areas that were in the earlier phases of the ERT replacement, such as the greater Vancouver metro area (e.g., Clark County and parts of Skamania County). In addition to recognizing and minimizing potential for geographic bias, the load study also ensures premises with daily meter reads used for sampling had three years of metering data (covering the calendar years 2022 through 2024) to best capture as much weather-related usage as possible. Due to year-over-year weather variability, customers can experience warmer or colder weather on any given calendar year; using multiple years of data ensures that the load study results are not contingent on data from just one winter heating season, as well as minimizes biasness due to short-term events such as service interruptions or economic factors that may, for instance, impact specific business sectors.

To get a geographically unbiased sample group, the Company started with a list of all active premises in the Company's Washington service territory as of March 31, 2025, and corresponding ZIP Code. The Company identified 26 unique ZIP Codes which it then organized into six groups ("strata") that were

geographically similar and would likely experience similar weather-related usage patterns. Using a stratified ratio sampling technique, the Company generated a sample of premises to achieve a balanced representation of its customer population in each ZIP Code strata. Refer to Table 4 below for map of the ZIP Codes in the Company's Washington service territory and the corresponding strata determined for this load study.

Table 4
Map of Washington Service Territory ZIP Codes by Sample Stratum



To determine the sample size by strata within each rate schedule for this load study, the Company identified which premises from the total customer count have daily metering data capabilities and matched them by ZIP Code to their geographic stratum. For each rate schedule, the Company calculated the total daily sample size required to achieve a 99 percent confidence level and confidence interval (e.g., margin of error) of 3 percent using a sample size estimator. Knowing the sample size criteria, the Company then broke out this number of customers proportionately amongst the six strata following the stratified sample formula (described below) to get the sampling amount of each of its six strata.

For example, given a total of 89,095 Rate Schedule ("RS") 2 Residential customers, the Company identified 11,066 customers as having daily metering data available every day for at least the past three years. To achieve a relevant sample of RS 2 Residential customers given the Company's sample criteria and with daily meter reads, it determined a sample size of 1,584 RS 2 Residential customers is necessary. To break this amount proportionately amongst the six strata, the Company took the proportion of its 1,584 sample from the 11,066 total customers with daily read capable meters and allocated the sample to the strata based on the size of each stratum. RS 2 Residential Stratum 1 is, for instance, comprised of 160 customers and the Company determined that a sample of 23 customers is required from Stratum 1

ZIP Codes.[1] The Company performed this calculation for each stratum until the total sample size for the rate schedule was apportioned across all strata.

This sampling technique provides the appropriate sample size needed of customers with daily read capabilities. To achieve a truly randomized sample, however, the Company then grossed up the daily read sample size to the entire population of customers. This step provides the total number of customers, regardless of whether they have daily meter reads, that will need to be sampled to get a randomized representation of just those customers with daily reads. Continuing the example for RS 2 Residential from above, there are 160 customers in Stratum1 ZIP Codes with daily reads, but out of the entire population of RS 2 Residential customers, there are 1,429 in Stratum 1. This means that the entire population of RS 2 Residential Stratum 1 customers is roughly nine times larger than just those with daily reads. Since the estimation calculated above shows the Company needed a sample size of 23 from just daily meters, grossing up sample size of 23 by a factor of nine times produces an amount customers needed to sample from the entire population. This calculation equates to 206 customers, a number that is expected to include the number of daily metered customers necessary for the Company's load study sample (23) if those 206 customers are randomly sampled.[2]

For the final step of the sampling methodology, the Company chose the load study premises using a randomized sampling approach for each stratum and the rate schedules noted below. To randomize, the Company took the entire customer population within these rate schedules as of March 31, 2025, by strata, and assigned a random number to each individual customer. Next, the Company sorted the entire group (1) by their stratum and then (2) their random number, which resulted in a fully randomized list of premises within each stratum. This process produced the number of premises required for the Company's sample set from each stratum. Continuing with the RS 2 Residential example, the sampling methodology indicated 206 premises from the total population of RS 2 Residential customers is necessary. Of those 206 premises, the Company needed at a minimum 23 of these premises to have daily metering capabilities to have a random sample at a 99 percent confidence level and a margin of error of 3 percent. The Company took a sample of 206 randomized premises from RS 2 Residential Stratum 1 and then matched this sample to its list of known daily meter capable premises. This process allowed the Company to identify total premises within the sample that have daily metering capabilities, which it could then compare to the minimum number of sampled premises required to meet the Company's standards for confidence and margin of error. If the count of daily read capable premises fell short of the Company's required amount for a given stratum, it increased the sample size for that stratum and sampled from the universe of premises (both daily read capable and incapable) to achieve the minimum daily meter read capable premises required as determined by the sampling formula.

The Company replicated the process described above for the schedules in the residential rate class (RS 1 Residential and RS 2 Residential) as well as the small commercial rate schedules (RS 1 Commercial, RS 3 Commercial). As indicated in Tables 1 through 3 above, many of the large volume rate schedules in the

[1] Stratified Sample Formula: Sample size of the strata = (size of entire sample /population size * strata size). In this example, the calculation is: 1,584/11,066*160 = 23.
[2] Daily sample size grossed up to all customers: (Count of customers with daily reads in strata/Count of all customers in strata * size of sample of strata calculated for daily reads). In this example, the calculation is: 1,429/160*23 = 206.

RS 41/42 rate classes plus RS 3 Industrial have one hundred percent daily read meter capable coverage. For those schedules in the RS 41/42 rate classes (and RS 3 Industrial) that do not have full daily read meter capable coverage, the Company found that, due to the small total customer size inherent of the its Washington large volume commercial and industrial customers, the sampling approach described above was not suitable (e.g., the number of customers needed to create a random sample at a 99 percent level with a 3 percent margin of error exceeds the total number of customers with daily read capable meters on that rate schedule). For these rate schedules, the Company examined the load profile of all customers with daily (and hourly) read capable meters and adjusted (if necessary) peak load demands based on the small number of large volume customers that still have non-AMR meters.

Daily Usage Data Collection and Aggregation Methodology

Once the Company derived a list of randomly sampled premises for each stratum for each of the residential and small commercial rate schedules identified above, it queried daily readings collected and reported by the AMR meters and stored in the Company's Customer Information System ("CIS"). Because the Company's random sample was designed to include premises with at least three years of daily readings, it pulled readings from January 1, 2022, through December 31, 2024, for a total of 1,096 days (365 days for each of the three years plus Leap Day 2024). This query resulted in 1,096 daily reading observations for every randomly sampled premises.

For each rate schedule that the Company randomly sampled, it aggregated these daily readings by day so that it had 1,096 total observations for each rate schedule. Using the number of sampled premises, the Company then derived therm usage per premises per day to be used as the dependent variable for the load study. This is consistent with the Company's weather normalized use per customer ("Normal UPC") analysis presented in Exh. RJW-1T, which uses weather normalized use per customer per day for each evaluated rate schedule as the dependent variable.

Daily Weather and Other Explanatory Variable Data Collection Methodology

The Company then matched the dependent variable usage data with normalized and design day weather using the Company's weather data model presented as Exh. RJW-2 in this proceeding and described in detail in Exh. RJW-1T. This model, which includes over thirty years of daily weather data, was the basis for the weather observations used in the Normal UPC analysis. The Company matched actual observed daily weather to usage per premises per day for the 1,096 days in the load study. It used the temperature data, translated into heating degree days ("HDDs"), to derive the HDD per day explanatory variable.

To evaluate the load study results against the Normal UPC analysis, as the Company explains in more detail below, it used the 30-year normalized weather for normalized usage prediction. As discussed in Exh. RJW-1T, the Company collects daily high and low temperature data observed in Vancouver (National Oceanic and Atmospheric Administration "NOAA" Station 94298 -- Vancouver Pearson Airport) and The Dalles (Bureau of Reclamation automated agricultural weather station network "AgriMet" station HOXO) for the period June 1, 1995, through May 31, 2025.

To derive the load study estimated design day load, the Company used its design day temperature assumption used as part of its resource planning processes. For NW Natural's 2022 Integrated Resource

Plan ("IRP"), the Company used a probabilistic planning standard to forecast peak load as function several key drivers. This planning standard sets a daily resource capacity requirement such that the Company would be 99 percent certain it would be capable of meeting load going into any winter. Using this methodology, the Company has calculated an average system weighted temperature around this planning standard of roughly 11-degrees Fahrenheit (47.9 and 46.9 HDDs for residential and commercial rate schedules using 59- and 58-degree Fahrenheit set points, respectively).

Consistent with the Normal UPC analysis, the Company included additional explanatory variables beyond standard HDDs which are a standard measure of weather in load forecasting analyses, including: Effective temperature, precipitation, solar radiation, wind speed, and wind chill. The use of multiple variables that measure weather are meant to control for the fact that day-of ambient temperature is not the only factor that can influence heat loss.

Additionally, the Company included (depending on the rate schedule model) monthly fixed effects to control for seasonality, an indicator variable for weekend and holiday days, and an indicator variable for heating months (November through April) only.

Load Study Regression Estimations

The Company developed statistical estimation models like those described in detail in Exh. RJW-1T so that it could compare the Company's current estimation techniques from the Normal UPC analysis to this load study to compare the accuracy of results estimating performance and fit. The Company used an Autoregressive Integrated Moving Average ("ARIMA") time series model to estimate weather normalized load per premises per day as the function of randomly sampled daily read capable customers and HDDs for the 1,096 days included in the load study. The results of the ARIMA model are used to help forecast both normalized and design day usage for each evaluated rate schedule.

Although the load study ARIMA models do not have model specifications that match the Normal UPC ARIMA models, the model specification selection process and model performance evaluation as described in detail in Exh. RJW-1T is consistent. For each of the models presented below, the Company evaluated the ARIMA models foremost on Durbin-Watson test statistics, r-squared values, and root mean squared error ("RMSE") results to assess model efficacy and determine model appropriateness.[3] The Company relied on root mean squared error results to evaluate the load study ARIMA models against the Company's Normal UPC ARIMA models.

The Normal UPC analysis uses billing cycle-based data that is matched to actual weather observations with the days between cycle meter read dates. Billing cycles are not necessarily tied to calendar months. For the Normal UPC analysis, this process ensures actual usage recorded for each billing period is appropriately matched to the observed weather for the same period. The daily read data used for this load study, however, is based on the calendar date the consumption occurred. Therefore, aggregating daily readings by month produces a mismatch between cycle-based months (which span calendar months) and consumption-based months (which are calendar months). The Company adjusted for this

[3] The Durbin-Watson test statistic, which is a test for autocorrelation, takes a value from 0 to 4. A value of 2 indicates no autocorrelation. A value less than 2 indicates positive autocorrelation, and a value greater than 2 indicates negative autocorrelation.

mis-match such that it could compare the Normal UPC analysis to the load study by aligning the cycle-based data to the halfway point (e.g., day 15) to the prior months' consumption data. This is because billing cycles for the following month begin halfway through the prior month. Data alignment was confirmed by examining graphs of the data which are presented below.

The load study regression estimations and evaluation against the Normal UPC is presented below by rate schedule and rate class. For each ARIMA model evaluated for this load study, the Company used fewer explanatory variables compared to the Normal UPC analysis out of necessity – the load study covers three heating seasons compared to the thirteen included in the Normal UPC analysis. It found some variables statistically insignificant in the load study that were significant in the Normal UPC analysis because more data in the time series is needed to establish a statistical trend in the data (which is especially true of macroeconomic data). The data that produces the tables below is presented in Exh. RJW-7.

RS 1 Residential

For the RS 1 Residential ARIMA model specification, the Company included an indicator variable for heating months only to control for seasonality. It found there was not enough statistical variation in RS 1 Residential customer usage between individual months to include twelve indicator variables. The Company chose a non-differenced ARIMA(2,0,2)(0,0,0)$_{[2]}$ specification for the model, which is as follows, where *m* is month and *y* is year:

$$\frac{R1\ UPC}{Day}m, y = \beta_1 \frac{R1\ HDD}{Day} + \beta_2 HeatingMonths + ARIMA(2,0,2)(0,0,0)_{[2]}$$

The RS 1 Residential load study model output is as follows:

```
ARIMA regression

Sample:  1 - 1096                               Number of obs     =       1096
                                                Wald chi2(6)      =   67493.63
Log likelihood =  1323.283                      Prob > chi2       =     0.0000

------------------------------------------------------------------------------
                     |                 OPG
R01UsePerCustomer_ADJ |      Coef.   Std. Err.      z    P>|z|     [95% Conf. Interval]
---------------------+--------------------------------------------------------------
R01UsePerCustomer_ADJ |
           RES_HDDDay |   .0230093   .0004826    47.67   0.000     .0220634    .0239553
        HeatingMonths |   .0371272   .0114965     3.23   0.001     .0145946    .0596598
                _cons |   .2213242   .0298149     7.42   0.000      .162888    .2797604
---------------------+--------------------------------------------------------------
ARMA                 |
                  ar |
                 L1. |   1.170885   .1945472     6.02   0.000     .7895792     1.55219
                 L2. |  -.1805552   .1913096    -0.94   0.345     -.555515    .1944047
                     |
                  ma |
                 L1. |  -.9036701   .1946289    -4.64   0.000    -1.285136   -.5222045
                 L2. |    .007695   .1664417     0.05   0.963    -.3185248    .3339148
---------------------+--------------------------------------------------------------
              /sigma |   .0723076   .0007094   101.92   0.000     .0709171     .073698
------------------------------------------------------------------------------
Note: The test of the variance against zero is one sided, and the two-sided
      confidence interval is truncated at zero.
```

This model produces an estimated annual UPC of 153.4 therms, which is 12.5 percent lower than the UPC of 175.3 therms estimated by the Normal UPCs analysis. The load study model produces a design day load that is 38.0 percent lower than that of the Normal UPC analysis (1.38 therms per customer compared to 1.89 therms). Table 5 below shows a comparison of the RS 1 Residential load study model against the Normal UPCs analysis and actual usage.

Table 5

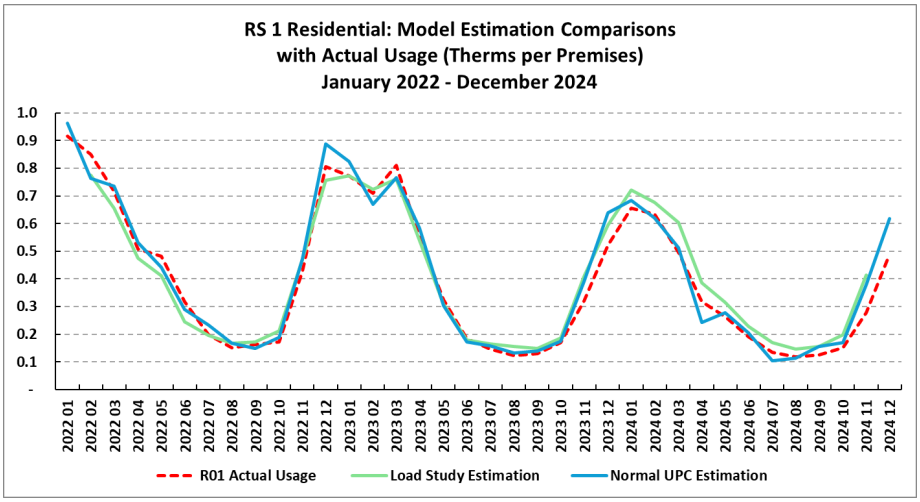


Table 5 shows that both the load study and the Normal UPC model each overpredict and underpredict the actual RS 1 Residential usage at times. The load study model under predicts in the winter and shoulder months of 2022 and overpredicts in the winter and shoulder months of 2024. The Normal UPC model overpredicts the winter peak in December 2022, but more closely predicts the winter peak in January 2024 compared to the load study model.

The Normal UPC model produces an RMSE value that is lower compared to the load study model (0.026 to 0.097, respectively). Other test statistics, such as Durbin-Watson, are similar. Based on the RMSE results, the Company concludes that the Normal UPC is the better estimator for RS 1 Residential.

RS 2 Residential

For the RS 2 Residential ARIMA model specification, the Company included an indicator variable for all months to control for seasonality. Further, it included additional weather variables (wind chill and radiation) as well as an indicator for weekends and holiday days. The Company chose a non-differenced ARIMA(2,0,2)(0,0,0)$_{[2]}$ specification for the model, which is as follows, where *m* is month and *y* is year. The variables and model specification chosen for this model align closely with the Normal UPCs RS 2 Residential model shown in Exh. RJW-1T.

$$\frac{R2\ UPC}{Day}m,y = \beta_1\frac{R2\ HDD}{Day} + \beta_2\frac{WindChill}{Day} + \beta_3\frac{SolarRadiation}{Day} + \beta_4 Jan_{=1} \ldots + \beta_{15} Dec_{=1} + \beta_{16} WeekendHolidayDays$$

$$+ ARIMA(2,0,2)(0,0,0)_{[2]}$$

The RS 2 Residential load study model output is as follows:

```
ARIMA regression

Sample:  1 - 1096                               Number of obs     =       1096
                                                Wald chi2(20)     =   92925.08
Log likelihood =  332.3048                      Prob > chi2       =     0.0000

------------------------------------------------------------------------------
                     |                 OPG
R02UsePerCustomer_ADJ |      Coef.   Std. Err.      z    P>|z|     [95% Conf. Interval]
---------------------+--------------------------------------------------------------
R02UsePerCustomer_ADJ |
           RES_HDDDay |   .1010192   .0013398    75.40   0.000     .0983931    .1036452
       WindChillValue |   .0031414   .0000986    31.87   0.000     .0029483    .0033346
            Radiation |  -.0000127   4.46e-06    -2.85   0.004    -.0000214   -3.95e-06
                  Jan |   .9920329   .0321285    30.88   0.000     .9290622    1.055004
                  Feb |   .9357089   .0336758    27.79   0.000     .8697057    1.001712
                  Mar |   .8419778   .0342328    24.60   0.000     .7748827    .9090729
                  Apr |   .7110592    .034001    20.91   0.000     .6444184       .7777
                  May |   .6580918   .0393463    16.73   0.000     .5809745    .7352091
                  Jun |   .5941356   .0615166     9.66   0.000     .4735653    .7147059
                  Jul |   .4851754    .154075     3.15   0.002      .183194    .7871568
                  Aug |   .4660253   .1534298     3.04   0.002     .1653085     .766742
                  Sep |   .5207765   .0728685     7.15   0.000      .377957    .6635961
                  Oct |   .6734636   .0333851    20.17   0.000     .6080299    .7388972
                  Nov |   .8794536   .0305304    28.81   0.000     .8196152     .939292
                  Dec |   .9722892    .033175    29.31   0.000     .9072674    1.037311
       WeekendHoliday |   .0169806   .0123613     1.37   0.170    -.0072471    .0412083
---------------------+--------------------------------------------------------------
ARMA                 |
                  ar |
                  L1. |   .5485354    .378239     1.45   0.147    -.1927995     1.28987
                  L2. |   .1238614   .2028867     0.61   0.542    -.2737892    .5215121
                      |
                  ma |
                  L1. |  -.2743389   .3779729    -0.73   0.468    -1.015152    .4664744
                  L2. |  -.1835089    .119886    -1.53   0.126    -.4184811    .0514632
---------------------+--------------------------------------------------------------
               /sigma |   .1786762    .002711    65.91   0.000     .1733627    .1839897
------------------------------------------------------------------------------
Note: The test of the variance against zero is one sided, and the two-sided
      confidence interval is truncated at zero.
```

This model produces an estimated annual UPC of 589.2 therms, which is 11.0 percent lower than the UPC of 662.3 therms estimated by the Normal UPC analysis. The load study model produces a design day load that is 17.6 percent lower than that of the Normal UPC analysis (6.30 therms per customer compared to 7.41 therms). Table 6 below shows a comparison of the RS 2 Residential load study model against the Normal UPCs analysis and actual usage.

Table 6

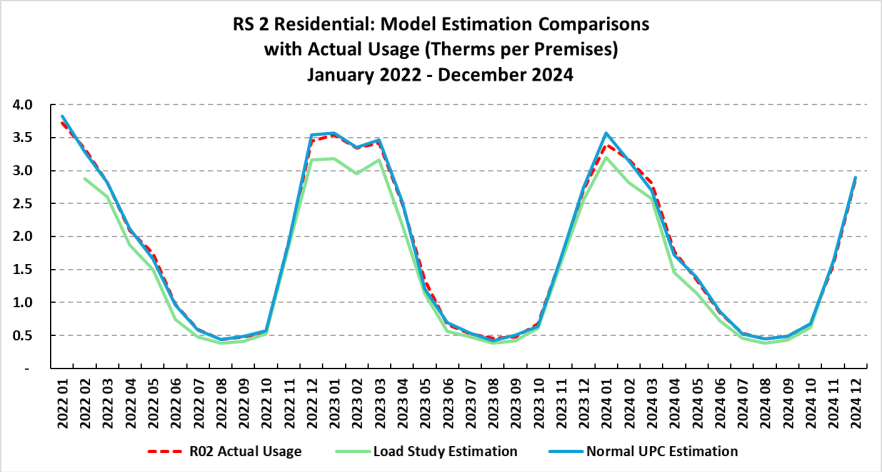


Table 6 shows that the Normal UPC model provides close estimation with actual RS 2 Residential usage over the analysis period. The load study model, however, serially underpredicts actual usage over the analysis period with the largest variances occurring during the winter heating months when usage is peaking.

As expected given the estimations shown in Table 6, the Normal UPC model produces an RMSE value that is lower compared to the load study model (0.017 to 0.066, respectively). Based on the RMSE results, the Company concludes that the Normal UPC is the better estimator for RS 2 Residential.

Small Commercial Rate Class

For the Small Commercial Rate Class (which includes RS 1 Commercial and RS 3 Commercial) ARIMA model specification, the Company used a model consistent with RS 2 Residential. It included an indicator variable for all months to control for seasonality. Further, the Company included additional weather variables (wind chill and radiation) as well as an indicator for weekends and holiday days. The Company chose a non-differenced ARIMA(2,0,2)(0,0,0)$_{[2]}$ specification for the model, which is as follows, where *m* is month and *y* is year. The variables and model specification chosen for this model align closely with the Normal UPCs RS 3 Commercial model shown in Exh. RJW-1T, but without macroeconomic variables that control for consumer price index changes or COVID-19, and without the multiplicative seasonal ARIMA specification.

$$\frac{SmlCom\ UPC}{Day}m,y = \beta_1\frac{SmlCom\ HDD}{Day} + \beta_2\frac{WindChill}{Day} + \beta_3\frac{SolarRadiation}{Day} + \beta_4 Jan_{=1} \ldots + \beta_{15} Dec_{=1} + \beta_{16} WeekendHolidayDays + ARIMA(2,0,2)(0,0,0)_{[2]}$$

The Small Commercial load study model output is as follows:

```
ARIMA regression

Sample:  1 - 1096                               Number of obs      =       1096
                                                Wald chi2(20)      =   69493.83
Log likelihood = -1645.112                      Prob > chi2        =     0.0000

------------------------------------------------------------------------------
                             |                 OPG
COMSALESUsePerCustomer_ADJ |      Coef.   Std. Err.      z    P>|z|     [95% Conf. Interval]
-----------------------------+------------------------------------------------------------------
COMSALESUsePerCustomer_ADJ |
                COM_HDDDay |   .5063853   .0091887    55.11   0.000     .4883758    .5243948
             WindChillValue |   .0140056   .0007234    19.36   0.000     .0125878    .0154234
                  Radiation |  -6.70e-06   .0000301    -0.22   0.824    -.0000658    .0000524
                        Jan |   9.906101   .2356972    42.03   0.000     9.444143    10.36806
                        Feb |   9.426586   .2476574    38.06   0.000     8.941186    9.911985
                        Mar |   8.435136   .2380944    35.43   0.000     7.968479    8.901792
                        Apr |   7.319556    .257197    28.46   0.000      6.81546    7.823653
                        May |   6.245103   .3189193    19.58   0.000     5.620032    6.870173
                        Jun |   5.650396   .3960387    14.27   0.000     4.874174    6.426618
                        Jul |   4.935233   .4568747    10.80   0.000     4.039775    5.830691
                        Aug |   4.835637    .453839    10.65   0.000     3.946129    5.725145
                        Sep |   5.368124   .4248099    12.64   0.000     4.535512    6.200736
                        Oct |   6.453456   .2641419    24.43   0.000     5.935747    6.971165
                        Nov |   8.335353    .221255    37.67   0.000     7.901701    8.769005
                        Dec |   9.707481    .233449    41.58   0.000     9.249929    10.16503
             WeekendHoliday |  -1.058056   .0709007   -14.92   0.000    -1.197019   -.9190935
-----------------------------+------------------------------------------------------------------
ARMA                         |
                         ar |
                         L1. |   .9560537   .4071778     2.35   0.019     .1579998    1.754108
                         L2. |  -.1350376   .2575855    -0.52   0.600    -.6398959    .3698207
                             |
                         ma |
                         L1. |  -.6153318   .4065566    -1.51   0.130    -1.412168    .1815045
                         L2. |  -.0298676   .1348906    -0.22   0.825    -.2942483    .2345131
-----------------------------+------------------------------------------------------------------
                      /sigma |   1.085474   .0149742    72.49   0.000     1.056125    1.114823
------------------------------------------------------------------------------
Note: The test of the variance against zero is one sided, and the two-sided
      confidence interval is truncated at zero.
```

This model produces an estimated annual UPC of 4,064.2 therms, which is 30.7 percent higher than a UPC of 3,122.1 therms estimated by using the same methods as the Normal UPC analysis. The load study model produces a design day load that is 18.8 percent higher than that of the Normal UPC analysis (35.6 therms per customer compared to 28.9 therms). Table 7 below shows a comparison of the Small Commercial load study model against the Normal UPCs analysis and actual usage.

Table 7

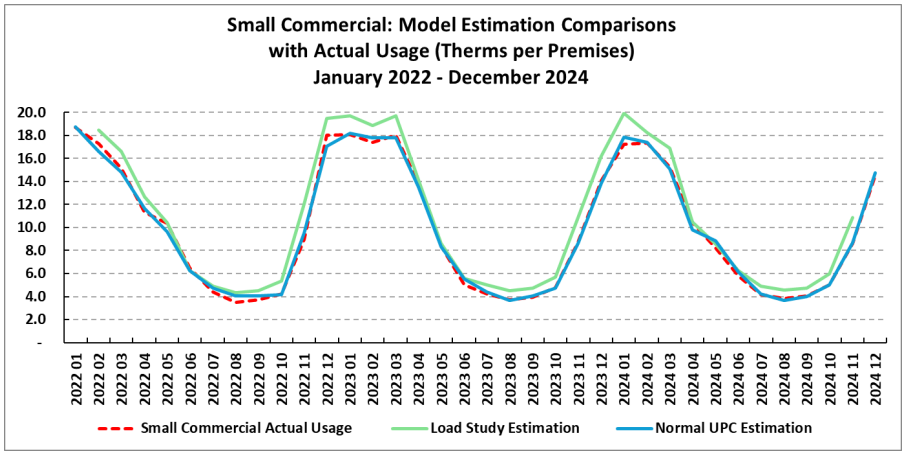


Table 7 shows that the Normal UPC model provides close estimation with actual Small Commercial usage over the analysis period. The load study model, however, serially overpredicts actual usage over the analysis period with the largest variances occurring during the winter heating months when usage is peaking.

As expected given the estimations shown in Table 7, the Normal UPC model produces an RMSE value that is lower compared to the load study model (0.026 to 0.097, respectively). Based on the RMSE results, the Company concludes that the Normal UPC is the better estimator for Small Commercial.

Large Volume Commercial and Industrial Rate Classes

Exh. RJW-1T discusses the Company's use of a five-year coincident peak value to derive the load factor for the large volume rate schedules for use in the EmCOSS model. These values, which are based on hourly, daily, and monthly data, are calculated in Exh. RJW-11. For this load study, the same load factor values are calculated in this exhibit without using the monthly data. Instead, an adjustment factor is used on the hourly and daily data to gross up the coincident peak demand to account for those large volume premises that do not have daily read meter capabilities. As shown in Tables 1 through 3 above, daily read capable meters are installed at all or nearly all premises in the RS 41 and RS 42 rate classes. Therefore, the coincident peak values are the same or nearly the same for the large volume schedules whether the monthly data is used or not.

The exceptions are RS 41 Commercial Sales Firm and RS 42 Commercial Sales Firm. As discussed in Exh. RJW-1T, the Company calculated the peak demands for these schedules using the Normal UPC analysis methodology. For this load study, the Company used the coincident peak method as shown in Exh. RJW-11 to calculate peak demands for these schedules using an adjustment for monthly usage.

Conclusion and Discussion

Based on the evaluation of the load study results compared to the Normal UPCs analysis, which concluded that the Normal UPC analysis methodology produces usage estimations with better performance and fit of actual usage, the Company decided to use the methodology presented in Exh. RJW-1T for the EmCOSS peak demand inputs. As shown above, the load study methodology both under- and over-predicts the winter heating peaks depending on the rate schedule modeled. Table 8 below

summarizes the peak demand estimates, by rate schedule, as estimated by the Normal UPC analysis and this load study.

Table 8
Load Factors
Derived for EmCOSS and Load Study

Rate Schedule	Design Day Load Factor	
	EmCOSS	Load Study
R01	25.5%	30.8%
R02	24.5%	25.6%
Small Commercial	29.6%	31.3%
C41SF	30.9%	40.6%
C42SF	42.2%	100.0%
I03	55.5%	55.6%
I41SF	69.5%	69.8%
C42SI	100.0%	100.0%
I42SF	91.0%	91.0%
I42SI	100.0%	100.0%
I42TF	100.0%	100.0%
I42TI	100.0%	100.0%
C41TF	32.5%	32.5%
C42TF	46.7%	46.7%

The Company presents two versions of the EmCOSS using peak demand inputs from the Normal UPC analysis as well as this load study. The EmCOSS using the Normal UPC analysis is presented as Exh. RJW-12, and the EmCOSS using the load study results is presented as Exh. RJW-13. The Company uses the Normal UPC EmCOSS (Exh. RJW-12) to determine its rate spread proposal as discussed in Exh. RJW-1T.

Relative to the sampled data used by the load study, the Normal UPC analysis uses all usage across all premises so any biases inadvertently introduced by sampling are avoided. Further, the Normal UPC evaluates usage across thirteen heating seasons compared to three for the load study. The Company believes that the current data constraints on the load study cause inferior usage estimations. As the Company continues to install daily read capable meters until it reaches full coverage, however, it expects that future iterations of this load study could provide useful insight for the EmCOSS.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Robert J. Wyman

EMBEDDED COST OF SERVICE MODEL AND RATE DESIGN/SPREAD

Exh. RJW-14

August 29, 2025

NW Natural
Washington Jurisdictional Rate Case
Test Year Twelve Months Ended March 31, 2025
Peer Fixed Rate Comparison - Tables for Testimony Exh. RJW-1T

Table 3

Residential Rate Tariffs	Fixed charge Residential	
Puget Sound Energy (NG)	$14.00	
Avista (NG)	$10.50	
NW Natural (RS 1 Residential Proposed)	$10.00	*At Rate Year 2*
NW Natural (RS 2 Residential Proposed)	$10.00	*At Rate Year 2*
NW Natural (RS 2 Residential Existing)	$8.00	
Cascade Gas	$5.50	*Increasing to $6.00 March 2026*
NW Natural (RS 1 Residential Existing)	$5.50	

Source: Puget Sound Energy Tariff Sheet Link
Source: Avista Utilities Tariff Sheet Link
Source: Cascade Natural Gas Tariff Sheet Link

Table 4

General Commercial Rate Tariffs	Fixed charge Commercial	
Puget Sound Energy (NG)	$50.56	*Increasing to $65.72 January 2026*
NW Natural (RS 3 Commercial Existing)	$22.00	
Cascade Gas	$20.00	*Increasing to $25.50 March 2026*
Avista (NG)	$10.50	
NW Natural (RS 1 Commercial Proposed)	$10.00	*At Rate Year 1*
NW Natural (RS 1 Commercial Existing)	$7.00	

Source: Puget Sound Energy Tariff Sheet Link
Source: Cascade Natural Gas Tariff Sheet Link
Source: Avista Utilities Tariff Sheet Link

Table 2

Rate Schedule	EmCOSS-Indicated Fixed Charge	Existing Fixed Charge	Ratio Existing to Indicated Fixed Charge	RY1 Proposed Fixed Charge	RY2 Proposed Fixed Charge	RY3 Proposed Fixed Charge	Ratio Proposed to Indicated Fixed Charge
	$	$	%	$	$	$	%
RS 1 Residential	$ 33.85	$5.50	16.2%	$8.00	$ 10.00	$ 10.00	29.5%
RS 1 Commercial	$ 67.09	$7.00	10.4%	$10.00	$ 10.00	$ 10.00	14.9%
RS 2 Residential	$ 30.87	$8.00	25.9%	$8.00	$ 10.00	$ 10.00	32.4%

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. NORTHWEST NATURAL GAS COMPANY, Respondent.	DOCKET UG-250610

NORTHWEST NATURAL GAS COMPANY

Exhibit of Robert J. Wyman

EMBEDDED COST OF SERVICE MODEL AND RATE DESIGN/SPREAD

Exh. RJW-17

August 29, 2025

NW Natural
Washington Jurisdictional Rate Case
Test Year Twelve Months Ended March 31, 2025
Rate Spread Allocation Proposal Methodology - Revenue Requirement Effects
Exhibit "250610-NWN-Exh-RJW-17-08-29-2025"
Note: Rate schedules with no current margin revenue do not currently have customers or volumes.
For these schedules, volumetric base billing rate will be increased by indicated percentage margin increase in the table below.

	Factor	Revenue %
01R CAP:	**1.25**	28.5%
02R CAP:	**1.01**	23.0%
27R CAP:	**2.00**	45.6%
01C CAP:	**1.25**	28.5%
03C CAP:	**1.06**	24.2%
FLOOR:	**0.69**	27.4%

	Margin %
03C CAP:	43.5%

1.006

Step 2 Remainder to Spread $ 954,545
FLOOR: Goal Seeked 27.4%

Line No.	Rate Schedule	Rate Schedule Description	Margin Revenue at Present Rates $	Total Revenue at Present Rates $	Target Revenue Increase (EmCOSS) %	Parity Ratio at Present Rates (Unit Parity = 1.0)	Target Revenue Increase (EmCOSS) $	Equal % of Margin Increase $	Step 1: Apply Caps: Parity Ratio Less than 1.0 Plus 03C	Step 2: Apply Equal Percent of Margin: Parity Ratio 1.20 and lower plus Commercial Sales Firm	Step 2: Apply Floor: Remaining Rate Schedules	Step 3: Final Remainder: Kept for Goal Seek Calculations)	Total Proposed Revenue Requirement Increase $	Proposed Margin Increase %	Proposed Revenue Increase %	Proposed Revenues from Rates $	Parity Ratio at Proposed Rates (Unit Parity = 1.0)
			A	**B**	**C**	**D**	**E**	**F**	**G**		**H**	**I**	**L**	**M**	**N**	**O**	**P**
1	R01	Residential Sales Firm	$ 408,288	$ 577,527	139.1%	0.51	$ 803,302	$ 161,293	$ 164,682				$ 164,682	40.3%	28.5%	$ 741,285	0.54
2	R02	Residential Sales Firm	$ 43,654,293	$ 74,304,204	29.7%	0.95	$ 22,031,975	$ 17,245,464	$ 17,053,968				$ 17,053,968	39.1%	23.0%	$ 91,291,565	0.95
3	R27	Commercial Sales Firm	$ 106,279	$ 206,591	66.9%	0.74	$ 138,144	$ 41,985	$ 94,255				$ 94,255	88.7%	45.6%	$ 301,699	0.88
4	C01	Commercial Sales Firm	$ 23,300	$ 35,046	144.5%	0.50	$ 50,652	$ 9,205	$ 9,993				$ 9,993	42.9%	28.5%	$ 45,006	0.53
5	C03	Commercial Sales Firm	$ 14,082,842	$ 25,323,976	16.1%	1.06	$ 4,066,841	$ 5,563,374	$ 6,119,711				$ 6,119,711	43.5%	24.2%	$ 31,429,071	1.07
6	I03	Industrial Sales Firm	$ 114,132	$ 212,197	20.4%	1.02	$ 43,387	$ 45,087		$ 45,087			$ 45,087	39.5%	21.2%	$ 257,067	1.01
7	C41SF	Commercial Sales Firm	$ 1,967,976	$ 4,054,168	-7.4%	1.33	$ (299,192)	$ 777,441		$ 777,441			$ 777,441	39.5%	19.2%	$ 4,827,473	1.29
8	C42SF	Commercial Sales Firm	$ 657,026	$ 1,792,903	-8.8%	1.35	$ (158,230)	$ 259,556		$ 259,556			$ 259,556	39.5%	14.5%	$ 2,050,706	1.26
9	C41SI	Commercial Sales Interruptible	$ 0	$ 0	0.0%	1.00	$ 0	$ 0					$ 0	0.0%	0.0%	$ 0	0.00
10	C42SI	Commercial Sales Interruptible	$ 198,724	$ 626,248	11.1%	1.11	$ 69,351	$ 78,505		$ 78,505			$ 78,505	39.5%	12.5%	$ 704,094	1.01
11	I41SF	Industrial Sales Firm	$ 439,388	$ 963,854	-11.6%	1.39	$ (111,354)	$ 173,579			$ 120,428		$ 120,428	27.4%	12.5%	$ 1,082,258	1.27
12	I42SF	Industrial Sales Firm	$ 509,046	$ 1,319,405	-13.2%	1.42	$ (174,639)	$ 201,097			$ 139,520		$ 139,520	27.4%	10.6%	$ 1,456,226	1.27
13	I41SI	Industrial Sales Interruptible	$ 0	$ 0	0.0%	1.00	$ 0	$ 0			$ 0		$ 0	0.0%	0.0%	$ 0	0.00
14	I42SI	Industrial Sales Interruptible	$ 50,180	$ 136,052	-32.2%	1.81	$ (43,830)	$ 19,823			$ 13,753		$ 13,753	27.4%	10.1%	$ 149,562	1.62
15	C41TF/I41TF	Transportation Firm	$ 190,120	$ 190,120	-17.7%	1.49	$ (33,725)	$ 75,106			$ 52,108		$ 52,108	27.4%	27.4%	$ 241,540	1.55
16	C42TF	Commercial Transportation Firm	$ 193,897	$ 193,897	-1.5%	1.25	$ (2,876)	$ 76,598			$ 53,143		$ 53,143	27.4%	27.4%	$ 246,352	1.29
17	I42TF	Industrial Transportation Firm	$ 973,915	$ 973,915	-14.2%	1.43	$ (138,627)	$ 384,741			$ 266,931		$ 266,931	27.4%	27.4%	$ 1,237,287	1.48
18	C42TI/I42TI	Transportation Interruptible	$ 1,126,172	$ 1,126,172	-60.7%	3.12	$ (683,436)	$ 444,890			$ 308,662		$ 308,662	27.4%	27.4%	$ 1,431,041	3.24
19	I43T	Transportation Firm	$ 0	$ 0	0.0%	1.00	$ 0	$ 0			$ 0		$ 0	0.0%	0.0%		
20	I43T	Transportation Interruptible	$ 0	$ 0	0.0%	1.00	$ 0	$ 0			$ 0		$ 0	0.0%	0.0%		
	SPECIAL		$ 0	$ 0	0.0%	1.00							$ 0			$ 0	1.00
	Total		**$ 64,695,580**	**$ 112,036,277**	**22.8%**		**$ 25,557,744**	**Rev Req Applied:**	**$ 23,442,610**	**$ 1,160,590**	**$ 954,545**	**$ -**	**$ 25,557,744**	**39.5%**	**22.8%**	**$ 137,492,231**	
			(1)	**(1)**	**39.5%**											**(1)**	
		Proposed Rev Req:	**$ 25,557,744**					**Rev Req Remainder:**	**$ 2,115,134**	**$ 954,545**	**$ 0**	**$ (0)**					

Note **(1)**: Includes special contract and miscellaneous revenues.

RS 2 Residential Remainder if use cap at 1.00: $ 103,674
Amount to use to Goal Seek R02 Cap: $ 17,053,968
$ (0)

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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NORTHWEST NATURAL GAS COMPANY

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EMBEDDED COST OF SERVICE MODEL AND RATE DESIGN/SPREAD

Exh. RJW-19C

REDACTED VERSION

August 29, 2025

THIS EXHIBIT IS BEING FILED IN ITS NATIVE EXCEL FORMAT. IT CONTAINS CONFIDENTIAL INFORMATION UNDER WAC 480-07-160. NO REDACTED VERSION EXISTS.