NW Natural®

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November 24, 2026 NWN OPUC Advice No. 26-11 / UG 532

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

Re: UG 532 – Application of NW Natural for a General Rate Revision

In accordance with OAR 860-022-0019, Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company"), files herewith its Application for a General Rate Revision ("Application"). As discussed with Public Utility Commission of Oregon ("Commission") Staff, no physical copies of the Executive Summary, Cumulative Economic Impact Analysis, Direct Testimonies, and Exhibits will be provided to the Commission. A petition for waiver of OAR 860-001-0170(2) has been filed with the Commission. In compliance with OAR 860-022-0019(2)(a), responses to the Standard Data Requests, in addition to work papers, are being provided on the Commission's Huddle site. Notices will be published in accordance with the requirements of OAR 860-022-0017.

Please note, the filing contains some confidential information that represents business-sensitive, non-public information. Confidential and Highly Confidential Information will be provided subject to General Protective Order No. 23-132 and Modified Protective Order No. 26-460, respectively.

Included with this filing are revisions to Tariff, P.U.C. Or. 25 (as Exhibit NW Natural/1216, Walker), stated to become effective with service on and after December 24, 2026. A list of all proposed tariff sheets can be found in the attached Table of Tariff Sheets Revisions.

The Company waives paper service in this proceeding.

Please address correspondence on this matter to me with copies to the following:

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Sincerely,

NW NATURAL

/s/ Zachary Kravitz

Zachary Kravitz
Vice President, Regulatory Affairs and Resource Planning

Enclosures

NW Natural
TABLE OF TARIFF SHEET REVISIONS
PROPOSED TO BECOME EFFECTIVE DECEMBER 24, 2026
OPUC Advice No. 26-11

Schedule Title	Proposed Sheet
Sheet ii – Map of Service Area	First Revision of Sheet ii
Rate Schedule H – Large Volume Non-Residential High Pressure Gas Service (HPGS) Rider	Eighth Revision of Sheet H-5
Rate Schedule 2 - Residential Sales Service	Nineteenth Revision of Sheet 2-1
Rate Schedule 3 - Basic Firm Sales Service – Non-Residential	Eighteenth Revision of Sheet 3-4
Rate Schedule 4 - Residential Multi-Family Service	Sixth Revision of Sheet 4-1
Rate Schedule 15 - Charges for Special Metering Equipment, Rental Meters, and Metering Services (Optional)	Seventh Revision of Sheet 15-2
Rate Schedule 27 - Residential Heating Dry-Out Service	Sixteenth Revision of Sheet 27-1
Rate Schedule 31 - Non-Residential Firm Sales and Firm Transportation Service	Eighteenth Revision of Sheet 31-11
Rate Schedule 31 - Non-Residential Firm Sales and Firm Transportation Service	Sixteenth Revision of Sheet 31-12
Rate Schedule 32 - Large Volume Non-Residential Sales and Transportation Service	Sixteenth Revision of Sheet 32-12
Rate Schedule 32 - Large Volume Non-Residential Sales and Transportation Service	Eighteenth Revision of Sheet 32-13
Rate Schedule 32 - Large Volume Non-Residential Sales and Transportation Service	Sixteenth Revision of Sheet 32-14
Rate Schedule 33 – High Volume Non-Residential Firm and Interruptible Transportation Service	Fifteenth Revision of Sheet 33-8
Schedule 100 – Summary of Temporary Adjustments	Fifteenth Revision of Sheet 100-1
Schedule 100 – Summary of Temporary Adjustments	Fifteenth Revision of Sheet 100-2
Schedule 100 – Summary of Temporary Adjustments	Fifteenth Revision of Sheet 100-3
Schedule 100 – Summary of Temporary Adjustments	Fourteenth Revision of Sheet 100-4
Schedule 122 – Amortization of GC 500 Mist Compressor Regulatory Asset	Second Revision of Sheet 122-1
Schedule 123 – Adjustment for Alternative Rate Mechanism	First Revision of Sheet 123-2
Schedule 124 – Amortization of GC 600 Mist Compressor Regulatory Asset	First Revision of Sheet 124-1
Schedule 125 – Coos County Pipeline Amortization	Original Sheet 125-1

Schedule 167 - General Adjustments to Rates	Seventh Revision of Sheet 167-1
Schedule 175 - Amortization of Horizon 1 Start-Up Cost Deferral	Fourth Revision of Sheet 175-1
Schedule 182 - Rate Adjustment for Environmental Cost Recovery	Sixth Revision of Sheet 182-1
Schedule 190 - Partial Decoupling Mechanism	Twentieth Revision of Sheet 190-1
Schedule 190 - Partial Decoupling Mechanism	Fifteenth Revision of Sheet 190-2
Schedule 195 - Weather Adjusted Rate Mechanism (WARM Program)	Seventh Revision of Sheet 195-3
Schedule 195 - Weather Adjusted Rate Mechanism (WARM Program)	Eleventh Revision of Sheet 195-4
Schedule 195 - Weather Adjusted Rate Mechanism (WARM Program)	Fifteenth Revision of Sheet 195-5
Schedule 196 - Adjustment for Certain Excess Deferred Income Taxes Related to the 2017 Federal Tax Cuts and Jobs Act	Eighth Revision of Sheet 196-2
Schedule 197 - Amortization of Pension Balancing Account	Sixth Revision of Sheet 197-2

NW Natural

UG 532

NOTICE OF APPLICATION FOR GENERAL RATE REVISION

November 24, 2026

To All Parties Who Participated in UG 520:

Please be advised that on November 24, 2026, Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company"), has filed for a GENERAL RATE REVISION. A copy of the Company's non-confidential, redacted UG 532 OPUC Advice No. 26-11 containing the EXECUTIVE SUMMARY, CUMULATIVE ECONOMIC IMPACT ANALYSIS, DIRECT TESTIMONIES, and EXHIBITS are available for inspection at its main office or at the Public Utility Commission of Oregon's ("Commission") eDocket website. An electronic courtesy copy is also attached.

The purpose of this Notice is to inform parties who participated in the Company's last general rate case, UG 520, that a General Rate Revision has been filed.

Parties who desire more information or who wish to obtain a copy of the filing, or notice of the time and place of any hearing, if scheduled, should contact the Company or the Commission as follows:

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Attn: Zach Kravitz
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Portland, Oregon 97204
Telephone: (503) 610-7617

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
PO Box 1088
Salem, Oregon 97308-1088
Telephone: (503) 378-6678

Any person may submit to the Commission written comments on this General Rate Revision within 25 days of service of this notice or seek to intervene in the proceeding. The granting of this General Rate Revision will authorize a change in rates.

* * * * *

NW Natural

CERTIFICATE OF SERVICE
UG 532

I hereby certify that on November 24, 2026, I have served by electronic delivery a non-confidential, redacted copy of UG 532 OPUC Advice No. 26-11 containing the EXECUTIVE SUMMARY, CUMULATIVE ECONOMIC IMPACT ANALYSIS, DIRECT TESTIMONIES, AND EXHIBITS OF NW NATURAL'S GENERAL RATE REVISION upon all parties of record for the Company's last general rate case, UG 520.

UG 520

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DATED November 24, 2026, Portland, Oregon.

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BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UG 532

In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Application for a General Rate Revision.	**NW Natural's Executive Summary**

I. INTRODUCTION

Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company"), is filing a general rate revision with the Public Utility Commission of Oregon ("Commission"), in accordance with ORS 757.205, 757.215, and 757.220, to revise its schedules of rates and charges for natural gas service in Oregon to become effective with service provided on and after December 24, 2026.[1]

With this filing, the Company requests a revision to customer base rates that will increase the Company's annual Oregon jurisdictional revenues by $90.1 million, or an approximate 9.1 percent increase over current customer rates. Importantly, however, $19.8 million of this increase is for revenue that the Commission has already authorized NW Natural to recover through its decoupling mechanism, and therefore, does not reflect any new or additional costs. Rather, it results from updating the weather-normalized use-per-customer ("UPC") assumed

[1] As explained below, however, the Company assumes the addition of the full 10-month statutory suspension period to the 30-day effective date normally applicable to tariff revisions and agrees to the limited additional suspension necessary to result in a rate effective date of October 31, 2027 for residential customers and November 1, 2027 for non-residential customers.

in rates to reflect declining residential and commercial usage. For this portion of the request, NW Natural is proposing only a change in rate design—*how* these revenues are collected, not *whether* they are collected. Excluding this amount, the net increase that the Company is requesting in this case is $70.3 million, or approximately 7.1 percent.

NW Natural's request in this proceeding is part of a strategy to spread cost recovery over multiple years at an average annual rate below recent inflation. As such, this proceeding is best understood as one step in a three-year path to the Company's first multiyear rate plan required by the Fairness and Affordability in Residential Energy Act ("FAIR Act") that will take effect in late 2029.[2] Specifically, from October 31, 2026 through October 30, 2029, NW Natural's customers will experience three rate changes to base rates: (1) the 1.3 percent Alternative Rate Mechanism ("ARM") increase that took effect on October 31, 2026; (2) the 7.1 percent net increase requested in this proceeding (excluding the UPC update discussed above), which would take effect on October 31, 2027;[3] and (3) the 1.2 percent bridge mechanism, which would take effect on October 31, 2028, and is discussed below.[4] Together, and as shown in Figure 1 below, these changes increase NW Natural's revenue requirement (excluding gas costs) by

[2] OAR 860-022-0081(3)(c).

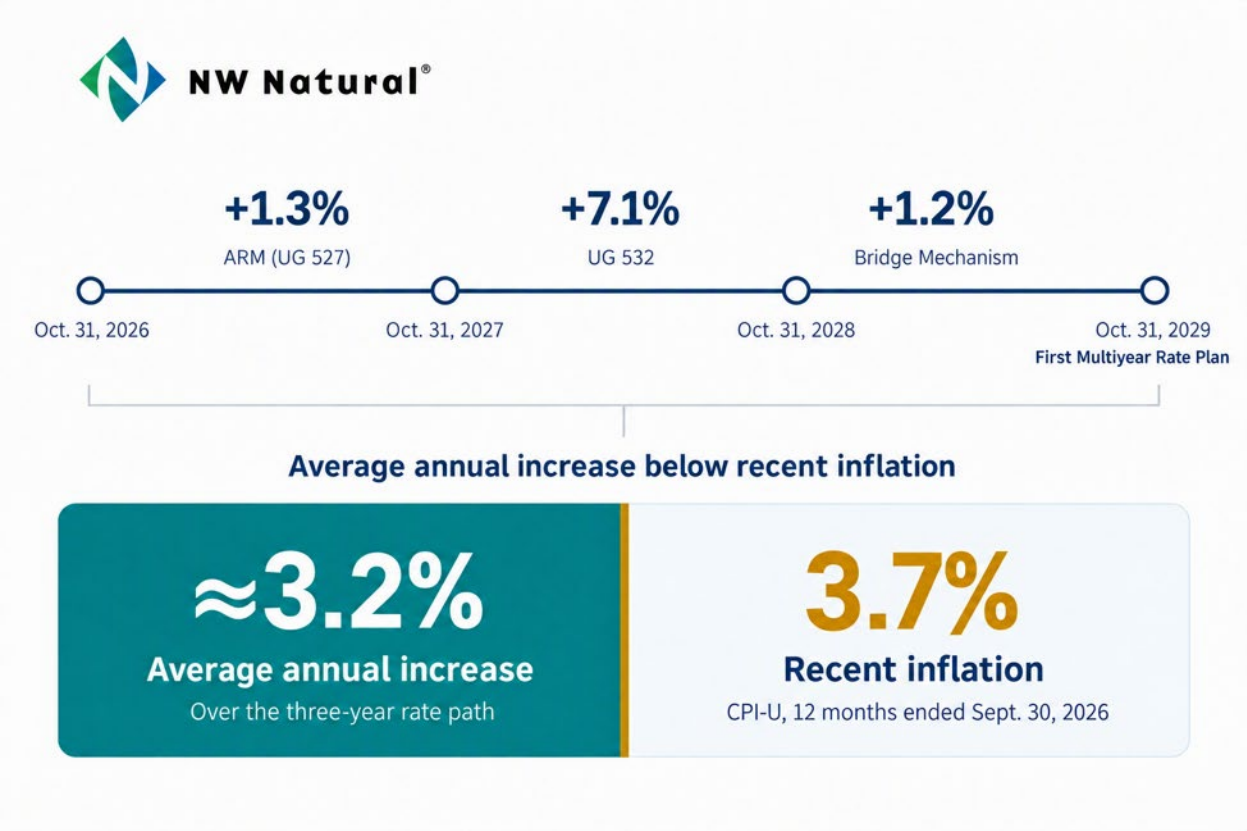
[3] As explained in footnote 1 above, the Company agrees to the limited additional suspension necessary to result in a rate effective date of October 31, 2027 for residential customers and November 1, 2027 for non-residential customers.

[4] These rate increases exclude gas costs, which are recovered in a separate proceeding and are largely outside the Company's control.

approximately 9.6 percent over three years, or approximately 3.2 percent per year. In comparison, inflation has increased 3.7 percent over the last 12 months.[5]

Figure 1

NW Natural Rate Changes Leading to Its First Multiyear Rate Plan



The revised rates produce revenues necessary to sustain the provision of safe, reliable, and low-cost natural gas service to customers in Oregon, while preserving the Company's ability to attract capital for future investments. Without the requested increase in base rates, NW Natural's gas distribution utility would expect the overall rate of return ("ROR") to be 4.829 percent, with a corresponding return on equity ("ROE") of 4.66

[5] The U.S. Consumer Price Index (CPI-U) rose 3.7 percent over the 12 months ending September 2026. See also the Direct Testimony of Jennifer E. Nelson, NW Natural/400, Nelson/82 (quoting the Chair of the Federal Reserve, Kevin M. Warsh, "The Fed's preferred measure of inflation, the 12-month change in the PCE [Personal Consumption Expenditures] price index, stands 3.7 percent, while the six-month change is 4.1 percent.").

percent. The Company files this Executive Summary in accordance with OAR 860-022-0019(1). Exhibit A to the Executive Summary provides the required information in accordance with OAR 860-022-0019(1)(a)-(h). As required by ORS 757.211(3) and OAR 860-022-0500, the Company is also providing the Cumulative Economic Impact Analysis, which is located in this filing after the Executive Summary and before the Company's testimony.

II. BACKGROUND

NW Natural is an Oregon corporation whose principal place of business is 250 SW Taylor Street, Portland, Oregon, 97204. NW Natural is a public utility providing natural gas service in Oregon within the meaning of ORS 757.005, and is subject to the jurisdiction of this Commission. NW Natural has over 700 thousand customer accounts in Oregon, consisting of approximately 645 thousand residential, 60 thousand commercial, and 800 industrial customers. Approximately 88 percent of NW Natural's customers are located in Oregon.

Communications regarding this filing, including data requests issued to the Company, should be addressed to:

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III. CASE SUMMARY

A. The Test Year

The Company's test year in this case is the 12-months ending October 31, 2028 ("Test Year"). NW Natural provides information for a historical base year of the 12-months ending June 30, 2026 ("Base Year") and makes adjustments to that information to reflect the forecasted Test Year. In order to meet the legal requirements that rates be fair, just, reasonable, and sufficient, the Company has selected the Test Year to closely reflect the investment and expense levels that will exist during the time that the rates adopted in this case are expected to be in effect. The new rates are filed with a requested effective date of December 24, 2026. However, the Company assumes the addition of the full 10-month statutory suspension period to the 30-day effective date normally applicable to tariff revisions and agrees to the limited additional suspension necessary to result in a rate effective date of October 31, 2027 for residential customers and November 1, 2027 for non-residential customers.

B. Factors Driving Rate Adjustments

The need to increase rates is driven by the cost of our investments to continue to support our utility service customers, as well as increasing operating costs due to persistently high inflation and higher interest rates. NW Natural has completed, or is in the process of completing, several long-planned investments in the safety and reliability

of its operations for which the Company is seeking timely cost recovery. The key drivers for the Company's proposed rate increase include:

- **Improving Reliability in the Distribution and Storage System**: NW Natural continues to make system investments to ensure safe and reliable operations. Specifically, the Company is performing necessary projects throughout its Oregon distribution system, including the Mile 98 Relocation Project to address landslide risk on the Coos County Pipeline, uprating the Forest Grove Feeder that is operating beyond its design capacity, relocating facilities to accommodate public works projects, upgrading metering, and rebuilding outdated gate stations. The Company is also undertaking several important projects at its storage facilities, which support NW Natural's gas supply portfolio to enable reliable and affordable gas service, including during peak winter events or other times when supply is constrained. Storage projects include replacing a key component of the Newport Liquefied Natural Gas ("LNG") Storage Facility that is nearly 50 years old, installing an emergency generator at the Newport LNG facility, updating the end-of-life power feed to the Mist Storage Facility, and replacing or updating several other Mist components that are critical to the continued safe and effective operation of the facility. Finally, NW Natural is completing several safety-related projects to allow for effective pipeline inspections.
- **Upgrading Facilities for Safety and Efficiency**: Consistent with its established facilities roadmap, which is nearing completion, the Company is making seismic upgrades to the Coos County Resource Center, installing

an emergency backup generator, and constructing an on-site fuel station. Upgrading this more than 60-year-old resource center will support efficient and resilient operations at the Company's only facility on the southern Oregon coast, and is needed regardless of who owns the Coos County Pipeline. NW Natural is also installing a decant system and truck scale at the Salem Resource Center, which will improve operational efficiency in the greater Salem area. In addition, the Company is completing its multi-year effort to enhance physical security at the Company's facilities in response to federal requirements and increasing attacks and threats.

- **Modernizing Information Technology Systems**: NW Natural continues to make investments to its information technology and services ("IT&S") systems. In this case, NW Natural is seeking cost recovery of essential projects that are necessary to ensure the continued functionality of its IT&S infrastructure. These projects include: (1) continuing the Company's multi-year initiative to update the Company's field and web mapping systems and tools that allow employees and contractors to view its infrastructure and other assets in a geospatial format and to collect various types of data related to these assets; (2) ongoing work to transition to an automated Identity Governance and Administration ("IGA") software solution to update, review, and determine access to technology systems for NW Natural employees and contractors to ensure consistent, secure monitoring and control of access and permissions; (3) beginning the Gas Control Daily Operations Platform multi-phase 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; (4) beginning a multi-year initiative for Customer Self-Service projects to provide customers with new features and efficiencies to improve communication and accessibility; and (5) performing work necessary to update and maintain critical IT&S equipment, applications, and platforms, which allows the Company to receive critical system and security patches, apply up-to-date technology features, and maintain license compliance as defined by support agreements. Because many of these new investments are cloud-based services and depreciate over a very short period of time (typically five years), NW Natural must seek cost recovery on a timely basis. Otherwise, the Company would not be able to recover a substantial portion of these investments (i.e., a delay of a year would result in NW Natural not recovering approximately 20 percent of its cloud-based IT&S investments).

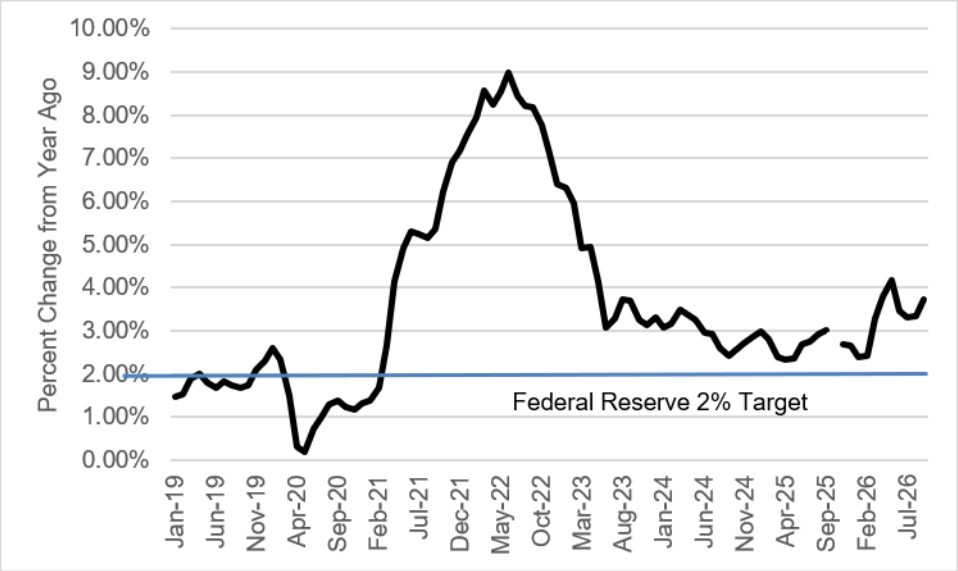
- **Inflationary Pressures**: NW Natural's operating costs continue to escalate, both due to inflation and higher interest rates. Inflation has a direct impact on Operations and Maintenance ("O&M") expense, which is the Company's second largest category of costs, after the purchase of natural gas. The Direct Testimony of Jennifer E. Nelson (NW Natural/400, Nelson) states that "inflation is expected to remain elevated and above pre-pandemic levels."[6]

[6] The Direct Testimony of Jennifer E. Nelson, NW Natural/400, Nelson/87.

Her testimony includes a figure, reproduced below, that shows the elevated inflation that has occurred since the pandemic:

Figure 2[7]

Consumer Price Index (2019-2026)



- Despite steady inflation, NW Natural did not recover any additional O&M expense in its Alternative Rate Mechanism proceeding (UG 527). Moreover, O&M expense continues to increase despite the Company proactively taking actions to reduce costs, such as renegotiating its locating and marking services contract, using a combination of technology and training to have its field technicians complete more jobs per day while improving response time, and implementing aggressive hiring control measures. Additionally, inflation impacts the Company's IT&S and capital investments because it costs more to obtain and install the same materials and equipment that are necessary to safely and reliably operate the system.

[7] The Direct Testimony of Jennifer E. Nelson, NW Natural/400, Nelson/83.

For example, IT&S hardware costs have risen sharply, and are expected to continue to rise, due to tariffs and increasing hardware demand associated with data center expansion. Finally, increasing interest rates also raise the Company's financing costs and put further pressure on rates.

C. Rate of Return

The Company's request is based on a capital structure of 50 percent common equity and 50 percent long-term debt, a requested 9.75 percent return on equity ("ROE"), and a resulting overall rate of return ("ROR") on rate base of 7.374 percent. The Company's current authorized ROE is 9.5 percent. As described in the Direct Testimony of Jennifer E. Nelson (NW Natural/400, Nelson), a reasonable ROE range for NW Natural is 9.75 percent to 11.75 percent using a combination of models and alternative input assumptions. Ms. Nelson's testimony includes analysis of persistently elevated inflation and U.S. Treasury yields. Long-term government and utility bond yields have increased by approximately 65 and 52 basis points, respectively, since NW Natural's last general rate case (docket UG 520).[8] These factors increase the benchmark returns investors require to commit capital to natural gas utilities such as NW Natural. Because utilities are capital-intensive and investors have many investment alternatives, NW Natural's financial profile must be adequate on a relative basis to ensure its ability to attract capital in order to make the necessary investments in its system that are required to provide safe and reliable service.

NW Natural has requested an authorized ROE at the lowest end of the range recommended by Ms. Nelson, however, reflecting the Company's consideration of

[8] The Direct Testimony of Jennifer E. Nelson, NW Natural/400, Nelson/7.

customer affordability concerns while providing NW Natural a reasonable return that enables it to continue to attract investor capital.

D. Promoting Rate Stability

1. Average Residential Customer Bill

With this proposed rate change, our average residential customer's bill is still less expensive than it was two decades ago after adjusting for inflation, as shown in Figure 3 below, and only 14 percent higher without such an adjustment. In comparison, if our residential bill simply tracked inflation since 2006, it would be approximately $142.22, which is substantially higher than the average residential bill of $96.98 that NW Natural is proposing in this proceeding.[9]

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[9] The $96.98 average residential bill is a weighted average of single-family and multi-family residential bills. In 2006, both types of residential housing were subject to the same rates, so NW Natural used a weighted average of residential customers' bills in order to make this comparison.

Figure 3

Twenty-Year Bill Comparison



NW Natural's affordability programs also help to mitigate energy burden for our customers. As shown in Figure 4 below, the bill discount program ("BDP") for income-eligible customers with incomes at or below 60 percent of the state median income ("SMI") has dramatically lowered participating customers' bills before taking into account any

other bill assistance programs. Beginning on November 1, 2006, the average monthly residential bill was $84.91 for all residential customers. After accounting for the BDP, the average monthly residential bill for participating customers beginning on November 1, 2027 will be lower than what that customer would have paid twenty years ago without adjusting for inflation, highlighting both the stability of our rates over that time and the value of the bill discount program. Please see Figure 4 below.

Figure 4

Comparison of Average 2027 BDP Bill to Average 2006 Residential Bill ($84.91)

BDP Tier Level	BDP Discount of Total Bill	Average 2027 Monthly Bill Under BDP	2027 BDP Monthly Bill Compared to Average 2006 Bill
Tier 0 0-15% SMI	85%	$14.55	-82.9%
Tier 1 16-30% SMI	50%	$48.49	-42.9%
Tier 2 31-45% SMI	30%	$67.89	-20.0%
Tier 3 46-60% SMI	15%	$82.43	-2.9%

In addition to the BDP, the Company's affordability portfolio includes tools to provide ongoing bill stability, respond to temporary crises, and help customers to reduce usage.

To provide ongoing bill stability by addressing past-due debt, NW Natural has developed an arrearage management program, which provides grants up to $1,000 every 24 months for customers who earn less than 15 percent of the state median income (Tier 0 of the bill discount program). Additionally, the Company allows for time payment arrangements as another means to address past-due balances.

To respond to temporary crises, the Oregon Low-Income Gas Assistance Program provides energy assistance grants to income-qualified customers. In addition, the Gas

Assistance Program provides a supplemental grant assistance program funded by NW Natural shareholders, employees, retirees, and customers matched up to $60,000 annually. The federal Low-Income Home Energy Assistance Program also provides grants to help eligible residents pay their energy bills. Finally, NW Natural's Oregon Low-Income Energy Efficiency program provides long-term affordability benefits through energy efficiency and weatherization improvements. These investments are complemented by customer education, equipment maintenance guidance, and partner-delivered maintenance support designed to help customers maximize and sustain energy savings.

2. Bridge Mechanism to Promote Rate Stability

As stated above, NW Natural is proposing a bridge mechanism to help promote rate stability and predictability until NW Natural's first multiyear rate plan takes effect in late 2029. To this end, the Company proposes that for rates effective during the Test Year, NW Natural will calculate utility plant in service by using a 13-month average of monthly averages ("AMA"), consistent with the Company's proposals in previous general rate cases. As of October 31, 2028, the Company proposes a bridge mechanism to update rates to recover the difference between the Test Year's 13-month AMA plant in service and end-of-period plant in service as of October 31, 2028. To ensure a balanced approach, the bridge mechanism will also update accumulated depreciation as of October 31, 2028, which will reduce rate base. The bridge mechanism is narrow in scope because it does not seek to include additional capital projects beyond what the Company is proposing in this case, nor does it include any O&M expense, despite continued inflationary pressure on these costs. The Company estimates that the bridge mechanism

will increase the Company's annual revenues by $11.6 million, or 1.2 percent. The corresponding increase for residential customers will be 1.0 percent.

Without the bridge mechanism, customers would be facing a larger rate increase at the beginning of NW Natural's first multiyear rate plan. As shown in Figure 1 above, in the three-year period between October 31, 2026 and October 30, 2029, the net increase in NW Natural's revenue requirement (excluding gas costs[10]) would be approximately 9.6 percent, or approximately 3.2 percent per year, which is lower than the current rate of inflation. The bridge mechanism also provides certainty to both the Company and its customers regarding future rate levels because the bridge mechanism increase will be known a year before it takes effect. In addition, NW Natural's proposal reduces the regulatory burden and expense for both the Company and its customers that could otherwise result from additional cost recovery proceedings before NW Natural's first multiyear rate plan. From the Company's perspective, this approach provides a limited and transparent means of aligning rates with the plant that will be serving customers at the end of the Test Year, while bridging the one-year period between the rate effective date in this case and the Company's first multiyear rate plan.

IV. TESTIMONY SUMMARY

The Company's direct case consists of the following testimony and witnesses:

- In NW Natural/100, Kim A. Rush and Zachary D. Kravitz provide an overview of both NW Natural and its requested rate increase and introduce the Company's proposed bridge mechanism. They explain the cost and business drivers that led to NW Natural making this request and how the

[10] For purposes of this comparison, NW Natural is excluding gas costs, which are largely outside its control.

Company has mitigated cost increases. They next discuss the Company's commitment to affordability and describe the value that NW Natural provides to the customers the Company serves, as well as to the entire Pacific Northwest. Finally, they provide a high-level overview of the Company's major projects included in its request for cost recovery, such as NW Natural's investments to ensure safe and reliable operations, including those at our Newport LNG Storage Facility, as well as continued investments to information technology and services (IT&S) systems.

- In NW Natural/200, Cecelia J. Tanaka, Energy Equity & Affordability Lead, explains how NW Natural identifies, evaluates, and responds to customer affordability challenges through a coordinated portfolio of affordability programs, customer protections, outreach and education, energy-efficiency investments, and stakeholder engagement. She also describes how the Company incorporates affordability and equity considerations into decision-making and evaluates the effectiveness of those efforts over time.
- In NW Natural/300, Brody J. Wilson, Vice President, Treasurer, Chief Accounting Officer and Controller, provides testimony about the Company's cost of capital. His testimony supports the Company's proposed cost of debt and explains the Company's financing strategy of maintaining an equal balance of long-term debt and equity financing, resulting in an ROR on rate base of 7.374 percent that will maintain financial health and benefit customers.

- In NW Natural/400, Jennifer E. Nelson, 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 9.75 percent and 11.75 percent. As explained above, NW Natural is seeking an opportunity to earn a 9.75 percent return on equity in the revenue requirement authorized in this proceeding, balancing affordability concerns while still attracting investor capital.
- In NW Natural/500, Jorge O. Moncayo, Business Planning Senior Director, describes the Company's capital project budgeting and forecasting processes, including management approval and lifecycle phases.
- In NW Natural/600, Daniel B. Kizer, Engineering Senior Director, and Michael C. Hwang, Gas Storage Facilities Development Director, describe major distribution system projects and storage facility projects serving Oregon customers that are included in this rate case, including the Company's safety-related projects to allow for effective pipeline inspections.
- In NW Natural/700, Wayne K. Pipes, Director of Facilities, Security and Emergency Management, describes the Company's execution on its long-term facilities strategy, including upgrades to the Coos Bay Resource Center ("RC") and the Salem RC, as well as the Company's continuing progress on physical security upgrades.

- In NW Natural/800, Brian E. Fellon, Vice President and Chief Information Officer, describes NW Natural's ongoing IT&S strategy and investments. Mr. Fellon provides an overview of NW Natural's IT&S environment, including the continued need to migrate to cloud-based software, the corresponding increase in incremental O&M expense, and the rapid evolution of IT&S systems, as well as the major IT&S investments for which the Company seeks cost recovery in this proceeding.
- In NW Natural/900, Kyra M. Patterson, Vice President, Chief People Officer, provides testimony on our labor costs, and describes the Company's practices related to compensation and benefits. Additionally, Ms. Patterson describes our overall employee count and the Company's request to include employee-related costs in the Company's revenue requirement.
- In NW Natural/1000, Cory A. Beck, Director of Customer Experience Services, provides testimony about the Company's communications to customers on matters of safety, as well as communicating information to customers about the nature of the services offered to them by the Company, and opportunities to conserve and be educated about the products that they purchase from us. Importantly, Mr. Beck describes a Language Access Plan that will expand access to essential billing, assistance, safety, and account information for customers with limited English proficiency and improve comprehension for English-proficient customers with limited literacy.

- In NW Natural/1100, Tobin F. Davilla, Director of Financial Planning and Budget, provides testimony about the O&M expense levels that the Company has incurred and expects to incur in the Test Year.
- In NW Natural/1200, Kyle T. Walker, Senior Manager of Rates and Regulatory Affairs, provides the calculation of the Company's revenue requirement, which represents the annual revenues needed to recover prudently incurred costs of operating the utility business, and presentation of tariffs. He also describes the proposed bridge mechanism.
- In NW Natural/1300, Robert J. Wyman, Regulatory Affairs Senior Economist, provides the Company's use-per-customer forecast, long run incremental cost study, and describes the Company's rate spread and rate design proposal.

V. CONCLUSION

For the reasons described in this application, and further by the testimony and exhibits of the witnesses offered in this proceeding, the Company requests that the Commission issue an order approving the proposed rate changes and tariff sheets.

Respectfully submitted this 24th day of November 2026.

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Exhibit A to NW Natural's Executive Summary
Summary of Requested General Rate Increase
Filed November 24, 2026

Total Revenues Collected Under Proposed Rates:	$1,083,776,469
Revenue Change Requested:	$90,061,116
Revenues Net of any Credits from Federal Agencies:	$1,083,776,469
Percentage Change in Revenue Requested:	9.105 %
Percentage Change in Revenues Net of any Credits from Federal Agencies:	9.105 %
Test Period:	November 1, 2027 to October 31, 2028
Requested Overall Rate of Return:	7.374%
Requested Rate of Return on Equity:	9.750%
Proposed Rate Base:	$2,494,868,282
Results of Operation	
Before Proposed Rate Change	
Utility Operating Income:	$120,478,127
Average Rate Base:	$2,494,868,282
Rate of Return on Capital:	4.829%
Rate of Return on Equity:	4.661%
After Proposed Rate Change	
Utility Operating Income:	$183,971,587
Average Rate Base:	$2,494,868,282
Rate of Return on Capital:	7.374%
Rate of Return on Equity:	9.750%

Bridge Mechanism Impact

Total Revenues Collected Under Proposed Rates:	$1,095,400,331
Revenue Change Requested:	$11,623,872
Revenues Net of any Credits from Federal Agencies:	$1,095,400,342
Percentage Change in Revenue Requested:	1.175 %
Percentage Change in Revenues Net of any Credits from Federal Agencies:	1.175 %

Test Period: Revenue requirement difference between the Test Year's 13-month average of monthly average plant in service and end-of-period plant in service as of October 31, 2028

Requested Overall Rate of Return	7.374%
Requested Rate of Return on Equity:	9.750%
Proposed Rate Base (after Bridge Mechanism Impact):	$2,557,881,631

Results of Operation

Before Proposed Rate Change	
Utility Operating Income:	$183,971,587
Average Rate Base:	$2,494,868,282
Rate of Return on Capital:	7.374%
Rate of Return on Equity:	9.750%
After Proposed Rate Change	
Utility Operating Income:	$188,618,191
Bridge Mechanism End of Period Rate Base:	$2,557,881,631
Rate of Return on Capital:	7.374%
Rate of Return on Equity:	9.750%

The $90.1 million of revenue requirement which includes $5.0 million of Plant EDIT amortization are as follows:

Rate Schedules	Current Average Monthly Bill	Proposed Average Monthly Bill	Change in Average Monthly Bill ($)	Change in Average Monthly Bill (%)
Schedule 2 – Single Family	$95.47	$103.91	$8.44	8.8%
Schedule 2 – Multi Family	$51.44	$55.74	$4.30	8.4%
Schedule 3 – Commercial	$382.64	$414.26	$31.62	8.3%
Schedule 3 – Industrial	$1,163.92	$1,253.41	$89.49	7.7%
Schedule 27 - Dry Out	$69.06	$75.43	$6.37	9.2%
Schedule 31 - Firm Sales - Commercial	$2,998.90	$3,166.82	$167.92	5.6%
Schedule 31 - Firm Transportation - Commercial	$1,793.71	$1,980.98	$187.27	10.4%
Schedule 31 - Firm Sales - Industrial	$4,646.27	$4,798.10	$151.83	3.3%
Schedule 31 - Firm Transportation - Industrial	$2,610.01	$2,803.08	$193.07	7.4%
Schedule 32 - Firm Sales - Commercial	$7,460.21	$7,785.95	$325.74	4.4%
Schedule 32 - Firm Sales - Industrial	$16,055.07	$16,567.93	$512.86	3.2%
Schedule 32 - Firm Transportation - Commercial	$4,598.62	$4,924.55	$325.93	7.1%
Schedule 32 - Firm Transportation - Industrial	$12,844.08	$13,888.30	$1,044.22	8.1%
Schedule 32 - Interruptible Sales - Commercial	$29,326.40	$30,023.16	$696.76	2.4%
Schedule 32 - Interruptible Sales - Industrial	$29,655.58	$30,301.67	$646.09	2.2%
Schedule 32 - Interruptible Transportation - Commercial	$27,724.19	$30,223.30	$2,499.11	9.0%
Schedule 32 - Interruptible Transportation - Industrial	$27,511.77	$28,595.45	$1,083.68	3.9%
Schedule 33 - Firm and Interruptible Transp Svcs	$38,250.00	$38,250.00	$0.00	0.0%
Rate Schedule 31 and 32 customers may choose demand charges at a volumetric rate or based on MDDV. For convenience of presentation, demand charges are not included in the calculation for those schedules.				

The revenue requirement plus additional temporary impacts to customers are as follows:

Rate Schedules	Current Average Monthly Bill	Proposed Average Monthly Bill	Change in Average Monthly Bill ($)	Change in Average Monthly Bill (%)
Schedule 2 – Single Family	$95.47	$103.95	$8.48	8.9%
Schedule 2 – Multi Family	$51.44	$55.75	$4.31	8.4%
Schedule 3 – Commercial	$382.64	$414.38	$31.74	8.3%
Schedule 3 – Industrial	$1,163.92	$1,253.73	$89.81	7.7%
Schedule 27 - Dry Out	$69.06	$75.46	$6.40	9.3%
Schedule 31 - Firm Sales - Commercial	$2,998.90	$3,167.58	$168.68	5.6%
Schedule 31 - Firm Transportation - Commercial	$1,793.71	$1,981.85	$188.14	10.5%
Schedule 31 - Firm Sales - Industrial	$4,646.27	$4,799.02	$152.75	3.3%
Schedule 31 - Firm Transportation - Industrial	$2,610.01	$2,804.24	$194.23	7.4%
Schedule 32 - Firm Sales - Commercial	$7,460.21	$7,787.46	$327.25	4.4%
Schedule 32 - Firm Sales - Industrial	$16,055.07	$16,570.20	$515.13	3.2%
Schedule 32 - Firm Transportation - Commercial	$4,598.62	$4,926.44	$327.82	7.1%
Schedule 32 - Firm Transportation - Industrial	$12,844.08	$13,893.24	$1,049.16	8.2%
Schedule 32 - Interruptible Sales - Commercial	$29,326.40	$30,027.45	$701.05	2.4%
Schedule 32 - Interruptible Sales - Industrial	$29,655.58	$30,305.60	$650.02	2.2%
Schedule 32 - Interruptible Transportation - Commercial	$27,724.19	$30,238.23	$2,514.04	9.1%
Schedule 32 - Interruptible Transportation - Industrial	$27,511.77	$28,602.17	$1,090.40	4.0%
Schedule 33 - Firm and Interruptible Transp Svcs	$38,250.00	$38,250.00	$0.00	0.0%
Rate Schedule 31 and 32 customers may choose demand charges at a volumetric rate or based on MDDV. For convenience of presentation, demand charges are not included in the calculation for those schedules.				

The $11.6 million that represents the bridge mechanism impacts to customers are as follows:

Rate Schedules	Current Average Monthly Bill	Proposed Average Monthly Bill	Change in Average Monthly Bill ($)	Change in Average Monthly Bill (%)
Schedule 2 – Single Family	$103.95	$105.04	$1.09	1.0%
Schedule 2 – Multi Family	$55.75	$56.31	$0.56	1.0%
Schedule 3 – Commercial	$414.38	$418.46	$4.08	1.0%
Schedule 3 – Industrial	$1,253.73	$1,265.28	$11.55	0.9%
Schedule 27 - Dry Out	$75.46	$76.28	$0.82	1.1%
Schedule 31 - Firm Sales - Commercial	$3,167.58	$3,189.26	$21.68	0.7%
Schedule 31 - Firm Transportation - Commercial	$1,981.85	$2,006.02	$24.17	1.2%
Schedule 31 - Firm Sales - Industrial	$4,799.02	$4,818.61	$19.59	0.4%
Schedule 31 - Firm Transportation - Industrial	$2,804.24	$2,829.15	$24.91	0.9%
Schedule 32 - Firm Sales - Commercial	$7,787.46	$7,829.51	$42.05	0.5%
Schedule 32 - Firm Sales - Industrial	$16,570.20	$16,636.40	$66.20	0.4%
Schedule 32 - Firm Transportation - Commercial	$4,926.44	$4,968.50	$42.06	0.9%
Schedule 32 - Firm Transportation - Industrial	$13,893.24	$14,028.02	$134.78	1.0%
Schedule 32 - Interruptible Sales - Commercial	$30,027.45	$30,117.38	$89.93	0.3%
Schedule 32 - Interruptible Sales - Industrial	$30,305.60	$30,388.96	$83.36	0.3%
Schedule 32 - Interruptible Transportation - Commercial	$30,238.23	$30,560.76	$322.53	1.1%
Schedule 32 - Interruptible Transportation - Industrial	$28,602.17	$28,742.04	$139.87	0.5%
Schedule 33 - Firm and Interruptible Transp Svcs	$38,250.00	$38,250.00	$0.00	0.0%
Rate Schedule 31 and 32 customers may choose demand charges at a volumetric rate or based on MDDV. For convenience of presentation, demand charges are not included in the calculation for those schedules.				

2026 General Rate Case (UG 532)

Cumulative Economic Impact Analysis

NW Natural

November 2026

NW Natural

NW Natural
General Rate Case (UG 532) – Cumulative Economic Impact Analysis

Introduction

Under ORS 757.211, in determining whether an electric or natural gas company's proposed residential rate or schedule of rates is fair, just and reasonable, the Public Utility Commission of Oregon (Commission) balances the interests of the utility investor and the consumer by considering the cumulative economic impact of the proposed rate or schedule of rates on the company's residential ratepayers. ORS 757.211(3) further provides:

> "An electric or natural gas company shall conduct and include with its filing an analysis of the cumulative economic impact of a proposed rate or schedule of rates on the electric or natural gas company's residential ratepayers if the electric or natural gas company's proposed residential rate or schedule of rates will result in an increase of residential rates and the electric or natural gas company's return on equity is subject to review and modification."

ORS 757.211(3) then identifies the information and data that such analysis must take into consideration. ORS 757.211(5) authorizes the Commission to "establish rules to carry out this section, including rules that require electric and natural gas companies to gather information or data necessary to carry out this section."

The Commission established such rules in OAR 860-022-0500, adopted in Docket AR 678 (Order No. 26-078), which sets out the minimum required content of the analysis. Because NW Natural's proposed residential rates in this general rate case will result in an increase in residential rates and the Company's return on equity is subject to review and modification, NW Natural provides the following cumulative economic impact analysis.

Bill Impact Analysis

Table 1: Average Monthly Residential Bill – 18 Months Preceding Proposed Effective Date

	Single Family	**Multi-Family**
Date Range	May 1. 2026 - October 30, 2027	May 1. 2026 - October 30, 2027
Average Monthly Energy Use-Per-Customer (therms)	43	23
Average Monthly Bill for the 18 months ending 10/30/2027	$ 74.93	$ 43.06

Table 2: Average Residential Winter Heating Bill Range – Two Years Preceding Proposed Rate Effective Date

	Single Family	Multi-Family
Date Range	November 1, 2025 - March 31, 2026 and November 1, 2026 - March 31, 2027	November 1, 2025 - March 31, 2026 and November 1, 2026 - March 31, 2027
High Winter Use-Per-Customer as Filed	110	56
Low Winter Use-Per-Customer as Filed	79	39
2025-2026 High Winter Average Monthly Bill	$ 165.91	$ 86.94
2025-2026 Low Winter Average Monthly Bill	$ 121.42	$ 63.08
2025-2026 Winter Average Bill Range	$121.42 to $165.91	$63.08 to $86.94
2026-2027 High Winter Average Monthly Bill	$ 178.82	$ 93.48
2026-2027 Low Winter Average Monthly Bill	$ 130.65	$ 67.64
2026-2027 Winter Average Bill Range	$130.65 to $178.82	$67.64 to $93.48

Table 3: Estimated Annual Residential Bill Impact

	Current Rates	UG 532 Proposed
Base Rates	$ 0.86	$ 1.01
Temporary Rates	$ 0.19	$ 0.19
Commodity Rates	$ 0.48	$ 0.48
Total Volumetric Billing Rate	$ 1.53	$ 1.68
Single-Family Fixed Charge	$ 10.00	$ 10.00
Multi-Family Fixed Charge	$ 8.00	$ 8.00
Annual Single-Family Use-Per-Customer	691	671
Annual Multi-Family Use-Per-Customer	351	341
Estimated Franchise Fee	2%	2%
Public Purpose Charge Percentage	4.13%	4.00%
Public Purpose Charge Fixed	$ 2.19	$ 2.19
Bill Discount Program	$ 1.97	$ 1.97
Single-Family Average Annual Bill	$ 1,299.32	$ 1,372.29
Multi-Family Average Annual Bill	$ 722.03	$ 759.06
Single-Family Bill Impact	N/A	5.62%
Multi-Family Bill Impact	N/A	5.13%

Narrative/Analysis: Average monthly bills for the 18 months ending October 30, 2027, are $74.93 and $43.06 for single-family and multi-family customers, respectively.

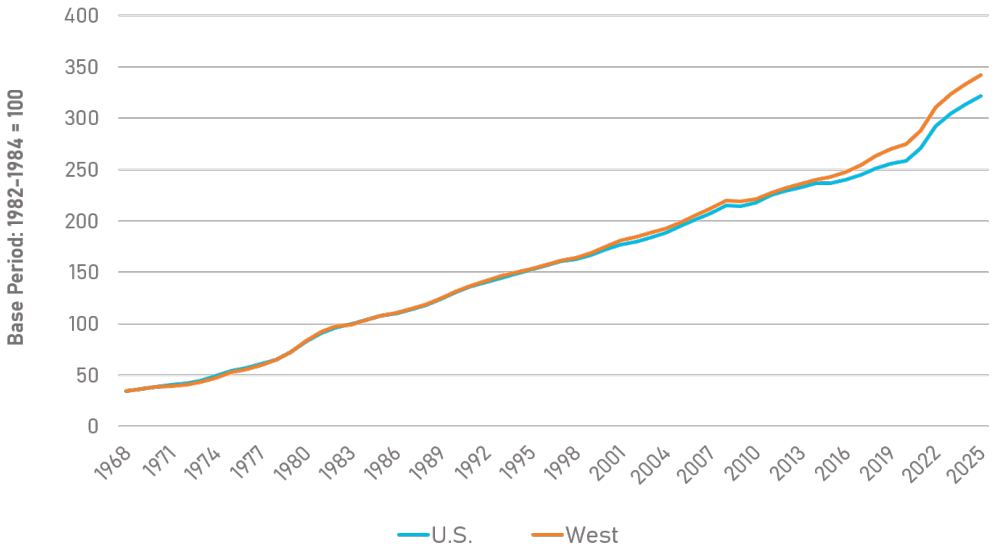
During the two preceding November through March heating seasons, average monthly bills range from $121.42 to $178.82 for single-family customers and $63.08 to $93.48 for multi-family customers. Multi-family use per customer is calculated using the current use-per-customer ratio between single-family and multi-family customers.

The proposed rates result in an estimated average annual bill impact of 5.62 percent for single-family customers and 5.13 percent for multi-family customers. The average bill estimates include current and forecast Public Purpose Charge and Bill Discount Program costs, along with base, temporary, commodity, and fixed charge rates. Use-per-customer annual values are also calculated using the current ratio between single-family and multi-family customers.

Cost of Living and Energy Costs

The Consumer Price Index (CPI) for All Urban Consumers in the U.S. and West Region (All Items) is presented in Figure 1 below. The annual change in the CPI for All Urban Consumers in the U.S. and West Region is presented in Figure 2 below. CPI data is not available for Oregon or NW Natural's service territory.

Figure 1: Consumer Price Index for All Urban Consumers (All Items)



Source: U.S. Bureau of Labor Statistics.

Figure 2: Annual Change in Consumer Price Index for All Urban Consumers (All Items)

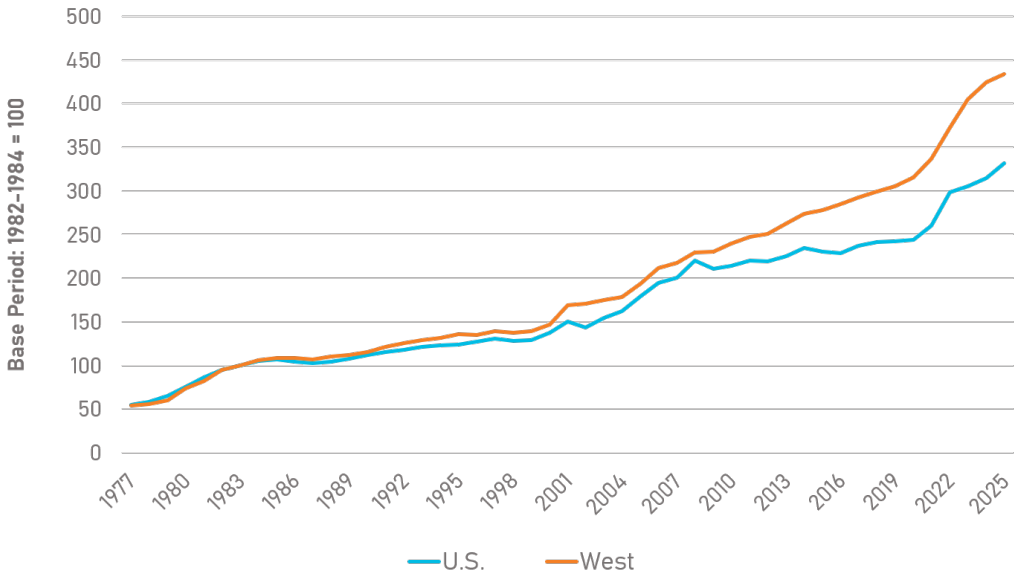


Source: U.S. Bureau of Labor Statistics.

Since 1985, consumer prices have been higher in the West than in the U.S. and that difference has widened over the past 10 years. Since 2015, consumer prices in the West have increased at an annualized rate of 3.5 percent compared to 3.1 percent in the U.S. In 2025, consumer prices in the West were 6.2 percent higher than prices in the U.S.

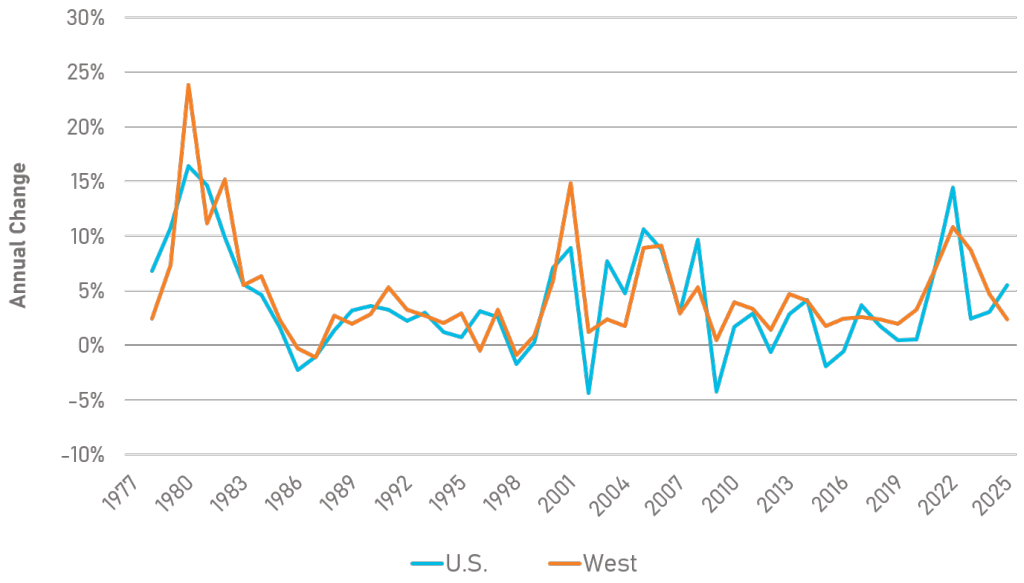
The cost of fuel and utilities from the CPI in the U.S. and West Region is presented in Figure 3 below. The annual change in the cost of fuel and utilities from the CPI in the U.S. and West Region is presented in Figure 4 below. The fuel and utilities component of the CPI (SAH2) is not limited to costs for household energy but also includes costs for water, wastewater, and trash collection. Household energy costs are specifically captured in Energy Services (SEHF), which is further detailed in Electricity (SEHF01) and Utility (Piped) Gas Service (SEHF02). Costs and annual change for household energy costs are presented in Figures 5 and 6 below.

Figure 3: Consumer Price Index for Fuels and Utilities for All Urban Consumers



Source: U.S. Bureau of Labor Statistics, Consumer Price Index for All Urban Consumers, Series ID: CUUR0000SAH2 and CUUR0400SAH2

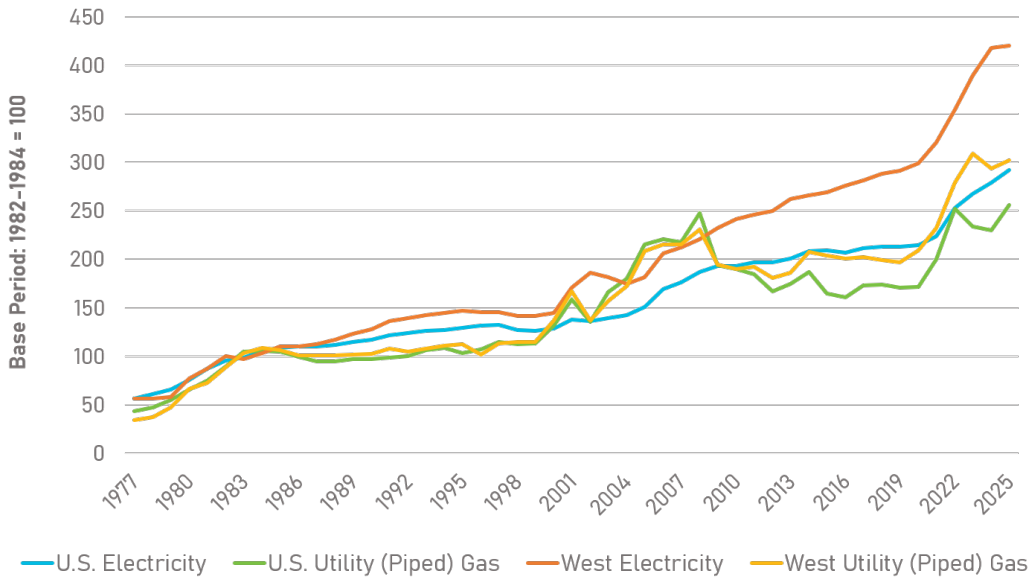
Figure 4: Annual Change in Consumer Price Index for Fuels and Utilities for All Urban Consumers



Source: U.S. Bureau of Labor Statistics, Consumer Price Index for All Urban Consumers, Series ID: CUUR0000SAH2 and CUUR0400SAH2.

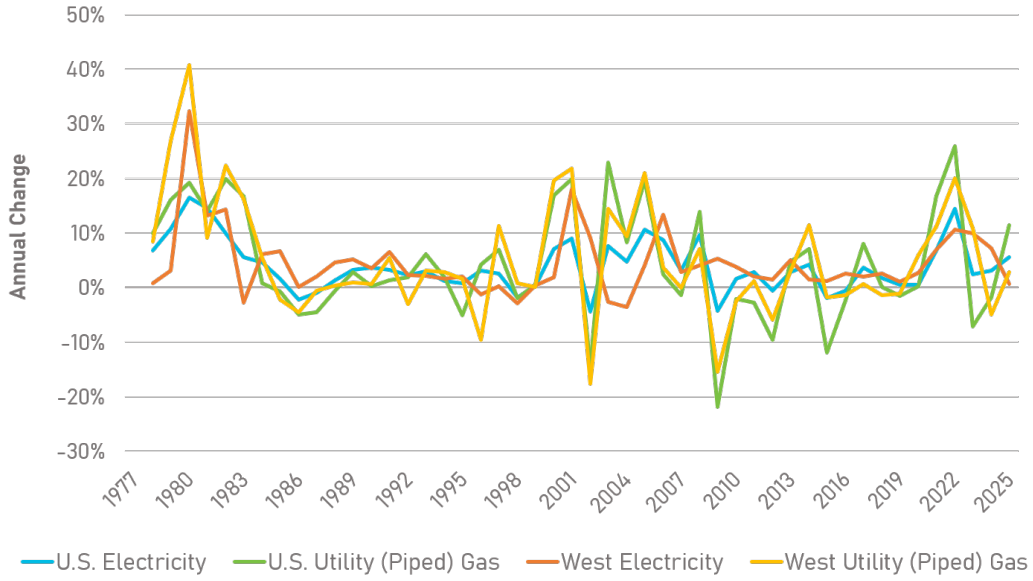
Consumer prices for fuels and utilities have also been higher in the West since the mid-1980s, and the difference with the U.S. has widened significantly over the past 15 years. Since 2010, consumer prices for fuels and utilities in the West have increased at an annualized rate of 4.0 percent compared to 3.0 percent in the U.S. In 2025, consumer prices for fuels and utilities in the West were 30.8 percent higher than prices in the U.S.

Figure 5: Consumer Price Index for Household Energy for All Urban Consumers



Source: U.S. Bureau of Labor Statistics, Consumer Price Index for All Urban Consumers, Series ID: CUUR0000SEHF01, CUUR0000SEHF02, CUUR0400SEHF01, CUUR0400SEHF02.

Figure 6: Annual Change in Consumer Price Index for Household Energy for All Urban Consumers



Source: U.S. Bureau of Labor Statistics, Consumer Price Index for All Urban Consumers, Series ID: CUUR0000SEHF01, CUUR0000SEHF02, CUUR0400SEHF01, CUUR0400SEHF02.

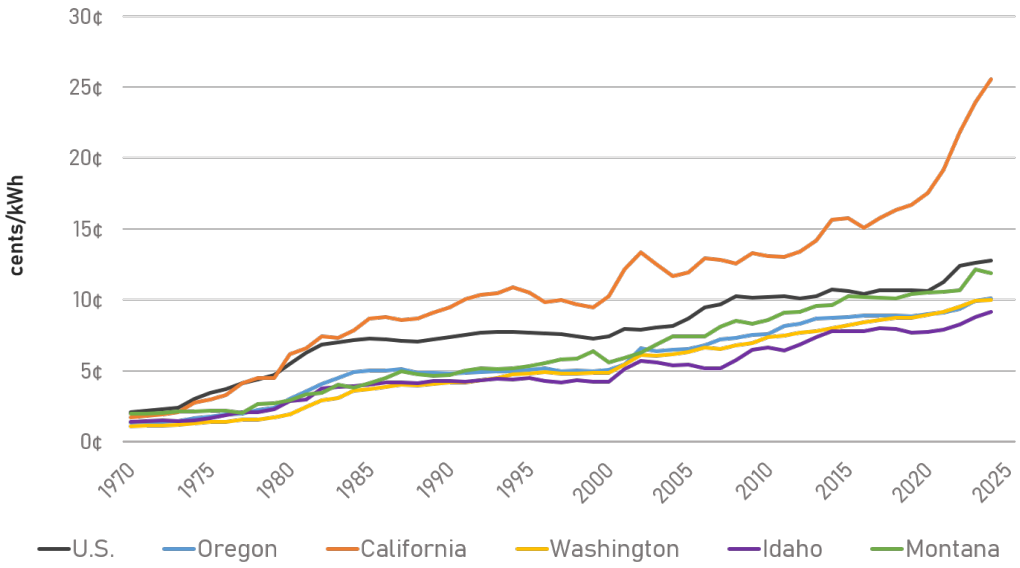
Household energy prices in the West have increased faster than in the U.S. since the mid-1980s, especially electricity. Since 1985, consumer prices in the West for electricity have increased at an annualized rate of 3.4 percent compared to 2.5 percent for natural gas. In the U.S., electricity and natural gas prices increased at rates of 2.5 and 2.3 percent, respectively. Household energy prices in the West and U.S. over the past five years have increased at historically high rates. From 2020 to 2025, electricity and natural gas prices in the West increased at rates of 7.0 and 7.6 percent, respectively, compared to 6.4 and 8.3 percent, respectively, in the U.S. In 2025, household prices for electricity in the West were 43.9 percent higher than prices in the U.S., while household prices for natural gas were 18.0 percent higher in the West than in the U.S.

Energy Costs – Commercial and Industrial

Energy Costs – Commercial

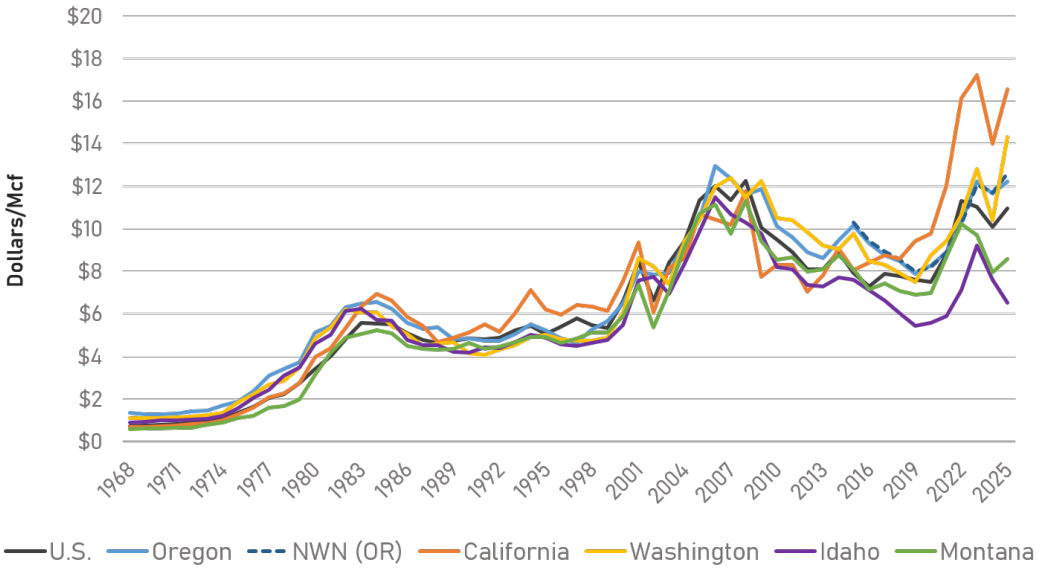
Commercial costs for electricity and natural gas in Oregon and other states in the region are presented in Figures 7 and 8 below. The annual change in commercial costs for electricity and natural gas is presented in Figures 9 and 10 below.

Figure 7: Commercial Average Retail Price for Electricity



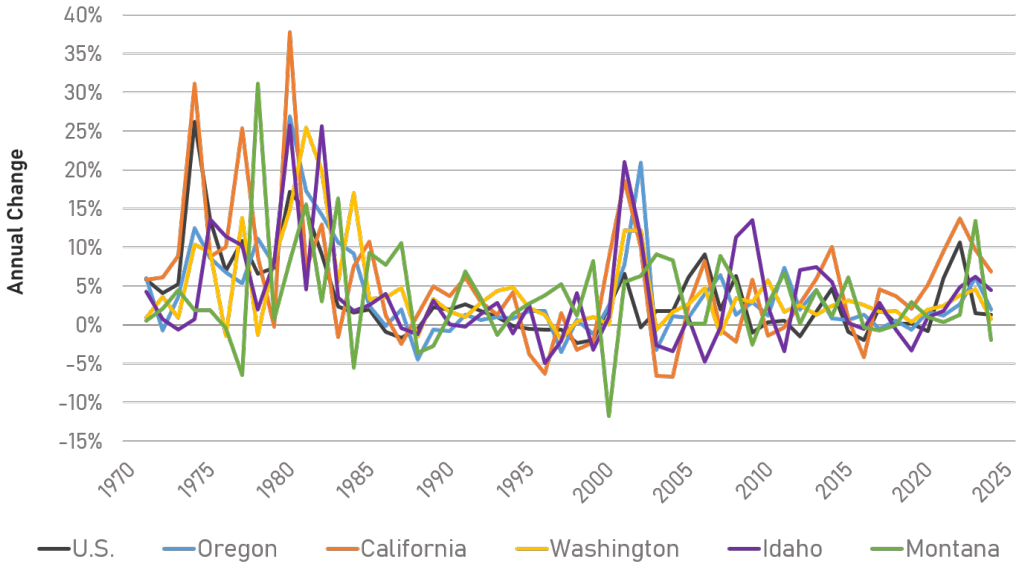
Source: U.S. Energy Information Administration, Historical State Data.

Figure 8: Commercial Average Retail Price for Natural Gas



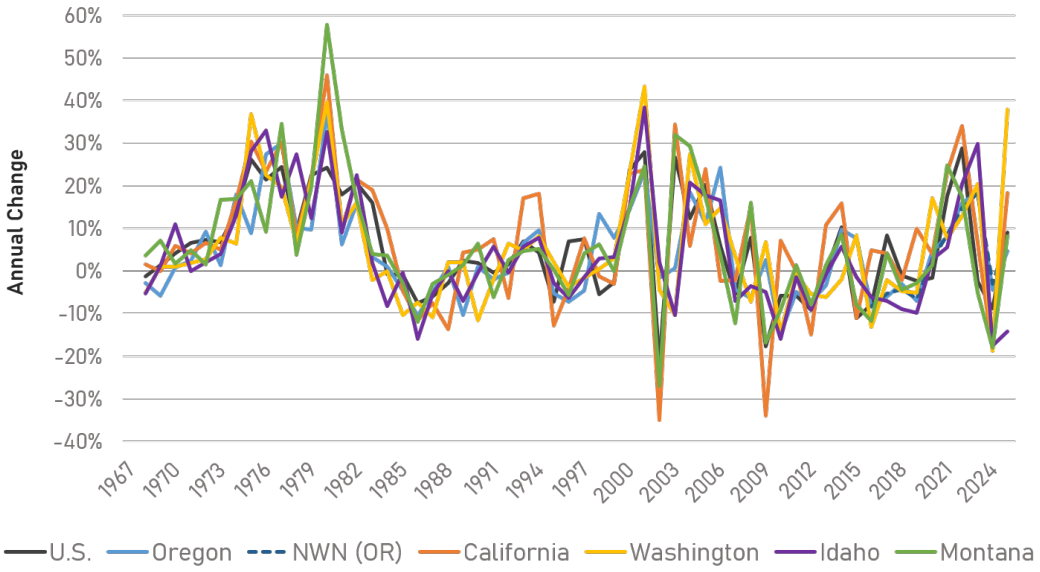
Source: U.S. Energy Information Administration.

Figure 9: Annual Change in Commercial Average Electricity Price



Source: U.S. Energy Information Administration, Historical State Data.

Figure 10: Annual Change in Commercial Average Natural Gas Price



Source: U.S. Energy Information Administration, Historical State Data.

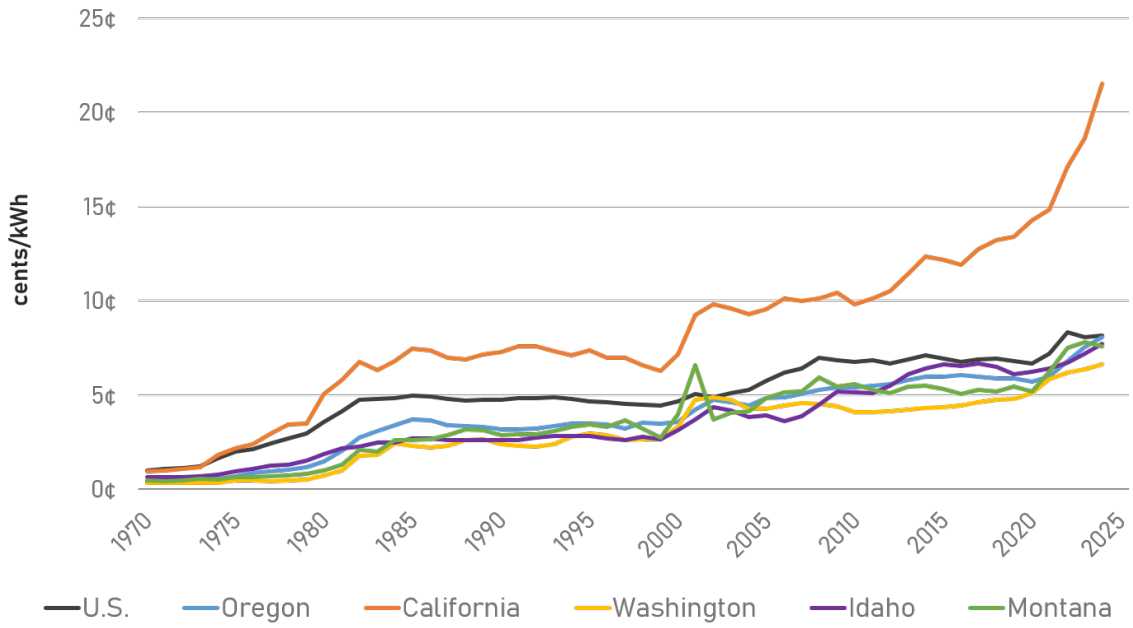
Commercial prices for electricity in Oregon have historically been lower than the U.S., but that price advantage has gradually declined over the past 50 years. In the 1970s, commercial prices for electricity in Oregon were about 45 percent lower than U.S. prices. In 2024, the average commercial price for electricity in Oregon was 20.7 percent lower than the U.S. Amongst its regional neighbors, Oregon's commercial price for electricity (10.1 cents/kWh) is far below California's commercial price for electricity (25.5 cents/kWh) where prices have risen dramatically over the past decade and below Montana's commercial price for electricity (11.9 cents/kWh), but is higher than the commercial price for electricity in Washington (10.0 cents/kWh) and Idaho (9.2 cents/kWh).

Commercial prices for natural gas in Oregon closely tracked those in the U.S. and regional states up until the Great Recession. Since then, prices in the region have still trended with the U.S. but with much more price divergence amongst states with prices trending higher in Oregon, Washington, and California, and lower in Idaho and Montana. In 2025, the commercial average natural gas price in Oregon ($12.2/Mcf) was 11.3 percent higher than the U.S. average. NW Natural's commercial average natural gas price in Oregon has historically trended closely with the statewide average and was $12.60/Mcf in 2025.

Energy Costs – Industrial

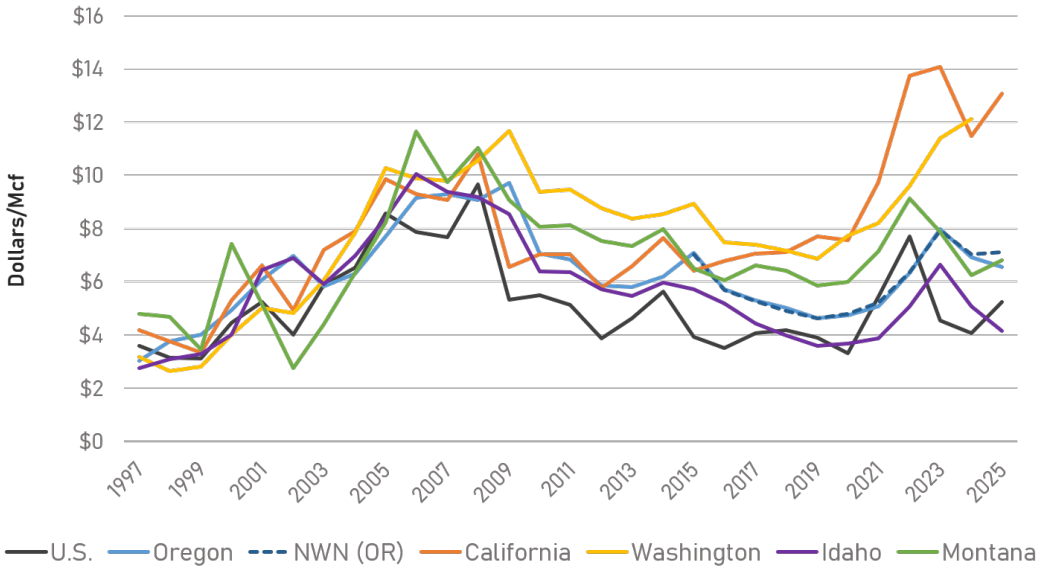
Industrial costs for electricity and natural gas in Oregon and other states in the region are presented in Figures 11 and 12 below. The annual change in costs for electricity and natural gas is presented in Figures 13 and 14 below.

Figure 11: Industrial Average Retail Price for Electricity



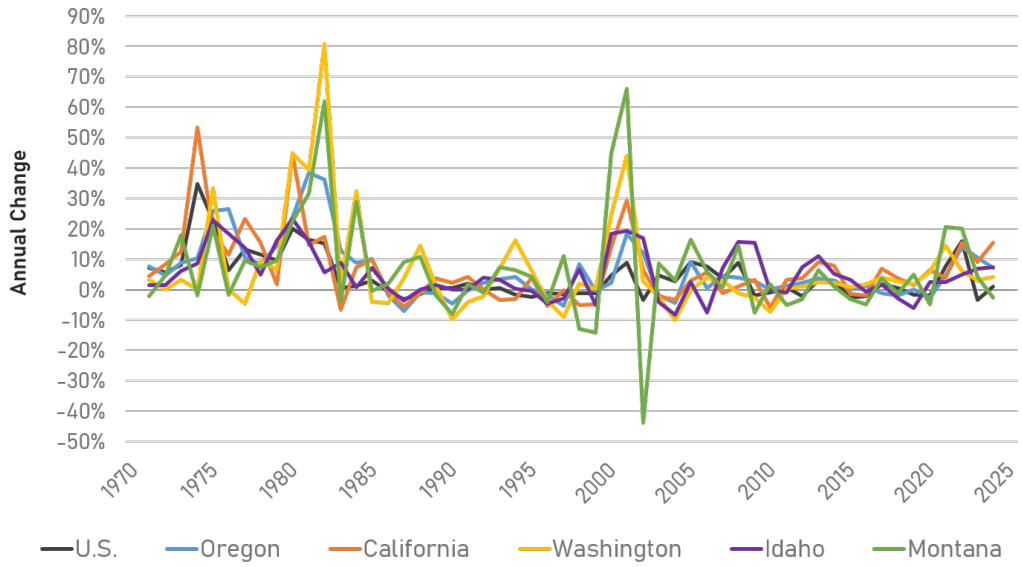
Source: U.S. Energy Information Administration, Historical State Data.

Figure 12: Industrial Average Natural Gas Price



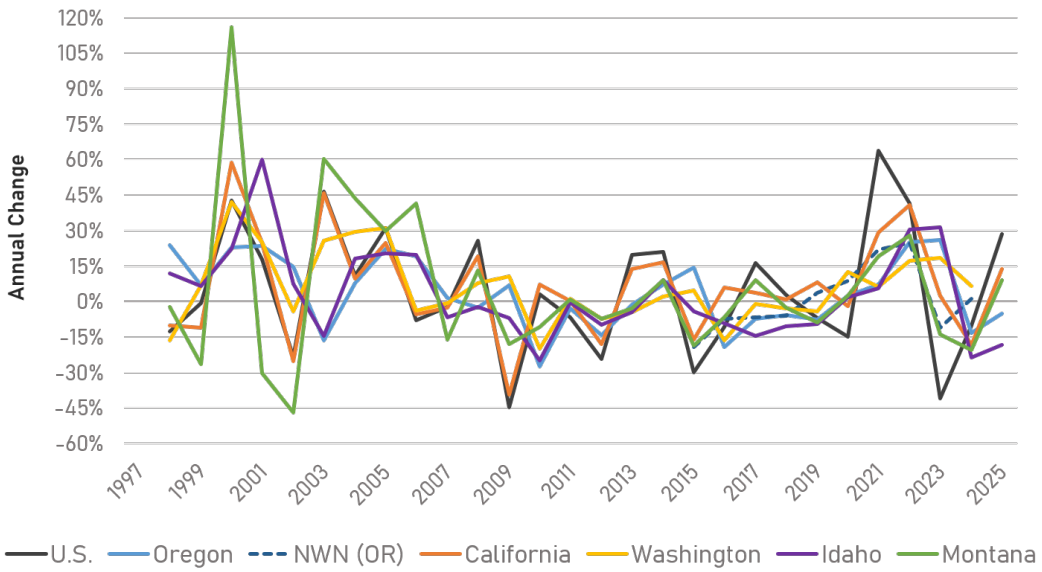
Source: U.S. Energy Information Administration.

Figure 13: Annual Change in Industrial Average Retail Price for Electricity



Source: U.S. Energy Information Administration, Historical State Data.

Figure 14: Annual Change in Industrial Average Price for Natural Gas



Source: U.S. Energy Information Administration.

Industrial prices for electricity in Oregon have historically been below those of the U.S. average, but the price difference has narrowed in recent years. In the 1970s, industrial prices for electricity in Oregon were 61 percent lower than in the U.S. Each decade since then has seen the price gap narrow, and by 2024 prices in Oregon were only 1 percent lower than in the U.S. Trends have been similar for other states in the region with the exception of California, whose industrial average price of electricity has far outpaced the price in the U.S. since the 1970s, and as of 2024 was 165 percent higher than the U.S. average price. Washington retains the lowest industrial prices for electricity.

Industrial prices for natural gas in Oregon and other states in the region have typically been higher than the prices in the U.S. since the mid-1990s. The industrial average price for natural gas in Oregon increased at an annualized rate of 2.8 percent from 1997 to 2015, which is higher than the U.S. rate of 1.4 percent and higher than the rates in Idaho and Montana, but lower than the rates in Washington and California. Post Great Recession, industrial prices for natural gas have trended downward in the region, except for in California and Washington, whose industrial prices for natural gas have nearly doubled over the past five years. Oregon's average industrial price for natural gas in 2025 ($6.55/Mcf) was 25 percent higher than the U.S. average price and higher than the price in Idaho ($4.15/Mcf) but much lower than prices in California ($13.06/Mcf) and Washington ($12.13/Mcf). NW Natural's average industrial price for natural gas in Oregon has historically trended closely with the statewide average and was $7.10/Mcf in 2025.

Residential Disconnection Analysis

Data supporting the following disconnection analysis was sourced from the Company's Customer Information System (CIS), energy burden metric reporting, and its most recent Energy Burden Assessment data refresh.[1]

Table 4 below provides the number of notices sent to residential customers warning of possible disconnection; the number and percentage of residential customers disconnected for non-payment; the number of medical certificates on file; and the number and percentage of customers receiving energy assistance (Low-Income Home Energy Assistance Program (LIHEAP), Oregon Low-Income Gas Assistance (OLGA), Gas Assistance Program (GAP)) who have been disconnected for non-payment. Table 5 below additionally provides the number of customers who are enrolled in the Company's Bill Discount Program (BDP); and the number and percentage of customers enrolled in BDP disconnected for non-payment.

During the timeframe of October 2025 to September 2026, the most recent 12-month period, residential disconnections for non-payment remained low, averaging less than 0.16 percent of active residential customers. Customers receiving energy assistance experienced very low disconnection rates, generally below 0.01 percent of active accounts, and no customers with medical certificates were disconnected during the reporting period.

BDP participation increased throughout the year, reaching more than 52,000 enrolled customers. BDP participants experienced relatively low disconnection rates, remaining below one percent in all months reviewed. The highest-disconnection zip codes, as shown in Table 6 below, generally experienced BDP saturation rates between about 50 and 84 percent, suggesting that enrollment efforts are reaching many eligible customers in areas experiencing elevated risk of disconnections. These results indicate that customer safeguards and assistance programs continue to help vulnerable customers maintain service. Targeted outreach and enrollment activities remain important opportunities to further reduce disconnections, which is especially important as BDP disconnection experience is generally higher than the experience for all customers.

[1] NW Natural completed a full Energy Burden Assessment in 2024 and updated the assessment with a more recent data set in 2026. The Company engaged Empower Dataworks for both studies.

Table 4: Residential Disconnections for Non-payment October 2025-September 2026

Month	# Notices Sent	# Disconnected for Non-payment	% Disconnected for Non-payment	# Customers with Medical Certificate*	#EA Recipients** Disconnected	% EA Recipients Disconnected (% of total active accounts)
2025-10	6,658	706	0.1088%	160	32	0.0049%
2025-11	7,301	404	0.0622%	145	14	0.0022%
2025-12	19,870	695	0.1068%	143	27	0.0041%
2026-01	31,474	834	0.1281%	172	24	0.0037%
2026-02	37,884	1,148	0.1764%	175	32	0.0049%
2026-03	31,268	1,490	0.2286%	178	40	0.0061%
2026-04	30,114	1,641	0.2517%	216	46	0.0071%
2026-05	21,399	1,452	0.2228%	210	53	0.0081%
2026-06	15,698	1,089	0.1671%	246	30	0.0046%
2026-07	10,946	1,302	0.1998%	210	37	0.0057%
2026-08	8,445	778	0.1196%	207	28	0.0043%
2026-09	7,530	720	0.1106%	180	23	0.0035%

*There were zero disconnections of customers with medical certificates.
**Energy Assistance (EA) recipients reflect those customers receiving an EA grant on their bill in the last 12 months.

Table 5: BDP Enrolled Customers Disconnections for Non-payment October 2025-September 2026

Month	# BDP Enrollments	# of BDP Disconnected	% of BDP Disconnected
2025-10	47,269	222	0.4697%
2025-11	47,986	108	0.2251%
2025-12	48,576	151	0.3109%
2026-01	49,408	147	0.2975%
2026-02	50,387	211	0.4188%
2026-03	51,156	317	0.6197%
2026-04	51,863	399	0.7693%
2026-05	52,175	428	0.8203%
2026-06	52,348	301	0.5750%
2026-07	52,269	389	0.7442%
2026-08	52,123	279	0.5353%
2026-09	52,110	213	0.4088%

Table 6: Top Disconnected Zip Codes and Corresponding BDP Saturation Rate

Zip Code	Estimated BDP Saturation
97026	51.85%
97042	84.21%
97071	57.39%
97232	48.79%
97301	49.24%
97303	59.72%
97347	40.59%
97380	56.31%
97420	47.71%
97458	43.75%

Residential Arrearage Analysis

Data supporting this arrearage analysis was sourced from the Company's CIS and energy burden metric reporting. Table 7 below summarizes residential arrearages over the October 2025 to September 2026 period and provides the number of residential customers with overdue balances; the average overdue balance amount; and the total amount of overdue balances owed to the Company. Table 8 below additionally summarizes arrearages for residential customers enrolled in the Company's BDP over the same timeframe.

Table 7: Residential Arrearages October 2025 through September 2026

Month	Total Residential Customers in Arrears	Total Arrears Balance	Average Arrears Balance
2025-10	54,823	$3,555,957.66	$64.86
2025-11	59,854	$4,420,725.91	$73.86
2025-12	50,315	$4,930,394.72	$97.99
2026-01	49,845	$6,319,634.65	$126.79
2026-02	55,010	$7,589,626.78	$137.97
2026-03	47,395	$6,138,441.69	$129.52
2026-04	49,626	$6,234,106.31	$125.62
2026-05	56,359	$6,443,953.89	$114.34
2026-06	51,543	$4,918,174.53	$95.42
2026-07	54,213	$4,371,446.48	$80.63
2026-08	55,660	$4,175,374.70	$75.02
2026-09	55,318	$3,884,390.01	$70.22

Table 8: Residential Customers Enrolled in BDP Arrearages October 2025 through September 2026

Month	Total BDP Enrolled Customers in Arrears	BDP Total Arrears Balance	BDP Average Arrears Balance
2025-10	10,052	$601,778.54	$59.87
2025-11	10,839	$710,231.32	$65.53
2025-12	10,769	$889,992.17	$82.64
2026-01	11,496	$1,244,771.91	$108.28
2026-02	11,916	$1,522,501.50	$127.77
2026-03	11,385	$1,338,638.32	$117.58
2026-04	11,796	$1,313,485.83	$111.35
2026-05	12,568	$1,332,821.55	$106.05
2026-06	11,878	$1,060,829.89	$89.31
2026-07	11,833	$906,084.96	$76.57
2026-08	11,729	$851,145.59	$72.57
2026-09	11,609	$789,654.70	$68.02

Residential arrearages have stayed relatively flat over the previous 24 months[2] with minor decreases in both the number of customers and total amount in arrears during the past 12 months. Balances are largely driven by seasonal heating demand. Residential arrearages increased seasonally during the winter heating months and declined as customer usage and bills decreased through the spring and summer. Average arrearage balances followed a similar pattern, rising to roughly $138 during winter months and falling to approximately $70 by the end of the reporting period.

Fewer than ten percent of all residential customers carried an arrears balance from October 2025 to September 2026, with an average arrears balance of about $98.00. Customer arrearages of those enrolled in the Company's BDP also declined steadily after the winter peak, mirroring broader customer trends. The Company's affordability programs, including the BDP and Arrearage Management Program (AMP),[3] provide important support for customers experiencing payment difficulties. During the reporting period, as shown in Table 9 below, the Company issued nearly 3,000 AMP grants totaling more than $650,000 helping eligible customers reduce outstanding balances and avoid service interruption.

[2] Residential arrearages are reported in the Company's Energy Burden Metric Quarterly Reporting, filed in Commission docket RO 16.
[3] The Company's AMP started April 1, 2025, providing grants to eligible residential customers qualifying for Tier 0 (85% discount) of the Company's BDP. The AMP provides instant grants up to $1,500 every 24 months.

Table 9: Arrearage Management Program Grant Summary October 2025 - September 2026

Month	# AMP Grants	Total AMP Grant Amt	Avg AMP Grant
2025-10	91	$21,990.00	$241.65
2025-11	156	$33,570.97	$215.20
2025-12	189	$45,168.86	$238.99
2026-01	254	$60,633.08	$238.71
2026-02	334	$91,583.42	$274.20
2026-03	342	$96,272.18	$281.50
2026-04	326	$78,905.29	$242.04
2026-05	309	$68,795.03	$222.64
2026-06	274	$51,448.52	$187.77
2026-07	269	$44,818.04	$166.61
2026-08	217	$33,835.22	$155.92
2026-09	201	$32,289.41	$160.64

Residential Energy Burden and Affordability Analysis

Data supporting the following energy burden and affordability analysis was sourced from the Company's recent Energy Burden Assessment (EBA) data refresh, completed in 2026. [4] The Company's EBA data refresh indicates that affordability challenges are concentrated among lower-income households.[5] While the median natural gas burden for all residential customers is approximately 0.8 percent of household income, the median burden for low-income households is 2.6 percent, exceeding the Company's two percent energy affordability threshold, before accounting for the Company's assistance programs. The majority of customers experiencing affordability challenges are the approximately 59,000 low-income households identified as having a high energy burden. The following data in Table 10 below are sourced from this refreshed EBA and are calculated without factoring in any form of energy assistance or bill discount.

[4] The Company shared its 2026 EBA data refresh with stakeholders on October 28, 2026, and has additionally filed the report in Commission docket UM 2211.

[5] The low-income thresholds are updated each program year, set at 60 percent of Oregon State Median Income, as updated by the Department of Health and Human Services. The Company's most recent EBA data refresh utilizes Oregon's program year 2026 (October 2025-September 2026) definition of low-income based on State Median Income.

Table 10: Energy Burden Assessment Data Refresh – Summary of Residential Energy Burden as of May 2026

Data Date Range: Jan 1, 2024-May 31, 2026	All Households	Low Income Households	Non-Low Income Households
# High burden customers (>2%)	83,430	59,266	24,164
Median gas burden	0.8%	2.6%	0.7%
Energy assistance need*	$43,900,000	$35,000,000	$8,880,000
Avg Energy Assistance needed to bring burden below 2% (per customer)	$526.00	$590.00	$368.00
*The total amount of customer bill spending in excess of the high-burden threshold (2%).			

NW Natural's Oregon residential customers have benefited from the availability of the Company's income-qualified programs (OLGA, GAP, Oregon Low-Income Energy Efficiency (OLIEE), BDP, and AMP) that support the reduction of energy burden in addition to federal energy assistance through LIHEAP. Further, all NW Natural residential customers have access to energy efficiency programs, offered through Energy Trust of Oregon and other partners, which can also aid in mitigating energy burden.

Since November 1, 2022, eligible customers have significantly benefited from the Company's BDP as shown in Table 11 below. Participation rates for BDP are strongest among the lowest-income households, reaching approximately 78 percent of Tier 0 customers and remaining above 40 percent across all discount tiers. This demonstrates a strong alignment between program spending and assistance need.

Table 11: Energy Burden Assessment Data Refresh – BDP Participation Rates

Income Tier	Current Discount Level	Estimated # Households	% High Energy Burden	Participation Rate
Tier 0: 0-15% SMI	85%	12,300	87%	78%
Tier 1: 15-30% SMI	50%	21,700	83%	63%
Tier 2: 30-45% SMI	30%	25,700	67%	57%
Tier 3: 45-60% SMI	15%	29,200	45%	44%

The assessment estimates approximately $35 million in annual assistance need among low-income households, compared to approximately $23.6 million in existing program support. Stated another way, to bring all NW Natural customers who earn under the 60% SMI below a 2% burden threshold would cost $35 million. Current assistance programs (including direct assistance grants and discounts) are estimated to address roughly 69 percent of this identified need by the end of 2026, primarily through BDP, with the majority of program benefits directed toward customers facing the highest energy burdens. Table 12 below illustrates this using a stratified view of energy burden.

Table 12: Energy Burden Assessment Data Refresh – Stratified Energy Burden

Gas Burden	# Low Income Customers	Assistance Need*	Program Funding (All)**	Participation Rate
0-2% (Affordable)	29,600	$0.0M	$5.9M	68%
2-5% (Unaffordable)	37,000	$13.2M	$8.7M	59%
5-10% (Very Unaffordable)	13,500	$11.7M	$4.3M	56%
10%+ (Extremely Unaffordable)	8,700	$10.0M	$4.6M	69%
Total	˜89,000	$35M	$23.6M	˜63%
*Energy Burden and assistance need are calculated without factoring in any form of assistance. **Approximately $16M is distributed through the Bill Discount Program.				

Analysis in the EBA data refresh concluded that discount levels "appear to be appropriate at this time and can accommodate moderate rate increases without requiring adjustments" and recommended maintaining the current discount levels as programs are successfully targeting higher-burden households. Further, the analysis revealed that current BDP discount levels can support moderate rate increases with no changes to the structure of the program.

Using data from NW Natural's energy burden metric reporting and income tables from the past two program years, Table 13 and Table 14 below illustrate the effectiveness of the BDP and the ability of the Company's energy affordability programs to support moderate rate increases.

Table 13: BDP Impact on Energy Burden – Annualized Bill

Program year	Tier	Discount %	Bill w disc	Bill w/out disc
Oct 2024-Sep 25	Tier 3	15%	$799.47	$930.18
(changed discount %s Nov 24)	Tier 2	30%	$804.63	$1,088.94
	Tier 1	50%	$717.49	$1,177.25
	Tier 0	85%	$229.32	$996.55
Oct 2025-Sep 26	Tier 3	15%	$796.00	$923.41
	Tier 2	30%	$670.82	$929.62
	Tier 1	50%	$484.76	$911.61
	Tier 0	85%	$110.66	$847.71

Table 14: BDP Impact on Energy Burden – Annualized Bill Min, Mid, Max

			Annual Bill WITHOUT discount as % of income tier			**Annual Bill WITH discount as % of income tier**			**Income tiers - Household of Four**		
Program year	**Tier**	**Discount %**	min	mid	max	min	mid	max	min	mid	max
Oct 2024-Sep 25	Tier 3	15%	1.75%	1.50%	1.31%	1.51%	1.29%	1.13%	$53,093	$61,941	$70,790
(changed discount %s Nov 24)	Tier 2	30%	3.08%	2.46%	2.05%	2.27%	1.82%	1.52%	$35,396	$44,244	$53,092
	Tier 1	50%	6.65%	4.43%	3.33%	4.05%	2.70%	2.03%	$17,698	$26,546	$35,395
	Tier 0	85%		11.26%	5.63%		2.59%	1.30%	$0	$8,849	$17,697
Oct 2025-Sep 26	Tier 3	15%	1.67%	1.43%	1.25%	1.44%	1.23%	1.08%	$55,363	$64,590	$73,817
	Tier 2	30%	2.52%	2.02%	1.68%	1.82%	1.45%	1.21%	$36,909	$46,135	$55,362
	Tier 1	50%	4.94%	3.29%	2.47%	2.63%	1.75%	1.31%	$18,455	$27,681	$36,908
	Tier 0	85%		9.19%	4.59%		1.20%	0.60%	$0	$9,227	$18,454

The EBA data refresh also estimates that during the calendar year of 2025, median program participant energy burden fell, from 2.7 percent before assistance to 1.7 percent after assistance. This also indicates that programs are successfully reducing energy burden for all participants, reaching a wider range than even the targeted audiences. Additional narratives on the effectiveness of NW Natural's suite of Energy Affordability programs are provided in the Direct Testimony of Kim A. Rush and Zachary D. Kravitz, NW Natural/100 Rush-Kravitz, and Cecelia J. Tanaka, NW Natural/200, Tanaka.

Continued BDP enrollment efforts, combined with energy efficiency, bill assistance and arrearage management programs, remain important tools for mitigating customer affordability concerns. NW Natural is also in the midst of completing its first Language Access Plan that will support targeting important programs to customers most in need, including those with limited English proficiency.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Direct Testimony of Kim A. Rush and Zachary D. Kravitz

POLICY EXHIBIT 100

November 24, 2026

EXHIBIT 100 - DIRECT TESTIMONY - POLICY

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I. INTRODUCTION AND SUMMARY

Q. Please state your names, positions with Northwest Natural Gas Company dba NW Natural ("NW Natural" or "the Company") and summarize your educational background and business experience.

A. My name is Kim A. Rush. 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. The purpose of our testimony is to provide a high-level overview of the Company's application for a general rate revision and explain the cost and business drivers that led to NW Natural making this request.

Q. Please summarize your testimony.

A. First, we provide an overview of both NW Natural and its requested rate increase. As part of its requested rate increase, NW Natural is proposing a bridge mechanism that would be in effect between the end of the Test Year in this proceeding (October 31, 2028) and the rate effective date of NW Natural's first multiyear rate plan (October 31, 2029) per OAR 860-022-0081(3)(c). NW Natural's proposed bridge mechanism would not add new capital investments or operations and maintenance ("O&M") expense into rates. Instead, it would update rate base to reflect end-of-period utility plant in service and depreciation expense as of October 31, 2028, increasing revenue requirement by an additional 1.2 percent.

Second, we identify the key cost categories that are driving NW Natural's proposed increase in revenue requirement (O&M expense, capital investment, and taxes). In this section, we explain how each cost category is putting upward pressure on rates, and the actions that NW Natural is taking to control these costs, mitigating rate pressure that customers would otherwise face.

Third, we discuss NW Natural's commitment to affordability and equity. The Company's average residential customer's bill is less expensive than it was two decades ago after adjusting for inflation. NW Natural's affordability portfolio,

including its Bill Discount Program ("BDP"), supplemental grant assistance programs, and its energy efficiency and weatherization programs, promote equity and further reduce costs for income-qualified customers.

Fourth, we provide a brief overview of major projects that NW Natural is seeking cost recovery of in this proceeding, such as NW Natural's investments to ensure safe and reliable operations, including those at our natural gas storage facilities at Newport and Mist, as well as continued investments to information technology and services ("IT&S") systems. Since 2003, NW Natural has passed back to customers $324 million in bill credits associated with its efficient optimization of Mist storage and pipeline capacity.

Fifth, we discuss NW Natural's vital role in ensuring that Oregonians continue to have access to affordable, safe, and reliable energy. Given the ongoing resource adequacy issues on the electric system, especially during winter peak, the capacity that NW Natural's system provides remains essential to meeting Oregon's energy needs.

Finally, we introduce the Company's witnesses and provide a high-level description of their testimony.

II. OVERVIEW OF NW NATURAL AND ITS GENERAL RATE APPLICATION

Q. Please describe NW Natural's business.

A. As the largest standalone gas utility in the Pacific Northwest, NW Natural serves more than 2 million people in Oregon and southwest Washington. In Oregon, our employee base of approximately 1,250 dedicated employees provides service to

over 710 thousand Oregon customer accounts in 126 cities in 15 different counties, representing approximately 88 percent of our total gas system customer base. The Company delivers natural gas to its customers through more than 14,000 miles of transmission and distribution pipelines. In addition, it has over 20 billion cubic feet of natural gas storage at our three storage operations, which allows us to reliably and affordably provide energy to our customers on the coldest of winter days.

Q. What is the rate increase that NW Natural is requesting in this proceeding?

A. NW Natural is seeking to increase revenues from base rates by $90.1 million, which would be a 9.1 percent increase in overall revenues. Importantly, however, $19.8 million of this increase does not reflect any new or additional costs. It results from updating the weather-normalized use-per-customer ("UPC") assumed in rates to reflect declining residential and commercial usage. These are revenues the Commission has already authorized NW Natural to recover, and absent this update, they would be collected through NW Natural's decoupling deferral. For this portion of the request, NW Natural is proposing only a change in rate design—*how* these revenues are collected, not *whether* they are collected. Excluding this amount, the net increase that the Company is requesting is $70.3 million or approximately 7.1 percent.

Without the requested increase in base rates, NW Natural's gas distribution utility would expect the overall ROR to be 4.829 percent, with a corresponding return on equity ("ROE") of 4.66 percent, well below the Company's currently authorized ROR and ROE of 7.120 percent and 9.5 percent, respectively, as well

as the proposed ROR and ROE in this case of 7.374 percent and 9.75 percent. The Company, therefore, needs to increase its rates in order to maintain an ability to recover our costs and have the opportunity to 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 our customers.

Q. Please explain why $19.8 million of NW Natural's requested revenue increase does not reflect new costs and would otherwise be collected through the Company's decoupling deferral.

A. Base rates are designed to recover the Commission-authorized revenue requirement based on an assumed UPC. When customers use less natural gas than assumed, base rates fall short of that authorized amount, and the decoupling deferral recovers the difference. Decoupling separates NW Natural's revenues from the amount of natural gas it sells, thereby removing the Company's financial incentive to promote greater throughput and discourage energy efficiency. In the Company's last rate case (docket UG 520), filed in December 2024, NW Natural's residential customers that connected to the system prior to 2018 (i.e., the vast majority of its residential customers) used 664.89 therms per year on a weather-normalized basis. Over the last two years, that usage has declined to a weather-normalized 641.76 therms per year.[1] Portland General Electric Company ("PGE") also recently noted that its residential customers' electric UPC has declined by 5.3

[1] NW Natural's residential customers that connected to the system after 2018 have had a similar drop in usage. See the Direct Testimony of Kyle T. Walker, NW Natural/1200, Walker.

percent on a weather-normalized basis, indicating that customers are using less energy overall.[2]

If NW Natural did not file this general rate case, the gap between the UPC assumed in rates and customers' actual use would continue to accumulate in the decoupling deferral and would ultimately be recovered from customers. Updating residential and commercial UPC therefore adds no new costs; it changes only *how* this portion of the already-authorized revenue requirement is collected—through base rates rather than the decoupling deferral. Last year, for instance, due to a combination of warmer than normal weather and UPC assumptions from the last general rate case (docket UG 520), NW Natural's decoupling deferral collected from residential and commercial customers was approximately $54.2 million.[3] By improving the accuracy of its weather-normalized UPC, NW Natural is seeking to reduce its reliance on the decoupling deferral, promoting more stable and predictable rates that do not vary as much from year to year.

Q. Is the decline in residential and commercial UPC consistent with Oregon policy that encourages customers to use energy as efficiently as possible?

A. Absolutely. Customers using less energy is an undoubtedly positive development that is consistent with the State's longstanding promotion of energy efficiency.

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[2] *In the Matter of Portland General Electric, Request for a General Rate Revision*, Docket No. UE 473, Direct Testimony of Angelica Espinosa, PGE/100, Espinosa/8 (Aug. 4, 2026) (available at: https://edocs.puc.state.or.us/efdocs/HTB/ue473htb348336029.pdf).

[3] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for 2026-2027 Purchase Gas Adjustments and Coincident Rate Adjustments*, Docket No. UG 531, Order No. 26-407, Appendix A at 13 (Oct. 28, 2026).

Customers using less natural gas also means that NW Natural's fixed costs are being spread across fewer therms, meaning that the cost per-therm in base rates increases, even though the Company's overall customer base continues to grow. As stated above, however, this increase in base rates is offset by a correspondingly smaller decoupling deferral balance, limiting rate volatility.

Q. How does this case align with the Fairness and Affordability in Residential Energy Act ("FAIR Act"), the shift to multiyear rate plans, and overall affordability concerns?

A. This case is designed to support each of these objectives. The FAIR Act (House Bill 3179, 2025) transitions Oregon's utilities to multiyear rate plans. Smaller, regular rate changes are particularly important in a highly inflationary environment, where even disciplined cost management cannot avoid macroeconomic pressures. When rates are not adjusted regularly, those pressures accumulate and must ultimately be reflected in a single, larger increase.

NW Natural has long advocated for smaller rate changes year over year, so that each change is manageable for customers, rather than larger increases that occur less frequently. This proceeding is presented as the final step in NW Natural's transition to its first multiyear rate plan, which is expected to take effect on October 31, 2029. Consistent with OAR 860-022-0081(3)(c), NW Natural is proposing a bridge mechanism that would take effect October 31, 2028, and limit the increase that customers would otherwise face when the multiyear rate plan

begins. Because the bridge mechanism's rate impact will be known a year in advance, it also gives customers greater rate certainty during this transition.

Q. Why does NW Natural need to come in for a rate case at all?

A. NW Natural's first priority is the safety and reliability of the critical infrastructure that serves our customers. We understand and take seriously the affordability concerns that customers, the Commission, and stakeholders have raised, and, as discussed throughout our testimony, those concerns have shaped this request. But a public utility cannot divert from its core mission of keeping energy flowing and keeping customers and communities safe. For a natural gas utility, underinvesting in the system is not an option; the consequences can include service interruptions on the coldest days of the year and, at worst, risks to public safety.

That obligation does not pause in an inflationary environment. NW Natural must continue to invest in its pipelines, storage facilities, and the systems that support them, and must continue to incur the O&M expense required to operate them safely, even as the costs of labor, materials, and construction rise faster than general inflation. This is the social contract that underlies utility regulation: NW Natural has an obligation to provide safe and reliable service to every customer it serves, and in turn, an opportunity to recover the prudent costs of doing so.

Delaying this case would not make these costs go away. The investments and expenses described in this testimony are necessary regardless of when NW Natural files a general rate case. If the Company did not seek recovery now, those

costs would continue to accumulate and would ultimately be reflected in a larger rate change later, which is precisely the outcome that smaller, regular rate changes are intended to avoid.

Q. Ahead of the transition to multiyear rate plans, why did NW Natural pursue an Alternative Rate Mechanism ("ARM") (docket UG 527) rather than a general rate case, and how does that affect the increase requested in this proceeding?

A. The ARM was designed to smooth the transition to multiyear rate plans. NW Natural utilized the ARM rather than a general rate case because the FAIR Act included a rate case "stay-out," which prohibited public utilities from filing a general rate case during a specified period. As a result, costs that otherwise could have been recovered through a general rate case were delayed by a year, and those costs are now reflected in this proceeding, contributing to the higher amount that NW Natural is requesting. Although NW Natural recently received a 1.3 percent increase to its revenue requirement through its ARM, the Company did not seek to recover any additional O&M costs in that proceeding and only sought to recover approximately half of the capital investments it had made since its last general rate case in order to reduce near-term rate pressure. While the ARM's cost recovery was limited by design, it helped prevent costs from compounding, lowering the rate increase that NW Natural would otherwise be seeking in this proceeding. Similarly, this proceeding seeks to limit the rate increase that NW Natural's customers would otherwise face in the first year of NW Natural's multiyear rate plan in 2029 per OAR

860-022-0081(3)(c). By filing our rate case now, NW Natural is seeking to recover increasing costs while attempting to avoid further compounding of cost recovery in the near-term future.

Q. Is NW Natural's proposed bridge mechanism also part of its strategy to avoid rate volatility between now and when the Company's first multiyear rate plan takes effect in 2029?

A. Yes. As fully explained in the Direct Testimony of Kyle T. Walker (NW Natural/1200, Walker), NW Natural is seeking a bridge mechanism, which is a defined rate increase strictly for capital investments that will be in effect between the end of the Test Year in this proceeding (October 31, 2028) and the rate effective date of NW Natural's first multiyear rate plan (expected to be October 31, 2029). The bridge mechanism will increase the Company's annual revenues by $11.6 million, or 1.2 percent. The corresponding increase for residential customers will be 1.0 percent. The bridge mechanism will limit rate volatility because it reduces the rate increase that will take effect after NW Natural's first multiyear rate plan is established in 2029. As stated above, the bridge mechanism also provides rate certainty to customers because its rate impact will be known on October 31, 2027, which is a year before it takes effect.

Q. How does NW Natural's request for a general rate revision, including its proposed bridge mechanism, fit into its larger strategy of avoiding rate volatility?

A. NW Natural's request in this proceeding is best understood as one step in a three-year path to its first multiyear rate plan, rather than in isolation. Over the three-year period from October 31, 2026 through October 30, 2029, NW Natural's customers will experience three base rate changes: (1) the 1.3 percent ARM increase that took effect on October 31, 2026; (2) the 7.1 percent net increase requested in this proceeding (excluding the UPC update discussed above), which would take effect on October 31, 2027; and (3) the 1.2 percent bridge mechanism, which would take effect on October 31, 2028. Together, these changes increase NW Natural's revenue requirement (excluding gas costs) by approximately 9.6 percent over three years, or approximately 3.2 percent per year. In comparison, inflation has increased 3.7 percent over the last 12 months.[4] These rate changes are illustrated in Figure 1 below.

[4] The U.S. Consumer Price Index (CPI-U) rose 3.7 percent over the 12 months ending September 2026. See also the Direct Testimony of Jennifer E. Nelson, NW Natural/400, Nelson/82 (quoting the Chair of the Federal Reserve, Kevin M. Warsh, "The Fed's preferred measure of inflation, the 12-month change in the PCE [Personal Consumption Expenditures] price index, stands at 3.7 percent, while the six-month change is 4.1 percent.").

Figure 1

NW Natural Rate Changes Leading to Its First Multiyear Rate Plan

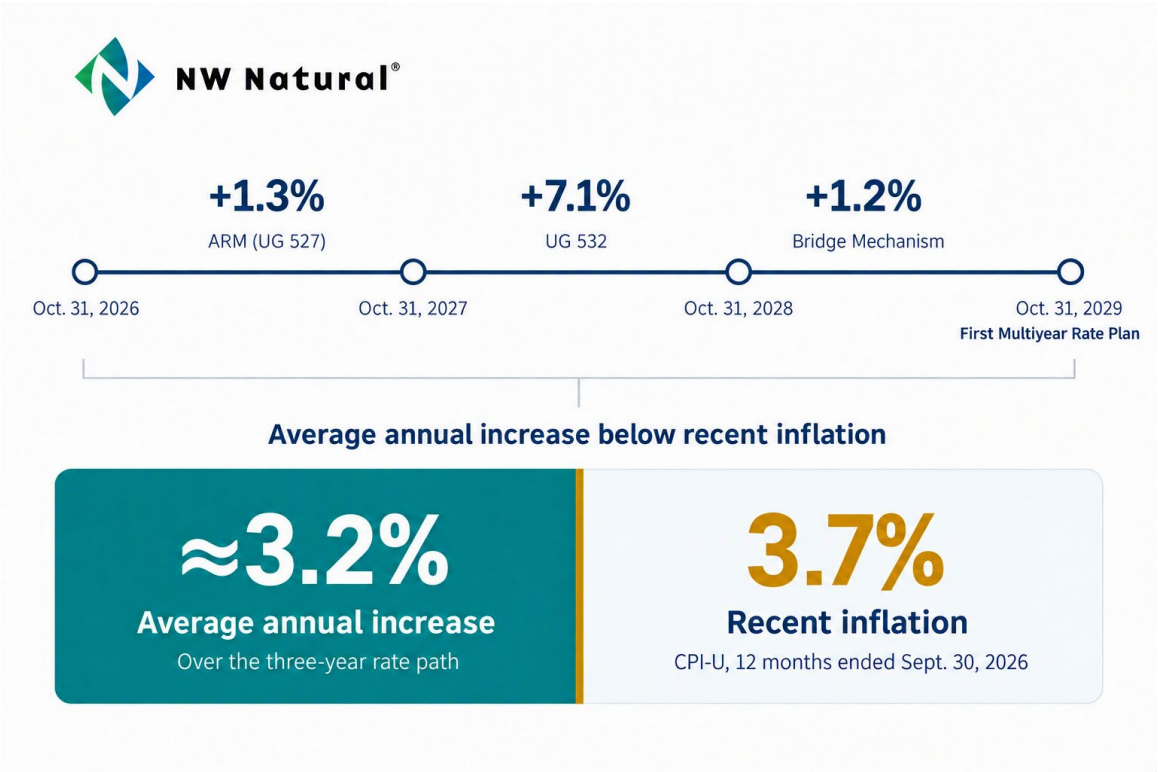

Figure 1 above includes the rates that are the subject of this proceeding, which are primarily fixed costs (largely capital investments and O&M expense). It does not include purchased gas costs, funding to the Energy Trust of Oregon, and adjustments that are recovered through other proceedings, which are included in the Company's Cumulative Economic Impact Assessment ("CEIA") that the Company filed with this rate application. These costs are largely outside the Company's control and are outside the scope of general rate cases.

NW Natural's requested rate increase, viewed in isolation, is larger than either the ARM or the bridge mechanism. As mentioned above, that is a result of the rate case stay-out required by the FAIR Act and NW Natural's decision to file

a very limited ARM that only sought recovery of approximately half the capital investments it made in the past year. Viewed holistically across the three-year period, however, NW Natural's request is part of a strategy to spread cost recovery over multiple years at an average annual rate below recent inflation. This avoids a larger, one-time increase when the Company's first multiyear rate plan takes effect in 2029 and gives customers greater rate predictability in the meantime.

III. ACTIONS NW NATURAL IS TAKING TO MITIGATE COST DRIVERS

Q. What are the major revenue requirement drivers that NW Natural is facing?

A. Figure 2, below, is a waterfall chart showing the major revenue requirement drivers of this proceeding. Importantly, this chart shows both increases in costs and increases in revenue due to the ARM and customer growth, as well as a slight reduction in tax expense, in order to provide an overall picture of the factors driving NW Natural's rate request.

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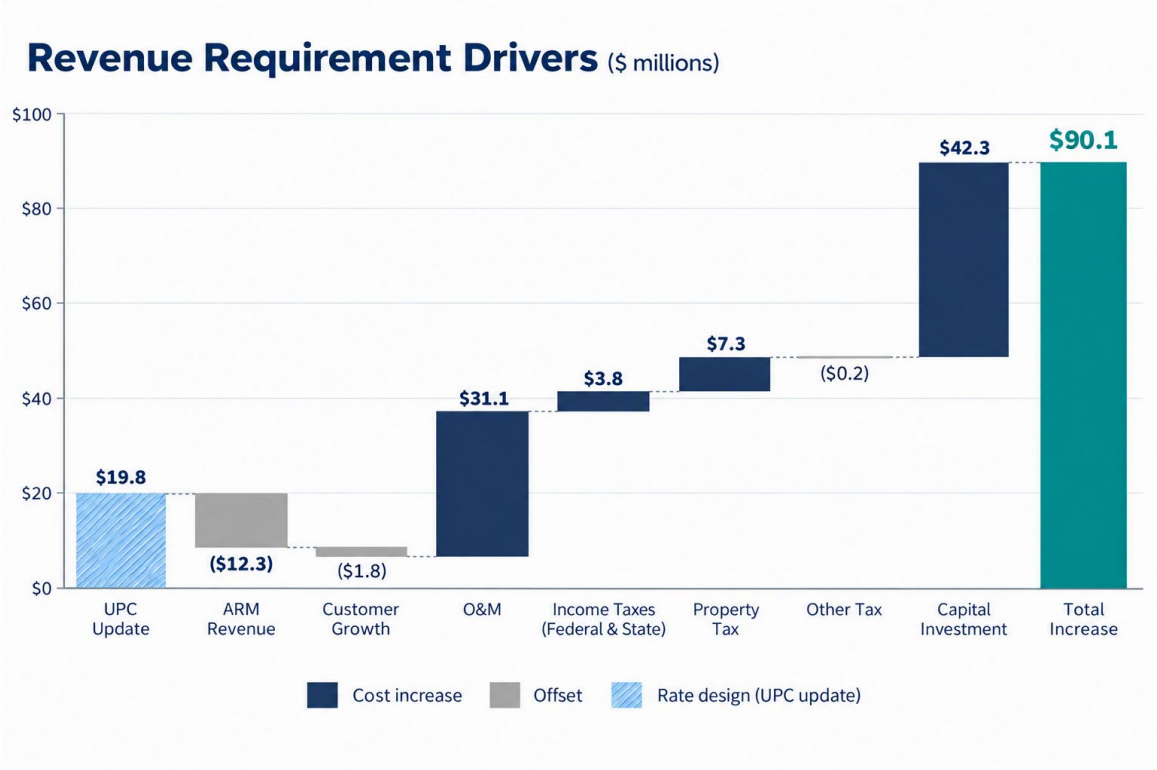
Figure 2



Of the net increase of $70.3 million (excluding the $19.8 million UPC update discussed above), the two major drivers are increased O&M expense and capital investment (depreciation expense, return on rate base, and necessary changes to the cost of capital). The remaining increase is due to taxes, notwithstanding the slight decrease in "Other Taxes" in Figure 2 above.

Q. Is NW Natural taking actions to mitigate these major revenue requirement drivers?

A. Yes. We discuss below how each of the major revenue requirement drivers identified in Figure 2 (O&M expense, capital investment, and taxes) are putting upward pressure on rates at the same time that NW Natural is taking actions to

control these costs. Although NW Natural's actions have not removed its need to file a general rate revision, they nonetheless have meaningfully reduced costs, mitigating rate pressure that its customers would otherwise face. Each major revenue requirement driver is addressed in turn.

A. O&M Expense

Q. Please briefly summarize the major factors that are putting upward pressure on O&M expense.

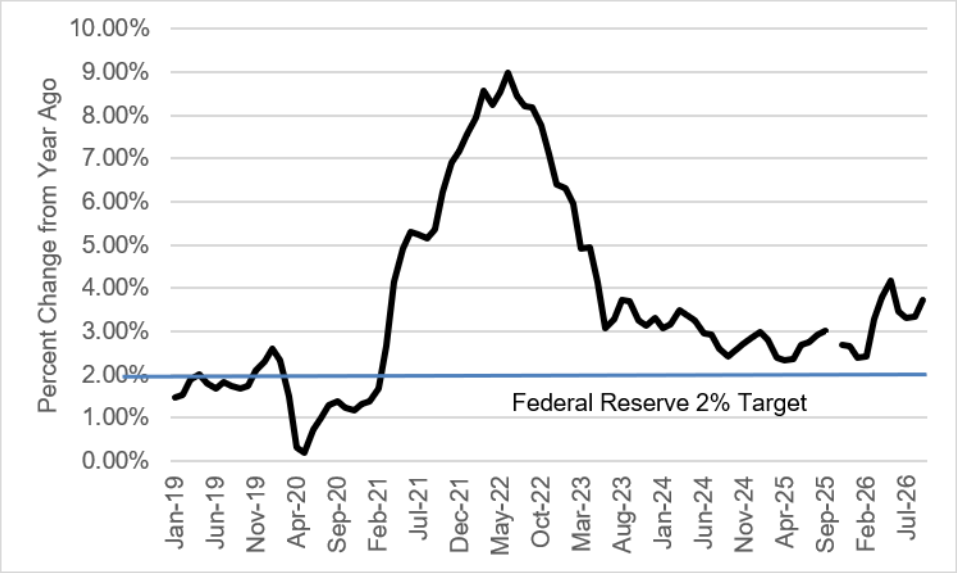
A. There are two major factors that are putting pressure on O&M expense. First, as explained above, NW Natural has not sought any increase in its O&M expense since its last general rate case (docket UG 520) approximately two years ago. O&M expense has been increasing since that time, but the Company has been unable to recover any of this increase.

Second, continued and persistent inflation continues to put pressure on rates. The Direct Testimony of Jennifer E. Nelson (NW Natural/400, Nelson) states that "inflation is expected to remain elevated and above pre-pandemic levels."[5] Her testimony includes a figure, reproduced below, that shows the elevated inflation that has occurred since the pandemic:

[5] NW Natural/400, Nelson/87.

Figure 3[6]

Consumer Price Index (2019-2026)



Ms. Nelson also cites analysis from the University of Michigan Surveys of Consumers preliminary October 2026 update that indicates inflation will remain elevated:

> Year-ahead inflation expectations ticked up from 4.6% last month to 4.7% this month. The current reading substantially exceeds the 3.4% seen in February before the Iran conflict began, along with all 2024 readings. Long-run inflation expectations also stepped up from 3.4% in September to 3.5%, notably higher than their 2024 range of 2.8% to 3.2%. Inflation expectations over both time horizons increased for the second straight month to their highest readings since May.[7]

The Direct Testimony of Tobin F. Davilla (NW Natural/1100, Davilla) discusses the specific increases in O&M expense that NW Natural is seeking.

[6] NW Natural/400, Nelson/83.

[7] NW Natural/400, Nelson/82.

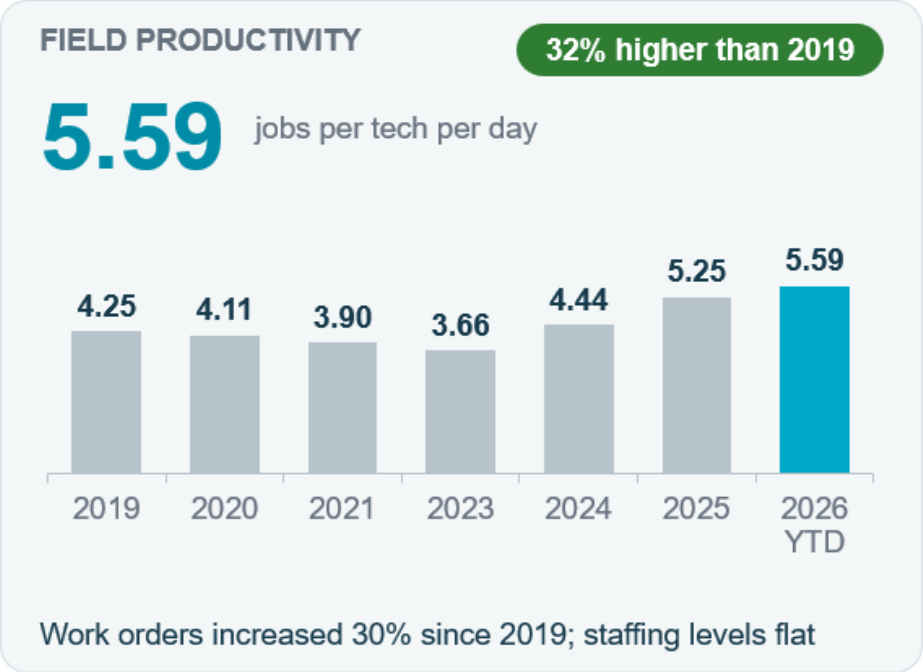
Q. Is NW Natural taking actions to control O&M expense despite continued and persistent inflation?

A. Yes. NW Natural has taken several actions to control O&M expense. First, as described in the Direct Testimony of Tobin F. Davilla (NW Natural/1100, Davilla), the Company entered into a new contract to provide locating and marking services, as well as survey and inspection services. During negotiations of this new contract in 2026, the Company leveraged multiple contracts, competitors' pricing and potential purchases of equipment known at that time to reduce rates compared to the existing agreement. This new contract reduced Test Year O&M expense by $2.3 million overall ($2.1 million on an Oregon-allocated basis).

Second, NW Natural's field technicians are completing more jobs in a day than they have done in the past while staffing levels have remained flat. Figure 4 below shows the corresponding gains in field productivity. Field technicians are completing 5.59 jobs per technician per day in 2026 year to date, which is 32 percent higher than in 2019, as shown in Figure 4 below. Over that same period, work orders have increased approximately 30 percent.

Figure 4[8]

Field Technician Productivity (Jobs per Technician per Day), 2019 – 2026



At the same time, NW Natural's response time to odor calls (i.e., response to calls from the general public that report smelling natural gas) has improved, as shown in Figure 5 below. NW Natural's average response time to odor calls has fallen from 30.2 minutes in 2023 to 26.6 minutes in 2026 year to date, which is 3.4 minutes faster than in 2019 and well within the Company's target of responding in under 30 minutes.

[8] Data from 2022 are unavailable because the Company was transitioning to a new IT&S system during this time.

Figure 5[9]

Average Odor Call Response Time (Minutes), 2019 – 2026 YTD



These improvements are the result of NW Natural's investments in modernizing its IT&S and training systems. Updated technology, improved reporting tools, and training initiatives have allowed technicians to complete more jobs per day and respond to odor calls faster without adding full-time employees ("FTEs"). In other words, the IT&S investments for which the Company seeks cost recovery in this proceeding, which are described further below and in the Direct Testimony of Brian E. Fellon (NW Natural/800, Fellon), are producing measurable efficiencies that benefit customers by controlling labor costs while improving the Company's emergency response.

[9] Data from 2022 are unavailable because the Company was transitioning to a new IT&S system during this time.

Third, NW Natural's number of FTEs has remained relatively flat since its last general rate case (docket UG 520). In its last general rate case, NW Natural had 1,249.1 FTEs. In this proceeding, NW Natural is seeking to recover the costs of 1,253.3 FTEs, which is a net gain of only four FTEs. We are committed to managing to this cost level until our first multiyear rate plan. In maintaining this staffing level, NW Natural had to make incredibly challenging decisions, such as its Voluntary Early Retirement and Reduction in Force initiative that reduced our staffing by over 30 FTEs in late 2025. This strategic reduction in FTEs in certain areas of the Company mitigated the cost impact of hiring additional staff in critical areas such as customer service, safety, and security where NW Natural identified the need for more FTEs. Although eliminating over 30 FTEs was a very difficult decision, it helped maintain the Company's focus on providing safe and reliable service while controlling costs.

Finally, NW Natural is not seeking to recover any incentive compensation for its executives in this proceeding. The Company decided not to seek recovery of this $5.4 million in order to mitigate the impact of its proposed rate increase. The compensation and benefits that NW Natural offers to all of its employees, including its executives, continue to reflect the market median and are necessary to attract a qualified workforce. However, even though executive incentive compensation is a reasonable and necessary expense of running a utility, NW Natural has nevertheless decided not to seek recovery of these costs, which reduces cost pressure to customers.

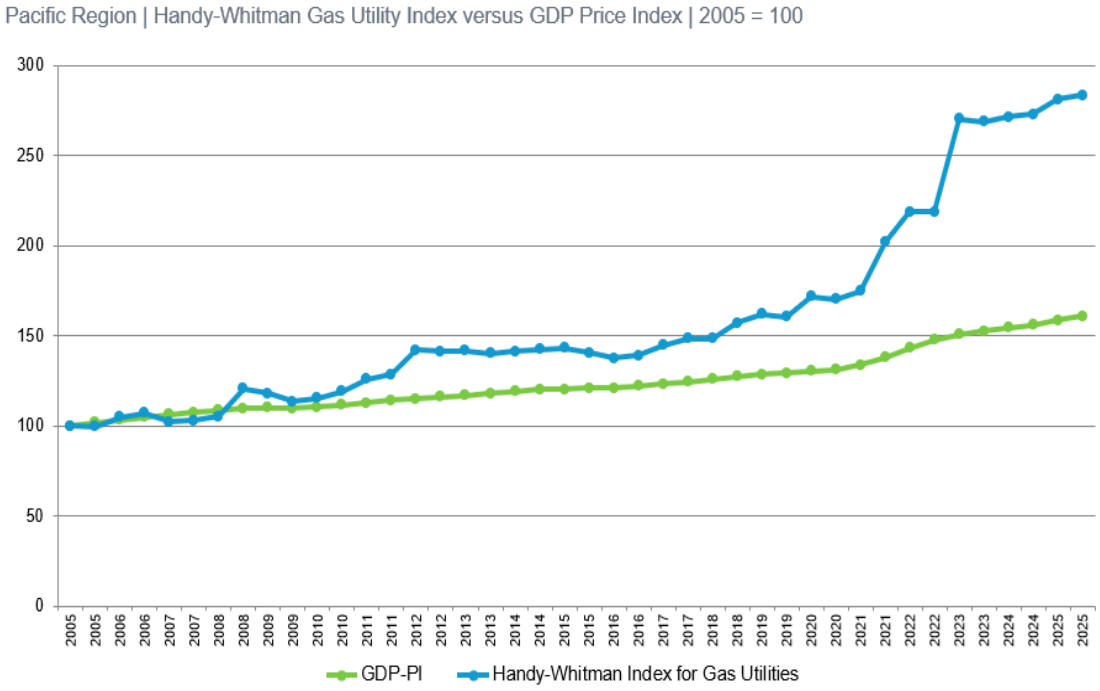
B. Capital Investment

Q. What are the major factors putting upward pressure on capital investment?

A. In addition to the increasing cost of capital (discussed below), the cost of constructing gas utility infrastructure has risen far faster than general inflation. Figure 6 compares the Handy-Whitman Index for Gas Utilities in the Pacific Region, which tracks changes in the cost of the labor, materials, and equipment needed to build gas utility plant, to the Gross Domestic Product Price Index ("GDP-PI"), a broad measure of general price inflation across the U.S. economy. Both indices are set to 100 in 2005 so that their rates of change can be compared directly.

Figure 6

Pacific Region Handy-Whitman Index for Gas Utilities Compared to GDP Price Index, 2005 – 2025 (2005 = 100)



As Figure 6 shows, between 2005 and 2025, the GDP-PI rose approximately 61 percent, while the Handy-Whitman Index for Gas Utilities rose approximately 183 percent. In other words, gas utility construction costs increased roughly three times as much as general inflation over the same period. The gap has widened considerably in recent years. Between 2021 and 2023, the Handy-Whitman Index increased approximately 13 percent per year, rising from approximately 175 to approximately 270 and has continued to climb since, reaching approximately 283 in 2025, while the GDP-PI increased at a much more moderate pace.[10]

This difference matters for customers because NW Natural must make its capital investments at today's construction costs, not at the cost levels reflected in the pre-existing system. Replacing pipelines, storage facilities, and other plant therefore costs significantly more than it would have two decades ago. This helps explain why the capital costs included in this proceeding put upward pressure on rates that outpaces inflation.

Q. Please provide real-world examples that show how construction costs have increased.

A. NW Natural and its customers face increasing costs to comply with municipal street-restoration requirements, which are outside of NW Natural's direct control.

[10] This data was provided in the gas utilities' written comments in docket AR 677 on March 30, 2026 (see *In the Matter of Rulemaking to Establish General Rate Revisions Filing Schedule and Exception Process (HB 3179 Implementation)*, Docket No. AR 677, NW Natural's, Avista Utilities', and Cascade Natural Gas Corporation's Joint Comments (Mar. 30, 2026).

In 2019, the Company completed 2,362 capital work orders and incurred approximately $4.65 million in associated restoration costs, or about $1,968 per capital work order. In 2025, the Company completed a similar amount of capital work orders (2,403), but restoration costs had risen to approximately $10.46 million, or $4,351 per order. In other words, the volume of capital work increased less than 2 percent, while restoration costs increased approximately 125 percent.

Another example is increased permitting costs from local municipalities. These costs are also outside of NW Natural's control. In 2026, roughly 631 service permits from the City of Portland cost about $557,000 annually. Under Portland's new 2027 fee structure, a 40-job sample indicates the same work could add approximately $1.6 million, bringing annual service-permit costs to an estimated $2.17 million, nearly four times the 2026 level. These costs do not include work on mains, which will face similar fees and could significantly increase the total cost impact to customers.

Q. Please describe the actions that NW Natural is taking to control the capital investment that it is seeking to recover in this proceeding despite rising costs.

A. As further described in the Direct Testimony of Jorge O. Moncayo (NW Natural/500, Moncayo), NW Natural uses a "bottom-up" approach to identify and prioritize capital investment projects based on the need to support system reliability and safety, integrity, regulatory compliance, jurisdictional requirements, system expansion, and customer growth. This "bottom-up" approach to budgeting, which

starts at each business unit and works upward to the executive team, ensures that NW Natural is allocating its capital to the needs that each business unit identifies, as opposed to setting a Company-wide target for capital investment and prioritizing projects based on hitting that predetermined target.

By following this "bottom-up" approach, NW Natural has been holding its overall capital investment steady over the last several years despite increasing costs. And, that trend is expected to continue as utility capital expenditures planned for calendar year 2026 is $367 million, for 2027 is $352 million, and for 2028 is $360.0 million. The capital expenditure forecasted during the Test Year is $351.1 million. That said, an increasing amount of capital expenditure is dedicated to IT&S investments that have shorter depreciable lives than other utility investments, resulting in a greater impact on revenue requirement.

Q. Please briefly summarize the major factors driving an increase in the cost of capital.

A. The Direct Testimony of Jennifer E. Nelson (NW Natural/400, Nelson) explains that the required cost of capital is a function of prevailing and expected economic and capital market conditions. When the Company filed its last rate case in December 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.[11] Since that time, however, economic and federal policy uncertainty has climbed sharply. Long-term government and utility bond yields

[11] NW Natural/400, Nelson/79.

have increased by approximately 65 and 52 basis points, respectively.[12] Ms. Nelson's testimony also describes ongoing geopolitical tensions, evolving trade policies, and broader macroeconomic uncertainty that have contributed to persistently elevated inflation and U.S. Treasury yields. These factors increase the benchmark returns investors require to commit capital to natural gas utilities such as NW Natural. Because utilities are capital-intensive and investors have many investment alternatives, NW Natural's financial profile must be adequate on a relative basis to ensure its ability to attract capital in order to make the necessary investments in its system that are required to provide safe and reliable service.

Q. How is NW Natural seeking to mitigate these factors increasing the cost of capital?

A. NW Natural has requested an authorized ROE at the lowest end of the range recommended by its third-party expert, Ms. Nelson. Her Direct Testimony (NW Natural/400, Nelson) demonstrates that a reasonable range of the cost of equity (i.e., the return that NW Natural should be given the opportunity to earn in order to attract capital) is between 9.75 percent and 11.75 percent. Ms. Nelson further explains that NW Natural's requested ROE of 9.75 percent is conservative, reflecting the Company's consideration of customer affordability concerns while providing NW Natural a reasonable return that enables it to continue to attract investor capital. In addition, NW Natural has proposed to retain its capital structure of 50 percent equity and 50 percent debt, even though it results in a significantly

[12] NW Natural/400, Nelson/7.

lower equity-to-capital ratio than the average of our peer natural gas utilities identified in Ms. Nelson's testimony (NW Natural/400, Nelson). The gas proxy group has an average equity ratio of 55.42 percent over the last three years.

C. Taxes

Q. Please briefly summarize the major factor that is putting upward pressure on taxes that NW Natural must pay.

A. As explained in the Direct Testimony of Kyle T. Walker (NW Natural/1200, Walker) and as shown in Figure 7 below, the amount of property tax that NW Natural must pay has increased meaningfully in recent years. As a utility, property tax is an unavoidable cost associated with owning and operating the property required to provide regulated natural gas service.

Figure 7

Year-Over-Year ("YoY") Proposed and Actual Property Tax Increase

Year	YoY Increase Proposed	YoY Increase Actual
2017	10.5%	6.2%
2018	7.4%	5.8%
2019	1.4%	1.4%
2020	13.7%	10.9%
2021	7.5%	7.5%
2022	16.1%	11.2%
2023	16.3%	2.0%
2024	1.4%	1.4%
2025	8.6%	8.6%
2026	24.5%	15.4%
	10.7%	7.0%
	Average	**Average**

Figure 7 shows that both the Oregon Department of Revenue's proposed property tax increases, as well as the final property tax assessed to NW Natural, are increasing at an amount that outpaces inflation.

Q. Does the difference between proposed and actual property tax increases show that NW Natural is attempting to control property tax cost as much as possible?

A. Yes. As fully explained in the Direct Testimony of Kyle T. Walker (NW Natural/1200, Walker), NW Natural reviews the Oregon Department of Revenue's proposed valuation and engages with the Department when the proposed value is not supported by the relevant valuation evidence. Figure 7, above, shows that the Department of Revenue's proposed annual average increase was approximately 10.7 percent, whereas the actual average increase was approximately 7.0 percent, which demonstrates that NW Natural is taking action to control these costs as much as possible.

IV. NW NATURAL'S COMMITMENT TO AFFORDABILITY AND EQUITY

Q. Is NW Natural committed to affordability?

A. Yes. NW Natural recognizes that natural gas is a fuel of choice that our customers continue to value. We are proud of the fact that we continue to affordably provide safe and reliable service to our customers. Even with the Company's proposed rate increase that it is seeking in this proceeding, our average residential customer bill is less expensive than it was twenty years ago after adjusting for inflation, and only 14 percent higher without such an adjustment. In comparison, if our

residential bill simply tracked inflation since 2006, it would be approximately $142.22, which is substantially higher than the average residential bill of $96.98 that NW Natural is proposing in this proceeding.[13]

Figure 8

20 Year Bill Comparison



[13] See U.S. Bureau of Labor Statistics, CPI Inflation Calculator (available at: https://www.bls.gov/data/inflation_calculator.htm). The $96.98 average residential bill is a weighted average of single-family and multi-family residential bills. In 2006, both types of residential housing were subject to the same rates, so NW Natural used a weighted average of residential customers' bills in order to make this comparison.

Q. Is the decline in the average residential bill for customers participating in NW Natural's bill discount program (BDP) even more dramatic?

A. Yes. As shown in Figure 9 below, the BDP has dramatically lowered bills for income-eligible customers with incomes at or below 60 percent of the state median income ("SMI"), even before accounting for any other bill assistance programs. The BDP provides a tiered discount of up to 85 percent on eligible customers' bills, with the deepest discounts going to customers with the lowest incomes.

Beginning on November 1, 2006, the average monthly residential bill was $84.91 for all residential customers. After accounting for the BDP, customers in Tiers 0 through 2 (incomes at or below 45 percent of SMI) will pay less each month beginning on November 1, 2027 than the average residential customer paid twenty years ago—*without adjusting for inflation*. For Tier 0 customers, the average monthly bill will be approximately 80 percent lower. These results highlight both the stability of our rates over that time and the value of the BDP.

Figure 9

Comparison of Average 2027 BDP Bill to Average 2006 Residential Bill ($84.91)

BDP Tier Level	BDP Discount of Total Bill	Average 2027 Monthly Bill Under BDP	2027 BDP Monthly Bill Compared to Average 2006 Bill
Tier 0 0-15% SMI	85%	$14.55	-82.9%
Tier 1 16-30% SMI	50%	$48.49	-42.9%
Tier 2 31-45% SMI	30%	$67.89	-20.0%
Tier 3 46-60% SMI	15%	$82.43	-2.9%

Q. Does the current design of the BDP remain effective in reducing energy burden for income-eligible customers?

A. Yes. As discussed further in the Direct Testimony of Cecelia J. Tanaka (NW Natural/200, Tanaka), the Company's 2026 refresh of the Energy Burden Assessment ("EBA") found that household natural gas energy burden at 2 percent (or below) would be an affordable, feasible, and meaningful threshold for NW Natural customers. Figure 10, 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 after accounting for the increase in residential rates that NW Natural is seeking in this proceeding.

Figure 10

NW Natural Bill Discount Effectiveness Targeting 2 Percent Energy Burden

Assuming a Family of 4	**Tier 3** *Example*	**Tier 2** *Example*	**Tier 1** *Example*	**Tier 0** *Example*
NW Natural bill discount tier	15%	30%	50%	85%
Average annual usage	631	631	631	631
Annual bill	$1,085.38	$1,085.38	$1,085.38	$1,085.38
Midpoint of income for the tier	$67,856	$48,469	$29,081	$9,694
Existing				
NW Natural bill discount	$162.81	$325.61	$542.69	$922.57
Annual bill after bill discount	$922.57	$759.77	$542.69	$162.81
Annual bill as a % of income before discount	1.6%	2.2%	3.7%	11.2%
Annual bill as a % of income after discount	**1.4%**	**1.6%**	**1.9%**	**1.7%**
Rate Case Increase				
Annual bill	$1,180.89	$1,180.89	$1,180.89	$1,180.89
NW Natural bill discount	$177.13	$354.27	$590.45	$1,003.76
Annual bill after bill discount	$1,003.76	$826.63	$590.45	$177.13
Annual bill as a % of income before discount	1.7%	2.4%	4.1%	12.2%
Annual bill as a % of income after discount	**1.5%**	**1.7%**	**2.0%**	**1.8%**

NW Natural notes that the BDP analysis presented in Figure 10 above is consistent with its initial design, using residential annual average usage and mid-points of income thresholds for each tier. The Company has additionally provided an analysis of the effectiveness of the BDP for the past two program years, including actual usage by tier and at various points of the income thresholds by tier. This analysis, included in NW Natural's CEIA that it filed with this rate application, indicates that the BDP has helped mitigate energy burden for income-qualified customers as well.

Finally, as discussed in the CEIA and the Direct Testimony of Cecelia J. Tanaka (NW Natural/200, Tanaka), the 2026 EBA data refresh analysis indicates that BDP discount levels continue to be appropriate and can accommodate the requested rate increase without requiring adjustments to these levels in this proceeding.

Q. Is NW Natural committed to equity?

A. Yes. In addition to the BDP that provides ongoing bill stability, the Company has built a portfolio that includes tools to respond to temporary crises and reduce usage as fully explained in the Direct Testimony of Cecelia J. Tanaka (NW Natural/200, Tanaka). To respond to temporary crises, the Oregon Low-Income Gas Assistance Program (OLGA) provides energy assistance grants to income-qualified customers. In addition, the Gas Assistance Program (GAP) provides supplemental grant assistance funded by NW Natural shareholders, employees, retirees, and customers matched up to $60,000 annually. The federal Low-Income

Home Energy Assistance Program (LIHEAP) also provides grants to help eligible residents pay their energy bills.

To address past-due debt, NW Natural has developed an arrearage management program (AMP), which provides grants up to $1,000 every 24 months for customers who earn less than 15 percent of the state median income (Tier 0 of the BDP). The Company also allows time payment arrangements, which provide a means for customers to address past-due balances through a payment plan.

Finally, NW Natural's Oregon Low-Income Energy Efficiency program (OLIEE) provides long-term affordability benefits through energy efficiency and weatherization improvements. These investments are complemented by customer education, equipment maintenance guidance, and partner-delivered maintenance support designed to help customers maximize and sustain energy savings.

Q. How has NW Natural developed these programs?

A. As discussed in the Direct Testimony of Cecelia J. Tanaka (NW Natural/200, Tanaka), the Company's equity programs have been enhanced by House Bill 2475 ("HB 2475"), which expanded the Commission's authority to consider differential energy burdens and economic, social equity, and environmental justice factors affecting affordability. Since HB 2475 was passed, Commission dockets and rulemakings have expanded NW Natural's affordability portfolio. Importantly, this portfolio was informed by feedback from customers, community-based organizations, stakeholders, and advisory groups. This feedback has also informed the Company's efforts to reduce barriers to participation, improve access

to information and services, strengthen customer communications, and make programs easier to understand and navigate.

Q. Please provide an example of how NW Natural is incorporating feedback to make its affordability portfolio easier to navigate.

A. NW Natural is working with its Community & Equity Advisory Group ("CEAG") in developing its Language Access Plan, as fully explained in the Direct Testimony of Cory A. Beck (NW Natural/1000, Beck).[14] NW Natural's Language Access Plan is a framework for improving and guiding how the Company communicates with customers who have limited English proficiency or limited literacy. It assesses customer language needs, evaluates existing language services, and identifies actions to improve access to important Company programs, services and communications. The Language Access Plan is intended to be a living framework that will evolve as customer needs and stakeholder feedback change over time. To date, NW Natural has received positive feedback from the CEAG, and will continue working with CEAG, Community Action Agencies and others as appropriate to help ensure outreach remains responsive to customer needs.

[14] As explained in Mr. Beck's testimony, NW Natural is willing to provide the Language Access Plan to parties in response to a data request after the stakeholder process is complete and the plan is finalized.

V. OVERVIEW OF MAJOR PROJECTS

Q. Please provide a brief overview of major projects that NW Natural is seeking cost recovery of in this proceeding.

A. The significant projects that NW Natural is seeking to recover the costs of in this proceeding are:

- Continued investments to the Company's IT&S systems. IT&S hardware costs have risen sharply, and are expected to continue to rise, due to tariffs and increasing hardware demand associated with data center expansion. Many other IT&S investments are cloud-based services and depreciate over a very short period of time (typically five years). Given this short period, NW Natural must seek cost recovery on a timely basis. Otherwise, the Company would not be able to recover a substantial portion of these investments (i.e., a delay of a year would result in NW Natural not recovering approximately 20 percent of its cloud-based IT&S investments).
- Investments to ensure safe and reliable service at our natural gas storage facilities at Newport and Mist.

In addition, as explained above, NW Natural's O&M expense continues to escalate, due to inflation, which is a major driver of the revenue requirement increase in this proceeding (see Figure 2 above).

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. The major functional categories include:

1. **Field and Web Mapping:** 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. This ongoing initiative was also part of NW Natural's last two general rate cases (dockets UG 490 and UG 520). 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, to collect various types of data related to these assets, maintain its gas asset records, and to model the Company's gas facilities and operations.
2. **Identity Governance and Administration ("IGA"):** NW Natural is completing several phased cyber security projects necessary to transition to an automated IGA software solution to update, review, and determine access to technology systems for NW Natural employees and contractors. Like Field and Web Mapping, this ongoing initiative was also part of NW Natural's last two general rate cases (dockets UG 490 and UG 520). These projects will ensure consistent, secure monitoring and control of access and permissions.

3. **Gas Control Daily Operations Platform ("GCDOP"):** The GCDOP is a multi-phase initiative to replace the Company's Supervisory Control and Data Acquisition ("SCADA") platform that is over twenty years old, difficult to maintain and support, and has become increasingly unstable and unreliable. To the best of NW Natural's knowledge, it is the only gas distribution company in the country using its current SCADA platform.
4. **Customer Self-Service:** Customer Self-Service projects are part of a multi-year initiative to provide customers with new features and efficiencies to improve communication and accessibility, thereby helping customers manage their accounts more easily through the web-based and phone systems. According to the Company's consultant, Accenture, comparable clients have experienced a 111 percent increase in customers' completed transactions following a replatform project. The project is also expected to increase effective website utilization and reduce contact center calls. By improving website engagement, comparable implementations have significantly reduced the volume of contact center calls.

The Direct Testimony of Brian E. Fellon (NW Natural/800, Fellon), the Company's Vice President, Chief Information Officer & Chief Information Security Officer, provides a comprehensive explanation of the Company's IT&S projects, including the project categories summarized above.

Q. Please briefly discuss the importance of natural gas storage, including why the Company must continue to invest in its storage facilities.

A. NW Natural relies on regional natural gas storage facilities to meet customer demand. As the regional energy system, including natural gas supply, becomes more and more constrained due to increasing demand, such as the growth of natural gas electric generation, natural gas storage is an increasingly important resource. NW Natural's access to these storage facilities gives it the ability to store natural gas for use during the coldest days of the year irrespective of increased demand during this time of year. NW Natural owns underground storage facilities at Mist and two liquefied natural gas ("LNG") storage facilities at Portland and Newport. In addition, NW Natural contracts for storage service at Jackson Prairie, which is located about 80 miles north of Portland near Centralia, Washington. In previous proceedings (dockets UG 520 and UG 527), NW Natural discussed its critical investments at Mist, replacing compressors that are necessary for its reliable operation.

In this proceeding, NW Natural is seeking to recover the costs of critical investments in its Newport LNG Storage Facility, as well as continued investments at the Mist Storage Facility. During peak winter operations, Newport LNG Storage Facility is used to provide firm gas supply directly to approximately 10,000 customers in Lincoln City, Toledo and Newport communities, and to an additional 115,000 to 125,000 customers in the communities of McMinnville, Sheridan,

Willamina, Grand Ronde, Dallas, Monmouth, Independence, Brooks, Gervais, Keizer, West Salem, North Salem, North Albany and North Corvallis.

The Mist Storage Facility, which is a 17.5 billion cubic feet ("Bcf") facility with 13.1 Bcf used to provide gas storage for core customers, is also critical to system reliability. It features a natural gas storage field consisting of seven different underground reservoirs, 21 injection/withdrawal (I/W) wells, gathering lines, an operational hub called Miller Station,[15] and other related facilities. About one-third of NW Natural's gas supply portfolio for core utility service on a peak day comes from the Mist Storage Facility. Utility peak day Mist Storage Facility supply of 340,000 dekatherms/day could serve over 460,000 average residential customers.

Q. Please briefly highlight the major investment that the Company is making in its Newport LNG Storage Facility.

A. NW Natural is replacing the cold box at the Newport LNG Storage Facility, which the Commission acknowledged in Order No. 21-274, entered in the Company's 2018 Integrated Resource Plan ("IRP") docket LC 71 on September 8, 2021.

The cold box 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 as wintertime peaking

[15] 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.

supply and also as a source of supply for emergency situations and pipeline maintenance. The cold box is therefore essential to the facility: NW Natural cannot operate the Newport LNG Storage Facility without it. Without the cold box, natural gas could not be liquefied or stored at the facility, and the facility could not provide peaking or emergency supply. The current cold box is almost 50 years old, which is well past its nominal 25- to 30-year design life, and it is currently showing signs of its age through performance problems, such as contamination fouling the interior of the heat exchangers, causing differential pressure in the system that is higher than design limits, reducing production capacity.

Q. Please briefly highlight several of the major investments that the Company is making in its Mist Storage Facility.

A. As fully explained in the Direct Testimony of Daniel B. Kizer and Michael C. Hwang (NW Natural/600, Kizer-Hwang), the major investments at the Mist Storage Facility include:

1. **Main Power Feed Replacement Project:** Installs a new 12.5 kV underground power line, in protective conduit, parallel to the existing feed from State Highway 202 to Miller Station. The existing cable is end-of-life (35 years old) and susceptible to water intrusion and vehicle damage.
2. **Well Separator Replacement Program:** Replaces end-of-life well separators, which remove liquids and solids from gas withdrawn at the wellheads, over a multi-year period. Nine separators have been replaced to date, including two in 2026 (included in the Company's ARM docket UG

527). The remaining work was accelerated to 2027 because underperforming separators have allowed debris to contaminate the dehydration process at Miller Station.

3. **Reservoir Ultrasonic Flowmeters Replacement Project:** Replaces the Honeywell Series 4 ultrasonic meters that measure gas injection and withdrawal, and associated obsolete instrumentation, with vendor-supported SICK FLOWSIC600-XT meters. The Honeywell meters are no longer supported by the manufacturer, and one experienced an electronic board failure in 2026, creating an elevated reliability and maintenance risk.

Mr. Kizer and Mr. Hwang's testimony (NW Natural/600, Kizer-Hwang) provides a comprehensive explanation of the Company's distribution system and storage facility investments, including those mentioned above. These investments are critical given NW Natural's vital role in Oregon's energy system.

VI. NW NATURAL'S VITAL ROLE IN OREGON'S ENERGY SYSTEM

Q. Please describe the vital role that NW Natural plays in Oregon's overall energy system.

A. NW Natural's role in the State's overall energy system can hardly be overstated. NW Natural provides more energy to Oregonians than any other utility—gas or electric. In Oregon, the gas and electric systems have a concurrent peak in winter. During this concurrent peak, the gas system delivers about twice as much energy as the electric system—with even more available. Despite this vast amount of energy delivered, NW Natural's residential and commercial customers' use

accounts for about 6 percent of the State's overall emissions, while the electric sector is at 29 percent.

Q. Will NW Natural play a vital role in Oregon's energy future?

A. Yes. The capacity and energy provided by NW Natural is critical to ensuring that Oregon's overall energy system remains reliable, resilient, and affordable. This amount of capacity would be extremely difficult to replace with electric solutions given the resource adequacy issues already facing the Pacific Northwest's power system.

Q. Please briefly explain the resource adequacy issues facing the Pacific Northwest's power system.

A. The Pacific Northwest Utilities Conference Committee ("PNUCC"), which is a trade association for regional electric utilities and power industry partners, stated in their 2026 Northwest Regional Forecast that "[a]s demand grows and other traditional firm resources retire, coordination between the electric and natural gas systems is increasingly important to maintain reliability, highlighting the growing interdependence between them, particularly during periods of reduced hydropower output."[16] In addition, PNUCC concluded that "system pressure is increasing, particularly during peak demand periods, reinforcing growing constraints on both capacity and energy adequacy."[17] During peak demand periods, PNUCC

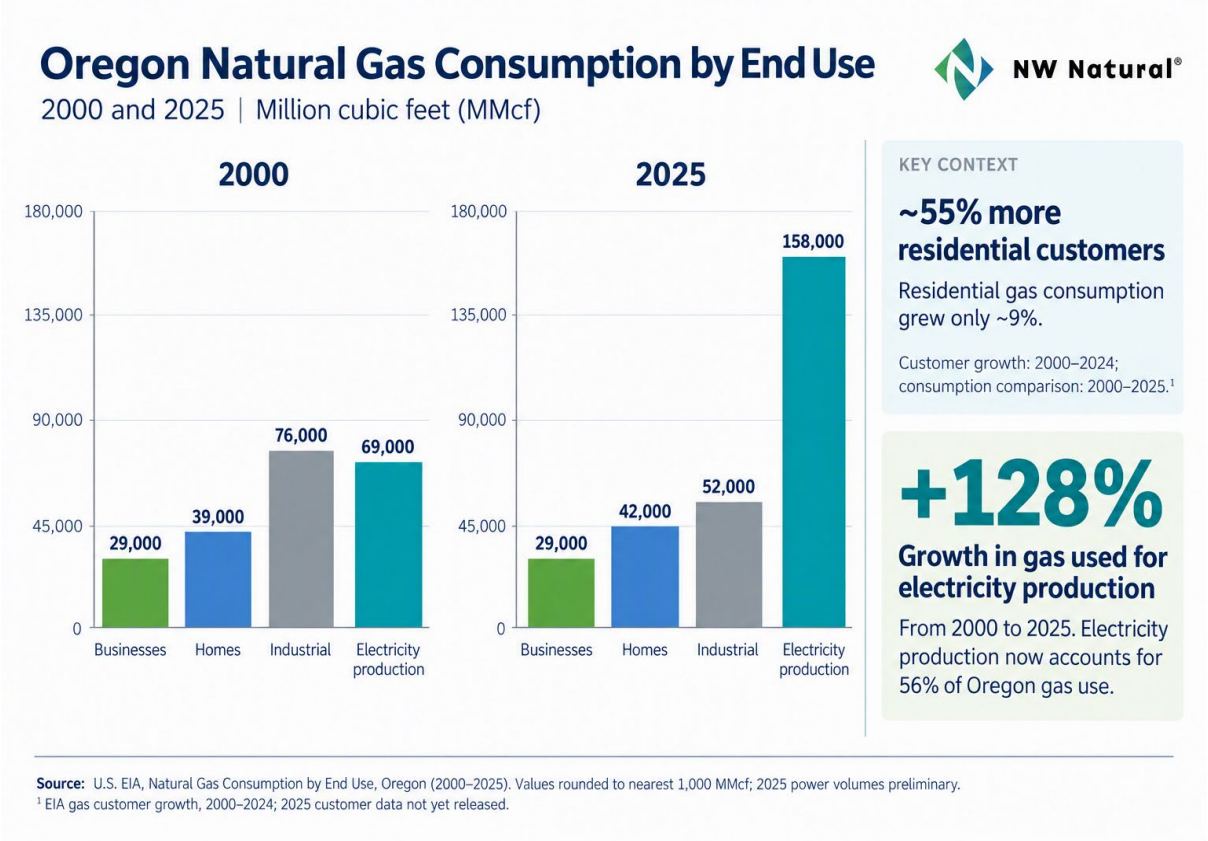
[16] PNUCC, Northwest Regional Forecast of Power Loads and Resources – August 2026 through July 2036, at 8 (Apr. 2026) (available at: 2026-PNUCC-Northwest-Regional-Forecast-4-21-26-final.pdf).

[17] *Id.* at 6.

forecasts power deficits. In the winter, this deficit is projected to grow to 13,100 MW by January 2036.[18] This gap exists even though gas consumption for power generation has increased 128 percent since 2000 and now makes up the majority of Oregon's gas use, as shown in Figure 11 below:

Figure 11

Natural Gas Consumption in Oregon



[18] *Id.* at 6.

Q. Is there additional analysis that also shows the region's electric system is facing resource adequacy issues?

A. Yes. The region's electric utilities sponsored a study by E3 examining this issue. The study found that there is a "resource gap that grows to 9 GW of effective capacity by 2030 and 14-18 GW by 2035."[19] This resource gap results in the Pacific Northwest "fac[ing] a multi-day reliability challenge driven by cold snaps and low hydro conditions,"[20] which are the precise conditions where NW Natural's capacity is most valuable.

Q. Has NW Natural's IRP also examined this issue?

A. Yes. NW Natural's 2025 IRP, docket LC 86, examined the potential impact of building electrification at a large scale. The Company formed an advisory group that consisted of a former Bonneville Power Administration administrator, the former Chief Executive Officer ("CEO") of Seattle City Light, the former CEO of Pacific Power, and a former chair of the Commission and Oregon State Senator. Cumulatively, the advisory group has over 100 years of combined energy experience in the Pacific Northwest. The advisory group evaluated several electric supply scenarios ranging from "current trends," where the system evolves consistent with current trends and permitting timelines, to an "aggressive improvement" scenario, where the electric system quickly develops new resources

[19] E3, Resource Adequacy and the Energy Transition in the Pacific Northwest, at 5, 14 and 52 (April 2026) (available at: https://www.ethree.com/wp-content/uploads/2026/04/E3-NW-RA-Final-Report_040826.pdf).

[20] *Id.* at 14.

due to technological advances leading to declining costs, as well as accelerated permitting timelines.[21]

The advisory group found each scenario "to be overly optimistic by assuming base assumptions that would result in electrification of current gas loads being easier, faster and cheaper than [their] own experience and judgment."[22] They concluded that the "electric future transition will be harder, slower and more expensive than the scenarios we were presented even without electrifying current natural gas [direct] use."[23] It also is the advisory group's "view that the electric system will be greatly challenged to meet the existing [clean energy] policy prescriptions and planned load growth even without taking into account electrification of the natural gas system."[24]

Specifically, they cite the increasing reliance on natural gas generation to meet peak demand, stating "electric systems of the region are also relying heavily on the gas systems for electric generation for peak load service," and that during a severe winter storm in January 2024 "the Pacific Northwest could have experienced rolling blackouts of a magnitude that would be unprecedented in our region . . . [w]ithout record electric imports from the Southwest and Rocky Mountain states."[25] Moreover, PNUCC has recently concluded in its 2026 Northwest

[21] NW Natural/101, Rush-Kravitz.

[22] *Id*.

[23] *Id*.

[24] *Id*.

[25] *Id*.

Regional Forecast that "relying heavily on imports or short-term purchases is not a prudent foundation for long-term resource planning," and that "[r]ecent events [such as the January 2024 winter storm] show that shortages can be expensive for consumers—both through exposure to high market prices and the need to procure emergency or unplanned capacity."[26]

Q. What is joint system planning, and why does it matter to Oregon's energy system?

A. Joint system planning is the coordinated planning of the gas and electric systems so that Oregon's energy needs are met at the lowest cost while maintaining safety, reliability, and affordability. The two systems have different but complementary strengths, and their growing interdependence, including the electric system's reliance on natural gas generation during winter peak, can create challenges if they are planned separately. Planning them together allows utilities to identify the lowest-cost, lowest-risk resources across both systems rather than optimizing each in isolation.

Q. Has NW Natural supported joint system planning?

A. Yes. NW Natural has routinely supported and advocated for joint system planning. In its 2025 IRP (docket LC 86), the Company commissioned an electrification study that estimated costs across both systems, including electric generation, transmission, and distribution, and, as explained above, retained an independent

[26] PNUCC, Northwest Regional Forecast of Power Loads and Resources – August 2026 through July 2036, at 8-9 (Apr. 2026) (available at: 2026-PNUCC-Northwest-Regional-Forecast-4-21-26-final.pdf).

advisory group of former electric utility and regulatory leaders to test its assumptions. The IRP's action plan commits NW Natural to seek opportunities for gas and electric joint planning (Action Item A-21) and to develop a hybrid heating pilot that explores joint system planning with an electric utility partner (Action Item B-16). NW Natural has also prioritized joint system planning in the Commission's implementation of Executive Orders 25-25 and 25-29 (docket UM 2417). There, the Company recommended that the Commission convene a working group on joint system planning, and it has continued to urge the Commission to focus the initial phase on governance. NW Natural has also joined Avista and Cascade in supporting improved coordination between electric and gas planning. In addition, the Company has welcomed partnerships with electric utilities on hybrid heating, including co-funding, demand response or capacity payments, and data sharing.

Q. Is NW Natural committed to finding solutions to the region's resource adequacy issues by leveraging its system's ability to reliably and affordably provide large amounts of on-demand energy in cold weather?

A. Yes. NW Natural recently filed Schedule 354, Hybrid Heating Program with the Commission. If approved, it will provide a one-time $3,500 incentive to install a hybrid heating system (a ducted air-source heat pump sized for air conditioning and space heating in milder weather above 35 degrees Fahrenheit, and a natural gas furnace that will serve homeowners' colder-weather space heating needs). By relying on NW Natural's system during colder weather, the strain on the electric system is reduced, helping to address the region's resource adequacy issues. E3

has found that "[h]ybrid heating could reduce RA [resource adequacy] need up to 7 GW in 2045."[27]

Q. Hybrid heat relies on NW Natural's system to meet peak demand. Is NW Natural also taking actions to reduce peak demand in constrained areas of its system?

A. Yes. Schedule 353, Geographically Targeted Energy Efficiency, is designed to avoid or defer system reinforcements through cost-effective energy efficiency measures in areas where NW Natural's system is expected to be constrained. Schedule 353 is an example of an emerging non-pipeline alternative that leads to better utilization of the existing system, which is more critical than ever to ensure Oregonians have continued access to safe, reliable, and affordable energy.

Q. How do these efforts support affordability?

A. NW Natural is seeking to optimize the use of the State's existing energy system in order to make energy more affordable. Geographically targeted energy efficiency and demand response will avoid or defer investments on NW Natural's system that would otherwise be needed, reducing costs for customers. Hybrid heating goes a step further, and seeks to optimize the use of both the existing natural gas and electric systems in order to reduce both systems' costs while ensuring resource adequacy and reducing emissions. By jointly planning the State's electric and natural gas systems, the electric generation, transmission, and distribution costs

[27] E3, Resource Adequacy and the Energy Transition in the Pacific Northwest, at 19 (April 2026) (available at: https://www.ethree.com/wp-content/uploads/2026/04/E3-NW-RA-Final-Report_040826.pdf).

to serve winter peaking load will be limited as the gas system continues to serve that load. On the gas side, it will moderate environmental compliance costs as the electric system serves a greater proportion of space heating load in milder weather when more intermittent renewable electric resources are available. NW Natural has already completed several hybrid heating pilot projects, including one in its Washington service territory that achieved savings for both the Company and the local electric utility.

These are significant developments. Joint system planning, hybrid heating, and non-pipeline alternatives such as geographically targeted energy efficiency and demand response represent a fundamentally different way of operating a gas system, and NW Natural is leading on this front.

VII. SUMMARY OF WITNESSES

Q. Please briefly describe the testimony provided by other witnesses in this case.

A. Thirteen other witnesses support NW Natural's filing and the requested rate increase.

Cecelia J. Tanaka, Energy Equity & Affordability Lead, explains how NW Natural identifies, evaluates, and responds to customer affordability challenges through a coordinated portfolio of affordability programs, customer protections, outreach and education, energy-efficiency investments, and stakeholder engagement. She also describes how the Company incorporates affordability and

equity considerations into decision-making and evaluates the effectiveness of those efforts over time. NW Natural/200, Tanaka.

Brody J. Wilson, Vice President, Treasurer, Chief Accounting Officer and Controller, provides testimony about the Company's cost of capital. His testimony supports the Company's proposed cost of debt and explains the Company's financing strategy of maintaining an equal balance of long-term debt and equity financing, resulting in an ROR on rate base of 7.374 percent that will maintain financial health and benefit customers. NW Natural/300, Wilson.

Jennifer E. Nelson, 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 9.75 percent and 11.75 percent. As explained above, NW Natural is seeking an opportunity to earn a 9.75 percent return on equity in the revenue requirement authorized in this proceeding, balancing affordability concerns while still attracting investor capital. NW Natural/400, Nelson.

Jorge O. Moncayo, Business Planning Senior Director, describes the Company's capital project budgeting and forecasting processes, including management approval and lifecycle phases. NW Natural/500, Moncayo.

Daniel B. Kizer, Engineering Senior Director, and **Michael C. Hwang**, Gas Storage Facilities Development Director, describe major distribution system

projects and storage facility projects serving Oregon customers that are included in this rate case, including the Company's ongoing plans for safety-driven system projects and programs. NW Natural/600, Kizer-Hwang.

Wayne K. Pipes, Director of Facilities, Security and Emergency Management, describes the Company's execution on its long-term facilities strategy, including upgrades to the Coos Bay Resource Center ("RC") and the Salem RC, as well as the Company's continuing progress on physical security upgrades. NW Natural/700, Pipes.

Brian E. Fellon, Vice President, Chief Information Officer & Chief Information Security Officer, describes NW Natural's ongoing IT&S strategy and investments. Mr. Fellon provides an overview of NW Natural's IT&S environment, including the continued need to migrate to cloud-based software, the corresponding increase in incremental O&M expense, and the rapid evolution of IT&S systems, as well as the major IT&S investments for which the Company seeks cost recovery in this proceeding. NW Natural/800, Fellon.

Kyra M. Patterson, Vice President, Chief People Officer, provides testimony on our labor costs, and describes the Company's practices related to compensation and benefits. Additionally, Ms. Patterson describes our overall employee count and the Company's request to include these costs in the Company's revenue requirement. NW Natural/900, Patterson.

Cory A. Beck, Director of Customer Experience Services, provides testimony about the Company's communications to customers on matters of

safety, as well as communicating information to customers about the nature of the services offered to them by the Company, and opportunities to conserve and be educated about the product that they purchase from us. Importantly, Mr. Beck describes the Language Access Plan that will expand access to essential billing, assistance, safety, and account information for customers with limited English proficiency and improve comprehension for English-proficient customers with limited literacy. NW Natural/1000, Beck.

Tobin F. Davilla, Director of Financial Planning and Budget, provides testimony about the operations and maintenance expense levels that the Company has incurred and expects to incur in the Test Year. NW Natural/1100, Davilla.

Kyle T. Walker, Senior Manager of Rates and Regulatory Affairs, provides the calculation of the Company's revenue requirement, which represents the annual revenues needed to recover prudently incurred costs of operating the utility business, and presentation of tariffs. He also describes the proposed bridge mechanism. NW Natural/1200, Walker.

Robert J. Wyman, Regulatory Affairs Senior Economist, provides the Company's use-per-customer forecast, long run incremental cost study, and describes the Company's rate spread and rate design proposal. NW Natural/1300, Wyman.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Kim A. Rush and Zachary D. Kravitz

POLICY EXHIBIT 101

November 24, 2026

EXHIBIT 101 – POLICY

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Exhibit 101 – NW Natural Advisory Group Statement 1-7

Statement of the Independent Advisory Group Regarding NW Natural's Integrated Resource Plan and Evaluation of Electrification of Current Gas Loads (IRP)

Independent Advisory Group Members:

Mr. Lee Beyer (1)

Mr. Stefan Bird (2)

Ms. Debra Smith (3)

Mr. Stephen Wright (4)

February 2025

Executive Summary:

The four-member independent Advisory Group (AG) provides this statement on the elements of NW Natural's IRP (IRP) we were asked to review. This IRP examines different scenarios related to electrification of natural gas loads currently served by the local distribution company, NW Natural. Our engagement was to focus on key assumptions that would affect cost, reliability and carbon emissions on the electric system of the Pacific Northwest (PNW) and particularly those electric systems that overlap with NW Natural's service territory.

The AG was presented an initial set of three supply-side scenarios and four demand-side scenarios. The AG focused on the supply-side scenarios. These initial scenarios had different assumptions about the future development costs, location, timing and availability of different supply-side generation resources and transmission expansion throughout the PNW region. These kinds of resources would be needed for normal electric load growth and these three supply-side resource scenarios also are used in the IRP to meet the varying degrees of load growth assumed in the four demand-side scenarios. We understand that these four demand-side scenarios are driven by different assumptions about electrification of loads currently served by natural gas and not fundamental differences in "base load" electric demand growth. Although we did not review the demand-side scenarios in detail, this statement does express a concern about the "base load" forecast possibly underrepresenting electric load growth based on current trends.

We found the initial three supply-side scenarios presented to the AG to be overly optimistic by assuming base assumptions that would result in electrification of current gas loads being easier, faster and cheaper than our own experience and judgment. Even the least optimistic scenario was not consistent with our view of current reality facing the PNW energy system. Our collective feedback was that the electric future transition will be harder, slower and more expensive than the scenarios we were presented even without electrifying current natural gas use.

NW Natural then developed a revised set of supply-side scenarios with one scenario called "Current Trends" that reflected the most change from the original three scenarios. The other two scenarios moved somewhat, but our judgment is they remain too reliant on overly favorable

assumptions. It is the AG's view that the electric system will be greatly challenged to meet the existing policy prescriptions and planned load growth even without taking into account electrification of the natural gas system.

As an overall observation, we think the electric systems are already being pressed against the edges of their capabilities and electric systems are experiencing more "close call" events such as in January 2024 in the PNW. The electric systems of the region are also relying heavily on the gas systems for electric generation for peak load service. For example, the PNW electric system was in severe emergency conditions last January. Without record electric imports from the Southwest and Rocky Mountain states, the Pacific Northwest could have experienced rolling blackouts of a magnitude that would be unprecedented in our region.

The AG expressed views about future supply side additions, load forecasts, and electric system planning for uncertainty. The AG also added thoughts about the need for better gas-electric integrated system planning in the future although not achievable in this study.

The AG noted the following about future supply side additions:

1. The biggest unknown about the cost of future supply is estimating the availability and cost of zero emission load following resources. There are substantial federal research and development dollars currently authorized, but it is unknown how effectively these will be deployed. The current very high cost of maintaining reliability under stress conditions without carbon-emitting load following resources (the status quo) should be a scenario that is analyzed. The AG recommends maintaining the availability of natural gas-fueled generation capability, which will increasingly operate at lower dispatch factors as more zero fuel cost renewable energy becomes available, until cost-effective, longer duration, zero emitting load following resources can make more advances.
2. Battery costs have been decreasing and are increasingly being adopted in the market. Currently cost-effective batteries, however, are limited to four hour duration. Longer duration batteries such as 100 hour iron-air batteries are on the horizon, but it is unclear how long they will take before they achieve widespread commercialization. Other proven technologies such as pumped hydro storage may be available in limited geographical locations but are historically higher cost and face more challenging permitting timelines. Longer term storage is necessary to maintain reliability in a system with increased reliance on variable resources and even more so without carbon-emitting dispatchable generation.
3. New standardized modular nuclear reactors are an option for both energy and peaking capability, but the technology currently carries an extraordinary array of risk in terms of cost and timeframe to be in place.
4. Demand side options hold tremendous potential but there are limits to the amounts of firm energy and capacity that can be assumed to be available in the most difficult circumstances due to consumers willingness to sustain demand reductions under stress temperature conditions.
5. The transmission assumptions we were presented are based on current planned schedules. For transmission upgrades that do not require new right of way the assumptions are likely reasonable. The increasing resistance to new transmission nationwide suggests caution with respect to schedules for new transmission that requires new right-of-way. The ability to

meet Western states' emission reduction targets with current load forecasts, let alone under more aggressive data center expansion and or more aggressive natural gas-based electrification assumptions, will require expansion of the transmission grid to access and deliver energy reliably from new remote renewable resources and new load following resources. Historically long timelines to permit new transmission lines, particularly across federal lands, as well as concerns about customer rate pressure, suggest caution with respect to the assumed speed of development of new transmission lines.

6. The accredited capacity for wind appears high relative to the capacity attributed to wind in regions using an established ELCC methodology. Offshore wind, which has received opposition by the new federal administration, is also limited by available transmission on the coast, which is generally weak due to small coastal loads. More sizable offshore wind resources will require new network transmission to be permitted and constructed to intertie to bulk transmission that can access large load centers, which adds to the timing risk and uncertainty.
7. There has also been a trend across the country to derate accredited capacity for thermal resources due to operational challenges occurring during extreme temperature conditions. There are a variety of reasons including inadequate weatherization of equipment and fuel supply disruptions. We recommend consideration as to whether the capacity factors for thermal units should be modified. The Western Power Pool may be able to help with this assessment.
8. There is substantial evidence that the cost of the clean electricity transition increases steadily over time, with rapid increases after 80% renewables is achieved, if there are not adequate cost-effective zero-emitting load following resources available.[1] Today, we are likely still on the upward slope prior to achieving 80%. This projected increase in costs translates into rate impacts. Utilities are increasingly seeing push back from customers on rate increases, mostly related to new resource capital expense. Oregon's House Bill 2021 – 100% Clean Energy for All - that was passed into law includes consumer protections for both affordability and reliability in the form of regulatory off-ramps. In addition, the physical siting of these resources is experiencing strong opposition from many customers. This raises concerns about the industry's ability to bring new resources online in a timely manner. A feedback loop is needed to recognize that if rates increase dramatically and quickly, or if permitting processes do not evolve to address siting concerns, there will be consequences for the rate at which the clean electricity transition can occur.

It is also important to understand that current and long-term concerns about product affordability are based on resource adequacy, as well as a myriad of other factors also putting pressure on forward rate trajectories. Although this work only deals with the rate impacts of acquiring sufficient resources within the regulatory framework established by each state, rate impacts are cumulative and customers generally do not look at individual drivers such as wildfire mitigation, system resiliency, grid modernization or general capital investment. Instead, rate actions associated with resource adequacy must be examined in the context of all other rate pressures.

[1] 2019 Resource Adequacy Study in the Pacific Northwest on the Public Generating Pool website.

As a result, we have concerns about the achievability of the supply side assumptions even in the "Current Trends" scenario.

For the demand side, the "base load" demand forecast was standardized across the demand scenarios using current load forecasts. Like locking down other variables so that the policies and rates of electrification could be examined as the changing variable, we understand the purpose of a single "base load" forecast. However, we remain concerned that this forecast likely underrepresents the potential electric load increases being driven by factors other than electrification of gas load. Regional electric load forecasts have increased in an unprecedented fashion in the last two years, and we expect the forecasts to continue to increase. Specifically, data centers and AI have become large swing short-term variables and vehicle electrification is a long-term driver.

Planning Reserve Margin (PRM) is a key assumption in this analysis that addresses uncertainty in electric utility planning. We have already seen upward pressure on PRMs around the country due to the increased use of energy and dispatchability limited resources, load growth uncertainty and the capability of resources to deliver capacity during temperature related stress events, a challenge which has been exacerbated by extreme weather events. We also expect there will be an increasing effort to address the duration and magnitude of reliability risk (through tools like expected unserved energy or EUE) in addition to the standard probabilistic assessment of the frequency of electric outages. The emerging long duration, high magnitude outages during extreme weather events, as experienced in Texas and California, present high level human health and safety issues. In addition, the PNW is in the midst of a transition from being an energy constrained to a capacity constrained system and systems need to evolve as well. Electrification of natural gas uses will have the biggest impact at the times which are becoming the most challenging for the electric system. All these factors point toward the use of higher than historical levels of planning reserve margin to maintain the level of reliability PNW consumers have come to expect from their electric power system.

Moreover, the AG thinks the study should also consider the reality of periodic severe ice or windstorm events as we have experienced in recent years. Such events have resulted in multi-day electric distribution grid outages disrupting electricity supply to thousands of customers until electric distribution grid damage is repaired and power is restored. If natural gas winter heating capability is fully displaced by electric heating without auxiliary/hybrid natural gas heat pump capability, or without extraordinary levels of storage at the local retail user level, there will be substantial public safety and economic impacts. It is possible to underground electric distribution but only at significant expense, over a lengthy time period and requiring increased maintenance. The AG encourages that this risk receive attention in discussion of electrification.

Finally, we note that the AG believes there is potential for consumer value to be generated through increasing coordinated/joint planning and/or coordinated operations between gas and electric systems where there are overlapping service territories. Building on recent efforts to build collaboration in the PNW, it is recommended that synergies be unlocked that can reduce cost, improve reliability and decrease carbon emissions through consideration of coordinated and/or joint integrated resource planning, investment and operations for options from supply source to consumer use of the gas and electric systems.

Our specific recommendations regarding assumptions are included in the "Detailed Recommendations" section that follows below.

Detailed Recommendations:

The AG recognizes there is never a perfectly accurate single point forecast for the future. The IRP's goal of evaluating the impacts of possible future scenarios to help inform policy and strategy is reasonable, as long as the probability is not evenly weighted between the various scenarios currently being utilized. Our collective view is that, of the scenarios NW Natural is studying, the "Current Trends" supply side scenario most accurately reflects current reality now and for the foreseeable future. However, we continue to have residual concerns that the reasonable risk to electric system reliability is outside the range of the scenarios to be studied. This is due to supply, demand and uncertainty assumptions embedded in the study. We recommend addressing these concerns through sensitivity analysis to better understand load and resource uncertainty.

- The Current Trends scenario includes near-term increase in costs for wind, solar and batteries that best reflects current reality for the supply side in electricity markets. The causes for these increases would best be described as driven by high demand, supply chain challenges, import tariffs and permitting issues, driving costs up in the near term while technological improvements are driving costs down over the longer term. The other two scenarios follow more traditional NREL cost forecasting. The AG also noted there is an interaction between load and costs for supply. Higher loads lead to more stress on generation and transmission supply chains lead to higher costs. A scenario that assumes costs of all resources are higher when load growth is high is within the realm of reason and should be considered for scenario analysis purposes.
- The AG has suggested use of a sensitivity analysis approach that would vary the base load forecast using a higher growth rate. Although we do not have a specific numerical recommendation, we have suggested using the trends from the last two years as a basis for assuming a corresponding increase for at least one additional year at the beginning of the forecast period.
- The single planning reserve margin (PRM) that is based on PNUCC's short-term PRM of 16% is reasonable in the short term. However, consistent with comments above, the AG believes this PRM is likely understated in long-term studies that assume increasingly higher percentages of variable generation resources over time. Electric system planning in this new long-term environment will require more sophisticated modeling techniques to ensure reliable service in all 8,760 hours of the year and not just the peak hour. In-lieu of deployment of these more sophisticated modeling techniques, the AG recommends consideration of an approach that would increase the PRM in relationship to increasingly higher percentage reliance on zero-emitting variable generation resources that is supported by review of other expert sources, or alternatively consider a sensitivity scenario with a gradually increasing PRM to provide an indicator of potential cost and risk impact. Potential sources of this PRM insight are information emerging in the work performed by the Electric Systems Integration Group (ESIG), Pacific Power's current 2025 IRP process, and PRM analysis performed by RTO/ISOs across the nation. In the future, the AG's recommendation

to pursue coordinated joint planning between the electric and gas utilities would support a more informed set of assumptions including PRM and improved quality of analysis.

- There has been a trend across the country to derate accredited capacity for thermal resources due to operational challenges occurring during extreme temperature conditions. There are a variety of reasons including inadequate weatherization of equipment and fuel supply disruptions. We recommend consideration as to whether the capacity factors for thermal units should be modified. The Western Power Pool may be able to help with this assessment.
- With respect to reliability and the issues of moving from a "dual fuel" (electric and gas) system to a "single fuel" (electric system) we have raised numerous concerns about assuring that the IRP analysis carefully assess issues around resulting system reliability and the potentially profound public health and safety issues of relying on a single fuel (electric) system. NW Natural's IRP process examines its own gas system but is also attempting to evaluate the electric systems of the PNW which is a reason we were asked to serve on the AG. What is lacking, not just in this study but in all current integrated resource plans across the country, is an integrated systems perspective incorporating the gas and electric systems. The risk of reliance on one fuel is increased due to the exposure of the electric distribution system to ice and wind events. Recent storms in Oregon have displayed that multi-day electric outages while distribution systems are repaired would create a substantially greater human health and safety risk following electrification of the natural gas system. While this risk is difficult to address in this study, we recommend at least addressing qualitatively. Ultimately, these critical issues should be addressed through regional joint system planning (gas and electric).

Independent Advisory Group Members Bios:

(1) **Lee Beyer:** Lee Beyer was a member of the Oregon Legislature for 22 years serving in both the House and State Senate. From 2001 until 2010 he served as a member and Chair of the Oregon Public Utility Commission. He also served for many years as a board member of the Western Electric Coordinating Council, as a member of the EPRI Advisory Council and member and Vice-Chair of the NARUC Electricity Committee. During his time in the Legislature, Beyer chaired the committees with oversight of energy policy and was directly involved in the drafting and sponsorship of much of Oregon's recent energy legislation.

(2) Stefan Bird: Stefan Bird previously served as CEO of Pacific Power, a division of PacifiCorp, senior vice president, commercial and trading, PacifiCorp Energy, CEO of CalEnergy, an independent power producer, and vice president of acquisitions and project development for Berkshire Hathaway Energy. During his 17-year tenure at PacifiCorp, among other activities, Bird led the dramatic expansion of PacifiCorp's renewable energy portfolio and interstate transmission grid, western electricity market transformation and engagement in Oregon energy legislation.

(3) **Debra Smith:** Deborah (Debra) Smith served as CEO of Seattle City Light, General Manager of Central Lincoln PUD (serving the Oregon coast), and various roles at the Eugene Water & Electric Board. During her 30 years in the electric utility industry, Deborah prioritized customer responsiveness, collaboration across the region, and electrification/decarbonization. Deborah also served as the first female chair of the Public Power Council, as well as on the boards of the Smart Energy Provider's Alliance, the Electric Power Research Institute EPRI, and the American Public Power Association. She remains active on the Pacific Northwest National Lab advisory committee, as well as the Western Transmission Consortium.

(4) Stephen Wright: Steve Wright began his career developing energy efficiency supply curves and integrated resource plans. He served as Administrator/CEO of the Bonneville Power Administration from 2000-2013, CEO of Chelan Public Utility District from 2013-2021 and is now a member of the Southwest Power Pool Board of Directors as well as the Interim Markets+ Independent Panel. He has served on the boards of the Alliance to Save Energy, Electric Power Research Institute and American Public Power Association.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Direct Testimony of Cecelia J. Tanaka

EQUITY
EXHIBIT 200

November 24, 2026

EXHIBIT 200 – DIRECT TESTIMONY – EQUITY

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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 & 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 20 years of experience developing and leading social impact and corporate responsibility initiatives focused on equity and social justice.

I joined NW Natural in January 2021 to lead the Company's community investments focused on energy equity and energy burden, including energy efficiency resources for multi-family residents, discounted rate programs for income-eligible customers and philanthropic giving across the Company's Oregon and Washington service territories. In April 2024, I joined NW Natural's Regulatory Affairs team to lead the Company's energy equity and affordability efforts. Before joining 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. Please describe your responsibilities.

A. I lead and coordinate the Company's energy equity and affordability policy work. My responsibilities include supporting the development, administration, evaluation,

and refinement of affordability-related programs; coordinating stakeholder engagement related to energy equity; translating customer data and community feedback into program and policy improvements; and supporting the integration of equity and affordability considerations into regulatory, planning, and customer-facing work.

Q. What is the purpose of your testimony?

A. My testimony explains how NW Natural identifies, evaluates, and responds to differences in customer affordability needs, barriers, access, participation, and outcomes. I describe the regulatory context for this work, the information the Company uses to understand customer need, its portfolio of affordability and energy-efficiency resources that effectively address the identified need, its approach to program access and customer safeguards, and how it uses evaluation and stakeholder input to improve implementation over time.

Q. Please summarize your testimony.

A. My testimony addresses three related points:

First, the regulatory landscape has evolved significantly. Through Oregon House Bill ("HB") 2475,[1] docket UM 2211,[2] docket UM 2417,[3] customer protection

[1] Oregon House Bill 2475 (2021), the Energy Affordability Act.

[2] *In the Matter of Public Utility Commission of Oregon, Implementation of House Bill 2475*, Docket No. UM 2211.

[3] *In the Matter of Public Utility Commission of Oregon, Identifying Priorities in Implementation of Executive Orders 25-25 and 25-29*, Docket No. UM 2417.

rulemakings AR 667 and AR 671,[4] and HB 3179,[5] Oregon's regulatory framework has significantly expanded stakeholder engagement and reporting requirements, and has placed greater emphasis on understanding customer impacts, evaluating affordability outcomes, supporting public participation, and incorporating equity considerations into planning, decision-making, and ratemaking. These developments reflect a broader and more integrated approach to equity and affordability in utility regulation.

Second, NW Natural's approach has matured in response to this evolving landscape, as well as customer and stakeholder feedback. The Company's work has progressed beyond implementing individual programs toward a more structured and evidence-based approach focused on understanding customer need, identifying barriers, evaluating outcomes, incorporating stakeholder input, and continuously improving performance.

Third, this work represents an ongoing operational responsibility that spans multiple departments and business functions. The operational scale and customer-funded nature of these efforts heighten the importance of disciplined prioritization, effective implementation, and meaningful evaluation. As NW Natural's efforts have evolved, the Company has focused on directing resources where they can provide meaningful customer benefit. My testimony explains how

[4] Public Utility Commission of Oregon, *In the Matter of Rulemaking to Adopt Temporary Rules Related to Protections Against Disconnections*, Docket No. AR 667; and Public Utility Commission of Oregon, *In the Matter of Rulemaking Regarding Customer Protections*, Docket No. AR 671.

[5] Oregon House Bill 3179 (2025), the Fairness & Affordability in Residential (FAIR) Energy Act.

the Company evaluates outcomes and uses that information to improve its affordability investments over time.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes.

- NW Natural/201, Tanaka – Updated Energy Burden Assessment
- NW Natural/202, Tanaka – Bill Discount Program Materials
- NW Natural/203, Tanaka – EM&V Report: NW Natural 2010-2022 Low-Income Energy Efficiency Programs

II. OREGON'S EVOLVING EQUITY & AFFORDABILITY LANDSCAPE

Q. What broader Oregon context informs NW Natural's equity and affordability work?

A. NW Natural's equity and affordability work operates within an evolving Oregon policy and regulatory environment that increasingly focuses on energy burden, differential rates, customer protections, public participation, procedural equity, distributional equity, affordability programs, and reporting.

Q. What laws, policies, and proceedings are especially relevant to this testimony?

A. The following laws, policies, and proceedings are particularly relevant:

- HB 2475 expanded the Public Utility Commission of Oregon's ("Commission") authority to consider differential energy burdens and economic, social equity, and environmental justice factors affecting affordability. The legislation also expanded intervenor-funding eligibility

to support participation in Commission proceedings by low-income and environmental justice communities.

- Docket UM 2211, the Commission's implementation docket for HB 2475, has included workstreams addressing affordability, customer assistance programs, bill discounts, rates, energy efficiency, weatherization, arrearages, disconnections, access barriers, customer data, and approaches for evaluating outcomes and improving program effectiveness.
- Docket UM 2417, which implements Executive Orders 25-25 and 25-29, is establishing priorities for how the Commission evaluates affordability, reliability, community impacts, and distributional equity across its regulatory work. The proceeding reflects growing attention to understanding how the benefits and burdens of utility decisions are experienced by different customers and communities.
- Dockets AR 667 and AR 671 address customer safeguard standards, including protections related to disconnection practices and affordability.
- In docket UG 520, the Commission approved stipulations advancing the Company's affordability portfolio, including enhancements to administration of the Oregon Low-Income Grant Assistance ("OLGA") program and efforts to expand automatic enrollment in the Bill Discount Program for eligible customers. These commitments reflect a continued

regulatory focus on improving access to affordability assistance and reducing participation barriers.

- The Fairness and Affordability in Residential ("FAIR") Energy Act (HB 3179) establishes additional requirements related to affordability, customer rate impacts, and cumulative economic impacts in applicable Commission decisions. Please see the Cumulative Economic Impact Analysis (CEIA) required by the FAIR Energy Act that NW Natural has included with its general rate case, as well as the Direct Testimony of Kim A. Rush and Zachary D. Kravitz (NW Natural/100, Rush-Kravitz) for additional discussion.

Q. What do these changes in the legal and regulatory landscape mean for the Company in practice?

A. Together, these developments require the Company to do much more than simply administer customer-assistance programs. NW Natural must connect regulatory policy with practical implementation through analysis of energy burden, program development and administration, supporting advisory group activities, stakeholder engagement, data analysis and reporting, and incorporating equity considerations into planning processes.

The regulatory landscape also requires a consistent connection between policy and implementation. NW Natural must maintain the analytical, programmatic, engagement, reporting, and implementation capabilities needed to understand customer needs, translate those needs into appropriate programs and

protections, improve access to available resources, evaluate outcomes, and incorporate what it learns into future decisions.

Table 1 summarizes how specific laws and proceedings translate into practical Company responsibilities:

Table 1. Regulatory Requirements and Practical Company Responsibilities

Proceeding	Primary Areas of Company Work
HB 2475	Affordability analysis, customer-impact reporting, and stakeholder engagement
UM 2211	Affordability reporting, program evaluation, and policy implementation
UM 2417	Distributional equity analysis, planning, and community engagement
AR 667 / AR 671	Customer protections, implementation, and compliance
UG 520	Administration and improvement of affordability programs
HB 3179 (FAIR Energy Act)	Residential rate-impact and affordability analysis

III. EQUITY & AFFORDABILITY AS A DECISION-MAKING FRAMEWORK

Q. How does NW Natural distinguish equity from affordability?

A. Affordability concerns a customer's ability to pay for energy service. Equity is the disciplined consideration of how customer circumstances, barriers, access, participation, and outcomes may differ. The concepts are related but not interchangeable. Careful consideration of equity-related issues helps the Company determine whether its affordability tools and customer protections are accessible and effective for the customers they are intended to serve.

Q. How does the Company apply an equity and affordability lens to its decision-making?

A. An equity and affordability lens informs NW Natural's decision-making throughout all areas of its business. Energy equity and affordability provide a framework for understanding how customer impacts may vary across customer groups and circumstances. This framework helps the Company identify affordability pressures, evaluate available measures and customer protections, improve access to programs and services, and incorporate customer and stakeholder feedback into ongoing program evaluation and refinement.

Customer and stakeholder feedback shapes our work. The Company's objective is to align available resources with customer needs and evaluate whether those investments are producing meaningful customer benefits. The Company draws on customer data, program experience, stakeholder engagement, and operational insights to identify affordability pressures, assess available tools and safeguards, evaluate participation and outcomes, and make program refinements. In practice, this turns equity from an abstract principle into a disciplined approach to decision-making—connecting customer need, program design, implementation, evaluation, and accountability.

IV. UNDERSTANDING CUSTOMER NEED

Q. Why does the Company begin with customer need?

A. It is critical to first focus on customer need, because affordability challenges are not uniform. A customer may struggle with a current bill, carry a past-due balance, face a short-term emergency, or have high usage associated with housing or

equipment conditions. An eligible customer may also face language, documentation, awareness, trust, or enrollment barriers. Different needs require different tools, and identifying specific customer needs allows the Company to use the tools that will best serve its customers.

Q. How does NW Natural identify and understand customer affordability needs?

A. NW Natural uses multiple sources of information to understand how affordability challenges vary across its customers. These include customer and energy-use data, program enrollment and participation, customer impact data, implementation experience, community and advisory group engagement, regulatory filings, peer utility engagement, and customer and stakeholder feedback. Together, these sources help the Company identify affordability differences, participation gaps, access barriers, and the alignment between available resources and customer needs. A key analytical tool supporting this work is the Company's Energy Burden Assessment ("EBA").

Q. What is the Energy Burden Assessment and how does the Company use it?

A. NW Natural engaged Empower Dataworks to complete an EBA in 2024.[6] The EBA examines energy burden alongside customer income, program participation,

[6] Docket No. UM 2211, NW Natural's Energy Burden Assessment (Aug. 2024), (Sept. 16, 2024) (available here: um2211hah331407120.pdf).

assistance levels, and other customer characteristics to better understand where affordability needs are concentrated and how assistance aligns with those needs.[7]

In 2026, NW Natural engaged Empower Dataworks to refresh the 2024 EBA with two additional years of data through March 2026. The refresh updates the underlying analysis of income eligibility, energy burden, program participation, assistance need, and energy-efficiency potential. NW Natural also took this opportunity to test the existing Bill Discount Program tier structure against estimated customer need to determine whether discounts were offered at the appropriate levels. See NW Natural/201, Tanaka for the 2026 EBA data refresh.

Q. What did the Company's 2026 EBA data refresh show about the effectiveness of the Company's programs?

A. The data refresh sharpens our understanding of where affordability challenges are concentrated, shows that assistance is materially reducing burden, and provides better information for targeting outreach and evaluating program design.

Specifically, the EBA provides several important updates to the Company's analysis of program performance:

- First, the affordability assistance available to participating customers is materially reducing energy burden. In 2025, discounts brought median energy burden to 1.7 percent—below the threshold that defines energy

[7] The EBA uses a 2 percent natural gas energy burden threshold to identify households experiencing high gas burden; and calculates energy burden before accounting for energy assistance. The EBA Oregon analysis defines low-income households as those with income at or below 60 percent of State Median Income ("SMI").

burdened and a full percentage point reduction from the burden those customers experienced before receiving assistance.

- Second, approximately 75 percent of assistance delivered through bill discounts are concentrated to customers with the highest burdens and lowest incomes—demonstrating a strong alignment between program spending and affordability need. Empower Dataworks characterized the programs as well designed and doing well at directing funds toward higher-burden customers.
- Third, and particularly relevant in this rate case, the data refresh tested the Bill Discount Program tiers against estimated assistance need to ascertain if a recalibration of discount levels was warranted. The analysis concluded that discount levels "appear to be appropriate at this time and can accommodate moderate rate increases without requiring adjustments." Based on this analysis, in the 2026 EBA refresh, Empower Dataworks recommends maintaining the current discount levels.

Q. What does the data refresh indicate about energy burden for customers, taking into account the proposed rate increase in this case and the Bill Discount Program levels?

A. The data refresh provides important evidence that existing discount levels remain appropriately calibrated to estimated customer need and can absorb moderate rate increases without adjustment. Accordingly, the updated data indicates that the

existing discount levels are adequate to mitigate energy burden for a moderate rate increase (such as the request included in this case).

Q. Does the Bill Discount Program represent the full range of affordability assistance available to participating customers?

A. No. The Bill Discount Program provides ongoing monthly bill support as one component of a broader affordability portfolio. Depending on their circumstances and eligibility, customers may also receive short-term bill assistance through OLGA, Gas Assistance Program ("GAP"), or Low Income Home Energy Assistance Program ("LIHEAP"); assistance with past-due balances through Arrearage Management Program ("AMP"); or longer-term support through Oregon Low-Income Energy Efficiency ("OLIEE").

This is important context for the EBA's conclusion regarding the adequacy of current bill discounts. The tier analysis assumes that the Bill Discount Program is the only assistance used to address energy burden, although Empower Dataworks notes that, in practice, most customers receive assistance from multiple programs. In addition, the EBA may not capture every source of assistance a customer receives, including certain energy-efficiency support provided outside the Company's assistance data.

The Bill Discount Program should therefore be viewed as the foundation for ongoing bill affordability, complemented by other resources that address different customer needs.

Q. How do these findings inform the Company's understanding of customer need?

A. These findings provide a more complete view of program performance than enrollment alone. They show not only whether customers are participating, but whether assistance is reducing burden and whether program resources are reaching customers with greater affordability challenges.

Taken together, these findings show that the current Bill Discount Program remains appropriately calibrated to estimated assistance need, materially reduces energy burden for participating customers, and directs the substantial majority of program spending to high-burden customers.

Q. How does NW Natural respond to different forms of customer need?

A. NW Natural uses a portfolio of complementary tools. No single program is designed to solve every affordability challenge, and customers may use multiple resources in tandem depending on their circumstances and eligibility. Short-term assistance addresses immediate costs. The Bill Discount Program and Arrearage Management Program address monthly bills and past-due balances. Energy-efficiency and weatherization resources address usage and housing conditions over time. Outreach, language access, simplified enrollment, verification, and customer protections support access, program integrity, and service continuity.

Table 2. Affordability Portfolio by Customer Need

Customer Need	Primary portfolio tool	Primary function
Immediate or short-term hardship	OLGA/GAP/LIHEAP	Direct bill assistance
Ongoing monthly affordability	Bill Discount Program	Reduces eligible customers' monthly bills
Past-due balances	Arrearage Management Program	Helps qualifying customers address arrears
Longer-term energy use and housing conditions	OLIEE, including CAP and OSP	Supports weatherization, eligible efficiency measures, and related work
Access barriers	Outreach, language access, community partnerships, and streamlined enrollment	Helps customers find, understand, and access support
Service-continuity risk	Customer safeguards	Provides options intended to reduce avoidable loss of service during hardship

V. NW NATURAL'S AFFORDABILITY PORTFOLIO

Q. How is the Company's affordability portfolio organized?

A. Effective January 2026, NW Natural reorganized its income-qualified customer programs under a unified Energy Affordability portfolio managed by a dedicated team within the Public Affairs organization. The portfolio brings together Energy Assistance (OLGA, GAP, and LIHEAP), Bill Discount Program, AMP, and OLIEE program under a single framework. The portfolio groups resources into Short-Term Support, Ongoing Bill Stability, and Long-Term Support. This structure supports greater coordination across programs and allows NW Natural to consider the portfolio more holistically, including opportunities to improve program access,

participation, and coordination while supporting responsible stewardship of customer-funded resources.

Q. Please describe the programs that fall under Short Term Support.

A. NW Natural's Short-Term Support resources include OLGA, GAP, and LIHEAP. These programs provide financial assistance to eligible customers to help manage near-term energy costs.

OLGA provides energy assistance grants to income-qualified customers. GAP provides supplemental assistance funded by NW Natural shareholders, employees, retirees, and customer contributions, with NW Natural matching contributions up to $60,000 annually. LIHEAP is a federally funded program that provides energy assistance to eligible households.

Q. Please describe the programs that fall under Ongoing Bill Stability.

A. The Bill Discount Program reduces monthly bills for eligible customers, while the AMP helps qualifying customers address accumulated past-due balances.

Q. Please describe the Bill Discount Program.

A. NW Natural launched its Oregon residential Bill Discount Program on November 1, 2022. The program is designed to reduce barriers to participation through features including auto-enrollment for customers who have received energy assistance and self-certification of income eligibility. The program uses a tiered discount structure, with larger discounts available to households with lower incomes. Customers with incomes below 60 percent of Oregon state median income ("SMI") may qualify for discounts ranging from 15 to 85 percent, depending on household income and size, as shown below.

Table 3: Bill Discount Program Thresholds

Income tier	Bill Discount
0-15%SMI	85%
16-30%SMI	50%
31-45%SMI	30%
46-60%SMI	15%

Q. Please describe the AMP.

A. The AMP complements the Bill Discount Program by helping qualifying customers address accumulated past-due balances. The AMP provides grants of up to $1,000 every 24 months to customers with incomes below 15 percent of SMI. The program is administered by NW Natural and was launched in April 2025. See NW Natural/202, Tanaka for additional Bill Discount Program materials.

Q. Please describe the programs that provide Long-Term Support.

A. Long-Term Support addresses factors that can contribute to energy burden over time, particularly household energy use and housing conditions that can limit a customer's ability to benefit from energy-efficiency improvements. The Company's primary long-term offering for income-qualified Oregon customers is the OLIEE program under Schedule 320.

OLIEE uses a designated portion of the Public Purpose Funding Surcharge to support weatherization, qualifying high-efficiency gas equipment, and energy-literacy services for income-qualified NW Natural customers. OLIEE includes two complementary components: the Community Action Program ("CAP") and the Open Solicitation Program ("OSP"). CAP supports weatherization and eligible energy-efficiency improvements through Community Action Agencies and other

approved providers. OSP supplements that model by providing an additional pathway for projects, housing types, and customer circumstances that fall outside CAP parameters. CAP provides an established delivery structure for home weatherization and eligible improvements, while OSP provides flexibility to address different housing types, project structures, and delivery needs. Together, they give OLIEE a broader set of tools to match program resources with the circumstances that can affect whether customers are able to access and benefit from energy-efficiency investments.

Q. Have there been recent updates to the OLIEE program?

A. OLIEE has evolved substantially in both program design and delivery. In 2024, Commission-approved changes to Schedule 320 raised income eligibility from 60 percent State Median Income to 80 percent Area Median Income, authorized full funding of eligible energy-efficiency measures and necessary health, safety, and structural repairs, and increased support for program delivery and evaluation. The revised tariff became effective March 20, 2024, following Commission approval in docket ADV 1593.[8]

OSP has expanded significantly in recent years, supported by greater flexibility in how OLIEE funds can be used and a broader network of community-based partners. This flexibility has increased opportunities to pursue projects involving housing types and customer circumstances that may not fit within the

[8] *NW Natural Advice No. 24-02 Schedule 320 OLIEE Programs*, Docket No. ADV 1593, Accepted Utility Filing Letter (Mar. 19, 2024).

traditional CAP model, including projects where health, safety, or structural repairs are needed to complete eligible efficiency improvements. Recent OSP projects have included whole-home upgrades and structural repairs through partnerships with culturally specific organizations, energy-efficiency improvements and structural repairs at the Eugene Mission shelter, and full-building energy retrofits in Habitat for Humanity communities.

These changes are significant because energy efficiency retrofits cannot always be delivered in isolation from the condition of the home. A needed repair or health and safety issue can prevent an efficiency measure from being installed. By allowing OLIEE to address those underlying barriers, the program is better positioned to complete eligible improvements and deliver their intended customer benefits.

Table 4 on the CAP program demonstrates the scale of this growth over the last few years—across key indicators like homes weatherized; investments in energy-efficiency and health, safety, and repair measures; and estimated annual therm savings. Estimated annual therm savings reflect completed CAP/CBO weatherization projects and do not include OSP projects. In addition, OSP added 12 new projects to its portfolio during the most recent program year, representing more than $8 million in project funding for multifamily housing, permanent supportive housing, workforce development initiatives, and partnerships with culturally specific organizations.

Table 4. Evolution of OLIEE CAP Program Delivery & Investment[9]

Program Year	Homes Weatherized	Energy Efficiency Investment	Health, Safety & Repair Investment	Estimated Annual Therm Savings
2021-22	165	$1.31M	$0.13M	58,037
2022-23	175	$1.33M	$0.22M	56,179
2023-24	223	$2.10M	$0.59M	59,175
2024-25	307	$2.86M	$1.60M	84,814

Q. How does the Company evaluate whether OLIEE is providing customer benefits?

A. NW Natural uses program reporting and independent evaluation to assess OLIEE performance. A recent third-party evaluation assessed energy savings, cost effectiveness, customer experience, and program performance. The evaluation found energy savings of approximately 16 to 19 percent and Total Resource Cost ratios above 2.0. It also found high satisfaction among participants, agencies, and contractors; and uncovered opportunities related to workforce capacity, customer awareness, project documentation, and measure-level data tracking. These findings provide an important complement to measures of program activity and spending. See NW Natural/203, Tanaka for the third-party evaluation.

[9] Program years run from October 1 through September 30. CAP/CBO figures reflect completed dwellings and reimbursed efficiency and health, safety, and repair costs OSP expenditures reflect program-year spending and may include completed and in-progress multi-year projects. Figures exclude NW Natural administrative and energy-education expenditures. Because OSP serves multiple housing types and supports both project delivery and delivery capacity, OSP expenditures should not be interpreted as a one-to-one measure of completed dwelling units.

Q. How does OLIEE fit within the Company's broader affordability strategy?

A. OLIEE complements resources that address more immediate affordability needs. Bill assistance can help customers manage current energy costs or past-due balances, while energy efficiency and weatherization can address energy use and housing conditions that contribute to affordability challenges over time. No single program is designed to address every affordability challenge. OLIEE provides a longer-term tool within the Company's broader portfolio by helping income-qualified customers access energy-efficiency improvements that can reduce energy use and support affordability over time.

Q. What about long-term resources for customers whose incomes exceed the OLIEE eligibility threshold?

A. NW Natural customers contribute to a separate public purpose charge that funds energy efficiency incentives and services for customers who earn above 80 percent Area Median Income. These offerings[10] are facilitated by the Energy Trust of Oregon ("ETO") and include incentives for high-efficiency equipment, weatherization improvements, and other measures designed to reduce energy consumption and lower utility costs.

Q. Please provide a history of the participation and customer benefits of the various programs you have discussed.

A. Please see the tables below.

[10] Energy Trust of Oregon, "Savings Within Reach," https://www.energytrust.org/incentives/savings-within-reach/ (last accessed Nov. 6, 2026).

Table 5.[11] History of Participation

Customers	Program Year October 1 - September 30				
	2021-22	2022-23	2023-24	2024-25	2025-26
Short-Term Support					
OLGA	6,086	7,553	6,783	6,214	5,383
LIHEAP	1,937	2,504	2,932	1,703	1,630
GAP	954	1,525	1,104	1,207	1,463
Ongoing Bill Stability					
Bill Discount Program*	0	30,257	41,272	46,072	52,110
Arrearage Management Program*	0	0	0	956	2,962
Long-Term Savings					
OLIEE - Community Action Program	165	175	223	307	322
TOTAL ALL PROGRAMS	9,142	42,014	52,314	56,459	63,870

* Bill discount program began Nov 1, 2022, Arrearage Management Program began Apr 1, 2025. Counts represent end of program period counts at September 30

Table 6.[12] History of Customer Benefits

Progam Benefits	Program Year October 1 - September 30				
	2021-22	2022-23	2023-24	2024-25	2025-26
Short-Term Support					
OLGA	$2,628,328	$3,688,238	$3,703,048	$3,355,785	$3,041,747
LIHEAP	$697,518	$1,130,831	$1,331,297	$694,743	$711,990
GAP	$114,247	$195,588	$133,016	$139,750	$160,455
Ongoing Bill Stability					
Bill Discount Program*	$0	$3,808,070	$6,983,818	$15,708,746	$18,241,451
Arrearage Management Program*	$0	$0	$0	$302,500	$659,310
Long-Term Savings					
OLIEE - Community Action Program	$1,440,729	$1,544,920	$2,686,180	$4,459,031	$5,564,430
OLIEE - Open Solicitation Program	$553,892	$1,140,460	$2,703,368	$8,171,528	$10,587,562
TOTAL ALL PROGRAMS	$5,434,714	$11,508,108	$17,540,727	$32,832,083	$38,966,945

* Bill discount program began Nov 1, 2022, Arrearage Management Program began Apr 1, 2025

Q. How is NW Natural informing customers about these programs?

A. NW Natural uses a combination of direct customer communications, community partnerships, targeted outreach, and paid advertising to increase awareness of its

[11] The program year runs October 1 through September 30, in alignment with the federal LIHEAP program schedule.

[12] Program benefits include customer grants and benefits spending, and excludes administrative and energy education costs.

income-qualified programs and help customers connect with available resources. The Company works with Community Action Agencies, community-based organizations, housing networks, places of worship, food banks, culturally specific organizations, healthcare networks, and other community partners throughout its service territory.

- **Customer communications.** NW Natural provides information about available programs through its website, bill inserts, postcards, digital communications, and materials distributed through community partners and events. The Company also cross-promotes income-qualified programs so customers who learn about one resource can be made aware of other assistance for which they may be eligible. Materials are designed to improve accessibility through plain language, multilingual information, and clear connections to program and partner resources.
- **Community-based outreach and education.** Community Action Agencies and other community partners extend the reach of these efforts by connecting customers with program information through energy education, workshops, and other community-based activities. Community Action Agencies receive additional OLIEE funding for energy education activities, which can include program outreach. These partnerships provide another means of reaching customers through organizations and networks already serving their communities.

- **Direct community engagement.** NW Natural also participates in resource fairs, health fairs, preparedness events, multicultural events, school events, and other community gatherings throughout its service territory. These events provide opportunities to share information about available assistance, answer customer questions, provide enrollment support, and distribute practical energy-saving resources. In 2025, NW Natural participated in 14 events reaching approximately 14,865 attendees and distributed 863 DIY weatherization kits and more than 2,200 individual weatherization supplies.

These efforts provide multiple ways for customers to learn about and connect with available assistance. The Company's approach recognizes that program availability alone does not ensure participation; customers must also be able to find, understand, and access the resources available to them.

Q. Is the Company also advertising its income-based offerings?

A. Yes. These efforts are further supported by paid ads on streaming radio stations, including Spanish-language ads, streaming video services, cable television, 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. These details are discussed more in the Direct Testimony of Cory A. Beck (NW Natural/1000, Beck).

VI. REDUCING BARRIERS, STRENGTHENING SAFEGUARDS & SUPPORTING SERVICE CONTINUITY

Q. Why is access a central part of NW Natural's equity framework?

A. Programs are only effective if customers can find them, understand them, access them, and maintain participation when they face hardship. Reducing barriers is therefore an essential component of affordability. Access barriers can include lack of awareness, language barriers, difficulty understanding program requirements, enrollment complexity, documentation burdens, limited trust, or challenges navigating multiple programs. A program that is technically available may still fail to reach customers if these barriers are not addressed. Strong equity practices require attention to implementation, not only program design.

Q. What types of access and enrollment issues does NW Natural consider?

A. The Company employs several access-related tools, including enrollment and access improvements, language accessibility, trusted community partnerships, service continuity measures, customer communications, geo-targeted direct mail, and language access planning. These tools help ensure that customers are not only eligible for assistance in theory, but able to understand and access support in practice.

Q. How does language access support customer outcomes?

A. Language access is an implementation function. If customers cannot understand eligibility requirements, enrollment instructions, available protections, documentation requests, or program obligations, otherwise eligible households may face avoidable barriers to receiving assistance.

The work required for language access includes identifying priority language needs, developing translated materials, supporting interpretation where appropriate, coordinating with community partners, reviewing customer-facing communications, and evaluating whether language barriers affect participation. Effectiveness can be evaluated through customer feedback, partner feedback, enrollment trends, call-center experience, translated material use, and observed barriers during outreach or verification processes.

Please see Cory A. Beck's Direct Testimony (NW Natural/1000, Beck) for additional discussion pertaining to language access and customer communications.

Q. How does the Company facilitate easy access to the Bill Discount Program while maintaining program integrity?

A. The Bill Discount Program combines streamlined enrollment with Post-Enrollment Verification ("PEV"). Income self-certification allows eligible customers to enroll without providing full income documentation at the outset, reducing a potential barrier to participation. PEV complements that approach by allowing the Company to verify the eligibility and discount tier of a sample of participants after enrollment. Together, these practices balance two program objectives: making the Bill Discount Program reasonably accessible to eligible customers and maintaining a mechanism to confirm that discounts are provided at the appropriate level.

Q. How does Post-Enrollment Verification work?

A. PEV applies income verification to a sample of Bill Discount Program participants rather than requiring verification from every enrolled customer. Current program

materials provide for a random sample equal to 3 percent of participants who were not automatically enrolled through another qualifying assistance program.

Customers selected for verification receive an initial written notice, a second notice if they do not respond, and additional outreach following continued non-response. Once a customer completes verification, the Company uses the verified household and income information to confirm program eligibility and the appropriate discount tier.

Q. How did stakeholder input and implementation experience inform Oregon's PEV process?

A. NW Natural developed its Oregon PEV process through stakeholder workshops and experience implementing PEV in Washington. That experience showed that non-response was a primary reason customers lost their discounts. It also reinforced the importance of clearly and repeatedly explaining why a customer was selected, what information is required, how to complete verification, and the potential consequence of not responding. The Company has used these lessons and stakeholder feedback to strengthen customer communications and outreach before launching PEV in Oregon.

Q. Has the timing for launching PEV in Oregon changed from the Company's original expectations?

A. Yes. NW Natural initially anticipated launching PEV in Oregon in 2026. The work necessary to strengthen customer communications took longer than anticipated. Stakeholders also asked the Company to avoid implementation timing that could

result in customers losing their discounts during the winter months. In response, NW Natural rescheduled the Oregon PEV launch to April 2027.

Q. How do customer safeguards fit within the Company's affordability and equity strategy?

A. Customer safeguards include medical certificates, payment arrangements, disconnection protections, and tools to address rising debt—and can help customers manage periods of hardship and reduce the risk of unavoidable loss of service or deeper hardship.

Q. Why is service continuity important?

A. Service continuity matters because the loss of utility service can worsen an existing hardship. Customers facing affordability pressure may also be managing health, housing, income, language, or documentation challenges. Maintaining service during periods of hardship gives customers a better opportunity to use available assistance, enter a payment arrangement, access protections, or resolve arrears before hardship escalates.

The work required to support service continuity includes implementing customer protections, communicating available options, coordinating payment arrangements, supporting medical certificate processes, monitoring disconnection-related data where available, and evaluating whether customer safeguards are functioning as intended.

Q. How does this work relate to the Company's implementation capabilities?

A. Access, language support, post-enrollment verification, and service continuity work require design, coordination, customer communications, partner

engagement, tracking, and follow-through. Without those capabilities, barriers can persist even when programs are well designed. With those capabilities, the Company can identify where customers encounter friction, determine whether barriers are affecting participation, and make practical improvements over time.

VII. EVALUATION, ENGAGEMENT AND CONTINUOUS IMPROVEMENT

Q. What tools does NW Natural employ to evaluate its equity and affordability work?

A. NW Natural relies on multiple sources of information to evaluate performance and identify opportunities for improvement, including Energy Burden Assessment findings, customer participation and enrollment data, program utilization trends, customer and community feedback, advisory group input, stakeholder engagement activities, regulatory proceedings and workshops, program evaluations and reporting, and lessons learned through implementation.

Quantitative data helps identify participation levels, enrollment trends, and affordability indicators. Qualitative stakeholder and customer feedback can identify barriers, implementation challenges, and aspects of the customer experience that may not be apparent from customer data alone. Together, these sources help the Company assess how programs and customer protections are working in practice and identify opportunities for improvement.

Q. How does the Company translate that information into program improvements?

A. The Company uses a consistent approach: identify an issue or opportunity through data, stakeholder feedback, evaluation, or implementation experience; determine

an appropriate response; and use subsequent results and experience to inform continued improvement. Table 7 provides examples of how that approach has informed the Company's work.

Table 7. Examples of How Data Inform Program Improvement

Information source	What the Company Learned	How the Company Responded	Why It Matters
Energy burden and participation data	Affordability needs and program participation vary across customers and communities	Use data to identify participation gaps and inform outreach	Connects identified customer need with specific Company action
PEV implementation experience and stakeholder feedback	Verification requirements and communications can create barriers to completing PEV	Refine customer communications, outreach, and implementation	Supports program integrity while reducing avoidable participation barriers
OLIEE implementation experience	Health, safety, and repair needs can prevent eligible efficiency work from proceeding	Expand eligible funding for efficiency and related health, safety, and repair measures	Enables more eligible projects to proceed
Customer and community feedback	Customers may need clearer, more accessible information and trusted sources of assistance	Use community partners, language access, plain-language materials, and tailored outreach	Helps customers find, understand, and access available resources
Customer protection experience	Affordability challenges can contribute to arrears and place continued service at risk	Implement protections and affordability tools designed to address different customer circumstances	Supports service continuity and helps prevent hardship from escalating

Q. How has the Company used the EBA to inform its work?

A. Broadly, EBA findings help the Company identify gaps in program participation, evaluate whether assistance is reaching customers facing greater affordability

challenges, and assess whether program design remains aligned with identified need. The Company has also used EBA findings to translate these insights into targeted action. For example, the Company designed a direct-mail campaign reaching more than 15,000 customers identified through the EBA as likely eligible for, but not participating in, the Bill Discount Program, including:

- customers in Coos, Linn, and Clatsop Counties and Pleasant Valley census tracts, which the EBA identified as low-enrollment areas;
- customers living in mobile home parks;
- customers receiving past-due notices;
- the top 10 percent of energy users;
- previously disconnected customers;
- customers with past-due notices;
- customers with high burdens who demonstrated difficulty paying their bills; and
- non-English speakers

Q. Why is stakeholder engagement an important part of this process?

A. Stakeholder engagement is a source of operational intelligence that informs better decisions; it is also a source of information that is often unavailable through quantitative data alone. Community organizations, customers, advisory groups, and other stakeholders may identify implementation challenges, communication barriers, or customer needs that would otherwise remain difficult to observe. That

information helps the Company evaluate programs as they function in practice rather than solely as they are designed.

Q. Why is continuous improvement important?

A. Continuous improvement is important because affordability challenges, customer needs, regulatory expectations, and program experience change over time. A program that was reasonable at launch may need refinement as participation grows, barriers become clearer, customer needs shift, or new data becomes available.

The Company's objective is not simply to administer a set of static programs. The objective is to understand whether those programs are reaching intended customers, whether barriers remain, whether customer protections are working as intended, and whether future decisions can be improved based on evidence and experience.

VIII. DEDICATED RESOURCES AND ORGANIZATIONAL CAPACITY

Q. Is the Company asking for cost recovery for additional resources to support its equity and affordability work?

A. No, not at this time. That said, dedicated resources are necessary because the work has become recurring, cross-functional, and closely tied to regulatory commitment and customer outcomes. NW Natural's current equity and affordability responsibilities include program administration, energy burden analysis, affordability evaluation, customer protection implementation, stakeholder engagement, reporting, data analysis, integrated resource planning coordination, distributional equity discussions, and program evaluation.

These responsibilities require sustained effort across multiple functions within the Company. The Company must maintain and analyze customer data, monitor participation, coordinate program implementation, support stakeholder and advisory processes, track feedback, document decisions, evaluate program effectiveness, support reporting, and translate lessons learned into program improvements. Those tasks cannot be sustained reliably through informal coordination alone because they require continuity, ownership, data discipline, documentation, and follow-through over time.

Q. What is the significance of understanding the resources and organizational support required for this work?

A. Understanding the resources and organizational support required for this work provides important context regarding the effort necessary to effectively implement equity and affordability initiatives. Expectations related to affordability, customer protections, stakeholder engagement, and equity considerations have continued to evolve, resulting in responsibilities that extend beyond policy development alone. Effective implementation requires the ability to translate regulatory expectations into actionable programs, evaluate outcomes, respond to stakeholder feedback, and continuously improve customer-facing efforts over time. Recognizing the operational effort associated with these responsibilities helps illustrate the commitment necessary to carry out this work effectively and achieve meaningful customer outcomes.

Q. How do these resources benefit customers?

A. Dedicated resources benefit customers by improving the Company's ability to identify need, target support, reduce access barriers, coordinate affordability and efficiency tools, support customer protections, and evaluate whether programs are working as intended. These activities improve the probability that eligible customers can find and use available support, that barriers are identified and addressed, and that program changes are based on evidence rather than assumption.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

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NW Natural

Exhibits of Cecelia J. Tanaka

EQUITY
EXHIBITS 201 – 203

November 24, 2026

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EQUITY
EXHIBIT 201

November 24, 2026



NW Natural

2026 Energy Burden Data Refresh

Summary and Recommendations

empower dataworks



	Energy Burden Assessment (EBA)	Energy Burden Data Refresh (EBDR)
Purpose	Complete and detailed understanding of energy burden and affordability in a service area	Fresh data to support utility's program activities and analysis
Audience	Utility, regulators and external stakeholders	Primarily for utility staff
Cadence	Every 4-5 years, to coincide with rate cases	Every 1-2 years, if data is actively used by program staff
Time required	6-9 months	3-4 months (cost is 40-60% of full EBA)
Program design	Potentially includes new program design or redesign of existing programs	Minor investigation of specific program design elements
Program evaluation	Deep look at overall program performance	Focused on program progress and saturation rates
Marketing/Outreach	Includes data to support strategic marketing/outreach	
Other sub-analyses	- Energy efficiency strategy - Energy assistance hole - Rate change impacts - Key customer and housing segments - Seasonal energy burden - Post-Enrollment Verification - Qualitative program evaluation (optional)	Limited/based upon request
External stakeholder engagement	Extensive engagement to guide analysis and recommendations	Informational only

Definitions

Low-income (Oregon):

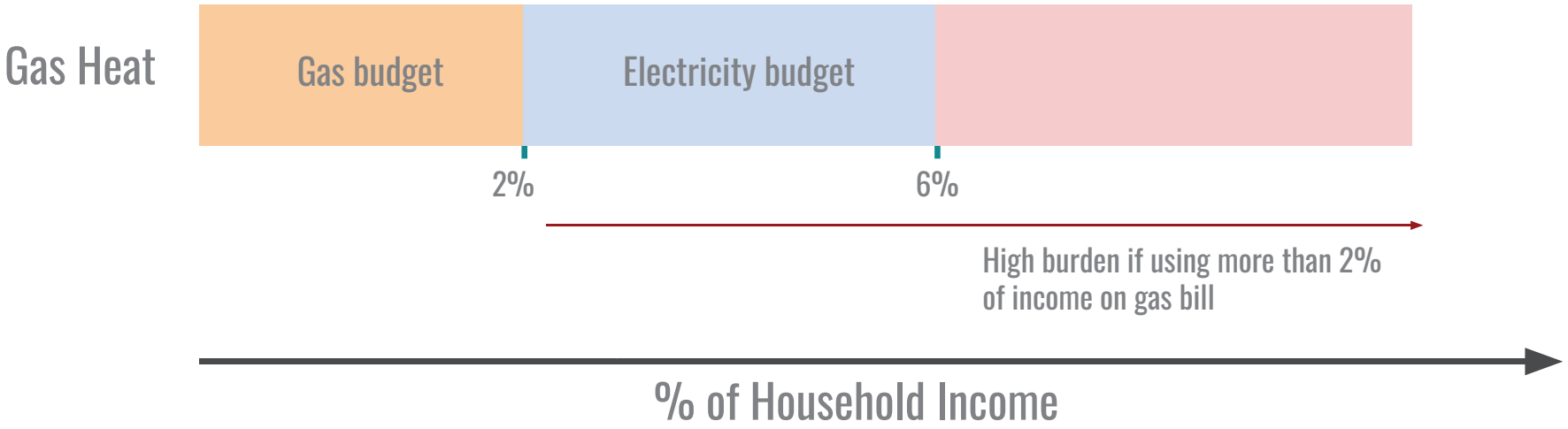
Households earning under 60% of the state median income (SMI)

Household Unit Size	Annual Gross Income
1	$38,384
2	$50,194
3	$62,005
4	$73,816
5	$85,626
6	$97,437

$3-5k/month after taxes for rent, groceries, transportation, childcare, healthcare and utilities

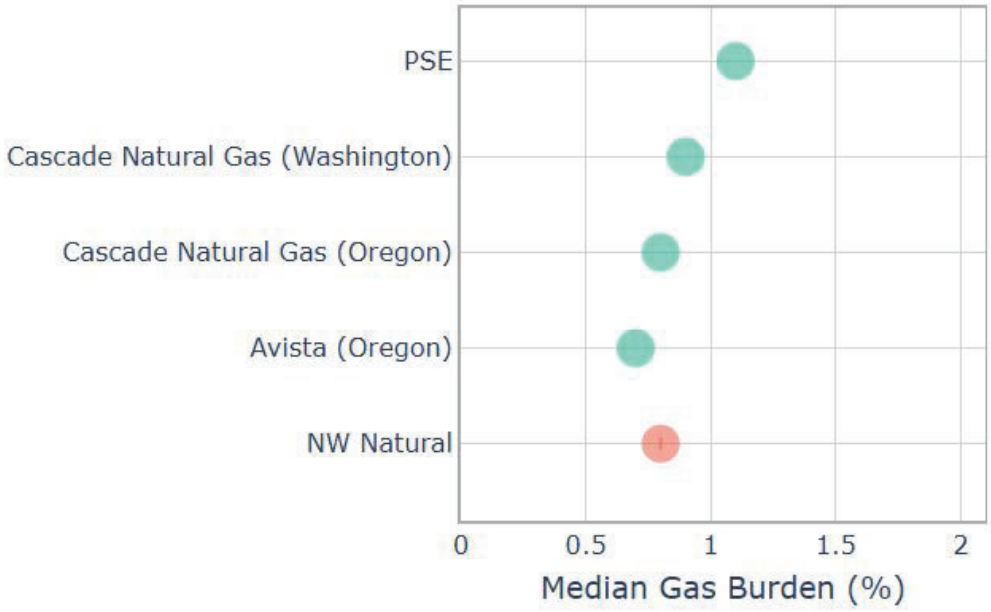
Note: Oregon State Median Income has increased by 15% since 2024. Median income in NWN's service area increased by 5-11% since 2024, depending on the county.

High burden thresholds for multiple fuel homes



Insights: **Energy Burden**

- ➔ Median gas energy burden (~0.8%) is average compared to other utility service areas in the Pacific Northwest.
- ➔ NWNatural customers have relatively higher incomes than the general population. Homes in the service area have had relatively lower gas usage in recent years.



Energy Burden - Oregon

Insights: **Energy Burden (Oregon)**

Number of Occupied Households

~615,000

Low Income Households Under 60% SMI:

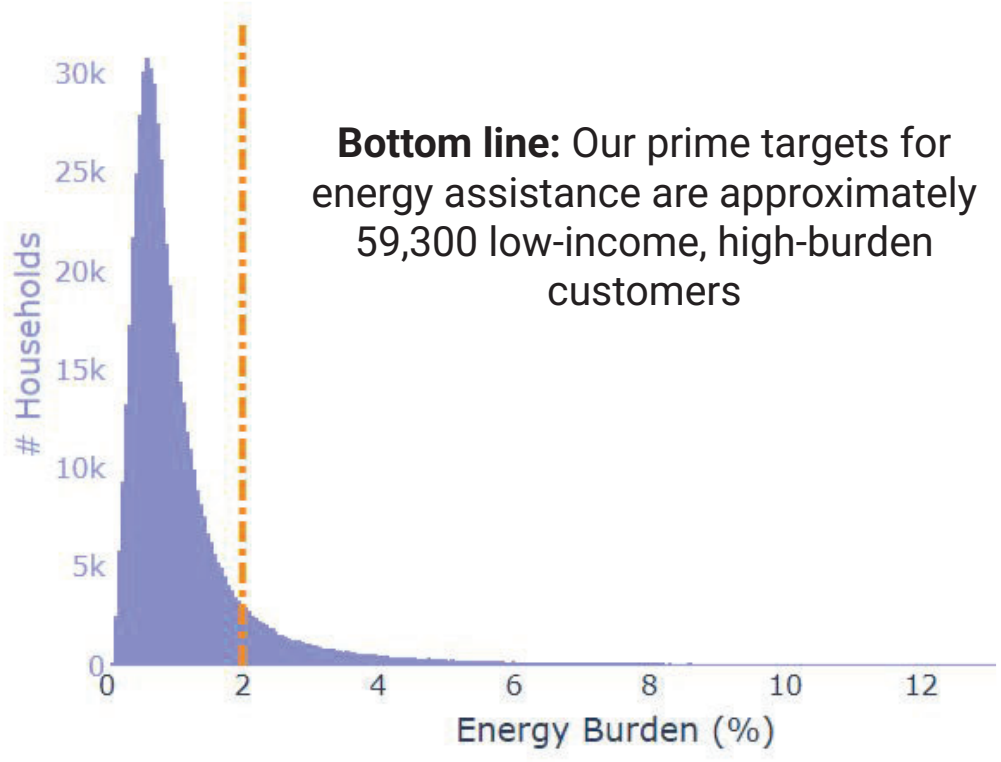
~89,000 ± 10%

High Burden Households*

~83,400 (all)

~59,300 (LI)

Median Gas Burden
~0.8% (all)
~2.8% (LI)



Bottom line: Our prime targets for energy assistance are approximately 59,300 low-income, high-burden customers

*Energy bills and burden are calculated without factoring in any forms of energy assistance

Insights: **High-level Assistance Gap (Oregon)**

Low-Income, High Burden Households

~59,300



Income-eligible only



2026 Projection not including additional program participation.

~$16M Bill Discount Program, ~$8M other

- ➔ Currently, NW Natural's programs appear to be correctly calibrated (funding is 67% of total assistance need with 63% program saturation)
- ➔ Median program participant energy burden in 2025:
  - 2.7% (before assistance) -> 1.7% (after assistance)
- ➔ In addition to helping high gas burden customers, assistance programs help many low-burden, low-income customers. Combining multiple programs reduces the gas burden of program participants below the target of 2%, on average

Insights: **Stratified Energy Burden (Oregon)**

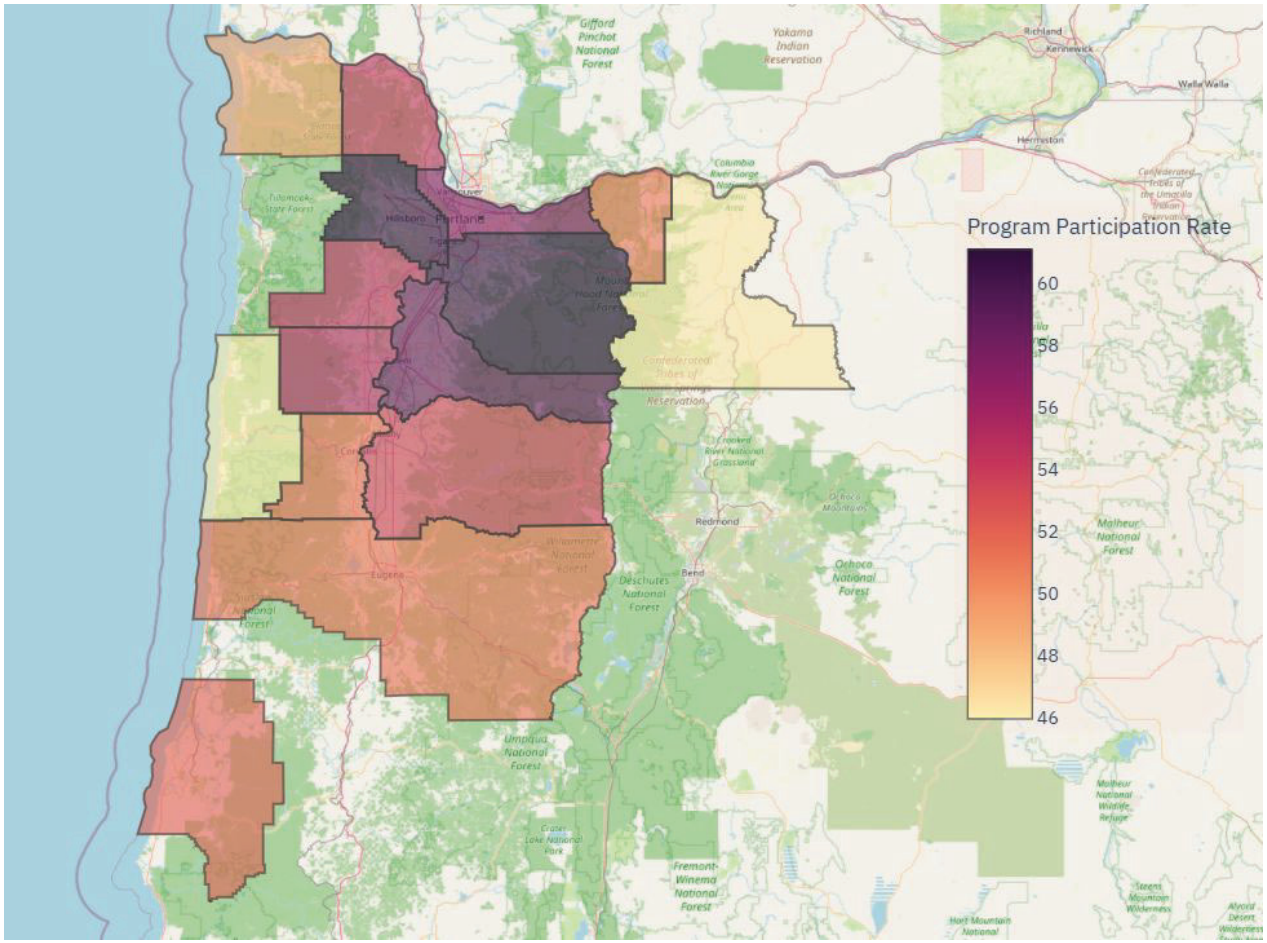
Gas Burden	Number of LI Customers	Assistance Need	Program Funding (All)	Participation Rate
A: 0-2% (Affordable)	29,600	$0.0M	$5.9M	68%
B: 2-5% (Unaffordable)	37,000	$13.2M	$8.7M	59%
C: 5-10% (Very unaffordable)	13,500	$11.7M	$4.3M	56%
D: 10%+ (Extremely unaffordable)	8,700	$10.0M	$4.6M	69%
Total	~89,000	$35M	~$23.6M	63%

75% of program spending is concentrated among high-burden customers - the programs are well-designed and doing well at directing funds to higher-burden customers

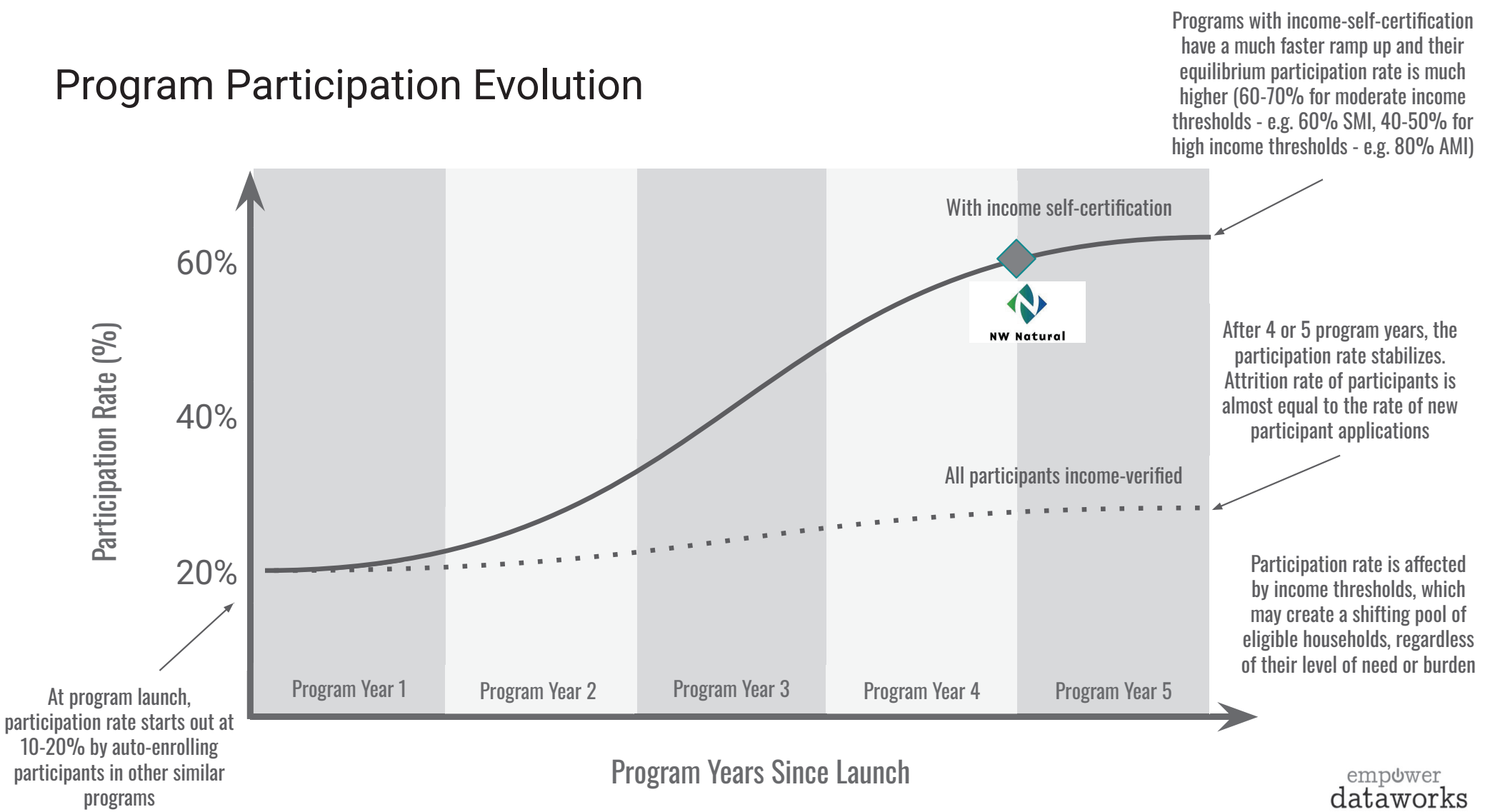
Bill Discount Program

Program Participation Rate **(Oregon)**

Recommendation: Overall participation rate is approximately 63%. Participation has increased across all areas, but regional variations have remained about the same as in 2024. Focus outreach on Clatsop. Lincoln, Benton and Lane counties.



Program Participation Evolution



Note: Figures on this slide are rough estimates based on anecdotal evidence/experience

Program Participation Rate by Tier **(Oregon)**

Overall participation appears to have reached equilibrium level around 63%. Major increases in participation are not expected in the future, as participant attrition will be equal to new program enrollments.

Income tier	Estimated number of households	% High-burden	Participation rate
Tier 1: 0-15% SMI	12,300	87%	78%
Tier 2: 15-30% SMI	21,700	83%	63%
Tier 3: 30-45% SMI	25,700	67%	57%
Tier 4: 45-60% SMI	29,200	45%	44%

Discount Tier Analysis (**Oregon)**

Income tier	Current Discount Level	Average assistance need as a percent of bill
Tier 1: 0-15% SMI	85%	73%
Tier 2: 15-30% SMI	50%	53%
Tier 3: 30-45% SMI	30%	33%
Tier 4: 45-60% SMI	15%	19%

Recommendation: Discount levels appear to be appropriate at this time and can accommodate moderate rate increases without requiring adjustments. These estimates assume only the bill discount is used to address energy burden. In practice, most customers receive assistance from multiple programs.

Main Takeaways - Energy Burden Data Refresh

- NW Natural's customers continue to have a generally low gas burden. Approximately **9% of NW Natural's customers suffer from a high gas burden and have a low-income** (gas bills exceed 2% of household income)
- The Bill Discount Program has been ramping up successfully and along with other assistance programs, funding will meet **67% of the energy assistance need** for NW Natural's customers in 2026.
- **Bill Discount Program:** Maintain current discount levels. Consult with community organizations in outlying counties to enhance participation rates. Overall, BDP appears to have reached full saturation - future enrollment will likely be in balance with participant attrition.

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EXHIBIT 202

November 24, 2026

OREGON

NW Natural®

NW Natural can help lower your energy bills.

You may be able to get 15% to 85% off your monthly gas bill with NW Natural's Bill Discount Program



Usted podría obtener un descuento de 15 a 85 % en su factura mensual de gas con el Programa de Descuento en Factura de NW Natural.

您可能有机会通过 NW Natural 的账单折扣计划将每月的燃气账单减少 15% 到 85%。

Quý vị có thể được giảm giá từ 15% đến 85% hóa đơn tiền gas hàng tháng với Chương Trình Giảm Giá Hóa Đơn của NW Natural.

Вы можете получить скидку в размере от 15 до 85 % от вашего ежемесячного счета за природный газ благодаря программе скидок на оплату счетов от компании NW Natural.

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

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250 SW Taylor Street
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EQUITY
EXHIBIT 203

November 24, 2026

EM&V REPORT: NW NATURAL 2010-2022 LOW-INCOME ENERGY EFFICIENCY PROGRAMS

SUBMITTED TO:

NW NATURAL

SUBMITTED BY:

ADM ASSOCIATES, INC.

SUBMITTED DATE:

JANUARY 10, 2025

ADM

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NW Natural®

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ADM Associates, Inc. would like to acknowledge the talented individuals who contributed to this report.

We would like to thank the staff at NW Natural for their time and effort in contributing to the EM&V of the Low-Income programs. NW Natural staff participated in a kickoff meeting, provided program data, and responded to additional follow-up questions, data requests and document requests.

This evaluation was conducted with regular coordination with staff at NW Natural, who provided quick feedback and turnaround to the requests of the evaluation team as well as open and forthright insights into the operations of their programs.

Further, we would like to acknowledge our gratitude towards NW Natural customers, implementation contractor staff and trade allies. As with the staff at NW Natural, their active participation allowed the evaluation team to collect all the data needed for this effort.

Additionally, we would like to thank the evaluation staff who supported the creation of this report.

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1 EXECUTIVE SUMMARY

This report is a summary of the impact and process evaluations for both of NW Natural's Low-Income Energy Efficiency programs: the Oregon Low-Income Energy Efficiency Program (OLIEE) and the Washington Low-Income Energy Efficiency Program (WALIEE). These Low-Income energy efficiency programs are designed to support housing stabilization for Low-Income Oregon and Washington NW Natural customers by providing energy bill payment assistance and weatherization services to effectively reduce energy costs and improve health.

NW Natural has requested separate impact analyses and evaluations conducted for the Low-Income energy efficiency programs every four years, since the last impact evaluation report in 2010. Therefore, ADM Associates, Inc. (herein referred to as the "Evaluators") have evaluated the following evaluation periods, by program:

Table 1-1: OLIEE and WALIEE Evaluation Periods

Program	Program Years	Impact Evaluation	Process Evaluation
OLIEE	PY2010-PY2013	✓	
	PY2014-PY2017PY2014-PY2017	✓	
	PY2018-PY2022	✓	✓
WALIEE	PY2010-PY2013	✓	
	PY2014-PY2017PY2014-PY2017	✓	
	PY2018-PY2022	✓	✓

1.1 Verified Savings and Process Findings

The Evaluators' analysis yields two estimates of gross savings for each project: an expected gross Therms savings estimates (as reported in the project documentation and program tracking system) and the verified net Therms savings estimates developed through our verification and evaluation procedures. Realization rates for each program are found by taking the ratio of these values. In addition to these impact estimates, the Evaluators conducted process evaluations resulting in several conclusions and recommendations. Lastly, cost-effectiveness testing was performed to estimate net program cost and benefits.

1.1.1 OREGON LOW-INCOME ENERGY EFFICIENCY PROGRAM (OLIEE)

Below, are expected and verified savings for each evaluated program year of the OLIEE program, conclusions and recommendations based on the process evaluations, and cost-effectiveness results from the same periods.

1.1.1.1 OLLIE Impact Results

Table 1-2 and Table 1-3 shows expected and verified savings by program year and program evaluation period for the OLIEE program. The Evaluators note that the first two evaluation periods cover 4 program years each, while the last evaluation period covers 5 program years. For example, evaluation period

PY2010-PY2013 includes program years 2010, 2011, 2012, and 2013. The year of the project completion date was used to define a project's program year.

Table 1-2: Verified Impact Savings by Program Year, OLIEE

Program Year	Number of Participant Homes	Average Number of Installed Measures	Expected Therms Saved	Verified Therms Saved	Realization Rate	Total Incentives and Agency Costs ($)
2010	561	3.2	219,489	52,224	24%	3,448,712
2011	332	3.1	96,895	30,906	32%	2,223,775
2012	268	3.5	76,989	24,948	32%	2,738,388
2013	149	3.3	35,682	13,871	39%	1,024,954
2014	189	3.4	50,778	20,673	41%	1,430,164
2015	182	3.3	42,701	19,907	47%	1,533,943
2016	248	4.0	53,697	27,126	51%	1,970,200
2017	287	4.1	69,094	31,392	45%	2,605,351
2018	295	4.2	97,583	35,046	36%	3,128,583
2019	262	3.9	79,394	31,125	39%	2,738,720
2020	248	3.4	66,745	29,462	44%	2,105,700
2021	176	3.8	55,348	20,909	38%	2,164,725
2022	189	3.8	57,521	22,453	39%	2,916,969
Total	**3,386**	**3.6**	**1,001,916**	**360,042**	**36%**	**30,030,184**

Table 1-3: Verified Impact Savings by Program Evaluation Period, OLIEE

Program Evaluation Period	Evaluation Period Homes	Average Number of Installed Measures	Expected Therms Saved	Verified Therms Saved	Realization Rate	Total Incentives and Agency Costs ($)
PY2010-PY2013	1,310	3.3	429,055	121,949	28%	9,435,829
PY2014-PY2017	906	3.8	216,270	99,098	46%	7,539,658
PY2018-PY2022	1,170	3.9	356,591	138,995	39%	13,054,697
Total	**3,386**	**3.6**	**1,001,916**	**360,042**	**36%**	**30,030,184**

Verified savings from 2010 to 2022 for the program are 360,042 Therms, 36 percent of Expected Savings. One reason for the low realization rate was due to the Expected Therms savings provided in the project tracking data. The Evaluators observed that total Expected Therms savings was high because savings in the project tracking data were not uniquely calculated for each project associated with a customer and reflected cumulative savings across multiple projects. Program costs were also affected by the same issue. However, the Evaluators were not able to obtain the number of projects associated with the Expected Therms savings and program costs and therefore could not provide adjustments to reflect project-level values. The Evaluators noted this issue applied to all program years and program evaluation periods.

In addition, the Evaluators requested measure-level savings from NW Natural to determine how Expected Therms savings were being calculated for the program, however, this data was not available. This prevented the Evaluators from recreating project-level savings to determine whether there were any issues with the calculations of project-level savings in the project tracking data.

1.1.1.2 OLLIE Cost-Effectiveness Results

The Evaluators estimated cost-effectiveness for the most recent evaluation periods (PY2014-PY2017 and PY2018-PY2022). The results of cost-effectiveness testing showed the program was cost-effective for the TRC, which is the primary cost test for NW Natural energy efficiency programs.

The participant cost test (PCT) is N/A because participants did not incur any costs from the program and were provided the benefits of the program free of charge. As with most Low-Income programs, the UCT and RIM are lower because the utility assumes the full cost of measure installation and equipment.

Table 1-4: Cost-Effectiveness Testing Results OLLIE, PY2014-PY2017

Evaluation Period	TRC	UCT	RIM	PCT	SCT
PY2014-PY2017	2.08	0.25	0.20	N/A	2.34
Overall	**2.08**	**0.25**	**0.20**	**N/A**	**2.34**

Table 1-5: Cost-Effectiveness Testing Results OLLIE, PY2018-PY2022

Evaluation Period	TRC	UCT	RIM	PCT	SCT
PY2018-PY2022	2.31	0.23	0.19	N/A	2.60
Overall	**2.31**	**0.23**	**0.19**	**N/A**	**2.60**

1.1.2 WASHINGTON LOW-INCOME ENERGY EFFICIENCY PROGRAM (WALIEE)

Below, are expected and verified savings for each evaluated program year of the WALIEE program, conclusions and recommendations based on the process evaluations and cost-effectiveness results from the same periods.

1.1.2.1 WALIEE Impact Results

Table 1-6 and Table 1-7 shows expected and verified savings by program year and program evaluation period for the WALIEE program.

Table 1-6: Verified Impact Savings by Program Year, WALIEE

Program Year	Number of Participant Homes	Average Number of Installed Measures	Expected Therms Saved	Verified Therms Saved	Realization Rate	Total Incentives and Agency Costs ($)
2010	16	3.4	6,393	2,598	41%	122,685
2011	11	2.9	3,634	1,786	49%	99,938
2012	8	3.5	2,517	1,299	52%	53,447
2013	20	3.5	7,684	3,248	42%	148,111
2014	10	2.8	3,050	1,624	53%	89,045
2015	9	3.2	3,219	1,462	45%	88,833
2016	17	3.5	6,409	2,761	43%	182,308
2017	13	2.9	6,148	2,111	34%	312,530
2018	16	3.7	7,605	2,598	34%	216,246
2019	22	4.4	20,214	3,573	18%	347,843
2020	8	2.1	1,136	1,299	114%	27,854
2021	14	2.5	3,598	2,273	63%	84,683
2022	11	2.6	703	1,786	254%	71,938
Total	**175**	**3.3**	**72,310**	**28,418**	**39%**	**1,845,461**

Table 1-7: Verified Savings by Program Evaluation Period, WALIEE

Program Evaluation Period	Evaluation Period Homes	Average Number of Installed Measures	Expected Therms Saved	Verified Therms Saved	Realization Rate	Total Incentives and Agency Costs ($)
PY2010-PY2013	55	3.3	20,228	8,931	44%	424,181
PY2014-PY2017	49	3.1	18,826	7,958	42%	672,716
PY2018-PY2022	71	3.3	33,256	11,529	35%	748,564
Total	**175**	**3.3**	**72,310**	**28,418**	**39%**	**1,845,461**

Verified savings from 2010 to 2022 for the program are 28,418 Therms, 39 percent of Expected Savings.

One reason for the low realization rate was due to the Expected Therms savings provided in the project tracking data. The Evaluators observed that the sum of total Expected Therms savings was high because savings in the project tracking data were not uniquely calculated for each project associated with a customer and reflected cumulative savings across multiple projects. Program costs were also affected by the same issue. However, the Evaluators were not able to obtain the number of projects associated with the Expected Therms savings and program costs and therefore could not adjust them to reflect project-level values.

In addition, the Evaluators requested measure-level savings from NW Natural to determine how Expected Therms savings were being calculated for the program, however, this data was not available. This prevented the Evaluators from recreating project-level savings to determine whether there were any issues with the calculations of project-level savings in the project tracking data.

1.1.2.2 WALIEE Cost-Effectiveness Results

The Evaluators estimated cost-effectiveness for the most recent evaluation periods (PY2014-PY2017 and PY2018-PY2022). The results of cost-effectiveness testing showed the program was cost-effective for the TRC, which is the primary cost test for NW Natural energy efficiency programs.

The participant cost test (PCT) is N/A because participants did not incur any costs from the program and were provided the benefits of the program free of charge. As with most Low-Income programs, the UCT and RIM are lower because the utility assumes the full cost of measure installation and equipment.

Table 1-8: Cost-Effectiveness Testing Results WALLIE, Evaluation Period PY2014-PY2017

Evaluation Period	TRC	UCT	RIM	PCT	SCT
PY2014-PY2017	1.37	0.23	0.19	N/A	1.57
Overall	**1.37**	**0.23**	**0.19**	**N/A**	**1.57**

Table 1-9: Cost-Effectiveness Testing Results WALLIE, Evaluation Period PY2018-PY2022

Evaluation Period	TRC	UCT	RIM	PCT	SCT
PY2018-PY2022	2.08	0.33	0.25	N/A	2.38
Overall	**2.08**	**0.33**	**0.25**	**N/A**	**2.38**

1.1.3 CONCLUSIONS AND RECOMMENDATIONS

The following section details the Evaluators' conclusions and recommendations for the Low-Income programs.

1) **Conclusion 1: NW Natural's Low-Income program utilizes lenient qualification criteria and provides comprehensive measure coverage.** Stakeholders from across the interview groups – program staff, CAP Agency and CBO staff, and trade allies – remarked on NW Natural's comprehensive measure coverage and willingness to expand eligibility for services they can provide. Not only did NW Natural modify the qualification criteria from 200% Federal Poverty Level (FPL) to 80% area median income (AMI) in response to requests by the CAP Agency, but they also expanded health and safety qualifying measures, allowing for more holistic coverage and home updates for customers. CAP agency and CBO staff noted that NW Natural's program has some of the most lenient and flexible qualification criteria – as compared to other similar programs – and participating trade allies indicated that the measures covered are thorough. Furthermore, the program passed the TRC, showing that the program is assisting customers cost-effectively.
2) **Conclusion 2: Most participants and eligible non-participants participate in the CAP Agencies and CBO energy related bill assistance programs. Waitlist times for the program vary across agencies.** One CBO representative explained that they avoid waitlists by making their program invite-only, while other CBO representatives and CAP agency staff indicated their wait list times range from a few months to over a year.

3) **Conclusion 3: Non-participants respondents explained that the cost of equipment upgrades was the main factor preventing them from engaging in this type of program**, suggesting awareness of NW Natural's assistance for Low-Income is limited and many eligible customers do not realize they may qualify for free weatherization and heating equipment updates.

    Recommendation 1: Although wait lists for some of the weatherization and HVAC programs can be lengthy, CAP agency and CBO staff should continue to enroll existing clients into this program to ensure comprehensive energy assistance, as more than half of all non-participant respondents expressed interest in making energy efficient improvements to their home.

4) **Conclusion 4: Workforce development issues limit program expansion**. Some CAP Agency representatives explained that workforce issues are their largest barrier to increased engagement. These representatives indicated that funds are available to help more customers, but they struggle to find qualified contractors. Representatives from across the CAP agencies and CBOs remarked that their existing auditors and contractors have been involved in the weatherization business for many years, but that they are concerned about the future longevity of the program due to the lack of new contractors and auditors. One CAP agency representative mentioned an internship program offered by Oregon Training Institute as a possible solution to this issue but noted the state needs more contractors.

    Recommendation 2: NW Natural should consider partnering with the Oregon Training Institute and other similar organizations to help offer more workforce development and training opportunities for future contractors and trade allies.

5) **Conclusion 5: CBO representatives underscored the importance of leveraging existing relationships in communities when promoting the program.**

Recommendation 3: NW Natural can continue to strengthen their program by expanding their presence in the communities they serve through attendance at and sponsorship of community events. One of the CBO representatives also noted that having a formal contract and master services agreement has also been very helpful in ensuring the program remains funded.

6) **Conclusion 6: Satisfaction across stakeholder groups – CAP agency and CBO staff, contractors, and participants – was high.** Interview respondents highlighted NW Natural's communicativeness and willingness to answer questions, while most survey respondents indicated they would recommend the program to others and that they believe NW Natural is a very or extremely trustworthy source of information regarding energy savings in the home.

7) **Conclusion 7: Reported program costs and Expected Therms savings in program tracking data was not unique for each project associated with a customer.** A primary reason for the low realization rate was due to the Expected Therms savings provided in the project tracking data. The Evaluators observed that total Expected Therms savings were high because savings in the project tracking data were not uniquely calculated for each project associated with a customer and reflected cumulative savings across multiple projects. Program costs were also affected by the same issue.

   Recommendation 4: NW Natural should require implementers to report costs and expected savings uniquely for each project associated with a customer to ensure accurate accounting of expected savings and cost data utilized in cost-effectiveness testing.

8) **Conclusion 8: Incomplete or missing project documentation for sampled projects that were part of document-based verification.** For OLIEE, the Evaluators found 25 percent of projects had incomplete, missing, duplicate, or other project documentation issues. For WALIEE, the Evaluators found most projects, 91%, had incomplete, missing, duplicate, or other project documentation issues.

   Recommendation 5: NW Natural should collect all application forms, supporting customer or contractor invoices, certificates, project installation photos, and any other associated project-level documents specific to each program for every project.

9) **Conclusion 9: Project documentation for sampled projects from documentation-based verification were missing measure specifications.** The Evaluators found that many specifications were missing from the project documentation such as insulation square footage[1], window/door quantities, and model information for furnaces and water heaters. Measures such as furnace tune-ups and direct vent space heaters did not provide any specification information. Furthermore, there were additional measures in the documentation that were not accounted for in the project tracking data for many customers.

[1] Insulation square footage differs from whole-home square footage and refers to the square footage of the installed insulation from insulation measures such as ceiling/attic insulation, floor insulation, and wall insulation.

Recommendation 6: NW Natural should collect additional measure information including installed square footage, baseline measure efficiency, retrofit measure efficiency, measure quantities, and make/model information for each project to aid verification efforts. In addition, all measures should be listed in the project tracking data for each project.

10) **Conclusion 10: Measure-level savings for each program were not available from the implementer or NW Natural.** The Evaluators requested measure-level savings from NW Natural to determine how Expected Therms savings were being calculated for the program, however, this data was not available.

    Recommendation 7: NW Natural should maintain a list of measures for the program with measure-level savings. This will allow for the recreation of Expected Therms savings by Evaluators for each project to determine if savings are being properly calculated and to identify potential issues with project data.

11) **Conclusion 11: The Evaluators found statistically significant savings for each program evaluation period.** For OLIEE, the Evaluators estimated savings between 93.1 and 118.8 Therms annually per customer across all cohorts. This results in percent savings between 16.6 percent and 19.2 percent compared to the counterfactual control customers. For WALIEE, the Evaluators note that the savings are near the upper end of the expected savings range normally observed for a weatherization program. The Evaluators estimated savings of 162.39 Therms annually per customer, a 25.2 percent savings compared to the control customers.

    Recommendation 8: The billing analysis results show the program is effectively reducing energy consumption for program participants. NW Natural should keep targeting the same customers and continue with the same general program implementation used in prior program years to continue providing positive energy savings to their customers.

12) **Conclusion 12: The Evaluators found statistically significant reductions in arrears for program participants.** The Evaluators estimated a $213 reduction in annual arrears for participants compared to the counterfactual control customers. The Evaluators found no statistically significant changes in disconnects or disconnection notices for participants.

    Recommendation 9: The Evaluators recommend NW Natural include a Non-Energy Benefit adder of $21.3 per participant for arrears when performing cost-effectiveness testing for the program.

1.2 Report Organization

From this point, the remaining report chapters include:

- Chapter 2: General Evaluation Methodology
- Chapter 3: OLIEE Program Impact Results
- Chapter 4: WALIEE Program Impact Results
- Chapter 5: Low-Income Program Process Results

- Appendix A: Cost-Effectiveness Testing
- Appendix B: Unit Energy Savings
- Appendix C: Data Collection Recommendations
- Appendix D: Survey Collections Instruments

2 GENERAL EVALUATION METHODOLOGY

The Evaluators completed an impact evaluation for each of the programs summarized in the Executive Summary. Our activities estimate and verify annual savings, conduct cost-effectiveness testing and provide energy savings from a single source, aimed at providing guidance for continuous program improvement.

2.1 Glossary of Terminology

As a first step to detailing the evaluation methodologies, the Evaluators have provided a glossary of terms to follow:

- **Deemed Savings** – An estimate of an energy savings outcome (gross savings) for a single unit of an installed energy efficiency measure. This estimate (a) has been developed from data sources and analytical methods that are widely accepted for the measure and purpose and (b) are applicable to the situation being evaluated.
- **Measure –** Energy saving device, unit, or service.
- **UES –** Unit Energy Savings are a single unitized savings estimate (e.g., savings per motor, savings per hp) that represent an average or weighted average of similar savings measures. UES measures are also known as deemed savings measures.
- **Expected Savings** – Calculated savings used for program and portfolio planning purposes.
- **Verified Savings** – Savings estimates after the updated unit-level savings values have been updated and energy impact evaluation has been completed, integrating results from billing analyses and appropriate RTF UES values.
- **Gross Savings** – The change in energy consumption directly resulting from program-related actions taken by participants in an efficiency program, regardless of why they participated.
- **Free Rider** – A program participant who would have implemented the program measure or practice in absence of the program.
- **Net-To-Gross** – A factor representing net program savings divided by gross program savings that is applied to gross program impacts to convert them into net program load impacts.
- **Net Savings** – The change in energy consumption directly resulting from program-related actions taken by participants in an efficiency program, with adjustments to remove savings due to free ridership.
- **Non-Energy Benefits** – Quantifiable impacts produced by program measures outside of energy savings (comfort, health and safety, reduced alternative fuel, etc.).
- **Non-Energy Impacts** – Quantifiable impacts in energy efficiency beyond the energy savings gained from installing energy efficient measures (reduced cost for operation and maintenance of equipment, reduced environmental and safety costs, etc.).

- **Pre-Period –** The period prior to installation of energy efficient equipment or upgrade, typically set to equal a one-year period.
- **Post-Period –** The period after installation of energy efficient equipment or upgrade, typically set to equal a one-year period.
- **HDD –** Heating degree days (HDD) are a measurement used to estimate the amount of energy required to heat a building or space during a specific period, typically a day or a month. It is primarily used in regions with cold climates to assess the demand for heating and to evaluate energy consumption.
- **TMY –** A Typical Meteorological Year (TMY) is a synthesized set of weather data representing the long-term climatic conditions for a specific location. It is constructed using historical weather data collected over several years (e.g., 15 or 30 years), typically obtained from weather stations in the vicinity of the location of interest. The purpose of a TMY is to provide a standardized dataset that represents the "typical" weather conditions for a particular location. The Evaluators utilized the latest available years of data from TMYx (2009-2023) to reflect the most recent historical weather data available.
- **Dummy Variable -** A dummy variable, also known as an indicator variable or binary variable, is a categorical variable that takes on one of two values to represent the presence or absence of a characteristic or condition. It is commonly used in statistical analysis and regression modeling to represent qualitative factors and typically takes the value of 0 or 1, where 0 represents the absence or reference category, and 1 represents the presence or alternative category.

2.2 Impact Evaluation Approach

The Evaluators used the following approaches to calculate energy impact defined by the International Performance Measurement and Verification Protocols (IPMVP) and the Uniform Methods Project (UMP):

- Database review
- Simple verification (document-based, survey-based)
- Deemed savings
- Whole building billing analysis (IPMVP Option C)

The table below summarizes the impact evaluation activities by program.

Table 2-1: Impact Evaluation Activities by Program

Program	Program Evaluation Period	Database Review	Document Verification	Survey Verification	Gas Impact Methodology
OLIEE	PY2010-PY2013	✓	✓	✓	IPMVP Option C: Billing analysis with comparison group
	PY2014-PY2017	✓	✓	✓	IPMVP Option C: Billing analysis with comparison group
	PY2018-PY2022	✓	✓	✓	IPMVP Option C: Billing analysis with comparison group
WALIEE	PY2010-PY2013	✓	✓	✓	IPMVP Option C: Billing analysis with comparison group*
	PY2014-PY2017	✓	✓	✓	IPMVP Option C: Billing analysis with comparison group*
	PY2018-PY2022	✓	✓	✓	IPMVP Option C: Billing analysis with comparison group*

*Due to low participation in the WALIEE Program, the Evaluators conducted a billing analysis for all 12 years combined, with weather-adjusted annual household savings extrapolated to actual 4-year evaluation period participants.

The Evaluators employed two major approaches to determining net savings for NW Natural's Low-Income programs:

- **A *Deemed Savings*** approach involves using stipulated savings for energy conservation measures for which savings values are well-known and documented. These prescriptive savings may also require an adjustment for certain measures, such as incorporation of in-service rates, in which an adjustment is made to reflect the proportion of measures verified to be installed on-site.
- **A *Billing Analysis*** approach involves estimating energy savings by applying a linear regression to measured participant energy consumption utility meter billing data. Billing analyses may also include billing data from nonparticipant customers. This approach does not require primary data collection or adjustments such as in-service rates, as the observed energy reductions inherently incorporate these adjustments. This approach aligns with the IPMVP Option C.

2.2.1 IMPACT EVALUATION FRAMEWORK

The Evaluators approach the impact evaluation was from the frame of mind that final M&V methodologies should be determined by approaches feasible with the given historical data and participation rates as well as the relative contribution of a given program to the overall energy efficiency impacts. The Evaluators reviewed relevant information on infrastructure, framework, and guidelines set

out for EM&V work in several guidebook documents that have been published over the past several years. These include the following:

- Northwest Regional Technical Forum (RTF)
- Technical reference manuals, such as the Energy Trust of Oregon or NW Natural Technical Reference Manuals
- National Renewable Energy Laboratory (NREL), United States Department of Energy (DOE) The Uniform Methods Project (UMP): Methods for Determining Energy Efficiency Savings for Specific Measures, April 2013[2]
- International Performance Measurement and Verification Protocol (IPMVP) maintained by the Efficiency Valuation Organization (EVO) with sponsorship by the U.S. Department of Energy (DOE)[3]

The Evaluators kept data collection instruments, calculation spreadsheets, and survey data available for NW Natural records.

2.2.2 DATA UTILIZED

For each of the programs and measures evaluated, the Evaluators obtained the following datasets from NW Natural:

- Program tracking data for each of the measures offered through OLIEE and WALIEE, completed between July 1, 2010 and June 30, 2022
- Participant monthly gas consumption data between July 1, 2009 and December 31, 2023
- Nonparticipant monthly gas consumption data between July 1, 2009 and December 31, 2023
- Project-level documentation, including application forms, equipment specification documents, equipment invoices, and project installation documents
- Customer contact information
- Trade ally contact information and number of projects completed in each program year
- Community Action Partnership staff contact information
- NW Natural staff contact information
- Typical Meteorological Year (TMY) X weather data (2018-2023), TMY3 weather data, and NOAA weather data for each evaluated program year.

To evaluate each of the measures, the Evaluators conducted primary data collection activities. The Evaluators performed the following data collection activities:

- Stratified sampling plan that achieves 90/10 confidence precision goals
- Surveyed a random subset of participating customers to collect information pertinent to validating associated energy impacts

Further details of measure-specific sampling plans and data collection activities are described in Section 2.2.4 below.

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[2] Notably, The Uniform Methods Project (UMP) includes the following chapters authored by the Evaluators. Chapter 9 (Metering Cross- Cutting Protocols) was authored by Dan Mort and Chapter 15 (Commercial New Construction Protocol) was Authored by Steven Keates.

[3] Core Concepts: International Measurement and Verification Protocol. EVO 100000 – 1:2016, October 2016.

The Evaluators used the data provided by NW Natural to first conduct a database review for each measure. The Evaluators then conducted a detailed document review for a sample of projects. The purpose and methods for these activities are described in the subsections below.

2.2.3 DATABASE REVIEW

At the outset of the Low-Income energy efficiency program impact and process evaluations, the Evaluators reviewed Low-Income program databases to ensure that they conform to industry standards, have a standardized and documented data dictionary, and adequately track key data relevant to the implementation and evaluation of the program.

The Evaluators recognize that failure to develop and maintain a sufficient tracking system can add significantly to the cost of implementation, monitoring, verification and evaluation; reduce confidence in results; and increase the variance in estimates of savings. Therefore, we make this a high priority in our iterative review of each program over the course of all evaluation periods of interest.

2.2.4 DOCUMENT-BASED VERIFICATION

In addition to an aggregate tracking database review, the Evaluators requested rebate and project documentation for a randomly selected subset of participating Low-Income customers in each of the programs, for each evaluation period of interest. Documentation for this task included application forms, supporting customer or contractor invoices, AHRI certificates, project installation photos, and any other associated project-level documents specific to each program.

For each project sampled, the Evaluators verified quantities and efficiencies for upgraded equipment or weatherization specifications according to the invoices and associated applications and documents. Deviations between tracking data and project documentation values were noted and summarized.

The Evaluators developed a sampling plan that aimed to achieve a sampling precision of ±10% at 90% statistical confidence – or "90/10 precision" – for net realized savings estimates at the measure category level for all significant measures during document-based verification for each program.

That is, at each state and program level, statistical precision and confidence will meet 90/10 precision at minimum. In a generalized form, simple random samples for a statistically infinite population are developed as follows:

$$n = \left(\frac{1.645 * cv}{rp}\right)^2$$

Where,

n = sample size

1.645 = *z* score reflecting 90% confidence for a two-tailed distribution

cv = Coefficient of Variation, defined as standard deviation / mean

rp = Required Precision, 10% for 90/10 sampling

Standard practice is to assume a CV of .50 for homogenous programs (such as residential programs). In this instance, the required sample for 90/10 is $(1.645 * .5 / .1)^2 = 68$. For programs with limited participation, this sample is adjusted as follows:

$$n_0 = \frac{n}{1 + \frac{n}{N}}$$

Where,

n_0 = Finite-population adjusted sample

n = Sample for a statistically infinite population

N = total population size

Thus, for a population of 400, the required sample to meet ±10% precision at 90% confidence is:

n_0 = 68 / [1+ 68/400)] = 58.12, rounding up to 59.

The Evaluators utilized the sample sizes for each program summarized in Table 2-2 for the OLIEE and WALIEE programs, by evaluation period.

Table 2-2: Document-Based Verification Sample Design for OLIEE and WALIEE

Program	Program Evaluation Period	Population of Homes	Sample of Homes	Precision
OLIEE	PY2010-PY2013	1,310	64	90% ± 9.93%
	PY2014-PY2017	906	63	90% ± 9.95%
	PY2018-PY2022	981	63	90% ± 9.98%
	Total	**3,197**	**192**	**90% ± 5.75%**
WALIEE	PY2010-PY2013	55	30	90% ± 9.86%
	PY2014-PY2017	49	28	90% ± 9.73%
	PY2018-PY2022	60	32	90% ± 9.83%
	Total	**164**	**84**	**90% ± 5.67%**

2.2.5 SURVEY-BASED VERIFICATION

This section describes the Evaluators' general methodology for conducting survey-based verification for NW Natural's Low-Income energy efficiency programs. In addition to the document-based verification summarized above, the Evaluators verified tracking data by surveying a sample of participant customer households.

A sample of participants were surveyed to confirm that the measure was installed and is still currently operational and whether the measure was a new construction, early retirement, or replace-on-burnout, if applicable to the measure. Although survey verification is not necessary for weatherization measures, which are unlikely to be removed, uninstalled, or fail, this verification effort is especially relevant for the non-weatherization measures, such as gas furnaces and gas tank water heaters.

This survey effort helped Evaluators develop in-service rates, or the percentage of projects in which the measure is still currently operational and installed. This in-service rate acts as an adjustment to deemed savings estimates to reflect verified savings in the service territory. The selected sample participants were offered a $10 gift card incentive to participate in the verification survey.

The Evaluators combined survey-based verification efforts with the survey-based process evaluation efforts to maximize the quality and quantity of data collected toward multiple deliverables while minimizing customer response fatigue. The findings from these activities will primarily serve the impact evaluation to:

- Verify measure was installed
- Verify measure is functional

Because this evaluation effort also includes a process evaluation of the Low-Income energy efficiency programs, the Evaluators included these verification questions in the overall process evaluation efforts, further defined in Section 2.3.3.

These verification surveys also serve an additional purpose: when billing analysis is infeasible, this simple verification will help the Evaluators more accurately estimate measure-level impacts using engineering algorithms while accounting for unforeseen new equipment failures or removed installations.

The Evaluators utilized the sample sizes for survey-based verification efforts in Table 2-3. The most recent program year was utilized for participant surveys to ensure participants would be able to recall their experiences with the program. Due to the low participation in the programs in 2023 and the similarity of measure offerings, the OLIEE and WALIEE programs were combined for this survey effort.

Table 2-3: Survey-Based Verification Sample Design for OLIEE and WALIEE

Program	Program Year	Population of Homes	Target Survey Response Goal	Assumed Response Rate	Target Responses
OLIEE /WALIEE	2023	186	50	10-15%	17-28

2.2.6 IMPACT EVALUATION METHODS

In this section, the Evaluators define the approach used to complete impact evaluation activities for NW Natural's Low-Income programs. As previously mentioned, the Evaluators define two major approaches to determining net savings for the OLIEE and WALIEE programs:

- Deemed Savings (for Deemed Measure List)
- Whole Building Billing Analysis (IPMVP Option C)

In the following sections, we summarize the general guidelines and activities the Evaluators will follow to conduct each of the above analyses.

2.2.7 IMPACT ANALYSIS WITH BILLING ANALYSIS

ADM evaluated NW Natural's Low-Income energy efficiency programs utilizing a billing analysis. The Evaluators explored multiple regression analyses using monthly gas consumption data. These model

specifications are recommended in the National Renewable Energy Laboratory (NREL) Uniform Methods Project (UMP)[4].

The regression models included a counterfactual control group, which is useful for estimating net energy savings – that is, participating homes are compared against nonparticipating homes. The nonparticipating homes represent the observed market baseline and equipment efficiencies demonstrated by NW Natural's actual customer base. Therefore, results from this analysis utilizing a counterfactual control group represent net energy savings. NW Natural could not identify non-participant homes that were also Low-Income customers, however, having any control group greatly improves the impact estimates.

The Evaluators understood that NW Natural wished to evaluate verified savings at the measure level for the most recent program year for both OLIEE and WALIEE. Therefore, as part of the billing data steps, the Evaluators explored analyses in which the households utilized in the analysis consist only of homes that have isolated measure participation to estimate measure-level savings within the most recent program year. This ensures that natural gas furnace savings are not included in the estimation of attic insulation projects, and vice versa. For all other program evaluation periods, the Evaluators explored whole-home billing analyses with participants of any measure included in the analysis.

2.2.7.1 Regression Model Specifications

The Evaluators explored two different regression models to estimate energy savings for the study: 1) Difference-in-Difference (D-n-D) with Fixed Effects; 2) Post Period Regression (PPR). The model specifications and required data are summarized in the table below.

For the purposes of this proposal, the "treatment group" is the group of participants that have received participated in the OLIEE or WALIEE Programs, while the "control group" is a group of non-participant residential homes displaying similar energy usage behaviors as the treatment group.

To create a matched control group of Low-Income households, the Evaluators utilized customers that did not participate in the Low-Income programs. Working with NW Natural, the Evaluators determined that NW Natural does not track Low-Income households in its customer database and that exact matching participants and non-participants on Low-Income status was not possible. However, utilizing a control group with similar energy usage characteristics after Propensity Score Matching greatly improves impact estimates. While bias can be introduced if economic, social, or other factors cause differential impacts to energy consumption for Low-Income households compared to non-participant households, this is an issue regardless of whether Low-Income households are exactly matched to other Low-Income households.

[4] https://energy.gov/sites/prod/files/2015/02/f19/UMPChapter17-residential-behavior.pdf

Table 2-4: Regression Models

Model	General Regression Equation	Quasi-Experimental Control Group
Difference-in-Difference with Fixed Effects (D-n-D)	Average Daily Usage ~ (Customer, Month, Post, Treatment, HDD, Post*Treatment, HDD*Post*Treatment	✓
Post-Program Regression (PPR)	Average Daily Usage ~ (Month, Treatment, Average Pre-period Spring Usage, Average Pre-period Winter Usage, Average Pre-period Summer Usage, Average Pre-period Fall Usage, HDD, HDD*Treatment, Month*Average Pre-period Spring Usage, Month*Average Pre-period Winter Usage, Month*Average Pre-period Summer Usage, Month*Average Pre-period Fall Usage)	✓

Each of the models has different methods of controlling for household-level differences and provide reliable estimates of savings, assuming participation is sufficient. In addition, all models have interaction terms between treatment and weather (or month) to provide seasonal and overall estimates of energy savings. The Evaluators provide further details for each model below:

1. The D-n-D with Fixed Effects regression model controls for individual differences through a variable that is equal to the customer's average daily energy use that has been averaged across the pre- and post-treatment period.
2. The PPR model uses post-period data, with lagged energy use for the same calendar month of the pre-program period, integrating the underlying logic is that systematic differences between participants and controls will be reflected in differences in their past energy use, which is highly correlated with their current energy use.

As part of regression modeling, the Evaluators' data scientists checked variable correlations and performed sensitivity testing. The Evaluators then extrapolated energy savings estimates to the weather data observed over the 4-year evaluation periods, for each program.

The selected regression model was based on model fit, the ability of the model to control for autocorrelation, and model performance during sensitivity testing.

2.2.7.2 Billing Data Preparation

The Evaluators prepared consumption data for each cohort's billing analysis tasks. The following steps were taken to prepare consumption data for each cohort analysis:

2. Identify homes in the consumption data that were participants in OLIEE and WALIEE, separately;
3. Exclude homes without sufficient pre- and post- consumption data (at least 9 months of valid consumption data in each period);
4. Exclude homes with consumption data indicating it is an outlier[5];

[5] The Evaluators examined data for outliers using multiple accepted identification techniques: simple Z-scores, Bonferroni Outlier Test, Grubbs Test for Outliers (G-test), or others as appropriate. The Evaluator aims to remove

5. Identify and remove duplicate records,
6. Calendarize the gas billing data;
7. Identify customers with isolated measure installs;

We report the number of retained customers in the analysis groups, after each step to identify issues or possible sources of bias.

2.2.7.3 Propensity Score Matching

To estimate the most reliable and unbiased results, it is ideal to estimate program impacts with a randomized control trial (RCT). However, RCTs are not viable due to the design of many programs, including NW Natural's Low-Income energy efficiency programs, which would require programs to turn away a portion of customers that sign up for the program, to use as a control group. There exists, however, methods for producing a control group via quasi-experimental methods. In this section the Evaluator further describes the steps required for cleaning billing data and creation of the counterfactual control groups.

The Evaluators created a statistically similar control group using propensity score matching (PSM), a method that allows us to find the most similar household based on the customers' billed consumption trends in the pre-period and verified with statistical difference testing. The Evaluators utilized this method because it is likely to have more meaningful results than a treatment-only analysis. The integration of a control group in a regression analysis allows the Evaluators to eliminate bias and outside influence as much as possible. Some examples of outside variables that a control group can sufficiently control for are changes in economies and markets, large-scale social changes, or impacts from weather-related anomalies such as flooding or hurricanes. A propensity score is a metric that summarizes several dimensions of household characteristics into a single metric that can be used to group similar households.

To create a post-hoc control group, the Evaluators compiled billing data for a control group to compare against treatment households via quasi-experimental methods. The Evaluators utilized billing data from customers that have not participated in NW Natural's Low-Income energy efficiency programs or in other energy efficiency programs. With this information, the Evaluators created a statistically valid control group via PSM, matching on seasonal pre-period usage.

Although quasi-experimental methods may result in selection bias (the possibility that those who are chosen in the treatment group are systematically different from those who did not participate), the PSM method ensures to the extent feasible that average characteristics of the treatment and comparison groups are similar, resulting in minimal bias within a non-RCT design.

2.2.7.4 Validity Testing

The Evaluators checked that the quasi-experimental control group was statistically similar to the treatment group by conducting the Welch's Two-Sample T-test for each month in the pre-period between each group. If the post-hoc control group passes the t-test for most pre-period months (at least

error readings rather than remove high and low users, as these subgroups contribute real behaviors to the average savings estimate.

9 of the 12 pre-period months), and the groups are validly balanced, the Evaluators continued with the regression models summarized in the sections above. This validity test is conducted to ensure that control and treatment groups are not statistically different at the 90% confidence interval. This method was completed separately for each of the 4-year evaluation periods, for both OLIEE and WALIEE.

2.2.8 DEEMED SAVINGS (UNIT ENERGY SAVINGS) APPROACH

The Evaluators created a deemed measure list based on current program offerings. The Evaluators completed the validation for specific measures across each program using applicable Regional Technical Forum (RTF) baseline assumptions, where applicable. Verified impact estimates depend on variables included but not limited to the following:

- Verify household type (SF, MF, MH, etc.)
- Verify space heating system type
- Verify cooling system type
- Verify water heating system type
- Verify heating and cooling zone
- Verify equipment sizing (tonnage, gallons)

Using this method, the Evaluators estimated deemed verified savings using region-based research conducted by the utilities in the region. The goal was to ensure that the proper measure unit savings are utilized in verified savings.

In addition, the Evaluators utilized the most recent 4-year evaluation of whole home projects, as well as the most recent year annual measure-level savings of offered individual measures to create an expected unit energy savings value for each of the measures offered through the program. These deemed measure values were weather adjusted for a typical meteorological year (TMYx) to assess future-looking expected program savings for each OLIEE and WALIEE.

The Evaluators reviewed program application documents for a sample of incented measures to verify the tracking data accurately represents the original program documents. This sample met 90/10 precision goals. The Evaluators ensured the home installed measures that meet or exceed program efficiency standards.

The Evaluators applied verification adjustments to these UES values if deviations were found between tracking data and document-based verification, and if in-service rates deviated from 100% reported in survey responses.

2.3 Process Approach and Methodology

The Evaluators conducted a thorough process evaluation of the OLIEE and WALIEE Programs to identify program strengths as well as areas for potential program improvement in each of the respective NW Natural programs. As detailed below, the process evaluation addressed the objectives identified in the RFP and covered all elements of a successful program, including design, staffing, marketing, implementation, delivery, and customer response. An important part of this evaluation was to identify market barriers that impede the program's reach into all parts of NW Natural's Low-Income residential Oregon and Washington markets. The Evaluators evaluated the most recent program year of activities,

as customers from earlier program years may not remember the upgrades completed in years prior.

The following subsections present overviews of our approach to process evaluation, followed by information on how we identified and answered important research questions, our data collection approaches, interview and survey implementation, and the timing and cadence of process evaluation activities.

2.3.1 PROCESS EVALUATION OVERVIEW

Our approach to process evaluation for the NW Natural Low-Income energy efficiency programs addressed the overall effectiveness of program activities in overcoming barriers and provides strategic guidance to assist program improvement. Data collection activities provided information on the effectiveness of program processes and procedures, including how well the program works with key stakeholders to optimize program operations. To this end, the Evaluators:

- Reviewed program documentation and interviewed program and implementer staff to understand program goals, rules, and processes - including any coordination with delivery of gas utility programs - as well as to reveal any issues or concerns to be investigated through other process evaluation data collection;
- Interviewed applicable market actors about their experiences with the program to shed light on the effectiveness of program processes, the communication between NW Natural and the CAP Agencies it partners with, its implementers, marketing activities, customer decision-making, and participation barriers;
- Surveyed program participants about their experiences, including satisfaction with the program, and their decision-making process; and
- Surveyed nonparticipants to reveal the level of program awareness and identify barriers to participation.

From the information obtained from the process evaluation, the Evaluators identified what the programs are doing well and what factors may be preventing the programs from achieving their goals or doing so more cost-effectively. The information will help NW Natural and the CAP Agencies better understand the impact evaluation results and make related management decisions.

The Evaluators used process evaluation best practices, which include:

- Allocating process evaluation resources based on each program's contribution to overall energy savings; evidence of evaluation need (e.g., failure to meet savings goals, feedback from CAP Agencies, or unsolicited feedback from customers or trade allies); changes in program design or implementation; and the recency with which these programs had a detailed process evaluation.
- Designing all data collection instruments to address specific research questions, ensuring that all needed information is collected, and none is collected that will not or cannot be used.
- Presenting the process evaluations results clearly and efficiently, identifying how each interview or survey finding addresses a specific research question. NW Natural will not have to sort through lengthy descriptions of every survey response trying to figure out the meaning of the

results.

- Providing meaningful high-level conclusions, which will form the basis for clear, actionable recommendations for process improvements where identified.

Where possible, we sought to achieve the standard level of 90% confidence of 10% precision (90/10) for participant surveys. We note, however, NW Natural's recognition that such a level of confidence and precision is not always feasible, particularly in programs with relatively small participant populations. In the case of market actors, such as contractors, retailers, and distributors, the choice of data collection approach was driven by the size of the relevant market actor population and the nature of the data to be collected.

Table 2-5 summarizes our preliminary proposed data collection approaches for each program, for the most recent program year. We discuss sample size and confidence/precision issues in more detail in the sections below.

Table 2-5: Summary of Process Evaluation Sources, by Program

Programs	Document & Data Review	Staff / Implementers	Trade Allies	CAP Agencies	Participants	Non-participants
OLIEE	Reviewed all program documentation, (e.g., marketing plans and materials, implementation plans, applications) and project files.	Individual or group interviews with program and implementer staff of each program in each state	Omnibus online survey and/or phone interviews	Omnibus online survey and/or phone interviews	Multi-mode surveys, targeting 90/10 confidence/ precision	Multi-mode survey, with 90/10 confidence/ precision
WALIEE						

2.3.2 IDENTIFYING AND ANSWERING THE IMPORTANT PROCESS QUESTIONS

The Evaluators used the various information sources – program documentation review, staff, CAP Agency staff, and implementer interviews, and customer surveys – to provide convergent information to address the identified research questions. We made maximally effective use of each source by identifying which sources provide the most applicable information to each question, as shown in Table 2-6. For example, while program and implementer staff interviews did not touch on most or all research questions, we relied more heavily on feedback from CAP Agency staff, participants, and nonparticipants to assess customer service and market barriers. Market actors and program participants provided important input into most questions relating to program implementation but were not major sources of information regarding management tools or cost management. Our assessment of nonparticipants' awareness of the program offerings and reasons for nonparticipation provide important information relating to program marketing, participation information, measure offerings, health and safety issues, and customer service as well as participation barriers.

Table 2-6: Data Sources to Answer Process Evaluation Research Questions

Process Evaluation Research Question	Document and Data	Staff	CAP Agencies	Market Actors	Participants	Nonparticipants
Are programs run per design and efficiently/effectively?	✓	✓	✓	✓	✓	
Is staffing/organization sufficient and appropriate?		✓	✓			
Is customer service of high quality, timely, and effective?			✓	✓	✓	✓
Are marketing plans implemented per design and effective?	✓	✓		✓	✓	✓
Are quality assurance procedures appropriate and effective?	✓	✓	✓	✓	✓	
Are management and implementation tools appropriate and effective?	✓	✓	✓			
Are implementation contractors running programs effectively?		✓	✓	✓	✓	
Are program materials effective and complete?	✓	✓	✓	✓	✓	✓
Are costs managed properly and efficiently?	✓	✓	✓			
Are contractors effectively capturing appropriate opportunities and ensuring comprehensive services?		✓	✓	✓	✓	
Are rebates/incentives appropriate for meeting program goals?		✓	✓	✓	✓	✓
What are the market barriers that impede program reach?			✓	✓	✓	✓
Is the program reaching the intended hard to reach customers?		✓	✓	✓		✓
Are there remaining customers that qualify for the program have issues or barriers with participating in these programs?		✓	✓	✓		✓

The key to delivering a truly valuable process evaluation is refining and specifying the research questions by reviewing previous evaluation findings and thoughtfully interviewing program and implementer staff. Another aspect of identifying and answering the important questions is understanding what is and is not meaningful in evaluation results. In preparing reports, the Evaluators sought to prioritize the dissemination of information that can lead to material and beneficial changes or insight for NW Natural Low-Income program managers and stakeholder groups.

2.3.3 DATA COLLECTION APPROACHES: CORE PROGRAMS

The following provides details on the process evaluation data collection approaches utilized.

2.3.3.1 Document and Data Review

The Evaluators reviewed available program documents, including program manuals, program logic models, contractor training materials, CAP Agency marketing materials and plans, and application forms to better understand how the program operates and to inform the evaluation design. The review also

served as process evaluation input, by helping us identify opportunities for program improvement, such as potentially overlooked marketing channels or tactics, or opportunities to streamline or expand application forms to collect needed data.

Reviewing NW Natural's Low-Income energy efficiency program logic models helped ensure our understanding of each program's objectives and how the program's activities are expected to achieve those objectives.

We also reviewed project tracking data, which is a valuable resource for understanding how the program is performing and the market response. A review of the data system also verified that the data is sufficient and complete enough to support program management and evaluation.

2.3.3.2 Program and Implementer Interviews

We conducted in-depth interviews (IDIs) with program management staff to fill out our understanding of program design, goals, processes, and marketing strategies; to assess communication and coordination between NW Natural and its implementers, CAP agencies, and hard-to-reach communities; to get NW Natural's input on its implementer performance; to gain insight into quality control and assurance processes; to identify challenges that the programs have encountered and how those challenges have been addressed; and to clarify evaluation goals and research questions. Because these programs revolve around hard to reach (HTR) customers and their unique barriers to program participation and unique energy needs, the Evaluators developed a unique battery of questions for this target demographic that focuses on energy burden, program satisfaction, program communication methods, and additional energy needs. This is prioritized as a part of the evaluation objectives due to the equity objectives in the Clean Energy Transformation Act (CETA), present in the state of Washington. Senior evaluation team members conducted the IDIs using semi-structured interview guides (see Instrument Development, below).

2.3.3.3 Market Actor, Participant, and Nonparticipant Surveys

We conducted telephone or web surveys with market actors, program participants, and nonparticipants. We anticipated conducting surveys as telephone, web, or mixed-phone/web surveys due to the demographics of these programs' customers.

The selection of survey type depended on the nature of the target audience, the anticipated challenges in reaching customers by various methods, and the nature of the information to be collected. Decreasing response rates to residential phone surveys over the past several years have made web surveys a more cost-effective approach for residential target audiences. Response to web surveys also have declined in recent years; thus, we considered and recommended other modes as appropriate.

2.3.3.4 Market Actors

In the case of market actors, such as contractors, retailers, and distributors, the choice of data collection approach was driven by the size of the relevant market actor population and the nature of the data to be collected.

2.3.3.5 Participants

The Evaluators conducted a survey of Northwest Natural's Low-Income Program participants from program year 2023 to gather feedback about customers' engagement with and experience of the program. The most recent program year was utilized for participant surveys to ensure participants would be able to recall their experiences with the program. Due to the low participation in 2023, participants from OLIEE and WALIEE were combined into a single survey, as shown in Table 2-7.

Table 2-7: Participant Survey Sample

Program	Program Year	Population of Homes	Sample of Homes	Precision
OLIEE/WALIEE	2023	186	35	90% ± 13.9%

2.3.3.6 Nonparticipants

The Evaluators conducted a nonparticipant survey of likely Low-Income residential customers in both Washington and Oregon, targeting 90/10 confidence/precision. As with participant surveys, we anticipated a mix of online and phone surveys, possibly including mailed recruitments to take the online survey. However, email surveys were performed and exceeded the required survey target.

2.3.4 INTERVIEW AND SURVEY IMPLEMENTATION

The Evaluators conducted all interviews and surveys using in-house resources. In the sections below, we detail our interview and survey instrument development and implementation.

2.3.4.1 Instrument Development

We developed all interview guides and survey instruments to address research questions identified in the RFP, during project initiation, or in staff and implementer interviews and with a mind to the analysis to be performed. Table 2-6 documents the research questions specific to each data source, which guided the process for developing each instrument. This ensured that the research questions for each instrument were vetted and discussed with NW Natural.

We provided a crosswalk between the vetted research questions and each interview or survey item when we submitted the draft instruments to NW Natural. This ensured that there is no question or confusion about the purpose of any given item. Providing NW Natural staff with a clear understanding of the purpose of each item in the instrument enabled them to provide focused feedback on those items. We revised each item as needed based on the feedback received.

2.3.4.2 Survey Programming and Testing

The Evaluators programmed all surveys, both phone and web, using an industry-standard survey platform, Qualtrics. The platform is widely used by professional survey research and evaluation firms and supports web, telephone, and dual-mode survey administration. It offers sophisticated programming features for developing user-friendly interfaces and offers a range of options for response validation and display logic. It also provides controls for preventing duplicate or ineligible submissions

and allows the option of completing surveys in multiple sessions. It provides the ability to allow respondents to select the survey language as well as the ability to embed screener questions in email invitations.

We tested each survey to ensure that all questions and responses are included and worded correctly, and all input and display logic works correctly. The program lead assessed the look and feel of the survey (size of font, amount of white space, location of page breaks, and so forth) and provided suggestions for improvement, when needed.

Once each survey was programmed, we carried out a soft launch of a small subsample as a second check to ensure the survey programming was correct as well as to determine whether any questions were not well understood or needed to be revised for any other reason.

2.3.4.3 Survey Recruitment

We prepared telephone and email recruitment scripts to deploy to participant and nonparticipant customers as a call to action to participate in the survey. These materials included several well-known elements, such as personalizing the message, stating the intended use of the responses and the importance of everyone's response, making a personal appeal, and so forth. They provided the name of the Evaluators evaluation staff contract to answer questions about the survey. We also provided NW Natural contact information to provide *bona fides* or answer questions. Email recruitment also provided a call-in number for customers who wanted to complete the survey by phone.

Survey recruitment was accomplished through multiple modes of recruitment, specifically:

- Initial email invitation
- Two reminder email invitations, three business days apart
- Telephone-based surveys for customers without email addresses

In recruiting for both phone and email surveys, we followed additional protocols to attempt to maximize response rates and reduce customer burden. We carried out multiple recruitment attempts but spaced them to provide adequate opportunity to respond to each one before sending another.

The Evaluators provided $10 incentives for survey completions.

2.3.5 COORDINATED EFFORTS

The Evaluators coordinated efforts with NW Natural staff regarding customer contact and conducted research to minimize the time impact on NW Natural's customers participating in this evaluation. We endeavored to facilitate a strong sense of coordination and collaboration with our clients through multiple avenues, including:

- Client review of interim and final work product: We included NW Natural into the review process for recruitment email and telephone messaging, survey instrument development, site-level M&V plans, and interim and final reporting. Messages included contact information for the customer call center, along with contact information for a senior project manager at the Evaluators.
- Involved NW Natural staff in the Quality Assurance (QA) process for data collection.

- The Evaluators involved NW Natural staff by allowing client staff to participate in and audit telephone surveys, including client to receive a survey and experience it from a program participant's perspective, and other potential methods as the opportunities present themselves.

The Evaluators worked with NW Natural to instruct their call centers on answering customer inquiries regarding the Evaluators' role as the EM&V contractor to ensure transparency and reliability to customers and to preserve NW Natural's customer relations with residential customers. The Evaluators maintained a 'do not contact' list for customers that expressed a desire to be removed from call lists for future EM&V work. For many residential programs, however, maintaining a 'do not contact' list does not compromise the impact evaluation process.

2.4 Cost-Effectiveness Testing

The Evaluators calculated each program's cost-effectiveness, avoided energy costs related to infrastructure capacity, commodity and transport/storage, environmental compliance, and risk reduction, and implementation costs for the most recent program year using the Evaluators-developed cost-effectiveness tool. Similar to other Low-Income evaluations completed by the Evaluators in the region, the Evaluators determined the economic performance with the following cost-effectiveness tests:

- Total Resource Cost (TRC) test;
- Utility Cost Test (UCT);
- Participant Cost Test (PCT);
- Rate Impact Measure (RIM) test; and
- Societal Cost Test (SCT).

2.4.1 NON-ENERGY BENEFITS

The Evaluators conducted a literature review to quantify non-energy benefits (NEBs) for Low-Income residential programs with established values where available.

The Evaluators also worked with NW Natural staff to identify a listing of NEIs and NEBs that were of interest for each program. Additionally, the Evaluator recognized there may be additional health and safety benefits for programs that target hard to reach communities. The Evaluators worked with NW Natural to prioritize the identification of such additional NEIs and NEBs for these programs as they are designed and rolled out.

Inputs and methods for cost-effectiveness testing are provided in Appendix A: Cost-Effectiveness Testing.

2.4.1.1 Disconnections and Arrearages

NW Natural provided information on arrears, service disconnection notices, and service disconnections for participants and non-participant customers during the analysis period (2010-2023). The Evaluators estimated a quantified impact of the program on customers' capability to stay current on their gas bills by comparing arrears and disconnections for participants and non-participants in the pre- and post-periods. The Evaluators utilized matched control customers from the billing analysis to estimate net

impacts for arrears and disconnections and to control for factors including differences in payment plans and other household characteristics.

Utilizing the data provided from NW Natural, the Evaluators calculated the following outcomes:

1. Annual arrearage reduction per participant,
2. Annual disconnection reduction per participant; and
3. Annual disconnection notice reduction per participant.

3 OLIEE IMPACT RESULTS

Since 2002, the OLIEE program has been offered to provide equitable access to DSM by funding high-efficiency equipment and weatherization measures to Low-Income homes. The program consists of two parts: The Community Action Program (CAP), and the Open Solicitation Program (OSP). OLIEE funding is used to improve the efficiency of NW Natural's Low-Income customers' homes through the installation of high efficiency equipment and weatherization measures. The program is delivered by ten Community Action Agencies (Agencies) within NW Natural's Oregon service territory.

OLIEE program was redesigned from paying prescriptive amounts for the installation of specific measures, to paying for all energy efficiency measures deemed cost-effective when analyzed at the whole-house level. The OLIEE pilot's new "whole house" perspective was adopted in conjunction with a series of annually escalating agency targets.

In the following tables, the Evaluator summarizes the number of historical homes treated through the OLIEE program, as well as expected Therms saved, verified Therms saved, and measure counts.

Table 3-1: OLIEE Program Measure Counts by Evaluation Period

Measure	Count of Measures (PY2010-PY2013)	Count of Measures (PY2014-PY2017)	Count of Measures (PY2018-PY2022)
Ceiling Insulation	723	519	631
Direct Vent Space Heater	86	2	5
Duct Insulation	463	363	505
Duct Sealing	588	449	616
Faucet Aerators	1	0	9
Floor Insulation	679	500	619
Furnace Tune-Up	83	47	66
HE Water Heater	20	15	22
HE Windows	236	115	179
High Efficiency Furnace	292	450	710
Hot Water Pipe Insulation	3	5	12
Infiltration	708	625	779
Thermal Doors	53	14	51
Wall Insulation	327	304	318
Totals	**4,262**	**3,408**	**4,522**

Table 3-2: Verified Impact Savings by Program Year, OLIEE

Program Year	Number of Participant Homes	Average Number of Installed Measures	Expected Therms Saved	Verified Therms Saved	Realization Rate	Total Incentives and Agency Costs ($)
2010	561	3.2	219,489	52,224	24%	3,448,712
2011	332	3.1	96,895	30,906	32%	2,223,775
2012	268	3.5	76,989	24,948	32%	2,738,388
2013	149	3.3	35,682	13,871	39%	1,024,954
2014	189	3.4	50,778	20,673	41%	1,430,164
2015	182	3.3	42,701	19,907	47%	1,533,943
2016	248	4.0	53,697	27,126	51%	1,970,200
2017	287	4.1	69,094	31,392	45%	2,605,351
2018	295	4.2	97,583	35,046	36%	3,128,583
2019	262	3.9	79,394	31,125	39%	2,738,720
2020	248	3.4	66,745	29,462	44%	2,105,700
2021	176	3.8	55,348	20,909	38%	2,164,725
2022	189	3.8	57,521	22,453	39%	2,916,969
Total	**3,386**	**3.6**	**1,001,916**	**360,042**	**36%**	**30,030,184**

Table 3-3: Verified Impact Savings by Program Evaluation Period, OLIEE

Program Evaluation Period	Evaluation Period Homes	Average Number of Installed Measures	Expected Therms Saved	Verified Therms Saved	Realization Rate	Total Incentives and Agency Costs ($)
PY2010-PY2013	1,310	3.3	429,055	121,949	28%	9,435,829
PY2014-PY2017	906	3.8	216,270	99,098	46%	7,539,658
PY2018-PY2022	1,170	3.9	356,591	138,995	39%	13,054,697
Total	**3,386**	**3.6**	**1,001,916**	**360,042**	**36%**	**30,030,184**

3.1 Database Review and Document-based Verification

Before conducting the impact analysis, the Evaluators conducted a database review for the OLIEE Program. The Evaluators selected a subset of rebate applications to cross-verify tracking data inputs, summarized in Section 2.2.4.

The Evaluators reviewed each measure's number of units, efficiency, square footage, capacity and insulation values where available. During the review, the Evaluators found there were some projects with incomplete, missing, duplicate, or other documentation issues, as summarized in Table 3-4.

Table 3-4: Project Documentation Summary, OLIEE

Project Documentation Status	Number of Participants	% of Participants
Complete	146	75%
Incomplete	18	9%
Missing	25	13%
Duplicate	2	1%
Other	3	2%
Total	**194**	**100%**

The Evaluators found 18 customers that had project documentation, but this documentation lacked the necessary information to successfully complete the database review. For example, many of these customers provided the NW Natural CAP Program Improvement Analysis Report but they did not provide an invoice for the work that was performed or information on the efficiency of the equipment or upgrade completed. Therefore, the Evaluators could not confirm these measures were upgraded.

The Evaluators did not receive any project documentation for 25 out of 194 customers. Lastly, there were three customers with documentation that did not match the names and addresses in the provided tracking data and one customer with two duplicate rows but different account/request ID numbers.

The Evaluators also found that many specifications were missing from the documentation such as insulation square footage, window/door quantities, and model information for furnaces and water heaters. Measures such as furnace tune-ups and direct vent space heaters did not provide any specification information. The Evaluators were not able to perform database review for these measures. Furthermore, there were additional measures in the documentation that were not accounted for in the raw tracking data for many customers. The required information necessary to complete verification activities and proper expected savings calculations are measure installed square footage values for insulation measures, measure quantities for window/door measures, and make/model information for Water Heaters/Furnaces to calculate precise savings.

3.2 Verification Survey

The Evaluators randomly selected a subset of participant customers to survey for simple verification of installed measures. The Evaluators included questions such as:

- Was the program equipment detailed in program records received?
- Are the received program measures installed and working?

The responses to this verification survey were used to calculate ISRs for the measures offered in the OLIEE Program. All survey respondents for each measure described equipment as currently functioning, leading to a 100% ISR.

3.3 Billing Analysis

The results of the billing analysis for the OLIEE Program are provided in this section. The methodology for the billing analysis is provided in Section 2.2.7.

Table 3-5 provides the number of customers and the evaluation period for the whole-home billing analyses performed for OLIEE.

Table 3-5: Whole-home Cohorts, OLIEE

Level of Analysis	Evaluation Period	Number of Participants
Whole-Home	PY2010-PY2013[6]	1,310
	PY2014-PY2017	902
	PY2018-PY2022	1,255

Table 3-6 displays customer counts for customers considered for measure-level billing analysis and identifies measures that met the requirements for a billing analysis. The Evaluators require at least 75 isolated projects in order to be sufficient for billing analysis estimates, depending on expected magnitude of measure savings. Of the eleven single measures installed, only the High Efficiency Furnace measure had sufficient participation to move forward with a measure-level billing analysis.

Table 3-6: Measures Considered for Billing Analysis, OLIEE Program Evaluation Period PY2018-PY2022

Measure	Measure Considered for Billing Analysis	Number of Customers w/ Isolated-Measure Installations	Sufficient Participation for Billing Analysis
Ceiling Insulation (OR)	✓	4	
Direct Vent Space Heater (OR)	✓	2	
Duct Insulation (OR)	✓	2	
Duct Sealing (OR)	✓	1	
Floor Insulation (OR)	✓	4	
Furnace Tune Up (OR)	✓	1	
HE Water Heater (OR)	✓	1	
HE Windows (OR)	✓	1	
High Efficiency Furnace (OR)	✓	123	✓
Infiltration (OR)	✓	12	
Wall insulation (OR)	✓	7	

The Evaluators were provided with a considerable pool of control customers to draw upon. Before matching treatment and control customers, both the treatment group and pool of control customers

[6] Although the earliest cohort initially included 1,310 customers, pre-period billing data was not available, and therefore the evaluation period was modified to 2011-2013, with 2010 set as the pre-period.

were restricted to customers with at least nine months of pre-period and post-period calendarized billing data. Additionally, customers were required to have billing data from all four seasons of the pre-period year. Once these restrictions were satisfied, the Evaluators used nearest neighbor matching with a 1-to-1 matching ratio. Matching with replacement was utilized, which allowed a control customer to be matched with more than one treatment customer. The final number of customers in each the treatment and control group are listed in Table 3-7 and Table 3-8.

The Evaluators performed three tests to determine the success of PSM:

1. *t*-test on pre-period usage by month
2. Joint chi-square test to determine if any covariates are imbalanced
3. Standardized difference test for each covariate employed in matching

All tests confirmed that PSM performed well for each measure and the Evaluators conducted a linear regression using the matched participant and nonparticipant monthly billing data.

Table 3-7: Treatment Group Counts After Data Restrictions, OLIEE

Cohort	Starting Number of Treatment Customers	Customers with Calendarized Billing Data	Customers with Pre-Period and Post-Period Billing Data	Customers with Sufficient Seasonal Pre-period Data	Customers After PSM Matching
Whole Home (PY2010-PY2013)	1,310	1,298	838	838	834
Whole Home (PY2014-PY2017)	902	899	590	589	587
Whole Home (PY2018-PY2022)	1,255	1,254	752	751	749
High Efficiency Furnace Measure (PY2018-PY2022)	123	123	66	66	66

Table 3-8: Control Group Counts After Data Restrictions, OLIEE

Cohort	Starting Number of Control Customers	Customers with Calendarized Billing Data	Customers with Pre-Period and Post-Period Billing Data	Customers with Sufficient Seasonal Pre-period Data	Customers After PSM Matching
Whole Home (PY2010-PY2013)	14,151	14,151	2,904	2,904	623
Whole Home (PY2014-PY2017)	14,151	14,151	3,457	3,454	504
Whole Home (PY2018-PY2022)	14,151	14,151	4,835	4,835	647
High Efficiency Furnace Measure (PY2018-PY2022)	14,151	14,151	4,834	4,834	63

Table 3-9 provides verified annual Therms savings per customer for each evaluated cohort. Model 2 (PPR) was selected as the final model for all cohorts as it provided the highest adjusted R-squared among the regression models. Regression Model 1 (D-n-D) provided similar estimates of whole-home savings, but with a lower model fit (adjusted R-squared). The Evaluators estimated savings between 93.1 and 118.8 Therms annually per customer across all cohorts. This results in percent savings between 16.6 percent and 19.2 percent compared to the control customers.

Table 3-9: Billing Analysis Results, OLIEE

Cohort	Number of Treatment Customers	Average Number of Installed Measures	Verified Annual Therms Savings per Customer	90% Confidence Interval	Average Annual Therms Usage for Control Customers	Percent Savings of Annual Therms Usage	Adjusted R-Squared
Whole Home (PY2010-PY2013)	834	3.3	93.1	(87.1, 99.1)	559.7	16.6%	0.96
Whole Home (PY2014-PY2017)	587	3.8	109.4	(102.3, 116.5)	587.3	18.6%	0.83
Whole Home (PY2018-PY2022)	749	3.9	118.8	(111.5, 126.1)	652.4	18.2%	0.98
High Efficiency Furnace Measure (PY2018-PY2022)	66	1.0	116.9	(82.8, 151.1)	610.1	19.2%	0.66

3.4 Program-Level Results

Table 3-10 and Table 3-11 shows expected and verified savings by program year and program evaluation period for the OLIEE program.

Table 3-10: Verified Impact Savings by Program Year, OLIEE

Program Year	Number of Participant Homes	Average Number of Installed Measures	Expected Therms Saved	Verified Therms Saved	Realization Rate	Total Incentives and Agency Costs ($)
2010	561	3.2	219,489	52,224	24%	3,448,712
2011	332	3.1	96,895	30,906	32%	2,223,775
2012	268	3.5	76,989	24,948	32%	2,738,388
2013	149	3.3	35,682	13,871	39%	1,024,954
2014	189	3.4	50,778	20,673	41%	1,430,164
2015	182	3.3	42,701	19,907	47%	1,533,943
2016	248	4.0	53,697	27,126	51%	1,970,200
2017	287	4.1	69,094	31,392	45%	2,605,351
2018	295	4.2	97,583	35,046	36%	3,128,583
2019	262	3.9	79,394	31,125	39%	2,738,720
2020	248	3.4	66,745	29,462	44%	2,105,700
2021	176	3.8	55,348	20,909	38%	2,164,725
2022	189	3.8	57,521	22,453	39%	2,916,969
Total	**3,386**	**3.6**	**1,001,916**	**360,042**	**36%**	**30,030,184**

Table 3-11: Verified Impact Savings by Program Evaluation Period, OLIEE

Program Evaluation Period	Evaluation Period Homes	Average Number of Installed Measures	Expected Therms Saved	Verified Therms Saved	Realization Rate	Total Incentives and Agency Costs ($)
PY2010-PY2013	1,310	3.3	429,055	121,949	28%	9,435,829
PY2014-PY2017	906	3.8	216,270	99,098	46%	7,539,658
PY2018-PY2022	1,170	3.9	356,591	138,995	39%	13,054,697
Total	**3,386**	**3.6**	**1,001,916**	**360,042**	**36%**	**30,030,184**

Verified savings from 2010 to 2022 for the program are 337,589 Therms, 36% of Expected Savings. Drivers of non-100% realization which are specific to the OLIEE program are:

- Verified Therms savings as a percentage of annual usage ranged from 16% to 20% across program evaluation periods; however, expected Therms savings as a percentage of annual usage ranged from 40% to 60%. Therefore, the expected Therms savings per customer are too high for the program, likely due to lack of project-level energy savings estimates in the tracking data. The Evaluators typically see whole-home retrofit savings for Low-Income programs fall between 10% and 20% of annual usage. The Evaluators observed that the expected savings in the tracking data for each customer may have represented savings for multiple projects.

4 WALIEE IMPACT RESULTS

In 2009, NW Natural launched a revised Low-Income program identified as WALIEE. Modeled after Oregon's Low-Income CAP program, the WA-LIEE program reimburses administering agencies for installing weatherization measures that are cost-effective when analyzed at the whole-house level. In Washington, two agencies co-administer the program. The program is informed by input from NW Natural's Energy Efficiency Advisory Group (EEAG).

Homes with gas in SW Washington tend to be newer construction with less of a need for weatherization, and only 2% of NW Natural's customers in Washington qualify as Low-Income. Therefore, barriers such as these limit participation and the participation rates for the WALIEE program are lower than the participation rates for OLIEE program.

In the following tables, the Evaluator summarizes the number of historical homes treated through the WALIEE program, as well as expected Therms saved, verified Therms saved, and measure counts.

Table 4-1: WALIEE Program Measure Counts by Evaluation Period

Measure	Count of Measures (PY2010-PY2013)	Count of Measures (PY2014-PY2017)	Count of Measures (PY2018-PY2022)
Ceiling Insulation	43	44	48
Direct Vent Space Heater	1	0	0
Duct Insulation	34	33	46
Duct Sealing	3	1	0
Faucet Aerators	0	0	0
Floor Insulation	22	36	45
Furnace Tune-Up	1	0	21
HE Water Heater	0	0	2
HE Windows	0	0	0
High Efficiency Furnace	7	1	5
Hot Water Pipe Insulation	14	4	17
Infiltration	34	21	43
Thermal Doors	0	0	0
Wall Insulation	25	14	9
Totals	**184**	**154**	**236**

Table 4-2: Verified Impact Savings by Program Year, WALIEE

Program Year	Number of Participant Homes	Average Number of Installed Measures	Expected Therms Saved	Verified Therms Saved	Realization Rate	Total Incentives and Agency Costs ($)
2010	16	3.4	6,393	2,598	41%	122,685
2011	11	2.9	3,634	1,786	49%	99,938
2012	8	3.5	2,517	1,299	52%	53,447
2013	20	3.5	7,684	3,248	42%	148,111
2014	10	2.8	3,050	1,624	53%	89,045
2015	9	3.2	3,219	1,462	45%	88,833
2016	17	3.5	6,409	2,761	43%	182,308
2017	13	2.9	6,148	2,111	34%	312,530
2018	16	3.7	7,605	2,598	34%	216,246
2019	22	4.4	20,214	3,573	18%	347,843
2020	8	2.1	1,136	1,299	114%	27,854
2021	14	2.5	3,598	2,273	63%	84,683
2022	11	2.6	703	1,786	254%	71,938
Total	**175**	**3.3**	**72,310**	**28,418**	**39%**	**1,845,461**

Table 4-3: Verified Savings by Program Evaluation Period, WALIEE

Program Evaluation Period	Evaluation Period Homes	Average Number of Installed Measures	Expected Therms Saved	Verified Therms Saved	Realization Rate	Total Incentives and Agency Costs ($)
PY2010-PY2013	55	3.3	20,228	8,931	44%	424,181
PY2014-PY2017	49	3.1	18,826	7,958	42%	672,716
PY2018-PY2022	71	3.3	33,256	11,529	35%	748,564
Total	**175**	**3.3**	**72,310**	**28,418**	**39%**	**1,845,461**

4.1 Database Review and Document-based Verification

Before conducting the impact analysis, the Evaluators conducted a database review for the WALIEE Program. The Evaluators selected a subset of rebate applications to cross-verify tracking data inputs, summarized in Section 2.2.4.

The Evaluators reviewed each measure's number of units, efficiency, square footage, capacity and insulation values where available. During the review, the Evaluators found there were some projects with incomplete, missing, duplicate, or other documentation issues, as summarized in Table 4-4.

Table 4-4: Project Documentation Summary, WALIEE

Project Documentation Status	Number of Participants	% of Participants
Complete	8	9%
Incomplete	77	83%
Missing	7	8%
Duplicate	0	0%
Other	1	1%
Total	**93**	**100%**

The Evaluators found that 77 out of 93 customers had project documentation, but this documentation lacked the necessary information to successfully complete the database review. Many of these customers did not provide an actual invoice for the work that was performed. The customers that did provide invoices were missing critical specification information needed to complete the database review such as square footage values, R-values, and make/model information. Therefore, the Evaluators could not complete the database review for these customers.

The Evaluators also found 7 customers did not have any project documentation and the Evaluators were not able to perform database review for these customers. Lastly, there was one customer with documentation that did not match the name and address in the raw tracking data.

The Evaluators found that the WALIEE program had some of the same data quality issues as the OILEE program. Only 8 of the 93 customers had complete project documentation from which to perform database review. Many specifications were missing from the project documentation such as insulation square footage values, window/door quantities, and model information for furnaces and water heaters. Measures such as furnace tune-ups and direct vent space heaters did not provide any specification information. The Evaluators were not able to perform database review for these measures. Furthermore, there were additional measures in the documentation that were not accounted for in the raw tracking data for many customers. The required information necessary to complete verification activities and proper expected savings calculations are measure installed square footage values for insulation measures, measure quantities for window/door measures, and make/model information for Water Heaters/Furnaces to calculate precise savings.

4.2 Verification Survey

The Evaluators randomly selected a subset of participant customers to survey for simple verification of installed measures. The Evaluators included questions such as:

- Was the program equipment detailed in program records received?
- Are the received program measures installed and working?

The responses to this verification survey were used to calculate ISRs for the measures offered in the WALIEE Program. All survey respondents for each measure described equipment as currently functioning, leading to a 100% ISR.

4.3 Billing Analysis

The results of the billing analysis for the WALIEE Program are provided in this section. The methodology for the billing analysis is provided in Section 2.2.7.

Table 4-5 displays customer counts for customers considered for measure-level billing analysis. The Evaluators require at least 75 isolated projects in order to be sufficient for billing analysis estimates, depending on expected magnitude of measure savings. None of the three single measures installed had sufficient participation to move forward with a measure-level billing analysis.

Table 4-5: Measures Considered for Billing Analysis, WALIEE Program Evaluation Period PY2018-PY2022

Measure	Measure Considered for Billing Analysis	Number of Customers w/ Isolated-Measure Installations	Sufficient Participation for Billing Analysis
90% High Efficiency Furn (WA)	✓	1	
Furnace Tune-up (WA)	✓	13	
HE Water Heater (EF=.62) (WA)	✓	1	

The Evaluators were provided with a considerable pool of control customers to draw upon. Before matching treatment and control customers, both the treatment group and pool of control customers were restricted to customers with at least nine months of pre-period and post-period calendarized billing data. Additionally, customers were required to have billing data from all four seasons of the pre-period year. Once these restrictions were satisfied, the Evaluators used nearest neighbor matching with a 1-to-1 matching ratio. Matching with replacement was utilized, which allowed a control customer to be matched with more than one treatment customer. The final number of customers in the treatment and control group are listed in Table 4-6.

The Evaluators performed three tests to determine the success of PSM:

1. *t*-test on pre-period usage by month
2. Joint chi-square test to determine if any covariates are imbalanced
3. Standardized difference test for each covariate employed in matching

All tests confirmed that PSM performed well for each measure and the Evaluators conducted a linear regression using the matched participant and nonparticipant monthly billing data.

Table 4-7 provides verified annual Therms savings per customer. Model 2 (PPR) was selected as the final model for as it provided the highest adjusted R-squared among the regression models. Regression Model 1 (D-n-D) provided similar estimates of whole-home savings, but with a lower model fit (adjusted R-squared). The Evaluators estimated savings of 162.39 Therms annually per customer, a 25.2 percent savings compared to the control customers.

Table 4-6: Customer Counts After Data Restrictions, WALIEE

Group	Starting Number of Treatment Customers	Customers with Calendarized Billing Data	Customers with Pre-Period and Post-Period Billing Data	Customers with Sufficient Seasonal Pre-period Data	Customers After PSM Matching
Treatment	173	172	49	49	49
Control	14,151	14,151	2,642	2,642	47

Table 4-7: Billing Analysis Results, WALIEE

Treatment Customers	Average Number of Installed Measures	Annual Savings per Customer	90% Confidence Interval	Average Annual Therms Usage for Control Customers	Percent Savings of Annual Therms Usage	Adjusted R-Squared	Model
49	3.3	162.39	(130.81, 193.97)	645.62	25.2%	0.807	PPR

4.4 Program-Level Results

Table 4-8 and Table 4-9 shows expected and verified savings by program year and program evaluation period for the WALIEE program.

Table 4-8: Verified Impact Savings by Program Year, WALIEE

Program Year	Number of Participant Homes	Average Number of Installed Measures	Expected Therms Saved	Verified Therms Saved	Realization Rate	Total Incentives and Agency Costs ($)
2010	16	3.4	6,393	2,598	41%	122,685
2011	11	2.9	3,634	1,786	49%	99,938
2012	8	3.5	2,517	1,299	52%	53,447
2013	20	3.5	7,684	3,248	42%	148,111
2014	10	2.8	3,050	1,624	53%	89,045
2015	9	3.2	3,219	1,462	45%	88,833
2016	17	3.5	6,409	2,761	43%	182,308
2017	13	2.9	6,148	2,111	34%	312,530
2018	16	3.7	7,605	2,598	34%	216,246
2019	22	4.4	20,214	3,573	18%	347,843
2020	8	2.1	1,136	1,299	114%	27,854
2021	14	2.5	3,598	2,273	63%	84,683
2022	11	2.6	703	1,786	254%	71,938
Total	**175**	**3.3**	**72,310**	**28,418**	**39%**	**1,845,461**

Table 4-9: Verified Savings by Program Evaluation Period, WALIEE

Program Evaluation Period	Evaluation Period Homes	Average Number of Installed Measures	Expected Therms Saved	Verified Therms Saved	Realization Rate	Total Incentives and Agency Costs ($)
PY2010-PY2013	55	3.3	20,228	8,931	44%	424,181
PY2014-PY2017	49	3.1	18,826	7,958	42%	672,716
PY2018-PY2022	71	3.3	33,256	11,529	35%	748,564
Total	**175**	**3.3**	**72,310**	**28,418**	**39%**	**1,845,461**

Verified savings from 2010 to 2022 for the program are 26,632 Therms, 37% of Expected Savings. Drivers of non-100% realization which are specific to the WALIEE program are:

- Verified Therms savings as a percentage of annual usage were 25%; however, expected Therms savings as a percentage of annual usage were 68%. Therefore, the expected Therms

savings per customer are too high for the program, likely due to lack of project-level energy savings estimates in the tracking data. The Evaluators typically see whole-home retrofit savings for Low-Income programs fall between 10% and 20% of annual usage. The Evaluators observed that the expected savings in the tracking data for each customer may have represented savings for multiple projects.

5 LOW-INCOME PROGRAM PROCESS RESULTS

5.1 Staff Interview

The Evaluators interviewed three NW Natural staff involved in the implementation of the Low-Income programs. Interviewees included the Energy Efficiency portfolio manager, the Low-Income Energy Efficiency program manager, and the Environmental Program Assistant. Staff explained that NW Natural's Low-Income program began in Oregon in 2006 and Washington in 2009. As of the 2024 program year, nine Oregon based CAP agencies, one Washington based CAP agency, and three community-based organizations partner with NW Natural to provide energy efficiency equipment upgrades to NW Natural customers.

5.1.1 PROGRAM DESIGN

The Low-Income program provides energy efficient weatherization and heating equipment to qualified customers, as well as health and safety upgrades. Prior to spring 2024 NW Natural capped the health-safety allowances to $2,000 per home, but after spring 2024 NW Natural did away with this cap to provide customers with more services and assistance. The program is funded by public service funds, as well as federal, state, and county specific funding. Staff explained that NW Natural continued to collect public service funds during the COVID-19 pandemic but were not able to update many homes and therefore the program currently has a healthy reserve of funds they are currently working through.

The participating CAP Agencies and community-based organizations complete the housing audits, contract with trade allies to install the upgrades, and submit reimbursement applications on behalf of their clients. Program participants receive all measures free of charge.

5.1.2 MARKETING

Promotion of the program is a joint effort between NW Natural, the CAP Agencies, and the community-organizations. Marketing strategies include bill inserts, DIY weatherization kits with program insert, website page, and booths at community events. NW Natural staff explained that depending on the county, the program has varying levels of waitlists so although they are actively promoting the program to all customers, they are cognizant of potential delays in service delivery.

5.1.3 PROGRAM PARTICIPANTS

Customers qualify for NW Natural funding if their annual household income is at or below 80% of the area median income (AMI). Prior to the spring of 2024, eligibility was based on annual household income being at or below 200% the federal poverty line, but NW Natural expanded its criteria based off feedback from CAP Agencies and other community representatives.

Most program participants live in single-family homes that they own. Although renters are eligible for the program, the landlord needs to agree to participate and promise to not raise rent nor evict tenants for a certain period-of-time. Additionally, although the program is open to multi-family apartment buildings, due to the low proliferation of multi-family apartment buildings with gas heating, few large buildings have participated in the program.

5.1.4 PROGRAM CHALLENGES

Staff cited a lack of engaged contractors and staff turnover as the primary barriers to increased program engagement. They explained that some contractors do not consider the projects lucrative due to the payment structure and proposal-based nature of the program. Staff noted a shortage of certified auditors available to assess homes. Additionally, staff explained that the CAP Agencies rely on a variety of funding sources and often prioritize customers based on need and funding availability.

Staff also explained that program engagement varies by county, indicating some counties have more capacity and staff to implement the program than other counties. For example, staff noted that Multnomah and Washington County can observe up to 80 projects per year, while Linn and Benton counties may observe less than 20 projects.

5.1.5 PROGRAM SUCCESSES

Despite these challenges, program staff feel optimistic about the Low-Income program moving forward. Recent partnerships and pilot program with local community-based organizations like LatinoBuilt, Oregon Energy Fund, and African American Alliance for Homeownership have enabled NW Natural to expand its program to traditional hard to reach communities as well as expand its services. Additionally, program staff indicated the change in program eligibility requirements opened the program up to more customers and allowed for more assistance.

Moving forward, NW Natural staff want to continue improving the program to better serve the needs of their CAP Agency and community-based organization partners and their customers.

5.2 CAP Agency Interview Results

The evaluation team conducted interviews with CAP Agency and community-based organization (CBO) associated with the NW Natural Low-Income program to learn more about how NW Natural works with these partners to deliver residential retrofit services to customers throughout Oregon and SW Washington. In general, these interviews focused on how NW Natural collaborates with these various entities, how these collaborations serve priority populations, and the various partnerships' strengths, weaknesses, and opportunities for improvement.

NW Natural staff provided the Evaluators contact information for representatives from the eleven participating CAP Agencies in Oregon (n=10) and SW Washington (n=1); as well as representatives from three community-based organizations. The Evaluators reached out to each CAP Agency and CBO up to three times via phone and email and invited them to participate in a thirty-minute interview. Seven CAP Agencies and three CBOs responded to interview requests. Table 5-1 outlines which CAP Agencies and CBOs responded to interview requests; Clark County Weatherization (WA), Mid-Willamette Valley Community Action Agency (OR), and Yamhill Community Action Partnership (OR) did not participate in an interview.

Table 5-1: Interviewed CAP Agencies and CBOs

Organization	Counties served	Type
Clackamas County Weatherization	Clackamas (OR)	CAP Agency
Community Action Organization - Hillsboro	Washington (OR)	CAP Agency
Community Action Team - Astoria (St. Helens)	Clatsop, Columbia (OR)	CAP Agency
Community Services Consortium - Corvallis	Benton, Lincoln, Linn (OR)	CAP Agency
Homes for Good Housing Agency	Lane (OR)	CAP Agency
Multnomah County Community Services Division	Multnomah (OR)	CAP Agency
SW OR Com Action Committee - OR Coast Com Action	Coos (OR)	CAP Agency
Oregon Energy Fund	Multnomah, Washington (OR)	CBO
African American Alliance for Homeownership (AAAH)	Multnomah (OR)	CBO
Latino Built	Multnomah, Clackamas, Washington, Marion, Polk (OR)	CBO

Representatives interviewed tended to be the agencies director or weatherization program manager, and tenures ranged from 2.5 years to 38 years. CAP Agency representatives explained that their agencies have been partnered with NW Natural since the onset of the Low-Income program; the three CBO representatives indicated that their partnerships began about two to three years ago and that these partnerships were part of pilot program aimed at expanding services past CAP Agencies.

5.2.1 FUNDING SOURCES & SERVICES PROVIDED

Eight of the CAP agencies and CBOs receive funding from other sources, like Energy Trust of Oregon and LIHEAP, to help fund the weatherization and heating equipment upgrades for their community members. All these agencies explained they braid funding sources to maximize the benefits available to their clients; each funding source has specific rules and regulations, so representatives make sure the funds are being used appropriately. For example, although NW Natural has more lenient income eligibility requirements – 200% area median income rather than 80% federal poverty line – only customers with gas fueled heat sources are eligible for NW Natural funding. In addition to the more lenient income qualifications, respondents indicated that NW Natural's health and safety measure coverage is broader and more comprehensive. They went on to explain that some funding sources are strict about making sure all measures meet a certain level of cost-effectiveness, however NW Natural is less strict, open to negotiations, and tries to do what needs to be done to improve the health, safety, and energy consumption of customers.

All the representatives indicated that NW Natural does not deny any cost-effective or health and safety related improvement and that the improvements they will deny are ones that are completely aesthetic in nature. Multiple representatives (n=4) cited windows as the most requested, but rejected measure, explaining that although customers desire new windows, the energy calculations often demonstrate

that new windows will not drastically reduce or improve energy usage and therefore they are not the best option for the home. Instead, updated insulation and furnaces tend to be the most effective measures at reducing energy usage.

All the representatives described a similar program design. Once a client enrolls in the program, they receive a home energy assessment from a qualified auditor. The auditor then provides a list of recommendations to both the client and the CAP agency or CBO, and the CAP agency or CBO contracts the work out to contractors. All the representatives noted that although clients can reject some measure recommendations, typically, the clients want all the measures provided; additionally certain measures, like bathroom fans are legally required to be a part of the program and therefore clients cannot reject this measure.

> *"We do our utmost to provide everything possible. We have the funding to do so and as long as we have the justification, we want to be as holistic as we can on every household. We, I believe, have become very adept at braiding dollars and finding the allowances within those dollars."* –CAP Agency representative

The CAP agencies and CBOs approach to external contractors vary. While one of CBOs explained that their auditors often double as contractors, the other two CBOs indicated they have a network of contractors they call on to make the home improvements recommended by the auditors. Meanwhile, the eight CAP agency representatives explained that all the auditors are in-house employees, but that equipment installations are contracted to contractors. Contractors must participate in regular RFP bids and are then assigned work based on their prices provided; the frequency of the RFP bids range from every project to every few years.

5.2.2 ENGAGING CUSTOMERS

All interviewees indicated the weatherization services are exclusive to residential customers. Although all the agencies and CBOs offer the services to multi-family apartment buildings, in general, participating customers are single-family home and/or mobile homeowners and/or tenants. Clients typically learn about the program through other social services providers, NW Natural bill inserts/communications, and community events. CAP agency representatives indicated that most of their clients are also enrolled in bill assistance programs. Interviewees explained that they do not heavily market the program because there is already substantial interest, and they want to reduce wait times as much as possible.

> "*We don't need to do marketing because we have our energy assistance list, and we don't want to keep adding people to the list. We do get some referrals from clients, housing authority, and other community orgs.*" –CAP agency Representative

Waitlists for the program vary by CAP agency and CBO. One of the CBOs explained that they avoid waitlists by making their program invite-only; the other two CBOS and all eight CAP agencies indicated they have a wait list. Wait list times range from a few months to over a year (n=6). Moreover, NW Natural and the other funding sources require substantial paperwork that can slow down the job completion timeline. These representatives understood and appreciated the need for reviews and paperwork but noted it can slow the process down.

5.2.3 WORKFORCE DEVELOPMENT

Some agency representatives explained that workforce issues are their largest barrier to increased engagement (n=3). These representatives indicated that funds are available to help more customers, but they struggle to find qualified contractors: "*the bottleneck is lack of contractors or existing contractors being busy.*" One CAP agency representative noted that "*what we are seeing is a whole trade issue. There's a shortage across the trades*." Representatives from across the CAP agencies and CBOs remarked that their existing auditors and contractors have been involved in weatherization business for many years and that they have a *"good formula nailed down*." These representatives are more concerned about the future longevity of the program due to the lack of new contractors and auditors. One CAP agency representative mentioned an internship program offered by Oregon Training Institute as a possible solution to this issue but noted the state needs more contractors.

5.2.4 SATISFACTION

Overall, all the CAP agency and CBO representatives were pleased with their relationship with NW Natural. Everyone underscored the NW Natural team's communicativeness, commitment to serving customers, and generally helpful nature.

"*We have the right partners and people*." –CBO representative
"*They always try to stretch program dollars and help more clients*." –CAP agency representative
"*I think NW Natural gas is a leader and our programs have gotten better because of their leadership*." –CAP agency representative

Moreover, multiple CAP agency representative (n=5) mentioned that NW Natural listened to their feedback and made actual programmatic changes based on that feedback, including adjusting income eligibility requirements and expanding the health and safety measure coverage. One CAP agency representative also highlighted NW Natural's allowances towards using funding for administrative costs, which greatly helps with program delivery.

"NW Natural is really great to work with; they listen to our needs and questions. They'll make changes based on our feedback – ex: they increased H&S amounts; it used to be really small and they increased; they're willing to cover more work than they had in the past." –CAP agency representative
"*They continually address things they hadn't previously addressed. Always getting better. I don't know how it will get any better*." –CAP agency representative
"Been at the table and been able to communicate with them about what's working and what's not working. It's been a great success story. NW Natural has listened to other gas programs and taken notes and made changes accordingly, they're always open to change." –CAP agency representative

Some CAP agency representatives identified challenges with the program (n=4). Challenges included the long waitlists (n=2), cost effectiveness requirements (n=3), and confusing application forms (n=2). Although these representatives acknowledged some of these challenges are out of NW Natural's

control, they suggested a more streamlined application process with clear instructions on what types of measures will and will not qualify before they take the time to assess someone's home.

CBO representatives were asked to reflect on how NW Natural can better engage similar organizations in this program. Two representatives emphasized that they need to build new, and leverage existing, relationships; these representatives explained that NW Natural could strengthen their program by expanding their presence in the communities they serve through attendance at and sponsorship of community events. One of the CBO representatives noted that having a formal contract and master services agreement has also been very helpful in ensuring the program remains funded.

5.3 Contractor Interview Results

The evaluation team conducted interviews with contractors and auditors associated with the participating CAP agencies and community-based organizations that deliver residential retrofit services to customers throughout Oregon and SW Washington. In general, these interviews focused on contractors' and auditors' involvement in the NW Natural program, market conditions and customer outreach, and their satisfaction with the program.

NW Natural staff, CAP agencies, and community-based organization staff provided evaluators contact information for 33 contractors and auditors who completed projects for the NW Natural program. Evaluators reached out to each contact up to three times via phone and email and invited them to participate in a thirty-minute interview. Eight contractors and one auditor responded to interview requests. Table 5-2provides additional background information about the respondents.

Table 5-2: Interviewed CAP Agencies and CBOs

Respondent	Organization	Type	Specialty
Respondent 1	Multnomah County Community Services Division Clackamas County Weatherization Community Action Organization - Hillsboro	Contractor	Weatherization
Respondent 2	Homes for Good Housing Agency	Auditor	Audits
Respondent 3	LatinoBuilt (Portland/Salem metros)	Contractor	HVAC
Respondent 4	LatinoBuilt (Portland/Salem metros)	Contractor	Weatherization
Respondent 5	LatinoBuilt (Portland/Salem metros)	Contractor	HVAC
Respondent 6	Multnomah County Community Services Division Community Action Team – Astoria Community Action Organization – Hillsboro Yamhill Community Action Partnership Mid-Willamette Valley Community Action Agency	Contractor	Weatherization
Respondent 7	Clackamas County Weatherization	Contractor	Weatherization
Respondent 8	Clackamas County Weatherization	Contractor	Weatherization
Respondent 9	LatinoBuilt (Portland/Salem metros)	Contractor	Weatherization

Most respondents primarily focused on weatherization measures (n=6) and respondents typically completed projects in the Portland and Salem metro areas (n=9). While the one auditor interviewed was directly employed by the CAP Agency, the contractors interviewed worked on a contract basis. Seven respondents indicated they primarily work on single family homes and manufactured homes; the remaining contractor respondent indicated they primarily focus on multi-family buildings but have expanded to single family and manufactured homes when working with CAP agencies and community-based organizations for the NW Natural program.

5.3.1 MARKET CONDITIONS & CUSTOMER OUTREACH

All respondents indicated the agencies they work with tend to have a steady flow of applicants and sizeable waitlists. They noted that the agencies do a good job promoting the program in their communities and providing services to community members in need. Two respondents noted that it is likely that some community members are being left behind due to language barriers and other accessibility issues, however overall, the CAP agencies and community-based organizations are going above and beyond to help their clients.

While the four respondents who work with LatinoBuilt generate their own project leads and are provided with project leads by LatinoBuilt, the CAP Agency focused respondents (n=6) noted that the agencies assign them all their NW Natural based work. One respondent went on to explain: *"we want to help expand the program, but we also don't want to flood the system. Don't want to overpromise."* Respondents indicated that each agency has an RFP process and bond limit, and that they are assigned leads based on their proposed bids and bond status. This process ensures work is both as cost effective as possible and spread out across participating contractors.

5.3.2 PROGRAM PARTICIPATION & PROCESS

The eight responding contractors explained that they are not involved in any of the application and rebate paperwork, but rather they are provided with a work order by the CAP Agency or community-based organization with a list of measures to install. The auditor respondent noted that these work orders are based off the recommendations provided in audits and the subsequent cost-effectiveness calculations and models.

The eight contractor respondents indicated that they are not involved in the process of determining what measures are and are not included in the work orders. However, based on the projects they have completed, they speculated that the program is comprehensive and provides the necessary assistance to improve customers' homes and reduce their utility bills.

In general, customers do not reject any of the proposed measures, as all measures are provided for free, and customers are often appreciative of the help. The measures customers are most commonly hesitant about are those that alter the general aesthetic and appearance of the home, such as door covers and vents. Customers are allowed to reject any measures – except the requisite air fan – however this rarely occurs. When customers do express concerns about certain measures or equipment the contractor explains why the measure is needed and/or refers the customer to the CAP agency for more information. Multiple respondents (n=3) indicated that customers request measures that are not part of the work order, most commonly windows; when these requests arise, contractors refer customers to CAP agencies, as they do not have the ability to add new measures without authorization.

A few respondents recalled attending training related to weatherization and HVAC upgrades and improvements, but they were not sure if these trainings were NW Natural specific (n=3). Three of the other respondents noted that they do not need any additional training opportunities as they and their staff *"have been in business for a while and know what [they're] doing."*

5.3.3 PROGRAM SATISFACTION

Respondents were satisfied with their relationship with the CAP agencies and community-based organizations and the NW Natural program:

"The whole process is streamlined, we get detailed workorders with specific directions for abnormalities. [We are] provided the entire audit so we know what was found. We have everything we need to do the job. They're setting us up for success." –Contractor
"*NW Natural is a really great company and I think the fact that they're even willing to help us out as well as helping out their customer base. It's been great working with them."* – Contractor
"What they do is very good. Getting homes weatherized can be pretty expensive for somebody with, you know, Low-Income or fixed income or something like that, right. What they do, you know, is good. The funding that they get. I know that sometimes you know they have to get creative, sometimes on things, and they do a good job of doing that to keep the, you know, the project going to help the homeowner, you know, get what they need." – Contractor

All the respondents ranked the process of receiving project leads, the range of qualifying measures, and the program overall as a "4" or "5" on a scale of 1-5, with "5" being "excellent." Respondents also noted they talk to their contacts at the CAP agencies and community-based organizations at least once a month and that staff are very responsive and communicated. One respondent suggested the CAP agencies and community-based organizations digitize as much of the process as possible rather than relying on paperwork orders and notes; none of the other respondents had ideas or suggestions for improvement. This lack of negative feedback and suggestions for improvement underscore the success and appreciation of the program amongst participating contractors and the customers they serve.

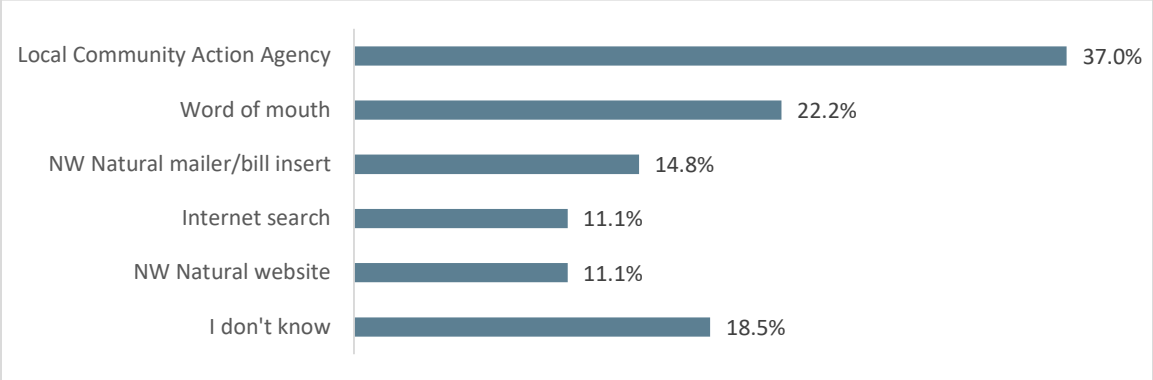
5.4 Participant Survey Results

The Evaluators conducted a survey of Northwest Natural's Low-Income Program participants in program year 2023 to gather feedback about customers' engagement with and experience of the program. The most recent program year was utilized for participant surveys to ensure participants would be able to recall their experiences with the program. Participants were contacted via phone and/or email three times and asked to complete a survey. In total, evaluators had contact information for 168 unique program participants and 35 responded to survey efforts. Three respondents did not remember receiving weatherization nor heating related measures from NW and five respondents stopped responding to questions mid survey and were excluded from analysis. Twenty-seven respondents were included in the analysis.

5.4.1 PROGRAM AWARENESS & MOTIVATION TO PARTICIPATE

Respondents learned about the program through a variety of avenues, most commonly through their local Community Action Agency (37.0%, n=10) or word of mouth (22.0%, n=6) (Figure 5-1).

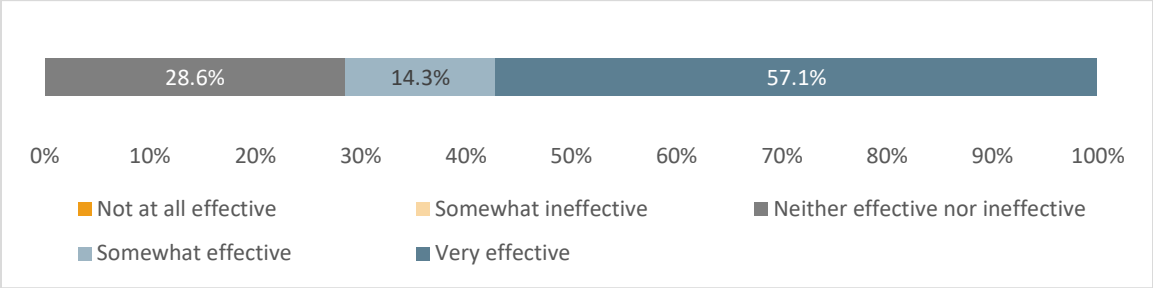
Figure 5-1: Program Awareness (n=498)



Just over half of the respondents remember receiving informational brochures or materials about the energy-efficiency program when they met with CAP Agency and/or local non-profit organization representatives (53.9%, n=14). Respondents who remembered receiving brochures noted the materials highlighted weatherization measures (n=8), furnaces (n=6), and water heaters (n=5) and most respondents found the materials effective in communicating the benefits of the program (Figure 5-2). Additionally, respondents noted that the CAP agency representatives highlighted the cost saving potential of receiving the upgrades (n=8), the free nature of the program (n=3), and the potential to

improve the comfort of their home (n=3). Respondents did not provide any feedback on how to improve the information provided. Only one respondent had concerns about the program before enrolling; they were skeptical of the offerings because they were free.

Figure 5-2: Informational Material's Effectiveness (n=14)



Respondents were motivated to participate to get their old equipment upgraded (n=12), save energy and money (n=4), and improve the comfort of their home (n=2). Respondents ranked increasing their home's energy efficiency as the most important factor they consider when considering home improvements, followed by improving health and safety, improving home comfort, and increasing home value (Table 5-3).

Table 5-3: Factors to Consider in Making Home Improvements (n=21)

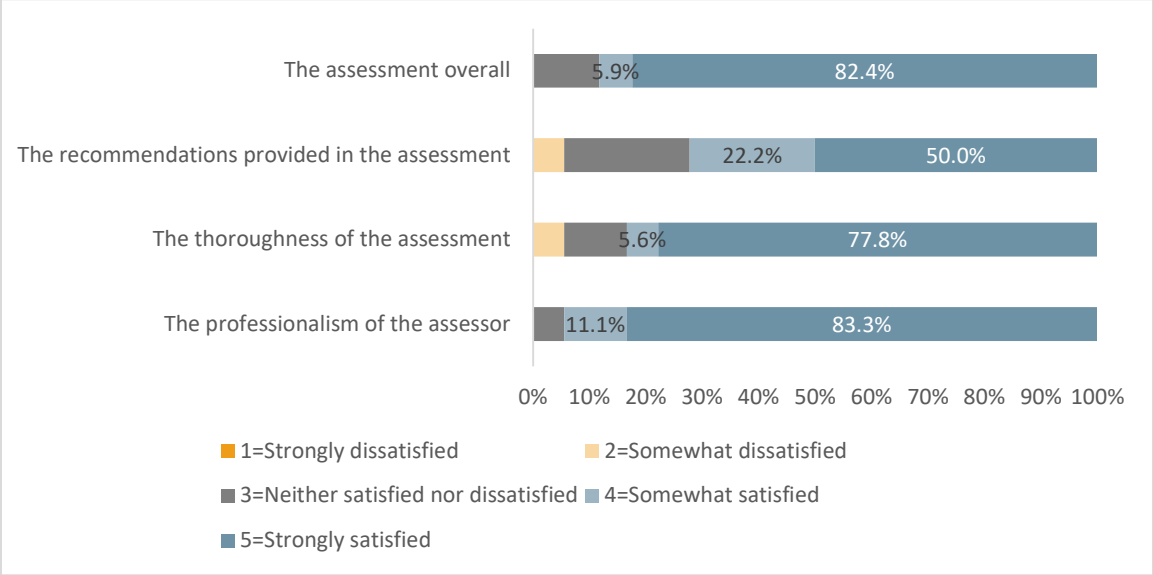
	1st	2nd	3rd	4th
Increasing home's energy efficiency	42.9%	42.9%	9.5%	4.8%
Improve your health and safety in your home	38.1%	19.1%	33.3%	9.5%
Improve your comfort in your home	14.3%	38.1%	47.6%	0.0%
Increase home value	4.8%	0.0%	9.5%	85.7%

5.4.2 ASSESSMENT AND CONTRACTOR EXPERIENCE

Two-thirds of respondents remember receiving an energy assessment of their home (66.7%, n=18); of these respondents, two-thirds remember receiving recommendations from their energy auditor (66.7%, n=12). Two respondents noted they did not act on some of the recommendations provided, including installing vents on the base of each door (n=1), as well as replacing attic, floor, and wall insulation (n=1), and windows (n=1). These respondents explained they did not like the aesthetics of the door vents (n=1) and that their roof needed to be repaired before they could install the new insulation and windows (n=1).

Respondents who remember receiving an assessment (n=18) indicated they were satisfied with the assessment overall, the recommendation provided, the thoroughness of the assessment, and the professionalism of the assessor (Figure 5-3).

Figure 5-3: Assessment Satisfaction (n=18)



Respondents found their contractor through a variety of sources including the internet, a personal contact, and referral from community agency (Figure 5-4). In general, respondents agreed that the work was scheduled and completed in a reasonable amount of time and the contractor was professional and courteous (Figure 5-5).

Figure 5-4: Contractor Source (n=27)

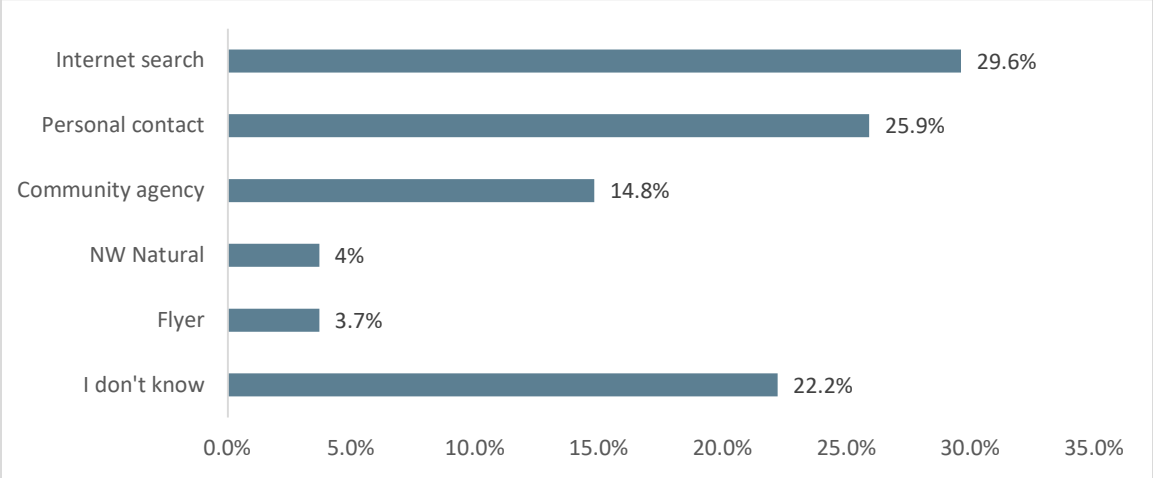
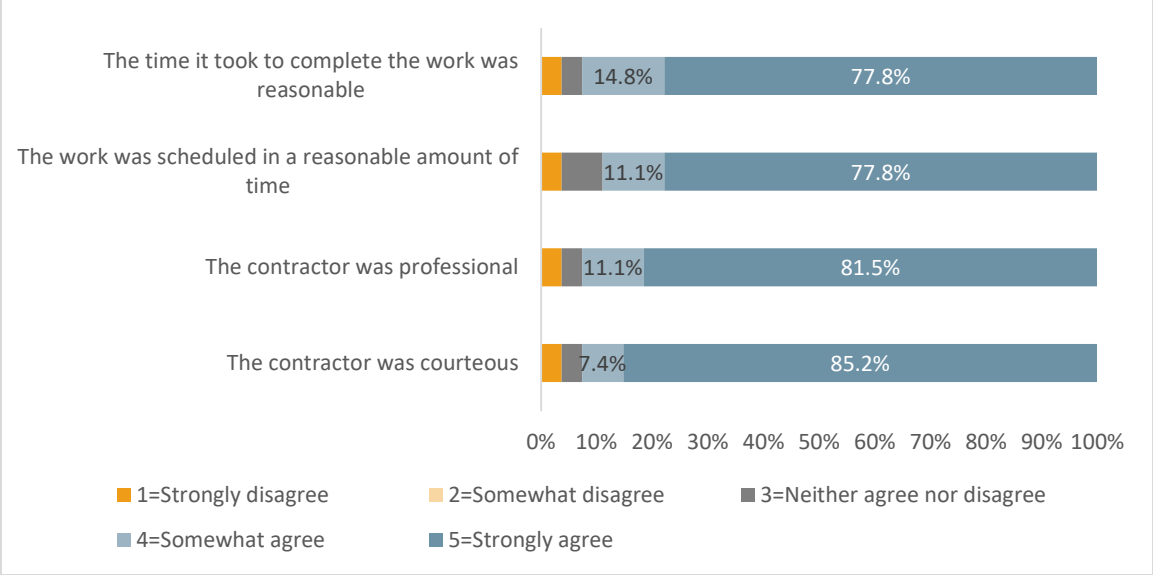


Figure 5-5: Contractor Satisfaction (n=27)

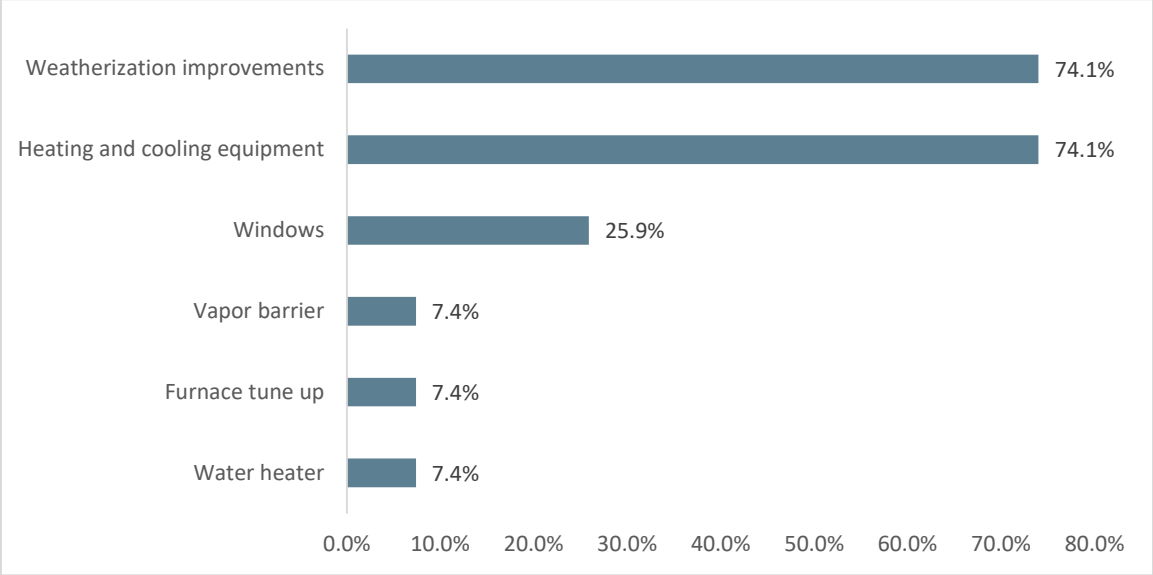


Three respondents noted their contractor suggested additional upgrades, including new windows (n=2) and a new refrigerator and water heater (n=1).

5.4.3 EQUIPMENT RECEIVED

Respondents received a variety of different equipment upgrades from the program, most commonly weatherization improvements and heating and cooling equipment upgrades (Figure 5-6). All the respondents reported that the equipment they received from the program was still installed and working.

Figure 5-6: Measures Received (n=27)



More than half of the respondents explained that there were additional measures they wanted, but did not receive (59.3%, n=16); the most common desired but not provided measures were windows and air conditioners (Table 5-4).

Table 5-4: Desired Measures (n=16)

Measure	n
Windows	6
Air conditioner	4
Additional insulation	3
Roof	2
Front door	1
Solar panels	1
Kitchen and bathroom vents	1
Electrical panel	1

5.4.4 PROGRAM SATISFACTION

Respondents were generally satisfied with NW Natural as their natural gas service provider and their experience with the program overall (Figure 5-7). About half of respondents did not have strong opinions regarding the application process, which may indicate they were not involved in this process and the CAP Agency completed the application on their behalf. About two-thirds of respondents indicated that participation in the program increased their satisfaction with NW Natural (63.0%, n=27); the remaining respondents noted that participation in the program did not increase nor decrease their satisfaction with the utility (Figure 5-8). Moreover, almost all respondents indicated they would recommend the program to others (88.9%, n=25) (Figure 5-9). More than three-quarters of respondents believe NW Natural is a very or extremely trustworthy source of information regarding energy savings in the home (77.8%, n=21).

Only two respondents provided negative reports about their experience with the program, indicating that they wished their fireplace could have been replaced (n=1) and that the contractor did not seal their windows and door properly (n=1).

Figure 5-7: Program Satisfaction (n=26)

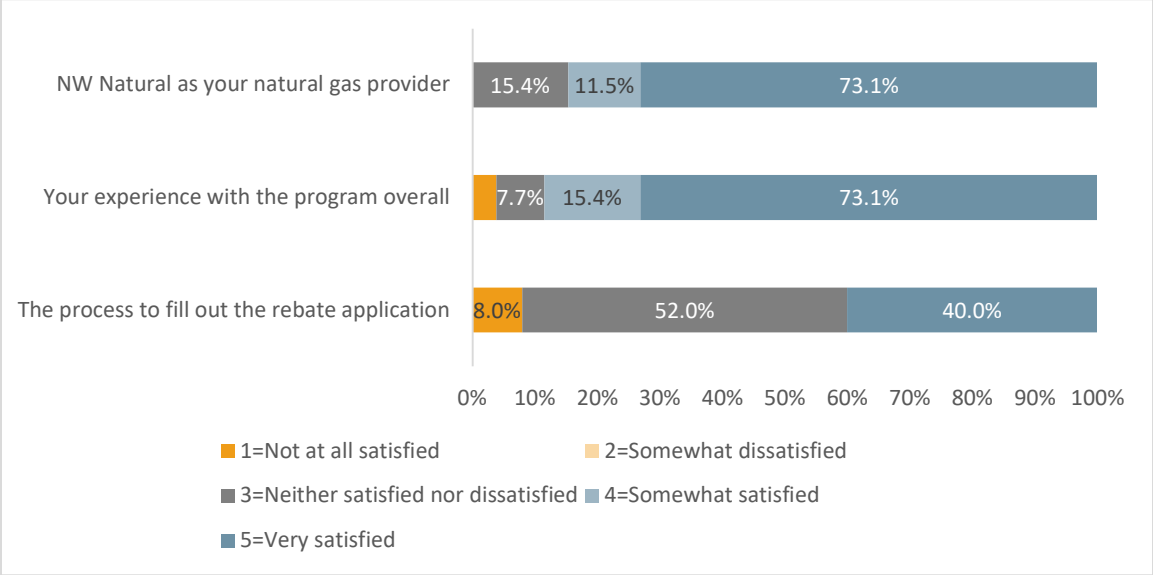


Figure 5-8: Impact of Program on Satisfaction with NW Natural (n=27)

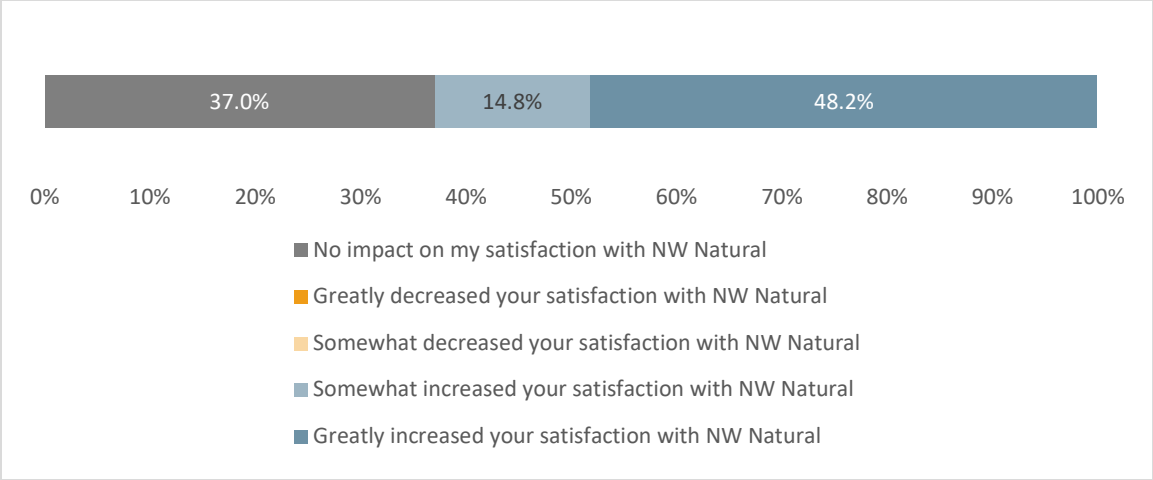
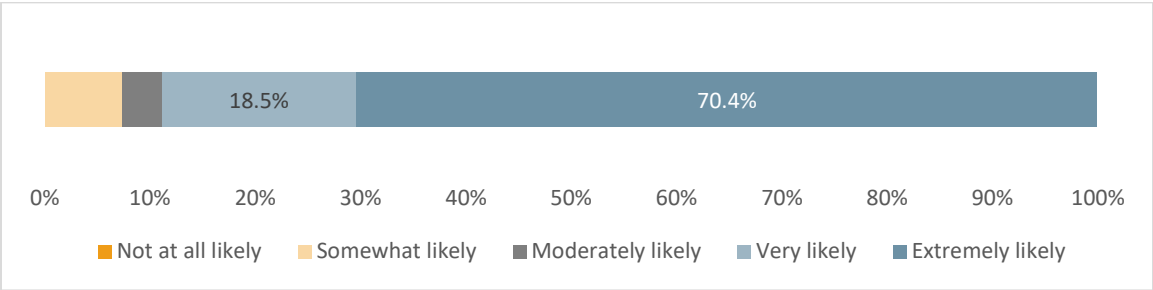


Figure 5-9: Likelihood to Recommend Program (n=27)



5.4.5 DEMOGRAPHICS

Table 5-5 describes the demographics of survey respondents. All respondents confirmed their annual income was at or below 80% the area median income of their county.

Table 5-5: Demographics (n=27)

Answer	%	Count
Homeownership		
Own	81.5%	22
Rent	11.1%	3
Own and rent to someone else	0.0%	0
Prefer not to answer	7.4%	2
Home Type		
Single-family house detached	85.2%	23
Mobile or manufactured home	11.1%	3
Apartment with 2 to 4 units	0.0%	0
Apartment with 5 or more units	0.0%	0
Prefer not to answer	3.7%	1
Building Age		
Before 1950	31.8%	7
1950 to 1959	9.1%	2
1960 to 1969	9.1%	2
1970 to 1979	22.7%	5
1980 to 1989	9.1%	2
1990 to 1999	18.2%	4
2000 to 2009	0.0%	0
2010 or later	0.0%	0
Don’t know	0.0%	0
Prefer not to answer	0.0%	0
Household Size		
1 person	40.7%	11
2 people	22.2%	6
3 people	7.4%	2
4 people	11.1%	3
5 people	3.7%	1
6 people	3.7%	1
7 people	0.0%	0
8 or more people	3.7%	1
Prefer not to answer	7.4%	2
Education		
Did not graduate high school	0.0%	0
High school graduate	22.2%	6
Associates degree, vocation/ technical school, or some college	18.5%	5
Four-year college degree	25.9%	7
Graduate or professional degree	22.2%	6
Prefer not to answer	11.1%	3
Race/Ethnicity		
American Indian or Alaska Native	7.4%	2

East Asian	3.7%	1
South Asian	0.0%	0
Black or African American	0.0%	0
Hispanic, Latino, or Spanish origin	3.7%	1
Native Hawaiian or Pacific Islander	0.0%	0
Middle Eastern or North African	0.0%	0
White or Caucasian	74.1%	20
Another race, ethnicity, or origin not listed	0.0%	0
Prefer not to answer	11.1%	3

5.5 Non-Participant Survey Results

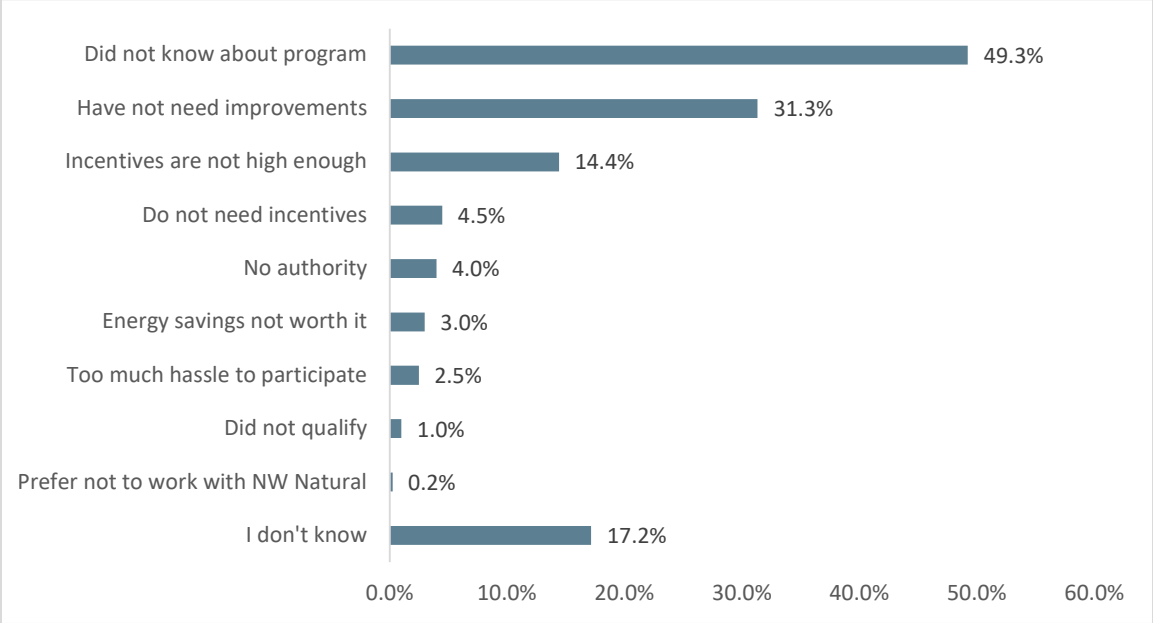
The Evaluators conducted a survey of Northwest Natural customers who qualified for the Low-Income Program but did not participate, to gather feedback about customers' awareness of NW Natural's offerings, opinions towards energy efficiency, and energy use behaviors. Participants were contacted via email two times and asked to complete a survey. In total, the Evaluators had valid emails for 5,495 unique customers; 520 responded to survey efforts. 118 respondents were excluded from analyses because they reported having no authority over the improvements made to their home (n=106) or they had received assistance from NW Natural to make improvements to their home (n=12). In total, 402 responses were included in the analyses.

5.5.1 ENGAGEMENT WITH NW NATURAL

Most respondents were homeowners and therefore had full authority to make changes and improvements to their home (81.1%, n=326); the remaining respondents were renters with some-to-full authority to make and/or request improvements (18.9%, n=76). Almost three-quarters of respondents indicated they had not replaced or upgraded any gas equipment in the past three years (70.4%, n=283). Among the 119 respondents who had replaced equipment, heating equipment, water heaters, and thermostats were the most popular equipment purchased. More than half of the respondents participated in NW Natural's bill assistance program (62.6%, n=251).

Respondents explained that they have not engaged in NW Natural's weatherization and furnace replacement program for a variety of reasons, including not knowing about the program (49.3%, n=198) and not needing improvements (31.3%, n=126) (Figure 5-1). Moreover, when asked directly, 80.4% (n=323) reported not knowing NW Natural offers weatherization and furnace replacement in partnership with local community agencies.

Figure 5-10: Reasons for Not Participating (n=402)



Among respondents who were previously aware of NW Natural's weatherization and furnace replacement assistance (n=79), most respondents had learned about the offerings through NW Natural mailers, website, or email (Figure 5-11). Respondents were most familiar with NW Natural's bill assistance and heating and cooling equipment incentive programs (Figure 5-12).

Figure 5-11: Program Awareness Source (n=79)

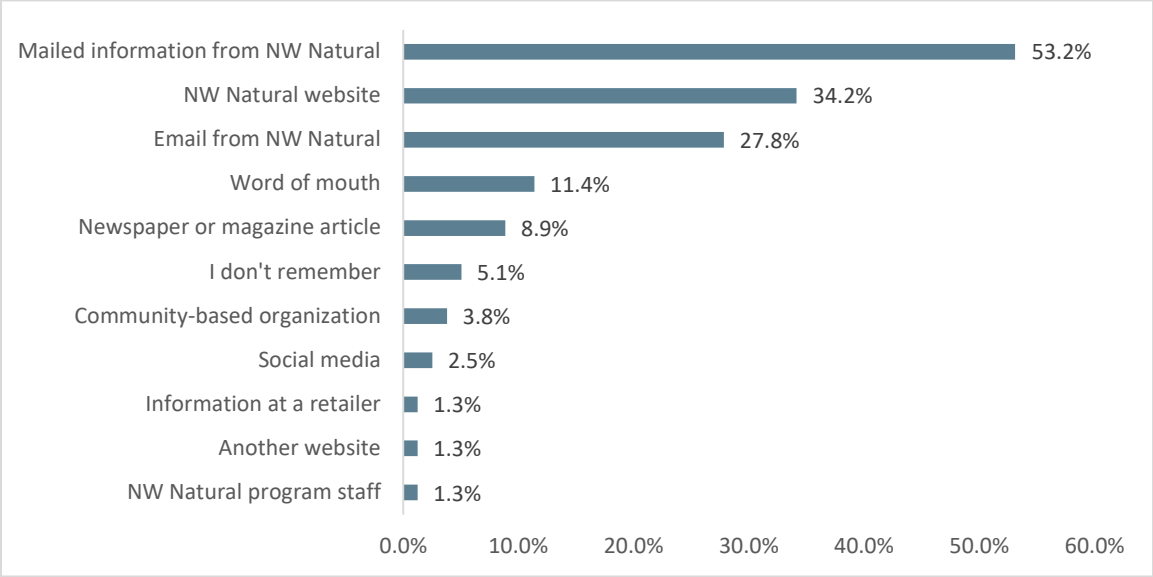
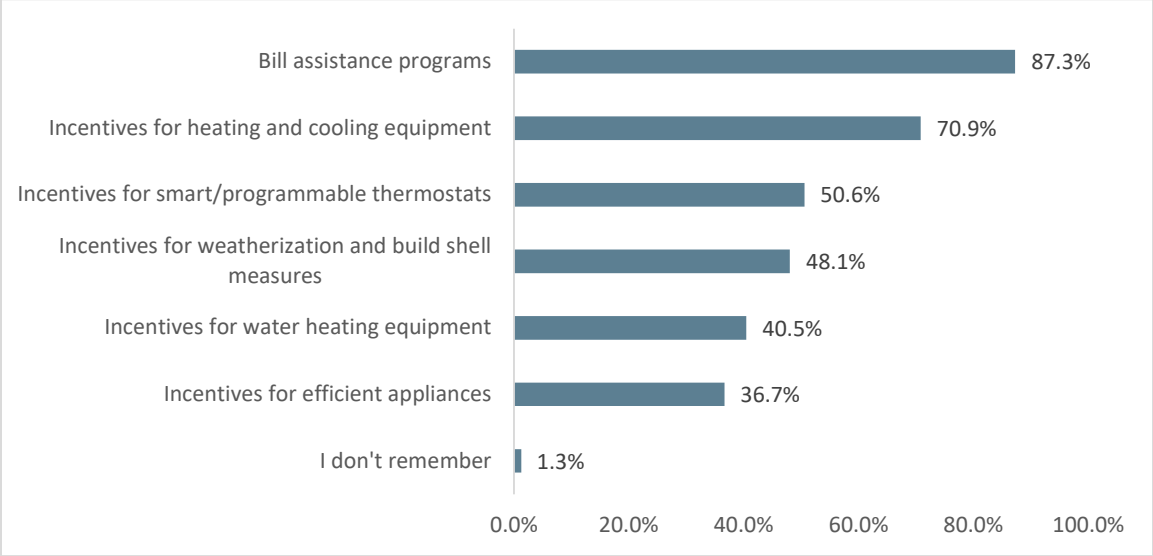


Figure 5-12: Program Awareness Levels (n=79)



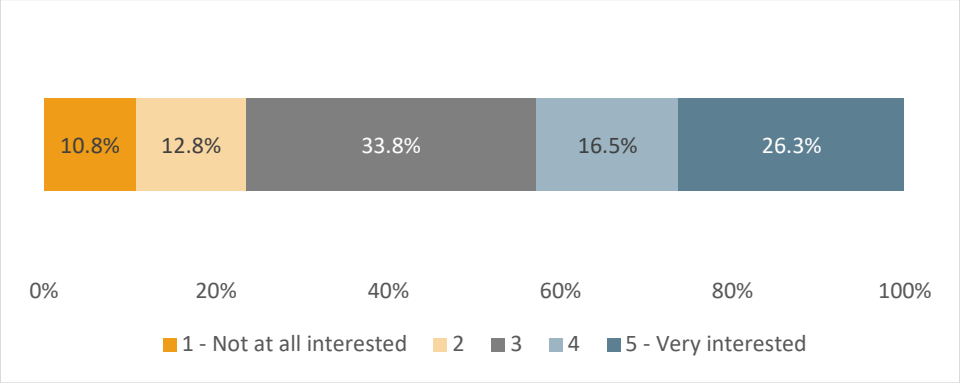
More than half of all non-participant respondents expressed interest in making energy efficient improvements to their home (61.7%, n=246). These respondents were most interested in weatherization and heating and cooling equipment updates (Table 5-6). Overall, 42.8% (n=171) indicated they were somewhat or very interested in participating in NW Natural's energy efficiency programs. ^

Respondents explained that the cost of equipment upgrades were the main factor preventing them from engaging in this type of program (51.0%, n=204); other reasons for not engaging included not needing new equipment, not having authority to make decisions, and needing more information about the program.

Table 5-6: Services Respondents are Interested In (n=246)

	%	n
Home weatherization	74.0%	182
Heating/cooling equipment	63.4%	156
Water heating equipment	44.3%	109
Smart/programmable thermostats	38.6%	95
Efficient appliances	36.6%	90
Windows	2.0%	5
Not sure	1.6%	4

Figure 5-13: Interest in NW Natural's Programs (n=400)



Respondents suggested NW Natural increases awareness of the programs through enhanced marketing, increased attendance at community events, and easier to understand application materials (n=55). Additionally, 50 respondents suggested NW Natural offer higher incentives and rebates. Together, these sets of comments suggest awareness of NW Natural's assistance for Low-Income is limited and many eligible customers do not realize they may qualify for free weatherization and heating equipment updates.

5.5.2 CURRENT ENERGY USAGE

About two-thirds of respondents believed their heating and/or cooling equipment are the largest energy consumer in their home (Figure 5-14). Most respondents fueled their homes with natural gas (82.0%, n=327). The age of respondents' heating system varied; one-third of respondents reported their heating system was less than 10 years old (32.6%, n=124), while half of respondents indicated their heating system was 10-20 years old or more than 20 years old (Figure 5-15). More than half of respondents had serviced their heating system in the last three years (59.3%, n=226) (Figure 5-16). Just over half of respondents have a programmable thermostat (53.9%, n=215); the remaining respondents either have a manual thermostat (17.7%, n=71), smart thermostat (21.8%, n=87), or are not sure (6.5%, n=26).

Figure 5-14: Largest Energy Consumers (n=399)

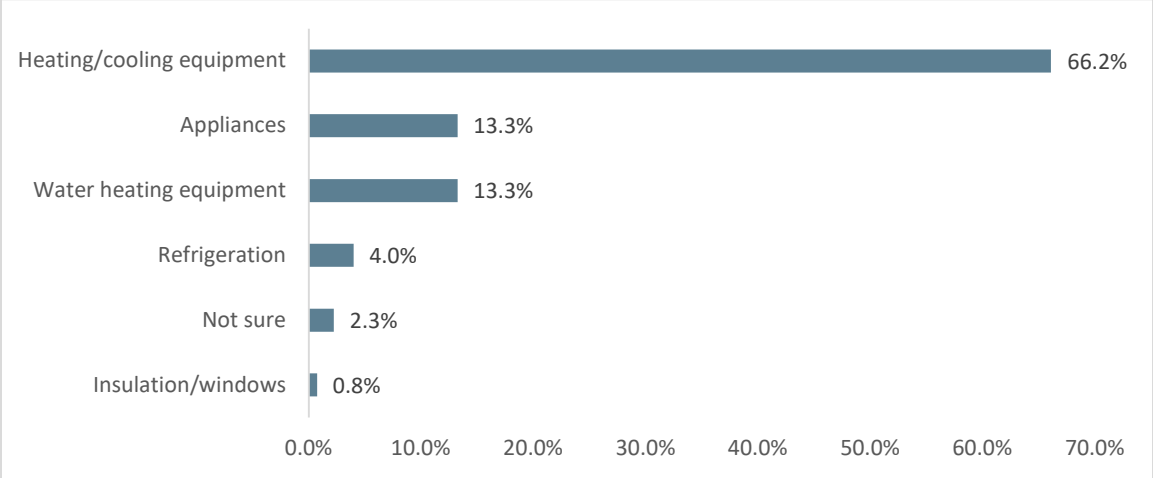


Figure 5-15: Age of Heating System (n=381)

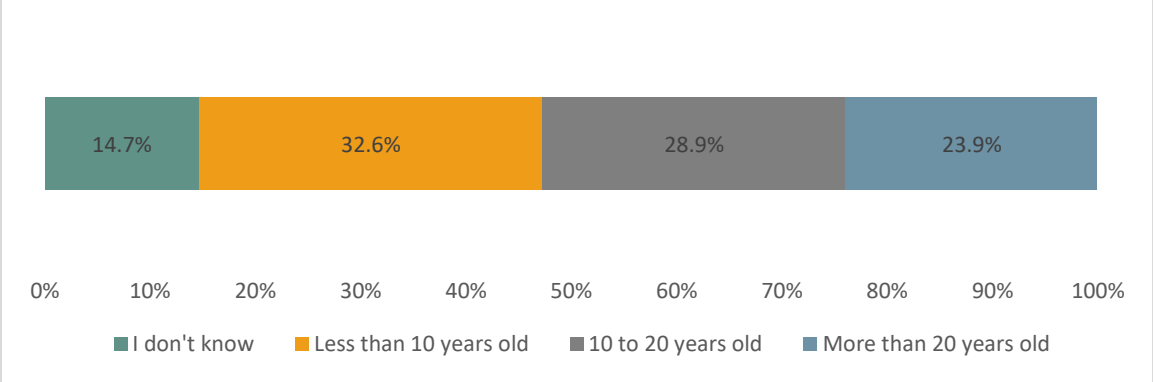
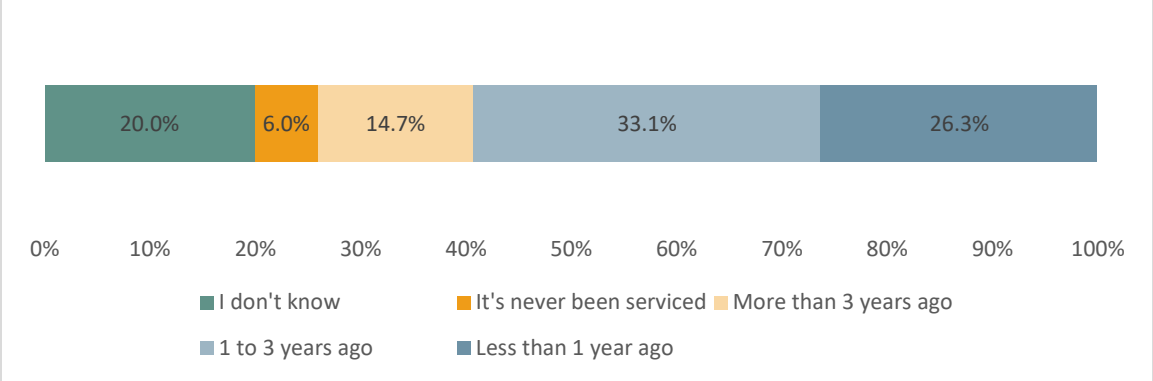


Figure 5-16: Time of Most Recent Heating System Service (n=381)



5.5.3 DEMOGRAPHICS

Table 5-5 describes the demographics of survey respondents. 285 respondents provided the data necessary to verify their eligibility for the NW Natural Low-Income program (annual household income is at or below 80% the area median income of their county); among these respondents 94.0% (n=268) qualified for the programs.

Table 5-7: Demographics (n varies)

Answer	%	Count
Homeownership (n=400)		
Own	79.8%	319
Rent	16.5%	66
Own and rent to someone else	0.3%	1
Prefer not to answer	3.5%	14
Home Type (n=397)		
Single-family house detached	83.4%	331
Single-family house attached to one or more other houses	11.8%	47
Mobile or manufactured home	2.3%	9
Apartment with 2 to 4 units	0.5%	2
Apartment with 5 or more units	0.8%	3
Prefer not to answer	1.3%	5
Building Age (n=317)		
Before 1950	16.4%	52
1950 to 1959	9.2%	29
1960 to 1969	7.3%	23
1970 to 1979	9.2%	29
1980 to 1989	5.7%	18
1990 to 1999	17.0%	54
2000 to 2009	19.6%	62
2010 to 2019	7.6%	24
2020 to Present	3.2%	10
I don't know	4.1%	13
Prefer not to answer	1.0%	3
Household Size (n=392)		
1 person	25.1%	99
2 people	31.7%	125
3 people	16.0%	63
4 people	7.3%	29
5 people	8.6%	34
6 people	5.1%	20
7 people	0.5%	2
8 or more people	0.5%	2
Prefer not to answer	5.3%	21
Education (n=387)		
Did not graduate high school	2.3%	9
High school graduate	18.4%	71
Associates degree, vocation/ technical school, or some college	32.0%	124
Four-year college degree	26.9%	104
Graduate or professional degree	13.7%	53
Prefer not to answer	6.7%	26
Race/Ethnicity (n=400)		

White or Caucasian	73.3%	293
Prefer not to answer	11.3%	45
Hispanic, Latino, or Spanish origin	8.0%	32
Black or African American	5.5%	22
East Asian (e.g. Chinese, Filipino, Asian Indian, Vietnamese, Korean, Japanese)	5.0%	20
American Indian or Alaska Native	2.8%	11
Native Hawaiian or Pacific Islander	0.5%	2
South Asian (e.g. Asian Indian, Pakistani, Bangladeshi)	0.3%	1
Middle Eastern or North African	0.3%	1
Jewish	0.3%	1
Mixed American	0.3%	1
Syrian	0.3%	1
Polish	0.3%	1

5.6 Process Conclusions and Recommendations

The following section details the Evaluators' conclusions and recommendations for the Low-Income programs.

1) **Conclusion 1: NW Natural's Low-Income program utilizes lenient qualification criteria and provides comprehensive measure coverage.** Stakeholders from across the interview groups – program staff, CAP Agency and CBO staff, and trade allies – remarked on NW Natural's comprehensive measure coverage and willingness to stretch the boundaries of the services they can provide. Not only did NW Natural modify the qualification criteria from 200% FPL to 80% AMI in response to requests by the CAP Agency, but they also expanded health and safety qualifying measures, allowing for more holistic coverage and home updates for customers. CAP agency and CBO staff noted that NW Natural's program has some of the most lenient and flexible qualification criteria – as compared to other similar programs – and participating trade allies indicated that the measures covered are thorough.

2) **Conclusion 2: Most participants and eligible non-participants participate in the CAP Agencies and CBO energy related bill assistance programs. Waitlist times for the program vary across agencies.** One CBO representative explained that they avoid waitlists by making their program invite-only, while other CBO representatives and CAP agency staff indicated their wait list times range from a few months to over a year.

3) **Conclusion 3: Non-participants respondents explained that the cost of equipment upgrades was the main factor preventing them from engaging in this type of program**, suggesting awareness of NW Natural's assistance for Low-Income is limited and many eligible customers do not realize they may qualify for free weatherization and heating equipment updates.

    Recommendation 1: Although wait lists for some of the weatherization and HVAC programs can be lengthy, CAP agency and CBO staff should continue to enroll existing

clients into this program to ensure comprehensive energy assistance, as more than half of all non-participant respondents expressed interest in making energy efficient improvements to their home.

4) **Conclusion 4: Workforce development issues limit program expansion**. Some CAP Agency representatives explained that workforce issues are their largest barrier to increased engagement. These representatives indicated that funds are available to help more customers, but they struggle to find qualified contractors. Representatives from across the CAP agencies and CBOs remarked that their existing auditors and contractors have been involved in the weatherization business for many years, but that they are concerned about the future longevity of the program due to the lack of new contractors and auditors. One CAP agency representative mentioned an internship program offered by Oregon Training Institute as a possible solution to this issue but noted the state needs more contractors.

   Recommendation 2: NW Natural should consider partnering with the Oregon Training Institute and other similar organizations to help offer more workforce development and training opportunities for future contractors and trade allies.

5) **Conclusion 5: CBO representatives underscored the importance of leveraging existing relationships in communities when promoting the program.**

   Recommendation 3: NW Natural can continue to strengthen their program by expanding their presence in the communities they serve through attendance at and sponsorship of community events. One of the CBO representatives also noted that having a formal contract and master services agreement has also been very helpful in ensuring the program remains funded.

6) **Conclusion 6: Satisfaction across stakeholder groups – CAP agency and CBO staff, contractors, and participants – was high.** Interview respondents highlighted NW Natural's communicativeness and willingness to answer questions, while most survey respondents indicated they would recommend the program to others and that they believe NW Natural is a very or extremely trustworthy source of information regarding energy savings in the home.

6 APPENDIX A: COST-EFFECTIVENESS TESTING

6.1 Summary

The Evaluators estimated the cost-effectiveness for the overall energy efficiency of programs, based on costs and savings estimates provided by NW Natural and their third-party implementers. This appendix provides the cost-effectiveness results, as well as a brief overview of the approach taken by the Evaluators. The tables below present the cost-effectiveness results for the most recent evaluation periods (Py2014-PY2017 and PY2018-PY2022).

Table 6-1: Cost-Effectiveness Results, PY2014-PY2017

Program	TRC	UCT	RIM	PCT	SCT
OLIEE	2.08	0.25	0.20	N/A	2.34
WALIEE	1.37	0.23	0.19	N/A	1.57
Total	**1.99**	**0.25**	**0.20**	**N/A**	**2.25**

Table 6-2: Cost-Effectiveness Results, PY2018-PY2022

Program	TRC	UCT	RIM	PCT	SCT
OLIEE	2.31	0.23	0.19	N/A	2.60
WALIEE	2.08	0.33	0.25	N/A	2.38
Total	**2.29**	**0.24**	**0.19**	**N/A**	**2.58**

The Evaluators benchmarked RIM tests for other recent Low-Income Weatherization programs and found NW Natural's RIM test results to be comparable with the average RIM test for other utilities (see Table 6-3). A low RIM test is expected for Low-Income programs because measures in these programs are usually provided free of charge to customers (e.g., incremental costs are zero), which increases the costs of the utility.

Table 6-3: RIM Test Benchmarking

Utility	Fuel Type	Program	Program Year	RIM
Utility 1	Electric	Income Eligible Single-Family	2022	0.29
Utility 1	Electric	Income Eligible Single-Family	2023	0.37
Utility 2	Electric	Income-Qualified Weatherization	2023	0.45
Utility 3	Electric	Income-Qualified Weatherization	2023	0.16
Utility 4	Gas	Residential Low-Income	2023	0.26
Utility 4	Electric	Residential Low-Income	2023	0.00
Utility 4	Gas	Residential Low-Income	2022	0.05
Utility 4	Electric	Residential Low-Income	2022	0.30
Average				**0.24**

6.2 Methods

The California Standard Practice Model was used as a guideline for the calculations, along with guidance from the 2020-2022 and 2023 Natural Gas Demand-Side Management (DSM) plans and the AR TRM V9.2. The cost-effectiveness analysis methods that were used in this analysis are among the set of standard methods used in this industry and include the Total Resource Cost Test (TRC), Utility Cost Test (UCT)[7], Ratepayer Impact Measure Test (RIM), Participant Cost Test (PCT) and Societal Cost Test (SCT). All tests weigh monetized benefits against costs. These monetized amounts are presented as Net Present Value (NPV) evaluated over the lifespan of the measure. The benefits and costs differ for each test based on the perspective of the test. The definitions below are taken from the California Standard Practice Manual.

The TRC measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs.

The UCT measures the net costs of a demand-side management program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the TRC benefits. Costs are defined more narrowly.

The PCT is the measure of the quantifiable benefits and costs to the customer due to participation in a program. Since many customers do not base their decision to participate in a program entirely on quantifiable variables, this test cannot be a complete measure of the benefits and costs of a program to a customer.

[7] The UCT is also referred to as the Program Administrator Cost Test (PACT).

The RIM test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. Rates will go down if the change in revenues from the program is greater than the change in utility costs. Conversely, rates or bills would go up if revenues collected after program implementation is less than the total costs incurred by the utility in implementing the program. This test indicates the direction and magnitude of the expected change in customer bills or rate levels.

The SCT test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs in the same way that the TRC measures these, but utilizes a societal discount rate, which is lower than the discount rate used for the TRC. The lower discount rate effectively assigns a higher net present value to program benefits that occur in the future.

A common misperception is that there is a single best perspective for evaluation of cost-effectiveness. Each test is useful and accurate, but the results of each test are intended to answer a different set of questions. The questions to be addressed by each cost test are shown in the table below.[8]

Table 6-4: Questions Addressed by the Various Cost Tests

Cost Test	Questions Addressed
Participant Cost Test (PCT)	▪ Is it worth it to the customer to install energy efficiency?
	▪ Is it likely that the customer wants to participate in a utility program that promotes energy efficiency?
Ratepayer Impact Measure (RIM)	▪ What is the impact of the energy efficiency project on the utility's operating margin?
	▪ Would the project require an increase in rates to reach the same operating margin?
Utility Cost Test (UCT)	▪ Do total utility costs increase or decrease?
	▪ What is the change in total customer bills required to keep the utility whole?
Total Resource Cost Test (TRC)	▪ What is the regional benefit of the energy efficiency project (including the net costs and benefits to the utility and its customers)?
	▪ Are all of the benefits greater than all of the costs (regardless of who pays the costs and who receives the benefits)?
	▪ Is more or less money required by the region to pay for energy needs?

Overall, the results of all five cost-effectiveness tests provide a more comprehensive picture than the use of any one test alone. The TRC and SCT cost tests address whether energy efficiency is cost-effective overall. The PCT, UCT, and RIM address whether the selection of measures and design of the program are balanced from the perspective of the participants, utilities, and non-participants. The scope of the benefit and cost components included in each test are summarized in the table below.[9]

[8] https://www.epa.gov/energy/understanding-cost-effectiveness-energy-efficiency-programs

[9] *Ibid*.

Table 6-5: Benefits and Costs Included in each Cost-Effectiveness Test

Test	Benefits	Costs
PCT (Benefits and costs from the perspective of the customer installing the measure)	▪ Incentive payments	▪ Incremental equipment costs
	▪ Bill Savings	▪ Incremental installation costs
	▪ Applicable tax credits or incentives	
UCT (Perspective of utility, government agency, or third party implementing the program	▪ Energy-related costs avoided by the utility	▪ Program overhead costs
	▪ Capacity-related costs avoided by the utility, including supply and distribution	▪ Utility/program administrator incentive costs
TRC (Benefits and costs from the perspective of all utility customers in the utility service territory)	▪ Energy-related costs avoided by the utility	▪ Program overhead costs
	▪ Capacity-related costs avoided by the utility, including supply and distribution	▪ Program installation costs
	▪ Additional resource savings	▪ Incremental measure costs
	▪ Monetized non-energy benefits as outlined by the TRM.	
RIM (Impact of efficiency measure on non-participating ratepayers overall)	▪ Energy-related costs avoided by the utility	▪ Program overhead costs
	▪ Capacity-related costs avoided by the utility, including supply and distribution	▪ Lost revenue due to reduced energy bills
		▪ Utility/program administrator installation costs

6.2.1 ECONOMIC INPUTS

The Evaluators used the avoided costs, discount rates, and other economic inputs provided by NW Natural for the cost benefit analysis.

Additionally, the table below outlines the discount rates, escalation rate and avoided costs used in the cost-effectiveness analysis.

Table 6-6: Economic Inputs for Cost-Effectiveness Analysis

Discount Rates	
Utility (TRC)	3.87%
Utility (UCT)	3.87%
Utility (RIM)	3.87%
Societal (SCT)	3.00%
Participant (PCT)	10.00%
Line Losses	
Line Losses	0.00%
Escalation rate	2.45%
Avoided Costs	
Avoided Energy ($/Therm)	$0.961

6.3 Arrearage and Disconnections Results

The table below displays the observed average differences in arrearages, disconnects, and disconnection notices between the matched treatment and control groups of each cohort. Data on arrearages is complete only for the latest evaluation period of customers in Oregon. On average, control customers accrued $97.98 more in annualized arrearages during 2023 than during 2017, while treatment customers on average accrued $115.00 less, resulting in a difference-in-difference savings of $212.97[10]. Assuming a participant discount rate of 10%, the NEB adder per participant is $21.30 for the arrearage reduction.

Additionally, the average number of disconnects and disconnection notices per customer decreased more in the treatment group than in the control group in the post-period year for every cohort with complete data except for Oregon customers during the PY2014-PY2017 evaluation period, where disconnects decreased more for control customers than treatment customers. However, the results for disconnects and disconnection notices were not statistically significant for any cohort.

Table 6-7: Arrearage and Disconnections Results

Statistic	Cohort	Difference in Annual Averages (Post - Pre)		Savings	Statistical Significance (alpha < .05)
		Control	Treatment		
Arrearages	EP3 (OR)	$97.98	$(115.00)	$ 212.97	Yes
Disconnects	EP2 (OR)	-0.026	-0.010	-0.016	No
Disconnects	EP3 (OR)	0.006	-0.015	0.021	No
Disconnection Notices	EP1 (OR)	0.268	-0.773	1.041	No
Disconnection Notices	EP2 (OR)	-0.429	-0.670	0.241	No
Disconnection Notices	EP3 (OR)	1.012	-0.693	1.705	No
Disconnection Notices	WA	0.468	0.143	0.325	No

[10] Annualized arrearage estimates were based on 90-day arrearage totals expected to increase at the same rate over the course of one year.

6.4 Program-Level Results

Sections below show results, benefits, costs and net benefits for the most recent evaluation periods (PY2014-PY2017and PY2018-PY2022).

6.4.1 COST-EFFECTIVENESS RESULTS FOR EVALUATED PROGRAM YEARS

The tables below outline the results for each test for both Low-Income programs.

Table 6-8: Cost-Effectiveness Results by Program, PY2014-PY2017

Program	TRC	UCT	RIM	PCT	SCT
OLIEE	2.08	0.25	0.20	N/A	2.34
WALIEE	1.37	0.23	0.19	N/A	1.57
Total*	**1.99**	**0.25**	**0.20**	**N/A**	**2.25**

*Sums may differ due to rounding.

Table 6-9: Cost-Effectiveness Benefits by Program, PY2014-PY2017

Program	TRC Benefits	UCT Benefits	RIM Benefits	PCT Benefits	SCT Benefits
OLIEE	$2,165,512	$2,146,214	$2,146,214	$9,123,859	$2,436,282
WALIEE	$187,075	$186,031	$186,031	$803,001	$214,087
Total*	**$2,352,587**	**$2,332,245**	**$2,332,245**	**$9,926,860**	**$2,650,370**

*Sums may differ due to rounding.

Table 6-10: Cost-Effectiveness Costs by Program, PY2014-PY2017

Program	TRC Costs	UCT Costs	RIM Costs	PCT Costs	SCT Costs
OLIEE	$1,043,227	$8,582,884	$10,729,099	$0	$1,043,227
WALIEE	$136,537	$809,253	$995,284	$0	$136,537
Total*	**$1,179,764**	**$9,392,137**	**$11,724,382**	**$0**	**$1,179,764**

*Sums may differ due to rounding.

Table 6-11: Cost-Effectiveness Net Benefits by Program, PY2014-PY2017

Program	TRC Net Benefits	UCT Net Benefits	RIM Net Benefits	PCT Net Benefits	SCT Net Benefits
OLIEE	$1,122,285	-$6,436,670	-$8,582,884	$9,123,859	$2,436,282
WALIEE	$50,538	-$623,222	-$809,253	$803,001	$214,087
Total*	**$1,172,823**	**-$7,059,892**	**-$9,392,137**	**$9,926,860**	**$2,650,370**

*Sums may differ due to rounding.

Table 6-12: Cost-Effectiveness Results by Program, PY2018-PY2022

Program	TRC	UCT	RIM	PCT	SCT
OLIEE	2.31	0.23	0.19	N/A	2.60
WALIEE	2.08	0.33	0.25	N/A	2.38
Total*	**2.29**	**0.24**	**0.19**	**N/A**	**2.58**

*Sums may differ due to rounding.

Table 6-13: Cost-Effectiveness Benefits by Program, PY2018-PY2022

Program	TRC Benefits	UCT Benefits	RIM Benefits	PCT Benefits	SCT Benefits
OLIEE	$3,360,868	$3,335,947	$3,335,947	$15,562,557	$3,781,270
WALIEE	$300,636	$299,123	$299,123	$961,630	$343,856
Total*	**$3,661,504**	**$3,635,070**	**$3,635,070**	**$16,524,188**	**$4,125,126**

*Sums may differ due to rounding.

Table 6-14: Cost-Effectiveness Costs by Program, PY2018-PY2022

Program	TRC Costs	UCT Costs	RIM Costs	PCT Costs	SCT Costs
OLIEE	$1,455,276	$14,509,972	$17,845,919	$0	$1,455,276
WALIEE	$144,593	$893,157	$1,192,280	$0	$144,593
Total*	**$1,599,869**	**$15,403,128**	**$19,038,199**	**$0**	**$1,599,869**

*Sums may differ due to rounding.

Table 6-15: Cost-Effectiveness Net Benefits by Program, PY2018-PY2022

Program	TRC Net Benefits	UCT Net Benefits	RIM Net Benefits	PCT Net Benefits	SCT Net Benefits
OLIEE	$1,905,592	-$11,174,024	-$14,509,972	$15,562,557	$3,781,270
WALIEE	$156,042	-$594,033	-$893,157	$961,630	$343,856
Total*	**$2,061,634**	**-$11,768,058**	**-$15,403,128**	**$16,524,188**	**$4,125,126**

*Sums may differ due to rounding.

7 APPENDIX B: UNIT ENERGY SAVINGS

Table 7-1 provides UES (or deemed) Therms savings for measures found in project documentation or program tracking data.

The Evaluators provide deemed measure savings to assist NW Natural with savings estimates, which may be useful in future program years. If the program measures change substantially, the whole-home billing analysis results from the evaluated periods in this report may not provide accurate estimates of whole-home savings in future program years.

The Evaluators used various sources to calculate deemed savings estimates such as the RTF, TRMs, and previous studies. The Evaluators identified separate efficiency levels for each measure where applicable and assigned savings using the sources mentioned in Table 7-1. The Evaluators then took an average of the Unit Energy Savings across different measure efficiency levels for the projects that had complete data. This resulted in average household level savings per measure which the Evaluators then used to assign to the sample based on document verification findings. The average savings per household using the deemed savings method resulted in 79.42 Therms. However, the Evaluators found 96 projects that did not provide enough specification information to calculate savings. Excluding these projects causes the average savings per household to increase to 119.34 Therms.

Table 7-1: Deemed Measure Savings, TRM-based

Measure	Efficiency	Savings % of Sampled Projects	Measure Unit	Measure Unit Average	Unit Energy Savings (Therms)	TRM Source
Attic/Ceiling Insulation	R0 to R38	12.45%	SQFT	799	164.1	RTF: ResSFWx_v6_2
	R0 to R49	5.24%	SQFT	843	176.0	RTF: ResSFWx_v6_2
	R11 to R38	2.62%	SQFT	943	65.2	RTF: ResSFWx_v6_2
	R11 to R49	3.28%	SQFT	800	58.0	RTF: ResSFWx_v6_2
	R19 to R38	1.31%	SQFT	825	24.3	RTF: ResSFWx_v6_2
	R19 to R49	0.66%	SQFT	676	22.6	RTF: ResSFWx_v6_2
	R30 to R49	0.98%	SQFT	775	12.6	RTF: ResSFWx_v6_2
Direct Vent Space	Unknown	Unknown	Unknown	Unknown	81.7	Avisa TRM
Duct	R0 to R11	9.44%	SQFT	206	35.8	RTF: ResSFWx_v6_2
Duct Sealing	Unknown	13.94%	CFM50 reduction	67	44.1	Illinois TRM Algorithm 5.3.4
Faucet Aerators	1.5 GPM	0.00%	Efficiency Value	Unknown	1.5	AR TRM V9

Floor Insulation	R0 to R19	1.61%	SQFT	726	32.2	RTF: ResSFWx_v6_2
	R0 to R25	6.85%	SQFT	1,115	53.9	RTF: ResSFWx_v6_2
	R0 to R30	7.85%	SQFT	1,018	51.7	RTF: ResSFWx_v6_2
Furnace Tune Up	Unknown	0.74%	Unknown	Unknown	14.0	Illinois TRM
HE Water Heater	Not ES, No Gas line Upgrade	0.14%	Efficiency Value	0.91	32.6	RTF: ResGasWH_v3_2
	Not ES, with Gas Line Upgrade	0.57%	Efficiency Value	0.91	32.6	RTF: ResGasWH_v3_2
HE Windows	Single Pane to Class 30	2.08%	Quantity of Windows	146	51.3	RTF: ResSFWx_v6_2
	Single Pane to Class 22	2.77%	Quantity of Windows	4	1.6	RTF: ResSFWx_v6_2
High Efficiency Furnace	CEE Tier 2	7.81%	Efficiency Value	0.95	42.9	RTF: ResESGasFurnaces_v2_1
	CEE Tier 3	6.28%	Efficiency Value	0.97	54.9	RTF: ResESGasFurnaces_v2_1
Hot Water Pipe	Unknown	0.21%	Foot of Insulation	Unknown	2.0	Illinois TRM Table 5.4.1
Infiltration	CFM50 reduction	5.38%	SQFT	1,217	13.9	RTF: ResSFWx_v6_2
Thermal Door	Unknown	0.19%	Unknown	Unknown	22.0	Illinois TRM
Wall	R0 to R11	7.59%	SQFT	694	28.8	RTF: ResSFWx_v6_2

Table 7-2 provides deemed measure savings and effective useful life (EUL) based on average measure efficiency values observed for sampled projects that were part of the document-based verification.

Table 7-2: Deemed Measure Savings (Average Efficiency), TRM-based

Measure	Measure Unit	Measure Unit Average	Unit Energy Savings (Therms)	EUL	EUL Source
Attic/Ceiling Insulation	SQFT	816	74.7	45	RTF
Direct Vent Space Heater	Unknown	Unknown	81.66	20	AR TRM V9
Duct Insulation	SQFT	206	35.8	45	RTF
Duct Sealing	CFM50 reduction	67	44.1	20	RTF
Faucet Aerators	Efficiency Value	Unknown	1.5	10	AR TRM V9
Floor Insulation	SQFT	1,036	45.9	45	RTF
Furnace Tune-Up	Unknown	Unknown	14.0	5	NY TRM V11
HE Water Heater	Efficiency Value	0.91	32.6	15	RTF
HE Windows	Quantity of Windows	150	52.7	25	RTF
High Efficiency Furnace	Efficiency Value	0.96	43.4	20	RTF
Hot Water Pipe Insulation	Foot of Insulation	Unknown	2.0	20	PGW TRM 2023
Infiltration	SQFT	1,217	13.9	15	RTF
Thermal Doors	Unknown	Unknown	22.0	40	RTF
Wall Insulation	SQFT	694	28.8	45	RTF

Table 7-3 provides deemed measure savings resulting from the billing analyses. The regression savings were extrapolated to TMY X data using the latest available years of data (2018-2023). Extrapolating to TMY X ensures that savings are weather normalized to average expected weather in the region[11].

Table 7-3: Deemed Measure Savings, Billing Analysis

Measure	Measure Unit	Unit Energy Savings (Therms)	Source
Whole-home Cohort (PY2018-PY2022)	Home	104.0	2024 Billing Analysis
High Efficiency Furnace (PY2018-PY2022)	Unit	116.3	2024 Billing Analysis

[11] The Evaluators weighted TMY X weather (HDD) by the number of participants belonging to each of the weather stations utilized in the billing analysis.

8 APPENDIX C: DATA COLLECTION RECOMMENDATIONS

To determine more accurate savings for individual measures in future program years, the Evaluators recommend collecting information detailed in Table 8-1.

In general, the following data collection fields are useful fields to collect for every measure: measure quantity, baseline operating conditions and efficiency values, efficient measure operating conditions and efficiency values, measure descriptions, make and model number for baseline equipment, make and model number for efficient measure equipment, relevant square footage (e.g., whole home, conditioned/unconditioned space, amount installed), heating type, and cooling type.

Table 8-1: Recommended Data Collection Information

Measure	Recommended Data Collection
Ceiling Insulation	Square footage of installed insulation, baseline efficiency and installed efficiency (R-values)
Direct Vent Space Heater	Quantity, make and model number
Duct Insulation	Conditioned square footage of home, baseline efficiency and installed efficiency (R-values), heating and cooling type
Duct Sealing	Measure specification information (e.g., pre/post duct leakage rate), gas furnace efficiency (AFUE)
Faucet Aerators	Quantity, baseline efficiency, installed efficiency
Floor Insulation	Square footage of installed insulation, baseline efficiency, installed efficiency (R-values)
Furnace Tune-Up	Quantity, make and model number, furnace input capacity pre tune-up (Btuh), efficiency of furnace before and after tune-up
HE Water Heater	Quantity, make and model number
HE Windows	Quantity, baseline and efficient window type (e.g., single vs. double pane) baseline and efficient U-values, square footage of area associated with window install
High Efficiency Furnace	Quantity, make and model number
Hot Water Pipe Insulation	Linear footage of installed insulation, thickness of pipe insulation, inside circumference of the pipe, baseline efficiency and installed efficiency (R-values)
Infiltration	Measure specification information (e.g., CFM50 reduction), square footage of affected areas, heating and cooling type
Thermal Doors	Quantity, baseline and efficient door type & installed efficiency (R-Values), square footage of area associated with thermal door install
Wall Insulation	Square footage of installed insulation, baseline efficiency, installed efficiency (R-values)

9 APPENDIX D: SURVEY COLLECTION INSTRUMENTS

9.1 Participant Survey

Table 9-1: Overview of Data Collection Activity

DESCRIPTOR	THIS INSTRUMENT
Instrument Type	Survey
Estimated Time to Complete	10 Mins
Population Description	participants

Table 9-2: Research Objectives

RESEARCH QUESTION FROM PROPOSAL
Is customer service of high quality, timely, and effective?
Are marketing plans implemented per design and effective?
Are program materials effective and complete?
Are rebates/incentives appropriate for meeting program goals?
What are the market barriers that impede program reach?
Is the program reaching the intended hard to reach customers?
Are there remaining customers that qualify for the program have issues or barriers with participating in these programs?

9.1.1 RECRUITMENT SCRIPTS

9.1.1.1 Email Recruitment (Initial & Reminder 1 & 2)

SUBJECT LINE: NW Natural wants your feedback!

Dear **${e://Field/CONTACT_NAME}**,

NW Natural wants to better understand customers' experience with its energy-efficiency programs, potential barriers to participate in these programs, and general awareness of energy-efficiency offerings. NW Natural is evaluating all of this through ADM Associates (ADM), a national research firm specializing in energy research and program evaluation, which is also the sender of this email.

NW Natural is asking for your help to improve its programs by completing the survey linked below. The survey should take about 10 to 15 minutes to complete, and you will receive a **$10 electronic gift card** as a thank you for your time. Your responses will be completely confidential.

Click the link below to access the survey:
[Survey link]
Or copy and paste the URL below into your internet browser:
[Survey link]

We value your time and feedback. If you have questions or require assistance using the link, please reach out to us at surveyinfo@admenergy.com. If you have questions about how the data will be used, please contact CONTACT AT NW Natural.

Best,

ADM Associates / Contractor to Northwest Natural

Note: ADM conducts research to support research and evaluation in the energy sector. Survey data is not shared with third parties for marketing purposes. Our full privacy statement is available here: admenergy.com/privacy. If you would prefer to opt out of future emailing, follow the link provided: ${l://OptOutLink?d=Click here to unsubscribe}

9.1.2 SURVEY INSTRUMENT

Welcome! Thank you for taking this survey to tell us about your participation in NW Natural's energy-efficiency programs. Your feedback is very important to us and will help us improve programs for our customers. This survey should take 10 to 15 minutes. Your responses are confidential and will be used for research purposes only. If you have questions about how we treat collected data, please see ADM's privacy police at *https://www.admenergy.com/privacy*.

Once you have entered a response for each question, use the arrow at the bottom right of the screen to get to the next question.

9.1.2.1 Awareness

1. Our records indicate that you received energy-efficient equipment improvements through NW Natural at **[ADDRESS]**, in collaboration with your local community agency, in 2023. Is that correct? Upgrades may have included a new gas furnace, new insulation, and/or other energy-related improvements.
    1. Yes
    2. No, I received upgrades BUT my address is incorrect (Please provide correct address) **[OPEN-ENDED]**
    3. No, I did not receive any upgrades **[TERMINATE]**

2. How did you first learn about the NW Natural energy-efficiency program? Select all that apply **[MULTI-SELECT]**
    1. NW Natural mailer or bill insert
    2. NW Natural website
    3. NW Natural email
    4. Local Community Action Agency
    5. Latino Built
    6. African American Alliance for Homeownership (AAAH)
    7. Oregon Energy Fund
    8. Newspaper or magazine
    9. Radio
    10. Television

11. Internet search
12. Social media (e.g. Facebook, Instagram, Twitter/X, Tik Tok, etc.)
13. Contractor
14. Word of mouth (friend, family, colleague, neighbor, etc.)
15. Other – please explain **[OPEN-ENDED]**
16. I don't know

3. Did you receive any informational brochures or materials about the energy-efficiency program from NW Natural or your local community agency?
    1. Yes
    2. No

[DISPLAY IF Q3=1]

4. What type of equipment and/or services did the brochure cover? **[OPEN ENDED]**

[DISPLAY IF Q3=1]

5. How effective were those materials in getting you to think about purchasing more efficient equipment and/or upgrading your existing equipment? **[SCALE = 1 (NOT AT ALL) TO 5 (EXTREMELY)]**

[DISPLAY IF Q5=4, 5]

6. What did you find effective about those materials?

7. How could the materials have been improved to be more effective?

9.1.2.2 CAP Agency

In this section, we'd like to learn more about your experience working with the community agency that installed your energy-efficiency improvements.

8. How did you find the community action agency that installed your energy-efficiency improvements?
    1. Through a personal contact (friend, family, colleague, neighbor, etc.)
    2. Internet search
    3. Through another community agency (please describe) **[OPEN ENDED]**
    4. Other (please describe) **[OPEN ENDED]**

9. How did the agency describe the program to you and motivate you to apply? **[OPEN ENDED]**

10. Before applying for the program, did you have any concerns about the program or the energy-efficiency improvements?
    1. Yes
    2. No

[DISPLAY if Q10=1]

11. What were these concerns? **[OPEN ENDED]**

[DISPLAY if Q10=1]

12. How did the agency address your concerns? **[OPEN ENDED]**

9.1.2.3 Participation

13. Why did you decide to participate in the program? **[OPEN ENDED]**

14. When thinking about making energy-efficiency improvements or purchases, what factors, if any, do you consider when making your decision? **[OPEN ENDED]**

15. Please rank the following reasons you might consider when making improvements to your home, in order of importance to you:
    1. Increase your home's energy efficiency
    2. Improve your comfort in your home
    3. Improve your health and safety in your home
    4. Increase home value

9.1.2.4 Assessment

16. As part of your participation in the program, you received an energy assessment of your home. Do you remember receiving this assessment?
    1. Yes
    2. No
    3. I don't remember

[DISPLAY IF Q16=1]

17. After the assessment, did the assessor provide you with a list of findings and recommendations for home improvements?
    1. Yes
    2. No
    3. I don't remember

[DISPLAY IF Q16=1]

18. Were there any recommendations from your assessment that you **DID NOT** act on?
    1. Yes. Please explain **[OPEN ENDED]**
    2. No
    3. I don't remember

[DISPLAY IF Q19=1]

19. Why did you choose not to act on those recommendations? **[OPEN ENDED]**

[DISPLAY IF Q16=1]

20. How satisfied are you with each of the following? **SCALE: 1=STRONGLY DISSATISFIED, 2=SOMEWHAT DISSATISFIED, 3=NEITHER SATISFIED NOR DISSATISFIED, 4=SOMEWHAT SATISFIED, 5=STRONGLY SATISFIED]**
    1. The professionalism of the assessor

2. The thoroughness of the assessment
3. The recommendations provided in the assessment
4. The assessment overall

[DISPLAY IF Q20<3]

21. You indicated some dissatisfaction, please explain. **[OPEN-ENDED]**

9.1.2.5 Contractor

In this section, we will ask you about your experience with the contractor who made the energy-efficiency improvements to your home.

22. How did you find the contractor who installed the energy-efficiency improvements?
    1. NW Natural representative referred me to the contractor
    2. Community agency representative referred me to the contractor
    3. The contractor was someone I've worked with before
    4. Through a personal contact (friend, family, colleague, neighbor, etc.)
    5. Internet search
    6. Other – please describe **[OPEN-ENDED]**
    7. I don't know

23. Please rate your agreement with the following statements regarding your experience with your contractor **[SCALE: 1=STRONGLY DISAGREE, 2=SOMEWHAT DISAGREE, 3=NEITHER AGREE NOR DISAGREE, 4=SOMEWHAT AGREE, 5=STRONGLY AGREE]**
    1. The contractor was courteous
    2. The contractor was professional
    3. The work was scheduled in a reasonable amount of time
    3. The time it took to complete the work was reasonable

[DISPLAY IF Q23<3]

24. You indicated some disagreement. Why do you disagree? **[OPEN-ENDED]**

9.1.2.6 Equipment

Next, we would like to confirm the type of equipment you received from the energy-efficiency program.

25. NW Natural records say that you received the following equipment and/or improvements. Is this correct? **[OPTIONS: Yes, No, Don't know]**
    1. Heating and cooling equipment (e.g. furnace, fireplace, HVAC system)
    2. Thermostat(s)
    3. Weatherization improvements (insulation, duct sealing, etc.)
    4. Other – please specify **[OPEN-ENDED]**

26. Are these improvements still installed and working?
    1. Yes
    2. No

[DISPLAY IF Q26=2]

27. What happened to the improvements that are no longer installed and/or working? **[OPEN ENDED]**

28. Were there additional energy-efficiency improvements you wanted, but did not receive? Please describe.
    1. No
    2. Yes **[OPEN ENDED]**

9.1.2.7 Satisfaction

In this section, we will ask about your overall satisfaction with the program.

29. Please rate your level of satisfaction with the following **[SCALE: 1=NOT AT ALL SATISIFED, 2=SOMEWHAT DISSATISFIED, 3=NEITHER SATISFIED NOR DISSATISFIED, 4=SOMEWHAT SATISFIED, 5=VERY SATISFIED]**
    1. The amount of the rebate you received
    2. The time it took to receive your rebate
    3. Your experience with the program overall
    5. NW Natural as your natural gas provider

[DISPLAY IF Q29<3]

30. You expressed some dissatisfaction. Why are you dissatisfied? **[OPEN-ENDED]**

31. Would you say that your participation in the energy-efficiency program has…
    1. Greatly decreased your satisfaction with NW Natural
    2. Somewhat decreased your satisfaction NW Natural
    4. Somewhat increased your satisfaction with NW Natural
    5. Greatly increased your satisfaction with NW Natural

32. How likely are you to recommend the energy-efficiency program to others?
    1. Not at all likely
    2. Somewhat likely
    3. Moderately likely
    4. Very likely
    5. Extremely likely

33. How trustworthy is NW Natural as a source of information about saving energy in your home?
    1. Not at all trustworthy
    2. Somewhat trustworthy
    3. Moderately trustworthy
    4. Very trustworthy
    5. Extremely trustworthy

34. Is there any other feedback you would like to provide to NW Natural and/or the community agency you worked with?
    1. No
    2. Yes **[OPEN ENDED]**

9.1.2.8 Demographics and Residence Characteristics

This last set of questions are about your home.

35. Do you rent or own your home?
    1. Own
    2. Rent
    3. Own, and rent out to someone else
    4. Prefer not to answer

36. Which of the following best describes your home?
    1. Single-family home
    2. Manufactured or mobile home
    3. Duplex or townhome
    4. Apartment or condominium
    5. Other – please specify **[OPEN-ENDED]**
    4. Prefer not to answer

37. Approximately when was your home built?
    1. Before 1960
    2. 1960 to 1979
    3. 1980 to 1989
    4. 1990 to 1999
    5. 2000 to 2009
    6. 2010 or later
    7. I don't know
    8. Prefer not to answer

38. About how many square feet is your home? If you are unsure, an estimate is okay.
    1. Less than 1,000 square feet
    2. 1,000 to 1,999 square feet
    3. 2,000 to 2,999 square feet
    4. 3,000 to 3,999 square feet
    5. 4,000 square feet or more
    6. I don't know
    7. Prefer not to answer

39. What is your age?
    1. 18 to 24
    2. 25 to 34

3. 35 to 44
4. 45 to 54
5. 55 to 64
6. 65 to 74
7. 75+
8. Prefer not to answer

40. Which of the following best describes you? Please select all that apply **[MULTI-SELECT]**
    1. American Indian or Alaska Native
    2. East Asian (e.g. Chinese, Filipino, Asian Indian, Vietnamese, Korean, Japanese)
    3. South Asian (e.g. Asian Indian, Pakistani, Bangladeshi)
    4. Black or African American
    5. Hispanic, Latino or Spanish origin
    6. Native Hawaiian or Pacific Islander
    7. Middle Eastern or North African
    8. White or Caucasian
    9. A race, ethnicity or origin not listed above– please specify **[OPEN-ENDED]**
    10. Prefer not to answer

41. What is the highest level of education you have completed?
    1. High school graduate or GED
    2. Associates degree, vocational/technical school, or college
    3. Four-year college degree
    4. Graduate or professional degree
    98. I don't know
    99. Prefer not to answer

42. What county do you live in?
    1. Benton, OR
    2. Clackamas, OR
    3. Clatsop, OR
    4. Columbia, OR
    5. Coos, OR
    6. Hood River, OR
    7. Lane, OR
    8. Lincoln, OR
    9. Linn, OR
    10. Marion-Polk, OR
    11. Multnomah, OR
    12. Washington, OR
    13. Yamhill, OR
    14. Clark, WA

43. Including yourself, how many people live in your home year-round?

1. 1 person
2. 2 people
3. 3 people
4. 4 people
5. 5 people
6. 6 people
7. 7 people
8. 8 or more people
9. Prefer not to answer

44. Including all money earned from wages, salaries, tips, commissions, workers' compensation, unemployment insurance, child support, or other sources, did your household make more than the following amount of money in 2023? **[MATRIX OPTIONS: The same amount or less, More, I don't know]**
    1. **IF Benton, OR** -- $108,000
    2. **IF Clackamas, OR** -- $118,000
    3. **IF Clatsop, OR** -- $92,300
    4. **IF Columbia, OR** -- $118,000
    5. **IF Coos, OR** -- $80,900
    6. **IF Hood River, OR** -- $97,900
    7. **IF Lane, OR** – $89,100
    8. **IF Lincoln, OR** -- $80,900
    9. **IF Linn, OR** -- $84,900
    10. **IF Marion-Polk, OR** -- $91,300
    11. **IF Multnomah, OR** -- $118,000
    12. **IF Washington, OR** -- $118,000
    13. **IF Yamhill, OR** -- $118,00
    14. **IF Clark, WA** -- $94,400

9.1.2.9 Thank You!

Thank you for taking time today to complete this survey. As stated in the email, we are providing a **$10 electronic gift card** as a thank you for your responses. You should receive this gift card in the next 3 to 5 business days; the email will be from Tango Rewards. The email address we have on file for you is **[EMAIL]**. Please confirm this information.

1. Yes, please send my electronic gift card to the above email address
2. No, please send my electronic gift card to the following email address **[OPEN-ENDED]**

9.2 Non-Participant Survey

Table 9-3 Overview of Data Collection Activity

DESCRIPTOR	THIS INSTRUMENT

Instrument Type	Survey
Estimated Time to Complete	10 Mins
Population Description	Nonparticipants

Table 9-4 Research Objectives

RESEARCH QUESTION FROM PROPOSAL
Is customer service of high quality, timely, and effective?
Are marketing plans implemented per design and effective?
Are program materials effective and complete?
Are rebates/incentives appropriate for meeting program goals?
What are the market barriers that impede program reach?
Is the program reaching the intended hard to reach customers?
Are there remaining customers that qualify for the program have issues or barriers with participating in these programs?

9.2.1 RECRUITMENT SCRIPTS

9.2.1.1 Email Recruitment (Initial & Reminder 1 & 2)

SUBJECT LINE: NW Natural wants your feedback!

Dear **${e://Field/CONTACT_NAME}**,

NW Natural hired ADM Associates, an independent research and evaluation firm, to gather feedback about its services and programs from residential customers like you. We would like to hear from 200 people by **[DATE TBD]**. Can you be one of those who help us reach that goal by answering a few quick questions about your experience with NW Natural? The survey should take about **10 minutes**. After you complete the survey, we will send you a **$10 e-gift card** that can be used at a variety of retailers as our way of saying thanks.

Your responses will be kept anonymous and completely confidential.

Click the link below to access the survey:
[Survey link]
Or copy and paste the URL below into your internet browser:
[Survey link]

We value your time and feedback. If you have questions or require assistance using the link, please reach out to us at surveyinfo@admenergy.com. If you have questions about how the data will be used, please contact CONTACT AT NW NATURAL.

Kind Regards,

ADM Associates / Contractor to NW Natural

Note: ADM conducts research to support research and evaluation in the energy sector. Survey data is not shared with third parties for marketing purposes. Our full privacy statement is available here: admenergy.com/privacy. If you would prefer to opt out of future emailing, follow the link provided: ${l://OptOutLink?d=Click here to unsubscribe}

9.2.2 SURVEY INSTRUMENT

9.2.2.1 Introduction

Thank you for agreeing to provide your feedback about your experience with NW Natural's services and programs. To start, we have a few questions about your awareness of NW Natural's programs and services. Your feedback is very important to us and will help us improve programs for customers like you. This survey should take 10-15 minutes.

Your responses are confidential and will be used for research purposes only. If you have questions about how we treat collected data, please see ADM's privacy policy at admenergy.com/privacy.

9.2.2.2 Screening

Q2. According to our records, NW Natural provides natural gas to your residence at [ADDRESS]. Is that correct?

1. Yes
2. Yes, but address is incorrect **[OPEN-ENDED: CORRECT ADDRESS]**
3. No **[TERMINATE]**

Q3. We understand that it is not always possible to make improvements to your home. Which of the following best describes your authority to make decisions?

1. No authority – as a renter, I am not allowed to make improvements **[TERMINATE]**
2. Some authority – as a renter, I am allowed to make some improvements
3. Full authority – I am the owner
4. Full authority – as part of my rental agreement, I am required to maintain/repair the home

Q4. To the best of your knowledge, have you replaced or upgraded equipment that requires gas, in the last three years? This could have been heating/cooling equipment, weatherization improvements (eg. insulation, duct sealing, etc.), or water heating equipment.

1. Yes
2. No
3. I don't know

[DISPLAY IF Q3=1]

Q5. What types of equipment or improvements did you replace in the last three years? Select all that apply **[MULTI-SELECT]**

1. Heating and cooling equipment (e.g. furnace, fireplace, HVAC system)
2. Efficient appliances (e.g. washer, dryer, range)
3. Thermostat(s)

4. Weatherization improvements (e.g. insulation, duct sealing, etc.)
5. Water heating equipment
7. Other – please specify [OPEN-ENDED]

[DISPLAY IF Q3=1]

Q6. Did you receive an incentive from NW Natural for any of that equipment?
1. Yes **[SKIP TO END, TERMINATE]**
2. No
3. Don't know

Q7. Have you participated in a NW Natural-sponsored bill assistance program?
1. Yes
2. No

Q8. Why haven't you participated in any of NW Natural's programs? Select all that apply **[MULTI-SELECT]**
1. I have not needed to replace any of my gas equipment or make weatherization improvements
2. I did not know enough about the programs and incentives
3. Energy savings from the equipment replacements or improvements was not worth the trouble
4. Too much time or trouble to receive the incentives
5. Prefer not to work with NW Natural
6. Incentives are not high enough to offset the cost of high-efficiency equipment, compared to standard-efficiency equipment
7. I am financially able to make the improvements without the incentives
8. I don't have the authority to participate in any NW Natural programs
9. Other – please specify **[OPEN-ENDED]**
10. I don't know

9.2.2.3 Program Awareness

[ASK ALL]

Q9. Before today, had you heard that NW Natural offers a weatherization (e.g. insulation, duct sealing, air sealing, etc.) and furnace-replacement program in collaboration with local community agencies?
1. Yes
2. No

[ASK IF Q9 =1, Yes]

Q10. How did you learn about NW Natural's weatherization and furnace-replacement offerings? **[OPEN-ENDED]**
1. Mailed information from NW Natural

2. Email from NW Natural
3. NW Natural program staff
4. NW Natural website
5. Community agency representative
6. Community-based organization representative
7. Newspaper or magazine article or advertisement
8. Contractor
9. Word of mouth from a personal contact (e.g., family member, friend, neighbor, colleague, etc.)
10. Radio advertisement
11. Another website
12. Social media (e.g. Facebook, Instagram, Twitter, Tik Tok, etc.)
13. Information at a retailer
14. Other, please specify: _____

[DISPLAY IF Q9=1]

Q11. What programs or services were you already aware of? Select all that apply **[MULTI-SELET]**

1. Bill assistance programs
2. Incentives for heating and cooling equipment (e.g. furnaces, fireplaces, HVAC systems)
3. Incentives for building shell improvements and weatherization (e.g. pipe wrap insulation, attic insulation)
4. Incentives for water heating equipment
5. Incentives for smart/programmable thermostats
6. Incentives for efficient appliances (e.g. washer, dryer, range)
7. Other – please specify **[OPEN-ENDED]**
8. I don't remember

Q12. Are you interested in making energy-efficiency improvements and participating in a NW Natural energy-efficiency program?

1. Yes
2. No

[DISPLAY IF Q12=1]

Q13. What energy-efficiency improvements or programs are you interested in? Select all that apply **[MULTI-SELECT]**

1. Heating/cooling equipment
2. Water heating equipment
3. Smart/programmable thermostats
4. Efficient appliances (e.g. washer, dryer, range)
5. Home weatherization (e.g. pipe wrap insulation, attic insulation, insulated door)
6. Other – please specify **[OPEN-ENDED]**

[DISPLAY IF Q12=1]

Q14. How soon do you plan to replace the equipment?

1. In the next year
2. In the next 1-2 years
3. In the next 2-4 years
4. More than 4 years from now
5. I don't know

9.2.2.4 Participation Barriers

Q15. On a scale of 1 through 5, where 1 means "not at all interested" and 5 means "very interested", how interested are you in participating in NW Natural's energy-efficiency programs?

1. 1 – Not at all interested
2. 2
3. 3
4. 4
5. 5 – Very interested

Q16. What might prevent you from participating in a NW Natural's program? **[OPEND ENDED]**

Q17. Are there any changes NW Natural can make to its programs to encourage you to participate? **[OPEN ENDED]**

9.2.2.5 End Uses

Q18. What do you think is the largest energy user in your home?

1. Heating/cooling equipment
2. Water heating equipment
3. Appliances (clothes washer/dryer, range, etc.)
4. Refrigeration
5. Other – please specify **[OPEN-ENDED]**

Q19. What type of heating system do you currently have in your home?

1. Gas furnace
2. Gas fireplace
3. Heat Pump
4. Mini split
5. Electric resistance (e.g. baseboard)
6. I don't heat the home

7. I don't know

Q20. What is the main fuel used to heat your home?

1. Electricity
2. Natural Gas
3. Propane
4. Other, please specify: _____
5. I don't heat my home
6. I don't know
7. Prefer not to answer

[SKIP IF 0=5 OR 98]

Q21. Approximately how old is the heating system?

1. Less than 10 years old
2. 10 to 20 years old
3. More than 20 years old
4. I don't know

Q22. When was the last time your heating system was serviced?

1. Less than 1 year ago
2. 1 to 3 years ago
3. More than 3 years ago
4. It's never been serviced
5. I don't know

Q23. What type of thermostat do you use?

1. Manual
2. Programmable
3. Smart thermostat
4. I don't know

9.2.2.6 Demographics

This last set of questions will help NW Natural develop more effective programs that may best serve the needs of the community. Your answers will remain anonymous, so no information will be linked with you or your household. You may choose "Prefer not to answer."

Q24. Do you own or rent the home at **${e://Field/ADDRESS}**?

1. Own
2. Rent
3. Own and rent to someone else
4. Prefer not to answer

[DISPLAY IF Q24 = 1 OR 3]

Q25. When was your home built?

1. Before 1950
2. 1950 to 1959
3. 1960 to 1969
4. 1970 to 1979
5. 1980 to 1989
6. 1990 to 1999
7. 2000 to 2009
8. 2010 to 2019
9. 2020 to Present
10. I don't know
11. Prefer not to answer

Q26. Which best describes your home?

1. Single-family house detached
2. Single-family house attached to one or more other houses (e.g., duplex, condominium, townhouse, etc.)
3. Mobile or manufactured home
4. Apartment with 2 to 4 units
5. Apartment with 5 or more units
6. Other, please specify: _____
7. Prefer not to answer

Q27. What county do you live in?

1. Benton, OR
2. Clackamas, OR
3. Clatsop, OR
4. Columbia, OR
5. Coos, OR
6. Hood River, OR
7. Lane, OR
8. Lincoln, OR
9. Linn, OR
10. Marion-Polk, OR
11. Multnomah, OR
12. Washington, OR
13. Yamhill, OR
14. Clark, WA

Q28. Including yourself, how many people live in your home year-round?

1. 1 person
2. 2 people
3. 3 people
4. 4 people
5. 5 people
6. 6 people
7. 7 people
8. 8 or more people
9. Prefer not to answer

Q29. Including all money earned from wages, salaries, tips, commissions, workers' compensation, unemployment insurance, child support, or other sources, did your household make more than the following amount of money in 2023? **[MATRIX OPTIONS: The same amount or less, More, I don't know]**

1. **IF Benton, OR** -- $108,000
2. **IF Clackamas, OR** -- $118,000
3. **IF Clatsop, OR** -- $92,300
4. **IF Columbia, OR** -- $118,000
5. **IF Coos, OR** -- $80,900
6. **IF Hood River, OR** -- $97,900
7. **IF Lane, OR** – $89,100
8. **IF Lincoln, OR** -- $80,900
9. **IF Linn, OR** -- $84,900
10. **IF Marion-Polk, OR** -- $91,300
11. **IF Multnomah, OR** -- $118,000
12. **IF Washington, OR** -- $118,000
13. **IF Yamhill, OR** -- $118,00
14. **IF Clark, WA** -- $94,400

Q30. What is the highest level of education you have completed?

1. Did not graduate high school
2. High school graduate
3. Associates degree, vocation/ technical school, or some college
4. Four-year college degree
5. Graduate or professional degree
6. Prefer not to answer

9.2.2.7 Customer Information and Thank You Page

Q31. This is the end of the survey. As a thank you for your time answering our questions, NW Natural would like to provide you with a $10 MasterCard gift card.
The email address we have for you is **${e://Field/RecipientEmail}**. Please let us know if you would like us to send your electronic gift card to this address or a different address.

1. Please send my electronic gift card to the **above** email address
2. Please send my electronic gift card to the **following** email address:
   _____

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Direct Testimony of Brody J. Wilson

COST OF CAPITAL
EXHIBIT 300

REDACTED

November 24, 2026

EXHIBIT 300 – DIRECT TESTIMONY – COST OF CAPITAL

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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 Brody J. Wilson. I am Vice President, Treasurer, Chief Accounting Officer, and Controller at NW Natural and Northwest Natural Holding Company ("NW Natural Holdings").

Q. Please state your experience and educational background.

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.

Q. Please describe the purpose of your testimony.

A. The purpose of my testimony is to support the Company's proposal to retain its current capital structure of 50 percent common equity and 50 percent long-term debt. I also explain the Company's financing strategy and how that leads to a financially healthy utility that benefits our 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 of 50 percent common equity and 50 percent long-term debt. The Company's investment grade credit ratings support its ability to access the capital markets. We work to manage interest rate risk and secure low-cost capital to fund utility infrastructure to maintain a safe and reliable system as well as utility operations. To do this, we intend to maintain a

strong balance sheet and focus on financing the long-term assets of the Company through a balance of long-term debt and equity financing. To further explain our financing strategy, my testimony:

- Describes NW Natural's request for a capital structure of 50 percent common equity and 50 percent long-term debt, with an overall rate of return ("ROR") on rate base of 7.374 percent;
- Describes NW Natural's plan to maintain its proposed ratios of equity and debt;
- Explains how I calculated the cost of debt for the Test Year (November 1, 2027 through October 31, 2028); and
- Discusses the Company's current credit ratings and why it is important for the Company to maintain its current credit ratings.

II. CAPITAL STRUCTURE AND RATE OF RETURN

Q. What is NW Natural's current Commission-authorized capital structure for ratemaking purposes and overall ROR?

A. In UG 520, the Commission authorized the following capital structure, capital costs and overall ROR for NW Natural:

Table 1. NW Natural's Capital Structure and Rate of Return
Order No. 25-420

Component	Ratio	Cost	Weighted Cost
Long-term Debt	50%	4.740%	2.370%
Common Equity	50%	9.50%	4.750%
Total	**100%**		**7.120%**

Q. What is NW Natural's requested capital structure for ratemaking purposes and overall ROR in this proceeding?

A. NW Natural is requesting a capital structure of 50 percent long-term debt and 50 percent equity, with an overall ROR on rate base of 7.374 percent, based upon a 4.997 percent embedded cost of long-term debt and a 9.75 percent cost of equity. The following table presents the proposed capital structure along with the calculation of the Company's ROR for the Test Year:

Table 2. Requested Capital Structure and Rate of Return

Component	Ratio	Cost	Weighted Cost
Long-term Debt	50%	4.997%	2.499%
Common Equity	50%	9.750%	4.875%
Total	**100%**		**7.374%**

Q. Does NW Natural always maintain exactly a 50/50 capital structure?

A. No. Although NW Natural's target capital structure has been 50/50 for a long time, there is a natural fluctuation in this ratio on a temporary basis over time. For example, the Company forecasts an equity ratio **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. The equity percentage will fluctuate throughout the year primarily based on the seasonal nature of the business among other factors.

Q. Why is it important to NW Natural to maintain a 50/50 capital structure at the utility?

A. Maintaining a 50 percent utility common equity ratio is important for several reasons. 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.

The converse is true too. Generally, companies with higher debt ratios are considered riskier. By maintaining a long-term debt ratio at 50 percent, the Company is maintaining its risk profile in line with its historical risk profile, although it continues to be higher than those of the natural gas peer group. If the Company were to increase its debt ratio beyond 50 percent, it is likely that the rating agencies would view such an action negatively. In the event our ratings were downgraded, the Company could face more difficulty accessing capital markets and higher costs of debt—potentially to the detriment of both our customers and the Company.

Q. What is NW Natural's plan to maintain the target utility common equity ratio of 50 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 our parent company, as needed.

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. Since the holding company structure was approved by the Commission, NW Natural Holdings has contributed approximately $628 million of equity to the Company through 2025. Equity infusions from the parent company help the Company manage its common equity and maintain a strong balance sheet.

Q. How does NW Natural's proposed capital structure compare with the natural gas peer group?

A. The Company's current and proposed capital structure has a significantly lower equity-to-capital ratio than the average of our peer natural gas utilities identified by Jennifer E. Nelson in the Company's Return on Equity Direct Testimony (NW Natural/400, Nelson). Specifically, our gas proxy group has an average equity ratio of 55.42 percent over the last three years.

Q. What are NW Natural's current credit ratings?

A. The table below and NW Natural/301, Wilson show the Company's current ratings for each type of debt security from Moody's Investor Service ("Moody's") and Standard and Poor's Ratings ("S&P"), as well as the outlook issued by each agency.

Table 3. 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 to do so (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 or access to capital markets during all market environments, it is imperative that the Company at a minimum maintain its existing ratings and ideally improve its ratings.

Q. Are there important factors that the rating agencies review in determining NW Natural's ratings?

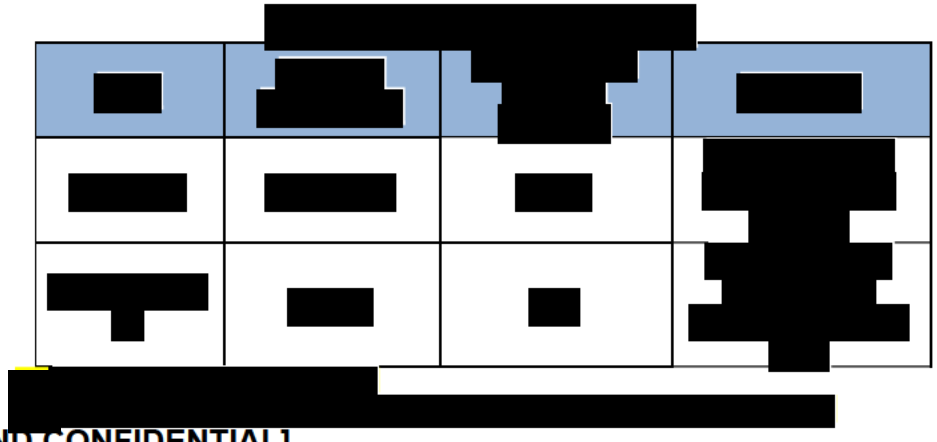
A. Yes. The rating agencies' most significant factors in determining ratings are how constructive the regulatory framework is in the jurisdictions the Company does business (business risk), the Company's ability to recover costs and earn a sufficient rate of return, and the financial strength of the organization as measured by its credit metrics. Moody's and S&P incorporate both qualitative and quantitative factors in evaluating these areas, including 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.

The tables below display Moody's and S&P's benchmarks and consolidated NW Natural's financial forecast for the 2026 year-end ("YE") period.

[BEGIN CONFIDENTIAL]





[END CONFIDENTIAL]

Q. How do NW Natural's credit ratings benefit customers?

A. Investment grade credit ratings provide NW Natural access to investors in the capital markets to provide funding to support infrastructure improvements that allow the Company to continue providing safe and reliable service. 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. Higher credit ratings generally provide a company with better access to the capital markets during difficult or volatile economic periods. Consistent access to the capital markets reduces the impacts that could occur from market disruptions that may require 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. Have any of NW Natural's credit ratings changed since the Commission issued its order in the Company's last general rate case (UG 520)?

A. No, there have not been any changes to NW Natural's credit ratings since the filing of the last general rate case, UG 520. The latest rating agency credit reports can be found in NW Natural/301, Wilson. Historical ratings for each rating agency can be found in NW Natural/302, Wilson.

III. LONG-TERM DEBT

Q. How was the cost of long-term debt calculated for the Test Year?

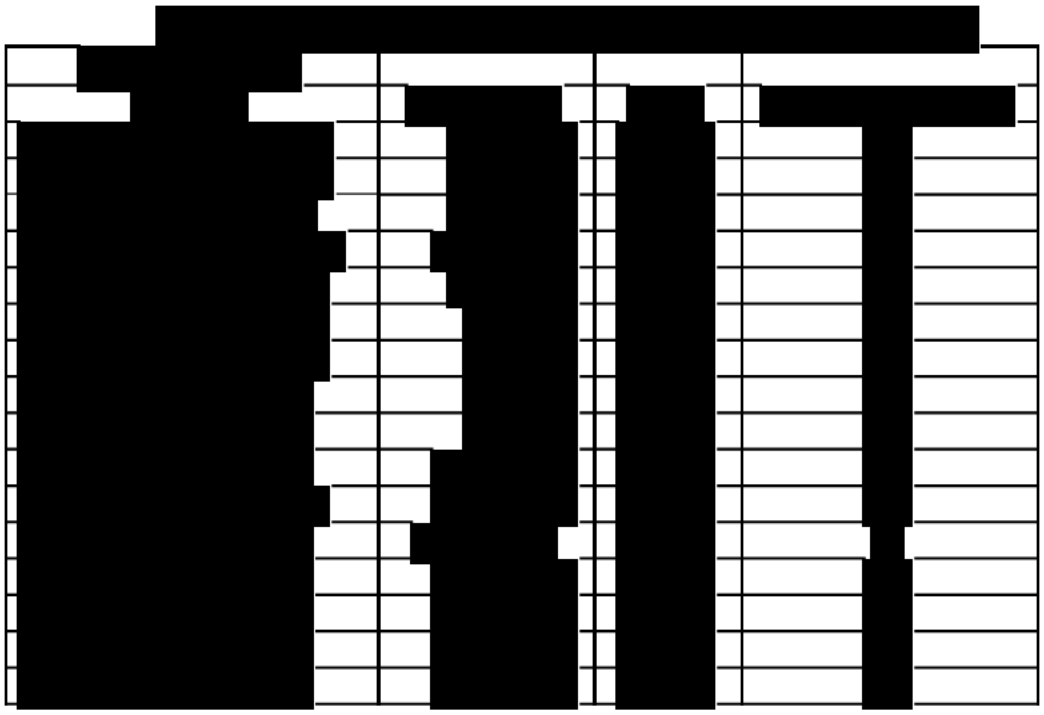
A. Confidential NW Natural/303, Wilson presents the details of the Company's long-term debt outstanding **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and the corresponding weighted average cost (4.997 percent) forecasted for the Test Year. The cost of long-term debt includes existing debt and forecasted debt. The weighted average cost of long-term debt was calculated by multiplying the debt outstanding, including future projected debt issuances, by the average cost for each debt issuance.

Column "s" of Confidential NW Natural/303, Wilson shows the annualized expense of each individual issuance in terms of an effective interest rate, which represents the total cost of issuance, including coupon rate, premiums or discounts, underwriter's commissions, gains on interest rate hedges, and other expenses related to the issuance 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 added 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. [BEGIN CONFIDENTIAL] [redacted]

[redacted]

[redacted]



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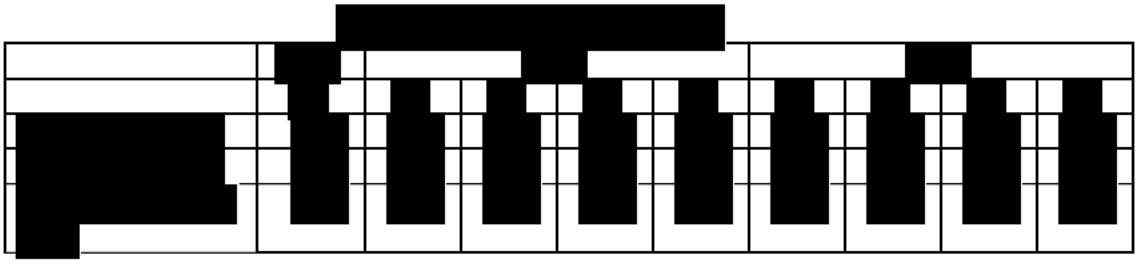

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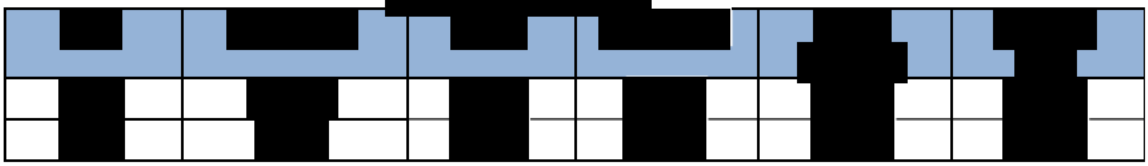

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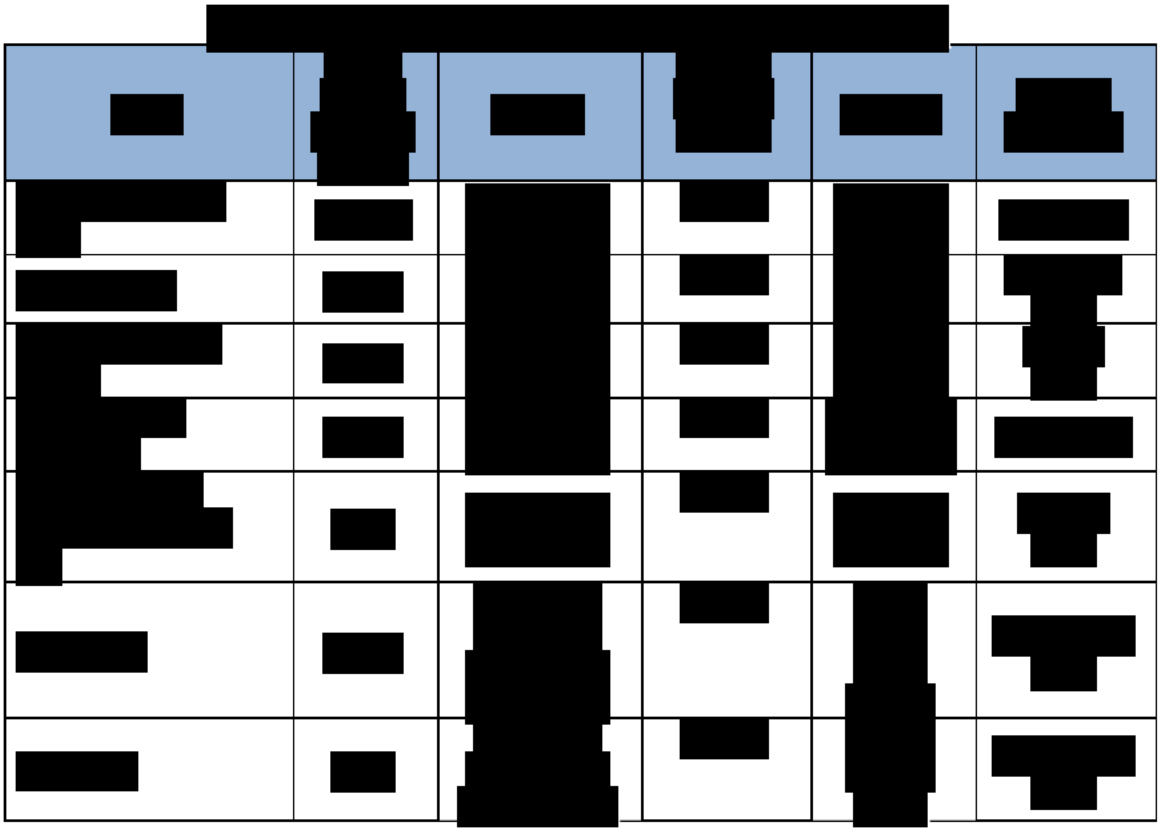

[redacted]

[redacted]

[redacted] **[END CONFIDENTIAL]**.

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibits of Brody J. Wilson

COST OF CAPITAL
EXHIBITS 301 – 305

November 24, 2026

EXHIBITS 301-305 – COST OF CAPITAL

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Brody J. Wilson

COST OF CAPITAL
EXHIBIT 301

November 24, 2026

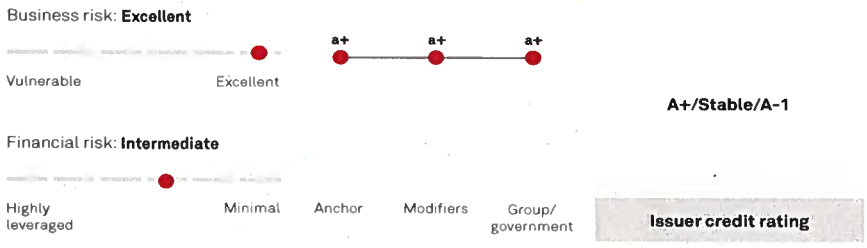
S&P Global
Ratings

Research

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

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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.

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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.

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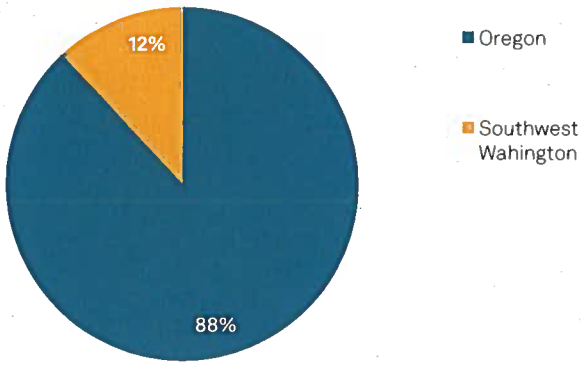
Northwest Natural Gas Co.'s customers by geographic area

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

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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

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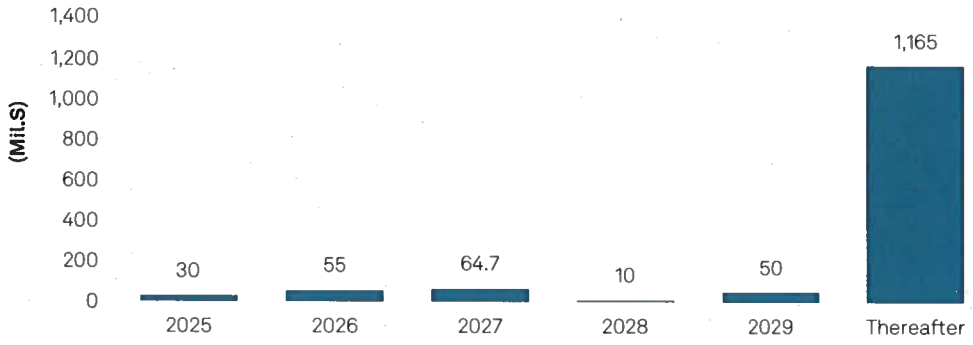
$350 million, and annual dividends averaging about $85 million through 2027. We expect a majority of the capital spending to fund replacing and improving system reliability.

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

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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

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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.

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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

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- 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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S&P Global
Ratings

Research

Tear Sheet:

Northwest Natural Gas Co. Adopted Rate Case Settlement In Line With Our Base-Case Expectations

November 13, 2025

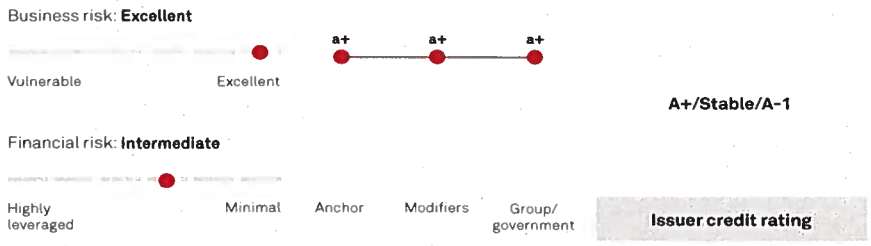
This report does not constitute a rating action.

What's new: The Public Utility Commission of Oregon (OPUC) recently adopted a $21.3 million base rate increase based on a 7.12% rate of return (9.5% return on equity and 50% equity component) within Northwest Natural Gas Co.'s (NWNG) natural gas rate case filing. The new rates are effective as of Oct. 31, 2025.

Why it matters: While the rate increase appears modest compared with the utility's original $59.4 million request, it is in line with our base-case expectations, and we believe it will continue to support credit quality. We continue to expect NWNG's stand-alone funds from operation (FFO) to debt to be 15%-17% through 2027, within the benchmark range of the financial risk profile category but below the midpoint.

The approved settlement also reflects NWNG's constructive management of regulatory risk under OPUC, which supports our assessment of its business risk profile as excellent.

Ratings Score Snapshot



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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.

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 FFO to debt of 15%-17% through 2027. The stable outlook also reflects our expectation for 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 return on equity.

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.

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Northwest Natural Gas Co. Adopted Rate Case Settlement In Line With Our Base-Case Expectations

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+**
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 (same as SACP)**

Related Criteria

- General Criteria: Hybrid Capital: Methodology And Assumptions, Feb. 10 2025
- 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: Recovery Rating Criteria For Speculative-Grade Corporate Issuers, Dec. 6 2016
- 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

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- General Criteria: Principles Of Credit Ratings, Feb. 16 2011

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MOODY'S RATINGS

CREDIT OPINION
16 July 2026

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

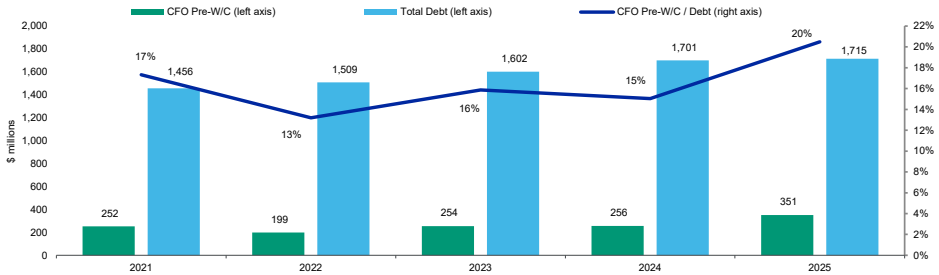
Northwest Natural Gas Company's (NW Natural, (P)Baa1 stable) credit profile incorporates the company's low business risk profile as a local gas distribution company (LDC) operating in generally supportive regulatory environments. In particular, Oregon's suite of cost recovery mechanisms and constructive stakeholder relationships have supported NW Natural's improved financial metrics, albeit volatile in the past.

NW Natural's cash flow from operations before changes in working capital (CFO pre-WC) to debt improved to 21% in 2025 from 16%-17% in 2023-24, supported by constructive rate case outcomes in Oregon over the last 1-2 years and a large one-off deferred income taxes. Our ratio calculation of CFO pre-WC excludes cloud-based software investments as the investments are included in rate base and earn a return. We expect NW Natural's credit metrics to weaken in 2026 because of a higher environmental remediation expense and additional debt to fund its capital spending without the one-off deferred income taxes. That said, the metrics will remain appropriate for the rating level and will likely rebound in 2027-28 as the rate base increases.

We expect the utility's capital spending to meaningfully increase in 2028-29 to fund its storage capacity expansion (MX3), which is expected to cost around $300 million. While NW Natural's financial metrics will be pressured during construction, the project provides cash flow predictability as it has long-term commitments from investment grade customers. The MX3 expansion project will be FERC-regulated.

We expect NW Natural's credit profile will continue to benefit from generally supportive regulatory environments in Oregon and Washington. Pending rate cases include an Oregon alternative rate mechanism filed in November 2025 and a Washington multi-year rate plan (August 2026-July 2029) filed in August 2025.

Exhibit 1
Historical CFO Pre-W/C, Total Debt and CFO Pre-W/C to Debt



All data based on adjusted financial data, which follow our Financial Statement Adjustments in Analysis of Nonfinancial Corporations methodology.
Source: Moody's Financial Metrics™

Credit strengths

» Low business risk profile as a natural gas local distribution company

» Generally supportive regulatory jurisdictions with multiple cost recovery mechanisms

Credit challenges

» Historically volatile financial metrics, despite recent improvements in metrics

» Heightened social risk due to state led decarbonization goals

Rating outlook

The stable outlook reflects our expectation that NW Natural's financial metrics will remain adequate for the current rating level, underpinned by generally supportive regulatory environments.

Factors that could lead to an upgrade

A rating upgrade could occur if NW Natural is able to generate a CFO pre-WC to debt above 18% on a sustained basis. An upgrade could also occur if its regulatory environment meaningfully improves.

Factors that could lead to a downgrade

A rating downgrade could occur if NW Natural's CFO pre-WC to debt deteriorates below 14% on a sustained basis, or if its regulatory environment becomes less credit supportive.

Key indicators

Exhibit 2

Northwest Natural Gas Company

	2021	2022	2023	2024	2025
CFO Pre-W/C + Interest Expense / Interest Expense	5.8x	4.4x	4.5x	4.4x	5.8x
CFO Pre-W/C / Debt	17.3%	13.2%	15.9%	15.0%	20.5%
CFO Pre-W/C – Dividends / Debt	13.5%	9.0%	10.1%	10.8%	16.0%
Debt / Capitalization	52.5%	49.3%	50.0%	49.9%	47.0%

All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology.
Source: Moody's Financial Metrics™

Profile

Northwest Natural Gas Company (NW Natural) is a natural gas local distribution company (LDC), serving 810,000 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 which 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

Improved financial metrics, despite historical volatility

NW Natural's CFO pre-WC/debt was approximately 21% in 2025, up from 16%-17% in 2023-24, supported by constructive rate outcomes in Oregon over the last 1-2 years and a large one-time deferred tax income, supporting the credit profile. We adjust our ratio calculation of CFO pre-WC to exclude cloud-based software investments as these are part of rate base and earn a return. Although we

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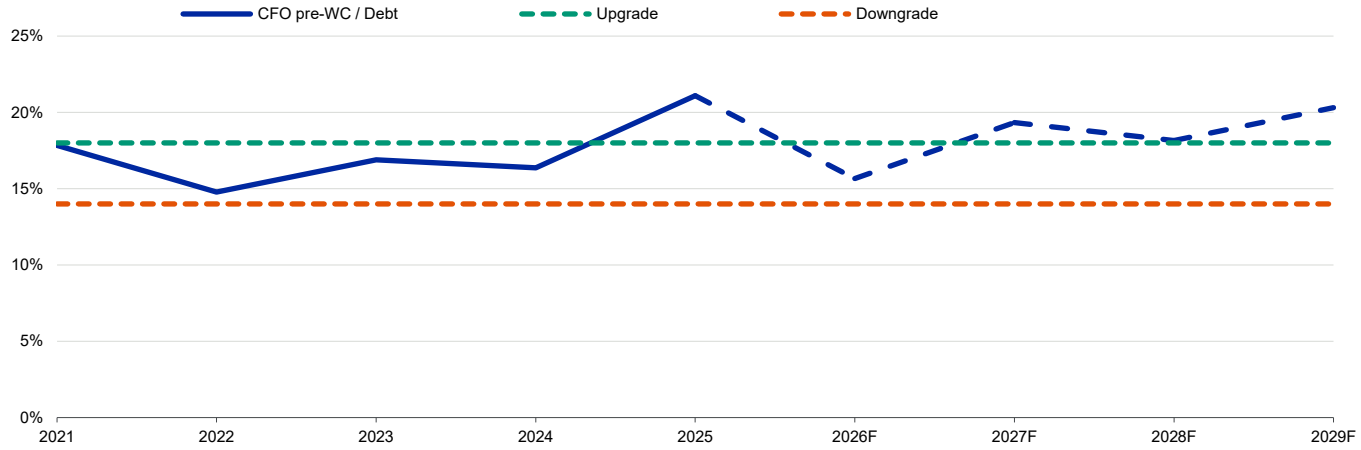
expect some moderation of metrics in 2026 because of a higher environmental remediation expenses and incremental debt to fund its capital spending, without the one-time benefit, NW Natural's financial metrics still remain adequate in 2026 and will rebound in 2027-28 as rate base grows.

We expect the utility's capital spending to meaningfully increase in 2028-29 to fund its storage capacity expansion (MX3), which is expected to cost around $300 million. While NW Natural's financial metrics will be pressured during construction, in operation the project will provide cash flow predictability as it has long-term commitments from investment grade customers. The MX3 will be FERC-regulated.

In the past, NW Natural's credit metrics experienced some volatility, primarily driven by one-time events, including the global pandemic in 2020, higher commodity prices in 2022 and the company's strategic investments in technology which increased regulatory lag. The utility recorded its CFO pre-WC debt of 15% in 2022, close to our downgrade threshold of 14%. That said, in its 2024 general rate case, NW Natural received regulatory approval to recover these investments. At the same time, constructive rate outcomes from the 2024 and 2025 Oregon general rate cases support the improved metrics.

Exhibit 3

Improved financial metrics in 2025, despite expected moderation in 2026



All data based on adjusted financial data, which follow our Financial Statement Adjustments in Analysis of Nonfinancial Corporations methodology. The metrics incorporate our adjustment for cloud-based software investments.
Sources: Moody's Financial Metrics™ and Moody's Ratings

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 the Washington Utilities and Transportation Commission (WUTC), which allow 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.

Despite being minor, a gas cost incentive sharing program exposes the utility to commodity prices as NW Natural has to elect each year an 80% deferral or a 90% deferral of higher or lower actual gas costs compared to estimated PGA costs.

The latest rate case in Oregon was in 2025, which approved a $20.7 million revenue requirement increase based on a 50% equity layer and 9.5% return on equity (ROE), up from the previously-authorized 9.4%, a credit positive.

Oregon is in the process of rulemaking for a multi-year rate case regime, which should improve timeliness of the utility's cost recovery. We expect the utility to file its first multi-year rate plan in 2028. In the meantime, NW Natural will utilize available mechanisms to reduce regulatory lag on capital spending. In fact, the utility filed an alternative rate mechanism associated with certain capital investments in November 2025, requesting a $15.6 million revenue requirement increase. In June 2026, NW Natural filed a multi-party settlement for $13.0 million. A commission order is expected later this year, with new rates expected 31 October 2026.

Washington

While we view Washington as a generally credit supportive jurisdiction for the utility with purchased gas adjustment and environmental cost recovery, it lacks certain mechanisms such as decoupling and weather normalization that Oregon provides.

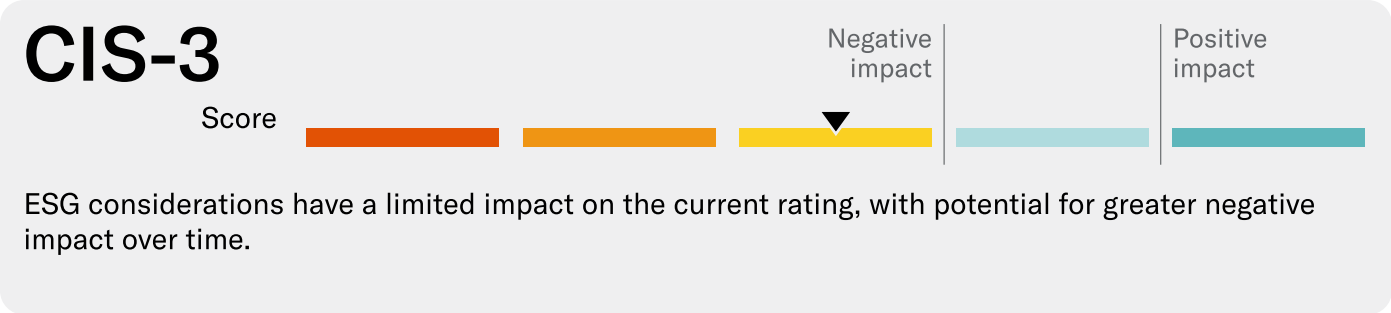
In October 2021, its most recent rate order for the utility, the WUTC authorized an annual revenue requirement increase over two years; a 6.4% or $5 million increase in the first year, effective 1 November 2021, and up to a 3.5% or $3 million increase in the second year beginning 1 November 2022. The order was based on an average rate base of $247.3 million.

In August 2025, NW Natural filed its 3-year rate plan (August 2026-July 2029). Multi-party settlement has been reached with a $20.1 million in Year 1, $7.7 million in Year 2 and $8.7 million in Year 3 based on a 9.5% ROE and 50% equity layer. New rates will take effect on August 1, 2026.

ESG considerations

Northwest Natural Gas Company's ESG credit impact score is CIS-3

Exhibit 4
ESG credit impact score



Source: Moody's Ratings

Northwest Natural Gas Company's (NW Natural) **CIS-3** indicates its ESG considerations that have a limited impact on the current rating, with greater potential for future negative impact over time, reflecting NW Natural's exposure to physical climate risks, carbon transition, and demographic and societal trends.

Exhibit 5
ESG issuer profile scores



Source: Moody's Ratings

Environmental

E-3. NW Natural is exposed to carbon transition risk from emissions associated with its natural gas distribution operations, and state led decarbonization goals. We also consider the company's exposure to physical climate risks including the potential for operational disruptions or unexpected increases in commodity prices.

Social

S-3. NW Natural is exposed to demographic and societal trends driven by public concern about environmental, social or affordability issues that could result in adverse regulatory or political outcomes. NW Natural is also moderately exposed to responsible production risk because of the risk to public safety inherent in its gas distribution operations.

Governance

NW Natural's **G-2** issuer profile score is broadly in line with other utilities and does not pose a particular risk.

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

We view NW Natural's liquidity to be adequate over the next 12 months.

NW Natural's liquidity is supported by its ability to generate operating cash flow and access to the capital markets. NW Natural had about $24.3 million of cash and cash equivalents as of 31 March 2026. We expect NW Natural to generate around $300 million-$400 million of annual operating cash flow over the next 1-2 years. However, its cash holdings and expected operating cash flow will not be sufficient to cover NW Natural's capital spending and other cash outlays such as dividends over the next 12 months.

The utility has access to a $400 million revolving credit agreement, maturing in November 2030, with an option to extend two additional 1-year period, subject to lender approval. There was no outstanding balance as of 31 March 2026 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. The credit agreement requires NW Natural to maintain a consolidated indebtedness to total capitalization ratio of 70% or less, which the utility was complaint with 49.2% at 31 March 2026.

There are uncommitted letter of credit and reimbursement agreements, totaling $250 million primarily to support the utility's participation in Washington Climate Commitment Act cap-and-investment program auctions.

NW Natural's next debt maturities are in October 2026 and December 2026, when $20 million and $35 million of senior secured notes are due, respectively.

Rating methodology and scorecard factors

The principal methodology used for this rating is Regulated Electric and Gas Utilities Industry rating methodology.

Exhibit 6

Rating factors

Northwest Natural Gas Company

Regulated Electric and Gas Utilities Industry Scorecard	Current FY Dec-25		Moody's 12-18 month forward view	
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	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	na	na	na	na
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	4.9x	A	4.5x-5.5x	A
b) CFO pre-WC / Debt (3 Year Avg)	17.2%	Baa	16%-19%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	12.3%	Baa	11%-15%	Baa
d) Debt / Capitalization (3 Year Avg)	48.9%	A	45%-50%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching		0	0	0
a) Scorecard-Indicated Outcome		A3		A3
b) Actual Rating Assigned		(P)Baa1		(P)Baa1

All data based on adjusted financial data, which follow our Financial Statement Adjustments in the Analysis of Nonfinancial Corporations methodology.
Moody's forecasts are Moody's opinion and do not represent the views of the issuer.
Sources: Moody's Financial Metrics and Moody's Ratings forecasts

Appendix

Exhibit 7

Peer comparison

Northwest Natural Gas Company

	Northwest Natural Gas Company (P)Baa1 Stable			Wisconsin Gas LLC A3 Positive			Berkshire Gas Company (The) A3 Negative			Southwest Gas Corporation Baa1 Stable		
(In $ millions)	FY Dec-23	FY Dec-24	FY Dec-25	FY Dec-23	FY Dec-24	FY Dec-25	FY Dec-23	FY Dec-24	FY Dec-25	FY Dec-23	FY Dec-24	FY Dec-25
Revenue	1,159	1,100	1,125	770	680	830	97	93	103	2,500	2,483	1,942
CFO Pre-W/C	254	256	351	154	303	234	20	14	19	525	559	727
Total Debt	1,602	1,701	1,715	1,112	1,112	1,206	93	118	115	3,621	3,603	3,553
CFO Pre-W/C + Interest / Interest	4.5x	4.4x	5.8x	4.9x	7.6x	6.0x	5.9x	3.8x	4.5x	4.3x	4.3x	4.9x
CFO Pre-W/C / Debt	15.9%	15.0%	20.5%	13.9%	27.2%	19.4%	21.6%	11.5%	16.5%	14.5%	15.5%	20.5%
CFO Pre-W/C – Dividends / Debt	10.1%	10.8%	16.0%	-1.5%	20.0%	11.1%	21.6%	11.5%	16.5%	10.3%	10.6%	18.0%
Debt / Capitalization	50.0%	49.9%	47.0%	41.2%	39.2%	40.7%	33.5%	36.8%	35.4%	47.9%	46.8%	43.8%

All data based on adjusted financial data, which follow our Financial Statement Adjustments in Analysis of Nonfinancial Corporations methodology.
Source: Moody's Financial Metrics™

Exhibit 8

Moody's-adjusted cash flow reconciliation

Northwest Natural Gas Company

(in $ millions)	2021	2022	2023	2024	2025
FFO	**227.3**	**206.7**	**241.2**	**245.0**	**348.0**
+/- Other	25.0	(7.6)	13.0	10.9	3.3
CFO Pre-WC	**252.4**	**199.1**	**254.3**	**255.9**	**351.3**
+/- ΔWC	(104.9)	(52.7)	29.1	(4.3)	(65.5)
CFO	**147.5**	**146.4**	**283.4**	**251.6**	**285.8**
- Div	56.1	62.7	92.4	72.8	77.4
- Capex	280.1	320.4	292.7	356.3	357.6
FCF	(188.6)	(236.7)	(101.7)	(177.5)	(149.2)
(CFO Pre-W/C) / Debt	17.3%	13.2%	15.9%	15.0%	20.5%
(CFO Pre-W/C - Dividends) / Debt	13.5%	9.0%	10.1%	10.8%	16.0%
Debt / Capitalization	52.5%	49.3%	50.0%	49.9%	47.0%
(FFO + Interest) / Interest	5.3x	4.5x	4.3x	4.2x	5.8x
Revenue	843.1	1,014.3	1,158.6	1,100.5	1,125.1
Interest Expense	52.8	59.0	73.6	76.0	73.0
Net Income	84.6	85.6	94.5	84.8	126.6
Total Assets	3,898.4	4,452.7	4,511.4	4,756.3	5,049.1
Total Liabilities	2,920.6	3,261.6	3,278.8	3,432.2	3,540.9
Total Equity	977.8	1,191.1	1,232.6	1,324.1	1,508.2

All data based on adjusted financial data, which follow our Financial Statement Adjustments in Analysis of Nonfinancial Corporations methodology.
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 1486621

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Brody J. Wilson

COST OF CAPITAL
EXHIBIT 302

November 24, 2026

NW Natural
UG 532 - Exhibit 302
NW Natural Credit Ratings 2018 - 2026

Debt Rating History

Standard & Poors

Rating Type	7/20/2018	3/23/2021	6/15/2022	6/15/2023	10/9/2023	4/19/2024	6/24/2024	6/25/2025	11/13/2025	Current
Outlook	Stable	Stable	Stable	Stable	Negative	Stable	Stable	Stable	Stable	Stable
Senior Secured LT Debt	AA-	AA-	AA-	AA-	AA-	AA-	AA-	AA-	AA-	AA-
Corporate Credit Rating	A+	A+	A+	A+	A+	A+	A+	A+	A+	A+
Short-Term	A-2	A-1	A-1	A-1	A-1	A-1	A-1	A-1	A-1	A-1

Moody's Investor Service

Rating Type	2/1/2018	1/10/2019	5/17/2019	6/21/2021	6/27/2022	7/19/2023	7/30/2024	7/8/2025	7/16/2026	Current
Outlook	Negative	Negative	Stable	Stable	Stable	Stable	Stable	Stable	Stable	Stable
Senior Secured LT Debt	A1	A1	A2	A2	A2	A2	A2	A2	A2	A2
Corporate Credit Rating	A3	A3	Baa1	Baa1	Baa1	Baa1	Baa1	Baa1	Baa1	Baa1
Short-Term	P-2	P-2	P-2	P-2	P-2	P-2	P-2	P-2	P-2	P-2

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Brody J. Wilson

COST OF CAPITAL
EXHIBIT 303

REDACTED

November 24, 2026

NORTHWEST NATURAL GAS COMPANY
EMBEDDED COST OF LONG-TERM DEBT CAPITAL AT
October 31, 2028

#	Coupon Rate	Description of Issue	Date Issued	Maturity Date	10/31/2028 Years to Maturity	Outstanding	Offered	Premium or Discount Amount	Premium or Discount Per $ 100 Principal Amount	Underwriter's Commission Amount	Underwriter's Commission Per $ 100 Principal Amount	Expense of Issue Amount	Expense of Issue Per $ 100 Principal Amount	Net Proceeds Amount	Net Proceeds Per $100 Principal Amount	Original Term to Maturity Yrs.	Cost of Money (Bond Table)	Annual Cost Out-standing Debt
		(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		Medium-Term Notes																
		First Mortgage Bonds:																
1	3.141%	3.141% Series	6/17/2019	6/15/2029	0.6	50,000,000	50,000,000	0	0.00	312,500	0.625	255,252	0.51	49,432,248	98.864	10	3.275%	1,637,500
2	7.740%	7.740% Series	8/29/2000	8/29/2030	1.8	20,000,000	20,000,000	0	0.00	150,000	0.750	1,354,914 [1]	6.77	18,495,086	92.475	30	8.433%	1,686,600
3	7.850%	7.850% Series	9/6/2000	9/1/2030	1.8	10,000,000	10,000,000	0	0.00	75,000	0.750	678,107 [3]	6.78	9,246,893	92.469	29	8.551%	855,100
4	5.820%	5.820% Series	9/24/2002	9/24/2032	3.9	30,000,000	30,000,000	0	0.00	225,000	0.750	165,382	0.55	29,609,618	98.699	30	5.913%	1,773,900
5	5.660%	5.660% Series	2/25/2003	2/25/2033	4.3	40,000,000	40,000,000	0	0.00	300,000	0.750	56,663	0.14	39,643,337	99.108	30	5.723%	2,289,200
6	5.250%	5.250% Series	6/21/2005	6/21/2035	6.6	10,000,000	10,000,000	0	0.00	75,000	0.750	22,974	0.23	9,902,026	99.020	30	5.316%	531,600
7	4.000%	4.000% Series	10/30/2012	10/31/2042	14.0	50,000,000	50,000,000	0	0.00	300,000	0.600	235,479	0.47	49,464,522	98.929	30	4.062%	2,031,000
8	4.136%	4.136% Series	12/5/2016	12/5/2046	18.1	40,000,000	40,000,000	0	0.00	300,000	0.750	307,712	0.77	39,392,288	98.481	30	4.226%	1,690,400
9	3.685%	3.685% Series	9/13/2017	9/13/2047	18.9	75,000,000	75,000,000	0	0.00	562,500	0.750	367,946	0.49	74,069,554	98.759	30	3.754%	2,815,500
10	4.110%	4.110% Series	9/10/2018	9/10/2048	19.9	50,000,000	50,000,000	0	0.00	125,000	0.250	174,695	0.35	49,700,305	99.401	30	4.145%	2,072,500
11	3.869%	3.869% Series	6/17/2019	6/15/2049	20.6	90,000,000	90,000,000	0	0.00	675,000	0.750	415,358	0.46	88,909,642	98.788	30	3.938%	3,544,200
12	3.600%	3.600% Series	3/31/2020	3/15/2050	21.4	150,000,000	150,000,000	(598,500)	0.40	1,125,000	0.750	713,011	0.48	147,563,490	98.376	30	3.690%	5,535,000
13	3.078%	3.078% Series	11/15/2021	12/1/2051	23.1	130,000,000	130,000,000	0	0.00	975,000	0.750	451,489	0.35	128,573,511	98.903	30	3.135%	4,075,500
14	4.780%	4.780% Series	9/30/2022	9/30/2052	23.9	140,000,000	140,000,000	0	0.00	424,000	0.303	143,604	0.10	139,432,396	99.595	30	4.806%	6,728,400
15	5.430%	5.430% Series	1/6/2023	1/6/2053	24.2	100,000,000	100,000,000	0	0.00	248,409	0.248	253,523	0.25	99,498,068	99.498	30	5.464%	5,464,000
16	5.750%	5.750% Series	3/8/2023	3/8/2033	4.4	100,000,000	100,000,000	(220,000)	0.22	625,000	0.625	456,295	0.46	98,698,705	98.699	10	5.924%	5,924,000
17	5.180%	5.180% Series	8/4/2023	8/4/2034	5.8	80,000,000	80,000,000	0	0.00	232,253	0.290	133,001	0.17	79,634,746	99.543	11	5.235%	4,188,000
18	5.230%	5.230% Series	8/4/2023	8/4/2038	9.8	50,000,000	50,000,000	0	0.00	158,036	0.316	74,871	0.15	49,767,092	99.534	15	5.275%	2,637,500
25	5.130%	5.130% Series	12/16/2025	5/1/2036	7.5	75,000,000	75,000,000	0	0.00	228,518	0.305	217,341	0.29	74,554,142	99.406	10	5.204%	3,903,000
26	5.900%	5.900% Series	12/16/2025	12/1/2055	27.1	125,000,000	125,000,000	0	0.00	380,863	0.305	352,235	0.28	124,266,903	99.414	30	5.942%	7,427,500
27	5.620%	5.620% Series	9/3/2026	9/3/2036	7.8	60,000,000	60,000,000	0	0.00	183,591	0.306	197,457	0.33	59,618,952	99.365	10	5.704%	3,422,400
28	6.260%	6.260% Series	9/3/2026	9/3/2056	27.9	60,000,000	60,000,000	0	0.00	183,591	0.306	197,457	0.33	59,618,952	99.365	30	6.307%	3,784,200
Confidential Forecast																		
[redacted]																		
												EQUALS =		**4.997%**				

WEIGHTED EMBEDDED COST:

[1] INCLUDES $992,143 PREMIUM, $178,966 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 9.75% SERIES BONDS, AND $148,605 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 15.375% SERIES BONDS ALLOCATED TO THE 7.74% SERIES.

[2] INCLUDES $826,786 PREMIUM, $149,139 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 9.75% SERIES BONDS, AND $123,837 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 15.375% SERIES BONDS ALLOCATED TO THE 7.72% SERIES.

[3] INCLUDES $496,071 PREMIUM, $89,483 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 9.75% SERIES BONDS, AND $74,302 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 15.375% SERIES BONDS ALLOCATED TO THE 7.85% SERIES.

[4] INCLUDES $150,000 PREMIUM AND $405,971 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 7.50% SERIES BONDS, $413,600 PREMIUM AND $1,116,479 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 7.52% SERIES BONDS AND $730,000 PREMIUM AND $136,800 UNAMORTIZED COSTS ON EARLY REDEMPTION OF 7.25% SERIES BONDS ALLOCATED TO 5.62% SERIES.

[5] In November 2009 one investor exercised its right under a one-time put option to redeem $0.3 million of the $20 million outstanding. This one-time put option has now expired, and the remaining $19.7 million remaining principal outstanding is expected to be redeemed at maturity in November 2027.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Brody J. Wilson

COST OF CAPITAL
EXHIBIT 304

November 24, 2026

NW Natural
UG 532 - Exhibit 304
Market Implied Treasury Forwards

Market Implied Treasury Forwards

	2026	2027				2028			
Indices	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
Fed Funds Effective (Avg.)	4.085	4.115	4.085	3.995	3.925	3.685	3.595	3.525	3.525
3-Month SOFR	4.09	4.13	4.1	4.02	3.97	3.82	3.73	3.66	3.66
5-Year UST Note	4.64	4.55	4.47	4.39	4.33	4.25	4.21	4.16	4.16
10-Year UST Note	4.86	4.8	4.72	4.66	4.6	4.53	4.48	4.4	4.4
30-Year UST Note	5.26	5.2	5.15	5.09	5.04	4.98	4.94	4.89	4.89

Source: Bloomberg, as of
October 25, 2024

NW Natural's Calculation

	2026	2027				2028			
Implied 20-Year UST Note	5.06	5.00	4.94	4.88	4.82	4.76	4.71	4.65	4.65

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Brody J. Wilson

COST OF CAPITAL
EXHIBIT 305

REDACTED

Under General Protective Order No. 23-132, this exhibit is confidential in its entirety and has been redacted.

November 24, 2026

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Direct Testimony of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 400

November 24, 2026

EXHIBIT 400 – DIRECT TESTIMONY – RETURN ON EQUITY

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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. Concentric provides 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 15 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 clients on a range of financial and regulatory issues including cost of capital, ratemaking policy, and regulatory strategy. 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 have earned the Certified Rate of Return Analyst designation from the Society of Utility and Regulatory Financial Analysts. I hold a Bachelor's degree in Business Economics from Bentley University and a Master's degree in Resource and Applied Economics from the University of Alaska. A

summary of my professional and educational background, including a list of my testimony filed before regulatory commissions, is included as Exhibit NW Natural/401, Nelson.

Q. On whose behalf are you submitting this testimony?

A. I am submitting this direct testimony ("Direct Testimony") before the Public Utility Commission of Oregon (the "Commission") on behalf of Northwest Natural Gas Company ("NW Natural" or "the Company").

Q. Have you previously submitted testimony to the Commission?

A. Yes, I have. I submitted testimony regarding the cost of capital on behalf of the Company in Docket No. UG 520 and Docket No. UG 490. Additionally, I have previously filed testimony before more than 20 state regulatory commissions as detailed in Exhibit NW Natural/401, Nelson. 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 ("FERC").

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 the appropriate ROE 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 conclusions are supported

by the analyses presented in Exhibit NW Natural/402, Nelson, through Exhibit NW Natural/414, Nelson, which have been prepared by me or those under my direction.

Q. What are your conclusions regarding the appropriate cost of equity[1] and capital structure for the Company?

A. Based on my analyses of three widely used market-based financial models, the Company's specific risk profile, and the current capital market environment, I conclude that a range of 9.75 percent to 11.75 percent reflects the return equity investors require for NW Natural. Within that range, the Company requests an ROE at the bottom of the range, 9.75 percent, to balance its need for a reasonable return that enables the Company to provide safe and reliable service with the rate impact on customers.

As to the Company's capital structure, I conclude its requested capital structure consisting of approximately 50.00 percent common equity and 50.00 percent long-term debt is consistent with the proportions of long-term capital that finance the regulated natural gas operations of the proxy group and is therefore reasonable. Accordingly, I recommend the Commission approve the Company's requested capital structure. NW Natural's Weighted Average Cost of Capital ("WACC") is shown in Figure 1 below.

[1] Throughout my testimony, I use the terms "cost of equity" and "ROE" interchangeably.

Figure 1: Weighted Average Cost of Capital

	% of Capital	Cost (%)	Weighted Cost
Long-Term Debt	50.00%	4.997%	2.499%
Common Equity	50.00%	9.750%	4.875%
Total	100.00%		7.374%

Q. Please provide a brief overview of the analyses that led to your ROE determination.

A. I developed my recommendation using three widely accepted financial modeling approaches applied to a proxy group of six natural gas distribution companies ("Gas Proxy Group"): (1) the constant growth and quarterly 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 approach ("Risk Premium"). Although I generally disagree with the appropriateness of a Multi-Stage DCF analysis for utility companies that are in the mature stage of development, in deference to the Commission's past decisions, I also consider the results of a Multi-Stage DCF analysis. I also present the results of these same models for a Combined Proxy Group that includes the Gas Proxy Group and electric utilities with material regulated natural gas operations. The results of my analytical approaches are summarized in Exhibit NW Natural/402, Nelson.

Q. How did you determine your recommended ROE range from the results of your analytical approaches?

A. The cost of equity is an opportunity cost that cannot be precisely quantified. Therefore, it must be estimated using various financial models. Each ROE estimation model is subject to limiting assumptions and each model provides a unique 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. The low end of my range, 9.75 percent, is approximately equal to the average of the low DCF and CAPM results using the most conservative inputs. The high end of my range, 11.75 percent, is within the upper half of the DCF results and the average of the CAPM, Empirical CAPM ("ECAPM"), and Risk Premium results (see Figure 2).

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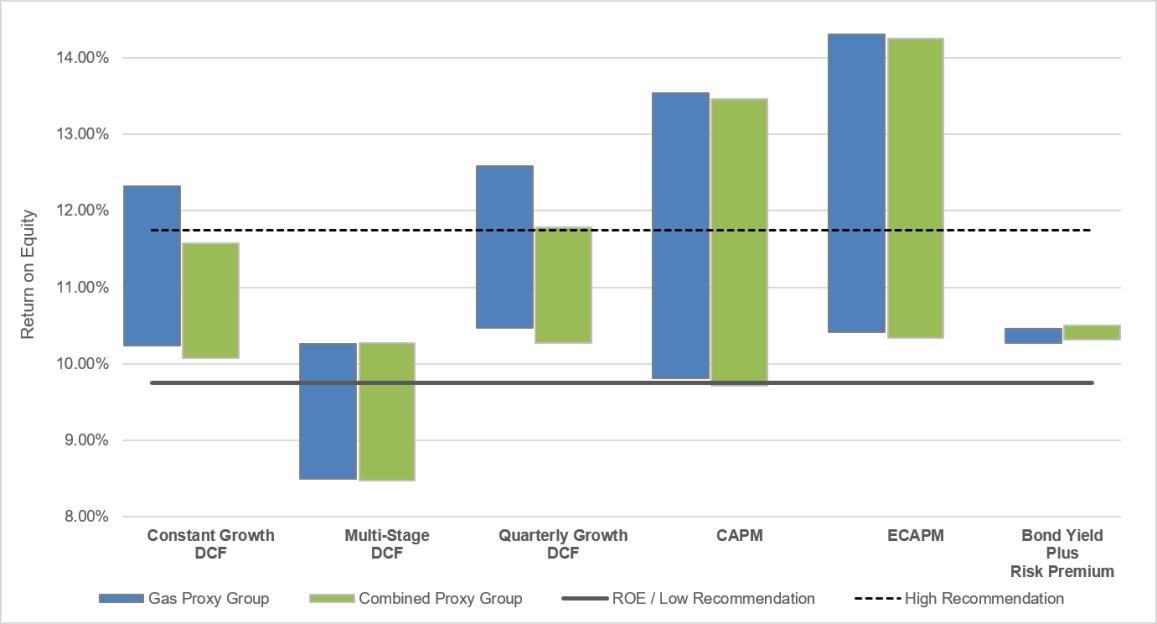
Figure 2: Range of ROE Model Results and Recommendation



In addition to the analytical results summarized in Figure 2, my recommendation considers: (1) NW Natural's capital expenditure program, (2) the regulatory environment in which NW Natural operates, (3) the risk associated with the environmental policy relative to the proxy companies, and (4) the Company's relatively small size. Although these factors are relevant to investors, their effect on the Company's cost of equity cannot be directly quantified. Further, my recommendation reflects the current capital market and macroeconomic environment in which utilities such as NW Natural operate. While these factors would support an ROE above the midpoint of the range for NW Natural, it is my opinion that an ROE at the low end of the range, 9.75 percent, is a conservative estimate of NW Natural's cost of equity. This recommendation addresses the Company's consideration of affordability concerns for customers while providing

NW Natural a reasonable return that enables it to continue to attract investor capital.

Q. Does your recommendation consider changes in economic and financial market conditions since NW Natural's last rate case?

A. Yes, it does. I assessed the changes in the economic and capital market environment since the time of NW Natural's last rate case in Docket No. UG 520. On December 31, 2024, the 30-day average yield of 30-year Treasury bonds was 4.56 percent and Moody's A-rated utility bond yield averaged 5.57 percent. By comparison, as of August 31, 2026, the 30-day average yield on 30-year Treasury bonds was 5.21 percent and Moody's A-rated utility bond index averaged 6.09 percent. In other words, since the Company filed its last rate case, long-term government and utility bond yields have increased by approximately 65 and 52 basis points, respectively. As discussed in Section V, ongoing geopolitical tensions, evolving trade policies, and broader macroeconomic uncertainty have contributed to persistently elevated inflation and U.S. Treasury yields, increasing the benchmark returns investors require to commit capital to natural gas utilities such as NW Natural.

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, the

development of my proxy group, and the analyses on which my ROE determination is based;

- Section IV – Discusses the Company's business risks relative to the proxy group that affect its cost of equity;
- Section V – Reviews the current capital market conditions and their effect on the cost of equity;
- Section VI – Provides an assessment of the Company's proposed capital structure; and
- Section VII – Summarizes my conclusions and recommendations.

III. COST OF EQUITY ESTIMATION

A. Regulatory Guidelines and Principles

Q. Before addressing your cost of equity analyses, 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.[2] Conceptually, the cost of capital is: (1) forward looking; (2) an opportunity cost; (3) determined in the capital markets; and (4) dependent on, and proportional to, the risk of the investment.[3]

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

[2] A. Lawrence 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, at 13 (1985).

[3] *Id.*

higher returns than debt holders. In the end, 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 quantified through a strict mathematical exercise.[4] Therefore, 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 summarize 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 safe and reliable public utility service for customers at reasonable rates. The Supreme Court of the United

[4] 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.

States ("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 & Improvement Co. v. Public Service Comm'n* ("*Bluefield*");[5] and (2) *Federal Power Comm'n v. Hope Natural Gas Co.* ("*Hope*").[6] In *Bluefield*, the Supreme Court stated:

> A public utility is entitled to such rates as will permit it to earn a return on 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 such profits 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.[7]

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

[5] Bluefield Water Works & Improvement Co. v. Public Service Comm'n 262 U.S. 679, 692 (1923).

[6] Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).

[7] Bluefield Water Works & Improvement Co. v. Public Service Comm'n 262 U.S. 679, 692 (1923).

> financial integrity of the enterprise, so as to maintain its credit and to attract capital.[8]

In summary, the Supreme Court has recognized that the fair rate of return on equity should be: (1) commensurate with 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. Has the Commission also looked to *Hope* and *Bluefield* standards as guidance for setting rates?

A. Yes. The Commission has followed the principles set out in *Hope* and *Bluefield* in establishing a fair return, and the *Hope* and *Bluefield* standards have been codified in Oregon law.[9] For example, in Order No. 07-015, the Commission stated:

> Under these decisions, a utility's authorized rate of return, and the resulting overall rates, should be sufficient to maintain financial integrity, allow the utility to attract capital under reasonable terms, and be commensurate with returns investors could earn by investing in other enterprises of comparable risk. This standard has been codified in Oregon law.[10]

[8] Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).

[9] ORS 756.040.

[10] Public Utility Commission of Oregon, In the Matters of Portland General Electric Company, Docket Nos. UE 180, UE 181, and UE 184, Order No. 07-015, at 28 (January 12, 2007).

Based on those standards, the authorized ROE should provide NW Natural with a reasonable opportunity (which is not a guarantee) to earn a fair return and enable efficient access to external capital under a variety of market conditions.

Q. Why is it important for a utility to be allowed the opportunity to earn a return that is adequate to attract capital on 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, or when it provides service. Utility service requires substantial amounts of capital, and a utility must ensure it has access to external financial capital (debt and equity) on cost-effective terms to finance its assets not only during times when markets are 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).

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. 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.

Further, the financial community carefully monitors utility companies' current and expected financial conditions, including 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.[11] That consideration is especially important during uncertain economic and financial conditions in which the utility may require access to capital markets.

The outcome of the Commission's order in this case, therefore, must provide NW Natural with the opportunity to earn an 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

[11] See, e.g., Moody's Ratings, *Rating Methodology: Regulated Electric and Gas Utilities*, at 2 (August 6, 2024).

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 satisfy each of the three standards discussed above.

Because utilities are capital-intensive and investors have many investment alternatives, NW Natural's financial profile must be adequate on a relative basis to ensure its ability to attract capital at reasonable terms 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 service to customers.

B. 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 Oregon-jurisdictional operations. Because the ROE is a market-based concept, and NW Natural's Oregon service territory is not a separate entity with its own stock price, it is necessary to establish a group of companies that are both publicly traded and comparable to NW Natural in certain fundamental respects to serve as its "proxy" in the ROE estimation process. Even if NW Natural's regulated gas utility operations in Oregon made up the entirety of the publicly traded entity, shorter-term events could bias its market value during a given period. A significant benefit of using a proxy group is that it moderates the effects of anomalous, temporary events associated with any one company.

Q. Please provide a brief overview of NW Natural's operations.

A. NW Natural distributes natural gas to approximately 810,000 residential, commercial, and industrial customers in Oregon and southwest Washington.[12] The Company's Oregon territory represents approximately 88 percent of its customer base, while 12 percent of its customer base is in southwest Washington.[13] NW Natural's long-term issuer rating is A+ from Standard & Poor's ("S&P") with a "Stable" outlook. The Company's senior unsecured shelf rating from Moody's Ratings ("Moody's") is (P)Baa1.[14]

Q. How did you select the companies included in your proxy group?

A. Because estimating the cost of equity is a comparative exercise, it is necessary to develop a proxy group of companies with risk profiles that are reasonably comparable to the subject company. As each company is unique, no two companies will have identical business and financial risk profiles. 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. Consistent with my approaches in the Company's last two rate cases, I developed two proxy groups: a Gas Proxy Group and a Combined Proxy Group. To develop the Gas Proxy Group, I began with the nine companies that

[12] Northwest Natural Holding Company, SEC Form 10-K as of December 31, 2025, at 8.

[13] Northwest Natural Holding Company, SEC Form 10-K as of December 31, 2025, at 8.

[14] Source: S&P Capital IQ. NW Natural's rating from Moody's is a provisional rating.

Value Line Investment Survey ("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 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 Capital IQ, and Zacks Investment Research ("Zacks");
5. Regulated net operating income makes up the majority of the consolidated company's net operating income, on average, for the three years ended 2025;
6. Natural gas distribution net operating income makes up the majority of the consolidated company's net operating income, on average, for the three years ended 2025; and
7. Has not had recent significant merger activity or transaction or 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 Holding Company, I arrived at a proxy group consisting of six publicly traded natural gas utilities shown in Figure 3.

Figure 3: 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. 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. Moreover, a larger proxy group does not necessarily improve the representative nature of the proxy group. In my opinion, 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 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 the 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 35 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 Capital IQ, and Zacks;
5. Regulated net operating income makes up the majority of the consolidated company's net operating income, on average, for the three years ended 2025;
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 2025; and
7. Has not had recent significant merger activity or transaction or a recent significant financial event that could affect its market data or financial condition.

Based on these screening criteria, 10 electric utilities were added to the six gas proxy companies to produce a Combined Proxy Group consisting of the following 16 companies (see also Exhibit NW Natural/403, Nelson), as shown in Figure 4:

Figure 4: 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
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
WEC Energy Group, Inc.	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 operations distinguishes

utilities that are subject to regulation from those with substantial unregulated operations that are exposed to higher risks. In my opinion, these screens collectively reflect key risk factors that investors consider in making investments in utility companies.

C. Cost of Equity Models

Q. What analytical approaches do you rely on to determine NW Natural's ROE?

A. I rely on the constant, multi-stage, 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.[15] Additionally, each model provides a different perspective of investors' views of risk and return. Using multiple methods provides a more comprehensive, and therefore more reliable, perspective on investors' return requirements.

1. Constant Growth DCF 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, which sets the ROE equal to the expected dividend yield plus the expected long-term annual growth rate in perpetuity:

[15] See, e.g., Eugene F. Brigham and Louis C. Gapenski, Financial Management: Theory and Practice, 7th Ed., 1994, at 341.

$$k = \frac{D_0(1+g)}{P} + g \qquad [1]$$

where:

k = the required market cost of equity;

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 in your Constant Growth DCF analysis?

A. I calculate Constant Growth DCF results for each of the proxy group companies using the following inputs:

1. The average daily closing prices for the 30-, 90-, and 180-trading days ended August 31, 2026, for the term *P*;
2. The current quarterly dividend as of August 31, 2026, multiplied by four, for the term $D_{0;}$ and
3. Long-term earnings per share ("EPS") growth rate projections as of August 31, 2026, reported by Zacks, S&P Capital IQ, and Value Line.

Q. Why do you use three averaging periods to calculate an average stock price?

A. I use three averaging periods to calculate an average stock price 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 the 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 EPS 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.[16] 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.[17] 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.

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 results. The mean result combines the average

[16] 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 Vol. 21, No. 2 (Summer 1992); Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988); and Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management (Spring 1986).

[17] See Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988).

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 to 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 5 below, and Exhibit NW Natural/404, Nelson). 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.

Figure 5: Constant Growth DCF Results[18]

	Low	Mean	High
Gas Proxy Group			
30-day average	10.27%	11.42%	12.32%
90-day average	10.24%	11.35%	12.25%
180-day average	10.27%	11.35%	12.25%
Combined Proxy Group			
30-day average	10.11%	10.80%	11.58%
90-day average	10.08%	10.76%	11.50%
180-day average	10.08%	10.77%	11.50%

[18] Exhibit NW Natural/404, Nelson (average of the mean and median proxy group results).

2. Multi-Stage DCF Model

Q. Have you considered another form of the DCF model?

A. Yes, I have. I understand that the Commission has given substantial weight to the Multi-Stage DCF model in prior decisions.[19] Although I generally disagree with the appropriateness of the Multi-Stage DCF model for companies, such as utilities, that are in the mature stage of development, in deference to the Commission, I have also considered a Multi-Stage DCF model.

Q. Please summarize the Multi-Stage DCF model.

A. The Multi-Stage DCF model tempers the assumption of constant growth in perpetuity with a three-stage approach based on near-term, transitional, and long-term growth rates.

The Multi-Stage DCF model transitions from near-term growth (i.e., the average of Value Line, Zacks, and S&P Capital IQ earnings forecasts used in the Constant Growth model) for the first stage (years 1-5) to the long-term forecast of nominal Gross Domestic Product ("GDP") growth for the third stage (year 11 and beyond). The second, or transitional, stage connects near-term growth with long-term growth by changing the growth rate each year on a pro rata basis. In the terminal stage, the dividend cash flow then grows in perpetuity at the same rate as nominal GDP (for a total of 200 years). The ROE is the internal rate of return based on the current average stock price and this stream of dividend payments.

[19] See, e.g., In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision, Docket No. UE 374, Order No. 20-473, at 30 (December 18, 2020).

The projected nominal GDP growth rate was developed using data reported by Blue Chip Financial Forecasts for the period from 2033 to 2037.[20] This forecast is based on a projected real (constant dollar) GDP growth rate of 1.90 percent and a projected inflation rate of 2.20 percent, for a projected nominal GDP growth rate of 4.14 percent.[21] Additionally, as shown in Exhibit NW Natural/405, Nelson, I present a Multi-Stage DCF analysis using the long-term historical average growth rate in nominal GDP of 6.32 percent from 1929 to 2025, as an alternative estimate of third-stage growth.[22] The projected GDP growth rate is materially lower than nearly 100 years of economic history, yet no evidence explains what structural shifts in the economy are expected to occur that would reduce GDP growth by one-third over the long term relative to history. Therefore, it is reasonable to assume that, over the long term, growth in the U.S. economy will revert toward its long-term average. The results of the Multi-Stage DCF analysis are shown in Figure 6 below (see also Exhibit NW Natural/405, Nelson).

[20] Blue Chip Financial Forecasts, Vol. 45, No. 6, at 14 (June 1, 2026).

[21] 4.14% = (1 + 1.90%) x (1 + 2.20%) – 1

[22] Source: Bureau of Economic Analysis.

Figure 6: Multi-Stage DCF Results[23]

	Gas Proxy Group		Combined Proxy Group	
	Projected GDP Growth (4.14%)	**Historical GDP Growth (6.32%)**	**Projected GDP Growth (4.14%)**	**Historical GDP Growth (6.32%)**
30-day average	8.54%	10.26%	8.55%	10.28%
90-day average	8.50%	10.22%	8.47%	10.20%
180-day average	8.53%	10.26%	8.49%	10.22%

Q. Do you have concerns with the Multi-Stage DCF model and the results produced by it?

A. Yes, I do. The Multi-Stage DCF results using projected GDP growth are below all ROEs authorized for a natural gas utility in the last 47 years and, therefore, fail to meet the *Hope* and *Bluefield* comparable return standard. As noted earlier, the unduly low Multi-Stage ROE estimates are driven by an inexplicably low projected GDP terminal growth rate. Whereas the estimates using the long-term historical GDP growth rate are supported by the ROE estimates of the other models, the Multi-Stage DCF results using projected GDP growth diverge significantly from the other models.

Moreover, the Multi-Stage DCF model projects dividends using growth rates that change over time, beginning with analysts' near-term EPS growth forecasts and transitioning to long-term nominal GDP growth in perpetuity. The stock price, dividend yield and expected growth rate are interrelated: all else equal, higher

[23] Exhibit NW Natural/405, Nelson.

expected growth increases demand for a stock, raising its price and lowering its dividend yield, and vice versa. Because the model takes the observed market price as given and solves for the return that equates that price to the projected dividends, its results are only as reliable as the consistency between its growth inputs and the growth expectations already reflected in the price.

A second, related concern is the assumption that all companies' growth will equal GDP growth in the long term, when in fact each company is unique and the growth and prospects of each company are unique. Using a single long-term growth rate for all proxy companies is illogical and inconsistent with financial theory.

Q. Has any other regulatory commission agreed with these concerns regarding the Multi-Stage DCF model?

A. Yes. In an order for Duke Energy Carolinas, the North Carolina Utilities Commission ("NCUC") acknowledged these flaws with the Multi-Stage DCF model and rejected the results produced by it, which ranged from 8.41 percent to 8.56 percent.[24] Other commissions have expressed concern about using the Multi-Stage DCF model, such as the Illinois Commerce Commission:

[24] North Carolina Utilities Commission Docket No. E-7, Sub 1276, *Order Accepting Stipulations, Granting Partial Rate Increase, Requiring Public Notice, and Modifying Lincoln CT CPCN Conditions*, at 201-203 (December 18, 2023).

> Both Staff and CUB/PCR/City utilized two types of DCF models to estimate the cost of common equity: the constant growth model and the non-constant growth model… The Commission observes that these estimates are well over 100 basis points less than both parties' constant growth DCF estimates. The estimates are also well below any ROE the Commission has approved for a natural gas utility. Neither party attempted to explain the divergence. Therefore, the Commission will not consider the non-constant growth DCF estimates in developing the authorized ROE for the Companies.[25]

Q. Are a utility's earnings strongly related to the national GDP growth?

A. No. A utility's earnings are primarily driven by rate base growth, which is not necessarily related to growth in the national economy. For example, utilities must invest in their systems to replace aging infrastructure regardless of customer and sales growth or growth in the national economy. The assumption that utilities' earnings are limited by national GDP growth is an unfounded constraint.

Q. What is your recommendation regarding the results from the Multi-Stage DCF analysis?

A. The presumption that all companies will grow at the rate of GDP in the long run and that the dividend yield will remain constant as growth declines over time limits the usefulness of the Multi-Stage DCF model. Therefore, in my opinion, it is inappropriate to give substantial or exclusive weight to the results of the Multi-Stage DCF model. However, in deference to the Commission's and the

[25] Illinois Commerce Commission Docket Nos. 23-0068 and 23-0069 (Cons.), North Shore Gas Company and The Peoples Gas Light and Coke Company, Proposed general increase in rates and revisions to service classification, riders and terms and conditions of service, Order at 200 (November 16, 2023).

Commission Staff's past preference for the model, I have considered it with the results of the other DCF model approaches.

3. 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.

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 that all cash flows received by investors are paid annually.[26]

[26] Roger A. Morin, Ph.D., New Regulatory Finance, Public Utilities Reports, Inc., at 344 (2006).

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 market cost of equity.[27]

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 each company and multiplied them by one plus the earnings growth rate (i.e., 1 + *g*). For the *P* 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 Exhibit NW Natural/406, Nelson). As with my Constant Growth DCF results, I rely on the average of the mean and median proxy group results.

[27] Because the required market cost of equity (*k*) is a variable in the dividend yield calculation, the Quarterly Growth DCF model is solved iteratively.

Figure 7: Quarterly Growth DCF Results[28]

	Low	Mean	High
Gas Proxy Group			
30-day average	10.50%	11.66%	12.58%
90-day average	10.47%	11.58%	12.50%
180-day average	10.50%	11.58%	12.50%
Combined Proxy Group			
30-day average	10.31%	11.01%	11.79%
90-day average	10.27%	10.96%	11.70%
180-day average	10.28%	10.97%	11.72%

4. 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 approach 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 cost of equity for a security;

β = the Beta coefficient of that security;

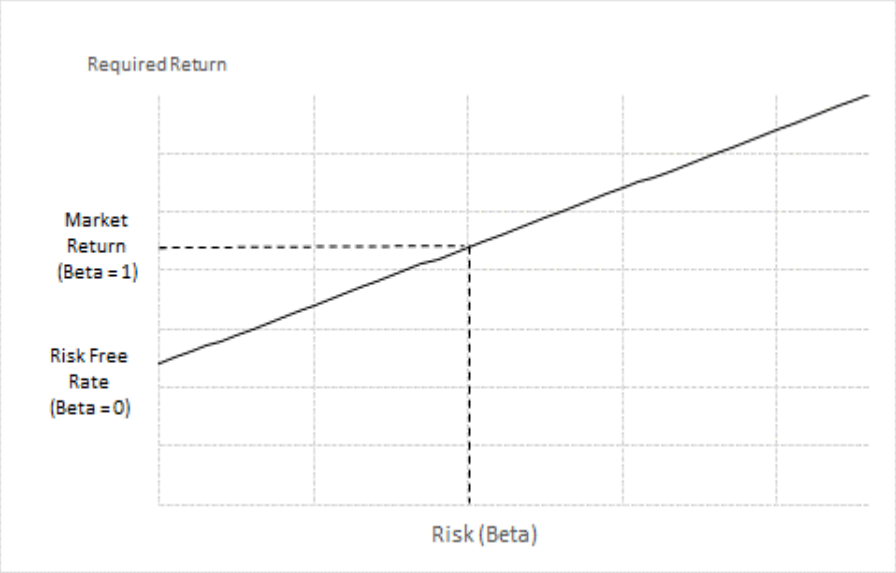
[28] See Exhibit NW Natural/406, Nelson.

r_f = the risk-free rate of return; and

r_m = the required return for 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 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:

$$\beta_{j} = \frac{\sigma_j}{\sigma_m} x\ \rho_m \qquad [4]$$

where:

β_j = the Beta coefficient of company "*j*";

σ_j = the standard deviation of returns for company "*j*";

σ_m = the standard deviation of returns for the broad market ("*m*," as measured, for example, by the S&P 500 Index); and

$\rho_{j,m}$ = the correlation of returns between company "*j*" and the broad market, "*m*."

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.

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Q. What risk-free rates did you use 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., 5.21 percent)[29] and (2) a projected 30-year Treasury yield (i.e., 4.83 percent).[30]

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 analysis?

A. As shown in Exhibit NW Natural/408, Nelson, 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 August 31, 2026. 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. Second, I consider a version of the CAPM analysis using the

[29] Federal Reserve Bank of St. Louis (FRED), Series DGS 30, Market Yield on U.S. Treasury Securities at 30-Year Constant Maturity, Quoted on an Investment Basis, https://fred.stlouisfed.org/series/DGS30 (as of August 31, 2026).

[30] The average of: (1) the average projected 30-year Treasury yield for the six quarters ended Q4 2027 and (2) the average long-term projected 30-year Treasury yield for the years 2028-2032 and 2033-2037 reported by Blue Chip Financial Forecasts. See Blue Chip Financial Forecasts, September 2026 Edition, at 9 (September 1, 2026); Blue Chip Financial Forecasts, Vol. 45, No. 6, at 14 (June 1, 2026).

Bloomberg Beta coefficients calculated using weekly return data over the ten years ended August 31, 2026, rather than a five-year period.

Q. What estimates of the market return do you use to calculate the market risk premium?

A. I apply two estimates of the market return. The first calculates the market capitalization-weighted ROE of the S&P 500 Index by applying the Constant Growth DCF model described earlier to the S&P 500 Index. The second estimate applies the long-run historical arithmetic average market return of 12.23 percent between 1926 and 2025 reported by Kroll (formerly Duff & Phelps).[31]

Q. Please explain the forward-looking DCF approach to estimating the market return.

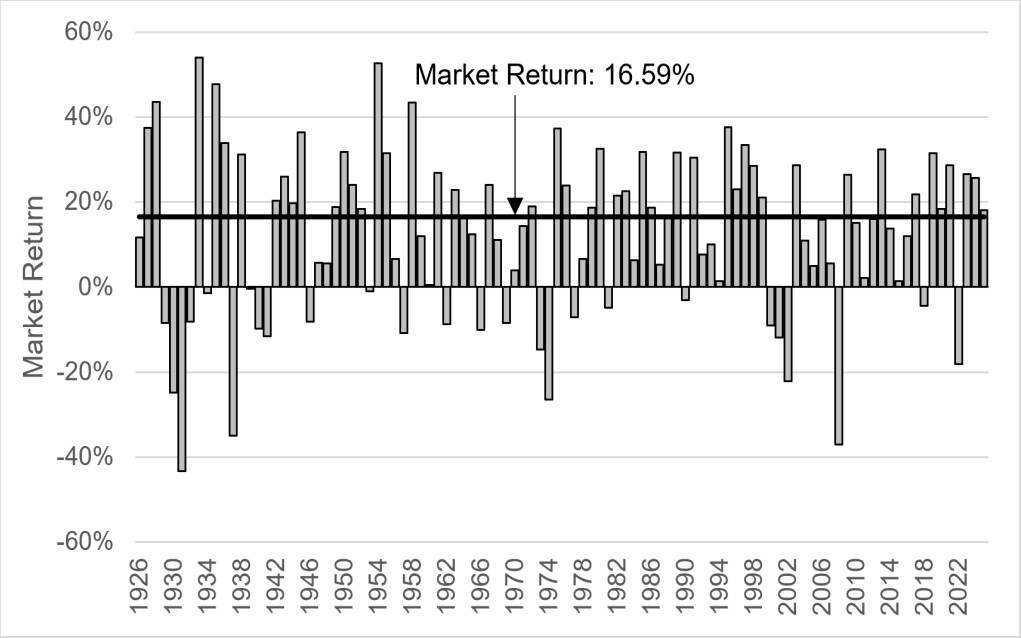
A. Using the Constant Growth DCF model described earlier, I develop two forward-looking estimates of the market return for the S&P 500 Index using dividend yields from S&P Capital IQ and earnings growth rates from Bloomberg Professional and Value Line. As shown in Exhibit NW Natural/407, Nelson, these independent estimates of the market return range from 16.59 percent to 26.22 percent. To be conservative, I rely on Value Line's market return estimate of 16.59 percent in my CAPM analysis.

[31] Kroll, Cost of Capital Navigator.

Q. Is the Value Line DCF-based market return estimate of 16.59 percent consistent with actual observed returns on the market?

A. Yes, it is. As shown in Figure 9 below, a market return of 16.59 percent or higher occurred in 47 of the last 100 years (i.e., nearly 50 percent of the time). Since 2009, the annual market return has averaged 15.72 percent, and equaled or exceeded 16.59 percent in nine of the last 17 years. In other words, an annual market return of 16.59 percent, or higher, has occurred frequently and is not an outlier.

Figure 9: Annual Market Return (1926–2025)[32]



[32] Kroll, 2023 SBBI Yearbook, Appendix A-1 (years 1926-2022); Kroll, Cost of Capital Navigator (years 2023-2025).

Q. Why do you also consider the long-term arithmetic average historical return on the market of 12.23 percent as an alternative estimate of the market return?

A. My objective is to develop a reasonable estimate of the market return over the long term to calculate a market risk premium. Because the cost of equity is forward looking, any estimate—whether based on historical or projected data—assumes the estimate reflects investors' expectations into the future. Although the 16.59 percent market return is highly consistent with historically observed market returns (as shown in Figure 9 above), it is above the long-term arithmetic annual average market return. Therefore, it may be reasonable to expect that, over the long term, the market return will revert to its long-run historical arithmetic average. From that perspective, the application of the long-run historical arithmetic average market return as an alternate estimate of the market return is prospective in nature.

Q. With the risk-free rates and market return estimates described above, how do you calculate the market risk premium?

A. I apply two estimates of the risk-free rate and two estimates of the market return. Combined, those variables produce four estimates of the market risk premium, ranging from 7.03 percent to 11.76 percent, as shown below in Figure 10.

Figure 10: Market Risk Premium Estimates

	Current Risk-Free Rate (5.21%)	Projected Risk-Free Rate (4.83%)
Value Line DCF-based Forward Market Return (16.59%)	11.38%	11.76%
Long-Term Historical Average Market Return (12.23%)	7.03%	7.40%

Q. What are the results of your CAPM analyses?

A. As shown in Figure 11 below, the CAPM results range from 9.71 percent to 13.54 percent.

Figure 11: CAPM Results[33]

	Current 30-Year Treasury Yield (5.21%)	Projected 30-Year Treasury Yield (4.83%)
Gas Proxy Group		
Forward Market Return, 5-Yr Average Betas	12.87%	12.75%
Forward Market Return, 10-Yr Bloomberg Betas	13.54%	13.44%
Historical Market Return, 5-Yr Average Betas	9.94%	9.81%
Historical Market Return, 10-Yr Bloomberg Betas	10.35%	10.25%
Combined Proxy Group		
Forward Market Return, 5-Yr Average Betas	12.71%	12.58%
Forward Market Return, 10-Yr Bloomberg Betas	13.47%	13.36%
Historical Market Return, 5-Yr Average Betas	9.84%	9.71%
Historical Market Return, 10-Yr Bloomberg Betas	10.31%	10.20%

[33] See Exhibit NW Natural/408, Nelson.

Q. Did you consider another form of the CAPM?

A. Yes, I also considered the 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 to the market risk premium, without any effect from the Beta coefficient.[34] 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 cost of equity for a security;

β = the Beta coefficient of that security;

r_f = the risk-free rate of return; and

r_m = the required return for 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 underestimates the Alpha (α), or the constant return term.[35]

[34] See, e.g., Roger A. Morin, Ph.D., New Regulatory Finance, at 189-190 (2006).

[35] Roger A. Morin, Ph.D., New Regulatory Finance, at 191 (2006).

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.[36] Fama and French state that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[37] Similarly, Dr. 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:
>
> $$K = R_F + 0.25(R_M - R_F) + 0.75\,\beta(R_M - R_F)$$[38]

Q. Does the use of adjusted Beta coefficients in the ECAPM address the empirical issues with the CAPM?

A. No, it does not. The ECAPM is an adjustment to the slope of the SML, not to the Beta coefficient. Beta coefficients are adjusted because of their general regression

[36] 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.

[37] Eugene F. Fama and Kenneth R. French, *The Capital Asset Pricing Model: Theory and Evidence*, Journal of Economic Perspectives, Vol. 18, No. 3, Summer 2004, at 33.

[38] Roger A. Morin, Ph.D., New Regulatory Finance, at 175, 190 (2006).

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, Dr. 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 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.[39]

Therefore, it is appropriate to rely on adjusted Beta coefficients in both the CAPM and ECAPM.

[39] Roger A. Morin, Ph.D., New Regulatory Finance, at 191 (2006).

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.[40] 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 at predicting the observed risk premium for the various utility subgroups.

Q. Have any regulatory commissions explicitly accepted the ECAPM?

A. Yes. The New York Public Service Commission ("NYPSC") relies on both the traditional and empirical forms of the CAPM.[41] Additionally, the NCUC accepted the ECAPM in recent orders for Duke Energy Carolinas and Duke Energy

[40] Stéphane Chrétien and Frank Coggins, *Cost of Equity for Energy Utilities: Beyond the CAPM*, Energy Studies Review, Vol. 18, No. 2 (2011).

[41] See New York Public Service Commission, Case 16-G-0058, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corporation d/b/a National Grid for Gas Service, Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plans, at 32 (December 16, 2016).

Progress.[42] I note that both the NYPSC and NCUC used adjusted Beta coefficients with the ECAPM analysis. Additionally, I am aware that the ECAPM has been accepted by regulatory commissions in Alaska, Maryland, and Mississippi.[43] Lastly, I am aware the ECAPM has been presented by state regulatory commission staff in Maryland and Nevada, and by the Department of Commerce in Minnesota.[44] In summary, the ECAPM is an accepted approach used by investors and regulators and should be accepted by the Commission.

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 12 below.

[42] See In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation, Docket No. E-7, Sub 1276, Order Accepting Stipulations, Granting Partial Rate Increase, Requiring Public Notice, and Modifying Lincoln CT CPCN Conditions, at 209-210 (December 18, 2023); In the Matter of Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation, Docket No. E-2, Sub 1300, Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Public Notice, at 162-163 (August 18, 2023).

[43] See Regulatory Commission of Alaska, Docket No. P-97-4, Order No. 151, at 146 (November 27, 2002); Maryland Public Service Commission, Case No. 9311, Order No. 85724, at 105 (July 12, 2013); Mississippi Public Service Commission, Docket No. 01-UN-0548, *Notice of Intent of Mississippi Power Company to Change Rates for Electric Service in its Certificated Areas in the Twenty-Three Counties of Southeast Mississippi*, Final Order, at 16-19 (December 3, 2001).

[44] See Maryland Public Service Commission, Case No. 9311, Order No. 85724, at 88 (July 12, 2013); Minnesota Public Utilities Commission, MPUC Docket No. G011/GR-15-736, *Findings of Fact, Conclusions of Law, and Recommendation*, at 29 (August 19, 2016); Public Utilities Commission of Nevada, Docket No. 12-02019, Second Modified Final Order, at 36 (March 20, 2013).

Figure 12: Summary of ECAPM Results[45]

	Current 30-Year Treasury Yield (5.21%)	Projected 30-Year Treasury Yield (4.83%)
Gas Proxy Group		
Forward Market Return, 5-Yr Average Betas	13.80%	13.71%
Forward Market Return, 10-Yr Bloomberg Betas	14.30%	14.23%
Historical Market Return, 5-Yr Average Betas	10.51%	10.42%
Historical Market Return, 10-Yr Bloomberg Betas	10.82%	10.75%
Combined Proxy Group		
Forward Market Return, 5-Yr Average Betas	13.68%	13.58%
Forward Market Return, 10-Yr Bloomberg Betas	14.25%	14.17%
Historical Market Return, 5-Yr Average Betas	10.44%	10.34%
Historical Market Return, 10-Yr Bloomberg Betas	10.79%	10.71%

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[45] Exhibit NW Natural/408, Nelson.

5. Bond Yield Plus Risk Premium Analysis

Q. Please describe the Bond Yield Plus Risk Premium approach that you used.

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 with equity ownership. The approach estimates the cost of equity as the sum of the 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 1,409 natural gas utility rate proceedings between January 1, 1980, and August 31, 2026. To reflect the prevailing bond yields during the pendency of each proceeding, 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 natural gas rate cases and 201 days for the electric rate cases). For the electric utilities in the Combined Proxy Group, I performed the same analysis using 1,888 electric utility rate cases between January 1, 1980, and August 31, 2026.

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.[46] That finding is particularly relevant given the relatively low, but increasing, level of current Treasury bond yields.

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 is expressed as a function of the natural log of the 30-year Treasury yield:

$$RP = \alpha + \beta(LN(T_{30})) \qquad [6]$$

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[46] 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).

Figure 13: Gas Equity Risk Premium[47]

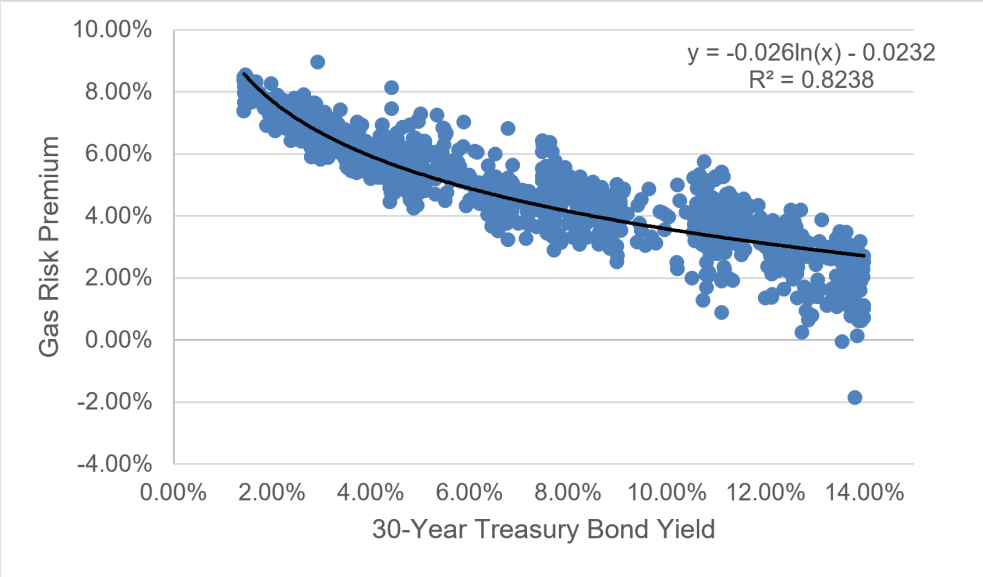
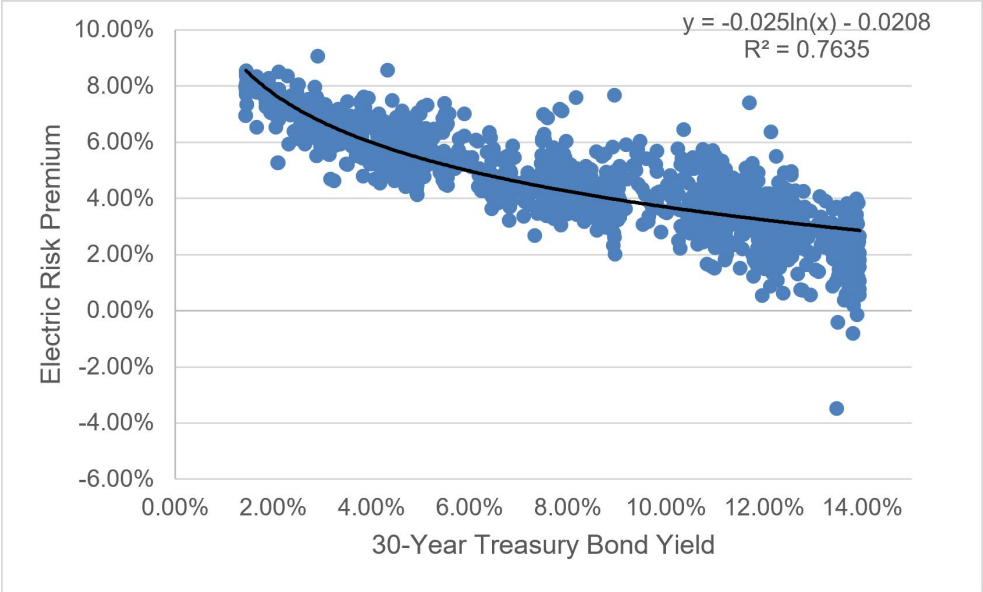


Figure 14: Electric Equity Risk Premium[48]



[47] Exhibit NW Natural/409, Nelson.

[48] Exhibit NW Natural/409, Nelson.

As Figure 13 and Figure 14 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. 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."[49] Based on the regression coefficients in Figures 13 and 14, the implied ROE ranges from 10.28 percent to 10.54 percent for natural gas and electric utilities (see Figure 15 and Exhibit NW Natural/409, Nelson).

Figure 15: Risk Premium Results Using 30-Year Treasury Yield

Gas Risk Premium	**30-Year Treasury Bond**	**Risk Premium**	**Return on Equity**
Current 30-Year Treasury	5.21%	5.25%	10.46%
Projected 30-Year Treasury	4.83%	5.44%	10.28%
Electric Risk Premium	**30-Year Treasury Bond**	**Risk Premium**	**Return on Equity**
Current 30-Year Treasury	5.21%	5.33%	10.54%
Projected 30-Year Treasury	4.83%	5.52%	10.35%

[49] Roger A. Morin, Ph.D., New Regulatory Finance, Public Utilities Reports, Inc., at 128 (2006).

Q. Do investors use a regression-based approach similar to your Risk Premium method?

A. Yes, they do. As an example, in a December 2023 report from UBS on the utility sector, the investment bank presented a regression analysis which showed that current authorized ROEs were below what would be expected given the level of the 10-year Treasury bond yield – i.e., the premise of my Risk Premium analysis.[50]

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 relevant benchmark 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 authorized ROE also provides a signal to investors about the degree 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.

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

[50] UBS, "US Utilities 2024 Outlook: A Year for Resolutions and Resolve," December 12, 2023, at 10.

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. The change in the risk premium (and therefore the ROE estimate) as a result of a change in bond yields is less than one-to-one. For example, as shown in Figure 15 above, a 38-basis-point increase in the bond yield (from 4.83 percent to 5.21 percent) results in an 18-basis-point change in the ROE from 10.28 percent to 10.46 percent for the Gas Proxy Group.

6. Flotation Costs

Q. What are flotation costs?

A. Flotation costs are the costs associated with issuing equity, including out-of-pocket costs for preparing, filing, underwriting, and other costs of issuing equity. These costs reduce the net proceeds a company receives from an equity issuance. As explained below, failing to allow for the recovery of flotation costs inhibits a utility's ability to fully earn its authorized ROE, diminishing its ability to efficiently attract capital.

Q. Why is it important to recognize flotation costs in the authorized ROE?

A. To attract and retain investors, a regulated utility must have a reasonable opportunity to earn a return that is competitive with returns available on other investments of similar risk and compensatory to investors. To the extent a company is denied the opportunity to recover equity issuance costs, actual returns will fall short of expected (or required) returns, diminishing its ability to attract capital on reasonable terms.

Q. Are flotation costs part of the utility's invested costs or expenses?

A. Flotation costs are invested (i.e., capital) costs of the utility and are reflected on the balance sheet under "paid-in capital." Flotation costs are not expenses and, therefore, are not included on the income statement. Like rate base or long-term debt issuance costs, flotation costs are incurred over time. Although much of a utility's flotation costs are incurred prior to the test year, they remain part of the cost structure long after they are incurred. As such, recovery of equity issuance costs is appropriate for the same reasons debt issuance costs are recoverable. Even if no new issuances are planned in the near future, failure to allow such cost recovery may deny NW Natural the opportunity to earn its required rate of return going forward.

Q. Do the DCF, CAPM, and Risk Premium models account for the effect of flotation costs?

A. No. The models used to estimate the investor-required return assume no transaction costs (i.e., "friction"); therefore, flotation costs are not reflected in stock

prices or the risk premium. Consequently, an adjustment must be made to the quantitative model results to reflect equity issuance costs.

Q. Does Staff include flotation costs in its ROE analyses and recommendations?

A. Yes, Staff has routinely included 12.5 basis points for flotation costs.[51]

Q. How do you calculate the effect of flotation costs on the cost of equity?

A. As shown in Exhibit NW Natural/410, Nelson, I calculate the weighted average issuance costs for the two most recent equity issuances for each Combined Proxy Group company, as applicable. I then modify the DCF calculation to adjust the dividend yield to reimburse investors for direct equity issuance costs. As Exhibit NW Natural/410, Nelson, shows, a reasonable estimate of flotation costs is approximately seven basis points (0.07 percent).

7. Evaluation of Model Results

Q. Please explain how you considered the results of the DCF, CAPM, and Risk Premium analyses to arrive at your ROE recommendation.

A. Based on the results of the analyses described earlier, I estimate an ROE range of 9.75 percent to 11.75 percent, inclusive of flotation costs, for NW Natural. The low end of my recommended range is the approximate average of the most conservative approaches for both proxy groups (the low DCF estimates and the

[51] See, e.g., Public Utility Commission of Oregon, In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision, Docket No. UG 490, Opening Testimony of Matt Muldoon, Staff/105, Muldoon (April 18, 2024); In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision, Docket No. UG 435, Opening Testimony of Matt Muldoon, Staff/104, Muldoon (April 22, 2022).

historical CAPM estimates using five-year Beta coefficients and projected risk-free rate). The high end of my recommended range is the approximate average of the mean and high DCF estimates, the average CAPM estimates, and the average Risk Premium estimates.

IV. 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 proxy group, including (1) its capital expenditure program, (2) the regulatory environment in which it operates, (3) the risk associated with the environmental policy relative to its proxy group companies, and (4) the Company's relatively small size. While I do not make an explicit adjustment to my ROE recommendation to account for these risks, they should be considered in determining the Company's cost of equity.

A. Capital Expenditures 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. Because NW Natural is a capital-intensive enterprise, the allowed ROE should enable it 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. As discussed throughout my Direct Testimony, a

return that is adequate to attract capital on reasonable terms enables a utility to provide safe and 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 half as much revenue per dollar of assets as the non-utility U.S. companies covered by Value Line.[52] 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 are often cash flow negative (i.e., cash spent on plant investment is often greater than cash flow received from operations), it is critical that regulation enable timely cost recovery and provide predictable, adequate, and achievable allowed returns that support the financial integrity of the utility.

Q. Please briefly summarize the Company's projected capital investments.

A. NW Natural is planning approximately $1.6 billion to $1.8 billion in capital expenditures during the 2026 to 2030 time frame, or approximately $300 to $400 million per year.[53] The investments are primarily related to safety and reliability investments and customer growth. In total, these capital expenditures are approximately 48 percent to 54 percent of the Company's total net utility plant of

[52] Source: Value Line, accessed September 14, 2026.

[53] Source: Northwest Natural Investor Presentation, August 5, 2026, at 12.

$3.31 billion as of December 31, 2025.[54] Because the Company must continue to make substantial investments in its utility operations regardless of the economic and financial market environment at the time, it will require efficient access to external capital.

B. Regulatory Environment

Q. Please explain the importance of the regulatory environment in assessing a utility's cost of capital.

A. 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 utilities' credit and financial integrity, especially during adverse market conditions. Rating agencies also recognize the importance of the regulatory environment when assessing a utility's business risk profile.

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.[55] 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

[54] Source: S&P Capital IQ.

[55] Moody's Ratings, *Rating Methodology*: *Regulated Electric and Gas Utilities,* at 2 (August 6, 2024).

> flow metrics than comparably rated companies in other industrial sectors.
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> ***
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> In situations where the regulatory framework is less supportive, or is more contentious, a utility's credit quality can deteriorate rapidly.[56]

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."[57] 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."[58] Those four subfactors are (1) regulatory stability, (2) tariff-setting procedures and design, (3) financial stability, and (4) regulatory independence and insulation.[59] With respect to capital expenditures, S&P notes that a 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."[60] Thus, predictability and consistency of regulatory actions are among the primary considerations for the rating agencies, as is full and timely cost recovery, including recovery of capital costs.

[56] Moody's Investors Service, Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities, at 2 (June 18, 2010).

[57] S&P Global Ratings, *Sector-Specific Corporate Methodology*, Section 29 Regulated Utilities, at 147 (April 4, 2024).

[58] *Id*.

[59] *Id*.

[60] *Id*.

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 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 allowed 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. Is there evidence that investors perceive NW Natural's Oregon regulatory risk to be greater than that of comparable utilities?

A. Yes. Regulatory Research Associates ("RRA"), the regulatory research branch of S&P Capital IQ, maintains three principal rating categories for regulatory climates: Above Average, Average, and Below Average. Within the principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger rating; 2, a mid-range rating; and 3, a weaker rating. The evaluations are assigned from an investor perspective and indicate the relative regulatory risk associated with the ownership of securities issued by the jurisdiction's utilities. In June 2025, RRA lowered the Oregon jurisdiction's rating to Average/3 from Average/2, and considers Oregon regulation to be "somewhat restrictive from an investor perspective."[61] RRA also noted that the Company's

[61] RRA, "Ore. regulators approve NW Natural gas rate increase, slight equity return boost" (October 30, 2025).

authorized ROE was below the prevailing authorized ROEs for natural gas utilities.[62]

Authorized returns are one of several factors that shape investors' assessment of Oregon's regulatory environment. For example, NW Natural's rate case Docket No. UG 490, in which the Company reached a settlement on most issues, including the cost of capital (i.e., the ROE, capital structure, and cost of debt), did not reach settlement on NW Natural's line extension allowance. The Commission ultimately ordered that the Company's allowance for new gas customers to connect to the system be phased out by November 1, 2027. The termination of the allowance for new customers to connect to the system is likely to impede the Company's ability to add new customers, thus increasing its risk relative to its peers that operate in jurisdictions that are not disincentivizing gas utility customer growth. In other words, removing the line extension allowance affects NW Natural's growth prospects relative to other gas utilities without such restrictions. Additionally, restrictions on NW Natural's ability to add customers may place a greater burden of capital and operating costs on existing customers, which could result in higher rates for existing customers than would occur if NW Natural retained its line extension allowance. In the end, investors will require a higher return to compensate for the increase in NW Natural's risk.

[62] *Id*.

Following NW Natural's more recent rate case in Docket No. UG 520, RRA noted that despite a modest increase in authorized ROE, the authorized ROE of 9.50 percent is "somewhat below the prevailing average 9.78% ROE authorized for gas utilities in rate cases decided through the first nine months of 2025, and the 9.70% average for 2024."[63]

Q. Have you compared NW Natural's regulatory risk relative to the natural gas utilities in 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 and the test year convention.

As shown in Exhibit NW Natural/411, Nelson:

- Like NW Natural, all the proxy group operating companies with a retail supply obligation have a purchased gas cost recovery mechanism;
- 100 percent have a mechanism to mitigate weather or volumetric risk, such as revenue decoupling or a weather normalization adjustment mechanism, similar to the Company's partial weather normalization decoupling mechanism for its residential and commercial customers;

[63] *Id*.

- 100 percent have a mechanism for timely recovery of new capital investments like NW Natural; and
- 54 percent operate in jurisdictions that permit the use of fully or partially forecasted test years. Notably, NW Natural's test year was a contested issue during its last proceeding, Docket No. UG 520.[64]

Collectively, these mechanisms support the Company's earnings. On balance, I conclude that the regulatory structures available to NW Natural are not superior to those available to the proxy companies and there are aspects that are less supportive.

Q. Do the Company's regulatory mechanisms reduce its risk profile relative to its peers?

A. No, they do not. While NW Natural's regulatory mechanisms serve to reduce the Company's absolute level of risk, the cost recovery mechanisms employed by NW Natural are similar to those used by the proxy group. As such, its risk relative to the proxy group is not reduced as a result of its ratemaking structure. In other words, the Company's regulatory mechanisms are credit supportive, but not necessarily credit enhancing relative to its peers. Further, because the proxy companies all have similar mechanisms, any effects on the cost of equity associated with the rate mechanisms are implicitly captured in the analytical model results. Therefore, my ROE recommendation considers the fact that NW Natural

[64] Public Utility Commission of Oregon, In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision, Docket No. UG 520, Order No. 25-420, at 4 (October 24, 2025).

and its peers all have mechanisms that enable timely cost recovery and support earnings.

It is important to remember that risk assessment is a comparative exercise. Rate adjustment mechanisms are common in the industry, and the financial community is fully aware of their prevalence. In fact, rate adjustment mechanisms have become more common in the industry, not less. As noted earlier, the proxy companies all have mechanisms similar to NW Natural. 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, NW Natural's regulatory mechanisms simply render it more comparable to its peers, and not less risky from a creditworthiness standpoint.

Q. Please describe the Company's proposed bridge mechanism.

A. As explained in the Direct Testimony of NW Natural witness Kyle T. Walker (Exhibit NW Natural/1200), the Company is proposing a bridge mechanism that would incorporate cost recovery until the Company files for a multi-year rate plan ("MYRP") as required by Section 7 of HB 3179, the FAIR Energy Act of 2025. The bridge increase equals the difference between the test year's 13-month average of monthly average plant in service and end-of-period plant in service as of October 31, 2028, and will take effect October 31, 2028, for residential customers and

November 1, 2028, for non-residential customers. The MYRP, as outlined in Order No. 26-370,[65] will have rates effective October 31, 2029, for residential customers and November 1, 2029, for non-residential customers.

Q. Would approval of the proposed bridge mechanism cause you to reconsider your recommended ROE?

A. No, it would not. While the proposed bridge mechanism provides the Company timely recovery of prudent investments in a transparent and efficient ratemaking process, it does not reduce NW Natural's overall regulatory or investment risk to warrant a lower ROE. The bridge mechanism's limited duration and scope are intended to address the one-year period between the rates established in this proceeding and the commencement of the Company's first MYRP. Moreover, the relevant consideration in determining the Company's ROE is its risk relative to the proxy companies. As discussed above, regulatory mechanisms that provide for more timely cost recovery are common among regulated utilities. NW Natural's proposed bridge mechanism is intended to achieve similar outcomes as mechanisms available to its peers, and does not reduce the Company's risk or its required ROE.

[65] Public Utility Commission of Oregon, In the Matter of Rulemaking to Establish General Rate Revisions Filing Schedule and Exception Process (HB 3179 Implementation), Docket No. AR 677, Order No. 26-370 (September 30, 2026).

Q. Would a potential future adoption of an MYRP mechanism cause you to reassess your ROE recommendation?

A. No, it would not. My ROE recommendation reflects a holistic assessment of the Company's overall business and regulatory risk profile, including the regulatory framework in Oregon relative to those of the proxy group companies. While the adoption of an MYRP mechanism may reduce certain aspects of regulatory lag, MYRP regulatory frameworks and similar regulatory mechanisms such as capital trackers, forecasted test years, and decoupling are standard in the industry and would not be unique to NW Natural. Furthermore, investors are aware of these mechanisms from utility disclosures; as such, these mechanisms are already embedded in the market-based models used in my analysis.

It is important to note that simply implementing an MYRP does not automatically eliminate risk for the utility. Notably, New York utilities, which have historically implemented MYRPs, have been awarded "stay-out" premiums because "the JP's [Joint Proposal] ROE is supported by the Commission's long-standing recognition that the extended term of a multi-year JP results in more financial risk to Company shareholders as forecasts become less certain given that economic conditions may change during the lengthened period of the rate plan."[66] Furthermore, the Commission has recognized that alternative ratemaking

[66] New York Public Service Commission, Case 23-G-0627, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service, Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plan with Minor Modifications, at 33 (December 19, 2024).

mechanisms do not uniformly eliminate regulatory lag, noting that such mechanisms are effective at recovering new investments but may not provide corresponding recognition of depreciated assets and other offsetting changes.[67] Accordingly, the effect of any MYRP on overall regulatory risk depends on the specific design and operation of the mechanism and should not be assumed to automatically reduce risk.

Q. What are your conclusions regarding the Company's regulatory risk environment and its need to access capital?

A. NW Natural requires ongoing access to capital markets on favorable terms to provide safe and reliable service. The Company's regulatory mechanisms generally support its ability to recover costs in a timely manner and render it comparable in risk to its peers. Therefore, there is no reduction in the Company's risk, or its ROE, on account of its regulatory mechanisms.

The regulatory environment is one of the most important factors considered by both debt and equity investors in assessing the risks and prospects of utility companies. The return authorized by the Commission in this proceeding will send a signal to the financial community regarding the constructiveness of the regulatory environment in Oregon. From the perspective of investors, the authorized return should enable the Company to generate the cash flow needed to meet its near-term financial obligations, make the capital investments needed to maintain and

[67] Public Utility Commission of Oregon, In re Portland General Electric Co., Docket No. UE 435, Order No. 24-454, at 122 (December 20, 2024).

expand its system, and maintain sufficient levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally generated funds, but also from efficient access to external capital. Because utilities are capital-intensive enterprises, it is essential that the ROE authorized in this proceeding enable NW Natural to continue to invest the capital necessary to meet its obligation to serve in a variety of market environments, as well as maintain confidence in Oregon's regulatory environment among credit rating agencies and investors.

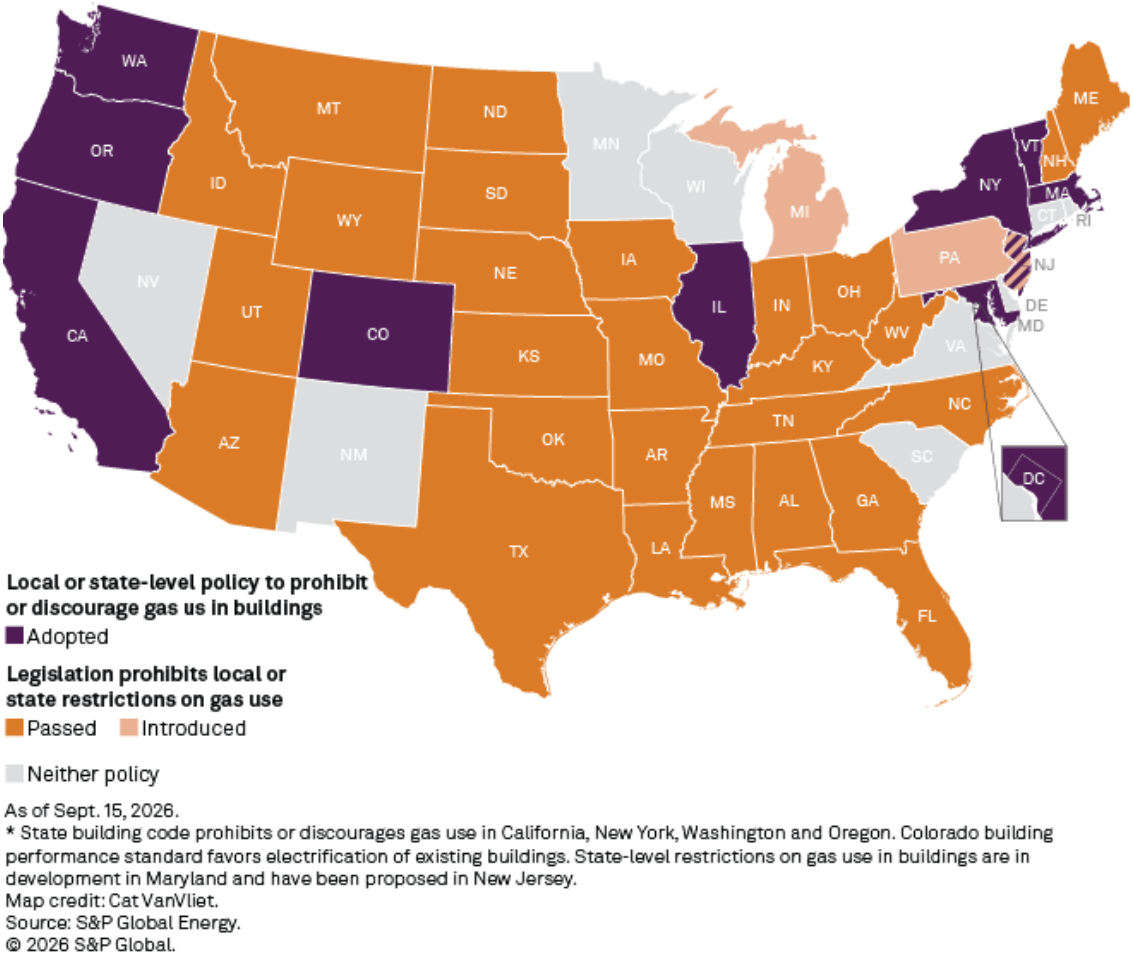
C. Energy Transition Policy Risk

Q. Please briefly summarize the risk associated with energy transition policies.

A. Energy transition and decarbonization policies have advanced to varying degrees across the United States and present risks for utilities, particularly natural gas utilities. Investors recognize that exposure to those risks differs substantially based on jurisdiction-specific legislative, regulatory, and public policy frameworks. While multiple states have adopted climate legislation, Oregon has adopted some of the nation's more ambitious climate and decarbonization policies, including Executive Order 20-04, House Bill 2021, and Oregon's 2024 Climate Protection Program, which have established a policy framework intended to substantially reduce greenhouse gas emissions and accelerate the transition to lower-carbon energy resources. Oregon's 2024 Climate Protection Program, for example, is designed to reduce greenhouse gas emissions from fossil fuels, including natural

gas, by 50 percent by 2035 and 90 percent by 2050.[68] Oregon is among the states with "aggressive" clean energy or renewable goals.[69] As shown in Figure 16 below, Oregon is one of the nine states that have adopted policies to prohibit or discourage gas use in buildings:

Figure 16: State and Local Restrictions on Natural Gas Use in Buildings and Bills to Prohibit Gas Bans[70]



As of Sept. 15, 2026.
* State building code prohibits or discourages gas use in California, New York, Washington and Oregon. Colorado building performance standard favors electrification of existing buildings. State-level restrictions on gas use in buildings are in development in Maryland and have been proposed in New Jersey.
Map credit: Cat VanVliet.
Source: S&P Global Energy.
© 2026 S&P Global.

[68] Administrative Order No. DEQ-18-2024, Oregon State Government, Climate Protection Program 2024, https://www.oregon.gov/deq/rulemaking/adopted/Pages/CPP2024.aspx.

[69] S&P Global Platts, "Commodities 2021: States Racing to Set Goals Towards Net-Zero Emission, 100% Renewable Electricity," December 24, 2020.

[70] RRA, "Affordability looms large over gas ban debate in 2026 elections" (September 24, 2026).

The Commission has recognized that compliance with the state's decarbonization policies will require significant changes to utility operations and resource planning: "[g]as utilities will need to take significant near-term action to decarbonize: 'Business as Usual' growth and operations of the system result in emissions exceeding the 2035 compliance targets."[71] Additionally, while the Commission has noted that one of its objectives in this study was to "identify appropriate regulatory tools to mitigate potential customer impacts and accommodate utility action," there is no guarantee of cost recovery or long-term business viability of natural gas utilities.[72]

Q. Have the credit rating agencies noted energy transition risk as a specific risk for NW Natural?

A. Yes. For example, in a June 2025 credit rating report for the Company, S&P listed "[d]ecarbonization initiatives that pressure future growth" as one of the key risks to the Company's credit ratings.[73] S&P further explains that it would lower NW Natural's credit rating if "[t]he 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."[74] Similarly, Moody's noted

[71] Public Utility Commission of Oregon, Natural Gas Fact Finding Final Report, at 11 (January 2023).

[72] *Id.* at 1.

[73] S&P Global Ratings, "Northwest Natural Gas Co." (June 25, 2025).

[74] *Id*.

"[h]eightened social risk due to state led decarbonization goals" as a credit challenge for NW Natural.[75]

Following the Commission's October 2025 order in Docket No. UG 520, RRA noted that "implementation of the state's aggressive emission targets presents added risks for gas utilities, as issues regarding electrification and other non-pipe alternative capital investments will continue to arise in the state's gas utility rate cases."[76]

Q. Do the natural gas utilities in the proxy group also face energy transition risk?

A. Yes, although to a somewhat lesser extent. According to the Climate Policy Dashboard, Oregon and Washington rank seventh and sixth, respectively, among U.S. states in the number of enacted environmental policies.[77] While a few of the proxy group companies also operate in jurisdictions with comparatively robust environmental policy frameworks, such as California, Colorado, and Maryland, those companies generally operate across multiple jurisdictions. As a result, the exposure to energy transition and decarbonization policy risk that these companies experience is diversified across multiple regulatory jurisdictions, including jurisdictions with fewer enacted or pending environmental policies. For example,

[75] Moody's Ratings, "Credit Opinion: Northwest Natural Gas Company," at 2 (July 16, 2026).

[76] RRA, "Ore. regulators approve NW Natural gas rate increase, slight equity return boost" (October 30, 2025).

[77] Climate Policy Dashboard, Sorted by Number of Enacted Policies. Environmental policies tracked by the Climate Policy Dashboard include various policy areas such as climate action plans/greenhouse gas targets, carbon pollution pricing, appliance standards, and vehicle standards. https://www.climatepolicydashboard.org/states?region=All&state=&order=policies_related&sort=desc.

Southwest Gas, Atmos Energy, and NiSource serve customers in California, Colorado, and Maryland, but also operate in states with less extensive environmental policy frameworks. By contrast, NW Natural operates in Oregon and Washington, which rank among the top ten states for enacted environmental policies. Consequently, changes in environmental and decarbonization policy in those jurisdictions have a greater potential to affect NW Natural's business risk profile than is the case for more geographically diversified natural gas utilities.

Q. What are your conclusions regarding the risk associated with energy transition on NW Natural's cost of equity?

A. While energy transition is a risk for many utilities, 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.

D. Small Size

Q. Please explain the risk associated with small size.

A. Both the financial and academic communities have long accepted the proposition that the cost of equity for small firms is subject to a "size effect."[78] Although empirical evidence of the size effect often is from studies of industries beyond

[78] See Mario Levis, *The Record on Small Companies: A Review of the Evidence*, Journal of Asset Management, at 368-397 (March 2002), for a review of literature relating to the size effect.

regulated utilities, utility analysts also have noted the risks associated with small market capitalization. Specifically, an analyst from Ibbotson Associates noted:

> For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.[79]

Q. How does the comparatively small size of NW Natural affect its business risk relative to the proxy group companies?

A. My ROE recommendation for NW Natural is developed based on market data applied to a risk-comparable proxy group. Consequently, an evaluation of the Company's risk associated with its small size is necessarily based on a comparison of its size relative to the proxy group. NW Natural's smaller size relative to the proxy group companies indicates greater relative business risk for the Company because, all else being equal, size has a material bearing on risk.

In general, smaller utility companies are less able to withstand events that adversely affect their revenues and expenses. Capital expenditures for system maintenance and replacements put proportionately greater pressure on customer costs, potentially leading to customer attrition or demand reduction. These risks affect the return required by investors for smaller companies.

Q. Is there support in the financial community for the small size premium?

A. Yes, several studies have demonstrated the existence of the size premium. One of the earliest studies found that over a period of 40 years "the common stock of

[79] Michael Annin, *Equity and the Small-Stock Effect*, Public Utilities Fortnightly (October 15, 1995).

small firms had, on average, higher risk-adjusted returns than the common stock of large firms."[80] The author, who referred to that finding as the "size effect," suggested that the CAPM was misspecified, in that, on average, smaller firms had significantly larger risk-adjusted returns than larger firms. The author also concluded that the size effect was "most pronounced for the smallest firms in the sample."[81] Since then, additional empirical research has focused on explaining the size effect as a function of lower trading volume and other factors, but the proposition that Beta coefficients fail to reflect the risks of smaller firms persists.[82]

Simply put, investors generally demand greater returns from smaller firms to compensate for less marketability and liquidity of their securities. Duff & Phelps discusses the nature of the small-size phenomenon, providing an indication of the magnitude of the size premium based on several measures of size. In discussing "Size as a Predictor of Equity Returns," Duff & Phelps states:

> The size effect is based on the empirical observation that companies of smaller size are associated with greater risk and, therefore, have greater cost of capital [sic]. The "size" of a company is one of the most important risk elements to consider when developing cost of equity capital estimates for use in valuing a business simply because size has been shown to be a *predictor* of equity returns. In other words, there is a significant (negative) relationship between size and historical equity returns - as size *decreases*, returns tend to

[80] R.W. Banz, The Relationship Between Market Return and Market Value of Common Stocks, Journal of Financial Economics, at 3-4 (1981).

[81] *Id*. at 16.

[82] See, e.g., Mario Levis, *The Record on Small Companies: A Review of the Evidence*, Journal of Asset Management (March 2002).

> *increase*, and vice versa. (footnote omitted) (emphasis in original)[83]

Additionally, a 2011 study by Stéphane Chrétien and Frank Coggins, "Cost of Equity for Energy Utilities: Beyond the CAPM,"[84] considered the Fama-French three-factor model and a model similar to the ECAPM I described earlier. In the study, the Fama-French three-factor model explicitly included an adjustment to the CAPM for the risk associated with size. As Chrétien and Coggins show, the Beta coefficient on the size variable for a group of U.S. natural gas utilities was positive and statistically significant, supporting the position that small size risk is relevant for regulated utilities.[85]

Q. How does NW Natural compare in size to the proxy companies?

A. As a standalone company, NW Natural is substantially smaller than the proxy group companies. Because NW Natural is not a separately traded entity, an estimated standalone market capitalization for NW Natural must be calculated. I calculated the implied market capitalization of NW Natural by multiplying the median market-to-book ratio for the proxy group of 1.76 by the Company's Oregon-jurisdictional common equity of $1.08 billion.[86] The implied market capitalization based on that calculation is approximately $1.89 billion. As another perspective of

[83] Duff & Phelps, Valuation Handbook – U.S. Guide to Cost of Capital, Wiley 2020, at 4-1.

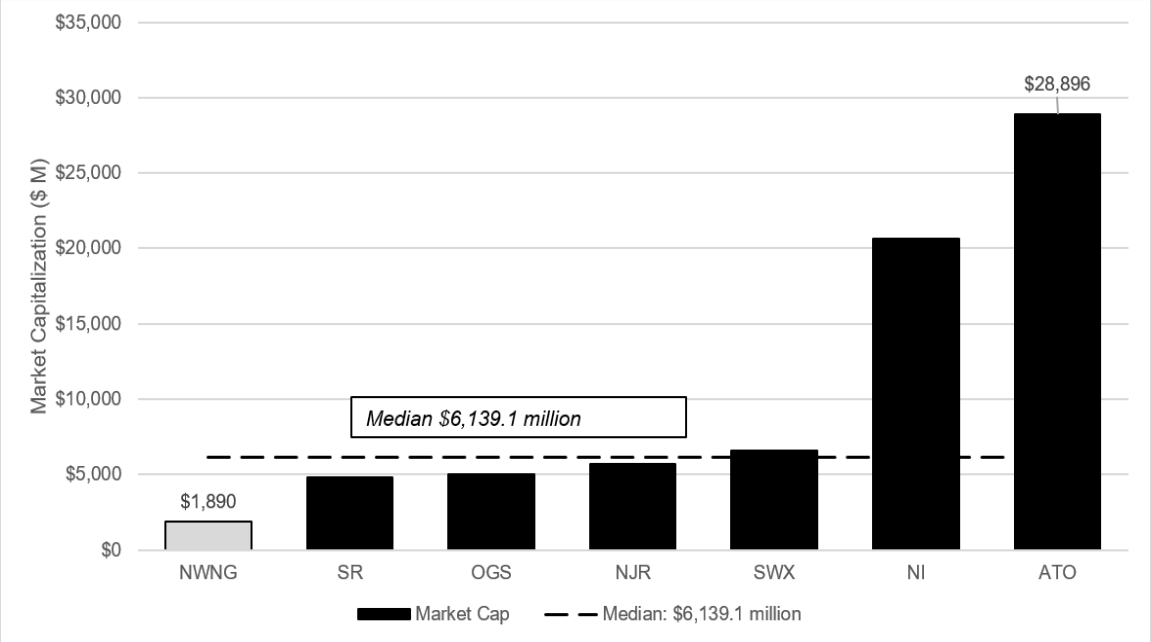
[84] Stéphane Chrétien and Frank Coggins, *Cost of Equity for Energy Utilities: Beyond the CAPM*, Energy Studies Review, Vol. 18, No. 2 (2011).

[85] *Id.* at 31.

[86] Source: NW Natural's Oregon Earnings Review for the 12 Months Ended December 31, 2025, Docket No. RG 40, filed April 30, 2026. See Exhibit NW Natural/412, Nelson. Adjusted rate base of $2.15 billion x 50.00% common equity ratio = $1.08 billion common equity for the Oregon jurisdiction.

the relative size difference, the proxy group median market capitalization is approximately $6.14 billion, which is over three times (3x) NW Natural's implied market capitalization.

Figure 17: Comparison of Market Capitalization – Gas Proxy Group



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 capitalization 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 proxy group median market capitalization and NW Natural's implied market capitalization.

As shown in Exhibit NW Natural/412, Nelson, the proxy group median market capitalization of $6.14 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 0.65 percent (or 65 basis points). The implied market capitalization for NW Natural is approximately $1.89 billion, which falls within the seventh decile and corresponds to a size premium of 1.05 percent (or 105 basis points). The difference between those size premiums is 40 basis points (1.05 percent minus 0.65 percent).

Q. Have you considered NW Natural's smaller size in your ROE recommendation?

A. Although NW Natural's smaller size supports an authorized ROE above the proxy group average, I do not adjust my ROE recommendation upward. Rather, it demonstrates that the Company's requested ROE recommendation at the bottom of the range is conservative.

V. ECONOMIC AND CAPITAL MARKET CONDITIONS

Q. Do economic conditions influence the required cost of capital and required 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 macroeconomic 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 currently 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) uncertainty in the economic environment caused by geopolitical events. As discussed below, interest rates and inflation are expected to remain above the levels experienced prior to the COVID-19 pandemic. Further, geopolitical events present uncertainties with respect to the near-term economic and capital market environment in which the Company will be raising external capital.

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. Throughout 2025 and 2026, however, economic and federal policy uncertainty climbed sharply. As Blue Chip Financial Forecasts explained:

> The global economy entered late August in a more unsettled position, though not a conspicuously weaker one. The collapse of US—Canada trade talks and Washington's subsequent 50 per cent tariffs suggested protectionism is proving persistent rather than episodic, while stalled US—Iran negotiations, attacks in Lebanon and disruption through the Strait of Hormuz kept oil prices elevated.
>
> ***
>
> Bond markets are the clearest expression of these tensions. Heavy public borrowing, firm private investment demand and lingering inflation risks have pushed long yields higher and

> steepened curves across the major economies. [Blue Chip Financial Forecasts] [p]anelists have responded in kind: bond yield forecasts have edged higher almost everywhere.[87]

Further, in its Outlook 2026 report, J.P. Morgan Private Bank emphasized the structural, rather than temporary, shift in the state of inflation.[88] J.P. Morgan notes that inflation is expected to remain more volatile and prone to upward shocks compared with the pre-pandemic period.[89] Consumer sentiment fell 28 percent between January 2025 and August 2026.[90]

Despite the uncertain economic outlook and weak consumer sentiment, Gross Domestic Product ("GDP") remained resilient, though growth has slowed in the most recent quarter. As shown in Figure 18, after posting a decline in the first quarter of 2025, real GDP rose in each of the next five quarters, most recently posting an annual increase of 1.5 percent in the second quarter of 2026.[91] This demonstrates that there are mixed signals among the economic indicators.

[87] Blue Chip Financial Forecasts, September 2026 Edition, at 4. (Clarification added.)

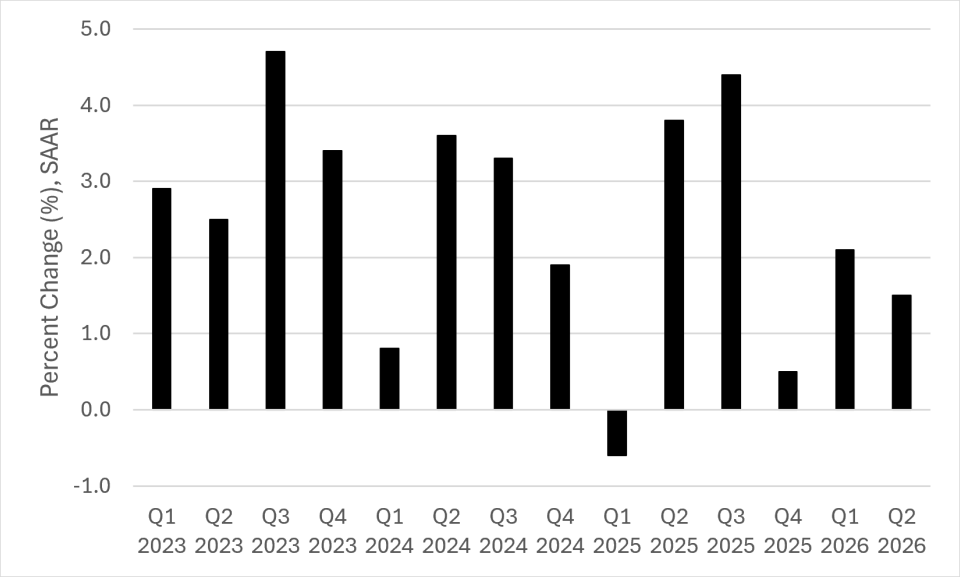
[88] J.P. Morgan Private Bank, *Outlook 2026: Promise and Pressure*, at 7.

[89] *Id*.

[90] University of Michigan, Surveys of Consumers, Index of Consumer Sentiment, https://www.sca.isr.umich.edu/charts.html.

[91] U.S. Bureau of Economic Analysis, (Advance Estimate), National Data, National Income and Product Accounts.

Figure 18: Quarterly Real GDP (Seasonally Adjusted at Annual Rates)[92]



Q. Please describe recent monetary policy actions by the Federal Reserve.

A. On May 22, 2026, Kevin Warsh was sworn in as the Chair of the Federal Reserve Board of Governors. The Federal Open Market Committee ("FOMC") maintained its Federal Funds rate target range at the June 2026 and July 2026 meetings.[93] However, in September 2026, the FOMC raised the target range for the Federal Funds rate by 25 basis points to 3.75 to 4.00 percent, noting that "[w]hile uncertainty remains elevated owing, in part, to geopolitical developments, domestic spending has been resilient," and "[i]nflation remains elevated."[94]

[92] Source: U.S. Bureau of Economic Analysis.

[93] Federal Reserve FOMC Press Release, June 17, 2026, https://www.federalreserve.gov/newsevents/pressreleases/monetary20260617a.htm; Federal Reserve FOMC Press Release, July 29, 2026, https://www.federalreserve.gov/newsevents/pressreleases/monetary20260729a.htm.

[94] Federal Reserve FOMC Press Release, September 16, 2026, https://www.federalreserve.gov/newsevents/pressreleases/monetary20260916a.htm.

Moreover, in a recent speech at the Federal Reserve's annual conference in Jackson Hole, Wyoming, Chair Warsh similarly expressed concern over inflation despite the economy showing signs of strength and resiliency:

> But on the price-stability side of our mandate, the numbers are more concerning. The Fed's preferred measure of inflation, the 12-month change in the PCE price index, stands at 3.7 percent, while the six-month change is 4.1 percent. The comparable measures from the consumer price index (CPI) are also elevated, as are the core measures of both PCE and CPI inflation. None of these measures are perfect, but they all tell a similar story: Inflation is running above our 2 percent target. So the Fed's predominant focus right now should be on prices.[95]

Q. Please describe the trend in inflation since the Company's last rate case.

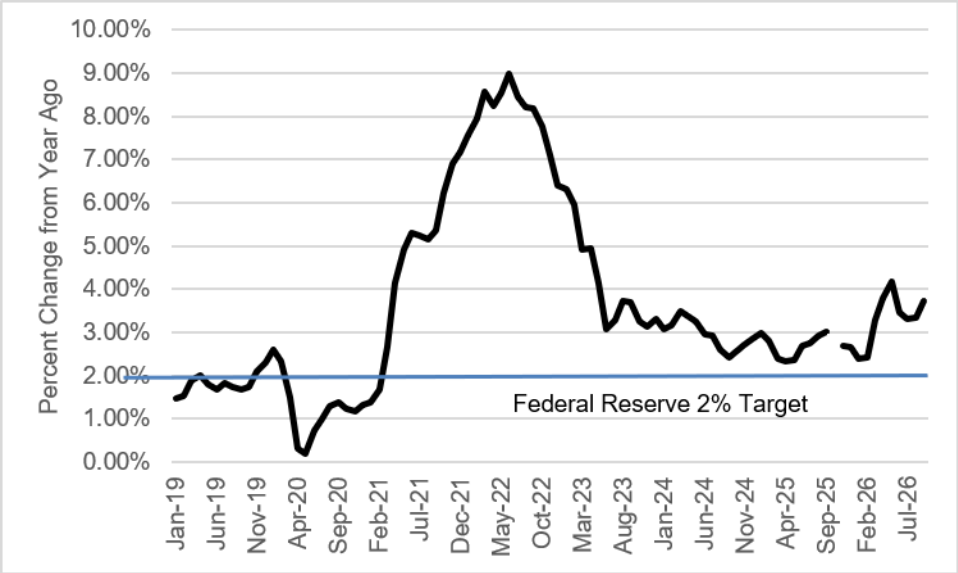
A. As Figure 19 below illustrates, the pace of inflation has subsided from its peak reached in 2022; however, inflation remains above the Federal Reserve's 2.0 percent target and has increased in recent months. Further, long-run inflation expectations are above the Federal Reserve's target as well. The University of Michigan Surveys of Consumers notes in its preliminary October 2026 update:

> Year-ahead inflation expectations ticked up from 4.6% last month to 4.7% this month. The current reading substantially exceeds the 3.4% seen in February before the Iran conflict began, along with all 2024 readings. Long-run inflation expectations also stepped up from 3.4% in September to 3.5%, notably higher than their 2024 range of 2.8% to 3.2%. Inflation expectations over both time horizons increased for the second straight month to their highest readings since May.[96]

[95] Kevin Warsh, Chair, Board of Governors of the Federal Reserve System, *In Our Time*, remarks at *Financial Innovation: Implications for Payments and Policy*, the Federal Reserve Bank of Kansas City Economic Policy Symposium, Jackson Hole, Wyoming (August 28, 2026).

[96] University of Michigan Surveys of Consumers, *Preliminary Results for October 2026*, accessed October 13, 2026, https://www.sca.isr.umich.edu/.

Figure 19: Consumer Price Index (2019-2026)[97]

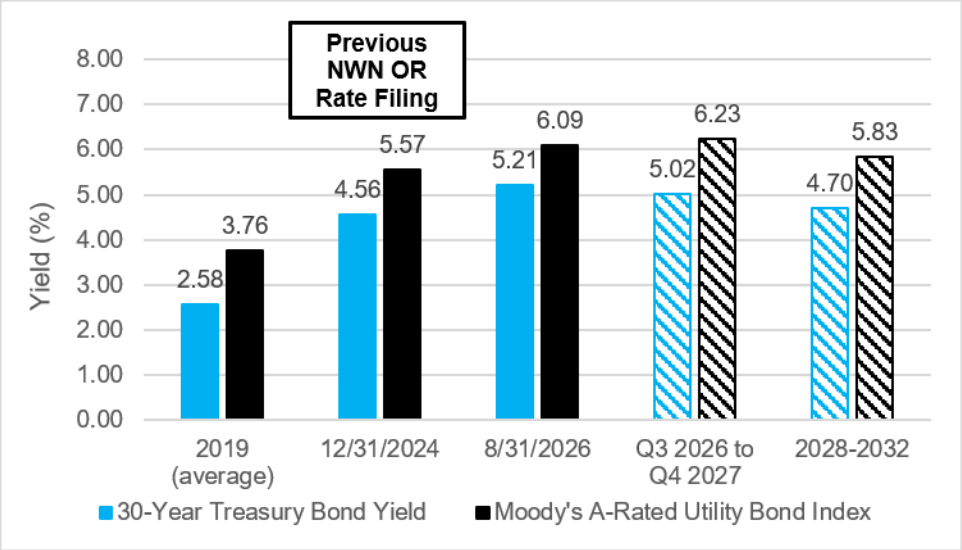


Q. What are the expectations for long-term government and utility bond yields in the near term?

A. Long-term government and utility bond yields are expected to remain elevated and significantly above their pre-pandemic levels. As shown in Figure 20, long-term government and utility bond yields have been higher than the levels experienced in 2019 prior to the COVID-19 pandemic and are expected to remain elevated and near current levels over the next five years.

[97] Source: Federal Reserve Bank of St. Louis, FRED Economic Database, series CPIAUCSL, https://fred.stlouisfed.org/series/CPIAUCSL.

Figure 20: 30-Year Treasury Yield and Moody's A-Rated Utility Bond Yields (2019 vs. 2026, and Forecasted)[98]



Q. How might persistent inflation and elevated interest rates affect the cost of equity for utilities?

A. 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 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

[98] Sources: Federal Reserve Bank of St. Louis, FRED Economic Database, series DGS30, https://fred.stlouisfed.org/series/DGS30; Bloomberg Professional; Federal Reserve Bank of St. Louis, FRED Economic Database, series DAAA, https://fred.stlouisfed.org/series/DAAA; Blue Chip Financial Forecasts, September 2026 Edition, at 9 and Blue Chip Financial Forecasts, Vol. 45, No. 6, at 14. Projected Utility "A" bond yields are estimated from Blue Chip Financial Forecasts' projected "Aaa" corporate bond yields plus the average historical spread between Aaa-rated corporate bonds and A-rated utility bond yields over the last five years.

utility stocks. Higher inflation and interest rates lead to increases in the cost of capital for utilities.

Q. Please discuss the recent changes in U.S. trade and geopolitical policy.

A. During 2025 and 2026, the Trump administration 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.[99] 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. On February 20, 2026, the Supreme Court struck down President Trump's tariffs,[100] though he responded with a pledge to impose a new global 15 percent tariff.[101] More recently, on September 8, 2026, President Trump modified the scope of tariffs on certain Canadian products previously implemented in July 2026.[102]

These events created significant policy and market uncertainty. As shown in Figure 21 below, the Federal Reserve Bank of St. Louis' Economic Policy Uncertainty Index (the "EPU Index") spiked above the levels reached during the

[99] 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/.

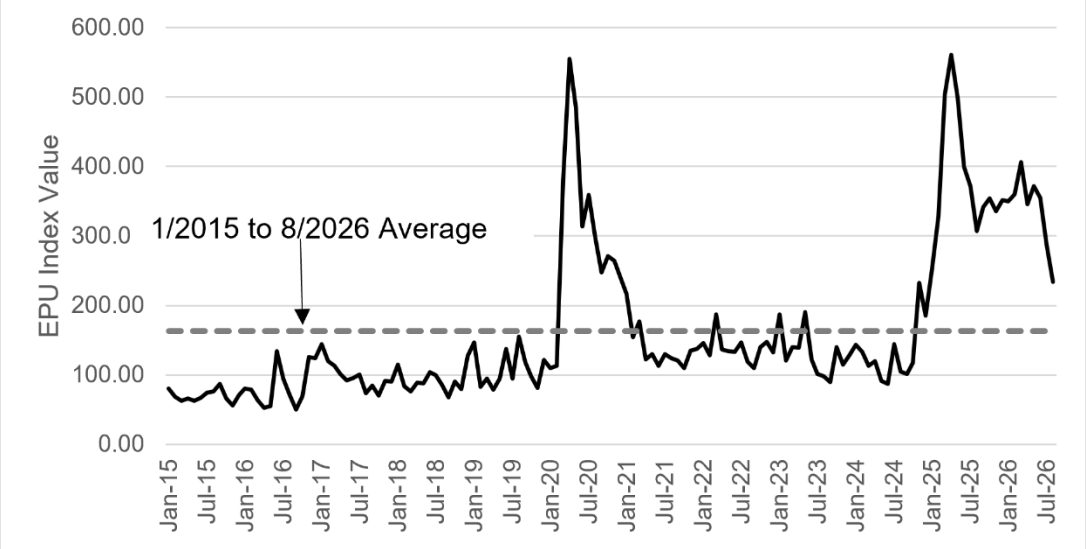
[100] https://apnews.com/article/supreme-court-tariffs-trump-0485fcda30a7310501123e4931dba3f9.

[101] https://www.nytimes.com/2026/02/21/business/trump-tariffs.html.

[102] https://www.whitehouse.gov/fact-sheets/2026/09/fact-sheet-president-donald-j-trump-responds-to-canadas-retaliation/.

COVID-19 pandemic. While the EPU Index has partially subsided in recent months (to 234.28 as of August 2026), it is still significantly above the average over the last 11 years (163.18). Notably, the EPU Index levels are significantly higher than when the Company submitted its last rate application in December 2024 (184.92) and have sustained elevated levels throughout 2026. Lastly, the ongoing conflict in Iran and subsequent attempts at a ceasefire between the U.S. and Iran[103] further add to the economic and geopolitical uncertainty. Uncertainty increases risk, which increases the cost of equity, all else equal.

Figure 21: Economic Policy Uncertainty Index, January 1, 2015 – August 31, 2026[104]



[103] Joe Gambrell, et al., *U.S. and Israel Launch a Major Attack on Iran, Trump Says Supreme Leader Khamenei Killed*, PBS News (February 28, 2026), https://www.pbs.org/newshour/world/u-s-and-israel-launch-a-major-attack-on-iran-trump-says-supreme-leader-khamenei-killed; Joe Gambrell, et al., *U.S. Launches Additional Strikes on Iran Ahead of Restoring Blockade, Official Says*, PBS News (July 14, 2026).

[104] Source: Federal Reserve Bank of St. Louis, FRED Economic Database, series USEPUINDXD, https://fred.stlouisfed.org/series/USEPUINDXD/.

Q. What conclusions do you draw from your review of the current capital market environment and its implications for the Company's cost of equity?

A. My primary conclusion is that the economic and financial market environment is uncertain concerning inflation, the strength of the economy, the outcome of federal trade policy and other geopolitical events, and the path of monetary policy. Long-term government and utility bond yields have increased since the Company's last rate case. Lastly, inflation is expected to remain elevated and above pre-pandemic levels. These factors underscore the importance of using multiple models when determining the Company's cost of equity to gain a comprehensive perspective of the effect of fluid and evolving market conditions on the cost of equity.

VI. CAPITAL STRUCTURE

Q. What common equity ratio is the Company proposing?

A. NW Natural is proposing a capital structure that includes 50.00 percent common equity and 50.00 percent long-term debt, as discussed in the Direct Testimony of Company witness Brody J. Wilson (Exhibit NW Natural/300, Wilson). The Company's proposed capital structure reflects its targeted capital structure over the coming 12 to 24 months.

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 to investors associated with additional leverage, or levels of debt. Therefore, the capital structure indicates a company's

financial risk, which reflects the risk that a company may not have adequate cash flows to meet its financial obligations. 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.[105] In essence, even if two firms face the same business risks, a company with meaningfully higher levels of debt in its capital structure is riskier, which increases its costs of both debt and equity.

Q. Please summarize the approaches to determining the appropriate capital structure for regulated utilities.

A. There are two primary approaches regulators use to determine the appropriate capital structure for ratemaking purposes. The most common approach is to use the subject utility's actual capital structure. This approach is preferred when the subject utility (1) issues its own debt, (2) has its own credit rating, and (3) has an actual capital structure that is within industry standards and practice. When the subject utility does not issue its own debt and have its own credit rating, or when the actual capital structure deviates substantially from industry practice, a hypothetical capital structure may be imputed.

Q. Does the Company issue its own debt and have its own credit rating?

A. Yes. Therefore, the next step is to assess the reasonableness of its actual capital structure within the context of industry practice.

[105] See Roger A. Morin, Ph.D., New Regulatory Finance, Public Utilities Reports, Inc., at 45-46 (2006).

Q. What are the guidelines for determining whether a utility's capital structure is within industry standards?

A. In a 2020 publication titled *A Cost of Capital and Capital Markets Primer for Utility Regulators*, the National Association of Regulatory Utility Commissioners ("NARUC") states that actual capital structure ratios should be used unless they "greatly diverge" from sound industry practice:

> A utility management must be permitted latitude, discretion, and flexibility in managing capital structure ratios. Since there is no practical methodology to pinpoint theoretically optimal capital structure ratios, targeted ratios can only be broadly conceptualized. Appropriate ratios may shift over time as capital market conditions or business risk characteristics change. Additionally, the timing of upcoming issuances and maturities may influence the capital structure ratios because both the size and frequency of issuances are affected by the relative cost-effectiveness of various issuance increments.
>
> Given these practical considerations, capital structure ratios cannot be deemed to be inappropriate unless the ratios greatly diverge from sound industry practice and cause a lack of financial flexibility that may lead to higher overall costs.
>
> ***
>
> As increasing financial leverage shifts the weight from common equity to lower cost debt, it also increases both the cost of debt and the cost of common equity. In practice, these offsetting impacts cancel each other out over a wide range of capital structure ratios.[106]

[106] NARUC, *A Cost of Capital and Capital Markets Primer for Utility Regulators* (April 2020), at 11. (Emphasis added.)

Further, James C. Bonbright explains in his seminal text *Principles of Public Utility Rates* that a hypothetical capital structure should be used only when actual capital structures are "clearly unsound" or "extravagantly conservative," reasoning that using hypothetical capital structures "substitutes an estimate of what the capital cost would be under non-existing conditions for what it actually is or will soon be under prevailing conditions."[107]

Q. Have you assessed whether NW Natural's proposed capital structure is consistent with sound industry practice?

A. Yes, I have. To make that assessment, I calculated the average capital structure for each of the proxy group operating companies over the last three years (see Exhibit NW Natural/413, Nelson). On average, the proxy group operating companies finance their regulated natural gas distribution operations with 55.42 percent common equity, within a range of 48.70 percent to 60.15 percent.[108] The proxy group median is 55.51 percent common equity. From that perspective, NW Natural's proposed capital structure is within the range of its peers, yet somewhat more leveraged.

Q. What is the basis for using average capital components rather than a point-in-time measurement?

A. Measuring the capital components at a particular point in time can skew the capital structure by the specific circumstances of a particular period. Therefore, it is

[107] James C. Bonbright, Principles of Public Utility Rates, at 243-244 (2005).

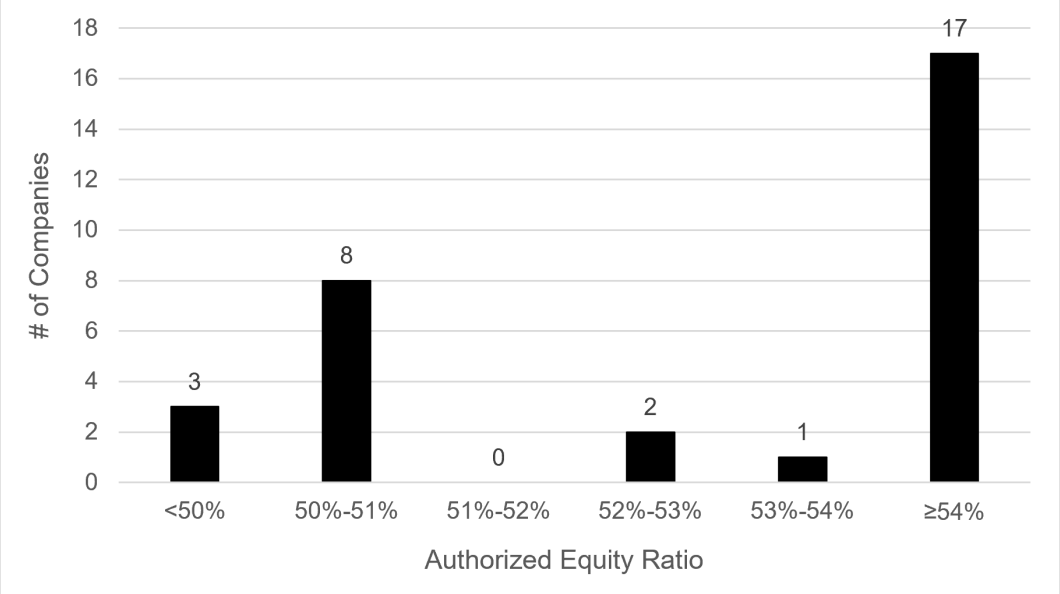
[108] Exhibit NW Natural/413, Nelson.

appropriate to normalize the relative relationship between the capital components over a period of time.

Q. Is NW Natural's proposed capital structure consisting of approximately 50.00 percent common equity consistent with authorized equity ratios for the proxy group?

A. Yes. As shown in Figure 22 below, an equity ratio of 50.00 percent is at the lower end of the average and median current authorized equity ratios for the proxy companies in the jurisdictions in which they operate (54.34 percent and 54.00 percent, respectively). In fact, 90 percent of the proxy group companies have an authorized equity ratio greater than or equal to 50.00 percent in the jurisdictions in which they operate (see also Exhibit NW Natural/414, Nelson).

Figure 22: Distribution of Proxy Group Current Authorized Equity Ratios[109]



[109] Exhibit NW Natural/414, Nelson.

Q. What is your conclusion regarding the Company's requested capital structure?

A. The Company's requested common equity ratio of 50.00 percent is at the lower end of the range of actual and authorized equity ratios for its peers and is, therefore, consistent with industry standards. As such, a capital structure including approximately 50.00 percent common equity and 50.00 percent long-term debt is reasonable, conservative, and should be approved.

VII. SUMMARY AND CONCLUSIONS

Q. Please summarize your ROE recommendation based on this range of results.

A. As discussed throughout my Direct Testimony, it is important to consider a variety of quantitative and qualitative information in arriving at an appropriate ROE determination. Based on my review of the results from three commonly used analytical approaches, I conclude an ROE in the range of 9.75 percent to 11.75 percent represents the range of investors' required ROE for investment in a natural gas distribution utility like NW Natural. While several factors would support an ROE above the midpoint of the range for NW Natural, the Company's requested ROE at the low end of the range, 9.75 percent, is a conservative estimate of NW Natural's cost of equity that considers the rate impact on customers while providing the Company with the opportunity to earn a reasonable return sufficient to attract investor capital.

As to capital structure, the Company's requested capital structure of 50.00 percent common equity and 50.00 percent long-term debt is within the range of

capital structures that finance the regulated natural gas utility operations of the proxy group and, therefore, is reasonable and appropriate and should be approved.

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibits of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBITS 401 – 414

November 24, 2026

EXHIBITS 401-414 – RETURN ON EQUITY

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NW Natural

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RETURN ON EQUITY
EXHIBIT 401

November 24, 2026

Exhibit NW Natural/401, Nelson
Resume of Jennifer E. Nelson

JENNIFER E. NELSON
VICE PRESIDENT

Jennifer Nelson is a Certified Rate of Return Analyst with more than 15 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, natural gas pipeline development, utility supply planning issues, and merger and acquisition transactions. She also 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. Ms. Nelson has been recognized as one of the *Top 25 Women Leaders in Consulting for 2026* by The Consulting Report.

AREAS OF EXPERTISE

Cost of Capital

- Submitted expert testimony on behalf of electric utilities before regulatory commissions in Arkansas, Kansas, Michigan, New Hampshire, New Jersey, New Mexico, North Carolina, Ohio, Oklahoma, Pennsylvania, 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, Michigan, North Carolina, Ohio, Oregon, Pennsylvania, 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

AWARDS, DESIGNATIONS, AND PROFESSIONAL AFFILIATIONS

Recognized as one of the *Top 25 Women Leaders in Consulting for 2026* by The Consulting Report
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
Cook Inlet Natural Gas Storage Alaska, LLC (CINGSA)	04/26	Cook Inlet Natural Gas Storage Alaska, LLC (CINGSA)	U-25-023	Reply Testimony on Cost of Debt in CINGSA's Formula Rate Mechanism Annual Revision filing
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	Evaluated the Return on Equity included in Rider FRP
Oklahoma Gas & Electric	10/21	Oklahoma Gas & Electric	21-087-U	Formula Rate Plan
The Empire District Electric Company	05/26	The Empire District Electric Company	26-20-U	Cost of Capital
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 Corporation 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
The Empire District Electric Company d/b/a Liberty	12/25	The Empire District Electric Company d/b/a Liberty	26-EPDE-0180-RTS	Capital Structure, Cost of Capital and Cost of Debt
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



SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Maine Public Utilities Commission				
Unitil Corporation	06/19	Northern Utilities, Inc.	19-00092	Co-sponsored testimony supporting a proposed capital tracking mechanism
Michigan Public Service Commission				
DTE Electric Company	04/25	DTE Electric Company	U-21860	Cost of Capital
DTE Gas Company	11/25	DTE Gas Company	U-21973	Cost of Capital
DTE Electric Company	04/26	DTE Electric Company	U-22046	Cost of Capital
Montana Public Utilities Commission				
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 Jersey Board of Public Utilities				
Jersey Central Power & Light	08/26	Jersey Central Power & Light	ER26080420	Cost of Capital
New Mexico Public Regulation Commission				
El Paso Electric Company	07/20	El Paso Electric Company	20-00104-UT	Cost of Capital
El Paso Electric Company	03/26	El Paso Electric Company	25-00082-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
Virginia Electric & Power Co., d/b/a Dominion Energy North Carolina	04/26	Virginia Electric & Power Co., d/b/a Dominion Energy North Carolina	E-22, Sub 765	Cost of Capital



SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
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
The East Ohio Gas Company d/b/a Enbridge Gas Ohio	01/26	The East Ohio Gas Company d/b/a Enbridge Gas Ohio	25-1097-GA-AIR	Cost of Capital
Ohio Edison Co., The Cleveland Electric Illuminating Co., and The Toledo Edison Co.	05/26	Ohio Edison Co., The Cleveland Electric Illuminating Co., and The Toledo Edison Co.	26-0347-EL-AIR	Cost of Capital
Oklahoma Corporation Commission				
Oklahoma Gas & Electric	12/21	Oklahoma Gas & Electric	PUD202100164	Formula Rate Plan
The Empire District Electric company	08/26	The Empire District Electric company	PUD2026-000048	Cost of Capital
Public Utility Commission of Oregon				
Northwest Natural Gas Company d/b/a NW Natural	12/23	Northwest Natural Gas Company d/b/a NW Natural	UG 490	Cost of Capital
Northwest Natural Gas Company d/b/a NW Natural	12/24	Northwest Natural Gas Company d/b/a NW Natural	UG 520	Cost of Capital
Pennsylvania Public Utility Commission				
PPL Electric Utilities Corporation	09/25	PPL Electric Utilities Corporation	R-2025-3057164	Cost of Capital
Peoples Natural Gas Company LLC	03/26	Peoples Natural Gas Company LLC	R-2026-3060855	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
Dominion Energy South Carolina, Inc.	01/26	Dominion Energy South Carolina, Inc.	2025-325-E	Cost of Capital
Piedmont Natural Gas	04/26	Piedmont Natural Gas	2026-61-G	Cost of Capital
Public Utilities Commission of Texas				
Sharyland Utilities L.L.C.	12/20	Sharyland Utilities L.L.C.	51611	Cost of Capital



SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
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				
Dominion Energy Utah	05/22	Dominion Energy Utah	22-057-03	Cost of Capital
Enbridge Gas Utah	05/25	Enbridge Gas Utah	25-057-06	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. 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
Hope Gas, Inc.	04/25	Hope Gas, Inc.	25-0417-G-42T	Cost of Capital
Washington Utilities & Transportation Commission				
Northwest Natural Gas Company d/b/a NW Natural	08/25	Northwest Natural Gas Company d/b/a NW Natural	UG-250610	Cost of Capital
Wyoming Public Service Commission				
Dominion Energy Wyoming	03/23	Dominion Energy Wyoming	30010-215-GR-23	Cost of Capital
Questar Gas Company d/b/a Enbridge Gas Wyoming	03/26	Questar Gas Company d/b/a Enbridge Gas Wyoming	30010-242-GR-26	Cost of Capital

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 402

November 24, 2026

SUMMARY OF RESULTS

	GAS PROXY GROUP			*COMBINED PROXY GROUP*		
	Constant Growth DCF			***Constant Growth DCF***		
	Low Growth	Average Growth	High Growth	Low Growth	Average Growth	High Growth
30-Day Average	10.27%	11.42%	12.32%	10.11%	10.80%	11.58%
90-Day Average	10.24%	11.35%	12.25%	10.08%	10.76%	11.50%
180-Day Average	10.27%	11.35%	12.25%	10.08%	10.77%	11.50%
Average	10.26%	11.37%	12.27%	10.09%	10.78%	11.53%
	Quarterly Growth DCF			***Quarterly Growth DCF***		
	Low Growth	Average Growth	High Growth	Low Growth	Average Growth	High Growth
30-Day Average	10.50%	11.66%	12.58%	10.31%	11.01%	11.79%
90-Day Average	10.47%	11.58%	12.50%	10.27%	10.96%	11.70%
180-Day Average	10.50%	11.58%	12.50%	10.28%	10.97%	11.72%
Average	10.49%	11.61%	12.53%	10.28%	10.98%	11.73%
	Multi-Stage DCF			***Multi-Stage DCF***		
	Projected GDP Growth	Historical GDP Growth	Average	Projected GDP Growth	Historical GDP Growth	Average
30-Day Average	8.54%	10.26%	9.40%	8.55%	10.28%	9.41%
90-Day Average	8.50%	10.22%	9.36%	8.47%	10.20%	9.34%
180-Day Average	8.53%	10.26%	9.39%	8.49%	10.22%	9.35%
Average	8.52%	10.25%	9.38%	8.51%	10.23%	9.37%

	GAS PROXY GROUP		*COMBINED PROXY GROUP*	
	30-Year Treasury Yield		30-Year Treasury Yield	
CAPM	Current	Projected	Current	Projected
Historical Market Return				
Average 5-year Beta	9.94%	9.81%	9.84%	9.71%
10-year Beta	10.35%	10.25%	10.31%	10.20%
Forward Market Return				
Average 5-year Beta	12.87%	12.75%	12.71%	12.58%
10-year Beta	13.54%	13.44%	13.47%	13.36%
ECAPM				
Historical Market Return				
Average 5-year Beta	10.51%	10.42%	10.44%	10.34%
10-year Beta	10.82%	10.75%	10.79%	10.71%
Forward Market Return				
Average 5-year Beta	13.80%	13.71%	13.68%	13.58%
10-year Beta	14.30%	14.23%	14.25%	14.17%
Risk Premium	10.46%	10.28%	10.50%	10.31%

	GAS PROXY GROUP		*COMBINED PROXY GROUP*	
	Low	*High*	*Low*	*High*
Range:	9.77%	11.75%	9.65%	11.57%
+ Flotation Costs (0.07%)	9.85%	11.82%	9.72%	11.65%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 403

November 24, 2026

PROXY GROUP SELECTION

Line	Company	Ticker	[1] Consistently pays dividends; No cuts prior 2 years	[2] Consistently Covered by More Than One Analyst (Yes/No)	[3] Positive EPS Growth Rates From At Least Two Sources	[4] S&P Credit Rating	[5] Moody's Credit Rating	[6] >50% Regulated Operating Income / Total (3-yr average)	[7] >50% (>15% for Electric Utilities) Natural Gas Distribution Net Operating Income / Total Net Operating Income (3-yr average)	[8] Significant Merger, Transaction Activity or Financial Event?	Include in Gas Proxy Group?	Include in Combined Proxy Group?	Note
	Natural Gas Utilities												
1	Atmos Energy Corporation	ATO	✓	Yes	Yes	A-	A2	100.00%	62.79%	No	✓	✓	
2	Chesapeake Utilities Corporation	CPK	✓	Yes	Yes	BBB+	n/a	86.36%	43.31%	No			
3	New Jersey Resources Corporation	NJR	✓	Yes	Yes	A-	A1	60.29%	53.26%	No	✓	✓	
4	NiSource Inc.	NI	✓	Yes	Yes	BBB+	Baa2	100.00%	68.01%	No	✓	✓	
5	Northwest Natural Holding Co.	NWN	✓	Yes	Yes	A-	(P)Baa1	95.37%	90.21%	No			*Parent of NW Natural*
6	ONE Gas, Inc.	OGS	✓	Yes	Yes	A-	A3	100.00%	100.00%	No	✓	✓	
7	Southwest Gas Holdings, Inc.	SWX	✓	Yes	Yes	BBB+	Baa2	100.00%	100.00%	No	✓	✓	
8	Spire Inc.	SR	✓	Yes	Yes	BBB+	Baa2	91.68%	81.13%	No	✓	✓	
9	UGI Corporation	UGI	✓	Yes	Yes	A-	A3	35.10%	29.10%	Yes			
	Electric Utilities												
10	Alliant Energy Corporation	LNT	✓	Yes	Yes	BBB+	Baa2	97.82%	12.38%	No			
11	Ameren Corporation	AEE	✓	Yes	Yes	BBB+	Baa1	100.00%	15.21%	No		✓	
12	American Electric Power Company, Inc.	AEP	✓	Yes	Yes	BBB+	Baa2	94.57%	0.00%	No			
13	Avista Corporation	AVA	✓	Yes	Yes	BBB	Baa2	100.00%	24.37%	No		✓	
14	Black Hills Corporation	BKH	✓	Yes	Yes	BBB+	Baa2	100.00%	53.58%	Yes			
15	CenterPoint Energy, Inc.	CNP	✓	Yes	Yes	BBB+	Baa2	100.00%	41.18%	No		✓	
16	CMS Energy Corporation	CMS	✓	Yes	Yes	BBB+	Baa2	100.00%	37.45%	No		✓	
17	Consolidated Edison, Inc.	ED	✓	Yes	Yes	A-	Baa1	90.75%	26.15%	No		✓	
18	Dominion Energy, Inc.	D	✓	Yes	Yes	BBB+	Baa2	89.85%	2.44%	Yes			
19	DTE Energy Company	DTE	✓	Yes	Yes	BBB+	Baa2	85.21%	20.94%	No		✓	
20	Duke Energy Corporation	DUK	✓	Yes	Yes	BBB+	Baa2	100.00%	10.27%	No			
21	Edison International	EIX	✓	Yes	Yes	BBB-	Baa2	100.00%	0.00%	No			
22	Entergy Corporation	ETR	✓	Yes	Yes	BBB+	Baa2	99.91%	0.78%	No			
23	Evergy, Inc.	EVRG	✓	Yes	Yes	BBB+	Baa2	100.00%	0.00%	No			
24	Eversource Energy	ES	✓	Yes	Yes	BBB+	Baa2	93.42%	16.83%	No		✓	
25	Exelon Corporation	EXC	✓	Yes	Yes	A-	Baa2	99.76%	11.03%	No			
26	FirstEnergy Corporation	FE	✓	Yes	Yes	BBB+	Baa3	100.00%	0.00%	No			
27	Hawaiian Electric Industries, Inc.	HE		Yes	No	BB-	Ba2	97.22%	0.00%	No			
28	IDACORP, Inc.	IDA	✓	Yes	Yes	BBB	Baa3	99.99%	0.00%	No			
29	MGE Energy, Inc.	MGEE	✓	No	No	A-	A1	79.17%	15.66%	No			
30	NextEra Energy, Inc.	NEE	✓	Yes	Yes	A-	Baa1	79.53%	0.00%	Yes			
31	NorthWestern Corporation	NWE	✓	Yes	Yes	BBB	Baa2	99.96%	13.82%	Yes			
32	OGE Energy Corporation	OGE	✓	Yes	Yes	BBB+	Baa1	100.00%	0.00%	No			
33	Otter Tail Corporation	OTTR	✓	Yes	No	BBB	Baa2	31.09%	0.00%	No			
34	PG&E Corporation	PCG	✓	Yes	Yes	BB+	Ba3	100.00%	41.72%	No			
35	Pinnacle West Capital Corporation	PNW	✓	Yes	Yes	BBB+	Baa2	100.00%	0.00%	No			
36	Portland General Electric Company	POR	✓	Yes	Yes	BBB+	A3	100.00%	0.00%	Yes			
37	PPL Corporation	PPL	✓	Yes	Yes	A-	Baa1	97.10%	5.43%	No			
38	Public Service Enterprise Group Inc.	PEG	✓	Yes	Yes	BBB+	Baa2	77.16%	17.04%	No		✓	
39	Sempra Energy	SRE	✓	Yes	Yes	BBB+	Baa2	78.32%	38.19%	Yes			
40	Southern Company	SO	✓	Yes	Yes	A-	Baa1	96.33%	14.64%	No			
41	TXNM Energy, Inc.	TXNM	✓	Yes	Yes	BBB	Baa3	100.00%	0.00%	Yes			
42	Unitil Corporation	UTL	✓	Yes	No	BBB+	Baa2	100.00%	68.82%	No			
43	WEC Energy Group, Inc.	WEC	✓	Yes	Yes	A-	Baa1	97.17%	41.64%	No		✓	
44	Xcel Energy Inc.	XEL	✓	Yes	Yes	BBB+	Baa1	100.00%	15.06%	No		✓	

[1] Source: S&P Capital IQ Pro
[2] Source: Zacks and S&P Capital IQ, as of 08/31/2026
[3] Source: Value Line, Zacks, and S&P Capital IQ
[4]-[5] Source: S&P Capital IQ Pro; Chesapeake Utilities Corporation is rated BBB+ by Fitch. NJR and UGI are not rated by S&P or Moody's; ratings for subsidiaries New Jersey Natural Gas Co. and UGI Utilities Inc. from Fitch and Moody's ratings are listed. MGEE is not rated by S&P or Moody's, subsidiary Madison Gas & Electric is used.
[6]-[7]: Source: Company 10-K reports, average of three most recent years
[8] Source: S&P Capital IQ Pro

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NW Natural

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November 24, 2026

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] S&P Capital IQ Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
Atmos Energy Corporation	ATO	$4.00	$171.78	2.33%	2.42%	6.80%	7.90%	8.50%	7.73%	9.21%	10.15%	10.93%
New Jersey Resources Corporation	NJR	$1.90	$56.13	3.38%	3.49%	n/a	6.30%	6.00%	6.15%	9.49%	9.64%	9.79%
NiSource Inc.	NI	$1.20	$43.10	2.78%	2.90%	6.60%	9.80%	9.00%	8.47%	9.48%	11.37%	12.72%
ONE Gas, Inc.	OGS	$2.72	$79.80	3.41%	3.53%	7.40%	6.75%	7.00%	7.05%	10.27%	10.58%	10.93%
Southwest Gas Holdings, Inc.	SWX	$2.58	$91.04	2.83%	3.00%	9.90%	14.00%	NMF	11.95%	12.87%	14.95%	17.03%
Spire Inc.	SR	$3.30	$81.98	4.03%	4.23%	11.20%	11.17%	8.50%	10.29%	12.70%	14.52%	15.45%
Ameren Corporation	AEE	$3.00	$109.11	2.75%	2.85%	7.70%	7.70%	7.50%	7.63%	10.35%	10.49%	10.56%
Avista Corporation	AVA	$1.97	$39.34	5.01%	5.13%	4.10%	5.90%	4.50%	4.83%	9.21%	9.96%	11.06%
CenterPoint Energy, Inc.	CNP	$0.96	$41.14	2.33%	2.44%	8.90%	8.80%	8.50%	8.73%	10.93%	11.17%	11.34%
CMS Energy Corporation	CMS	$2.28	$71.08	3.21%	3.33%	7.10%	7.70%	8.50%	7.77%	10.42%	11.10%	11.84%
Consolidated Edison, Inc.	ED	$3.55	$108.91	3.26%	3.37%	6.50%	6.44%	6.50%	6.48%	9.80%	9.84%	9.87%
DTE Energy Company	DTE	$4.66	$140.64	3.31%	3.42%	6.00%	8.10%	6.00%	6.70%	9.41%	10.12%	11.55%
Eversource Energy	ES	$3.15	$72.39	4.35%	4.44%	2.90%	5.25%	4.50%	4.22%	7.31%	8.66%	9.72%
Public Service Enterprise Group Inc.	PEG	$2.68	$75.93	3.53%	3.65%	6.10%	6.90%	7.50%	6.83%	9.74%	10.48%	11.16%
WEC Energy Group, Inc.	WEC	$3.81	$109.50	3.48%	3.63%	10.30%	8.00%	7.00%	8.43%	10.60%	12.06%	13.96%
Xcel Energy Inc.	XEL	$2.37	$78.36	3.02%	3.16%	9.40%	9.36%	8.00%	8.92%	11.15%	12.08%	12.57%
Gas Proxy Group Mean				3.13%	3.26%	8.38%	9.32%	7.80%	8.61%	10.67%	11.87%	12.81%
Gas Proxy Group Median				3.11%	3.25%	7.40%	8.85%	8.50%	8.10%	9.88%	10.97%	11.83%
Gas Proxy Group Average of Mean and Median				3.12%	3.25%	7.89%	9.08%	8.15%	8.35%	10.27%	11.42%	12.32%
Combined Proxy Group Mean				3.31%	3.44%	7.39%	8.13%	7.17%	7.64%	10.18%	11.07%	11.90%
Combined Proxy Group Median				3.29%	3.39%	7.10%	7.80%	7.50%	7.68%	10.04%	10.53%	11.25%
Combined Proxy Group Average of Mean and Median				3.30%	3.42%	7.25%	7.96%	7.33%	7.66%	10.11%	10.80%	11.58%

Notes:
[1] Source: S&P Capital IQ
[2] Source: S&P Capital IQ, equals indicated number of trading day average as of 08/31/2026
[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]
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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] S&P Capital IQ Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
Atmos Energy Corporation	ATO	$4.00	$174.89	2.29%	2.38%	6.80%	7.90%	8.50%	7.73%	9.16%	10.11%	10.88%
New Jersey Resources Corporation	NJR	$1.90	$56.29	3.38%	3.48%	n/a	6.30%	6.00%	6.15%	9.48%	9.63%	9.78%
NiSource Inc.	NI	$1.20	$45.78	2.62%	2.73%	6.60%	9.80%	9.00%	8.47%	9.31%	11.20%	12.55%
ONE Gas, Inc.	OGS	$2.72	$80.46	3.38%	3.50%	7.40%	6.75%	7.00%	7.05%	10.24%	10.55%	10.91%
Southwest Gas Holdings, Inc.	SWX	$2.58	$90.10	2.86%	3.03%	9.90%	14.00%	NMF	11.95%	12.91%	14.98%	17.06%
Spire Inc.	SR	$3.30	$82.75	3.99%	4.19%	11.20%	11.17%	8.50%	10.29%	12.66%	14.48%	15.41%
Ameren Corporation	AEE	$3.00	$110.16	2.72%	2.83%	7.70%	7.70%	7.50%	7.63%	10.33%	10.46%	10.53%
Avista Corporation	AVA	$1.97	$40.57	4.86%	4.97%	4.10%	5.90%	4.50%	4.83%	9.06%	9.81%	10.90%
CenterPoint Energy, Inc.	CNP	$0.96	$42.35	2.27%	2.37%	8.90%	8.80%	8.50%	8.73%	10.86%	11.10%	11.27%
CMS Energy Corporation	CMS	$2.28	$73.21	3.11%	3.24%	7.10%	7.70%	8.50%	7.77%	10.32%	11.00%	11.75%
Consolidated Edison, Inc.	ED	$3.55	$108.66	3.27%	3.37%	6.50%	6.44%	6.50%	6.48%	9.81%	9.85%	9.87%
DTE Energy Company	DTE	$4.66	$144.65	3.22%	3.33%	6.00%	8.10%	6.00%	6.70%	9.32%	10.03%	11.45%
Eversource Energy	ES	$3.15	$71.04	4.43%	4.53%	2.90%	5.25%	4.50%	4.22%	7.40%	8.74%	9.80%
Public Service Enterprise Group Inc.	PEG	$2.68	$78.36	3.42%	3.54%	6.10%	6.90%	7.50%	6.83%	9.62%	10.37%	11.05%
WEC Energy Group, Inc.	WEC	$3.81	$112.39	3.39%	3.53%	10.30%	8.00%	7.00%	8.43%	10.51%	11.97%	13.86%
Xcel Energy Inc.	XEL	$2.37	$79.24	2.99%	3.12%	9.40%	9.36%	8.00%	8.92%	11.11%	12.04%	12.53%
Gas Proxy Group Mean				3.09%	3.22%	8.38%	9.32%	7.80%	8.61%	10.63%	11.83%	12.77%
Gas Proxy Group Median				3.12%	3.26%	7.40%	8.85%	8.50%	8.10%	9.86%	10.87%	11.73%
Gas Proxy Group Average of Mean and Median				3.10%	3.24%	7.89%	9.08%	8.15%	8.35%	10.24%	11.35%	12.25%
Combined Proxy Group Mean				3.26%	3.38%	7.39%	8.13%	7.17%	7.64%	10.13%	11.02%	11.85%
Combined Proxy Group Median				3.24%	3.35%	7.10%	7.80%	7.50%	7.68%	10.03%	10.51%	11.16%
Combined Proxy Group Average of Mean and Median				3.25%	3.37%	7.25%	7.96%	7.33%	7.66%	10.08%	10.76%	11.50%

Notes:
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Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment
180 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] S&P Capital IQ Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
Atmos Energy Corporation	ATO	$4.00	$176.04	2.27%	2.36%	6.80%	7.90%	8.50%	7.73%	9.15%	10.09%	10.87%
New Jersey Resources Corporation	NJR	$1.90	$53.94	3.52%	3.63%	n/a	6.30%	6.00%	6.15%	9.63%	9.78%	9.93%
NiSource Inc.	NI	$1.20	$45.36	2.65%	2.76%	6.60%	9.80%	9.00%	8.47%	9.33%	11.22%	12.58%
ONE Gas, Inc.	OGS	$2.72	$81.75	3.33%	3.44%	7.40%	6.75%	7.00%	7.05%	10.19%	10.49%	10.85%
Southwest Gas Holdings, Inc.	SWX	$2.58	$87.76	2.94%	3.12%	9.90%	14.00%	NMF	11.95%	12.99%	15.07%	17.15%
Spire Inc.	SR	$3.30	$85.28	3.87%	4.07%	11.20%	11.17%	8.50%	10.29%	12.53%	14.36%	15.29%
Ameren Corporation	AEE	$3.00	$108.33	2.77%	2.88%	7.70%	7.70%	7.50%	7.63%	10.37%	10.51%	10.58%
Avista Corporation	AVA	$1.97	$40.41	4.88%	4.99%	4.10%	5.90%	4.50%	4.83%	9.08%	9.83%	10.92%
CenterPoint Energy, Inc.	CNP	$0.96	$41.72	2.30%	2.40%	8.90%	8.80%	8.50%	8.73%	10.90%	11.13%	11.30%
CMS Energy Corporation	CMS	$2.28	$73.70	3.09%	3.21%	7.10%	7.70%	8.50%	7.77%	10.30%	10.98%	11.72%
Consolidated Edison, Inc.	ED	$3.55	$108.06	3.29%	3.39%	6.50%	6.44%	6.50%	6.48%	9.83%	9.87%	9.89%
DTE Energy Company	DTE	$4.66	$142.29	3.28%	3.38%	6.00%	8.10%	6.00%	6.70%	9.37%	10.08%	11.51%
Eversource Energy	ES	$3.15	$70.46	4.47%	4.56%	2.90%	5.25%	4.50%	4.22%	7.44%	8.78%	9.84%
Public Service Enterprise Group Inc.	PEG	$2.68	$79.99	3.35%	3.46%	6.10%	6.90%	7.50%	6.83%	9.55%	10.30%	10.98%
WEC Energy Group, Inc.	WEC	$3.81	$112.12	3.40%	3.54%	10.30%	8.00%	7.00%	8.43%	10.52%	11.97%	13.87%
Xcel Energy Inc.	XEL	$2.37	$78.67	3.01%	3.15%	9.40%	9.36%	8.00%	8.92%	11.13%	12.07%	12.55%
Gas Proxy Group Mean				3.10%	3.23%	8.38%	9.32%	7.80%	8.61%	10.64%	11.84%	12.78%
Gas Proxy Group Median				3.13%	3.28%	7.40%	8.85%	8.50%	8.10%	9.91%	10.86%	11.72%
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Combined Proxy Group Mean				3.28%	3.40%	7.39%	8.13%	7.17%	7.64%	10.14%	11.03%	11.86%
Combined Proxy Group Median				3.28%	3.39%	7.10%	7.80%	7.50%	7.68%	10.01%	10.50%	11.14%
Combined Proxy Group Average of Mean and Median				3.28%	3.39%	7.25%	7.96%	7.33%	7.66%	10.08%	10.77%	11.50%

Notes:
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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 405

November 24, 2026

Exhibit NW Natural/405, Nelson

Multi-Stage Discounted Cash Flow Model with Projected GDP Growth
30 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Growth Rate, Years 1-5	[4] Year 6	[5] Year 7	[6] Year 8	[7] Year 9	[8] Year 10	[9] GDP Growth (perpetuity)	[10] ROE
Atmos Energy Corporation	ATO	$4.00	$171.78	7.73%	7.13%	6.54%	5.94%	5.34%	4.74%	4.14%	7.30%
New Jersey Resources Corporation	NJR	$1.90	$56.13	6.15%	5.82%	5.48%	5.15%	4.81%	4.48%	4.14%	8.30%
NiSource Inc.	NI	$1.20	$43.10	8.47%	7.75%	7.03%	6.30%	5.58%	4.86%	4.14%	8.09%
ONE Gas, Inc.	OGS	$2.72	$79.80	7.05%	6.57%	6.08%	5.60%	5.11%	4.63%	4.14%	8.57%
Southwest Gas Holdings, Inc.	SWX	$2.58	$91.04	11.95%	10.65%	9.35%	8.05%	6.74%	5.44%	4.14%	9.10%
Spire Inc.	SR	$3.30	$81.98	10.29%	9.26%	8.24%	7.22%	6.19%	5.17%	4.14%	10.47%
Ameren Corporation	AEE	$3.00	$109.11	7.63%	7.05%	6.47%	5.89%	5.31%	4.72%	4.14%	7.85%
Avista Corporation	AVA	$1.97	$39.34	4.83%	4.72%	4.60%	4.49%	4.37%	4.26%	4.14%	9.84%
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DTE Energy Company	DTE	$4.66	$140.64	6.70%	6.27%	5.85%	5.42%	4.99%	4.57%	4.14%	8.35%
Eversource Energy	ES	$3.15	$72.39	4.22%	4.20%	4.19%	4.18%	4.17%	4.15%	4.14%	8.89%
Public Service Enterprise Group Inc.	PEG	$2.68	$75.93	6.83%	6.38%	5.94%	5.49%	5.04%	4.59%	4.14%	8.67%
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Xcel Energy Inc.	XEL	$2.37	$78.36	8.92%	8.12%	7.33%	6.53%	5.73%	4.94%	4.14%	8.55%
Gas Proxy Group Mean											8.64%
Gas Proxy Group Median											8.43%
Gas Proxy Group Average of Mean and Median											8.54%
Combined Proxy Group Mean											8.58%
Combined Proxy Group Median											8.53%
Combined Proxy Group Average of Mean and Median											8.55%

Notes:
[1] Source: S&P Capital IQ
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[3] Source: Exhibit NW Natural/404
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Sources: Blue Chip Financial Forecasts 2033-2037 Real GDP growth (1.9%) and projected Inflation (2.2%) = ((1+GDP) x (1+ CPI)) - 1
[10] Internal rate of return

Multi-Stage Discounted Cash Flow Model with Projected GDP Growth
90 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Growth Rate, Years 1-5	[4] Year 6	[5] Year 7	[6] Year 8	[7] Year 9	[8] Year 10	[9] GDP Growth (perpetuity)	[10] ROE
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NiSource Inc.	NI	$1.20	$45.78	8.47%	7.75%	7.03%	6.30%	5.58%	4.86%	4.14%	7.86%
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Spire Inc.	SR	$3.30	$82.75	10.29%	9.26%	8.24%	7.22%	6.19%	5.17%	4.14%	10.41%
Ameren Corporation	AEE	$3.00	$110.16	7.63%	7.05%	6.47%	5.89%	5.31%	4.72%	4.14%	7.81%
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CenterPoint Energy, Inc.	CNP	$0.96	$42.35	8.73%	7.97%	7.20%	6.44%	5.67%	4.91%	4.14%	7.42%
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Consolidated Edison, Inc.	ED	$3.55	$108.66	6.48%	6.09%	5.70%	5.31%	4.92%	4.53%	4.14%	8.24%
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Public Service Enterprise Group Inc.	PEG	$2.68	$78.36	6.83%	6.38%	5.94%	5.49%	5.04%	4.59%	4.14%	8.53%
WEC Energy Group, Inc.	WEC	$3.81	$112.39	8.43%	7.72%	7.00%	6.29%	5.57%	4.86%	4.14%	8.94%
Xcel Energy Inc.	XEL	$2.37	$79.24	8.92%	8.12%	7.33%	6.53%	5.73%	4.94%	4.14%	8.51%
Gas Proxy Group Mean											8.58%
Gas Proxy Group Median											8.41%
Gas Proxy Group Average of Mean and Median											8.50%
Combined Proxy Group Mean											8.51%
Combined Proxy Group Median											8.44%
Combined Proxy Group Average of Mean and Median											8.47%

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New Jersey Resources Corporation	NJR	$1.90	$53.94	6.15%	5.82%	5.48%	5.15%	4.81%	4.48%	4.14%	8.47%
NiSource Inc.	NI	$1.20	$45.36	8.47%	7.75%	7.03%	6.30%	5.58%	4.86%	4.14%	7.90%
ONE Gas, Inc.	OGS	$2.72	$81.75	7.05%	6.57%	6.08%	5.60%	5.11%	4.63%	4.14%	8.47%
Southwest Gas Holdings, Inc.	SWX	$2.58	$87.76	11.95%	10.65%	9.35%	8.05%	6.74%	5.44%	4.14%	9.28%
Spire Inc.	SR	$3.30	$85.28	10.29%	9.26%	8.24%	7.22%	6.19%	5.17%	4.14%	10.23%
Ameren Corporation	AEE	$3.00	$108.33	7.63%	7.05%	6.47%	5.89%	5.31%	4.72%	4.14%	7.87%
Avista Corporation	AVA	$1.97	$40.41	4.83%	4.72%	4.60%	4.49%	4.37%	4.26%	4.14%	9.68%
CenterPoint Energy, Inc.	CNP	$0.96	$41.72	8.73%	7.97%	7.20%	6.44%	5.67%	4.91%	4.14%	7.47%
CMS Energy Corporation	CMS	$2.28	$73.70	7.77%	7.16%	6.56%	5.95%	5.35%	4.75%	4.14%	8.34%
Consolidated Edison, Inc.	ED	$3.55	$108.06	6.48%	6.09%	5.70%	5.31%	4.92%	4.53%	4.14%	8.26%
DTE Energy Company	DTE	$4.66	$142.29	6.70%	6.27%	5.85%	5.42%	4.99%	4.57%	4.14%	8.30%
Eversource Energy	ES	$3.15	$70.46	4.22%	4.20%	4.19%	4.18%	4.17%	4.15%	4.14%	9.02%
Public Service Enterprise Group Inc.	PEG	$2.68	$79.99	6.83%	6.38%	5.94%	5.49%	5.04%	4.59%	4.14%	8.44%
WEC Energy Group, Inc.	WEC	$3.81	$112.12	8.43%	7.72%	7.00%	6.29%	5.57%	4.86%	4.14%	8.95%
Xcel Energy Inc.	XEL	$2.37	$78.67	8.92%	8.12%	7.33%	6.53%	5.73%	4.94%	4.14%	8.54%
Gas Proxy Group Mean											8.59%
Gas Proxy Group Median											8.47%
Gas Proxy Group Average of Mean and Median											8.53%
Combined Proxy Group Mean											8.53%
Combined Proxy Group Median											8.45%
Combined Proxy Group Average of Mean and Median											8.49%

Notes:
[1] Source: S&P Capital IQ
[2] Source: S&P Capital IQ, equals indicated number of trading day average as of 08/31/2026
[3] Source: Exhibit NW Natural/404
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Sources: Blue Chip Financial Forecasts 2033-2037 Real GDP growth (1.9%) and projected Inflation (2.2%) = ((1+GDP) x (1+ CPI)) - 1
[10] Internal rate of return

Multi-Stage Discounted Cash Flow Model with Historical GDP Growth
30 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Growth Rate, Years 1-5	[4] Year 6	[5] Year 7	[6] Year 8	[7] Year 9	[8] Year 10	[9] GDP Growth (perpetuity)	[10] ROE
Atmos Energy Corporation	ATO	$4.00	$171.78	7.73%	7.50%	7.26%	7.02%	6.79%	6.55%	6.32%	9.13%
New Jersey Resources Corporation	NJR	$1.90	$56.13	6.15%	6.18%	6.21%	6.23%	6.26%	6.29%	6.32%	10.04%
NiSource Inc.	NI	$1.20	$43.10	8.47%	8.11%	7.75%	7.39%	7.03%	6.67%	6.32%	9.86%
ONE Gas, Inc.	OGS	$2.72	$79.80	7.05%	6.93%	6.81%	6.68%	6.56%	6.44%	6.32%	10.29%
Southwest Gas Holdings, Inc.	SWX	$2.58	$91.04	11.95%	11.01%	10.07%	9.13%	8.19%	7.25%	6.32%	10.78%
Spire Inc.	SR	$3.30	$81.98	10.29%	9.63%	8.96%	8.30%	7.64%	6.98%	6.32%	12.04%
Ameren Corporation	AEE	$3.00	$109.11	7.63%	7.41%	7.19%	6.97%	6.75%	6.53%	6.32%	9.63%
Avista Corporation	AVA	$1.97	$39.34	4.83%	5.08%	5.33%	5.57%	5.82%	6.07%	6.32%	11.45%
CenterPoint Energy, Inc.	CNP	$0.96	$41.14	8.73%	8.33%	7.93%	7.52%	7.12%	6.72%	6.32%	9.33%
CMS Energy Corporation	CMS	$2.28	$71.08	7.77%	7.52%	7.28%	7.04%	6.80%	6.56%	6.32%	10.23%
Consolidated Edison, Inc.	ED	$3.55	$108.91	6.48%	6.45%	6.42%	6.40%	6.37%	6.34%	6.32%	9.98%
DTE Energy Company	DTE	$4.66	$140.64	6.70%	6.64%	6.57%	6.51%	6.44%	6.38%	6.32%	10.09%
Eversource Energy	ES	$3.15	$72.39	4.22%	4.57%	4.92%	5.27%	5.62%	5.97%	6.32%	10.58%
Public Service Enterprise Group Inc.	PEG	$2.68	$75.93	6.83%	6.75%	6.66%	6.57%	6.49%	6.40%	6.32%	10.38%
WEC Energy Group, Inc.	WEC	$3.81	$109.50	8.43%	8.08%	7.73%	7.37%	7.02%	6.67%	6.32%	10.74%
Xcel Energy Inc.	XEL	$2.37	$78.36	8.92%	8.49%	8.05%	7.62%	7.18%	6.75%	6.32%	10.28%
Gas Proxy Group Mean											10.36%
Gas Proxy Group Median											10.17%
Gas Proxy Group Average of Mean and Median											10.26%
Combined Proxy Group Mean											10.30%
Combined Proxy Group Median											10.25%
Combined Proxy Group Average of Mean and Median											10.28%

Notes:
[1] Source: S&P Capital IQ
[2] Source: S&P Capital IQ, equals indicated number of trading day average as of 08/31/2026
[3] Source: Exhibit NW Natural/404
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Sources: Bureau of Economic Analysis, Historical Average Nominal GDP Growth 1929-2025, as of August 26, 2026
[10] Internal rate of return

Multi-Stage Discounted Cash Flow Model with Historical GDP Growth
90 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Growth Rate, Years 1-5	[4] Year 6	[5] Year 7	[6] Year 8	[7] Year 9	[8] Year 10	[9] GDP Growth (perpetuity)	[10] ROE
Atmos Energy Corporation	ATO	$4.00	$174.89	7.73%	7.50%	7.26%	7.02%	6.79%	6.55%	6.32%	9.08%
New Jersey Resources Corporation	NJR	$1.90	$56.29	6.15%	6.18%	6.21%	6.23%	6.26%	6.29%	6.32%	10.03%
NiSource Inc.	NI	$1.20	$45.78	8.47%	8.11%	7.75%	7.39%	7.03%	6.67%	6.32%	9.65%
ONE Gas, Inc.	OGS	$2.72	$80.46	7.05%	6.93%	6.81%	6.68%	6.56%	6.44%	6.32%	10.26%
Southwest Gas Holdings, Inc.	SWX	$2.58	$90.10	11.95%	11.01%	10.07%	9.13%	8.19%	7.25%	6.32%	10.82%
Spire Inc.	SR	$3.30	$82.75	10.29%	9.63%	8.96%	8.30%	7.64%	6.98%	6.32%	11.98%
Ameren Corporation	AEE	$3.00	$110.16	7.63%	7.41%	7.19%	6.97%	6.75%	6.53%	6.32%	9.60%
Avista Corporation	AVA	$1.97	$40.57	4.83%	5.08%	5.33%	5.57%	5.82%	6.07%	6.32%	11.29%
CenterPoint Energy, Inc.	CNP	$0.96	$42.35	8.73%	8.33%	7.93%	7.52%	7.12%	6.72%	6.32%	9.24%
CMS Energy Corporation	CMS	$2.28	$73.21	7.77%	7.52%	7.28%	7.04%	6.80%	6.56%	6.32%	10.11%
Consolidated Edison, Inc.	ED	$3.55	$108.66	6.48%	6.45%	6.42%	6.40%	6.37%	6.34%	6.32%	9.99%
DTE Energy Company	DTE	$4.66	$144.65	6.70%	6.64%	6.57%	6.51%	6.44%	6.38%	6.32%	9.99%
Eversource Energy	ES	$3.15	$71.04	4.22%	4.57%	4.92%	5.27%	5.62%	5.97%	6.32%	10.66%
Public Service Enterprise Group Inc.	PEG	$2.68	$78.36	6.83%	6.75%	6.66%	6.57%	6.49%	6.40%	6.32%	10.25%
WEC Energy Group, Inc.	WEC	$3.81	$112.39	8.43%	8.08%	7.73%	7.37%	7.02%	6.67%	6.32%	10.63%
Xcel Energy Inc.	XEL	$2.37	$79.24	8.92%	8.49%	8.05%	7.62%	7.18%	6.75%	6.32%	10.23%
Gas Proxy Group Mean											10.30%
Gas Proxy Group Median											10.14%
Gas Proxy Group Average of Mean and Median											10.22%
Combined Proxy Group Mean											10.24%
Combined Proxy Group Median											10.17%
Combined Proxy Group Average of Mean and Median											10.20%

Notes:
[1] Source: S&P Capital IQ
[2] Source: S&P Capital IQ, equals indicated number of trading day average as of 08/31/2026
[3] Source: Exhibit NW Natural/404
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Sources: Bureau of Economic Analysis, Historical Average Nominal GDP Growth 1929-2025, as of August 26, 2026
[10] Internal rate of return

Multi-Stage Discounted Cash Flow Model with Historical GDP Growth
180 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Growth Rate, Years 1-5	[4] Year 6	[5] Year 7	[6] Year 8	[7] Year 9	[8] Year 10	[9] GDP Growth (perpetuity)	[10] ROE
Atmos Energy Corporation	ATO	$4.00	$176.04	7.73%	7.50%	7.26%	7.02%	6.79%	6.55%	6.32%	9.06%
New Jersey Resources Corporation	NJR	$1.90	$53.94	6.15%	6.18%	6.21%	6.23%	6.26%	6.29%	6.32%	10.20%
NiSource Inc.	NI	$1.20	$45.36	8.47%	8.11%	7.75%	7.39%	7.03%	6.67%	6.32%	9.68%
ONE Gas, Inc.	OGS	$2.72	$81.75	7.05%	6.93%	6.81%	6.68%	6.56%	6.44%	6.32%	10.19%
Southwest Gas Holdings, Inc.	SWX	$2.58	$87.76	11.95%	11.01%	10.07%	9.13%	8.19%	7.25%	6.32%	10.94%
Spire Inc.	SR	$3.30	$85.28	10.29%	9.63%	8.96%	8.30%	7.64%	6.98%	6.32%	11.82%
Ameren Corporation	AEE	$3.00	$108.33	7.63%	7.41%	7.19%	6.97%	6.75%	6.53%	6.32%	9.65%
Avista Corporation	AVA	$1.97	$40.41	4.83%	5.08%	5.33%	5.57%	5.82%	6.07%	6.32%	11.31%
CenterPoint Energy, Inc.	CNP	$0.96	$41.72	8.73%	8.33%	7.93%	7.52%	7.12%	6.72%	6.32%	9.28%
CMS Energy Corporation	CMS	$2.28	$73.70	7.77%	7.52%	7.28%	7.04%	6.80%	6.56%	6.32%	10.08%
Consolidated Edison, Inc.	ED	$3.55	$108.06	6.48%	6.45%	6.42%	6.40%	6.37%	6.34%	6.32%	10.01%
DTE Energy Company	DTE	$4.66	$142.29	6.70%	6.64%	6.57%	6.51%	6.44%	6.38%	6.32%	10.05%
Eversource Energy	ES	$3.15	$70.46	4.22%	4.57%	4.92%	5.27%	5.62%	5.97%	6.32%	10.70%
Public Service Enterprise Group Inc.	PEG	$2.68	$79.99	6.83%	6.75%	6.66%	6.57%	6.49%	6.40%	6.32%	10.17%
WEC Energy Group, Inc.	WEC	$3.81	$112.12	8.43%	8.08%	7.73%	7.37%	7.02%	6.67%	6.32%	10.64%
Xcel Energy Inc.	XEL	$2.37	$78.67	8.92%	8.49%	8.05%	7.62%	7.18%	6.75%	6.32%	10.26%
Gas Proxy Group Mean											10.31%
Gas Proxy Group Median											10.20%
Gas Proxy Group Average of Mean and Median											10.26%
Combined Proxy Group Mean											10.25%
Combined Proxy Group Median											10.18%
Combined Proxy Group Average of Mean and Median											10.22%

Notes:
[1] Source: S&P Capital IQ
[2] Source: S&P Capital IQ, equals indicated number of trading day average as of 08/31/2026
[3] Source: Exhibit NW Natural/404
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Sources: Bureau of Economic Analysis, Historical Average Nominal GDP Growth 1929-2025, as of August 26, 2026
[10] Internal rate of return

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 406

November 24, 2026

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] S&P Capital IQ Earnings Growth	[12] Value Line Earnings Growth	[13] Average Earnings Growth	[14] Low ROE	[15] Mean ROE	[16] High ROE
Atmos Energy Corporation	ATO	$1.00	$1.00	$1.00	$1.00	$1.08	$1.08	$1.08	$1.08	$171.78	6.80%	7.90%	8.50%	7.73%	9.37%	10.34%	11.13%
New Jersey Resources Corporation	NJR	$0.48	$0.48	$0.48	$0.48	$0.50	$0.50	$0.50	$0.50	$56.13	n/a	6.30%	6.00%	6.15%	9.72%	9.87%	10.03%
NiSource Inc.	NI	$0.28	$0.30	$0.30	$0.30	$0.30	$0.33	$0.33	$0.33	$43.10	6.60%	9.80%	9.00%	8.47%	9.62%	11.56%	12.95%
ONE Gas, Inc.	OGS	$0.67	$0.68	$0.68	$0.68	$0.72	$0.73	$0.73	$0.73	$79.80	7.40%	6.75%	7.00%	7.05%	10.51%	10.83%	11.20%
Southwest Gas Holdings, Inc.	SWX	$0.62	$0.62	$0.65	$0.65	$0.69	$0.69	$0.72	$0.72	$91.04	9.90%	14.00%	NMF	11.95%	13.10%	15.23%	17.36%
Spire Inc.	SR	$0.79	$0.83	$0.83	$0.83	$0.87	$0.91	$0.91	$0.91	$81.98	11.20%	11.17%	8.50%	10.29%	13.02%	14.91%	15.87%
Ameren Corporation	AEE	$0.71	$0.71	$0.75	$0.75	$0.76	$0.76	$0.81	$0.81	$109.11	7.70%	7.70%	7.50%	7.63%	10.49%	10.62%	10.69%
Avista Corporation	AVA	$0.49	$0.49	$0.49	$0.49	$0.51	$0.52	$0.52	$0.52	$39.34	4.10%	5.90%	4.50%	4.83%	9.49%	10.27%	11.42%
CenterPoint Energy, Inc.	CNP	$0.22	$0.23	$0.23	$0.24	$0.24	$0.25	$0.25	$0.26	$41.14	8.90%	8.80%	8.50%	8.73%	11.02%	11.26%	11.44%
CMS Energy Corporation	CMS	$0.54	$0.57	$0.57	$0.57	$0.58	$0.61	$0.61	$0.61	$71.08	7.10%	7.70%	8.50%	7.77%	10.62%	11.32%	12.09%
Consolidated Edison, Inc.	ED	$0.85	$0.89	$0.89	$0.89	$0.91	$0.94	$0.94	$0.94	$108.91	6.50%	6.44%	6.50%	6.48%	9.99%	10.04%	10.06%
DTE Energy Company	DTE	$1.09	$1.17	$1.17	$1.17	$1.16	$1.24	$1.24	$1.24	$140.64	6.00%	8.10%	6.00%	6.70%	9.58%	10.31%	11.77%
Eversource Energy	ES	$0.75	$0.75	$0.79	$0.79	$0.78	$0.78	$0.82	$0.82	$72.39	2.90%	5.25%	4.50%	4.22%	7.40%	8.79%	9.89%
Public Service Enterprise Group Inc.	PEG	$0.63	$0.63	$0.67	$0.67	$0.67	$0.67	$0.72	$0.72	$75.93	6.10%	6.90%	7.50%	6.83%	9.86%	10.63%	11.33%
WEC Energy Group, Inc.	WEC	$0.89	$0.95	$0.95	$0.95	$0.97	$1.03	$1.03	$1.03	$109.50	10.30%	8.00%	7.00%	8.43%	10.81%	12.31%	14.27%
Xcel Energy Inc.	XEL	$0.57	$0.57	$0.59	$0.59	$0.62	$0.62	$0.65	$0.65	$78.36	9.40%	9.36%	8.00%	8.92%	11.34%	12.30%	12.80%
Gas Proxy Group Mean											8.38%	9.32%	7.80%	8.61%	10.89%	12.12%	13.09%
Gas Proxy Group Median											7.40%	8.85%	8.50%	8.10%	10.12%	11.19%	12.07%
Gas Proxy Group Average of Mean and Median															10.50%	11.66%	12.58%
Combined Proxy Group Mean											7.39%	8.13%	7.17%	7.64%	10.37%	11.29%	12.14%
Combined Proxy Group Median											7.10%	7.80%	7.50%	7.68%	10.24%	10.73%	11.43%
Combined Proxy Group Average of Mean and Median															10.31%	11.01%	11.79%

Notes:
[1] Source: S&P Capital IQ
[2] Source: S&P Capital IQ
[3] Source: S&P Capital IQ
[4] Source: S&P Capital IQ
[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: S&P Capital IQ, equals indicated number of trading day average as of 08/31/2026
[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

Quarterly Growth Discounted Cash Flow Model
90 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] S&P Capital IQ Earnings Growth	[12] Value Line Earnings Growth	[13] Average Earnings Growth	[14] Low ROE	[15] Mean ROE	[16] High ROE
Atmos Energy Corporation	ATO	$1.00	$1.00	$1.00	$1.00	$1.08	$1.08	$1.08	$1.08	$174.89	6.80%	7.90%	8.50%	7.73%	9.33%	10.29%	11.08%
New Jersey Resources Corporation	NJR	$0.48	$0.48	$0.48	$0.48	$0.50	$0.50	$0.50	$0.50	$56.29	n/a	6.30%	6.00%	6.15%	9.71%	9.86%	10.02%
NiSource Inc.	NI	$0.28	$0.30	$0.30	$0.30	$0.30	$0.33	$0.33	$0.33	$45.78	6.60%	9.80%	9.00%	8.47%	9.44%	11.38%	12.76%
ONE Gas, Inc.	OGS	$0.67	$0.68	$0.68	$0.68	$0.72	$0.73	$0.73	$0.73	$80.46	7.40%	6.75%	7.00%	7.05%	10.48%	10.80%	11.17%
Southwest Gas Holdings, Inc.	SWX	$0.62	$0.62	$0.65	$0.65	$0.69	$0.69	$0.72	$0.72	$90.10	9.90%	14.00%	NMF	11.95%	13.13%	15.27%	17.40%
Spire Inc.	SR	$0.79	$0.83	$0.83	$0.83	$0.87	$0.91	$0.91	$0.91	$82.75	11.20%	11.17%	8.50%	10.29%	12.97%	14.87%	15.83%
Ameren Corporation	AEE	$0.71	$0.71	$0.75	$0.75	$0.76	$0.76	$0.81	$0.81	$110.16	7.70%	7.70%	7.50%	7.63%	10.46%	10.60%	10.66%
Avista Corporation	AVA	$0.49	$0.49	$0.49	$0.49	$0.51	$0.52	$0.52	$0.52	$40.57	4.10%	5.90%	4.50%	4.83%	9.32%	10.11%	11.25%
CenterPoint Energy, Inc.	CNP	$0.22	$0.23	$0.23	$0.24	$0.24	$0.25	$0.25	$0.26	$42.35	8.90%	8.80%	8.50%	8.73%	10.95%	11.19%	11.36%
CMS Energy Corporation	CMS	$0.54	$0.57	$0.57	$0.57	$0.58	$0.61	$0.61	$0.61	$73.21	7.10%	7.70%	8.50%	7.77%	10.52%	11.22%	11.98%
Consolidated Edison, Inc.	ED	$0.85	$0.89	$0.89	$0.89	$0.91	$0.94	$0.94	$0.94	$108.66	6.50%	6.44%	6.50%	6.48%	10.00%	10.05%	10.07%
DTE Energy Company	DTE	$1.09	$1.17	$1.17	$1.17	$1.16	$1.24	$1.24	$1.24	$144.65	6.00%	8.10%	6.00%	6.70%	9.48%	10.21%	11.67%
Eversource Energy	ES	$0.75	$0.75	$0.79	$0.79	$0.78	$0.78	$0.82	$0.82	$71.04	2.90%	5.25%	4.50%	4.22%	7.48%	8.88%	9.98%
Public Service Enterprise Group Inc.	PEG	$0.63	$0.63	$0.67	$0.67	$0.67	$0.67	$0.72	$0.72	$78.36	6.10%	6.90%	7.50%	6.83%	9.74%	10.51%	11.21%
WEC Energy Group, Inc.	WEC	$0.89	$0.95	$0.95	$0.95	$0.97	$1.03	$1.03	$1.03	$112.39	10.30%	8.00%	7.00%	8.43%	10.71%	12.21%	14.17%
Xcel Energy Inc.	XEL	$0.57	$0.57	$0.59	$0.59	$0.62	$0.62	$0.65	$0.65	$79.24	9.40%	9.36%	8.00%	8.92%	11.30%	12.26%	12.76%
Gas Proxy Group Mean											8.38%	9.32%	7.80%	8.61%	10.84%	12.08%	13.04%
Gas Proxy Group Median											7.40%	8.85%	8.50%	8.10%	10.09%	11.09%	11.96%
Gas Proxy Group Average of Mean and Median															10.47%	11.58%	12.50%
Combined Proxy Group Mean											7.39%	8.13%	7.17%	7.64%	10.31%	11.23%	12.09%
Combined Proxy Group Median											7.10%	7.80%	7.50%	7.68%	10.23%	10.70%	11.30%
Combined Proxy Group Average of Mean and Median															10.27%	10.96%	11.70%

Notes:
[1] Source: S&P Capital IQ
[2] Source: S&P Capital IQ
[3] Source: S&P Capital IQ
[4] Source: S&P Capital IQ
[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: S&P Capital IQ, equals indicated number of trading day average as of 08/31/2026
[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

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] S&P Capital IQ Earnings Growth	[12] Value Line Earnings Growth	[13] Average Earnings Growth	[14] Low ROE	[15] Mean ROE	[16] High ROE
Atmos Energy Corporation	ATO	$1.00	$1.00	$1.00	$1.00	$1.08	$1.08	$1.08	$1.08	$176.04	6.80%	7.90%	8.50%	7.73%	9.31%	10.27%	11.07%
New Jersey Resources Corporation	NJR	$0.48	$0.48	$0.48	$0.48	$0.50	$0.50	$0.50	$0.50	$53.94	n/a	6.30%	6.00%	6.15%	9.87%	10.03%	10.18%
NiSource Inc.	NI	$0.28	$0.30	$0.30	$0.30	$0.30	$0.33	$0.33	$0.33	$45.36	6.60%	9.80%	9.00%	8.47%	9.47%	11.40%	12.79%
ONE Gas, Inc.	OGS	$0.67	$0.68	$0.68	$0.68	$0.72	$0.73	$0.73	$0.73	$81.75	7.40%	6.75%	7.00%	7.05%	10.42%	10.74%	11.10%
Southwest Gas Holdings, Inc.	SWX	$0.62	$0.62	$0.65	$0.65	$0.69	$0.69	$0.72	$0.72	$87.76	9.90%	14.00%	NMF	11.95%	13.22%	15.36%	17.49%
Spire Inc.	SR	$0.79	$0.83	$0.83	$0.83	$0.87	$0.91	$0.91	$0.91	$85.28	11.20%	11.17%	8.50%	10.29%	12.84%	14.73%	15.69%
Ameren Corporation	AEE	$0.71	$0.71	$0.75	$0.75	$0.76	$0.76	$0.81	$0.81	$108.33	7.70%	7.70%	7.50%	7.63%	10.51%	10.65%	10.72%
Avista Corporation	AVA	$0.49	$0.49	$0.49	$0.49	$0.51	$0.52	$0.52	$0.52	$40.41	4.10%	5.90%	4.50%	4.83%	9.34%	10.13%	11.27%
CenterPoint Energy, Inc.	CNP	$0.22	$0.23	$0.23	$0.24	$0.24	$0.25	$0.25	$0.26	$41.72	8.90%	8.80%	8.50%	8.73%	10.99%	11.23%	11.40%
CMS Energy Corporation	CMS	$0.54	$0.57	$0.57	$0.57	$0.58	$0.61	$0.61	$0.61	$73.70	7.10%	7.70%	8.50%	7.77%	10.50%	11.19%	11.96%
Consolidated Edison, Inc.	ED	$0.85	$0.89	$0.89	$0.89	$0.91	$0.94	$0.94	$0.94	$108.06	6.50%	6.44%	6.50%	6.48%	10.02%	10.07%	10.09%
DTE Energy Company	DTE	$1.09	$1.17	$1.17	$1.17	$1.16	$1.24	$1.24	$1.24	$142.29	6.00%	8.10%	6.00%	6.70%	9.53%	10.27%	11.73%
Eversource Energy	ES	$0.75	$0.75	$0.79	$0.79	$0.78	$0.78	$0.82	$0.82	$70.46	2.90%	5.25%	4.50%	4.22%	7.52%	8.92%	10.02%
Public Service Enterprise Group Inc.	PEG	$0.63	$0.63	$0.67	$0.67	$0.67	$0.67	$0.72	$0.72	$79.99	6.10%	6.90%	7.50%	6.83%	9.67%	10.44%	11.13%
WEC Energy Group, Inc.	WEC	$0.89	$0.95	$0.95	$0.95	$0.97	$1.03	$1.03	$1.03	$112.12	10.30%	8.00%	7.00%	8.43%	10.72%	12.22%	14.18%
Xcel Energy Inc.	XEL	$0.57	$0.57	$0.59	$0.59	$0.62	$0.62	$0.65	$0.65	$78.67	9.40%	9.36%	8.00%	8.92%	11.32%	12.28%	12.78%
Gas Proxy Group Mean											8.38%	9.32%	7.80%	8.61%	10.86%	12.09%	13.05%
Gas Proxy Group Median											7.40%	8.85%	8.50%	8.10%	10.15%	11.07%	11.95%
Gas Proxy Group Average of Mean and Median															10.50%	11.58%	12.50%
Combined Proxy Group Mean											7.39%	8.13%	7.17%	7.64%	10.33%	11.24%	12.10%
Combined Proxy Group Median											7.10%	7.80%	7.50%	7.68%	10.22%	10.69%	11.33%
Combined Proxy Group Average of Mean and Median															10.28%	10.97%	11.72%

Notes:
[1] Source: S&P Capital IQ
[2] Source: S&P Capital IQ
[3] Source: S&P Capital IQ
[4] Source: S&P Capital IQ
[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: S&P Capital IQ, equals indicated number of trading day average as of 08/31/2026
[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

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 407

November 24, 2026

Forward Market Return
Market DCF Based Method - Value Line EPS Growth

[1] Market Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.12%
[2] Market Cap. Weighted Estimate of the S&P 500 Growth Rate	15.39%
[3] Market Cap. Weighted Estimated Required Market Return	16.59%

Notes:
[1] Source: S&P Capital IQ as of August 31, 2026
[2] Source: Value Line DCF-based forward market return provided in Confidential WP
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]

Forward Market Return
Market DCF Based Method - Bloomberg EPS Growth

[4] Market Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.11%
[5] Market Cap. Weighted Estimate of the S&P 500 Growth Rate	24.97%
[6] Market Cap. Weighted Estimated Required Market Return	26.22%

Notes:
[4] Source: S&P Capital IQ as of August 31, 2026
[5] Source: Bloomberg DCF-based forward market return provided in Confidential WP
[6] Equals ([4] x (1 + (0.5 x [5]))) + [5]

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 408

November 24, 2026

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Using DCF-derived Forward Market Return and 5-Year Beta Coefficients

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Company	Ticker	Current 30-Year Treasury Yield	Bloomberg Beta Coefficient	Value Line Beta Coefficient	Average Beta Coefficient	DCF Forward Market Return	Market Risk Premium	Traditional CAPM	Empirical CAPM
Atmos Energy Corporation	ATO	5.21%	0.59	0.75	0.67	16.59%	11.38%	12.83%	13.77%
New Jersey Resources Corporation	NJR	5.21%	0.56	0.75	0.65	16.59%	11.38%	12.66%	13.64%
NiSource Inc.	NI	5.21%	0.64	0.85	0.74	16.59%	11.38%	13.68%	14.41%
ONE Gas, Inc.	OGS	5.21%	0.54	0.75	0.64	16.59%	11.38%	12.54%	13.55%
Southwest Gas Holdings, Inc.	SWX	5.21%	0.61	0.80	0.71	16.59%	11.38%	13.26%	14.09%
Spire Inc.	SR	5.21%	0.57	0.75	0.66	16.59%	11.38%	12.74%	13.70%
Ameren Corporation	AEE	5.21%	0.59	0.75	0.67	16.59%	11.38%	12.83%	13.77%
Avista Corporation	AVA	5.21%	0.51	0.70	0.60	16.59%	11.38%	12.08%	13.21%
CenterPoint Energy, Inc.	CNP	5.21%	0.61	0.75	0.68	16.59%	11.38%	12.96%	13.86%
CMS Energy Corporation	CMS	5.21%	0.52	0.70	0.61	16.59%	11.38%	12.18%	13.28%
Consolidated Edison, Inc.	ED	5.21%	0.43	0.65	0.54	16.59%	11.38%	11.33%	12.65%
DTE Energy Company	DTE	5.21%	0.55	0.75	0.65	16.59%	11.38%	12.63%	13.62%
Eversource Energy	ES	5.21%	0.60	0.85	0.73	16.59%	11.38%	13.48%	14.26%
Public Service Enterprise Group Inc.	PEG	5.21%	0.66	0.85	0.75	16.59%	11.38%	13.77%	14.48%
WEC Energy Group, Inc.	WEC	5.21%	0.52	0.70	0.61	16.59%	11.38%	12.16%	13.27%
Xcel Energy Inc.	XEL	5.21%	0.55	0.70	0.63	16.59%	11.38%	12.33%	13.39%
							Gas Proxy Group Mean:	12.95%	13.86%
							Gas Proxy Group Median:	12.78%	13.73%
							Gas Proxy Group Average of Mean and Median:	12.87%	13.80%
							Combined Proxy Group Mean:	12.72%	13.68%
							Combined Proxy Group Median:	12.70%	13.67%
							Combined Proxy Group Average of Mean and Median:	12.71%	13.68%

		[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
Company	Ticker	Projected 30-Year Treasury Yield	Bloomberg Beta Coefficient	Value Line Beta Coefficient	Average Beta Coefficient	DCF Forward Market Return	Market Risk Premium	Traditional CAPM	Empirical CAPM
Atmos Energy Corporation	ATO	4.83%	0.59	0.75	0.67	16.59%	11.76%	12.70%	13.67%
New Jersey Resources Corporation	NJR	4.83%	0.56	0.75	0.65	16.59%	11.76%	12.53%	13.54%
NiSource Inc.	NI	4.83%	0.64	0.85	0.74	16.59%	11.76%	13.58%	14.33%
ONE Gas, Inc.	OGS	4.83%	0.54	0.75	0.64	16.59%	11.76%	12.41%	13.45%
Southwest Gas Holdings, Inc.	SWX	4.83%	0.61	0.80	0.71	16.59%	11.76%	13.15%	14.01%
Spire Inc.	SR	4.83%	0.57	0.75	0.66	16.59%	11.76%	12.62%	13.61%
Ameren Corporation	AEE	4.83%	0.59	0.75	0.67	16.59%	11.76%	12.71%	13.68%
Avista Corporation	AVA	4.83%	0.51	0.70	0.60	16.59%	11.76%	11.93%	13.10%
CenterPoint Energy, Inc.	CNP	4.83%	0.61	0.75	0.68	16.59%	11.76%	12.84%	13.77%
CMS Energy Corporation	CMS	4.83%	0.52	0.70	0.61	16.59%	11.76%	12.03%	13.17%
Consolidated Edison, Inc.	ED	4.83%	0.43	0.65	0.54	16.59%	11.76%	11.16%	12.52%
DTE Energy Company	DTE	4.83%	0.55	0.75	0.65	16.59%	11.76%	12.50%	13.52%
Eversource Energy	ES	4.83%	0.60	0.85	0.73	16.59%	11.76%	13.38%	14.18%
Public Service Enterprise Group Inc.	PEG	4.83%	0.66	0.85	0.75	16.59%	11.76%	13.68%	14.41%
WEC Energy Group, Inc.	WEC	4.83%	0.52	0.70	0.61	16.59%	11.76%	12.02%	13.16%
Xcel Energy Inc.	XEL	4.83%	0.55	0.70	0.63	16.59%	11.76%	12.19%	13.29%
							Gas Proxy Group Mean:	12.83%	13.77%
							Gas Proxy Group Median:	12.66%	13.64%
							Gas Proxy Group Average of Mean and Median:	12.75%	13.71%
							Combined Proxy Group Mean:	12.59%	13.59%
							Combined Proxy Group Median:	12.57%	13.58%
							Combined Proxy Group Average of Mean and Median:	12.58%	13.58%

Notes:
[1] Source: Federal Reserve Bank of St. Louis (FRED); 30-day average
[2] Source: Bloomberg Professional Service
[3] Source: Value Line
[4] Equals Average of Col. [2] and Col. [3]
[5] Source: Exhibit NW Natural/407; Value Line DCF-based forward market return
[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, September 2026 Edition, September 1, 2026 at 9 and Vol. 45, No. 6, June 1, 2026 at 14
[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])

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Using DCF-derived Forward Market Return and 10-Year Bloomberg Beta Coefficient

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-Year Treasury Yield	Bloomberg Beta Coefficient (10 Year)	DCF Forward Market Return	Market Risk Premium	Traditional CAPM	Empirical CAPM
Atmos Energy Corporation	ATO	5.21%	0.70	16.59%	11.38%	13.19%	14.04%
New Jersey Resources Corporation	NJR	5.21%	0.73	16.59%	11.38%	13.55%	14.31%
NiSource Inc.	NI	5.21%	0.75	16.59%	11.38%	13.76%	14.47%
ONE Gas, Inc.	OGS	5.21%	0.72	16.59%	11.38%	13.38%	14.18%
Southwest Gas Holdings, Inc.	SWX	5.21%	0.80	16.59%	11.38%	14.26%	14.84%
Spire Inc.	SR	5.21%	0.72	16.59%	11.38%	13.42%	14.21%
Ameren Corporation	AEE	5.21%	0.70	16.59%	11.38%	13.22%	14.06%
Avista Corporation	AVA	5.21%	0.69	16.59%	11.38%	13.05%	13.93%
CenterPoint Energy, Inc.	CNP	5.21%	0.91	16.59%	11.38%	15.52%	15.78%
CMS Energy Corporation	CMS	5.21%	0.69	16.59%	11.38%	13.04%	13.93%
Consolidated Edison, Inc.	ED	5.21%	0.57	16.59%	11.38%	11.71%	12.93%
DTE Energy Company	DTE	5.21%	0.76	16.59%	11.38%	13.85%	14.53%
Eversource Energy	ES	5.21%	0.77	16.59%	11.38%	13.97%	14.62%
Public Service Enterprise Group Inc.	PEG	5.21%	0.81	16.59%	11.38%	14.40%	14.94%
WEC Energy Group, Inc.	WEC	5.21%	0.68	16.59%	11.38%	12.99%	13.89%
Xcel Energy Inc.	XEL	5.21%	0.71	16.59%	11.38%	13.24%	14.07%
					Gas Proxy Group Mean:	13.59%	14.34%
					Gas Proxy Group Median:	13.49%	14.26%
					Gas Proxy Group Average of Mean and Median:	13.54%	14.30%
					Combined Proxy Group Mean:	13.53%	14.30%
					Combined Proxy Group Median:	13.40%	14.20%
					Combined Proxy Group Average of Mean and Median:	13.47%	14.25%

		[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Projected 30-Year Treasury Yield	Bloomberg Beta Coefficient (10 Year)	DCF Forward Market Return	Market Risk Premium	Traditional CAPM	Empirical CAPM
Atmos Energy Corporation	ATO	4.83%	0.70	16.59%	11.76%	13.08%	13.96%
New Jersey Resources Corporation	NJR	4.83%	0.73	16.59%	11.76%	13.45%	14.24%
NiSource Inc.	NI	4.83%	0.75	16.59%	11.76%	13.67%	14.40%
ONE Gas, Inc.	OGS	4.83%	0.72	16.59%	11.76%	13.27%	14.10%
Southwest Gas Holdings, Inc.	SWX	4.83%	0.80	16.59%	11.76%	14.18%	14.78%
Spire Inc.	SR	4.83%	0.72	16.59%	11.76%	13.32%	14.13%
Ameren Corporation	AEE	4.83%	0.70	16.59%	11.76%	13.11%	13.98%
Avista Corporation	AVA	4.83%	0.69	16.59%	11.76%	12.93%	13.85%
CenterPoint Energy, Inc.	CNP	4.83%	0.91	16.59%	11.76%	15.48%	15.76%
CMS Energy Corporation	CMS	4.83%	0.69	16.59%	11.76%	12.93%	13.84%
Consolidated Edison, Inc.	ED	4.83%	0.57	16.59%	11.76%	11.55%	12.81%
DTE Energy Company	DTE	4.83%	0.76	16.59%	11.76%	13.76%	14.46%
Eversource Energy	ES	4.83%	0.77	16.59%	11.76%	13.88%	14.56%
Public Service Enterprise Group Inc.	PEG	4.83%	0.81	16.59%	11.76%	14.32%	14.89%
WEC Energy Group, Inc.	WEC	4.83%	0.68	16.59%	11.76%	12.87%	13.80%
Xcel Energy Inc.	XEL	4.83%	0.71	16.59%	11.76%	13.13%	13.99%
					Gas Proxy Group Mean:	13.50%	14.27%
					Gas Proxy Group Median:	13.38%	14.19%
					Gas Proxy Group Average of Mean and Median:	13.44%	14.23%
					Combined Proxy Group Mean:	13.43%	14.22%
					Combined Proxy Group Median:	13.29%	14.12%
					Combined Proxy Group Average of Mean and Median:	13.36%	14.17%

Notes:
[1] Source: Federal Reserve Bank of St. Louis (FRED); 30-day average
[2] Source: Bloomberg Professional Service
[3] Source: Exhibit NW Natural/407; Value Line DCF-based forward market return
[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, September 2026 Edition, September 1, 2026 at 9 and Vol. 45, No. 6, June 1, 2026 at 14
[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])

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	Bloomberg Beta Coefficient	Value Line Beta Coefficient	Average Beta Coefficient	Long-Term Average Historical Market Return (1926-2025)	Market Risk Premium	Traditional CAPM	Empirical CAPM
Atmos Energy Corporation	ATO	5.21%	0.59	0.75	0.67	12.23%	7.03%	9.91%	10.49%
New Jersey Resources Corporation	NJR	5.21%	0.56	0.75	0.65	12.23%	7.03%	9.81%	10.41%
NiSource Inc.	NI	5.21%	0.64	0.85	0.74	12.23%	7.03%	10.44%	10.89%
ONE Gas, Inc.	OGS	5.21%	0.54	0.75	0.64	12.23%	7.03%	9.74%	10.36%
Southwest Gas Holdings, Inc.	SWX	5.21%	0.61	0.80	0.71	12.23%	7.03%	10.18%	10.69%
Spire Inc.	SR	5.21%	0.57	0.75	0.66	12.23%	7.03%	9.86%	10.45%
Ameren Corporation	AEE	5.21%	0.59	0.75	0.67	12.23%	7.03%	9.91%	10.49%
Avista Corporation	AVA	5.21%	0.51	0.70	0.60	12.23%	7.03%	9.45%	10.15%
CenterPoint Energy, Inc.	CNP	5.21%	0.61	0.75	0.68	12.23%	7.03%	9.99%	10.55%
CMS Energy Corporation	CMS	5.21%	0.52	0.70	0.61	12.23%	7.03%	9.51%	10.19%
Consolidated Edison, Inc.	ED	5.21%	0.43	0.65	0.54	12.23%	7.03%	8.99%	9.80%
DTE Energy Company	DTE	5.21%	0.55	0.75	0.65	12.23%	7.03%	9.79%	10.40%
Eversource Energy	ES	5.21%	0.60	0.85	0.73	12.23%	7.03%	10.32%	10.80%
Public Service Enterprise Group Inc.	PEG	5.21%	0.66	0.85	0.75	12.23%	7.03%	10.49%	10.93%
WEC Energy Group, Inc.	WEC	5.21%	0.52	0.70	0.61	12.23%	7.03%	9.50%	10.18%
Xcel Energy Inc.	XEL	5.21%	0.55	0.70	0.63	12.23%	7.03%	9.60%	10.26%
							Gas Proxy Group Mean:	9.99%	10.55%
							Gas Proxy Group Median:	9.88%	10.47%
							Gas Proxy Group Average of Mean and Median:	9.94%	10.51%
							Combined Proxy Group Mean:	9.84%	10.44%
							Combined Proxy Group Median:	9.83%	10.43%
							Combined Proxy Group Average of Mean and Median:	9.84%	10.44%

		[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
Company	Ticker	Projected 30-Year Treasury Yield	Bloomberg Beta Coefficient	Value Line Beta Coefficient	Average Beta Coefficient	Long-Term Average Historical Market Return (1926-2025)	Market Risk Premium	Traditional CAPM	Empirical CAPM
Atmos Energy Corporation	ATO	4.83%	0.59	0.75	0.67	12.23%	7.40%	9.79%	10.40%
New Jersey Resources Corporation	NJR	4.83%	0.56	0.75	0.65	12.23%	7.40%	9.68%	10.32%
NiSource Inc.	NI	4.83%	0.64	0.85	0.74	12.23%	7.40%	10.34%	10.81%
ONE Gas, Inc.	OGS	4.83%	0.54	0.75	0.64	12.23%	7.40%	9.60%	10.26%
Southwest Gas Holdings, Inc.	SWX	4.83%	0.61	0.80	0.71	12.23%	7.40%	10.07%	10.61%
Spire Inc.	SR	4.83%	0.57	0.75	0.66	12.23%	7.40%	9.73%	10.36%
Ameren Corporation	AEE	4.83%	0.59	0.75	0.67	12.23%	7.40%	9.79%	10.40%
Avista Corporation	AVA	4.83%	0.51	0.70	0.60	12.23%	7.40%	9.30%	10.04%
CenterPoint Energy, Inc.	CNP	4.83%	0.61	0.75	0.68	12.23%	7.40%	9.87%	10.46%
CMS Energy Corporation	CMS	4.83%	0.52	0.70	0.61	12.23%	7.40%	9.36%	10.08%
Consolidated Edison, Inc.	ED	4.83%	0.43	0.65	0.54	12.23%	7.40%	8.82%	9.67%
DTE Energy Company	DTE	4.83%	0.55	0.75	0.65	12.23%	7.40%	9.66%	10.30%
Eversource Energy	ES	4.83%	0.60	0.85	0.73	12.23%	7.40%	10.21%	10.72%
Public Service Enterprise Group Inc.	PEG	4.83%	0.66	0.85	0.75	12.23%	7.40%	10.40%	10.86%
WEC Energy Group, Inc.	WEC	4.83%	0.52	0.70	0.61	12.23%	7.40%	9.35%	10.07%
Xcel Energy Inc.	XEL	4.83%	0.55	0.70	0.63	12.23%	7.40%	9.46%	10.15%
							Gas Proxy Group Mean:	9.87%	10.46%
							Gas Proxy Group Median:	9.76%	10.38%
							Gas Proxy Group Average of Mean and Median:	9.81%	10.42%
							Combined Proxy Group Mean:	9.72%	10.34%
							Combined Proxy Group Median:	9.70%	10.34%
							Combined Proxy Group Average of Mean and Median:	9.71%	10.34%

[1] Source: Federal Reserve Bank of St. Louis (FRED); 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, September 2026 Edition, September 1, 2026 at 9 and Vol. 45, No. 6, June 1, 2026 at 14
[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])

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Using Long-Term Historical Market Return and 10-Year Bloomberg Beta Coefficient

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-Year Treasury Yield	Bloomberg Beta Coefficient (10 Year)	Long-Term Average Historical Market Return (1926-2025)	Market Risk Premium	Traditional CAPM	Empirical CAPM
Atmos Energy Corporation	ATO	5.21%	0.70	12.23%	7.03%	10.14%	10.66%
New Jersey Resources Corporation	NJR	5.21%	0.73	12.23%	7.03%	10.36%	10.83%
NiSource Inc.	NI	5.21%	0.75	12.23%	7.03%	10.49%	10.92%
ONE Gas, Inc.	OGS	5.21%	0.72	12.23%	7.03%	10.25%	10.75%
Southwest Gas Holdings, Inc.	SWX	5.21%	0.80	12.23%	7.03%	10.79%	11.15%
Spire Inc.	SR	5.21%	0.72	12.23%	7.03%	10.28%	10.77%
Ameren Corporation	AEE	5.21%	0.70	12.23%	7.03%	10.15%	10.67%
Avista Corporation	AVA	5.21%	0.69	12.23%	7.03%	10.05%	10.59%
CenterPoint Energy, Inc.	CNP	5.21%	0.91	12.23%	7.03%	11.57%	11.74%
CMS Energy Corporation	CMS	5.21%	0.69	12.23%	7.03%	10.04%	10.59%
Consolidated Edison, Inc.	ED	5.21%	0.57	12.23%	7.03%	9.22%	9.97%
DTE Energy Company	DTE	5.21%	0.76	12.23%	7.03%	10.54%	10.96%
Eversource Energy	ES	5.21%	0.77	12.23%	7.03%	10.62%	11.02%
Public Service Enterprise Group Inc.	PEG	5.21%	0.81	12.23%	7.03%	10.88%	11.22%
WEC Energy Group, Inc.	WEC	5.21%	0.68	12.23%	7.03%	10.01%	10.57%
Xcel Energy Inc.	XEL	5.21%	0.71	12.23%	7.03%	10.16%	10.68%
					Gas Proxy Group Mean:	10.38%	10.85%
					Gas Proxy Group Median:	10.32%	10.80%
					Gas Proxy Group Average of Mean and Median:	10.35%	10.82%
					Combined Proxy Group Mean:	10.35%	10.82%
					Combined Proxy Group Median:	10.26%	10.76%
					Combined Proxy Group Average of Mean and Median:	10.31%	10.79%

		[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Projected 30-Year Treasury Yield	Bloomberg Beta Coefficient (10 Year)	Long-Term Average Historical Market Return (1926-2025)	Market Risk Premium	Traditional CAPM	Empirical CAPM
Atmos Energy Corporation	ATO	4.83%	0.70	12.23%	7.40%	10.02%	10.58%
New Jersey Resources Corporation	NJR	4.83%	0.73	12.23%	7.40%	10.26%	10.75%
NiSource Inc.	NI	4.83%	0.75	12.23%	7.40%	10.39%	10.85%
ONE Gas, Inc.	OGS	4.83%	0.72	12.23%	7.40%	10.15%	10.67%
Southwest Gas Holdings, Inc.	SWX	4.83%	0.80	12.23%	7.40%	10.72%	11.10%
Spire Inc.	SR	4.83%	0.72	12.23%	7.40%	10.17%	10.69%
Ameren Corporation	AEE	4.83%	0.70	12.23%	7.40%	10.04%	10.59%
Avista Corporation	AVA	4.83%	0.69	12.23%	7.40%	9.93%	10.51%
CenterPoint Energy, Inc.	CNP	4.83%	0.91	12.23%	7.40%	11.54%	11.71%
CMS Energy Corporation	CMS	4.83%	0.69	12.23%	7.40%	9.93%	10.50%
Consolidated Edison, Inc.	ED	4.83%	0.57	12.23%	7.40%	9.06%	9.85%
DTE Energy Company	DTE	4.83%	0.76	12.23%	7.40%	10.45%	10.90%
Eversource Energy	ES	4.83%	0.77	12.23%	7.40%	10.53%	10.96%
Public Service Enterprise Group Inc.	PEG	4.83%	0.81	12.23%	7.40%	10.81%	11.16%
WEC Energy Group, Inc.	WEC	4.83%	0.68	12.23%	7.40%	9.89%	10.48%
Xcel Energy Inc.	XEL	4.83%	0.71	12.23%	7.40%	10.05%	10.60%
					Gas Proxy Group Mean:	10.29%	10.77%
					Gas Proxy Group Median:	10.22%	10.72%
					Gas Proxy Group Average of Mean and Median:	10.25%	10.75%
					Combined Proxy Group Mean:	10.25%	10.74%
					Combined Proxy Group Median:	10.16%	10.68%
					Combined Proxy Group Average of Mean and Median:	10.20%	10.71%

[1] Source: Federal Reserve Bank of St. Louis (FRED); 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, September 2026 Edition, September 1, 2026 at 9 and Vol. 45, No. 6, June 1, 2026 at 14
[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

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

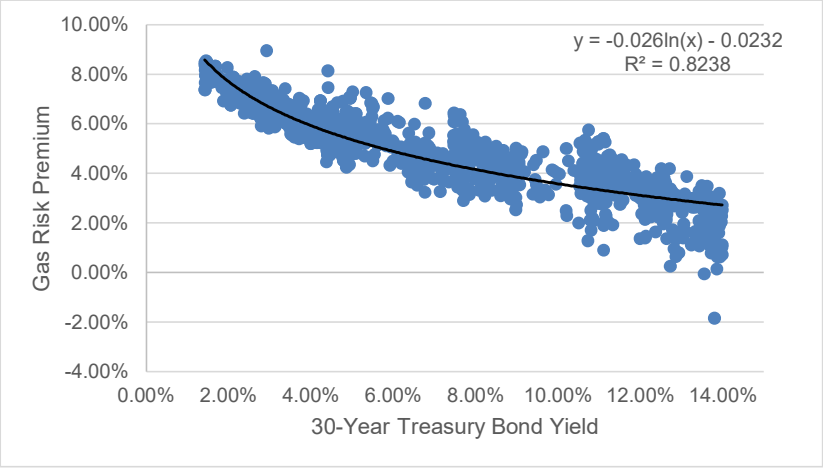
Exhibit of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 409

November 24, 2026

Bond Yield Plus Risk Premium - Gas

[1]	[2]	[3]	[4]	[5]
Constant	Slope	30-Year Treasury Yield	Risk Premium	Return on Equity
-2.32%	-2.56%			
Current 30-Year Treasury		5.21%	5.25%	10.46%
Projected 30-Year Treasury		4.83%	5.44%	10.28%



Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Sources: Current = Federal Reserve Bank of St. Louis (FRED),
Projected = Average of near-term and long-term projected 30-year Treasury yield from
Blue Chip Financial Forecasts, September 2026 Edition, September 1, 2026 at 9 and Vol. 45, No. 6, June 1, 2026, at 14
[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]

Bond Yield Plus Risk Premium - Gas

[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%
12/17/1980	14.40%	11.16%	3.24%
12/17/1980	14.20%	11.16%	3.04%
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%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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%
4/8/1981	15.00%	11.88%	3.12%
4/29/1981	13.50%	12.11%	1.39%
4/29/1981	14.25%	12.11%	2.14%
4/30/1981	15.00%	12.13%	2.87%
4/30/1981	13.60%	12.13%	1.47%
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	14.20%	12.86%	1.34%
7/31/1981	13.50%	12.86%	0.64%
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	17.00%	13.49%	3.51%
10/20/1981	16.50%	13.49%	3.01%
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%
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	16.10%	13.66%	2.44%
11/25/1981	16.10%	13.66%	2.44%
11/25/1981	15.25%	13.66%	1.59%
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	16.00%	13.71%	2.29%
12/22/1981	15.70%	13.71%	1.99%
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%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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%
4/5/1982	15.00%	13.98%	1.02%
4/8/1982	16.50%	13.99%	2.51%
4/11/1982	15.10%	13.99%	1.11%
4/11/1982	16.70%	13.99%	2.71%
4/17/1982	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	16.00%	13.80%	2.20%
7/1/1982	15.55%	13.80%	1.75%
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%
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	16.50%	13.42%	3.08%
9/30/1982	16.70%	13.42%	3.28%
9/30/1982	15.50%	13.42%	2.08%
9/30/1982	14.74%	13.42%	1.32%
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%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
11/24/1982	16.02%	12.78%	3.24%
11/24/1982	14.50%	12.78%	1.72%
11/30/1982	16.10%	12.73%	3.37%
11/30/1982	15.50%	12.73%	2.77%
11/30/1982	15.50%	12.73%	2.77%
11/30/1982	12.98%	12.73%	0.25%
11/30/1982	15.65%	12.73%	2.92%
11/30/1982	16.00%	12.73%	3.27%
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	16.00%	12.14%	3.86%
1/24/1983	15.50%	12.14%	3.36%
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%
4/11/1983	13.25%	11.33%	1.92%
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	15.10%	10.71%	4.39%
7/19/1983	15.00%	10.71%	4.29%
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	15.25%	10.86%	4.39%
8/31/1983	14.75%	10.86%	3.89%
9/8/1983	14.75%	10.89%	3.86%
9/16/1983	15.51%	10.93%	4.58%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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	15.33%	11.07%	4.26%
10/27/1983	14.88%	11.07%	3.81%
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%
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	16.00%	11.26%	4.74%
12/20/1983	15.40%	11.26%	4.14%
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%
4/8/1984	15.20%	11.80%	3.40%
4/17/1984	16.20%	11.85%	4.35%
4/26/1984	15.85%	11.89%	3.96%
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	15.90%	12.60%	3.30%
9/12/1984	15.60%	12.60%	3.00%
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%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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%
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%
4/8/1985	15.50%	12.04%	3.46%
4/15/1985	15.70%	11.98%	3.72%
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	15.00%	10.60%	4.40%
12/20/1985	14.88%	10.60%	4.28%
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%
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%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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	13.25%	8.93%	4.32%
12/31/1987	12.85%	8.93%	3.92%
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%
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%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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%
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	12.50%	8.70%	3.80%
11/21/1990	12.10%	8.70%	3.40%
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	13.60%	8.67%	4.93%
12/21/1990	13.00%	8.67%	4.33%
12/21/1990	12.50%	8.67%	3.83%
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%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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	12.00%	8.18%	3.82%
11/26/1991	11.60%	8.18%	3.42%
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%
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	12.00%	7.68%	4.32%
11/25/1992	11.00%	7.68%	3.32%
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	11.75%	7.25%	4.50%
5/3/1993	11.50%	7.25%	4.25%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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	11.25%	6.58%	4.67%
10/29/1993	10.20%	6.58%	3.62%
10/29/1993	10.10%	6.58%	3.52%
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	11.20%	6.46%	4.74%
12/16/1993	10.60%	6.46%	4.14%
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	11.70%	7.59%	4.11%
12/8/1994	11.50%	7.59%	3.91%
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%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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	11.30%	6.86%	4.44%
11/8/1995	11.10%	6.86%	4.24%
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%
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%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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%
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	11.00%	5.54%	5.46%
10/24/2001	10.30%	5.54%	4.76%
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%
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%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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	11.00%	4.53%	6.47%
12/21/2005	10.40%	4.53%	5.87%
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%
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%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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	10.10%	4.84%	5.26%
6/29/2007	9.53%	4.84%	4.69%
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%
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%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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%
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	10.50%	4.26%	6.24%
12/18/2009	10.40%	4.26%	6.14%
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	10.33%	4.37%	5.96%
1/21/2010	10.23%	4.37%	5.86%
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	9.40%	4.46%	4.94%
4/29/2010	9.19%	4.46%	4.73%
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	10.30%	4.31%	5.99%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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%
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%
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	9.75%	3.16%	6.59%
4/24/2012	9.50%	3.16%	6.34%
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	10.00%	2.92%	7.08%
10/31/2012	9.30%	2.92%	6.38%
10/31/2012	9.90%	2.92%	6.98%
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	10.50%	2.87%	7.63%
12/4/2012	10.00%	2.87%	7.13%
12/20/2012	10.40%	2.84%	7.56%
12/20/2012	10.30%	2.84%	7.46%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/20/2012	10.10%	2.84%	7.26%
12/20/2012	10.25%	2.84%	7.41%
12/20/2012	10.50%	2.84%	7.66%
12/20/2012	9.50%	2.84%	6.66%
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%
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	9.59%	3.71%	5.88%
5/8/2014	9.10%	3.71%	5.39%
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%

[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%
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%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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%
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%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/18/2019	9.60%	2.44%	7.16%
12/19/2019	10.20%	2.44%	7.76%
12/19/2019	10.05%	2.44%	7.61%
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%
1/9/2020	9.80%	2.39%	7.41%
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%
2/17/2020	9.80%	2.29%	7.51%
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%
10/15/2020	9.35%	1.47%	7.88%
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	9.90%	1.42%	8.48%
11/19/2020	8.80%	1.42%	7.38%
11/19/2020	8.80%	1.42%	7.38%
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	9.65%	1.44%	8.21%
12/16/2020	9.38%	1.44%	7.94%
12/23/2020	10.00%	1.45%	8.55%
1/4/2021	9.95%	1.46%	8.49%
1/6/2021	9.60%	1.47%	8.13%
1/6/2021	9.40%	1.47%	7.93%
1/12/2021	9.95%	1.48%	8.47%
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]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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	9.95%	2.10%	7.85%
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	9.80%	2.11%	7.69%
11/17/2021	9.60%	2.11%	7.49%
11/18/2021	9.75%	2.11%	7.64%
11/18/2021	9.00%	2.11%	6.89%
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	9.60%	2.03%	7.57%
12/28/2021	9.35%	2.03%	7.32%
12/28/2021	9.38%	2.03%	7.35%
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%
5/19/2022	9.95%	2.23%	7.72%
5/19/2022	9.95%	2.23%	7.72%
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%
9/30/2022	9.70%	2.88%	6.82%
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%

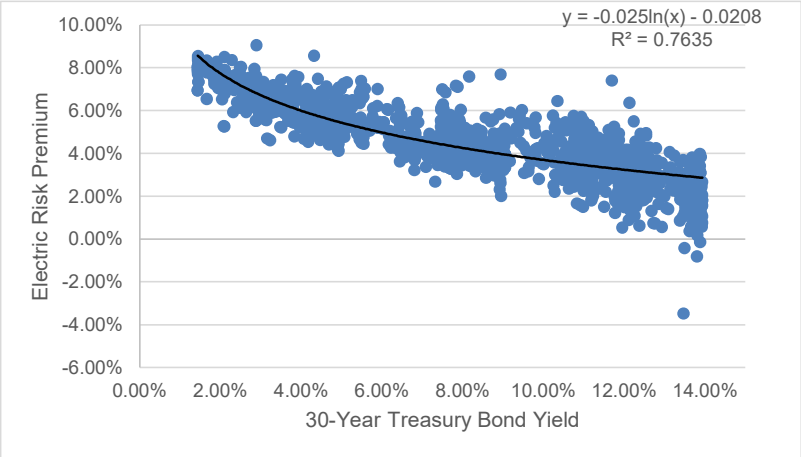
[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/21/2022	9.60%	3.38%	6.22%
12/22/2022	9.40%	3.38%	6.02%
12/22/2022	9.80%	3.38%	6.42%
12/23/2022	9.60%	3.39%	6.21%
12/29/2022	9.80%	3.41%	6.39%
12/29/2022	9.80%	3.41%	6.39%
1/19/2023	9.60%	3.48%	6.12%
1/23/2023	9.30%	3.48%	5.82%
1/24/2023	10.25%	3.49%	6.76%
1/26/2023	9.60%	3.49%	6.11%
3/15/2023	9.80%	3.61%	6.19%
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	9.90%	3.85%	6.05%
8/30/2023	9.80%	3.85%	5.95%
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%
10/6/2023	9.80%	3.96%	5.84%
10/12/2023	9.20%	3.99%	5.21%
10/12/2023	9.20%	3.99%	5.21%
10/19/2023	9.35%	4.02%	5.33%
10/25/2023	9.55%	4.05%	5.50%
10/26/2023	9.65%	4.06%	5.59%
10/26/2023	9.50%	4.06%	5.44%
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	10.15%	4.12%	6.03%
11/9/2023	9.80%	4.12%	5.68%
11/9/2023	9.80%	4.12%	5.68%
11/16/2023	9.44%	4.14%	5.30%
11/16/2023	9.38%	4.14%	5.24%
11/16/2023	9.51%	4.14%	5.37%
11/16/2023	9.38%	4.14%	5.24%
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%
12/29/2023	11.16%	4.23%	6.93%
12/29/2023	11.16%	4.23%	6.93%
12/29/2023	11.16%	4.23%	6.93%
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	11.88%	4.41%	7.47%
4/8/2024	9.50%	4.41%	5.09%
4/8/2024	9.50%	4.41%	5.09%
4/17/2024	9.75%	4.44%	5.31%
5/13/2024	9.80%	4.48%	5.32%
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%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
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	9.85%	4.40%	5.45%
11/21/2024	9.60%	4.40%	5.20%
11/21/2024	9.60%	4.40%	5.20%
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%
4/25/2025	9.95%	4.51%	5.44%
4/25/2025	9.95%	4.51%	5.44%
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%
6/24/2025	9.55%	4.68%	4.87%
6/24/2025	9.65%	4.68%	4.97%
6/26/2025	9.79%	4.69%	5.10%
7/1/2025	9.75%	4.70%	5.05%
8/11/2025	9.75%	4.76%	4.99%
8/14/2025	9.50%	4.76%	4.74%
8/14/2025	9.50%	4.76%	4.74%
8/26/2025	9.30%	4.79%	4.51%
8/29/2025	9.60%	4.79%	4.81%
9/30/2025	9.80%	4.80%	5.00%
10/7/2025	10.30%	4.79%	5.51%
10/8/2025	9.60%	4.79%	4.81%
10/24/2025	9.50%	4.78%	4.72%
11/4/2025	9.40%	4.77%	4.63%
11/5/2025	9.48%	4.77%	4.71%
11/6/2025	9.80%	4.77%	5.03%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
11/6/2025	9.80%	4.77%	5.03%
11/19/2025	9.60%	4.78%	4.82%
11/19/2025	9.60%	4.78%	4.82%
11/19/2025	9.60%	4.78%	4.82%
11/20/2025	9.65%	4.78%	4.87%
11/20/2025	9.80%	4.78%	5.02%
12/4/2025	10.00%	4.78%	5.22%
12/9/2025	9.65%	4.79%	4.86%
12/9/2025	9.85%	4.79%	5.06%
12/17/2025	9.60%	4.79%	4.81%
12/17/2025	9.85%	4.79%	5.06%
12/18/2025	9.78%	4.79%	4.99%
12/23/2025	9.80%	4.80%	5.00%
12/30/2025	9.50%	4.80%	4.70%
1/7/2026	9.79%	4.81%	4.98%
1/22/2026	9.40%	4.81%	4.59%
2/5/2026	9.80%	4.81%	4.99%
2/10/2026	9.75%	4.81%	4.94%
2/16/2026	9.78%	4.80%	4.98%
2/18/2026	10.00%	4.80%	5.20%
2/19/2026	9.61%	4.80%	4.81%
3/27/2026	9.30%	4.79%	4.51%
5/21/2026	9.35%	4.80%	4.55%
7/27/2026	9.40%	4.88%	4.52%
7/29/2026	9.50%	4.88%	4.62%
7/31/2026	9.28%	4.89%	4.39%
8/13/2026	10.00%	4.91%	5.09%
8/13/2026	10.00%	4.91%	5.09%
8/13/2026	10.00%	4.91%	5.09%
8/21/2026	9.28%	4.93%	4.35%
		# of Cases:	1,409

Bond Yield Plus Risk Premium - Electric

[1]	[2]	[3]	[4]	[5]
Constant	Slope	30-Year Treasury Yield	Risk Premium	Return on Equity
-2.08%	-2.51%			
Current 30-Year Treasury		5.21%	5.33%	10.54%
Projected 30-Year Treasury		4.83%	5.52%	10.35%



Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Sources: Current = Federal Reserve Bank of St. Louis (FRED),
Projected = Average of near-term and long-term projected 30-year Treasury yield from
Blue Chip Financial Forecasts, September 2026 Edition, September 1, 2026 at 9 and Vol. 45, No. 6, June 1, 2026, at 14
[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 201-trading day average (i.e. lag period)
[9] Equals [7] - [8]

Bond Yield Plus Risk Premium - Electric

[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%	9.38%	5.01%
1/9/1980	15.00%	9.39%	5.61%
1/14/1980	15.17%	9.41%	5.76%
1/17/1980	13.93%	9.43%	4.50%
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%	9.63%	3.17%
2/14/1980	13.00%	9.64%	3.36%
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%	9.89%	2.81%
3/14/1980	13.50%	9.96%	3.54%
3/26/1980	14.16%	10.09%	4.07%
3/27/1980	14.24%	10.11%	4.13%
3/28/1980	14.50%	10.13%	4.37%
4/10/1980	12.75%	10.25%	2.50%
4/13/1980	13.85%	10.27%	3.58%
4/15/1980	15.50%	10.29%	5.21%
4/21/1980	13.90%	10.33%	3.57%
4/21/1980	13.25%	10.33%	2.92%
4/23/1980	16.80%	10.36%	6.44%
4/29/1980	15.50%	10.40%	5.10%
5/6/1980	13.70%	10.44%	3.26%
5/7/1980	15.00%	10.45%	4.55%
5/8/1980	13.75%	10.45%	3.30%
5/9/1980	14.35%	10.46%	3.89%
5/13/1980	13.60%	10.47%	3.13%
5/15/1980	13.25%	10.49%	2.76%
5/19/1980	13.75%	10.50%	3.25%
5/27/1980	14.60%	10.53%	4.07%
5/27/1980	13.62%	10.53%	3.09%
5/29/1980	16.00%	10.55%	5.45%
5/30/1980	13.80%	10.56%	3.24%
6/2/1980	15.63%	10.56%	5.07%
6/9/1980	15.90%	10.59%	5.31%
6/10/1980	13.78%	10.59%	3.19%
6/12/1980	14.25%	10.60%	3.65%
6/19/1980	13.40%	10.61%	2.79%
6/30/1980	13.00%	10.64%	2.36%
6/30/1980	13.40%	10.64%	2.76%
7/9/1980	14.75%	10.67%	4.08%
7/10/1980	15.00%	10.67%	4.33%
7/15/1980	15.80%	10.69%	5.11%
7/18/1980	13.80%	10.70%	3.10%
7/22/1980	14.10%	10.71%	3.39%
7/24/1980	15.00%	10.72%	4.28%
7/25/1980	13.48%	10.73%	2.75%
7/31/1980	14.58%	10.75%	3.83%
8/8/1980	14.00%	10.77%	3.23%
8/8/1980	13.50%	10.77%	2.73%
8/8/1980	15.45%	10.77%	4.68%
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%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
8/29/1980	12.50%	10.83%	1.67%
9/15/1980	15.80%	10.87%	4.93%
9/15/1980	13.93%	10.87%	3.06%
9/15/1980	13.50%	10.87%	2.63%
9/24/1980	12.50%	10.92%	1.58%
9/24/1980	15.00%	10.92%	4.08%
9/26/1980	13.75%	10.94%	2.81%
9/30/1980	14.20%	10.96%	3.24%
9/30/1980	14.10%	10.96%	3.14%
10/1/1980	13.90%	10.96%	2.94%
10/3/1980	15.50%	10.98%	4.52%
10/7/1980	12.50%	10.99%	1.51%
10/9/1980	14.50%	11.00%	3.50%
10/9/1980	14.50%	11.00%	3.50%
10/9/1980	13.25%	11.00%	2.25%
10/16/1980	16.10%	11.02%	5.08%
10/17/1980	14.50%	11.03%	3.47%
10/31/1980	14.25%	11.10%	3.15%
10/31/1980	13.75%	11.10%	2.65%
11/4/1980	15.00%	11.11%	3.89%
11/5/1980	14.00%	11.12%	2.88%
11/5/1980	13.75%	11.12%	2.63%
11/8/1980	13.75%	11.14%	2.61%
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%	11.21%	2.79%
11/26/1980	14.00%	11.21%	2.79%
12/8/1980	15.10%	11.23%	3.87%
12/8/1980	14.15%	11.23%	2.92%
12/9/1980	15.35%	11.23%	4.12%
12/12/1980	15.45%	11.23%	4.22%
12/17/1980	13.25%	11.24%	2.01%
12/18/1980	15.80%	11.24%	4.56%
12/19/1980	14.50%	11.24%	3.26%
12/19/1980	14.64%	11.24%	3.40%
12/22/1980	13.45%	11.24%	2.21%
12/22/1980	15.00%	11.24%	3.76%
12/30/1980	14.50%	11.22%	3.28%
12/30/1980	14.95%	11.22%	3.73%
12/31/1980	13.39%	11.22%	2.17%
1/2/1981	15.25%	11.22%	4.03%
1/7/1981	14.30%	11.21%	3.09%
1/19/1981	15.25%	11.20%	4.05%
1/23/1981	14.40%	11.20%	3.20%
1/23/1981	13.10%	11.20%	1.90%
1/26/1981	15.25%	11.21%	4.04%
1/27/1981	15.00%	11.21%	3.79%
1/31/1981	13.47%	11.22%	2.25%
2/3/1981	15.25%	11.23%	4.02%
2/5/1981	15.75%	11.24%	4.51%
2/11/1981	15.60%	11.28%	4.32%
2/20/1981	15.25%	11.33%	3.92%
3/11/1981	15.40%	11.49%	3.91%
3/12/1981	14.51%	11.50%	3.01%
3/12/1981	16.00%	11.50%	4.50%
3/13/1981	13.02%	11.51%	1.51%
3/18/1981	16.19%	11.54%	4.65%
3/19/1981	13.75%	11.55%	2.20%
3/23/1981	14.30%	11.57%	2.73%
3/25/1981	15.30%	11.60%	3.70%
4/1/1981	14.53%	11.67%	2.86%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
4/3/1981	19.10%	11.70%	7.40%
4/8/1981	15.00%	11.75%	3.25%
4/8/1981	15.30%	11.75%	3.55%
4/8/1981	17.00%	11.75%	5.25%
4/8/1981	16.50%	11.75%	4.75%
4/9/1981	13.75%	11.77%	1.98%
4/12/1981	13.57%	11.79%	1.78%
4/14/1981	15.30%	11.82%	3.48%
4/15/1981	13.50%	11.84%	1.66%
4/16/1981	14.10%	11.86%	2.24%
4/20/1981	16.80%	11.88%	4.92%
4/20/1981	14.00%	11.88%	2.12%
4/23/1981	16.00%	11.92%	4.08%
4/27/1981	13.61%	11.96%	1.65%
4/27/1981	12.50%	11.96%	0.54%
4/29/1981	13.65%	11.99%	1.66%
4/30/1981	13.50%	12.01%	1.49%
5/4/1981	16.22%	12.04%	4.18%
5/5/1981	14.40%	12.06%	2.34%
5/7/1981	16.25%	12.10%	4.15%
5/7/1981	16.27%	12.10%	4.17%
5/8/1981	13.00%	12.12%	0.88%
5/8/1981	16.00%	12.12%	3.88%
5/12/1981	13.50%	12.15%	1.35%
5/15/1981	15.75%	12.21%	3.54%
5/18/1981	14.88%	12.22%	2.66%
5/20/1981	16.00%	12.25%	3.75%
5/21/1981	14.00%	12.27%	1.73%
5/26/1981	14.90%	12.29%	2.61%
5/27/1981	15.00%	12.31%	2.69%
5/29/1981	15.50%	12.33%	3.17%
6/1/1981	16.50%	12.34%	4.16%
6/3/1981	14.67%	12.36%	2.31%
6/5/1981	13.00%	12.38%	0.62%
6/10/1981	16.75%	12.41%	4.34%
6/17/1981	14.40%	12.45%	1.95%
6/18/1981	16.33%	12.46%	3.87%
6/25/1981	14.75%	12.51%	2.24%
6/26/1981	16.00%	12.52%	3.48%
6/30/1981	15.25%	12.54%	2.71%
7/1/1981	15.50%	12.55%	2.95%
7/1/1981	17.50%	12.55%	4.95%
7/10/1981	16.00%	12.61%	3.39%
7/14/1981	16.90%	12.63%	4.27%
7/15/1981	16.00%	12.64%	3.36%
7/17/1981	15.00%	12.66%	2.34%
7/20/1981	15.00%	12.67%	2.33%
7/21/1981	14.00%	12.68%	1.32%
7/28/1981	13.48%	12.73%	0.75%
7/31/1981	13.50%	12.77%	0.73%
7/31/1981	16.00%	12.77%	3.23%
7/31/1981	15.00%	12.77%	2.23%
8/5/1981	15.71%	12.82%	2.89%
8/10/1981	14.50%	12.86%	1.64%
8/11/1981	15.00%	12.87%	2.13%
8/20/1981	16.50%	12.94%	3.56%
8/20/1981	13.50%	12.94%	0.56%
8/24/1981	15.00%	12.96%	2.04%
8/28/1981	15.00%	13.01%	1.99%
9/3/1981	14.50%	13.05%	1.45%
9/10/1981	14.50%	13.10%	1.40%
9/11/1981	16.00%	13.11%	2.89%
9/16/1981	16.00%	13.14%	2.86%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
9/17/1981	16.50%	13.15%	3.35%
9/23/1981	15.85%	13.19%	2.66%
9/28/1981	15.50%	13.23%	2.27%
10/9/1981	15.75%	13.32%	2.43%
10/15/1981	16.25%	13.36%	2.89%
10/16/1981	16.50%	13.37%	3.13%
10/16/1981	15.50%	13.37%	2.13%
10/19/1981	14.25%	13.38%	0.87%
10/20/1981	15.25%	13.40%	1.85%
10/20/1981	17.00%	13.40%	3.60%
10/23/1981	16.00%	13.44%	2.56%
10/27/1981	10.00%	13.48%	-3.48%
10/29/1981	16.50%	13.50%	3.00%
10/29/1981	14.75%	13.50%	1.25%
11/3/1981	15.17%	13.53%	1.64%
11/5/1981	16.60%	13.55%	3.05%
11/6/1981	15.17%	13.55%	1.62%
11/24/1981	15.50%	13.60%	1.90%
11/25/1981	16.10%	13.60%	2.50%
11/25/1981	16.10%	13.60%	2.50%
11/25/1981	15.25%	13.60%	1.65%
11/25/1981	15.35%	13.60%	1.75%
12/1/1981	16.50%	13.61%	2.89%
12/1/1981	15.70%	13.61%	2.09%
12/1/1981	16.49%	13.61%	2.88%
12/1/1981	16.00%	13.61%	2.39%
12/4/1981	16.00%	13.61%	2.39%
12/11/1981	16.25%	13.62%	2.63%
12/14/1981	14.00%	13.62%	0.38%
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%	13.63%	2.87%
12/18/1981	15.45%	13.63%	1.82%
12/30/1981	16.00%	13.66%	2.34%
12/30/1981	16.25%	13.66%	2.59%
12/30/1981	14.25%	13.66%	0.59%
12/31/1981	16.15%	13.67%	2.48%
1/4/1982	15.50%	13.67%	1.83%
1/11/1982	14.50%	13.72%	0.78%
1/11/1982	17.00%	13.72%	3.28%
1/13/1982	14.75%	13.74%	1.01%
1/14/1982	15.75%	13.74%	2.01%
1/15/1982	15.00%	13.75%	1.25%
1/15/1982	16.50%	13.75%	2.75%
1/22/1982	16.25%	13.79%	2.46%
1/27/1982	16.84%	13.81%	3.03%
1/28/1982	13.00%	13.81%	-0.81%
1/29/1982	15.50%	13.81%	1.69%
2/1/1982	15.85%	13.82%	2.03%
2/3/1982	16.44%	13.83%	2.61%
2/8/1982	15.50%	13.85%	1.65%
2/11/1982	16.00%	13.87%	2.13%
2/11/1982	16.20%	13.87%	2.33%
2/17/1982	15.00%	13.88%	1.12%
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%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
3/22/1982	15.10%	13.88%	1.22%
3/27/1982	15.40%	13.89%	1.51%
3/30/1982	15.50%	13.90%	1.60%
3/31/1982	17.00%	13.90%	3.10%
4/1/1982	16.50%	13.91%	2.59%
4/1/1982	14.70%	13.91%	0.79%
4/2/1982	15.50%	13.91%	1.59%
4/4/1982	15.50%	13.91%	1.59%
4/7/1982	16.40%	13.92%	2.48%
4/12/1982	14.50%	13.93%	0.57%
4/22/1982	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	15.50%	13.94%	1.56%
4/30/1982	14.70%	13.94%	0.76%
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%	13.91%	0.78%
5/20/1982	15.10%	13.91%	1.19%
5/20/1982	15.50%	13.91%	1.59%
5/20/1982	16.30%	13.91%	2.39%
5/20/1982	15.00%	13.91%	1.09%
5/21/1982	17.75%	13.91%	3.84%
5/27/1982	15.00%	13.89%	1.11%
5/28/1982	15.50%	13.89%	1.61%
5/28/1982	17.00%	13.89%	3.11%
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%	13.88%	0.97%
6/18/1982	15.50%	13.87%	1.63%
6/21/1982	14.90%	13.87%	1.03%
6/23/1982	16.00%	13.87%	2.13%
6/23/1982	16.17%	13.87%	2.30%
6/24/1982	14.85%	13.86%	0.99%
6/25/1982	14.70%	13.86%	0.84%
7/1/1982	16.00%	13.85%	2.15%
7/2/1982	15.62%	13.84%	1.78%
7/2/1982	17.00%	13.84%	3.16%
7/13/1982	14.00%	13.82%	0.18%
7/13/1982	16.80%	13.82%	2.98%
7/14/1982	15.76%	13.82%	1.94%
7/14/1982	16.02%	13.82%	2.20%
7/19/1982	16.50%	13.80%	2.70%
7/22/1982	17.00%	13.78%	3.22%
7/22/1982	14.50%	13.78%	0.72%
7/27/1982	16.75%	13.75%	3.00%
7/29/1982	16.50%	13.74%	2.76%
8/11/1982	17.50%	13.69%	3.81%
8/18/1982	17.07%	13.64%	3.43%
8/20/1982	15.73%	13.61%	2.12%
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	13.08%	13.50%	-0.42%
9/15/1982	16.25%	13.50%	2.75%
9/16/1982	16.00%	13.50%	2.50%
9/17/1982	15.25%	13.49%	1.76%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
9/23/1982	17.17%	13.47%	3.70%
9/24/1982	14.50%	13.46%	1.04%
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%	13.25%	2.50%
10/22/1982	17.15%	13.25%	3.90%
10/29/1982	15.54%	13.17%	2.37%
11/1/1982	15.50%	13.15%	2.35%
11/3/1982	17.20%	13.13%	4.07%
11/4/1982	16.25%	13.12%	3.13%
11/5/1982	16.20%	13.10%	3.10%
11/9/1982	16.00%	13.06%	2.94%
11/23/1982	15.85%	12.89%	2.96%
11/23/1982	15.50%	12.89%	2.61%
11/30/1982	16.50%	12.82%	3.68%
12/1/1982	17.04%	12.79%	4.25%
12/6/1982	15.00%	12.74%	2.26%
12/6/1982	16.35%	12.74%	3.61%
12/10/1982	15.50%	12.67%	2.83%
12/13/1982	16.00%	12.65%	3.35%
12/14/1982	16.40%	12.63%	3.77%
12/14/1982	15.30%	12.63%	2.67%
12/20/1982	16.00%	12.58%	3.42%
12/21/1982	15.85%	12.56%	3.29%
12/21/1982	14.75%	12.56%	2.19%
12/22/1982	16.75%	12.55%	4.20%
12/22/1982	16.58%	12.55%	4.03%
12/22/1982	16.25%	12.55%	3.70%
12/29/1982	14.90%	12.49%	2.41%
12/29/1982	16.25%	12.49%	3.76%
12/30/1982	16.35%	12.47%	3.88%
12/30/1982	16.00%	12.47%	3.53%
12/30/1982	16.77%	12.47%	4.30%
1/5/1983	17.33%	12.41%	4.92%
1/11/1983	15.90%	12.35%	3.55%
1/12/1983	15.50%	12.34%	3.16%
1/12/1983	14.63%	12.34%	2.29%
1/20/1983	17.75%	12.24%	5.51%
1/21/1983	15.00%	12.23%	2.77%
1/24/1983	14.50%	12.21%	2.29%
1/24/1983	15.50%	12.21%	3.29%
1/25/1983	15.85%	12.20%	3.65%
1/27/1983	16.14%	12.17%	3.97%
2/1/1983	18.50%	12.14%	6.36%
2/4/1983	14.00%	12.10%	1.90%
2/10/1983	15.00%	12.06%	2.94%
2/21/1983	15.50%	11.99%	3.51%
2/22/1983	15.50%	11.98%	3.52%
2/23/1983	15.10%	11.96%	3.14%
2/23/1983	16.00%	11.96%	4.04%
3/2/1983	15.25%	11.90%	3.35%
3/9/1983	15.20%	11.83%	3.37%
3/15/1983	13.00%	11.78%	1.22%
3/18/1983	15.25%	11.74%	3.51%
3/23/1983	15.40%	11.70%	3.70%
3/24/1983	15.00%	11.68%	3.32%
3/29/1983	15.50%	11.64%	3.86%
3/30/1983	16.71%	11.62%	5.09%
3/31/1983	15.00%	11.61%	3.39%
4/3/1983	15.20%	11.61%	3.59%
4/7/1983	15.50%	11.54%	3.96%
4/10/1983	14.81%	11.52%	3.29%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
4/18/1983	14.50%	11.41%	3.09%
4/19/1983	16.00%	11.39%	4.61%
4/29/1983	16.00%	11.26%	4.74%
5/1/1983	14.50%	11.26%	3.24%
5/9/1983	15.50%	11.16%	4.34%
5/11/1983	16.46%	11.13%	5.33%
5/12/1983	14.14%	11.12%	3.02%
5/18/1983	15.00%	11.06%	3.94%
5/23/1983	14.90%	11.02%	3.88%
5/23/1983	15.50%	11.02%	4.48%
5/25/1983	15.50%	11.00%	4.50%
5/27/1983	15.00%	10.97%	4.03%
5/31/1983	15.50%	10.96%	4.54%
5/31/1983	14.00%	10.96%	3.04%
6/2/1983	14.50%	10.94%	3.56%
6/17/1983	15.03%	10.85%	4.18%
7/1/1983	14.80%	10.78%	4.02%
7/1/1983	14.90%	10.78%	4.12%
7/8/1983	16.25%	10.76%	5.49%
7/13/1983	13.20%	10.76%	2.44%
7/19/1983	15.10%	10.75%	4.35%
7/19/1983	15.00%	10.75%	4.25%
7/25/1983	16.25%	10.74%	5.51%
7/28/1983	15.90%	10.74%	5.16%
8/3/1983	16.50%	10.75%	5.75%
8/3/1983	16.34%	10.75%	5.59%
8/19/1983	15.00%	10.80%	4.20%
8/22/1983	16.40%	10.80%	5.60%
8/22/1983	15.50%	10.80%	4.70%
8/31/1983	14.75%	10.84%	3.91%
9/7/1983	15.00%	10.86%	4.14%
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%	10.94%	4.56%
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%	10.98%	4.54%
10/17/1983	15.50%	10.99%	4.51%
10/18/1983	14.50%	11.00%	3.50%
10/19/1983	16.50%	11.00%	5.50%
10/19/1983	16.25%	11.00%	5.25%
10/26/1983	15.00%	11.03%	3.97%
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	16.00%	11.13%	4.87%
11/23/1983	16.15%	11.13%	5.02%
11/30/1983	15.00%	11.14%	3.86%
12/5/1983	15.25%	11.15%	4.10%
12/6/1983	15.07%	11.15%	3.92%
12/8/1983	15.90%	11.16%	4.74%
12/9/1983	14.75%	11.17%	3.58%
12/12/1983	14.50%	11.17%	3.33%
12/15/1983	15.56%	11.19%	4.37%
12/19/1983	14.80%	11.21%	3.59%
12/20/1983	16.00%	11.21%	4.79%
12/20/1983	14.69%	11.21%	3.48%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/20/1983	16.25%	11.21%	5.04%
12/22/1983	15.75%	11.23%	4.52%
12/22/1983	14.75%	11.23%	3.52%
1/3/1984	14.75%	11.26%	3.49%
1/10/1984	15.90%	11.29%	4.61%
1/12/1984	15.60%	11.30%	4.30%
1/18/1984	13.75%	11.32%	2.43%
1/19/1984	15.90%	11.33%	4.57%
1/30/1984	16.10%	11.36%	4.74%
1/31/1984	15.25%	11.37%	3.88%
2/1/1984	14.80%	11.38%	3.42%
2/6/1984	14.75%	11.40%	3.35%
2/6/1984	13.75%	11.40%	2.35%
2/9/1984	15.25%	11.42%	3.83%
2/15/1984	15.70%	11.44%	4.26%
2/20/1984	15.00%	11.45%	3.55%
2/20/1984	15.00%	11.45%	3.55%
2/22/1984	14.75%	11.47%	3.28%
2/28/1984	14.50%	11.50%	3.00%
3/2/1984	14.25%	11.53%	2.72%
3/20/1984	16.00%	11.64%	4.36%
3/23/1984	15.50%	11.66%	3.84%
3/26/1984	14.71%	11.67%	3.04%
4/1/1984	15.50%	11.70%	3.80%
4/5/1984	14.74%	11.74%	3.00%
4/10/1984	15.72%	11.76%	3.96%
4/16/1984	15.00%	11.80%	3.20%
4/17/1984	16.20%	11.80%	4.40%
4/24/1984	14.64%	11.84%	2.80%
4/30/1984	14.40%	11.87%	2.53%
5/16/1984	14.69%	11.98%	2.71%
5/16/1984	15.00%	11.98%	3.02%
5/22/1984	14.40%	12.02%	2.38%
5/29/1984	15.10%	12.06%	3.04%
6/13/1984	15.25%	12.15%	3.10%
6/15/1984	15.60%	12.17%	3.43%
6/22/1984	16.25%	12.21%	4.04%
6/29/1984	15.25%	12.25%	3.00%
7/2/1984	13.35%	12.26%	1.09%
7/10/1984	16.00%	12.31%	3.69%
7/12/1984	16.50%	12.32%	4.18%
7/13/1984	16.25%	12.33%	3.92%
7/17/1984	14.14%	12.35%	1.79%
7/18/1984	15.50%	12.35%	3.15%
7/18/1984	15.30%	12.35%	2.95%
7/19/1984	14.30%	12.36%	1.94%
7/24/1984	16.79%	12.39%	4.40%
7/31/1984	16.00%	12.42%	3.58%
8/3/1984	14.25%	12.44%	1.81%
8/17/1984	14.30%	12.48%	1.82%
8/20/1984	15.00%	12.49%	2.51%
8/27/1984	16.30%	12.50%	3.80%
8/31/1984	15.55%	12.52%	3.03%
9/6/1984	16.00%	12.53%	3.47%
9/10/1984	14.75%	12.54%	2.21%
9/13/1984	15.00%	12.55%	2.45%
9/17/1984	17.38%	12.55%	4.83%
9/26/1984	14.50%	12.57%	1.93%
9/28/1984	16.25%	12.57%	3.68%
9/28/1984	15.00%	12.57%	2.43%
10/9/1984	14.75%	12.58%	2.17%
10/12/1984	15.60%	12.58%	3.02%
10/22/1984	15.00%	12.58%	2.42%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
10/26/1984	16.40%	12.58%	3.82%
10/31/1984	16.25%	12.58%	3.67%
11/7/1984	15.60%	12.58%	3.02%
11/9/1984	16.00%	12.58%	3.42%
11/14/1984	15.75%	12.58%	3.17%
11/20/1984	15.25%	12.57%	2.68%
11/20/1984	15.92%	12.57%	3.35%
11/23/1984	15.00%	12.57%	2.43%
11/28/1984	16.15%	12.56%	3.59%
12/3/1984	15.80%	12.56%	3.24%
12/4/1984	16.50%	12.56%	3.94%
12/18/1984	16.40%	12.53%	3.87%
12/19/1984	14.75%	12.53%	2.22%
12/19/1984	15.00%	12.53%	2.47%
12/20/1984	16.00%	12.52%	3.48%
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%
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%	12.36%	2.11%
3/1/1985	13.84%	12.31%	1.53%
3/8/1985	16.85%	12.29%	4.56%
3/14/1985	15.50%	12.26%	3.24%
3/15/1985	15.62%	12.26%	3.36%
3/29/1985	15.62%	12.17%	3.45%
4/3/1985	14.60%	12.14%	2.46%
4/8/1985	15.50%	12.12%	3.38%
4/15/1985	15.70%	12.07%	3.63%
4/21/1985	14.00%	12.03%	1.97%
4/25/1985	15.50%	12.00%	3.50%
4/29/1985	15.00%	11.98%	3.02%
5/2/1985	14.68%	11.94%	2.74%
5/8/1985	15.62%	11.90%	3.72%
5/10/1985	16.50%	11.88%	4.62%
5/29/1985	14.61%	11.74%	2.87%
5/31/1985	16.00%	11.72%	4.28%
6/14/1985	15.50%	11.61%	3.89%
7/9/1985	15.00%	11.45%	3.55%
7/16/1985	14.50%	11.40%	3.10%
7/26/1985	14.50%	11.33%	3.17%
8/2/1985	14.80%	11.29%	3.51%
8/7/1985	15.00%	11.27%	3.73%
8/28/1985	14.25%	11.15%	3.10%
8/28/1985	15.50%	11.15%	4.35%
8/29/1985	14.50%	11.15%	3.35%
9/9/1985	14.90%	11.11%	3.79%
9/9/1985	14.60%	11.11%	3.49%
9/17/1985	14.90%	11.09%	3.81%
9/23/1985	15.00%	11.07%	3.93%
9/27/1985	15.50%	11.05%	4.45%
9/27/1985	15.80%	11.05%	4.75%
10/2/1985	14.75%	11.04%	3.71%
10/2/1985	14.00%	11.04%	2.96%
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%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
10/29/1985	16.65%	10.95%	5.70%
10/31/1985	15.06%	10.93%	4.13%
11/4/1985	14.50%	10.92%	3.58%
11/7/1985	15.50%	10.90%	4.60%
11/8/1985	14.30%	10.89%	3.41%
12/12/1985	14.75%	10.73%	4.02%
12/18/1985	15.00%	10.70%	4.30%
12/20/1985	15.00%	10.68%	4.32%
12/20/1985	14.50%	10.68%	3.82%
12/20/1985	14.50%	10.68%	3.82%
1/24/1986	15.40%	10.41%	4.99%
1/31/1986	15.00%	10.36%	4.64%
2/5/1986	15.00%	10.33%	4.67%
2/5/1986	15.75%	10.33%	5.42%
2/10/1986	13.30%	10.30%	3.00%
2/11/1986	12.50%	10.28%	2.22%
2/14/1986	14.40%	10.25%	4.15%
2/18/1986	16.00%	10.24%	5.76%
2/24/1986	14.50%	10.18%	4.32%
2/26/1986	14.00%	10.16%	3.84%
3/5/1986	14.90%	10.08%	4.82%
3/11/1986	14.50%	10.02%	4.48%
3/12/1986	13.50%	10.01%	3.49%
3/27/1986	14.10%	9.86%	4.24%
3/31/1986	13.50%	9.84%	3.66%
4/1/1986	14.00%	9.83%	4.17%
4/2/1986	15.50%	9.81%	5.69%
4/4/1986	15.00%	9.78%	5.22%
4/13/1986	13.40%	9.71%	3.69%
4/22/1986	15.00%	9.59%	5.41%
5/16/1986	14.50%	9.33%	5.17%
5/16/1986	14.50%	9.33%	5.17%
5/29/1986	13.90%	9.20%	4.70%
5/30/1986	15.10%	9.19%	5.91%
6/2/1986	12.81%	9.17%	3.64%
6/11/1986	14.00%	9.08%	4.92%
6/24/1986	16.63%	8.94%	7.69%
6/26/1986	12.00%	8.91%	3.09%
6/26/1986	14.75%	8.91%	5.84%
6/30/1986	13.00%	8.88%	4.12%
7/10/1986	14.34%	8.76%	5.58%
7/11/1986	12.75%	8.74%	4.01%
7/14/1986	12.60%	8.72%	3.88%
7/17/1986	12.40%	8.67%	3.73%
7/25/1986	14.25%	8.58%	5.67%
8/6/1986	13.50%	8.45%	5.05%
8/14/1986	13.50%	8.36%	5.14%
9/16/1986	12.75%	8.07%	4.68%
9/19/1986	13.25%	8.04%	5.21%
10/1/1986	14.00%	7.96%	6.04%
10/3/1986	13.40%	7.94%	5.46%
10/31/1986	13.50%	7.78%	5.72%
11/5/1986	13.00%	7.76%	5.24%
12/3/1986	12.90%	7.59%	5.31%
12/4/1986	14.44%	7.58%	6.86%
12/16/1986	13.60%	7.53%	6.07%
12/22/1986	13.80%	7.51%	6.29%
12/30/1986	13.00%	7.49%	5.51%
1/2/1987	13.00%	7.49%	5.51%
1/12/1987	12.40%	7.47%	4.93%
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%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
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%	7.47%	5.53%
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%
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%	7.83%	7.17%
6/30/1987	12.50%	7.84%	4.66%
7/8/1987	12.00%	7.86%	4.14%
7/10/1987	12.90%	7.86%	5.04%
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	13.00%	7.92%	5.08%
7/27/1987	13.40%	7.92%	5.48%
7/27/1987	13.50%	7.92%	5.58%
7/31/1987	12.98%	7.94%	5.04%
8/26/1987	12.63%	8.05%	4.58%
8/26/1987	12.75%	8.05%	4.70%
8/27/1987	13.25%	8.06%	5.19%
9/9/1987	13.00%	8.13%	4.87%
9/30/1987	13.00%	8.30%	4.70%
9/30/1987	12.75%	8.30%	4.45%
10/2/1987	11.50%	8.33%	3.17%
10/15/1987	13.00%	8.43%	4.57%
11/2/1987	13.00%	8.54%	4.46%
11/19/1987	13.00%	8.63%	4.37%
11/30/1987	12.00%	8.68%	3.32%
12/3/1987	14.20%	8.70%	5.50%
12/15/1987	13.25%	8.77%	4.48%
12/16/1987	13.72%	8.78%	4.94%
12/16/1987	13.50%	8.78%	4.72%
12/17/1987	11.75%	8.78%	2.97%
12/18/1987	13.50%	8.79%	4.71%
12/21/1987	12.01%	8.80%	3.21%
12/22/1987	12.75%	8.81%	3.94%
12/22/1987	12.00%	8.81%	3.19%
12/22/1987	12.00%	8.81%	3.19%
12/22/1987	13.00%	8.81%	4.19%
1/20/1988	13.80%	8.93%	4.87%
1/26/1988	13.90%	8.95%	4.95%
1/29/1988	13.20%	8.95%	4.25%
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%	8.95%	2.01%
5/3/1988	12.91%	8.97%	3.94%
5/11/1988	13.50%	8.99%	4.51%
5/16/1988	13.00%	8.99%	4.01%
6/30/1988	12.75%	9.00%	3.75%
7/1/1988	12.75%	9.00%	3.75%
7/20/1988	13.40%	8.97%	4.43%
8/5/1988	12.75%	8.92%	3.83%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
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%
9/8/1988	12.60%	8.95%	3.65%
10/13/1988	13.10%	8.93%	4.17%
12/19/1988	13.00%	9.01%	3.99%
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%	9.03%	4.37%
1/27/1989	13.00%	9.05%	3.95%
1/31/1989	13.00%	9.05%	3.95%
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%	9.01%	4.19%
6/8/1989	13.50%	8.98%	4.52%
6/27/1989	13.25%	8.92%	4.33%
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%	8.49%	4.51%
12/15/1989	13.00%	8.34%	4.66%
12/20/1989	12.90%	8.32%	4.58%
12/21/1989	12.90%	8.32%	4.58%
12/27/1989	13.00%	8.30%	4.70%
12/27/1989	12.50%	8.30%	4.20%
1/10/1990	12.80%	8.25%	4.55%
1/11/1990	12.90%	8.24%	4.66%
1/17/1990	12.80%	8.22%	4.58%
1/26/1990	12.00%	8.20%	3.80%
2/9/1990	12.10%	8.18%	3.92%
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%	8.31%	4.89%
6/20/1990	12.92%	8.32%	4.60%
6/27/1990	12.90%	8.33%	4.57%
6/29/1990	12.50%	8.33%	4.17%
7/6/1990	12.35%	8.34%	4.01%
7/6/1990	12.10%	8.34%	3.76%
8/10/1990	12.55%	8.40%	4.15%
8/16/1990	13.21%	8.42%	4.79%
8/22/1990	13.10%	8.44%	4.66%
8/24/1990	13.00%	8.46%	4.54%
9/26/1990	11.45%	8.59%	2.86%
10/2/1990	13.00%	8.61%	4.39%
10/5/1990	12.84%	8.62%	4.22%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
10/19/1990	13.00%	8.66%	4.34%
10/25/1990	12.30%	8.67%	3.63%
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%	8.65%	4.45%
1/4/1991	12.50%	8.65%	3.85%
1/15/1991	12.75%	8.64%	4.11%
1/25/1991	11.70%	8.63%	3.07%
2/4/1991	12.50%	8.61%	3.89%
2/7/1991	12.50%	8.59%	3.91%
2/12/1991	13.00%	8.58%	4.42%
2/14/1991	12.72%	8.57%	4.15%
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%	8.44%	4.31%
6/12/1991	12.00%	8.41%	3.59%
6/25/1991	11.70%	8.39%	3.31%
6/28/1991	12.50%	8.38%	4.12%
7/1/1991	12.00%	8.38%	3.62%
7/3/1991	12.50%	8.37%	4.13%
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	12.50%	8.20%	4.30%
10/23/1991	12.55%	8.20%	4.35%
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	12.50%	8.18%	4.32%
11/12/1991	13.25%	8.18%	5.07%
11/25/1991	12.40%	8.18%	4.22%
11/26/1991	12.50%	8.18%	4.32%
11/26/1991	11.60%	8.18%	3.42%
11/27/1991	12.10%	8.18%	3.92%
12/18/1991	12.25%	8.15%	4.10%
12/19/1991	12.60%	8.15%	4.45%
12/19/1991	12.80%	8.15%	4.65%
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%
1/27/1992	12.65%	8.06%	4.59%
1/31/1992	12.00%	8.05%	3.95%
2/11/1992	12.40%	8.03%	4.37%
2/25/1992	12.50%	8.01%	4.49%
3/16/1992	11.43%	7.99%	3.44%
3/18/1992	12.28%	7.98%	4.30%
4/2/1992	12.10%	7.95%	4.15%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
4/9/1992	11.45%	7.94%	3.51%
4/10/1992	11.50%	7.94%	3.56%
4/14/1992	11.50%	7.93%	3.57%
5/5/1992	11.50%	7.90%	3.60%
5/12/1992	12.46%	7.89%	4.57%
5/12/1992	11.87%	7.89%	3.98%
6/1/1992	12.30%	7.87%	4.43%
6/12/1992	10.90%	7.86%	3.04%
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	13.50%	7.84%	5.66%
7/13/1992	11.90%	7.84%	4.06%
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%	7.70%	4.05%
10/2/1992	13.00%	7.70%	5.30%
10/12/1992	12.20%	7.70%	4.50%
10/16/1992	13.16%	7.70%	5.46%
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	12.30%	7.65%	4.65%
12/22/1992	12.40%	7.65%	4.75%
12/29/1992	12.25%	7.63%	4.62%
12/30/1992	12.00%	7.63%	4.37%
12/31/1992	11.90%	7.63%	4.27%
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	11.80%	7.48%	4.32%
2/26/1993	12.20%	7.48%	4.72%
4/23/1993	11.75%	7.29%	4.46%
5/11/1993	11.75%	7.25%	4.50%
5/14/1993	11.50%	7.24%	4.26%
5/25/1993	11.50%	7.23%	4.27%
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%
7/23/1993	10.46%	7.09%	3.37%
8/24/1993	11.50%	6.96%	4.54%
9/21/1993	10.50%	6.81%	3.69%
9/29/1993	11.47%	6.77%	4.70%
9/30/1993	11.60%	6.76%	4.84%
11/2/1993	10.80%	6.61%	4.19%
11/12/1993	12.00%	6.57%	5.43%
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%	6.45%	3.62%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
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	11.25%	6.36%	4.89%
2/25/1994	12.00%	6.36%	5.64%
3/1/1994	11.00%	6.35%	4.65%
3/4/1994	11.00%	6.35%	4.65%
4/25/1994	11.00%	6.41%	4.59%
5/10/1994	11.75%	6.45%	5.30%
5/13/1994	10.50%	6.46%	4.04%
6/3/1994	11.00%	6.53%	4.47%
6/27/1994	11.40%	6.64%	4.76%
8/5/1994	12.75%	6.87%	5.88%
10/31/1994	10.00%	7.32%	2.68%
11/9/1994	10.85%	7.38%	3.47%
11/9/1994	10.85%	7.38%	3.47%
11/18/1994	11.20%	7.45%	3.75%
11/22/1994	11.60%	7.46%	4.14%
11/28/1994	11.06%	7.49%	3.57%
12/8/1994	11.70%	7.54%	4.16%
12/8/1994	11.50%	7.54%	3.96%
12/14/1994	10.95%	7.56%	3.39%
12/15/1994	11.50%	7.57%	3.93%
12/19/1994	11.50%	7.57%	3.93%
12/28/1994	12.15%	7.61%	4.54%
1/9/1995	12.28%	7.64%	4.64%
1/31/1995	11.00%	7.68%	3.32%
2/10/1995	12.60%	7.70%	4.90%
2/17/1995	11.90%	7.70%	4.20%
3/9/1995	11.50%	7.71%	3.79%
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%	7.71%	3.39%
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%	7.52%	3.58%
9/11/1995	11.30%	7.21%	4.09%
9/27/1995	11.50%	7.13%	4.37%
9/27/1995	11.75%	7.13%	4.62%
9/27/1995	11.30%	7.13%	4.17%
9/29/1995	11.00%	7.12%	3.88%
11/9/1995	12.36%	6.90%	5.46%
11/9/1995	11.38%	6.90%	4.48%
11/17/1995	11.00%	6.86%	4.14%
12/4/1995	11.35%	6.78%	4.57%
12/11/1995	11.40%	6.75%	4.65%
12/20/1995	11.60%	6.70%	4.90%
12/27/1995	12.00%	6.67%	5.33%
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%	6.44%	4.81%
4/30/1996	11.00%	6.43%	4.57%
5/13/1996	11.00%	6.44%	4.56%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
5/23/1996	11.25%	6.44%	4.81%
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%	6.70%	4.30%
10/16/1996	12.25%	6.76%	5.49%
11/5/1996	11.00%	6.80%	4.20%
11/26/1996	11.30%	6.83%	4.47%
12/18/1996	11.75%	6.83%	4.92%
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%	6.61%	4.39%
12/23/1997	11.12%	6.57%	4.55%
2/2/1998	12.75%	6.40%	6.35%
3/2/1998	11.25%	6.29%	4.96%
3/6/1998	10.75%	6.27%	4.48%
3/20/1998	10.50%	6.23%	4.27%
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%	5.55%	6.65%
12/17/1998	12.10%	5.52%	6.58%
2/5/1999	10.30%	5.39%	4.91%
3/4/1999	10.50%	5.34%	5.16%
4/6/1999	10.94%	5.32%	5.62%
7/29/1999	10.75%	5.51%	5.24%
9/23/1999	10.75%	5.70%	5.05%
11/17/1999	11.10%	5.89%	5.21%
1/7/2000	11.50%	6.04%	5.46%
1/7/2000	11.50%	6.04%	5.46%
2/17/2000	10.60%	6.17%	4.43%
3/28/2000	11.25%	6.19%	5.06%
5/24/2000	11.00%	6.18%	4.82%
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%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
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	11.00%	5.48%	5.52%
6/20/2002	12.30%	5.48%	6.82%
7/15/2002	11.00%	5.47%	5.53%
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%	5.05%	7.25%
3/6/2003	10.75%	5.03%	5.72%
3/7/2003	9.96%	5.02%	4.94%
3/20/2003	12.00%	4.99%	7.01%
4/3/2003	12.00%	4.96%	7.04%
4/15/2003	11.15%	4.94%	6.21%
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%	4.80%	4.70%
8/26/2003	10.50%	4.83%	5.67%
12/17/2003	9.85%	4.93%	4.92%
12/17/2003	10.70%	4.93%	5.77%
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%	4.98%	5.77%
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%
5/25/2004	10.25%	5.08%	5.17%
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%	5.06%	5.44%
11/23/2004	11.00%	5.06%	5.94%
12/14/2004	10.97%	5.06%	5.91%
12/21/2004	11.25%	5.07%	6.18%
12/21/2004	11.50%	5.07%	6.43%
12/22/2004	10.70%	5.07%	5.63%
12/22/2004	11.50%	5.07%	6.43%
12/29/2004	9.85%	5.07%	4.78%
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%	4.90%	5.40%
4/4/2005	10.00%	4.88%	5.12%
4/7/2005	10.25%	4.87%	5.38%
5/18/2005	10.25%	4.78%	5.47%
5/25/2005	10.75%	4.77%	5.98%
5/26/2005	9.75%	4.76%	4.99%
6/1/2005	9.75%	4.75%	5.00%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
7/19/2005	11.50%	4.65%	6.85%
8/5/2005	11.75%	4.62%	7.13%
8/15/2005	10.13%	4.62%	5.51%
9/28/2005	10.00%	4.54%	5.46%
10/4/2005	10.75%	4.54%	6.21%
12/12/2005	11.00%	4.55%	6.45%
12/13/2005	10.75%	4.55%	6.20%
12/21/2005	10.29%	4.55%	5.74%
12/21/2005	10.40%	4.55%	5.85%
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%	4.61%	5.59%
4/26/2006	10.60%	4.64%	5.96%
5/17/2006	11.60%	4.69%	6.91%
6/6/2006	10.00%	4.74%	5.26%
6/27/2006	10.75%	4.80%	5.95%
7/6/2006	10.20%	4.82%	5.38%
7/24/2006	9.60%	4.86%	4.74%
7/26/2006	10.50%	4.86%	5.64%
7/28/2006	10.05%	4.86%	5.19%
8/23/2006	9.55%	4.89%	4.66%
9/1/2006	10.54%	4.89%	5.65%
9/14/2006	10.00%	4.90%	5.10%
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%
11/21/2006	10.12%	4.95%	5.17%
12/1/2006	10.50%	4.95%	5.55%
12/1/2006	10.25%	4.95%	5.30%
12/7/2006	10.75%	4.95%	5.80%
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	10.10%	4.95%	5.15%
1/11/2007	10.10%	4.95%	5.15%
1/11/2007	10.90%	4.95%	5.95%
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%	4.87%	6.48%
3/22/2007	9.75%	4.87%	4.88%
5/15/2007	10.00%	4.81%	5.19%
5/17/2007	10.25%	4.81%	5.44%
5/17/2007	10.25%	4.81%	5.44%
5/22/2007	10.20%	4.81%	5.39%
5/22/2007	10.50%	4.81%	5.69%
5/23/2007	10.70%	4.81%	5.89%
5/25/2007	9.67%	4.81%	4.86%
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%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
10/17/2007	9.10%	4.91%	4.19%
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	10.70%	4.86%	5.84%
12/14/2007	10.80%	4.86%	5.94%
12/19/2007	10.20%	4.85%	5.35%
12/20/2007	10.20%	4.85%	5.35%
12/20/2007	11.00%	4.85%	6.15%
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%	4.82%	5.93%
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%	4.69%	4.41%
4/22/2008	10.25%	4.61%	5.64%
4/24/2008	10.10%	4.60%	5.50%
5/1/2008	10.70%	4.59%	6.11%
5/19/2008	11.00%	4.57%	6.43%
5/27/2008	10.00%	4.55%	5.45%
6/10/2008	10.70%	4.54%	6.16%
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%	4.52%	4.88%
7/30/2008	10.80%	4.51%	6.29%
7/31/2008	10.70%	4.51%	6.19%
8/11/2008	10.25%	4.51%	5.74%
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%	4.48%	5.72%
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%	4.40%	5.85%
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%	4.12%	6.38%
1/21/2009	10.50%	4.12%	6.38%
1/21/2009	10.50%	4.12%	6.38%
1/27/2009	10.76%	4.09%	6.67%
1/30/2009	10.50%	4.08%	6.42%
2/4/2009	8.75%	4.06%	4.69%
3/4/2009	10.50%	3.97%	6.53%
3/12/2009	11.50%	3.93%	7.57%
4/2/2009	11.10%	3.86%	7.24%
4/21/2009	10.61%	3.80%	6.81%
4/24/2009	10.00%	3.79%	6.21%
4/30/2009	11.25%	3.78%	7.47%
5/4/2009	10.74%	3.77%	6.97%
5/20/2009	10.25%	3.75%	6.50%
5/28/2009	10.50%	3.75%	6.75%
6/22/2009	10.00%	3.77%	6.23%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
6/24/2009	10.80%	3.77%	7.03%
7/8/2009	10.63%	3.77%	6.86%
7/17/2009	10.50%	3.78%	6.72%
8/21/2009	10.25%	3.81%	6.44%
8/31/2009	10.25%	3.82%	6.43%
10/14/2009	10.70%	4.01%	6.69%
10/23/2009	10.88%	4.05%	6.83%
11/2/2009	10.70%	4.09%	6.61%
11/3/2009	10.70%	4.09%	6.61%
11/24/2009	10.25%	4.15%	6.10%
11/25/2009	10.75%	4.15%	6.60%
11/30/2009	10.35%	4.16%	6.19%
12/3/2009	10.50%	4.17%	6.33%
12/7/2009	10.70%	4.18%	6.52%
12/16/2009	11.00%	4.21%	6.79%
12/16/2009	10.90%	4.21%	6.69%
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%
12/22/2009	10.40%	4.23%	6.17%
12/30/2009	10.00%	4.26%	5.74%
1/4/2010	10.80%	4.27%	6.53%
1/11/2010	11.00%	4.30%	6.70%
1/26/2010	10.13%	4.35%	5.78%
1/27/2010	10.40%	4.35%	6.05%
1/27/2010	10.40%	4.35%	6.05%
1/27/2010	10.70%	4.35%	6.35%
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%	4.42%	5.58%
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%	4.46%	5.84%
5/12/2010	10.30%	4.46%	5.84%
5/28/2010	10.20%	4.44%	5.76%
5/28/2010	10.10%	4.44%	5.66%
6/7/2010	10.30%	4.44%	5.86%
6/16/2010	10.00%	4.44%	5.56%
6/28/2010	10.50%	4.43%	6.07%
6/28/2010	9.67%	4.43%	5.24%
6/30/2010	9.40%	4.43%	4.97%
7/1/2010	10.25%	4.43%	5.82%
7/15/2010	10.70%	4.43%	6.27%
7/15/2010	10.53%	4.43%	6.10%
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%	4.33%	5.67%
9/16/2010	10.00%	4.33%	5.67%
9/30/2010	9.75%	4.29%	5.46%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
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%	4.20%	6.50%
11/19/2010	10.20%	4.18%	6.02%
11/22/2010	10.00%	4.18%	5.82%
12/1/2010	10.13%	4.16%	5.97%
12/6/2010	9.86%	4.16%	5.70%
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%	4.15%	5.85%
12/20/2010	10.60%	4.15%	6.45%
12/21/2010	10.30%	4.15%	6.15%
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%	4.13%	6.17%
1/13/2011	10.30%	4.13%	6.17%
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%	4.12%	5.48%
2/3/2011	10.00%	4.12%	5.88%
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%	4.23%	5.44%
4/27/2011	10.40%	4.23%	6.17%
5/4/2011	10.00%	4.24%	5.76%
5/4/2011	10.00%	4.24%	5.76%
5/24/2011	10.50%	4.27%	6.23%
6/8/2011	10.75%	4.30%	6.45%
6/16/2011	9.20%	4.31%	4.89%
6/17/2011	9.95%	4.31%	5.64%
7/13/2011	10.20%	4.36%	5.84%
8/1/2011	9.20%	4.38%	4.82%
8/8/2011	10.00%	4.38%	5.62%
8/11/2011	10.00%	4.37%	5.63%
8/12/2011	10.35%	4.37%	5.98%
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%	3.88%	7.02%
11/30/2011	10.90%	3.88%	7.02%
12/14/2011	10.00%	3.80%	6.20%
12/14/2011	10.30%	3.80%	6.50%
12/20/2011	10.20%	3.77%	6.43%
12/21/2011	10.20%	3.76%	6.44%
12/22/2011	9.90%	3.75%	6.15%
12/22/2011	10.40%	3.75%	6.65%
12/23/2011	10.19%	3.75%	6.44%
1/25/2012	10.50%	3.57%	6.93%
1/27/2012	10.50%	3.56%	6.94%
2/15/2012	10.20%	3.48%	6.72%
2/23/2012	9.90%	3.44%	6.46%
2/27/2012	10.25%	3.43%	6.82%
2/29/2012	10.40%	3.42%	6.98%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
3/29/2012	10.37%	3.32%	7.05%
4/4/2012	10.00%	3.30%	6.70%
4/26/2012	10.00%	3.21%	6.79%
5/2/2012	10.00%	3.19%	6.81%
5/7/2012	9.80%	3.17%	6.63%
5/15/2012	10.00%	3.15%	6.85%
5/29/2012	10.05%	3.11%	6.94%
6/7/2012	10.30%	3.08%	7.22%
6/14/2012	9.40%	3.06%	6.34%
6/15/2012	10.40%	3.06%	7.34%
6/18/2012	9.60%	3.06%	6.54%
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%
10/23/2012	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	9.88%	2.90%	6.98%
11/29/2012	9.75%	2.90%	6.85%
12/5/2012	9.71%	2.89%	6.82%
12/5/2012	10.40%	2.89%	7.51%
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%	2.88%	6.83%
12/19/2012	10.25%	2.88%	7.37%
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	10.25%	2.87%	7.38%
12/20/2012	10.25%	2.87%	7.38%
12/20/2012	9.80%	2.87%	6.93%
12/20/2012	9.50%	2.87%	6.63%
12/21/2012	10.20%	2.87%	7.33%
12/26/2012	9.80%	2.86%	6.94%
1/9/2013	9.70%	2.85%	6.85%
1/9/2013	9.70%	2.85%	6.85%
1/9/2013	9.70%	2.85%	6.85%
2/13/2013	10.20%	2.85%	7.35%
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%	3.07%	6.29%
8/8/2013	9.83%	3.14%	6.69%
8/14/2013	9.15%	3.16%	5.99%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
9/11/2013	10.25%	3.26%	6.99%
9/11/2013	10.20%	3.26%	6.94%
9/24/2013	10.20%	3.30%	6.90%
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%	3.47%	6.73%
12/9/2013	8.72%	3.48%	5.24%
12/9/2013	9.75%	3.48%	6.27%
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%	3.50%	6.00%
12/17/2013	10.95%	3.50%	7.45%
12/18/2013	8.72%	3.51%	5.21%
12/18/2013	9.80%	3.51%	6.29%
12/19/2013	10.15%	3.51%	6.64%
12/30/2013	9.50%	3.54%	5.96%
2/20/2014	9.20%	3.68%	5.52%
2/26/2014	9.75%	3.69%	6.06%
3/17/2014	9.55%	3.72%	5.83%
3/26/2014	9.40%	3.72%	5.68%
3/26/2014	9.96%	3.72%	6.24%
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%	3.57%	6.18%
8/25/2014	9.60%	3.56%	6.04%
8/29/2014	9.80%	3.54%	6.26%
9/15/2014	10.25%	3.51%	6.74%
10/9/2014	9.80%	3.45%	6.35%
11/6/2014	9.56%	3.37%	6.19%
11/6/2014	10.20%	3.37%	6.83%
11/14/2014	10.20%	3.36%	6.84%
11/26/2014	9.70%	3.33%	6.37%
11/26/2014	10.20%	3.33%	6.87%
12/4/2014	9.68%	3.31%	6.37%
12/10/2014	9.25%	3.29%	5.96%
12/10/2014	9.25%	3.29%	5.96%
12/11/2014	10.07%	3.29%	6.78%
12/12/2014	10.20%	3.28%	6.92%
12/17/2014	9.17%	3.27%	5.90%
12/18/2014	9.83%	3.27%	6.56%
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%	2.96%	6.54%
3/26/2015	9.72%	2.96%	6.76%
4/23/2015	10.20%	2.87%	7.33%
4/29/2015	9.53%	2.86%	6.67%
5/26/2015	9.75%	2.83%	6.92%
6/17/2015	9.00%	2.82%	6.18%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
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%
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%	2.89%	7.11%
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%	2.90%	6.70%
12/17/2015	9.70%	2.91%	6.79%
12/18/2015	9.50%	2.91%	6.59%
12/30/2015	9.50%	2.92%	6.58%
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%	2.79%	6.21%
6/15/2016	9.00%	2.79%	6.21%
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%	2.62%	7.13%
9/1/2016	9.50%	2.60%	6.90%
9/8/2016	10.00%	2.58%	7.42%
9/28/2016	9.58%	2.54%	7.04%
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	9.37%	2.54%	6.83%
12/19/2016	9.00%	2.54%	6.46%
12/22/2016	9.90%	2.55%	7.35%
12/22/2016	9.60%	2.55%	7.05%
12/28/2016	9.50%	2.56%	6.94%
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%
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%	2.71%	7.54%
4/12/2017	9.40%	2.73%	6.67%
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] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
6/22/2017	9.70%	2.90%	6.80%
6/22/2017	9.70%	2.90%	6.80%
7/24/2017	9.50%	2.94%	6.56%
8/15/2017	10.00%	2.97%	7.03%
9/22/2017	9.60%	2.93%	6.67%
9/28/2017	9.80%	2.93%	6.87%
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%	2.88%	5.52%
12/6/2017	8.40%	2.88%	5.52%
12/7/2017	9.80%	2.87%	6.93%
12/14/2017	9.65%	2.87%	6.78%
12/14/2017	9.60%	2.87%	6.73%
12/18/2017	9.50%	2.86%	6.64%
12/20/2017	9.58%	2.86%	6.72%
12/21/2017	9.10%	2.86%	6.24%
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	9.25%	2.89%	6.36%
4/18/2018	10.00%	2.89%	7.11%
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%
8/24/2018	9.28%	3.00%	6.28%
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	9.77%	3.04%	6.73%
9/26/2018	10.00%	3.04%	6.96%
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%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
1/9/2019	10.00%	3.13%	6.87%
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%	2.90%	6.70%
8/29/2019	9.06%	2.81%	6.25%
9/4/2019	10.00%	2.79%	7.21%
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%	2.53%	6.97%
12/4/2019	8.91%	2.51%	6.40%
12/4/2019	9.75%	2.51%	7.24%
12/16/2019	8.91%	2.48%	6.43%
12/17/2019	10.50%	2.48%	8.02%
12/17/2019	9.70%	2.48%	7.22%
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	9.45%	2.47%	6.98%
12/20/2019	9.65%	2.47%	7.18%
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%	2.40%	7.10%
1/23/2020	9.86%	2.39%	7.47%
2/6/2020	10.00%	2.35%	7.65%
2/11/2020	9.30%	2.34%	6.96%
2/14/2020	9.40%	2.33%	7.07%
2/19/2020	8.25%	2.31%	5.94%
2/24/2020	9.75%	2.30%	7.45%
2/27/2020	9.40%	2.28%	7.12%
3/11/2020	9.70%	2.23%	7.47%
3/25/2020	9.40%	2.18%	7.22%
4/17/2020	9.70%	2.07%	7.63%
4/27/2020	9.25%	2.03%	7.22%
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%	1.85%	7.40%
7/8/2020	9.40%	1.83%	7.57%
7/14/2020	9.60%	1.81%	7.79%
7/28/2020	9.50%	1.77%	7.73%
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%
10/15/2020	9.35%	1.52%	7.83%
10/22/2020	9.50%	1.50%	8.00%
10/28/2020	9.60%	1.49%	8.11%
11/19/2020	8.80%	1.45%	7.35%
11/19/2020	8.80%	1.45%	7.35%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
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%	1.45%	7.70%
12/23/2020	10.00%	1.45%	8.55%
12/30/2020	9.65%	1.45%	8.20%
1/13/2021	9.30%	1.47%	7.83%
3/31/2021	9.60%	1.67%	7.93%
4/16/2021	9.60%	1.73%	7.87%
5/4/2021	9.85%	1.79%	8.06%
5/18/2021	9.50%	1.84%	7.66%
6/4/2021	9.28%	1.90%	7.38%
6/4/2021	9.50%	1.90%	7.60%
6/8/2021	10.18%	1.91%	8.27%
6/22/2021	9.50%	1.94%	7.56%
6/23/2021	9.00%	1.94%	7.06%
6/28/2021	9.55%	1.95%	7.60%
6/30/2021	9.43%	1.96%	7.47%
6/30/2021	9.43%	1.96%	7.47%
7/14/2021	9.60%	1.99%	7.61%
7/21/2021	9.50%	2.00%	7.50%
8/5/2021	9.60%	2.01%	7.59%
8/18/2021	9.50%	2.03%	7.47%
8/31/2021	8.57%	2.04%	6.53%
9/1/2021	9.40%	2.04%	7.36%
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%	2.10%	6.80%
11/4/2021	9.48%	2.11%	7.37%
11/17/2021	9.70%	2.11%	7.59%
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%	2.07%	7.83%
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%
6/7/2022	10.64%	2.28%	8.36%
8/31/2022	8.57%	2.64%	5.93%
9/8/2022	9.50%	2.68%	6.82%
9/15/2022	9.35%	2.73%	6.62%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
10/4/2022	10.10%	2.84%	7.26%
10/4/2022	10.80%	2.84%	7.96%
10/25/2022	9.50%	2.99%	6.51%
11/3/2022	10.25%	3.06%	7.19%
11/3/2022	10.20%	3.06%	7.14%
11/3/2022	10.30%	3.06%	7.24%
11/17/2022	7.85%	3.16%	4.69%
11/18/2022	9.90%	3.16%	6.74%
11/30/2022	9.80%	3.22%	6.58%
12/1/2022	7.85%	3.23%	4.62%
12/14/2022	9.60%	3.29%	6.31%
12/14/2022	9.50%	3.29%	6.21%
12/14/2022	10.00%	3.29%	6.71%
12/15/2022	10.00%	3.29%	6.71%
12/15/2022	9.95%	3.29%	6.66%
12/15/2022	10.05%	3.29%	6.76%
12/16/2022	9.50%	3.30%	6.20%
12/20/2022	10.50%	3.31%	7.19%
12/22/2022	9.40%	3.32%	6.08%
12/22/2022	9.80%	3.32%	6.48%
12/27/2022	9.56%	3.35%	6.21%
12/29/2022	9.30%	3.36%	5.94%
12/29/2022	9.80%	3.36%	6.44%
1/19/2023	9.90%	3.44%	6.46%
1/23/2023	9.65%	3.45%	6.20%
1/26/2023	9.75%	3.46%	6.29%
2/9/2023	9.60%	3.49%	6.11%
2/17/2023	9.50%	3.52%	5.98%
3/9/2023	9.70%	3.58%	6.12%
3/24/2023	9.90%	3.60%	6.30%
4/27/2023	10.00%	3.66%	6.34%
5/31/2023	9.35%	3.75%	5.60%
6/1/2023	9.25%	3.76%	5.49%
6/6/2023	9.35%	3.77%	5.58%
6/6/2023	9.75%	3.77%	5.98%
6/13/2023	11.16%	3.78%	7.38%
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%	3.89%	5.76%
10/12/2023	9.75%	3.97%	5.78%
10/12/2023	9.20%	3.97%	5.23%
10/12/2023	9.20%	3.97%	5.23%
10/18/2023	9.50%	3.99%	5.51%
10/19/2023	9.35%	4.00%	5.35%
10/19/2023	9.50%	4.00%	5.50%
10/25/2023	9.65%	4.02%	5.63%
11/3/2023	9.30%	4.07%	5.23%
11/3/2023	9.70%	4.07%	5.63%
11/9/2023	9.80%	4.09%	5.71%
11/9/2023	9.80%	4.09%	5.71%
11/17/2023	9.60%	4.12%	5.48%
11/28/2023	9.35%	4.15%	5.20%
12/1/2023	9.90%	4.16%	5.74%
12/7/2023	9.70%	4.16%	5.54%
12/14/2023	10.00%	4.17%	5.83%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/14/2023	8.72%	4.17%	4.55%
12/14/2023	8.91%	4.17%	4.74%
12/14/2023	9.50%	4.17%	5.33%
12/15/2023	10.10%	4.17%	5.93%
12/18/2023	9.50%	4.17%	5.33%
12/22/2023	10.70%	4.18%	6.52%
12/22/2023	10.65%	4.18%	6.47%
12/22/2023	10.75%	4.18%	6.57%
12/26/2023	9.52%	4.18%	5.34%
12/28/2023	9.60%	4.19%	5.41%
1/3/2024	9.26%	4.19%	5.07%
1/19/2024	9.75%	4.23%	5.52%
1/30/2024	9.75%	4.25%	5.50%
2/14/2024	9.60%	4.28%	5.32%
2/28/2024	9.70%	4.31%	5.39%
3/1/2024	9.90%	4.31%	5.59%
3/5/2024	9.55%	4.32%	5.23%
3/26/2024	9.80%	4.35%	5.45%
4/17/2024	9.90%	4.40%	5.50%
4/18/2024	9.60%	4.41%	5.19%
5/8/2024	9.85%	4.46%	5.39%
6/10/2024	9.50%	4.49%	5.01%
6/13/2024	11.39%	4.50%	6.89%
6/19/2024	9.70%	4.50%	5.20%
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%	4.48%	5.02%
8/8/2024	9.94%	4.43%	5.51%
8/21/2024	10.30%	4.40%	5.90%
8/26/2024	9.97%	4.40%	5.57%
9/13/2024	9.70%	4.37%	5.33%
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%
9/26/2024	9.86%	4.36%	5.50%
9/30/2024	9.35%	4.36%	4.99%
10/3/2024	9.76%	4.36%	5.40%
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%	4.46%	5.54%
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	10.20%	4.46%	5.74%
3/12/2025	9.40%	4.46%	4.94%

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
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%
6/2/2025	9.50%	4.58%	4.92%
6/17/2025	11.66%	4.62%	7.04%
6/26/2025	9.75%	4.65%	5.10%
7/25/2025	9.50%	4.73%	4.77%
8/14/2025	9.50%	4.75%	4.75%
8/14/2025	9.50%	4.75%	4.75%
8/28/2025	9.75%	4.77%	4.98%
8/29/2025	9.60%	4.77%	4.83%
8/29/2025	9.94%	4.77%	5.17%
9/16/2025	9.51%	4.79%	4.72%
10/2/2025	9.80%	4.80%	5.00%
10/3/2025	9.65%	4.80%	4.85%
10/28/2025	9.45%	4.78%	4.67%
11/5/2025	10.00%	4.77%	5.23%
11/6/2025	9.80%	4.77%	5.03%
11/6/2025	9.80%	4.77%	5.03%
11/19/2025	9.65%	4.77%	4.88%
11/19/2025	9.63%	4.77%	4.86%
11/19/2025	9.63%	4.77%	4.86%
11/19/2025	9.63%	4.77%	4.86%
11/20/2025	10.95%	4.77%	6.18%
11/20/2025	9.99%	4.77%	5.22%
11/20/2025	9.80%	4.77%	5.03%
11/21/2025	9.60%	4.77%	4.83%
11/25/2025	9.80%	4.77%	5.03%
12/4/2025	9.99%	4.77%	5.22%
12/18/2025	9.98%	4.78%	5.20%
12/18/2025	9.93%	4.78%	5.15%
12/18/2025	10.03%	4.78%	5.25%
12/30/2025	9.60%	4.79%	4.81%
1/22/2026	9.40%	4.81%	4.59%
1/23/2026	9.65%	4.81%	4.84%
2/5/2026	9.80%	4.81%	4.99%
2/16/2026	9.78%	4.81%	4.97%
2/16/2026	9.78%	4.81%	4.97%
2/19/2026	9.90%	4.81%	5.09%
2/20/2026	9.40%	4.81%	4.59%
2/28/2026	9.75%	4.80%	4.95%
3/12/2026	9.70%	4.79%	4.91%
3/19/2026	9.75%	4.79%	4.96%
3/27/2026	9.90%	4.79%	5.11%
4/1/2026	9.84%	4.79%	5.05%
4/7/2026	9.70%	4.79%	4.91%
4/17/2026	9.75%	4.79%	4.96%
4/27/2026	9.45%	4.79%	4.66%
6/11/2026	9.99%	4.81%	5.18%
6/17/2026	9.50%	4.81%	4.69%
6/18/2026	9.60%	4.82%	4.78%
6/18/2026	11.52%	4.82%	6.70%
6/30/2026	9.60%	4.82%	4.78%
7/30/2026	9.65%	4.87%	4.78%
8/18/2026	9.30%	4.91%	4.39%
8/21/2026	9.28%	4.92%	4.36%
8/28/2026	9.40%	4.93%	4.47%
8/28/2026	9.05%	4.93%	4.12%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
		# of Cases:	1,888

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 410

November 24, 2026

FLOTATION COST ADJUSTMENT

Flotation Costs from Inception to Date		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Issuing Company	Date	Shares Issued (000)	Offering Price	Underwriting Discount	Offering Expense ($000)	Net Proceeds Per Share	Total Flotation Costs ($000)	Gross Equity Issue before Costs ($000)	Net Proceeds ($000)	Flotation Cost Percentage
Atmos Energy Corporation	11/28/2018	8,059	$ 92.75	$ 0.98	$1,000	$91.65	$8,873	$747,500	$738,627	1.19%
Atmos Energy Corporation	11/28/2017	4,558	$ 88.56	$ 1.77	N/A	$86.79	$8,068	$403,692	$395,624	2.00%
New Jersey Resources Corporation	12/4/2019	6,545	$ 41.25	$ 1.24	$500	$39.94	$8,600	$270,000	$261,400	3.19%
NiSource Inc.	9/8/2010	24,265	$ 16.50	$ 0.54	$400	$15.95	$13,411	$400,373	$386,962	3.35%
NiSource Inc.	11/6/2002	41,400	$ 18.30	$ 0.55	$300	$17.74	$23,029	$757,620	$734,591	3.04%
ONE Gas, Inc.	5/8/2025	2,875	$ 78.76	$ 0.95	$350	$77.69	$3,081	$226,435	$223,354	1.36%
ONE Gas, Inc.	9/11/2023	1,380	$ 74.73	$ 1.06	$316	$73.44	$1,778	$103,127	$101,349	1.72%
Southwest Gas Holdings, Inc.	3/8/2023	4,113	$ 60.12	$ 2.03	$538	$57.96	$8,883	$247,250	$238,367	3.59%
Southwest Gas Holdings, Inc.	3/28/2022	6,325	$ 74.00	$ 2.50	$730	$71.39	$16,527	$468,050	$451,523	3.53%
Spire Inc.	6/13/2023	1,745	$ 64.20	$ 0.60	$450	$63.34	$1,497	$112,000	$110,503	1.34%
Spire Inc.	5/7/2018	2,300	$ 68.75	$ 2.11	$325	$66.50	$5,177	$158,125	$152,948	3.27%
Ameren Corporation	5/12/2025	5,550	$ 94.00	$ 2.12	$425	$91.81	$12,164	$521,739	$509,575	2.33%
Ameren Corporation	8/5/2019	7,549	$ 74.30	$ 0.12	$750	$74.08	$1,656	$560,906	$559,250	0.30%
Avista Corporation	12/12/2006	3,163	$ 25.05	$ 0.48	$300	$24.48	$1,818	$79,221	$77,403	2.29%
CenterPoint Energy, Inc.	5/27/2025	21,622	$ 37.00	$ 0.74	$700	$36.23	$16,700	$800,000	$783,300	2.09%
CenterPoint Energy, Inc.	8/7/2024	9,754	$ 25.63	$ 0.27	$400	$25.32	$3,034	$250,000	$246,966	1.21%
CMS Energy Corporation	3/30/2005	23,000	$ 12.25	$ 0.43	$325	$11.81	$10,187	$281,750	$271,563	3.62%
CMS Energy Corporation	10/7/2004	32,775	$ 9.10	$ 0.32	$325	$8.77	$10,764	$298,253	$287,489	3.61%
Consolidated Edison, Inc.	3/4/2025	6,300	$ 102.15	$ 1.94	$400	$100.15	$12,616	$643,545	$630,929	1.96%
Consolidated Edison, Inc.	12/3/2024	7,000	$ 97.53	$ 0.87	$450	$96.60	$6,540	$682,710	$676,170	0.96%
DTE Energy Company	10/30/2019	26,000	$ 50.00	$ 1.25	$2,100	$48.67	$34,600	$1,300,000	$1,265,400	2.66%
DTE Energy Company	10/30/2019	2,760	$ 126.00	$ 3.15	$300	$122.74	$8,994	$347,760	$338,766	2.59%
Eversource Energy	6/11/2020	6,000	$ 86.26	$ 1.35	$600	$84.81	$8,700	$517,560	$508,860	1.68%
Eversource Energy	5/30/2019	17,940	$ 72.50	$ 1.02	$615	$71.45	$18,914	$1,300,650	$1,281,736	1.45%
Public Service Enterprise Group Inc.	9/30/2003	9,488	$ 41.75	$ 1.25	$350	$40.46	$12,233	$396,103	$383,870	3.09%
Public Service Enterprise Group Inc.	11/11/2002	17,250	$ 26.55	$ 0.86	$350	$25.67	$15,235	$457,988	$442,753	3.33%
WEC Energy Group, Inc.	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Xcel Energy Inc.	11/4/2024	21,069	$ 65.50	$ 1.06	$1,200	$64.38	$23,626	$1,380,000	$1,356,374	1.71%
Xcel Energy Inc.	10/30/2019	11,845	$ 63.32	$ 0.63	$650	$62.64	$8,112	$750,025	$741,913	1.08%
Weighted Average Flotation Costs						Total	$304,815	$14,462,381	$14,157,566	2.11%

The flotation adjustment is derived by dividing the dividend yield by 1-F (where F = flotation costs expressed in percentage terms), or by 0.9789, and adding that result to the constant growth rate to determine the cost of equity. Using the formulas shown previously in my testimony, the Constant Growth DCF calculation is modified as follows to accommodate an adjustment for flotation costs:

$$k = \frac{D \times (1 + 0.5g)}{P \times (1 - F)} + g$$

Notes
[1] - [3] Source: S&P Capital IQ; Two most recent equity issuances of each company in the proxy group, excluding issuances without gross underwriting discount
[4] Source: Company Prospectus Supplements
[5] Equals [2] - [3] - [4]
[6] Equals ([2] - [5])*([1])
[7] Equals [1] x [2]
[8] Equals [1] x [5]
[9] Equals [6] / [7]

FLOTATION COST ADJUSTMENT

Company	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Expected Dividend Yield Adjusted for Flotation Costs	[6] Value Line Earnings Growth	[7] S&P Capital IQ Earnings Growth	[8] Zacks Earnings Growth	[9] Average Growth Estimate	[10] DCF k(e)	[11] Flotation Adjusted DCF k(e)
Atmos Energy Corporation	$4.00	$ 171.78	2.33%	2.42%	2.47%	8.50%	7.90%	6.80%	7.73%	10.15%	10.20%
New Jersey Resources Corporation	$1.90	$ 56.13	3.38%	3.49%	3.56%	6.00%	6.30%	n/a	6.15%	9.64%	9.71%
NiSource Inc.	$1.20	$ 43.10	2.78%	2.90%	2.96%	9.00%	9.80%	6.60%	8.47%	11.37%	11.43%
ONE Gas, Inc.	$2.72	$ 79.80	3.41%	3.53%	3.60%	7.00%	6.75%	7.40%	7.05%	10.58%	10.65%
Southwest Gas Holdings, Inc.	$2.58	$ 91.04	2.83%	3.00%	3.07%	NMF	14.00%	9.90%	11.95%	14.95%	15.02%
Spire Inc.	$3.30	$ 81.98	4.03%	4.23%	4.32%	8.50%	11.17%	11.20%	10.29%	14.52%	14.61%
Ameren Corporation	$3.00	$ 109.11	2.75%	2.85%	2.92%	7.50%	7.70%	7.70%	7.63%	10.49%	10.55%
Avista Corporation	$1.97	$ 39.34	5.01%	5.13%	5.24%	4.50%	5.90%	4.10%	4.83%	9.96%	10.07%
CenterPoint Energy, Inc.	$0.96	$ 41.14	2.33%	2.44%	2.49%	8.50%	8.80%	8.90%	8.73%	11.17%	11.22%
CMS Energy Corporation	$2.28	$ 71.08	3.21%	3.33%	3.40%	8.50%	7.70%	7.10%	7.77%	11.10%	11.17%
Consolidated Edison, Inc.	$3.55	$ 108.91	3.26%	3.37%	3.44%	6.50%	6.44%	6.50%	6.48%	9.84%	9.92%
DTE Energy Company	$4.66	$ 140.64	3.31%	3.42%	3.50%	6.00%	8.10%	6.00%	6.70%	10.12%	10.20%
Eversource Energy	$3.15	$ 72.39	4.35%	4.44%	4.54%	4.50%	5.25%	2.90%	4.22%	8.66%	8.76%
Public Service Enterprise Group Inc.	$2.68	$ 75.93	3.53%	3.65%	3.73%	7.50%	6.90%	6.10%	6.83%	10.48%	10.56%
WEC Energy Group, Inc.	$3.81	$ 109.50	3.48%	3.63%	3.70%	7.00%	8.00%	10.30%	8.43%	12.06%	12.14%
Xcel Energy Inc.	$2.37	$ 78.36	3.02%	3.16%	3.23%	8.00%	9.36%	9.40%	8.92%	12.08%	12.15%
PROXY GROUP MEAN			3.31%	3.44%	3.51%	7.17%	8.13%	7.39%	7.64%	11.07%	11.15%
UNADJUSTED CONSTANT GROWTH DCF MEAN											11.07%
DIFFERENCE (FLOTATION COST ADJUSTMENT)										[12]	0.07%

[1] Source: S&P Capital IQ
[2] Source: S&P Capital IQ, equals 30-trading day average as of 08/31/2026
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [9])
[5] Equals [4] /(1- [Flotation Cost Percentage])
[6] Source: Value Line
[7] Source: S&P Capital IQ
[8] Source: Zacks
[9] Equals average ([6], [7], [8])
[10] Equals [4] + [9]
[11] Equals [5] + [9]
[12] Equals [11] - [10]

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 411

November 24, 2026

Gas Proxy Group Regulatory Risk Comparative Assessment

Company	Parent	Jurisdiction	Natural Gas Commodity [1]	Decoupling (F/P) [2]	New Capital Investment [3]	Energy Efficiency [4]	Other [5]	Jurisdiction Test Year Convention	Jurisdiction 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	✓	P	✓	✓	✓	Partially Forecast	Year End	
Northern Indiana Public Service Co.	NI	Indiana	✓	P	✓	✓	✓	Forecast Permitted	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%	100%	69%	92%	54%	35%	35%
Northwest Natural Gas Company	NWN	Oregon	✓	P	✓	✓	✓	Partially Forecast	Average	

Notes:

A mechanism may cover one or more cost categories; therefore, designations may not indicate separate mechanisms for each category.

[1] Columbia Gas of Ohio does not have a supply obligation for retail customers.

[2] 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).

[3] Includes recovery of capital costs including infrastructure replacement programs and capital/plant additions.

[4] Utility-sponsored conservation, energy efficiency, or other demand side management programs.

[5] Pension expenses, bad debt costs, storm costs, environmental costs, regulatory fee, government franchise fees and taxes, economic development, and low income assistance

Sources: Company SEC Form 10-Ks; Operating company tariffs; Regulatory Research Associates, *State Regulatory Evaluations Quarterly Update* , July 2025; Regulatory Research

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 412

November 24, 2026

SIZE PREMIUM ANALYSIS

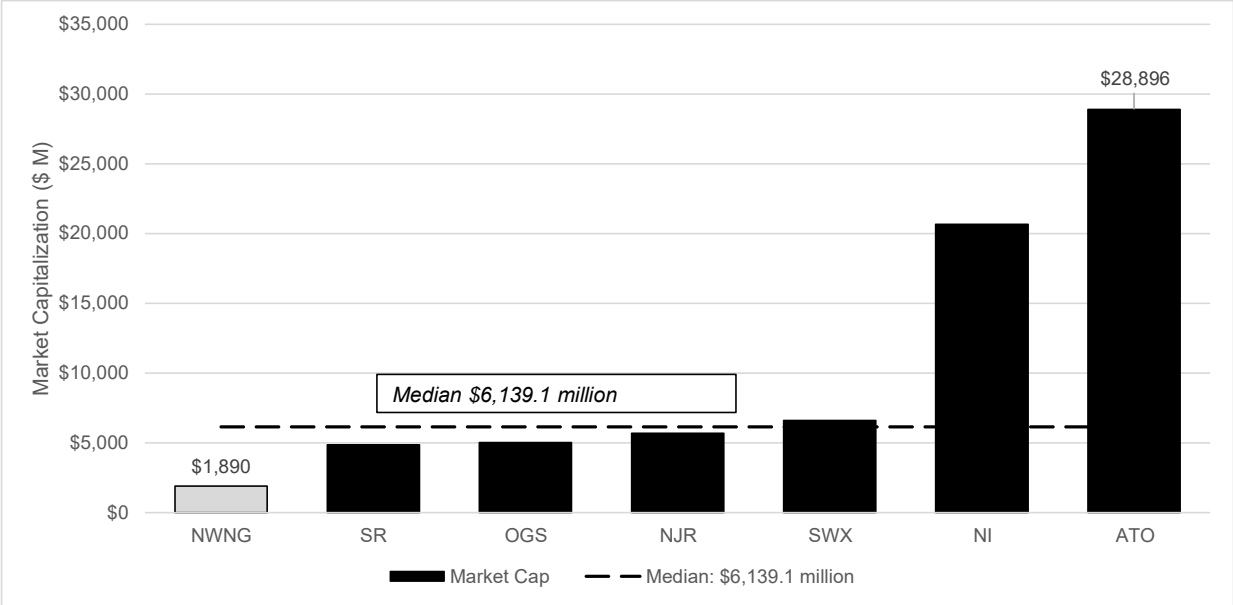
	[1] ($Mil)
NW Natural Gas Oregon Jurisdictional Rate Base	$2,153
NW Natural Gas Oregon Jurisdictional Proposed Equity Ratio	0.50
NW Natural Oregon Equity	$1,076
Median Market to Book for Proxy Group	1.76
NW Natural Implied Market Cap	$1,890

Company Name	Ticker	[2] Market Cap ($Mil)	[3] Market to Book Ratio
Atmos Energy Corp.	ATO	$28,896	1.91
New Jersey Resources Corporation	NJR	$5,685	2.15
NiSource Inc.	NI	$20,667	2.15
ONE Gas, Inc.	OGS	$5,014	1.42
Southwest Gas Holdings, Inc.	SWX	$6,593	1.60
Spire Inc.	SR	$4,846	1.38
MEDIAN		$6,139.1	1.76
MEAN		$11,950.1	1.77

	Market Capitalization ($Mil) [4]		
Decile	Low End Market Capitalization	High End Market Capitalization	Size Premium
1	$ 53,678	$ 4,542,663	0.01%
2	$ 20,548	$ 53,648	0.27%
3	$ 10,784	$ 20,494	0.40%
4	$ 6,449	$ 10,708	0.37%
5	$ 4,237	$ 6,443	0.65%
6	$ 2,522	$ 4,232	0.88%
7	$ 1,472	$ 2,518	1.05%
8	$ 783	$ 1,472	0.77%
9	$ 351	$ 782	1.68%
10	$ 4	$ 351	4.37%
Proxy Group Median		$6,139.1	0.65%
7th Decile Size Premium		$1,889.9	1.05%
		Difference from Proxy Group Median	0.40%

Notes:
[1] Source: NW Natural's Oregon Earnings Review for the 12 Months Ended 12/31/2025, filed April 30, 2026 (Docket RG 40).
[2] Source: S&P Global Market Intelligence, 30-day average
[3] Source: S&P Global Market Intelligence, 30-day average
[4] Source: Kroll Cost of Capital Navigator, Size Premia Deciles as of August 31, 2026

NW Natural Oregon Jurisdictional Market Capitalization vs. Proxy Group Market Capitalization



BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 413

November 24, 2026

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO [1]

Proxy Group Company	Ticker	2025	2024	2023	Average
Atmos Energy Corp.	ATO	60.00%	60.26%	60.20%	60.15%
New Jersey Resources Corporation	NJR	55.86%	55.92%	55.15%	55.64%
NiSource Inc.	NI	55.83%	54.89%	55.44%	55.39%
ONE Gas, Inc.	OGS	59.76%	58.96%	60.41%	59.71%
Southwest Gas Holdings, Inc.	SWX	50.52%	48.13%	47.45%	48.70%
Spire, Inc.	SR	53.85%	52.99%	51.91%	52.92%
Ameren Corporation	AEE	53.52%	53.52%	53.94%	53.66%
Avista Corporation	AVA	50.29%	50.45%	50.24%	50.33%
CenterPoint Energy, Inc.	CNP	47.13%	47.72%	48.10%	47.65%
CMS Energy Corporation	CMS	49.14%	48.71%	49.10%	48.98%
Consolidated Edison, Inc.	ED	47.31%	45.95%	47.50%	46.92%
DTE Energy Company	DTE	49.79%	50.06%	50.11%	49.99%
Eversource Energy	ES	55.92%	56.81%	57.55%	56.76%
Public Service Enterprise Group Inc.	PEG	55.22%	55.03%	55.40%	55.21%
WEC Energy Group, Inc.	WEC	58.60%	56.95%	57.43%	57.66%
Xcel Energy Inc.	XEL	54.64%	54.24%	54.47%	54.45%
Gas Proxy Group					
MEAN		55.97%	55.19%	55.09%	55.42%
MEDIAN		55.85%	55.40%	55.30%	55.51%
LOW		50.52%	48.13%	47.45%	48.70%
HIGH		60.00%	60.26%	60.41%	60.15%
Combined Proxy Group					
MEAN		53.59%	53.16%	53.40%	53.38%
MEDIAN		54.24%	53.88%	54.20%	54.05%
LOW		47.13%	45.95%	47.45%	46.92%
HIGH		60.00%	60.26%	60.41%	60.15%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2025	2024	2023	Average
Atmos Energy Corporation	ATO	60.00%	60.26%	60.20%	60.15%
New Jersey Natural Gas Company	NJR	55.86%	55.92%	55.15%	55.64%
Columbia Gas of Kentucky, Incorporated	NI	53.65%	51.44%	53.66%	52.91%
Columbia Gas of Maryland, Incorporated	NI	55.10%	52.00%	52.00%	53.03%
Columbia Gas of Ohio, Inc.	NI	50.68%	50.27%	50.50%	50.48%
Columbia Gas of Pennsylvania, Inc.	NI	56.22%	56.07%	55.88%	56.06%
Columbia Gas of Virginia, Incorporated	NI	52.94%	44.58%	45.25%	47.59%
Northern Indiana Public Service Company, LLC	NI	58.48%	58.24%	59.26%	58.66%
Kansas Gas Service Company, Inc.	OGS	59.96%	59.53%	60.44%	59.98%
Oklahoma Natural Gas Company	OGS	59.66%	59.23%	60.46%	59.78%
Texas Gas Service Company, Inc.	OGS	59.73%	58.22%	60.35%	59.43%
Southwest Gas Corporation	SWX	50.52%	48.13%	47.45%	48.70%
Spire Alabama Inc.	SR	57.77%	55.84%	55.31%	56.31%
Spire Gulf Inc.	SR	50.44%	48.89%	46.42%	48.58%
Spire Missouri Inc.	SR	52.43%	51.95%	50.66%	51.68%
Ameren Illinois Company	AEE	55.24%	55.36%	56.21%	55.60%
Union Electric Company	AEE	52.03%	51.92%	51.87%	51.94%
Avista Corporation	AVA	49.95%	49.96%	49.74%	49.89%
Alaska Electric Light and Power Company	AVA	58.33%	63.01%	62.52%	61.29%
CenterPoint Energy Houston Electric, LLC	CNP	43.53%	44.52%	44.46%	44.17%
Indiana Gas Company, Inc.	CNP	55.59%	55.90%	57.51%	56.33%
Southern Indiana Gas and Electric Company	CNP	55.76%	55.93%	55.66%	55.79%
Vectren Energy Delivery of Ohio, Inc.	CNP	53.94%	53.91%	57.65%	55.16%
Consumers Energy Company	CMS	49.14%	48.71%	49.10%	48.98%
Consolidated Edison Company of New York, Inc.	ED	47.37%	45.86%	47.44%	46.89%
Orange and Rockland Utilities, Inc.	ED	46.30%	47.75%	48.57%	47.54%
DTE Electric Company	DTE	49.61%	49.79%	49.72%	49.71%
DTE Gas Company	DTE	50.49%	51.08%	51.67%	51.08%
Bay State Gas Company	ES	54.49%	55.11%	57.06%	55.55%
Connecticut Light and Power Company	ES	56.50%	56.06%	56.77%	56.44%
NSTAR Electric Company	ES	55.82%	57.43%	57.61%	56.95%
NSTAR Gas Company	ES	56.90%	59.77%	62.16%	59.61%
Public Service Company of New Hampshire	ES	55.00%	56.37%	56.16%	55.84%
Yankee Gas Services Company	ES			60.06%	60.06%
Public Service Electric and Gas Company	PEG	55.22%	55.03%	55.40%	55.21%
Michigan Gas Utilities Corporation	WEC	54.91%	66.28%	59.38%	60.19%
North Shore Gas Company	WEC	56.48%	56.93%	54.68%	56.03%
The Peoples Gas Light and Coke Company	WEC	50.73%	54.79%	50.27%	51.93%
Upper Michigan Energy Resources Corporation	WEC	48.64%	56.22%	53.92%	52.93%
Wisconsin Gas LLC	WEC	57.62%	59.95%	61.44%	59.67%
Wisconsin Electric Power Company	WEC	60.18%	58.32%	60.74%	59.75%
Wisconsin Public Service Corporation	WEC	63.12%	54.43%	56.45%	58.00%
Northern States Power Company - MN	XEL	53.72%	53.37%	52.58%	53.22%
Northern States Power Company - WI	XEL	52.86%	53.23%	52.77%	52.95%
Public Service Company of Colorado	XEL	55.80%	55.21%	56.47%	55.83%
Southwestern Public Service Company	XEL	54.23%	54.17%	54.41%	54.27%

Operating Company				
MEAN	54.29%	54.38%	54.64%	54.52%
MEDIAN	55.00%	55.11%	55.35%	55.58%
LOW	43.53%	44.52%	44.46%	44.17%
HIGH	63.12%	66.28%	62.52%	61.29%

Notes:
Sources: Operating Company Annual LDC Reports; S&P Capital IQ
[1] Ratios are weighted by actual common equity and total long-term debt of operating subsidiaries.
[2] Citizens Gas Fuel Company, Spire Mississippi and Rockland Electric were excluded because they do not report long-term debt.

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2025	2024	2023	Average
Atmos Energy Corp.	ATO	40.00%	39.74%	39.80%	39.85%
New Jersey Resources Corporation	NJR	44.14%	44.08%	44.85%	44.36%
NiSource Inc.	NI	44.17%	45.11%	44.56%	44.61%
ONE Gas, Inc.	OGS	40.24%	41.04%	39.59%	40.29%
Southwest Gas Holdings, Inc.	SWX	49.48%	51.87%	52.55%	51.30%
Spire, Inc.	SR	46.15%	47.01%	48.09%	47.08%
Ameren Corporation	AEE	46.48%	46.48%	46.06%	46.34%
Avista Corporation	AVA	49.71%	49.55%	49.76%	49.67%
CenterPoint Energy, Inc.	CNP	52.87%	52.28%	51.90%	52.35%
CMS Energy Corporation	CMS	50.86%	51.29%	50.90%	51.02%
Consolidated Edison, Inc.	ED	52.69%	54.05%	52.50%	53.08%
DTE Energy Company	DTE	50.21%	49.94%	49.89%	50.01%
Eversource Energy	ES	44.08%	43.19%	42.45%	43.24%
Public Service Enterprise Group Inc.	PEG	44.78%	44.97%	44.60%	44.79%
WEC Energy Group, Inc.	WEC	41.40%	43.05%	42.57%	42.34%
Xcel Energy Inc.	XEL	45.36%	45.76%	45.53%	45.55%
Gas Proxy Group					
MEAN		44.03%	44.81%	44.91%	44.58%
MEDIAN		44.15%	44.60%	44.70%	44.49%
LOW		40.00%	39.74%	39.59%	39.85%
HIGH		49.48%	51.87%	52.55%	51.30%
Combined Proxy Group					
MEAN		46.41%	46.84%	46.60%	46.62%
MEDIAN		45.76%	46.12%	45.80%	45.95%
LOW		40.00%	39.74%	39.59%	39.85%
HIGH		52.87%	54.05%	52.55%	53.08%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2025	2024	2023	Average
Atmos Energy Corporation	ATO	40.00%	39.74%	39.80%	39.85%
New Jersey Natural Gas Company	NJR	44.14%	44.08%	44.85%	44.36%
Columbia Gas of Kentucky, Incorporated	NI	46.35%	48.56%	46.34%	47.09%
Columbia Gas of Maryland, Incorporated	NI	44.90%	48.00%	48.00%	46.97%
Columbia Gas of Ohio, Inc.	NI	49.32%	49.73%	49.50%	49.52%
Columbia Gas of Pennsylvania, Inc.	NI	43.78%	43.93%	44.12%	43.94%
Columbia Gas of Virginia, Incorporated	NI	47.06%	55.42%	54.75%	52.41%
Northern Indiana Public Service Company, LLC	NI	41.52%	41.76%	40.74%	41.34%
Kansas Gas Service Company, Inc.	OGS	40.04%	40.47%	39.56%	40.02%
Oklahoma Natural Gas Company	OGS	40.34%	40.77%	39.54%	40.22%
Texas Gas Service Company, Inc.	OGS	40.27%	41.78%	39.65%	40.57%
Southwest Gas Corporation	SWX	49.48%	51.87%	52.55%	51.30%
Spire Alabama Inc.	SR	42.23%	44.16%	44.69%	43.69%
Spire Gulf Inc.	SR	49.56%	51.11%	53.58%	51.42%
Spire Missouri Inc.	SR	47.57%	48.05%	49.34%	48.32%
Ameren Illinois Company	AEE	44.76%	44.64%	43.79%	44.40%
Union Electric Company	AEE	47.97%	48.08%	48.13%	48.06%
Avista Corporation	AVA	50.05%	50.04%	50.26%	50.11%
Alaska Electric Light and Power Company	AVA	41.67%	36.99%	37.48%	38.71%
CenterPoint Energy Houston Electric, LLC	CNP	56.47%	55.48%	55.54%	55.83%
Indiana Gas Company, Inc.	CNP	44.41%	44.10%	42.49%	43.67%
Southern Indiana Gas and Electric Company	CNP	44.24%	44.07%	44.34%	44.21%
Vectren Energy Delivery of Ohio, Inc.	CNP	46.06%	46.09%	42.35%	44.84%
Consumers Energy Company	CMS	50.86%	51.29%	50.90%	51.02%
Consolidated Edison Company of New York, Inc.	ED	52.63%	54.14%	52.56%	53.11%
Orange and Rockland Utilities, Inc.	ED	53.70%	52.25%	51.43%	52.46%
DTE Electric Company	DTE	50.39%	50.21%	50.28%	50.29%
DTE Gas Company	DTE	49.51%	48.92%	48.33%	48.92%
Bay State Gas Company	ES	45.51%	44.89%	42.94%	44.45%
Connecticut Light and Power Company	ES	43.50%	43.94%	43.23%	43.56%
NSTAR Electric Company	ES	44.18%	42.57%	42.39%	43.05%
NSTAR Gas Company	ES	43.10%	40.23%	37.84%	40.39%
Public Service Company of New Hampshire	ES	45.00%	43.63%	43.84%	44.16%
Yankee Gas Services Company	ES			39.94%	39.94%
Public Service Electric and Gas Company	PEG	44.78%	44.97%	44.60%	44.79%
Michigan Gas Utilities Corporation	WEC	45.09%	33.72%	40.62%	39.81%
North Shore Gas Company	WEC	43.52%	43.07%	45.32%	43.97%
The Peoples Gas Light and Coke Company	WEC	49.27%	45.21%	49.73%	48.07%
Upper Michigan Energy Resources Corporation	WEC	51.36%	43.78%	46.08%	47.07%
Wisconsin Gas LLC	WEC	42.38%	40.05%	38.56%	40.33%
Wisconsin Electric Power Company	WEC	39.82%	41.68%	39.26%	40.25%
Wisconsin Public Service Corporation	WEC	36.88%	45.57%	43.55%	42.00%
Northern States Power Company - MN	XEL	46.28%	46.63%	47.42%	46.78%
Northern States Power Company - WI	XEL	47.14%	46.77%	47.23%	47.05%
Public Service Company of Colorado	XEL	44.20%	44.79%	43.53%	44.17%
Southwestern Public Service Company	XEL	45.77%	45.83%	45.59%	45.73%

Operating Company				
MEAN	45.71%	45.62%	45.36%	45.48%
MEDIAN	45.00%	44.89%	44.65%	44.42%
LOW	36.88%	33.72%	37.48%	38.71%
HIGH	56.47%	55.48%	55.54%	55.83%

Notes:
Sources: Operating Company Annual LDC Reports; S&P Capital IQ
[1] Ratios are weighted by actual common equity and total long-term debt of operating subsidiaries.
[2] Citizens Gas Fuel Company, Spire Mississippi and Rockland Electric were excluded because they do not report long-term debt.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Jennifer E. Nelson

RETURN ON EQUITY
EXHIBIT 414

November 24, 2026

Gas 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-25AL-0499G	CO	5/21/2026	54.00%	
	Kansas Division	D-26-ATMG-026-RTS	KS	2/26/2026	NA	
	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-2024-00276	KY	8/11/2025	53.50%	
	Louisiana Division	C-2024-00277	LA	7/21/2025	58.00%	[1]
	Mississippi Division	C-2024-00278	MS	11/4/2025	50.00%	
	Tennessee Division	D-26-00009	TN	7/22/2026	58.00%	
	West Texas Division	OS-24-00018879 [2]	TX RRC	5/13/2025	60.97%	
	Mid-Tex (Environs)	OS-24-00019196	TX RRC	6/17/2025	60.97%	
	Mid-Tex (Cities)	[2]	TX RRC	10/1/2023	58.00%	
	Mid-Tex (Dallas)	[2]	TX RRC	6/1/2024	60.00%	
	Mid-Tex (ATM Cities)	[2]	TX RRC	6/17/2025	61.00%	
	Virginia Division	PUR-2023-00008	VA	5/13/2024	60.59%	
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-2025-3053499	PA	12/4/2025	54.40%	
	Columbia Gas of Virginia, Incorporated	C-PUR-2024-00030	VA	5/15/2025	43.17%	[3]
	Northern Indiana Public Service Company	Ca-45967	IN	7/31/2024	58.51%	[4]
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-PUD2025-000011	OK	7/23/2025	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.	D-OS-25-00028202	TX RRC	2/5/2026	59.92%	
SR	Spire Inc.					[5]
	Spire Alabama Inc.	D-18328	AL	9/30/2022	55.50%	
	Spire Missouri Inc.	C-GR-2025-0107	MO	9/3/2025	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 Holdings Inc.					
	Arizona Division	D-G-01551A-23-0341	AZ	3/27/2025	48.50%	
	California Division (SoCal)	A-24-09-001 (SoCal)	CA	8/13/2026	50.00%	
	California Division (NoCal)	A-24-09-001 (NoCal)	CA	8/13/2026	50.00%	
	California Division (LkTah)	A-24-09-001 (LkTah)	CA	8/13/2026	50.00%	
	Nevada Division (Northern)	D-23-09012 (Northern)	NV	4/8/2024	50.00%	
	Nevada Division (Southern)	D-23-09012 (Southern)	NV	4/8/2024	50.00%	
	Average				54.34%	
	Median				54.00%	
	High				61.00%	
	Low				43.17%	
	Count≥50.00%				28	
	Total Count				31	
	Percentage ≥50.00%				90%	

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] Atmos' Louisiana jurisdiction is authorized through rate stabilization clause (RSC) proceedings, not a general rate case

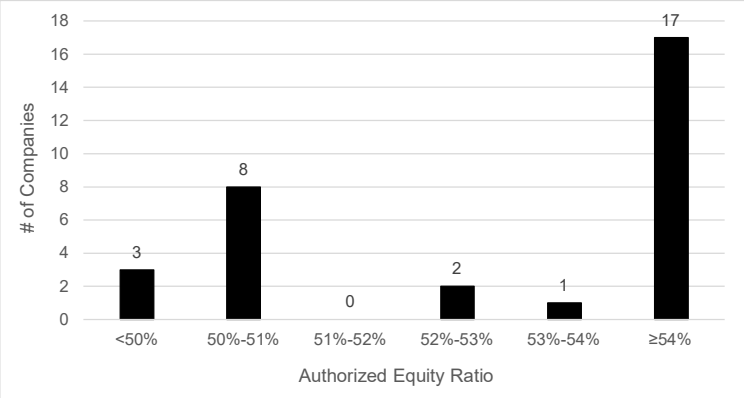
[2] Gas utilities regulated by the Texas Rail Road Commission (RRC) have a general rate case only if they are unable to reach a settlement with the cities and unincorporated areas ("environs") within their service territories. Current authorized equity ratio for Atmos Texas' territories is published in ATO's December 2025 Investor Presentation and 2024 10-K.

[3] 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.

[4] 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%.

[5] Source: Spire, Inc. 2025 Investor Presentation and 2024 10-K; authorized equity ratios in Spire's AL and MS jurisdictions are authorized through rate stabilization proceedings, not general rate cases.

Equity Ratio	Count
<50%	3
50%-51%	8
51%-52%	0
52%-53%	2
53%-54%	1
≥54%	17



BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Direct Testimony of Jorge O. Moncayo

CAPITAL EXPENDITURES: BUDGETING/FORECASTING, MANAGEMENT APPROVAL AND PROJECT LIFECYCLES EXHIBIT 500

November 24, 2026

EXHIBIT 500 – DIRECT TESTIMONY – CAPITAL EXPENDITURES: BUDGETING/FORECASTING, MANAGEMENT APPROVAL AND PROJECT LIFECYCLES

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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 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. Nothing in my testimony impacts the revenue requirement the Company is requesting in this case.

Q. Have you prepared any exhibits to accompany your testimony?

A. Yes. The following exhibits accompany my testimony:

- NW Natural/501, Moncayo – General Procedure No. G-67 (Project Management Processes)
- Confidential NW Natural/502, Moncayo – Project Management Handbook

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 towards the end of each calendar year.

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, Tools & 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 benefits, financial impacts, 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. If overall capital expenditures are expected to exceed the amount approved by the Board, management must seek additional authorization from the Board.

Q. Please describe the categorization of capital investments.

A. The Company's capital expenditures can be thought of as falling into one of two categories. The first category consists of "discrete investments" that the Company has proposed to fulfill a specific operational aim, address a specific system issue, comply with a particular regulatory requirement or maintain safety and reliability. These discrete projects tend to fall into subcategories of system betterments (*e.g.* investments in Newport Liquefied Natural Gas ("LNG") and Mist Storage Facilities

or gate stations), system reinforcement projects, IT&S, and land and structures. These discrete projects tend to represent lumpy investments, and costs associated with these projects can vary year-over-year.

The second category can be thought of as "non-discrete capital expenditures," in which investments are made consistently year-over-year, and over which the Company generally does not exercise much discretion. The consistency of expenditures in this category forms the basis of a predictable, recurring level of investment. These investments, which are described below, include public works, relocates, damages, transportation and equipment, tools, technical refresh, leakage, customer growth, Transmission Integrity Management Program ("TIMP"), and Distribution Integrity Management Program ("DIMP"). A portion of the Company's IT&S investment falls under this category as well and is very consistent year-over-year, following a clear trend line and, therefore, is very predictable.

It is important to point out that for all capital expenditures, but especially for discrete capital expenditures, NW Natural's forecast accuracy improves as the time horizon shortens. Forecast projections for discrete capital expenditures further out in time necessarily rely on higher-level planning assumptions. As the planning cycle advances each year, previously longer-term discrete 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 discrete 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. I discuss discrete and non-discrete capital in further detail later in my testimony.

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. 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.

Non-discrete 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 non-discrete 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 identified 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 non-discrete capital expenditures include work such as damages, public works, leakage, district regulators, and relocates. These capital expenditures are based on historical spending trends adjusted for inflation. Each is 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.
- ***Public Works*** – These are projects that are required by the governmental jurisdictions in which the Company operates. These may include moving, replacing, or adding infrastructure. Typically, at the time budgets are prepared for these projects, the Company has no project-specific information about what will be required in the upcoming year, and therefore it budgets based on historical trends.
- ***Leakage*** – Leakage costs represent replacements of services and mains to address leaks on the Company's system. Like damages and public works projects, the specific 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 equipment at end of life,

equipment manufacturer obsolescence, 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.

Non-discrete capital expenditures also 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's) TIMP and DIMP.

The Direct Testimony of Daniel B. Kizer and Michael C. Hwang (NW Natural/600, Kizer-Hwang) 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. Within these categories, there are both discrete and non-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.
- ***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 Direct Testimony of Brian E. Fellon (NW Natural/800, Fellon) 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 the Facilities department for consideration. Forecasts for each project are

updated quarterly. Typically, Facilities projects are discrete. The Direct Testimony of Wayne K. Pipes (NW Natural/700, Pipes) introduces and describes the discrete facilities projects, as well as the non-discrete 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 non-discrete. 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 no 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 Meter Shop business units.

A. Vehicle, equipment, and trailer replacements are non-discrete and are routinely replaced over time.

Tool replacement is non-discrete and tools are consistently being replaced over time. 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 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 non-discrete projects. 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 Brian E. Fellon (NW Natural/800, Fellon) describes the Company's Temetra Implementation Project, which is part of its multi-year Meter Modernization Program.

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 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 NW Natural/501, Moncayo. 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. NW Natural/501, Moncayo is the current version of the Procedure, issued in January 2026. Additionally, the Company maintains a Project Management Handbook that provides the detailed step-by-step process for a project, the current version of which, dated May 15, 2026, is provided as Confidential NW Natural/502, Moncayo.

Q. What is the purpose of the Procedure?

A. As stated in NW Natural/501, Moncayo, 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 (e.g., scope, budget variance and schedule).

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 NW Natural/501, Moncayo and Confidential NW Natural/502, Moncayo) is initially determined by its estimated total cost (i.e., prior to any jurisdictional allocation), and 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 submit it to the PMC. 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[1]), 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 several leaders of the Company. Cost estimates developed at the Assess phase, such as in a FEED study, include some variability on the order of approximately -25% to +50%.

[1] 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.[2] 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

[2] 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).

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.

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. Under the PMO Procedure, a program could be a collection of discrete capital investments or short-lived IT&S investments. But a PMO program could also consist of a collection of thousands of small projects (*e.g.*, meter and encoder receiver transmitters replacements) that have a high impact to the Company and its customers, and therefore, it is appropriate to classify the many capital investments into an overarching program that is project-managed through the PMO.

Q. What are the forecasted capital expenditures for the next three calendar years and the Test Year?

A. Utility capital expenditures planned for calendar year 2026 is $367 million, for 2027 is $352 million, and for 2028 is $360.0 million. The capital expenditures forecasted during the Test Year is $351.1 million.

Q. Please explain the capital projects for which the Company seeks recovery in this case.

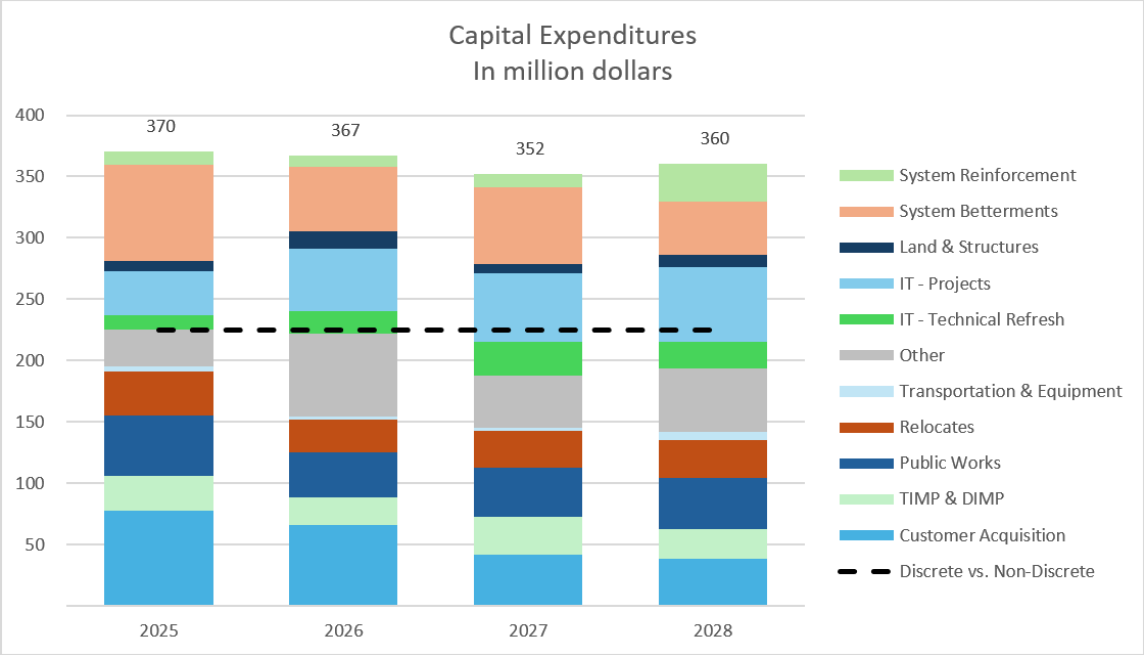
A. The Company seeks to add to rate base its investment in the following categories of capital projects:

1. All capital expenditures that have been completed since the Company's last rate case (UG 520) that were not reflected in rates through its Alternative Rate Mechanism (ARM) filing (UG 527), that will be used and useful as of October 31, 2027. These include both the Company's discrete and non-discrete investments. For these capital expenditures, the Company seeks to recover the total investment, less depreciation incurred since the date the investment was completed.
2. All capital expenditures, both discrete and non-discrete, that will be completed during the Test Year. These projects may be completed at various times during that year. The Company used an average through the Test Year so that customers' rates will reflect those investments only to the extent that they are used and useful in providing utility service within the Test Year.

Q. Have you prepared an illustration of the Company's discrete and non-discrete capital investment in recent years?

A. Yes. Figure 1 below shows year-over-year system capital expenditures, in both discrete and non-discrete capital, and I have added a trend line that shows the spend on non-discrete capital projects over time. Overall, the spending related to NW Natural's non-discrete investment is expected to remain consistent over time.

Figure 1



Q. Does the Company describe the primary drivers behind NW Natural's discrete planned capital expenditures?

A. Yes, these drivers are discussed in the Direct Testimonies of Daniel B. Kizer and Michael C. Hwang (NW Natural/600, Kizer-Hwang), Wayne K. Pipes (NW Natural/700, Pipes), and Brian E. Fellon (NW Natural/800, Fellon).

Q. In forecasting expenditures in non-discrete categories for the Test Year, did the Company rely solely on historical trends?

A. No. To forecast certain non-discrete investments for the Test Year, the Company also relied on plans prepared in the regular course of business by managers in charge of each category.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibits of Jorge O. Moncayo

CAPITAL EXPENDITURES: BUDGETING/FORECASTING, MANAGEMENT APPROVAL AND PROJECT LIFECYCLES EXHIBITS 501 – 502

November 24, 2026

EXHIBITS 501-502 – CAPITAL EXPENDITURES: BUDGETING/FORECASTING, MANAGEMENT APPROVAL AND PROJECT LIFECYCLES

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Jorge O. Moncayo

CAPITAL EXPENDITURES: BUDGETING/FORECASTING, MANAGEMENT APPROVAL AND PROJECT LIFECYCLES EXHIBIT 501

November 24, 2026

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.

	Phases	Gates	Gate + Change Order Approvals	Sponsorship Requirements	PMC Intake Approval
Tier 5: $10M+ or Major Risk / Impact / Complexity	Initiate Assess Plan Execute Close	Intake 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 Assess Plan Execute Close	Intake 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	Assess Plan Execute Close	Intake *(serves as 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 and Low Risk / Impact / Complexity	Plan Execute Close	Intake *(serves as 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	Plan Execute Close	Initiate *(serves as move to plan)* Move to execute Close	Portfolio Manager Sponsor	Sr. Director or above	PMC visibility; executive sponsor approval
Tier 0: <$100K and Very Low Risk / Impact / Complexity	Execute	None	None required; initial PPM gate if using for funding	Director	

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 (PMC review, moves a project to its first phase)**
    - **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 for initiate to support pre-assessment resource gathering.
        - For Tier 3: Funds assess as the first project phase
        - For Tiers 1 and 2: Funds plan as the first project phase.
    - **Required for:** Tiers 2, 3, 4 and 5 through the PMC, Tiers 0 and 1 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 3, 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.

GENERAL PROCEDURE

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.

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.

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

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Jorge O. Moncayo

CAPITAL EXPENDITURES: BUDGETING/FORECASTING, MANAGEMENT APPROVAL AND PROJECT LIFECYCLES EXHIBIT 502

REDACTED

Under General Protective Order No. 23-132, this exhibit is confidential in its entirety and has been redacted.

November 24, 2026

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Direct Testimony of Daniel B. Kizer and Michael C. Hwang

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS EXHIBIT 600

November 24, 2026

EXHIBIT 600 – DIRECT TESTIMONY – DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

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I. INTRODUCTION AND SUMMARY

Q. Please state your names, positions with Northwest Natural Gas Company dba NW Natural ("NW Natural" or "the Company") and summarize your educational background and business experience.

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. 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. I graduated from Oregon State University with a Bachelor of Science in Civil Engineering, and I am a registered Professional Engineer in the State of Oregon.

My name is Michael C. Hwang. I am the Gas Storage Facilities Development Director at NW Natural. In this position, I am responsible for the maintenance strategy and infrastructure investments at the Mist Storage Facility and Pipeline Compression Facilities that support Mist Storage Facility operations to ensure reliable operations and full regulatory compliance. I also direct the Company's underground storage facilities development including the design and permitting of above-ground assets at the Mist Storage Facility. Before being

promoted to my current position at NW Natural in November 2026, I was an Engineering Manager of the Company's Gas Storage and Compressor Stations since January 2025. Before joining NW Natural, I worked at Precision Castparts Corp. from 2013 to 2020, with my last role at that company being Facilities and Engineering Manager. I graduated from Washington State University in Mechanical Engineering, and I am a registered Professional Engineer in the State of Oregon.

Q. Which portions of this Direct Testimony are each of you sponsoring?

A. Mr. Hwang is sponsoring the portions of this Direct Testimony related to the Mist Storage Facility and its supporting Compression Facilities, and their significant projects, and Mr. Kizer is 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 significant distribution system projects and storage facility projects serving Oregon customers that are included in this rate case. Mr. Kizer also discusses the Company's In-Line Inspection ("ILI") Conversion Projects as part of its ongoing plans for safety-driven system projects and programs.[1]

[1] For a description of the Company's capital expenditures budgeting and forecasting processes, including management approval and project/program lifecycle phases, please see the Direct Testimony of Jorge O. Moncayo, NW Natural/500, Moncayo.

Q. Please summarize your testimony.

A. NW Natural continues to make system investments to ensure safe and reliable operations. Specifically, the Company is performing necessary projects throughout its Oregon distribution system, including the Mile 98 Relocation Project to address landslide risk on the Coos County Pipeline, uprating the Forest Grove Feeder that is operating beyond its design capacity, relocating facilities to accommodate public works projects, upgrading metering, and rebuilding outdated gate stations. The Company is also undertaking several important projects at its storage facilities, which support NW Natural's gas supply portfolio to enable reliable and affordable gas service, including during peak winter events or other times when supply is constrained. Storage projects include replacing a key component of the Newport liquefied natural gas ("LNG") storage facility that is nearly 50 years old, installing an emergency generator at the Newport LNG storage facility, updating the end-of-life power feed to the Mist Storage Facility, and replacing or updating several other Mist components that are critical to the continued safe and effective operation of the facility. Finally, NW Natural is completing several safety-related projects to allow for effective pipeline inspections.

II. SIGNIFICANT DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS

Q. Did the Company previously seek cost recovery in the Company's 2025 alternative rate mechanism ("ARM") filing (docket UG 527) for any significant distribution system and storage facility project that will be completed during this general rate case?

A. Yes. In its ARM filing, the Company sought cost recovery for the Mist Main Power Feed Replacement Project and the Mile 98 Relocation Project, and they are expected to be completed during this general rate case.

The Company removed the Mist Main Power Feed Replacement Project from the ARM case in its Reply Testimony, as third-party work on the project delayed its expected completion (UG 527, NW Natural/400, Kizer-Karney-Pipes/6). I will provide an update on the Mist Main Power Feed Project in the next section of my Direct Testimony, in connection with the significant storage facility projects in this case.

The second identified project is the Mile 98 Relocation Project. In Order No. 26-387, entered in docket UG 527 on October 13, 2026,[2] the Commission approved the Partial Multi-Party Stipulation Regarding All Issues Except for Rate Spread of Two Coos County Pipeline Projects (the "Stipulation") among NW Natural, Staff of the Public Utility Commission of Oregon ("Staff"), and the Alliance

[2] *In the Matters of Northwest Natural Gas Company, dba NW Natural, Application for an Alternative Rate Mechanism, New Schedule 123 (Docket No. UG 527); and Advice No. 25-23 (ADV 1798), Schedule 160, Cancellation of Charges for Coos County Pipeline (Docket No. UG 528),* Order No. 26-387 (Oct. 13, 2026) ("Order No. 26-387").

of Western Energy Consumers ("AWEC") (collectively, the "Stipulating Parties"). Stipulation Section III.1.b states that the Stipulating Parties agree that the Mile 98 Relocation Project is deemed prudent and was reflected in the revenue requirement in that case. In compliance with Stipulation Section III.1.g, the Company filed an officer-level attestation on October 2, 2026, by which the Company attested that the Mile 98 Relocation Project would not be placed in service by October 31, 2026 and, therefore, the Company removed the Mile 98 Relocation Project from the final revenue requirement. The Company expects to complete the Mile 98 Relocation Project in the first half of 2027, and has included this project in the revenue requirement in this case. I will provide an update on the Mile 98 Relocation Project in the next section of my Direct Testimony, in connection with the significant distribution system projects in this case. The other Coos County Pipeline project in docket UG 527, specifically the Coquille River Project, was completed and put in service in October 2026 and, therefore, already was included in rates made effective on October 31, 2026.

Q. With respect to the Coos County Pipeline, has the Company included operating expenses associated with it in this general rate case?

A. Yes. As noted in NW Natural/1100, Davilla, the Company has included $403 thousand in its Test Year operations and maintenance ("O&M") expense in this case.

Q. Please describe the nature of the Coos County O&M expenses included in the Test Year in this case.

A. The Coos County O&M expenses included in the Test Year in this case address activities related to utility locating, leakage surveying, corrosion control surveys, pipeline right-of-way patrols, pipeline station blowdown and bridle assembly maintenance inspections and painting, system operations maintenance inspections at gate stations and regulator stations, and rainfall monitoring and post-storm landslide monitoring.

Q. Please identify the significant distribution system and storage facility projects that are included for recovery in this case.

A. The Company is requesting recovery for the following significant distribution system projects:

- Mile 98 Relocation Project;
- Forest Grove Feeder Uprate Project;
- Lincoln City Grading S. Drift Creek Road Relocate Project ("Lincoln City Public Works Project");
- Central Coast Blowdown No. 6 Rebuild Project ("Central Coast Project");
- Deer Island Gate Station Rebuild Project;
- Sauvie Island Gate Station Metering Project;
- Molalla Gate Station Metering Project;
- Albany Gate Station Metering Project;
- McMinnville-Amity Gate Station Rebuild Project; and

- NE Gate Station Inlet Piping/Rebuild Project.

The Company is requesting recovery for the significant storage facility projects listed below. Those projects 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.

- Newport LNG Cold Box Replacement Project;
- Newport LNG Plant Supply Generator Project;
- Mist Main Power Feed Replacement Project;
- Mist Reservoir Ultrasonic Flowmeters Replacement Project;
- Mist Miller North Pool Controls Upgrade Project;
- Mist Well Separator Replacement 2027 Project; and
- Mist Miller Air Compressor and Receiver Tank Project.

A. Significant Distribution System Projects

1. Mile 98 Relocation Project

Q. Please describe the Mile 98 Relocation Project that the Company included in its ARM filing in docket UG 527.

A. The Mile 98 slide area has been identified as the highest risk location on the Coos County Pipeline. This segment of 12-inch transmission pipeline traverses down a sloping hillside within a Bonneville Power Administration ("BPA") right-of-way. A geotechnical analysis showed that the pipe is currently located at a depth where land movement is causing strain on the pipe. In March 2025, heavy rains in

southwest Oregon caused widespread damage due to flooding, landslides, mudslides, sinkholes, and rockfalls resulting in a Level 3 regional emergency response activation from the Oregon Department of Emergency Management. Those heavy rains resulted in a higher risk of failure for the Mile 98 slide area. To resolve this issue, the Mile 98 Relocation Project is installing approximately 2,200 feet of 12-inch transmission pipe via horizontal directional drilling ("HDD") technology at a deeper location where stable soils are located.

Q. Did the Commission address the Coos County Pipeline projects, including the Mile 98 Relocation Project, in Order No. 26-387?

A. Yes. As discussed above, in docket UG 527, the Commission determined that the Coos County Pipeline projects, including the Mile 98 Relocation Project, are prudent.[3]

Q. What is the current status of the Mile 98 Relocation Project?

A. NW Natural has obtained the necessary permits, but still is procuring one easement from a landowner before it can begin construction work on the Mile 98 Relocation Project. Now that the Pacific Northwest has entered its rainy season, the Company is being very mindful that winter wet weather can create constructability challenges, particularly towards the west end of the project near the Coquille River. High groundwater and poor weather can also create safety concerns for workers on this project. Once NW Natural procures the final easement, it will mobilize a vendor to construct gravel working pads at each end

[3] Docket No. UG 527, Order No. 26-387 at 8-9 (Oct. 13, 2026).

of the project for crew work during the wet winter months. Currently, the Company expects to begin construction in the second quarter of 2027 and complete the Mile 98 Relocation Project in the summer of 2027.

Q. What is the estimated total cost of the Mile 98 Relocation Project?

A. The total pre-design stage estimate to complete the Mile 98 Relocation Project that is included in the revenue requirement in this case is approximately $4.2 million. However, a recent Company design stage estimate has increased the project's estimated cost to approximately $5.6 million. The increase to $5.6 million from the $4.0 million amount identified in docket UG 527 is attributable to increased labor and equipment costs required to safely assemble and install the new pipeline under the landslide area, connecting to the existing 12-inch transmission pipeline at a deeper depth near the Coquille River, and including the design and construction of a crane hoisting system to lift the new pipe over the Coquille River when the pipe is pulled back through the HDD hole. The increased costs also include augmented restoration of the existing slide area including removal of sections of the existing pipeline to better manage rainwater and mitigate further erosion of the slide area.

2. Forest Grove Feeder Uprate Project

Q. Please describe the Forest Grove Feeder.

A. The Forest Grove Feeder (also known as the McKay Creek Feeder) is the primary supply pipeline for the western portion of the Portland metropolitan area. Customers in the communities of Hillsboro, Cornelius, Forest Grove, North Plains,

and Banks are supplied by this pipeline. The Forest Grove Feeder is fed from the 720 maximum allowable operating pressure ("MAOP") Rock Creek Feeder and South Mist Feeder and historically has operated at 175 MAOP. Most of this pipeline was constructed in 1989, and other sections were installed in 1994. The segment that serves Banks was installed in 1997.

Q. Please describe the Forest Grove Feeder Uprate Project.

A. Through the Forest Grove Feeder Uprate Project, the Company will uprate approximately 5.5 miles of high-pressure main from 175 MAOP to 375 MAOP; install four new district regulators and approximately 10,300 feet of two-inch polyethylene (PE) pipe; replace or rebuild three district regulators; replace one telemetry site; and abandon four district regulators and seven service regulators.

Q. Why is the Forest Grove Feeder Uprate Project necessary?

A. Significant demand growth has occurred in this area and modeling results indicate that this pipeline is operating beyond its design capacity during extreme conditions. System modeling using the Company's Customer Management Module ("CMM"), verified by field readings showing violation of system planning criteria, demonstrated that the Forest Grove Feeder Uprate Project is necessary to maintain safe and reliable service for existing customers during cold weather.

Q. Did the Company present the Forest Grove Feeder Uprate Project through the Commission's Integrated Resource Plan ("IRP") process?

A. Yes. The Company presented the Forest Grove Feeder Uprate Project for acknowledgement in its 2022 IRP filed in docket LC 79 on September 23 and October 21, 2022.

Q. Did Staff recommend acknowledgment of the Forest Grove Feeder Uprate Project in LC 79?

A. Yes. As stated on page 5 of the Commission's Order No. 23-281, entered in LC 79 on August 2, 2023, Staff recommended acknowledgment of the Forest Grove Feeder Uprate Project "based on an extensive technical analysis that concluded that reliable service to area customers could not be maintained through other mechanisms currently available to NW Natural."

Q. Did the Commission acknowledge the Forest Grove Feeder Uprate Project in docket LC 79?

A. Yes. The Commission "acknowledge[d] the Forest Grove feeder uprate" as "needed" on page 15 of Order No. 23-281. It did so expressly in combination with the following "firm expectations for NW Natural's updated distribution system plan and programming."[4]

> By the time of its next IRP Update filing, we expect NW Natural to file its initial distribution system plan, which should include alternatives analysis at least five years ahead for areas in which investments may be needed. In addition, by the time NW Natural's next IRP is filed, we expect the

[4] *In the Matter of Northwest Natural Gas Company, dba NW Natural, 2022 Integrated Resource Plan*, Docket No. LC 79, Order No. 23-281 at 15 (Aug. 2, 2023).

> company either to have its GEOTEE program ready to implement or have an RFP [(request for proposals)] ready to issue to the market for feeder-based load reduction. The company should work with Staff on both fronts to maximize alignment between NW Natural's efforts and our expectations. The company also should be prepared to respond in the future rate case to any new information about how it could or should have managed load in the Forest Grove area, as well as to CUB's cost recovery arguments discussed above.[5]

I will address how the Company is meeting these Commission's expectations next in my testimony, relative to the Commission's acknowledgement of the Forest Grove Feeder Uprate Project.

Q. As to the Commission's first expectation relative to its acknowledgement of the Forest Grove Feeder Uprate Project in Order No. 23-281, did the Company file its initial distribution system plan by the time of its next IRP Update filing?

A. Yes. The Company provided its initial Distribution System Forward Looking Plan as Appendix C of its 2022 IRP Update filed in docket LC 79 on August 2, 2024.

Q. In connection with that initial distribution system plan, please comment on whether the Company included alternatives analyses at least five years ahead for areas in which investments may be needed.

A. The Company explained why it did not include such alternative analyses in its 2022 IRP Update No. 2 filed in docket LC 79 on August 21, 2024. As an important preface, the Company "assure[d] the OPUC that it understands the expectations

[5] Docket No. LC 79, Order No. 23-281 at 15-16 (Aug. 2, 2023). As additional context, Commission-adopted Recommendation 18 reads as follows: "By the next IRP filing, if NW Natural's geographical load reduction programs are not available to alleviate forward-looking distribution system constraints, then a peak load reduction RFP should be issued to third parties." Order No. 23-281, Appendix B at 1.

and sense of urgency that the OPUC has expressed for the Company to manage load growth and avoid making unnecessary gas infrastructure investments."[6] The Company also emphasized that "[t]o comply with this expectation," it "updated its system modeling capabilities to more accurately identify the current state of the distribution system on a more granular basis as well as forecast the future constraints where load growth might be expected to occur over the next five years" and it "is conducting additional modeling to estimate how quickly that load growth may occur in those areas."[7] NW Natural then described its ongoing efforts for complying with the Commission's expectation that the Company provide alternatives analyses at least five years ahead for areas in which investments may be needed. Specifically,

> NW Natural is in the process of expanding its suite of non-pipeline alternative (NPA) solutions such as GeoTEE [Geographically Targeted Energy Efficiency] and Targeted Demand Response [(GeoDR)], as well as a system-wide demand response program. As noted in the Company's presentation, using updated, more sophisticated modeling, NW Natural's IRP Update identified several areas on the system that have the potential for early NPA solutions. 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 analysis concurrently and expects them to be available for alternatives planning purposes in the next IRP.[8]

[6] *In the Matter of Northwest Natural Gas Company, dba NW Natural, 2022 Integrated Resource Plan*, Docket No. LC 79, NW Natural's 2022 Integrated Resource Plan Update No. 2 at 2 (Aug. 21, 2024).

[7] *Id.*

[8] *Id.* at 3.

Q. Has the Company made those efforts and analyses available for alternatives planning purposes in its 2025 IRP?

A. Yes. The Company filed its 2025 IRP in docket LC 86 on August 1, 2025.[9] Section 12.6.2 of the 2025 IRP provides a summary of the various NPAs that the Company is considering, including GeoTEE and GeoDR, and Chapter 6 of the 2025 IRP describes the Company's system-wide residential and small commercial customer demand response program that the Company launched after the 2022 IRP, called the Bring Your Own Thermostat (BYOT) Program. Section 12.7 of the 2025 IRP addresses the Company's Forward Looking Distribution System Plan (provided in Appendix J of the 2025 IRP), which is intended to proactively identify areas on the Company's distribution network that may require a solution five years or more into the future, either through traditional pipeline solutions or NPAs, to continue to provide reliable service to firm customers.

Q. As to the Commission's second expectation relative to its acknowledgement of the Forest Grove Feeder Uprate Project in Order No. 23-281, please comment on the status of the Company's GeoTEE program or an RFP for feeder-based load reduction.

A. Chapter 12 of the Company's 2025 IRP evaluates GeoTEE (and GeoDR) in the three areas identified in the Forward Looking Distribution System Plan that I just referenced. As to an RFP for feeder-based load reduction, the last two pages of

[9] *In the Matter of Northwest Natural Gas Company, dba NW Natural, 2025 Integrated Resource Plan*, Docket No. LC 86 (Aug. 1, 2025) ("2025 IRP").

Appendix J of the Company's 2025 IRP is a memorandum from Energy Trust of Oregon ("ETO") to NW Natural, dated July 8, 2025, in which ETO specifically "does not recommend NW Natural create an RFP for a third-party to pursue a GeoTEE project for any of these three areas."[10]

Q. Does the Forest Grove Feeder Uprate Project continue to be necessary?

A. Yes. The Company completed an analysis using its Customer Management Module ("CMM")[11] in May 2026, which determined that the Forest Grove Feeder Uprate Project continues to be necessary because the system continues to operate above design capacity.

Q. Does the Forest Grove Feeder Uprate Project continue to be the least-cost, least-risk alternative for continuing to serve current customers safely and reliably?

A. Yes. Simply stated, there have been no material changes in the facts, circumstances, and assumptions that supported IRP acknowledgement of the Forest Grove Feeder Uprate Project, and the Company's execution of the Forest

[10] Page 2 of the ETO Memorandum states, in part: "Since Energy Trust and NW Natural plan to collaborate on developing GeoTEE projects in the McMinnville and Dallas areas, it is not necessary, nor is it recommended by Energy Trust, for NW Natural to create an RFP for a third-party to pursue GeoTEE projects in these two areas. Based on the results of Energy Trust's analysis of remaining energy efficiency potential in the Creswell area compared to the timing and magnitude of the system need, Energy Trust also does not recommend that NW Natural conduct a competitive RFP process for a third-party to pursue a GeoTEE project in the Creswell area, even though Energy Trust will not be pursuing a GeoTEE project in this area. The small amount of peak hour therm savings would require significant additional ratepayer expense to acquire, particularly for an entity new to the area where Energy Trust is already actively marketing and conducting outreach for energy efficiency products and services."

[11] For detailed information about the Company's CMM, please see *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 520, Direct Testimony of Daniel B. Kizer and Scott S. Johnson, NW Natural/500, Kizer-Johnson/4-6 (Dec. 30, 2024).

Grove Feeder Uprate Project has remained prudent and reasonable. Further, the Company has met the Commission's expectations relative to its acknowledgement of the Forest Grove Feeder Uprate Project as discussed above.

Q. What is the current status of Forest Grove Feeder Uprate Project?

A. The Forest Grove Feeder Uprate Project is expected to be completed by October 2027. The design work is substantially complete, and permitting activities have commenced. The Company expects construction to commence in early 2027.

Q. What is the estimated cost to complete the Forest Grove Feeder Uprate Project?

A. The total cost to complete the Forest Grove Feeder Uprate Project is expected to be approximately $3.6 million.

3. Lincoln City Public Works Project

Q. Please describe the Lincoln City Public Works Project.

A. Lincoln County Public Works is raising the grade of the S. Drift Creek Road roadway surface by approximately 5 feet to mitigate the effects of annual roadway flooding at the S. Anderson Creek Road intersection in Lincoln City, Oregon. The County's project includes installing sheet piles along each side of the roadway to avoid a fill slope into adjacent wetlands, installing a short bridge section, and re-aligning and channelizing one of the Anderson Creek tributaries that flows into Drift Creek.

NW Natural's 12-inch Central Coast Feeder transmission main, its bridle valves, blowdown equipment, and a 2-inch high-pressure inlet pipe to the district

regulator conflict with the County's planned improvements and must be relocated in accordance with NW Natural's County permit. Due to constructability and permitting challenges, the Company is performing this relocation work in two phases. The first phase, which the Company completed in October 2026, was the relocation of the S. Drift Creek Road bridle valves and blowdown equipment to a new location approximately 0.7 miles north of the County's project. The relocated site ensures that the Company is able to access its facilities at all times for emergency operations, as required by federal code. The second phase is the relocation of the 12-inch Central Coast Feeder transmission main and the 2-inch high-pressure inlet pipe, which requires a longer lead-time for environmental permitting.

Q. What is the current status of the second phase of the Lincoln City Public Works Project?

A. The second phase of the Lincoln City Public Works Project is currently in the Planning phase[12] and the Company expects to complete it by October 2027.

Q. What is the estimated total cost of the second phase of the Lincoln City Public Works Project?

A. The total cost of the second phase of the Lincoln City Public Works Project is expected to be approximately $2.9 million.

[12] The different lifecycle phases (Intake/Initiate, Assess, Plan, Execute and Close) are described in the Direct Testimony of Jorge O. Moncayo, NW Natural/500, Moncayo.

4. Central Coast Project

Q. Please describe the current state of the Central Coast pipeline as it relates to this project.

A. The Central Coast pipeline has an undocumented section of 8-inch transmission pipe that is connected to the existing 12-inch transmission main adjacent to a blowdown bridle located in a remote location in the Central Oregon Coast Range. The undocumented pipe was discovered during an ILI assessment of the Central Coast Feeder transmission pipeline in 2026. During that ILI assessment, higher-than-normal gas flows were required to allow the ILI tools to pass through this section of pipe. As a result of investigating those abnormal flows as well as a bent riser adjacent to the blowdown bridle, the Company uncovered the undocumented pipe that was connected to the 12-inch P30 Central Coast Feeder pipeline using an unbarred 12-inch by 6-inch tee. It was that tee that inhibited the passage of the ILI tools and required the higher-than-normal flows to allow for passage of the ILI tools. This tee and section of pipe were not part of the original 1965 documentation associated with the pipeline. Additionally, the existing blowdown bridle has difficult-to-operate valves due to their vintage (1965) and the actuation equipment is outdated and does not support remote operation by the Company's Gas Control department.

Q. Please describe the Central Coast Project.

A. The Central Coast Project will include the removal of the undocumented tee, section of pipe, and bridle. The Company will install a replacement valve assembly

and new piping that integrates with the Company's Gas Control systems (including the capability to remotely open and close the valve).

Q. Why is the Central Coast Project necessary?

A. The Central Coast Project is necessary because the undocumented section of transmission pipe does not have traceable, verifiable, and complete records to establish the MAOP of this pipeline. Section 2.1.8 of the NW Natural Transmission Integrity Management Program ("TIMP") requires that the Company have traceable, verifiable and complete records for our transmission pipe and anticipates replacement if such a pipe is discovered. In addition to the undocumented pipe, the difficult-to-operate valves and ineffective actuation capabilities (i.e., automatic shut off valve actuation via pressure sensing) limit the speed and reliability of isolation and blowdown activities, increase reliance on personnel operating equipment in the field, and hamper the Company's Gas Control department's ability to respond remotely during emergencies or abnormal operating conditions. Automatic shut off valves rely on pressure set points to operate the valve, which can lead to issues where downstream pressures do not reach the given set point, causing the operation of the valve to never occur, leaving the valve in the existing open/close position. If the valve does not operate as intended, field personnel would be required to operate the valve, which increases reliance on labor and increases risk as personnel would have increased field exposure in the event of an emergency or abnormal operating conditions. In total, the Central Coast Project provides the strongest alignment with safety, integrity,

emergency response, operability, and lifecycle objectives through a single, coordinated solution without requiring relocation of the full site.

Q. Did the Company consider alternatives to performing the Central Coast Project?

A. Yes. First, the Company considered removing the undocumented 8-inch transmission piping but retaining the existing blowdown bridle, valves and actuation. While that alternative would address the undocumented transmission pipe issue, it would leave unresolved the difficult-to-operate valves, ineffective actuation, limited remote capability, and associated personnel exposure. It also would likely require a separate future project and another pipeline isolation to rebuild the bridle. Additionally, this alternative would duplicate the need for operational technology support, as the site already requires separate telemetry upgrades that otherwise would be performed through the Central Coast Project.

Second, the Company considered removing the undocumented pipe and repairing existing valves or retrofitting actuators and controls while retaining most of the existing bridle. This alternative was not selected because repairing or retrofitting actuators and controls that are over 60 years old would not provide the same reliability, standardization, or maintainability as their replacement. Feasibility depends on the condition and compatibility of the existing valves, piping, and actuation interfaces. Detailed engineering would likely determine that modifications approach the cost and complexity of full replacement without

providing equivalent lifecycle value. This approach would result in more risks with more associated costs.

The Company also considered doing nothing, but that approach would not remove or resolve the undocumented 8-inch transmission pipe, would not correct the difficult-to-operate valves or ineffective actuation, and would not provide remote operating capability. Further, the identified safety, integrity, emergency response, and personnel exposure concerns would remain.

The Company further concluded that several alternatives were not viable. First, removing the undocumented segment and relocating the complete blowdown bridle and associated controls to a new site would add land, permitting, piping, design, and construction scope and costs without a documented need. Second, pressure testing the undocumented segment, which would need to be conducted at one and one-half times the operating pressure of the pipe, would have had a high risk of failure. Third, reducing the operating pressure such that the undocumented segment no longer was a transmission pipe would have caused severe supply disruption to residential and commercial customers throughout the Central Coast and the Willamette Valley (during wintertime Newport LNG plant vaporization activities). Fourth, the fact that the undocumented segment was so short made performing an ILI for an Engineering Critical Assessment (ECA) of it not feasible. Fifth, the Company is not aware of any alternative technologies that it could have submitted to the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA") to document the

material properties of the segment, or of any other operators submitting or getting PHMSA approval for alternative technologies to be utilized for MAOP reconfirmation.

Q. What is the current status of the Central Coast Project?

A. The project is currently in the Assess phase. The Company expects to complete the Central Coast Project by October 2027.

Q. What is the estimated total cost of the Central Coast Project?

A. The total cost of the Central Coast Project is expected to be approximately $1.5 million.

5. Deer Island Gate Station Rebuild Project

Q. Please describe the current state of the Deer Island Gate Station.

A. The Deer Island Gate Station is located in Columbia County and is at the west end of the Williams Northwest Pipeline ("NWP") Astoria Lateral. This gate station provides odorization and metering for gas deliveries to the North Coast Feeder pipeline, and un-odorized delivery south to an odorizer station in Columbia City. The North Coast Feeder pipeline is one of the pipelines that brings gas to the Mist Storage Facility. Currently, this station uses an early-generation ultrasonic meter that is not custody-transfer grade, and is unsupported by the manufacturer. Additionally, the manufacturer of the existing odorization system no longer supports the software or electronic package for that system.

Q. Please describe the Deer Island Gate Station Rebuild Project.

A. The Deer Island Gate Station Rebuild Project will install a new ultrasonic flow meter and odorization system with software and hardware supported by the manufacturer, and will modify and add telemetry to support the new meter and odorization system and provide situational awareness to the Company's Gas Control department.

Q. Why is the Deer Island Gate Station Rebuild Project necessary?

A. The Deer Island Gate Station Rebuild Project is necessary to eliminate the operational risk associated with two critical station assets that are end-of-life and no longer fully supported, improve the reliability and accuracy of odorization operations, and provide a maintainable platform for future operation and maintenance. Modern metering and odorization systems will provide improved reliability, enhanced diagnostic capabilities, readily available technical support, and replacement parts throughout the asset lifecycle. The replacement also reduces the likelihood of extended outages caused by failures of legacy hardware or software.

Q. Did the Company consider alternatives to performing the Deer Island Gate Station Rebuild Project?

A. Yes. The Company considered removing the legacy ultrasonic flow meter, installing a new annubar meter for odorizing the pipeline, and replacing wiring as needed. While doing so would have cost less than the Deer Island Gate Station Rebuild Project, annubar meters lack the precision necessary for custody transfer

applications, which are governed by standards including AGA Report No. 9 for ultrasonic meters. They also produce poor quality data when low flow velocities are present, which can exist at the Deer Island Gate Station. For example, at low flows the meter may show flows that create an inconsistent, unusable result for both odorizing the gas in the pipeline and balancing gate station flows with Williams NWP. Under-odorization will impact customer safety directly, and over-odorization can impact emergency response by generating odor calls and complaints, leading to safety impacts where real gas odor emergencies are obscured by large volumes of customer calls about gas odor. Annubar meters also can produce inaccurate and inconsistent reading at low flow velocities, which would undermine the Company's ability to verify gas volumes received by Williams NWP and adversely affect the Gas Control department's ability to make informed decisions.

Moreover, the Company concluded that several alternatives were not viable. First, mechanical meters (turbine or orifice) are less reliable and produce lower quality flow information than the selected ultrasonic flow meter, require routine maintenance the cost of which could more than offset their slightly lower capital cost, and create differential pressure in the pipeline resulting in a pressure drop across the meter. Second, when compared with the inline ultrasonic meter selected for the Deer Island Gate Station Rebuild Project, clamp-on ultrasonic meters are about the same cost, are less reliable, are more susceptible to water infiltration, require more maintenance, and provide less accurate modeling data.

Finally, the Company considered doing nothing, but that approach would not have remedied any of the operational concerns referenced above.

Q. What is the current status of the Deer Island Gate Station Rebuild Project?

A. The project is in the Assess phase. The project team is identifying long-lead equipment for purchase and is in the process of completing the 30 percent design. The Company expects to complete the Deer Island Gate Station Rebuild Project by October 2027.

Q. What is the estimated total cost of the Deer Island Gate Station Rebuild Project?

A. The total cost of the Deer Island Gate Station Rebuild Project is expected to be approximately $2.5 million.

6. Sauvie Island Gate Station Metering Project

Q. Please describe the current state of the Sauvie Island Gate Station.

A. The Sauvie Island Gate Station does not have custody-transfer grade ultrasonic flow metering, its odorization system is approaching end-of-life, and the site does not have a chromatograph for energy content measurement.

Q. Please describe the Sauvie Island Gate Station Metering Project.

A. The Sauvie Island Gate Station Metering Project will install a new custody-grade ultrasonic flow meter, a zero-emissions odorization system (including bulk storage tank and day tank with integral secondary containment) with software supported by the manufacturer, a remote terminal unit (RTU), pressure regulation equipment, and a chromatograph for energy content measurement.

Q. Why is the Sauvie Island Gate Station Metering Project necessary?

A. The Sauvie Island Gate Station Metering Project is needed to modernize critical station infrastructure, address aging odorization equipment, improve flow measurement accuracy, and provide gas quality information that supports safe and efficient system operations.

Q. Did the Company consider alternatives to performing the Sauvie Island Gate Station Metering Project?

A. Yes. First, the Company considered replacing the odorization system but retaining the current meter and other equipment. While this alternative would have had a lower capital cost, the Company did not select it because it would not have provided custody-grade ultrasonic metering, energy content measurement capabilities, or modernization of the station controls and metering infrastructure. As a result, NW Natural would still have lacked the improved measurement accuracy, gas quality data, reconciliation capability, and operational benefits needed to support forecasting, system modeling, IRP activities, the Company's Gas Control department, and long-term station modernization and asset management plan objectives to ensure continued reliable odorization.

Second, the Company considered replacing the odorization system and certain other equipment but retaining the current meter. While this alternative also would have had a lower capital cost, the Company did not select it because it would not have included custody-grade ultrasonic metering or full modernization of the station controls infrastructure. As a result, the station would have continued to rely

on the existing annubar meter for flow measurement and odorization calculations, improvements in measurement accuracy, accountability, and data quality.

Moreover, the Company concluded that several alternatives were not viable. First, mechanical meters (turbine) are less reliable and produce lower quality flow information than the selected ultrasonic flow meter, and they require routine maintenance the cost of which could more than offset their slightly lower capital cost. Second, when compared with the inline ultrasonic meter selected for the Sauvie Island Gate Station Metering Project, clamp-on ultrasonic meters are about the same cost, are less reliable, are more susceptible to water infiltration, require more maintenance, and provide less accurate modeling data. Finally, the Company considered doing nothing, but that approach would not have remedied any of the operational concerns referenced above.

Q. What is the current status of the Sauvie Island Gate Station Metering Project?

A. The project is in the Assess phase. The project team is identifying long-lead equipment for purchase and is in the process of completing the 30 percent design. The Company expects to complete the Sauvie Island Gate Station Metering Project by October 2027.

Q. What is the estimated total cost of the Sauvie Island Gate Station Metering Project?

A. The total cost of the Sauvie Island Gate Station Metering Project is expected to be approximately $4.7 million.

7. Molalla Gate Station Metering Project

Q. Please describe the current state of the Molalla Gate Station as it relates to this project.

A. The components of the Molalla Gate Station have not been updated since its initial construction in 2004. For example, the Molalla Gate Station does not have the custody-transfer grade ultrasonic flow metering recommended by standards including AGA Report No. 9 for ultrasonic meters, which is used to compare, balance and check the upstream custody-transfer meter used by Williams NWP. In addition, the Molalla Gate Station experiences bottlenecking of its regulator runs, which has created 50-95 pounds per square inch gauge ("psig") differential pressures that reduce inlet pressure and inhibit injections from the Mist Storage Facility and cold weather operations more generally.

Q. Please describe the Molalla Gate Station Metering Project.

A. The Molalla Gate Station Metering Project will install a new custody-grade ultrasonic flow meter and associated flow computer and chromatograph infrastructure, and will debottleneck regulation to improve Mist Storage Facility injection capability and gate station capacity during cold weather. During this project, Williams NWP will also be replacing the station's custody transfer meter, which the Company will reimburse as part of its agreement with Williams NWP.

Q. Why is the Molalla Gate Station Metering Project necessary?

A. The Molalla Gate Station Metering Project is needed to modernize critical station infrastructure, reduce pressure losses, improve flow measurement accuracy, and provide gas quality information that supports safe and efficient system operations.

Q. Did the Company consider alternatives to performing the Molalla Gate Station Metering Project?

A. Yes. The Company considered simply reimbursing Williams NWP for required custody-grade metering equipment, but doing so would not remedy the operational concerns referenced above.

Q. What is the current status of the Molalla Gate Station Metering Project?

A. The project is in the Assess phase. The project team is identifying long-lead equipment for purchase and is in the process of completing the 30 percent design. The Company expects to complete the Molalla Gate Station Metering Project by October 2027.

Q. What is the estimated total cost of the Molalla Gate Station Metering Project?

A. The total cost of the Molalla Gate Station Metering Project is expected to be approximately $3.2 million.

8. Albany Gate Station Metering Project

Q. Please describe the current state of the Albany Gate Station.

A. The Albany Gate Station is a custody transfer gate station located in Albany, Oregon. The existing station consists of custody transfer metering and regulation provided by Williams NWP and secondary regulation to a high-pressure

distribution system serving the communities of Lebanon and Sweet Home to the east. The Albany Gate Station does not have custody-transfer grade ultrasonic flow metering and the site does not have a chromatograph for energy content measurement.

Q. Please describe the Albany Gate Station Metering Project.

A. The Albany Gate Station Metering Project will install a new custody-grade ultrasonic flow meter and associated flow computer and gas chromatograph infrastructure to provide custody-transfer grade check metering and gas quality measurement. During the project, controls will be installed on the gas regulation system to allow remote setpoint control by the Company's Gas Control department for system balancing and situational awareness. These installations will improve the ability to evaluate measurement imbalance and better calculate the energy content of gas delivered at the station.

Q. Is the Company considering alternatives to performing the Albany Gate Station Metering Project?

A. Yes. The Company's alternatives analysis process for this project will be developed in early 2027.

Q. What is the current status of the Albany Gate Station Metering Project?

A. The Company expects to complete the Albany Gate Station Metering Project by October 2028.

Q. What is the estimated total cost of the Albany Gate Station Metering Project?

A. The total cost of the Albany Gate Station Metering Project is expected to be approximately $2.6 million.

9. McMinnville-Amity Gate Station Rebuild Project

Q. Please describe the current state of the McMinnville-Amity Gate Station.

A. The McMinnville-Amity Gate Station is a custody transfer gate station located in Silverton, Oregon. This station serves as the easternmost gas supply for the Central Coast Feeder transmission pipeline. The existing station consists of custody transfer metering, regulation and overpressure protection by Williams NWP, and interconnecting piping and inline inspection facilities at the eastern terminus of the Central Coast Feeder. This station supports gas flows to customers along the Central Coast Feeder and frequently sees demand that exceeds the station capacity. Williams NWP has notified the Company that the Company's flow rates through the McMinnville-Amity Station exceed their flow meter design capacity and has asked the Company to pay for Williams NWP to upgrade the upstream metering so that their meter capacity exceeds station flow rates.

Q. Please describe the McMinnville-Amity Gate Station Rebuild Project.

A. The McMinnville-Amity Gate Station Rebuild project will install a new custody-grade ultrasonic flow meter and associated flow computer and gas chromatograph infrastructure to provide custody-transfer grade check metering and gas quality measurement. During this project, Williams NWP will replace upstream metering

and regulation equipment to debottleneck the station and ensure adequate capacity for cold weather or high demand operations. As this project is still in the initial design phase, Williams NWP will likely require the Company to take over regulation and overpressure protection as a part of this large station project.

Q. Is the Company considering alternatives to performing the McMinnville-Amity Gate Station Rebuild Project?

A. Yes. The Company's alternatives analysis process for this project will be developed in early 2027.

Q. What is the current status of the McMinnville-Amity Gate Station Rebuild Project?

A. The Company expects to complete the McMinnville-Amity Gate Station Rebuild Project by October 2028.

Q. What is the estimated total cost of the McMinnville-Amity Gate Station Rebuild Project?

A. The total cost of the McMinnville-Amity Gate Station Rebuild Project is expected to be approximately $4.1 million.

10. NE Gate Station Inlet Piping/Rebuild Project

Q. Please describe the NE Gate Station.

A. The NE Gate Station is a key delivery point in the Northeast Portland area. The site contains existing telemetry and controls, a line heater, and piping infrastructure. The NE Gate Station primarily delivers to the NE Metro and Rivergate regions.

Q. Please describe the current state of the NE Gate Station.

A. To maintain compliance, this station has approximately 150 feet of undocumented transmission main pipe that needs to be replaced and slip on flanges that require investigation or remediation. The site contains difficult to turn/inoperable valves that are a safety concern for operators that need to be replaced to maintain safety compliance.

Q. Please describe the NE Gate Station Inlet Piping/Rebuild Project.

A. The NE Gate Station Inlet Piping/Rebuild Project includes replacement of the undocumented transmission main, investigating or remediating the slip-on-flanges, upgrading regulation and overpressure protection, and replacing difficult-to-operate and inoperable valves.

Q. Is the Company considering alternatives to performing the NE Gate Station Inlet Piping/Rebuild Project?

A. Yes. The Company's alternatives analysis process for this project will be developed in early 2027.

Q. What is the current status of the NE Gate Station Inlet Piping/Rebuild Project?

A. The project is in the Assess phase. The Company expects to complete the NE Gate Station Inlet Piping/Rebuild Project by October 2028.

Q. What is the estimated total cost of the NE Gate Station Inlet Piping/Rebuild Project?

A. The total cost of the NE Gate Station Inlet Piping/Rebuild Project is expected to be approximately $2.4 million.

B. Significant Storage Facility Projects

1. 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 dekatherm ("Dth") capacity storage tank, liquefaction facilities capable of processing about 2,150 Dth/day, and vaporization capacity of up to 131,520 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.[13] This facility was constructed by Chicago Bridge and Iron and commissioned in 1977.

[13] 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.

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 ("I/W") wells, gathering lines, an operational hub called Miller Station,[14] 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. I will provide more detail about the Mist Storage Facility later in this testimony.

Q. Are the Company's storage facility projects allocated to both Oregon and Washington?

A. Yes. The Company allocates storage facility projects to both states. Gas acquisition, including both capacity and commodity costs, has historically been accomplished on an integrated (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.

[14] 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.

Q. Please describe further how the Company operates the storage facilities on an integrated basis.

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 Williams NWP to serve the requirements of customers in Oregon as well as in Washington. For example, withdrawals from the Mist Storage Facility flow directly to 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 Oregon and Washington customers through the purchased gas adjustment ("PGA") process. In the PGA, upstream pipeline demand charges are allocated between Oregon and Washington 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 Oregon and Washington is also reflected in the resource acquisition decisions determined in the Company's IRP process.

Q. Please summarize the importance of the Company's storage facilities to the Company's overall operations and provision of reliable and affordable service to customers.

A. The Company's storage facilities already play a critical role in delivering reliable and affordable service, especially during the coldest days, and we anticipate their importance will only increase in the coming years as new West Coast LNG export facilities come online and impact the already constrained market as described below.

Q. How are the Company's storage facility projects allocated to Oregon customers?

A. The Company's storage facility projects are allocated to Oregon and Washington customers on the basis of firm sales volumes. The Oregon allocation factor for firm sales volumes is currently 88.86 percent. The Direct Testimony of Kyle T. Walker (NW Natural/1200, Walker) addresses the topic of allocation factors and their associated methodology.

2. 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 16 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 currently contracted with other utilities and third-party marketers through the Company's interstate storage service ("ISS"); however, core customers have the right to recall this storage capacity. Mist recall is typically identified as the least cost/risk option to serve customer needs in the IRP. 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. NW Natural/601, Kizer-Hwang, are charts that outline the growth of the Mist Storage Facility over time and highlight its allocation between core customers (including recall capacity) and ISS.

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 18 percent of

that supply, bringing the total on-system supply to just over half of our peak day. Our 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. 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 Portland area, NW Natural delivered 9 million therms of natural gas to homes and businesses throughout our service territory, virtually matching our previous record set in December 2022 for a single gas day, and approximately doubling our 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 our 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. The Mist Storage Facility is absolutely crucial to ensuring that NW Natural can provide safe and reliable service to our customers throughout the winter months.

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 our 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. The Company would also expect that permitting an interstate pipeline expansion would be a difficult process.

NW Natural/602, Kizer-Hwang is a map that shows the existing upstream pipeline and natural gas storage infrastructure in the Pacific Northwest. On the

map, 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 Company. 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, and marked 65 percent completion in June 2026.[15]

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 about 16 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

[15] Woodfibre LNG at 65% Complete: Partnership Driving Progress.

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.

We have 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 we 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, our IRP currently indicates the need to recall Mist capacity in place of this segmented capacity resource. A Mist recall would shift this deliverability (and the related capacity) from its ISS customers to NW Natural's core customers. Assuming no other recalls in the interim, a Mist recall of 60,000 Dth/day, for example, 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 our peak day supply from pipeline resources to the Mist Storage Facility, thereby increasing our reliance on the Mist Storage Facility to almost 40 percent of our portfolio on a peak day.

Q. Are there any other LNG export projects that could impact gas supplies in the West?

A. Yes. Construction recently completed 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 can liquefy 0.4 Bcf/day. 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 this, plus cold weather, drove prices up to approximately $50/Dth in the West. The Costa Azul LNG facility could have a similar impact. NW Natural/603, Kizer-Hwang is a map showing how Costa Azul LNG connects to the natural gas system in the Southwest. NW Natural/604, Kizer-Hwang 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. 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.

3. Newport LNG Cold Box Replacement Project

Q. What significant functions does the Company's Newport LNG facility perform?

A. The Newport LNG facility is a key resource in NW Natural's firm resource stack. The Newport LNG facility has a vaporization capacity of 100,000 Dth/day and can supply up to 78,000 Dth/day via the Central Coast Feeder transmission pipeline to

customers in the mid-Willamette Valley during times of peak demand, which is necessary because Williams NWP cannot meet all of the Company's demand during peak cold weather conditions or during late winter cold weather events when Mist storage levels have been partially depleted by previous winter supply usage. When the Company experienced a 32 Heating Degree Day (HDD) on January 29, 2023, the Company vaporized gas at the Newport LNG facility at a daily rate of 29,100 Dth/day. On February 12, 2021, the Company experienced a 35 HDD and the Company vaporized gas at Newport at a daily rate of 34,400 Dth/day.

It also serves as a source of supply for emergency situations and pipeline maintenance. Any significant damage or event along the 90-mile long Central Coast Feeder Pipeline can interrupt gas flow, which could cause outages to thousands of customers downstream of the event if the Newport LNG facility were not available. The Echo Mountain Wildfire in September 2020 served as an example of this capability of the Newport LNG facility, as the fire damaged the primary district regulator station serving Lincoln City. To safely operate NW Natural's high-pressure system, a portion of the Central Coast Feeder Pipeline was shut down near Lincoln City to reduce risk and damage. While the segment of the Central Coast Feeder Pipeline was shut down, the primary gas feed from the Williams NWP McMinnville-Amity gate station was severed. During the shutdown, which lasted from September 9 to 16, 2020, the Newport LNG facility was used to continue serving approximately 10,000 customers in Newport, Toledo

and Lincoln City. Without the Newport LNG facility, these customers would have lost gas service.

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 almost 50 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 low. Additionally, NW Natural installed a new pretreatment system in 2016 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

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 generally 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 described the project in detail in its 2018 IRP Update 3 filed in docket LC 71 on March 1, 2021.

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. During peak winter operations, Newport LNG is used to provide peak shaving gas supply directly to approximately 10,000 customers in Lincoln City, Toledo and Newport communities, and to an additional 115,000 to 125,000 customers in the communities of McMinnville, Sheridan, Willamina, Grand Ronde, Dallas, Monmouth, Independence, Brooks, Gervais, Keizer, West Salem, North Salem, North Albany and North Corvallis. In addition, Newport LNG can supply up to 78,000 Dth/day of vaporization capacity, which is used as peak gas supply during periods of high demand, offsetting gas deliveries from Williams NWP, when the spot price of gas is high, resulting in reduced costs to core customers.

Should the Newport LNG Cold Box fail, the ramifications to the plant would be significant. A replacement unit would require approximately two to three years to design, manufacture, permit and 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 be left without 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 3 when it sought Commission acknowledgement in docket LC 71?

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 3, 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 Staff support acknowledgement of the Newport LNG Cold Box Replacement Project?

A. Yes. In its Opening Comments filed in docket LC 71 on May 14, 2021, Staff stated (on page 5) that it "finds this action item, replacing the Newport [LNG] Cold Box, is a reasonable step in order to meet the Company's obligation to provide safe and reliable service and, based on the information provided by the Company, is the lowest cost option available." In its July 12, 2021 Staff Report to the Commission, Staff stated (on page 3) that "[a]fter reviewing stakeholder comments, Staff

continues to find the Newport Cold Box to be a reasonable investment and recommends acknowledgement."

Q. Did the Commission acknowledge the Newport LNG Cold Box Replacement Project?

A. Yes. The Commission acknowledged the Newport LNG Cold Box Replacement Project in Order No. 21-274, entered September 8, 2021.

Q. Did the Company request cost recovery for the Newport LNG Cold Box Replacement Project in its most recent general rate case, docket UG 520?

A. Yes. The Company filed Direct Testimony in docket UG 520 including the Newport LNG Cold Box Replacement Project in its revenue requirement based upon the expected completion of the project by October 2026.[16]

Q. Did the Company provide an update on the status of the Newport LNG Cold Box Replacement Project in its Reply Testimony in docket UG 520?

A. Yes. In its Reply Testimony filed on May 21, 2025, NW Natural reported that it had delayed the project's estimated in-service date to June 2027 after discovering that the pretreatment molecular sieve vessels suffered insulation failures. Accordingly, the Company removed the Newport LNG Cold Box Replacement Project from rate base in docket UG 520.

Q. Please describe the function of the pretreatment 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

[16] Docket No. UG 520, NW Natural/500, Kizer-Johnson (Dec. 30, 2024).

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 insulation failures suffered by the pretreatment molecular sieve vessels.

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 and CO_2 and moisture to bypass the treatment media. That bypass resulted in inlet feed gas composition that did not satisfy the performance criteria for the cold box design.

Q. What action did the Company take to address the insulation failures suffered by the pretreatment molecular sieve vessels?

A. To ensure the cold box performance remains as designed, the dehydration and CO_2 removal vessels were modified to repair the internal insulation failure and eliminate the ability for process gas to bypass the molecular sieve media. That project removed the vessels from service, and a pressure vessel contractor installed internal steel liners and new insulation in the vessels. These modifications are designed to enhance the high-temperature regeneration performance, ensure that process gas cannot bypass the molecular sieve media, and correct the feed gas composition. NW Natural completed that project in June 2026.

Q. Did that project delay the schedule for the Newport LNG Cold Box Replacement Project?

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 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. Does the Newport LNG Cold Box Replacement Project continue to be necessary?

A. Yes. Now that the molecular sieve vessels have been repaired and upgraded, the Company can move forward with the Newport LNG Cold Box Replacement Project to address the above-described operational issues that continue to persist. Accordingly, the Newport LNG Cold Box Replacement Project continues to be necessary to be able to continue to rely upon Newport LNG as a firm resource to serve NW Natural's current needs and as a source of supply for emergency situations and pipeline maintenance.

Q. What is the timing of the Newport LNG Cold Box Replacement Project?

A. The Company expects to complete the Newport LNG Cold Box Replacement Project by July 2027.

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 $34.5 million, or $30.7 million on an Oregon-allocated basis.

Q. Does the current estimated total cost of the Newport LNG Cold Box Replacement Project exceed the estimated total cost that the Company presented in its most recent general rate case, docket UG 520?

A. Yes. In docket UG 520, the Company expected the total cost of the Newport LNG Cold Box Replacement Project to be approximately $25.4 million, or $22.6 million on an Oregon-allocated basis.

Q. What are the primary drivers of the cost increase of the Newport LNG Cold Box Replacement Project from docket UG 520 to this current general rate case?

A. The primary drivers of the cost increase are inflation, progression from estimates to the final 100 percent design and guaranteed maximum price contract with the winning bidder, and an updated, project-specific construction overhead percentage. At the 100 percent design stage, final labor and materials costs were included reflecting final pricing by the selected bidder, Chicago Bridge & Iron.

Q. Does the Newport LNG Cold Box Replacement Project continue to be the least-cost, least-risk alternative for continuing to serve current customers safely and reliably?

A. Yes. The cost of the Newport LNG Cold Box Replacement Project still is an order of magnitude less than the cost of the Alternative B described above.

4. Newport LNG Plant Supply Generator Project

Q. Please describe the current state of power generation at the Newport LNG facility.

A. The purpose of the Newport LNG facility is to provide firm natural gas service during cold weather periods of high demand. The facility, however, is susceptible to losses of "grid power" from the local electrical utility. In the event of a power outage during vaporization, the facility loses the ability to supply gas. While the facility currently has an emergency generator that is designed to provide backup power to critical safety systems, its maximum power output is unable to supply sufficient power to support the vaporization processes at the facility. As a result, the Newport LNG facility can experience electricity outages that prevent operation of the production or vaporization send-out systems.

Q. Please describe the Newport LNG Plant Supply Generator Project.

A. The Newport LNG Plant Supply Generator Project will install a 1.5 MW natural gas reciprocating generator with standby operation that meets all of the facility's electrical demand.

Q. Why is the Newport LNG Plant Supply Generator Project necessary?

A. The Newport LNG Plant Supply Generator Project is necessary to provide sufficient standby power to continue vaporization during a grid-power outage and represents the lowest lifetime cost among all alternatives evaluated, which I will present next. The generator can be manually started during outages and ensures the facility remains an effective peak resource.

Q. Did the Company consider alternatives to performing the Newport LNG Plant Supply Generator Project?

A. Yes. The Company considered multiple alternatives. The first alternative was a 1.5 MW reciprocating generator configured for continuous operation. While that generator would have provided added pre-treatment efficiency benefits, its lifetime cost would have been double that of the selected option. Second, the Company considered a 1.2 MW turbine generator configured for continuous operation. While that generator would have been the most reliable from a maintenance standpoint, its lifetime cost would have been triple that of the selected option. NW Natural also considered doing nothing, but that decision would have left customers exposed to significant operational risks.

Further, the Company concluded that the following two alternatives were not viable. First, a preliminary evaluation of purchasing a portable generator concluded that doing so would have cost more than the selected option, involved complex logistics for its transportation and connection and scheduling seasonal labor, and created significant safety and operational risks to make the necessary connections during cold weather events. Second, renting a portable generator indefinitely would have had the same types of issues and the added risk due to seasonal availability and compatibility, making it unreliable during cold weather events when it would have been needed the most. It should be noted that a rental generator is a part of the initial project plan to provide emergency power during the lead time for the permanent generator being installed through the Newport LNG

Plant Supply Generator Project, and availability and compatibility risks are being temporarily addressed during this project. However, the cost of using a rental generator indefinitely would quickly exceed the cost of a permanently installed generator, and carry significant risks due to long-term availability, maintenance and third-party support. The cost of this temporary rental generator is offset by the potential expense to purchase spot gas if Newport LNG were unable to vaporize during a power outage.

Q. What is the current status of the Newport LNG Plant Supply Generator Project?

A. The project is in the Planning phase and at the 60 percent design stage, and the Company is negotiating procurement of a temporary rental generator during the construction phase and the permanent 1.5 MW generator. The Company expects to complete the Newport LNG Plant Supply Generator Project by October 2028.

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 $7.2 million, or approximately $6.4 million on an Oregon-allocated basis.

5. Mist Main Power Feed Replacement Project

Q. Please describe the Mist Main Power Feed Replacement Project that the Company included in its ARM filing in docket UG 527.

A. Miller Station is currently fed from a substation with above-ground 12.5 kilovolt ("kV") power lines that run along State Highway 202 to NW Natural's meter. From there, an underground NW Natural-owned 12.5 kV power line is fed up to Miller Station. The existing underground cable is end-of-life (35 years old), susceptible to water intrusion from heavy rain, and uses above-ground cable junction boxes that have been damaged from vehicles. Initially, the local electric cooperative utility was planning to construct a new substation located along the mainline near an existing electrical vault. The substation would have connected Miller Station directly with the 115 kV lines from BPA, thus bypassing the 12.5 kV lines that run along the highway. The 12.5 kV power lines that run along the highway are susceptible to outages during wind and ice storms. NW Natural initiated and requested this work to improve reliability and resiliency of the Company's winter operations.

Q. Did the Company provide an update on the Mist Main Power Feed Replacement Project in its Reply Testimony in docket UG 527?

A. Yes. In its Reply Testimony in docket UG 527, NW Natural/400, Kizer-Karney-Pipes/6, the Company reported that the local electric cooperative utility was continuing to work on the specifics of the project, which unfortunately delayed its expected completion until October 2027. As a result, the Company removed this

project from that case, as shown in UG 527, NW Natural/300, Kravitz-Siores-Walker/3, 64.

Q. What is the current status of the Mist Main Power Feed Replacement Project?

A. In May 2026, NW Natural decided to move forward with a variation of the project that does not involve the local electric cooperative utility, which had continued to experience delays. The Mist Main Power Feed Replacement Project now entails the Company installing a new 12.5kV underground 4/0 copper power line in parallel to the existing underground power line feed from State Highway 202 to Miller Station, to address the end-of-life existing underground cable that has been damaged and is susceptible to water intrusion. The new powerline will not be direct buried as is the existing powerline, but instead will be installed in a 5-inch high-density polyethylene ("HDPE") conduit to better protect the powerline from physical damage and water intrusion. The updated Mist Main Power Feed Replacement Project is in the Planning phase, with an expected completion by October 2027.

Q. What is the estimated total cost of the updated Mist Main Power Feed Replacement Project?

A. The estimated total cost of the utility-allocated portion of the updated Mist Main Power Feed Replacement Project is approximately $5.5 million, which is approximately $4.9 million on an Oregon-allocated basis.

Q. How does the estimated total cost of the updated Mist Main Power Feed Replacement Project compare with the initially scoped version of the project that the Company removed from docket UG 527?

A. The updated Mist Main Power Feed Replacement Project is approximately $1.1 million more than the initially scoped version of the project that the Company removed from docket UG 527. The cost increase can be attributed to the condensed construction window required to complete the work before fire season and the additional cost of using one third concentric neutral conductors to integrate with the local electric cooperative utility's power distribution system.

The need for the one third concentric neutral conductors is driven by the configuration of the local electric cooperative utility's distribution system, which differs from the majority of the electrical infrastructure at the Mist Storage Facility that uses standard conductors with a separate neutral conductor. To provide a grounded return path for fault current back to the utility's substation, each of the three-phase conductors incorporates 18 copper neutral strands concentrically arranged around the insulated phase conductor. This specialized conductor configuration requires additional copper, adds manufacturing complexity, and results in a higher material cost. This additional material cost was not present in the original project scope because the proposed new substation would have reused existing power feed conductors to feed the Mist Storage Facility.

Q. Does the updated Mist Main Power Feed Replacement Project continue to be the least-cost, least-risk alternative for continuing to serve current customers safely and reliably?

A. Yes. Moving forward with the local electric cooperative utility to build a new substation, as originally planned, is no longer an option. The updated Mist Main Power Feed Replacement Project replaces the end-of-life underground cable and, by installing it in a 5-inch HDPE conduit, improves reliability and resiliency of the Company's winter operations at the Mist Storage Facility.

6. Mist Reservoir Ultrasonic Flowmeters Replacement Project

Q. Please describe the current state of metering at the Mist reservoirs.

A. At the Mist Storage Facility, five pool meters use the Honeywell Series 4 ultrasonic meters to measure gas injection and withdrawal. These meters are no longer supported by the original equipment manufacturer ("OEM"), which limits access to spare parts, software and technical assistance. One of the meters already experienced an electronic board failure in 2026, and lack of OEM support was evident during the troubleshooting process. Moreover, the Burns & McDonnell 15-Year Mist Miller Facility Assessment (2023) produced for NW Natural also identified Honeywell ultrasonic meter obsolescence, support limitations, and replacement needs at the Mist Storage Facility.

The lack of OEM support creates an elevated reliability and maintenance risk for reservoir flow monitoring. If another meter fails, limited parts and vendor support could extend the time needed to restore accurate measurement, thus impacting well/reservoir downtime. Reliable flow data is needed to monitor

injection and withdrawal activities, support safe reservoir operations, and minimize business interruption.

Q. Please describe the Mist Reservoir Ultrasonic Flowmeters Replacement Project.

A. The Mist Reservoir Ultrasonic Flowmeters Replacement Project will replace the Honeywell Series 4 ultrasonic meters and associated obsolete pressure and temperature instrumentation with the vendor-supported solution of SICK FLOWSIC600-XT meters.

Q. Why is the Mist Reservoir Ultrasonic Flowmeters Replacement Project necessary?

A. The Mist Reservoir Ultrasonic Flowmeters Replacement Project is necessary to improve long-term reliability of well monitoring, reduce the risk of unplanned outages due to component failures, and ensure continued access to vendor support, spare parts, and configuration tools. The project will also standardize flow meter installations across wells, improving maintainability, operational confidence, and lifecycle asset management.

Q. Did the Company consider alternatives to performing the Mist Reservoir Ultrasonic Meter Replacements Project?

A. Yes. The Company considered replacing the Honeywell Series 4 ultrasonic meters and associated instrumentation with another type of inline ultrasonic meter that has a similar estimated total capital cost compared with the meters being deployed through the Mist Reservoir Ultrasonic Flowmeters Replacement Project. The

software accompanying the identified alternative meter, however, is outdated and difficult to use, which would have compromised reliability of flow metering. Further, there is very limited field technician support in the United States for the identified alternative meter, which could have prolonged downtime and service time. And, as the Company continues standardizing SICK meters across other sites for better OEM support, quicker troubleshooting, and ease of training, introducing an alternative meter to replace the existing non-standard meter in this case would have detracted from the Company's efforts of streamlining the spare parts and simplifying training by reducing the number of non-standard meter platforms. For these reasons, while the estimated total capital cost of the identified alternative meter is similar, the expected ongoing maintenance and support cost of the identified alternative meter is much higher compared to the selected SICK FLOWSIC600-XT meter.

The Company also considered doing nothing. Doing nothing would risk the loss of critical monitoring capability, impacting operational decision making and situational awareness at wells. It also would risk the escalation of maintenance costs due to reactive repairs, custom workarounds, or emergency replacements. And, doing nothing would lead to technology obsolescence risk, leaving the Company reliant on equipment that cannot be reasonably sustained long-term.

Q. What is the current status of the Mist Reservoir Ultrasonic Meter Replacements Project?

A. The project currently is in the Assess phase. The Company expects to complete the Mist Reservoir Ultrasonic Meter Replacements Project by October 2027.

Q. What is the estimated total cost of the Mist Reservoir Ultrasonic Meter Replacements Project?

A. The total utility cost of the Mist Reservoir Ultrasonic Meter Replacements Project is expected to be approximately $1.7 million, or approximately $1.5 million on an Oregon-allocated basis.

7. Mist Miller North Pool Controls Upgrade Project

Q. Please describe the current state of the controls system at the Mist well sites.

A. As highlighted in the Burns & McDonnell 15-Year Mist Miller Facility Assessment (2023), there is not a consistent controls system at each of the Mist well sites associated with the Bruer and Flora well pads. Communication between the well sites and Miller Station continues to depend on copper circuits installed in approximately 1988. After nearly four decades of service, the circuits are experiencing increasingly frequent failures. Restoring communication has required a growing number of splices, created additional points of vulnerability, and made the system more difficult to troubleshoot and maintain. Although these repairs temporarily restore service, they do not address the underlying deterioration of the cable system.

Portions of a fiber-optic Device Level Ring (DLR) have been installed, but the North Pool well-site controls have not been fully modernized to utilize this infrastructure. The current condition leaves critical storage operations dependent on an aging, repeatedly repaired copper communication network that has already demonstrated a worsening failure trend.

The sites were also developed over time using different generations of communications and controls technology, resulting in inconsistent controls architecture. Some wells have remote input-output ("I/O") panels connected to the station control system, while others rely on older configurations with limited connectivity, monitoring, and diagnostic capability.

Q. Please describe the Mist Miller North Pool Controls Upgrade Project.

A. The Mist Miller North Pool Controls Upgrade Project will implement communications and controls upgrades for 13 North Pool I/W Wells located within the Bruer and Flora well pads. The scope includes evaluation and modernization of existing communication infrastructure, upgrading the controls system from copper to fiber optic, expansion or installation of remote I/O equipment as required, integration of well sites with the existing fiber optic network, installation of centralized controls equipment at Miller Station, and updates required to support monitoring and control of injection and withdrawal operations.

Q. Why is the Mist Miller North Pool Controls Upgrade Project necessary?

A. The Mist Miller North Pool Controls Upgrade Project is necessary because upgrading and streamlining the controls system at each well site will promote

accurate process monitoring, standardize communications and controls architecture across the North Pool facilities, and improve the reliability of remote operations, process monitoring, and safety systems. The Mist Miller North Pool Controls Upgrade Project is the least-cost, least-risk alternative for achieving these objectives.

Q. Did the Company consider alternatives to performing the Mist Miller North Pool Controls Upgrade Project?

A. Yes. The Company considered two alternatives to the selected remote I/O solution: One alternative is to utilize local wellpad level programmable logic controllers ("PLCs") and the other alternative is to do nothing. Though the alternative to utilize local wellpad level PLCs would improve communication reliability through use of fiber optic infrastructure, it would add multiple field PLC processors across the well sites, thus increasing programming, maintenance, spare parts, lifecycle support, and troubleshooting complexity. The Mist Miller North Pool Controls Upgrade Project utilizes a central PLC at Miller Station with distributed well-site remote I/O panels, and that setup provides a more standardized and maintainable architecture while still improving reliability and operational visibility.

The second alternative is to do nothing, which would not address the recurring failures associated with the aging copper communication infrastructure, nor would it improve controls standardization across the North Pool well sites. Continued operation under current conditions is expected to increase maintenance

requirements due to further deterioration of the copper circuit, thus increasing risk to injection and withdrawal capability.

Q. What is the current status of the Mist Miller North Pool Controls Upgrade Project?

A. The project currently is in the Assess phase. The Company expects to complete the Mist Miller North Pool Controls Upgrade Project by October 2027.

Q. What is the estimated total cost of the Mist Miller North Pool Controls Upgrade Project?

A. The total utility cost of the Mist Miller North Pool Controls Upgrade Project is expected to be approximately $3.3 million, or approximately $2.9 million on an Oregon-allocated basis.

8. Mist Well Separator Replacement 2027 Project

Q. Please describe the Mist Well Separator Replacement Program and the Mist Well Separator Replacement 2027 Project.

A. The Mist Well Separator Replacement Program is replacing functionally end-of-life well separators at the Als, Bruer, Meyer, and Flora pools of the Mist Storage Facility over a multi-year period, which had been scheduled through 2030.

That schedule has been accelerated to 2027, through the Mist Well Separator Replacement 2027 Project, after the Company determined that the dehydration process at the Mist Miller Facility has been experiencing significant debris accumulation as a result of those well separators underperforming. The underperforming separators have allowed debris to bypass the compressors' high-

efficiency filters, enter the dehydration system and contaminate the process during free-flowing conditions.

Q. Please describe the function of the well separators at the Mist Storage Facility.

A. At the Mist Storage Facility, the primary function of a well separator is to remove liquids and solids from the natural gas stream withdrawn from the corresponding reservoir wellhead. Because the reservoirs are sandstone formations containing water, the withdrawal process can produce both liquids and solids. When the Company first began using Mist for gas storage, many of the existing production well separators, which were installed in 1987, were reused because gas withdrawal rate requirements were lower at that time.

Today, however, the Company withdraws gas from the underground reservoirs at higher flow rates and at lower inventory levels during periods of peak demand. These operating conditions require separators with greater flow capacity to adequately remove the liquids and solids produced during withdrawal. I will discuss how the Company has responded to these changing conditions next in my testimony.

Produced liquids can carry sand from the reservoirs. At higher withdrawal rates, inadequately sized or designed separators may not effectively remove these materials. The resulting liquids and solids can scour and erode downstream steel equipment at high velocities and can accumulate as deposits at pipeline low points when flow rates decrease.

Well inspection requirements also have introduced additional operating conditions. To perform a well inspection, a "well kill" first must be conducted by injecting fluid into the well to create sufficient hydrostatic head pressure. Not all of this fluid can be recovered immediately following the inspection, so residual liquids may subsequently be produced during withdrawal operations.

Properly sized separators using appropriate separation technology protect downstream equipment from liquids, solids, and slugging. This protection is important for maintaining reliable operations and supporting compliance at Miller Station.

Q. Please describe how the Company has responded to the changing conditions that you just described.

A. In 2020, NW Natural began performing non-destructive testing (NDT) inspections of the well separators as part of the Well Integrity Program. One separator was identified as being worn beyond safe operating limits, triggering a shut in of that I/W well and the prompt replacement of the separator to return the well to service. Other I/W well separators were also found to have significant wear and were assigned rapid replacement dates. In total, 21 I/W well separators were put on a schedule for replacement over a multi-year program.

In 2021, NW Natural identified increased liquid loading conditions resulting from reworked wells and a greater utilization of the Mist Storage Facility at lower inventory levels with higher flow rates. As wells have been reworked over time, production rates have increased, resulting in higher flow volumes and greater

water production. The increased liquid loading has exceeded the effective operating capacity of the aging separators, reducing their ability to adequately remove water and solids from the gas stream. Continued carryover of these contaminants posed an increased risk of corrosion, fouling, and damage to downstream pipelines and processing equipment, and thus raised concerns over complying with the PHMSA requirement of protecting compressors from liquids.

To address those process conditions, NW Natural conducted a 2021 Miller Station Filtration Engineering Assessment in collaboration with Harris Group. The assessment identified scopes of work recommended for mitigating immediate risks to deliverability and compliance. It also highlighted areas for further investigation of the well separators to ensure long-term reliability.

In 2022, NW Natural identified new risks associated with the well separators. Inspections were performed in accordance with American Petroleum Institute (API) recommendations, revealing there was wall loss to many of the separators across the field. Separators with significant wall loss that exceeded the corrosion allowance were immediately removed from service. NW Natural successfully remediated immediate reliability and safety risks through these corrective actions. Additionally, given the process conditions that have caused wall loss in the separators, the internals—such as mesh screens—most likely wore away, even if only minimal wall loss was observed. This wear of the internals of the separators further reduced its ability to remove liquids and sands from the natural gas stream.

In 2023, NW Natural incorporated the wall loss observed in the well separators, as outlined in the original Harris Group study, into its Burns & McDonnell 15-Year Mist Miller Facility Assessment. In early 2024, abandonment and cleaning of the Bruer well pipeline revealed significant accumulations of water and sand, prompting a broader evaluation of the well-site separator replacement program timeline. The 2023 assessment and early-2024 finding led to a dedicated 2024 Burns & McDonnell Well Separator Study. This study produced a Basis of Design report that included sizing recommendations to mitigate the wall loss issue discovered in 2022, new technology selection to manage updated liquid process conditions, and a recommended replacement schedule to ensure long-term reliability.

As a result of that study, the Company has replaced 9 separators so far, with two separators replaced in 2026 (included in the Company's ARM docket UG 527) with two different separator technologies. I describe the technologies below, as part of a field performance evaluation of performance, operability, maintainability, reliability, site fit and implementation risk. The objective of that evaluation is to determine which design provides the most effective removal of water and solids under current operating conditions, taking into account initial capital cost and lifecycle costs. Based on the results of that evaluation, which the Company expects to know by the beginning of 2027, the balance of the separators will be replaced in 2027 using the selected technology. Afterwards, the Company plans to inspect the separators on a periodic basis and replace them as necessary.

Q. What are the expected benefits of the Mist Well Separator Replacement 2027 Project?

A. The Mist Well Separator Replacement 2027 Project will improve the facility's ability to remove liquids and solids from the natural gas stream before they reach Miller Station and other downstream equipment. Improved separation performance will reduce the carryover of water, sand, and other contaminants, helping protect critical assets, improve system reliability, and reduce maintenance requirements.

Improved liquid removal will also help minimize liquid accumulation within the pipeline system, reducing the potential for flow restrictions, operational inefficiencies, and hydrate formation. Collectively, these improvements will enhance operational performance, extend equipment life, and support safer and more reliable operation of the Mist Storage Facility.

Q. What are the two technologies that the Company is evaluating?

A. The Company is evaluating horizontal separators and cyclonic separators. Horizontal separators are better suited for bulk liquid and debris removal with minimal risk of hydrate formation. The technology relies on increasing the vessel volume and slowing the storage gas velocity, allowing liquids and debris to be captured by a vane pack or mesh pad. The filtration efficiency is not as high as that of a cyclonic separator; however, a horizontal separator is sufficiently effective at capturing any liquids or debris that may drop out during transportation of the storage gas to Miller Station. Jackson Prairie, another gas storage facility that has

similar reservoir formation and operating parameters to the Mist Storage Facility, also uses the horizontal separator technology.

A cyclonic separator relies on reducing the flow area, increasing the velocity of the storage gas, and creating a cyclone effect. The resulting centrifugal force separates liquids and debris from the gas stream. The reduced volume increases the risk of hydrate formation and potential blockages. In addition, cyclonic separators typically require a secondary chamber for bulk liquid and debris removal, increasing the need for additional ancillary equipment and overall system complexity.

Q. While the final technology selection will be made based on the results of the field performance evaluation and cost considerations, does the Company have a recommended option at this time that is reflected in this rate case?

A. Yes. The Company recommends replacing the existing well separators with horizontal separators, and the rate case reflects this recommendation.

Q. Why is the Company recommending the horizontal separators at this time?

A. Horizontal separators are recommended as the current planning basis due to prior operating experience, and their simpler, conventional design is expected to provide a maintainable configuration with liquid-retention volume and separation capacity suited to variable well conditions. Further, the expected direct capital cost of the recommended option is approximately $2 million less than if the Company were to replace the existing well separators with cyclonic separators.

Q. After the field performance evaluation is complete, which is expected by the beginning of 2027, is it possible that the Company could change its recommendation to cyclonic separators?

A. Yes. If the evaluation demonstrates that the cyclonic separators provide superior and needed performance across flow range, water production, solids loading, and pressure conditions to justify the operational complexity and increase in cost, then the Company could change its recommendation to cyclonic separators.

Q. Did the Company also consider doing nothing, and continuing to operate the existing well separators without the planned replacement?

A. Yes. The Company considered doing nothing, but then the separators would continue to operate with diminished effectiveness, increasing the amount of water and solids entering the downstream system. This would elevate the risk of hydrate formation, equipment damage, unplanned outages, and reduced throughput capacity, and also would increase maintenance costs and operational risk across the gas gathering system.

Q. What is the current status of the Mist Well Separator Replacement 2027 Project?

A. The Company expects to complete replacement of the separators by October 2027.

Q. What is the estimated total cost of the Mist Well Separator Replacement 2027 Project?

A. The total utility cost of the Mist Well Separator Replacement 2027 Project is expected to be approximately $6.0 million, or $5.3 million on an Oregon-allocated basis.

9. Mist Miller Air Compressor and Receiver Tank Project

Q. Please describe the current state of the air compressor system at Mist's Miller Station.

A. The Mist Miller Air Compressor and Receiver Tank Project is necessary because an air usage study performed by Burns and McDonnell in 2024, and reaffirmed in the Burns and McDonnell 2025 Facility Assessment, determined that the existing air compressor system at Mist's Miller Station does not have sufficient capacity during an emergency shutdown to operate with a single air compressor, as originally designed. Additionally, the receiver tank is not sized to provide sufficient reserve capacity to return the plant to a safe state in the event of a power outage, when all air compression would become unavailable.

Q. Please describe the Mist Miller Air Compressor and Receiver Tank Project.

A. The Mist Miller Air Compressor and Receiver Tank Project will upgrade the existing air compression system to have sufficient capacity for pneumatic controls for an emergency shutdown to ensure valves return to a safe state.

Q. Is the Company considering alternatives to performing the Mist Miller Air Compressor and Receiver Tank Project?

A. Yes. The Company's alternatives analysis process for this project will be developed in early 2027.

Q. What is the current status of the Mist Miller Air Compressor and Receiver Tank Project?

A. The Company expects to complete the Mist Miller Air Compressor and Receiver Tank Project by October 2028.

Q. What is the estimated total cost of the Mist Miller Air Compressor and Receiver Tank Project?

A. The total cost of the Mist Miller Air Compressor and Receiver Tank Project is expected to be approximately $1.5 million, or $1.3 million on an Oregon-allocated basis.

III. ILI CONVERSION PROJECTS

Q. Is the Company performing safety-related projects on its distribution system and at its storage facilities?

A. Yes. NW Natural currently is performing several safety-related projects on its transmission and distribution systems and at its storage facilities. These projects are also discussed in the Company's 2027 Safety Project Plan ("SPP"),[17] filed in docket UM 1900 on September 30, 2026. NW Natural estimates for 2027 that it

[17] The dollar amounts stated in this section of the testimony (III. ILI Conversion Projects) are project costs before construction overhead costs are added.

will invest approximately $19.9 million in capital to comply with PHMSA's TIMP, Distribution Integrity Management Program (DIMP) and other federal and state regulations.[18] For the purpose of this testimony, the Company will address its ILI Conversion Projects.

Q. Will the Company provide additional information to the Commission about these safety-related projects as they move forward?

A. Yes, the Company will keep the Commission and interested stakeholders informed through its SPPs filed in docket UM 1900.

Q. Please describe NW Natural's ILI Conversion Projects.

A. PHMSA requires transmission lines to be assessed at seven-year intervals, using one of three methodologies: ILI, External Corrosion Direct Assessment ("ECDA"), or pressure testing. On balance, ILI represents the most complete assessment of transmission pipeline and addresses the most threats to the system to meet PHMSA transmission line assessment requirements. NW Natural has been proactively upgrading its transmission facilities in a planful way to allow for the use of ILI for integrity assessment. For many of our transmission pipelines, NW Natural will need to invest in pipeline facilities such as 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

[18] The Company also expects to incur approximately $4.6 million of expenses to address and comply with DIMP, TIMP, damage prevention and public awareness.

advantage over direct assessment and pressure testing because they 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, bad pipe seams and metal loss. 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 as specified per Code is performed only in High Consequence Areas ("HCAs"), Moderate Consequence Areas ("MCAs") and "identified sites" (as that term is defined in 49 CFR 192.903), 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.

ILI conversion projects allow the Company to have a better understanding of a larger portion of the transmission pipeline system via ILI assessment methods,

than does assessment via ECDA methods, which results in a safer and more reliable natural gas system.

Q. How much of the Company's transmission pipeline network is capable of inspection with inline inspection technology?

A. Of the Company's 652 miles of transmission pipelines, approximately 530 miles have been inspected via ILI. The Company estimates that approximately 578 miles will have been inspected via ILI once the Company completes the planned ILI conversion projects identified in its 2025 ECDA to ILI Plan.

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 had been inspected by ECDA. No anomalies were found from the ECDA inspections. 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 (described in the Company's docket UG 490 rate case), 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 projects are you addressing in your testimony?

A. NW Natural expects to complete the following ILI projects to continue to comply with PHMSA's seven-year inspection requirement: P09 St. Helens 6"/8" Trans ILI Project, P21 Highway 212 Launcher Relocation Project, and P53.03 Front Avenue Robot Pig ILI Project.

Q. Please describe the P09 St. Helens 6"/8" Trans ILI Project.

A. The P09 St. Helens 6"/8" Trans ILI Project S03 Salem Bypass Trans ILI Project changes the ECDA assessment methodology to ILI. The Company is replacing approximately 0.4 miles of 12-inch transmission main with 6-inch pipeline, after analysis was performed that determined a smaller-sized pipe would have no impact on future gas supply to the area and to allow for a continuous ILI assessment of 6-inch and 8-inch pipeline from the Sauvie Island Gate Station to Columbia City. The Company expects to complete this project and place it in service by October 2027, at an estimated total cost of $5.9 million. Completion of this project results in the entire 22-mile long P09 pipeline being constructed of a diameter that will allow for a complete ILI assessment of the P09 pipeline.

Q. Please describe the P21 Highway 212 Launcher Relocation Project.

A. The P21 Highway 212 Launcher Relocation Project will relocate the existing pigging facility currently located in Happy Valley on the northeast corner of Highway 212 and SE 102nd Avenue to a lower-risk location at the northwest corner of SE Evelyn Street and SE Vista Avenue. The relocation is required due to the site being transitioned from a restaurant with a limited traffic pattern to a gas station

with an increased traffic pattern, and to ensure continued safe operations and compliance with ILI inspection requirements. The project does not involve changing the assessment methodology. The Company expects to complete this project and place it in service by October 2027, at an estimated total cost of $2.0 million.

Q. Please describe the P53.03 Front Avenue Robot Pig ILI Project.

A. The P53.03 Front Avenue Robot Pig ILI Project involves the first inline assessment of 1,000 feet of 16-inch transmission main from River Parkway to the Marquam Bridge station south of downtown Portland utilizing robotic technology. This pipeline was constructed in 1989. The P53.03 transmission pipeline is located in an area of Portland that is congested with traffic, park space, and other underground utilities, which has made it logistically challenging to install pig launchers and receivers for inline inspection and assessment. For this reason, this pipeline was previously assessed using ECDA. The Company expects to complete this project and place it in service by October 2027, at an estimated total cost of $1.2 million.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibits of Daniel B. Kizer and Michael C. Hwang

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS EXHIBITS 601 – 604

November 24, 2026

EXHIBITS 601-604 – DISTRIBUTION SYSTEM & STORAGE FACILITY PROJECTS

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

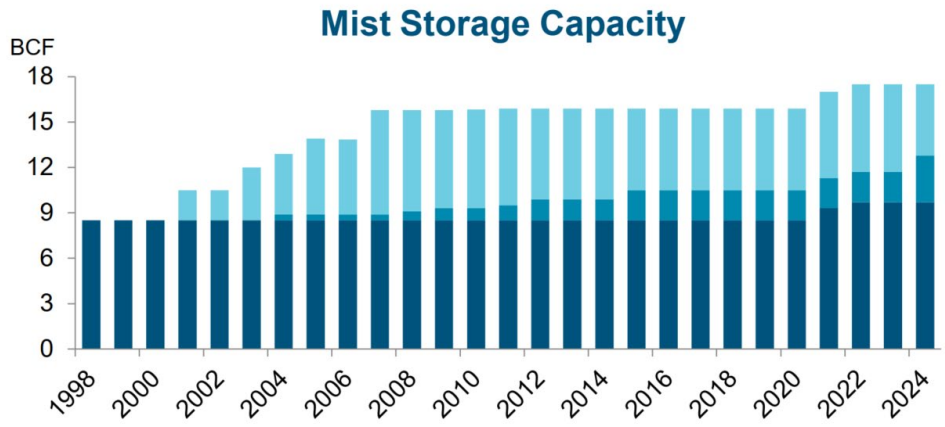
UG 532

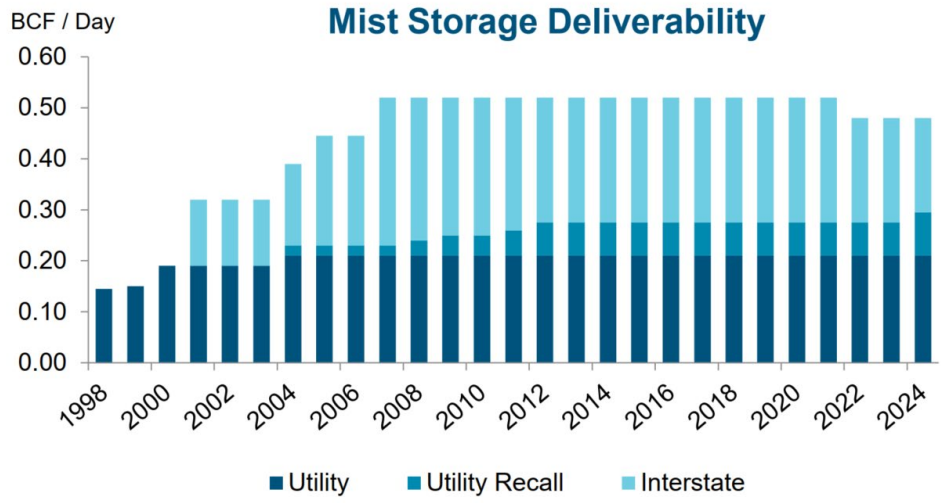
NW Natural

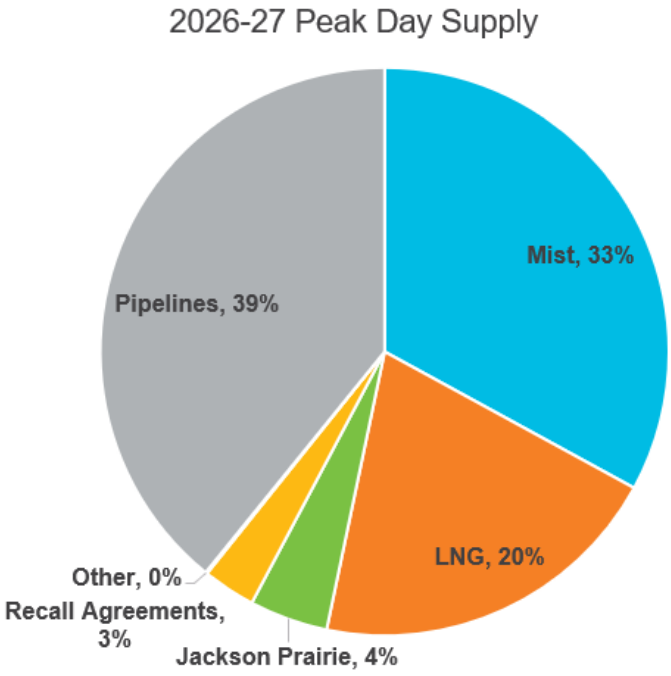
Exhibit of Daniel B. Kizer and Michael C. Hwang

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS EXHIBIT 601

November 24, 2026


Mist Storage Capacity
BCF
18
15
12
9
6
3
0
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024


Mist Storage Deliverability
BCF / Day
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
Utility
Utility Recall
Interstate


2026-27 Peak Day Supply
Mist, 33%
LNG, 20%
Jackson Prairie, 4%
Recall Agreements, 3%
Other, 0%
Pipelines, 39%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

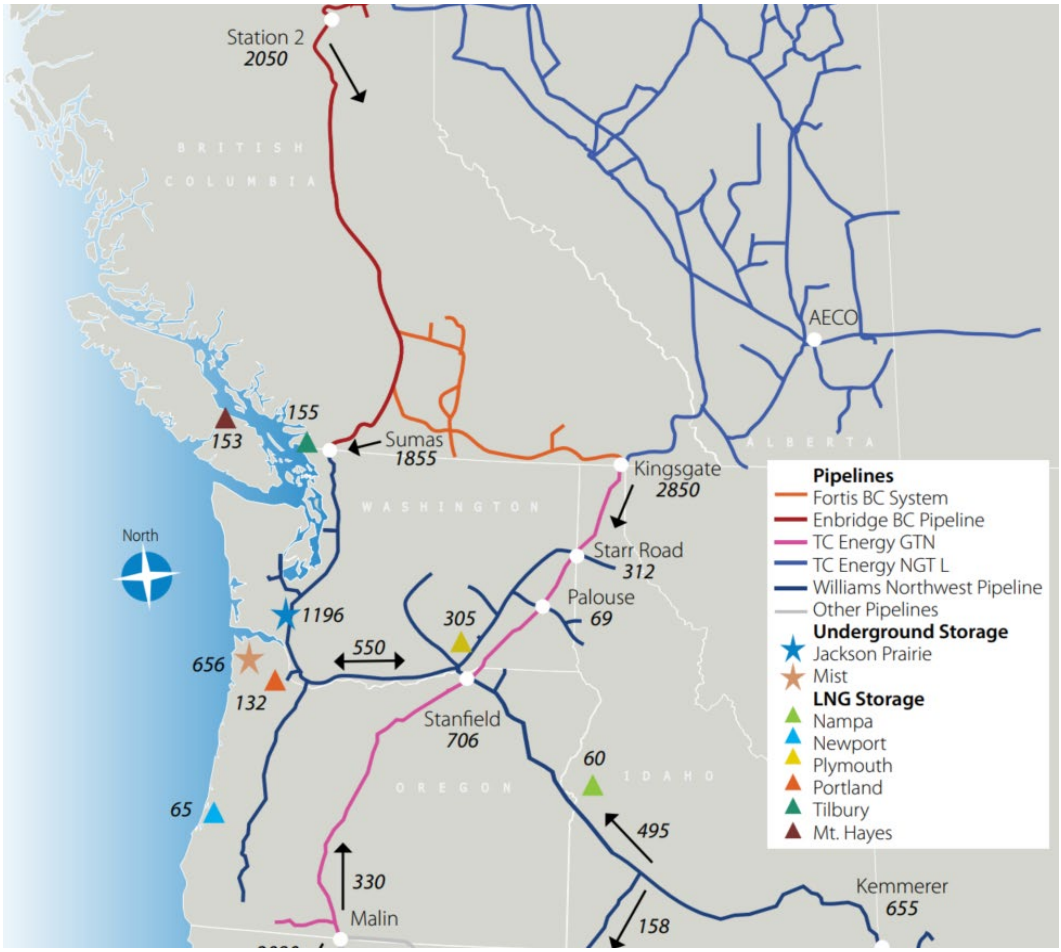
UG 532

NW Natural

Exhibit of Daniel B. Kizer and Michael C. Hwang

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS EXHIBIT 602

November 24, 2026


Station 2
2050
BRITISH
COLUMBIA
AECO
155
153
Sumas
1855
WASHINGTON
Kingsgate
2850
ALBERTA
North
Starr Road
312
Palouse
69
1196
305
550
656
132
Stanfield
706
60
IDAHO
OREGON
65
495
330
Malin
Kemmerer
655
158
Pipelines
Fortis BC System
Enbridge BC Pipeline
TC Energy GTN
TC Energy NGT L
Williams Northwest Pipeline
Other Pipelines
Underground Storage
Jackson Prairie
Mist
LNG Storage
Nampa
Newport
Plymouth
Portland
Tilbury
Mt. Hayes

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

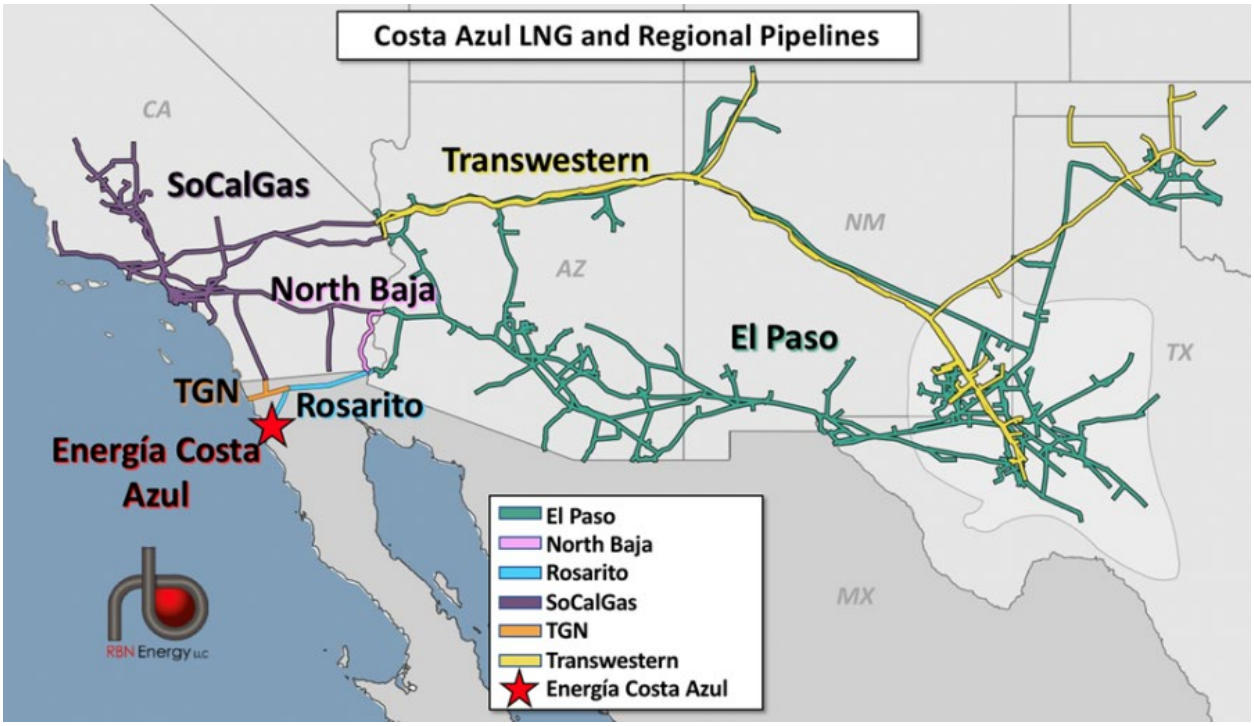
UG 532

NW Natural

Exhibit of Daniel B. Kizer and Michael C. Hwang

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS EXHIBIT 603

November 24, 2026


Costa Azul LNG and Regional Pipelines
CA
SoCalGas
Transwestern
NM
AZ
North Baja
El Paso
TX
TGN
Rosarito
Energía Costa Azul
MX
RBN Energy LLC
El Paso
North Baja
Rosarito
SoCalGas
TGN
Transwestern
Energía Costa Azul

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

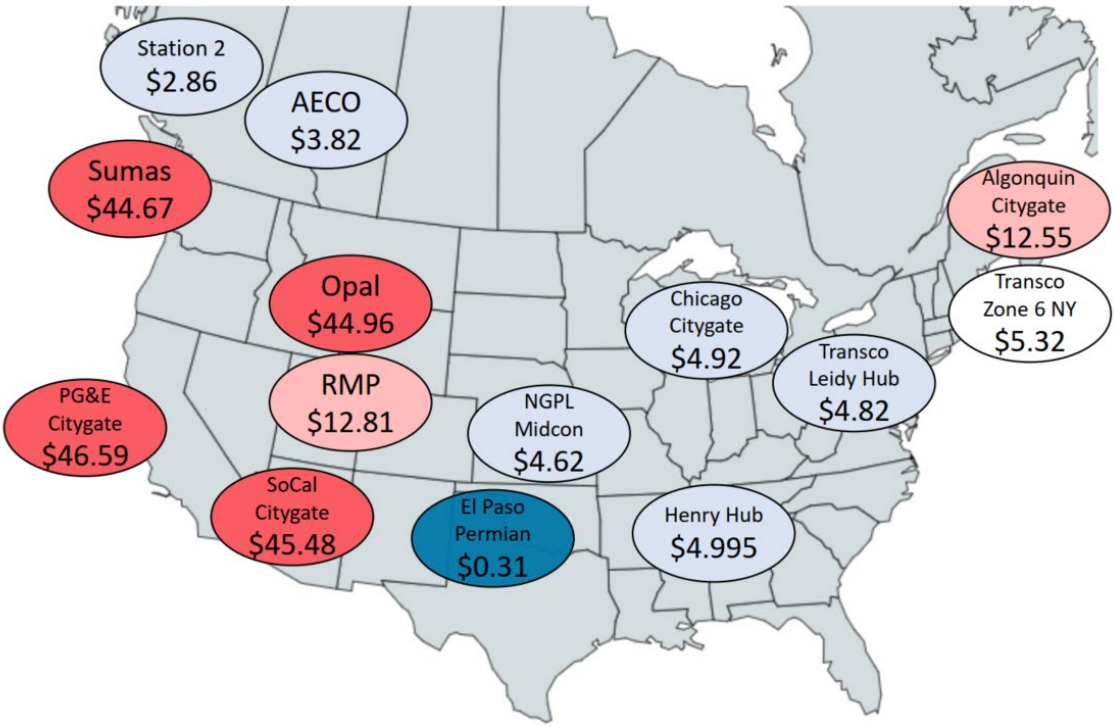
UG 532

NW Natural

Exhibit of Daniel B. Kizer and Michael C. Hwang

DISTRIBUTION SYSTEM AND STORAGE FACILITY PROJECTS EXHIBIT 604

November 24, 2026


Station 2
$2.86
AECO
$3.82
Sumas
$44.67
Opal
$44.96
RMP
$12.81
PG&E
Citygate
$46.59
SoCal
Citygate
$45.48
El Paso
Permian
$0.31
NGPL
Midcon
$4.62
Chicago
Citygate
$4.92
Henry Hub
$4.995
Transco
Leidy Hub
$4.82
Algonquin
Citygate
$12.55
Transco
Zone 6 NY
$5.32

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Direct Testimony of Wayne K. Pipes

FACILITIES
EXHIBIT 700

November 24, 2026

EXHIBIT 700 – DIRECT TESTIMONY – FACILITIES

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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 Wayne K. Pipes. I am the Director of Facilities, Security and Emergency Management for NW Natural. In this role I am responsible for facilities, planning, and management of real estate, construction, capital projects, maintenance, security, and emergency management activities for NW Natural.

Q. Please describe your education and employment background.

A. I have over 40 years of Facilities Management and Construction experience. I have been employed at NW Natural since 2014. Prior to assuming my current position at NW Natural, 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 purpose of my testimony is to describe facilities projects that are included in this rate case. Specifically, I discuss upgrades to the Coos Bay Resource Center ("RC") and the Salem RC, and our continuing progress on physical security upgrades.[1]

[1] For a description of the Company's capital expenditures budgeting and forecasting processes, including management approval and project/program lifecycle phases, please see the Direct Testimony of Jorge O. Moncayo, NW Natural/500, Moncayo.

Q. Please summarize your testimony.

A. This general rate case includes the following three important facilities projects, which will improve the resiliency of the Company's facilities and support ongoing safe and efficient operations.

- Coos Bay RC Project - Phase 2 – As part of our ongoing facilities strategy and the broader effort to retrofit the Coos Bay RC, NW Natural will be upgrading the Coos Bay RC by installing a fueling station and generator. Additionally, the Company is making seismic upgrades to the Coos Bay RC office and warehouse to address known seismic vulnerabilities so that the buildings meet operational safety performance objectives. Project completion is expected by October 2027.
- Salem RC Project – To enable more efficient and safe operations and ensure compliance with applicable requirements, NW Natural is installing a new decant system and truck scale at the Salem RC. Project completion is expected by September 2028.
- Physical Security Upgrades – NW Natural is continuing its multi-year effort of physical security upgrades at its facilities and field infrastructure. 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 through 2028, with project completions expected by October 2027 and October 2028.

Q. Prior to your discussion of these three projects, please provide an update on the Company's Facilities roadmap.

A. In 2008, NW Natural developed a facilities strategy as a flexible roadmap to guide the Company's facilities decisions and investments. Work at NW Natural facilities has been ongoing since then and is nearing completion. The Company completed the relocation of its The Dalles RC in October 2026. The Company's Albany RC Project is scheduled to be completed in 2029, and Phase 3 of its Coos Bay RC Project is scheduled to be completed in 2030. A few smaller projects, such as the installation of a new decant system and truck scale at the Mt. Scott RC and the Parkrose RC, will be completed by 2030.

Q. Have you prepared any exhibits to accompany your testimony?

A. Yes. The following exhibit accompanies my testimony:

- NW Natural/701, Pipes – KPFF Report – Coos Bay RC

II. DISCUSSION OF PROJECTS IN THIS CASE

A. Coos Bay RC Project – Phase 2

Q. Please provide an overview of the Coos Bay RC and the Coos Bay RC Project.

A. The Coos Bay RC, which is more than 60 years old and is located on a four-acre site purchased by the Company in 2005, is essential for supporting the delivery of safe and reliable service to, and providing regional emergency response for, Coos County and the western part of Douglas County. The site is outside of the tsunami inundation zone. The services provided out of the Coos Bay RC include customer field services, emergency response, construction,

transmission maintenance, leakage inspection, system operations, and field engineering. The facility also provides materials and equipment storage. Six employees work from this site.

The Coos Bay RC Project is a long-planned phased effort to update the site. The Company completed Coos Bay RC Project – Phase 1 in 2018, which involved a minor remodel to the interior office space at the RC. The Company identified the Coos Bay RC's seismic vulnerabilities in a 2016 assessment and previewed Coos Bay RC Project – Phase 2 in its Direct Testimony in UG 490, filed in December 2023.[2] The Coos Bay RC Project began well before, and is independent of, the Company's decision to pursue ownership of the Coos County Pipeline. The project would be needed regardless of who owns the Coos County Pipeline, because the Coos Bay RC supports safe and reliable service to the Company's distribution customers in Coos County.

Q. Please describe the scope of the Coos Bay RC Project - Phase 2.

A. Phase 2 of the Coos Bay RC Project is making seismic upgrades to the office and warehouse, installing an emergency backup generator, and constructing an on-site fuel station.

Q. Why is the Coos Bay RC Project - Phase 2 necessary?

A. The Coos Bay RC lacks key functionality that is now standard at NW Natural resource centers to ensure business continuity and to address emergency

[2] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Direct Testimony of Wayne K. Pipes, NW Natural/600, Pipes/36 (Dec. 29, 2023).

response and employee safety needs. That standard functionality includes seismic resiliency, backup power generation, and on-site fueling.

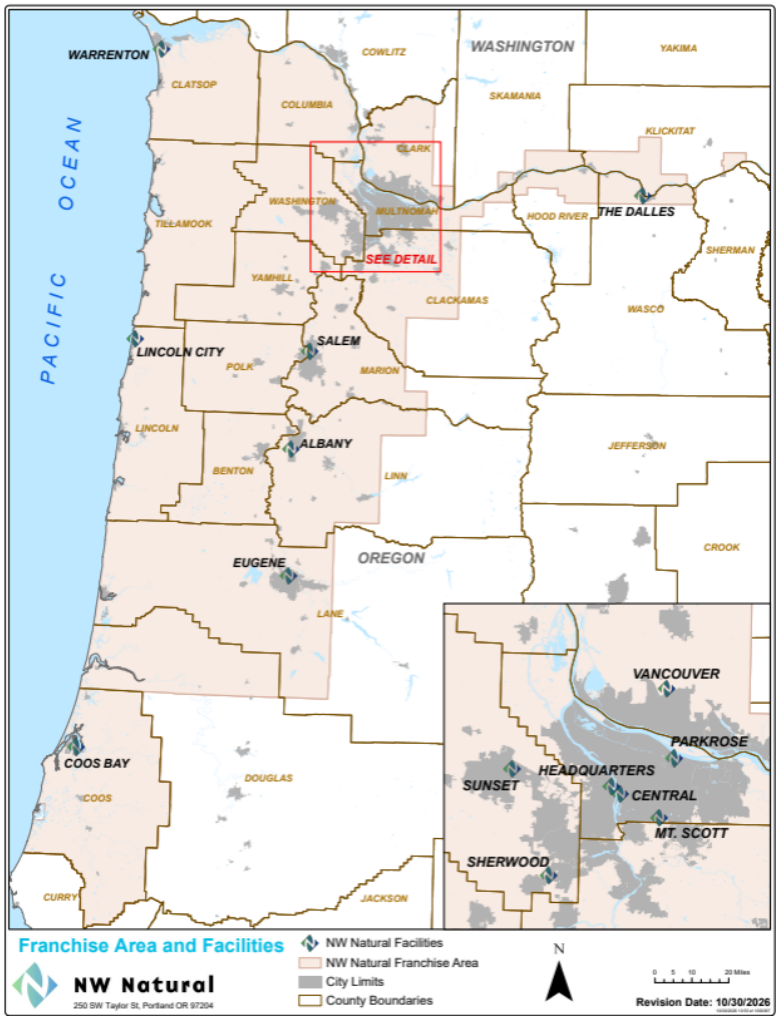
A seismic assessment by KPFF Engineering in 2016 (NW Natural/701, Pipes) determined that the office building and the parts warehouse do not meet basic operational safety performance objectives for existing buildings. This lack of seismic resiliency poses safety concerns for employees and could hinder the Company's ability to respond after a large seismic event.

Q. How is the Coos Bay RC Project – Phase 2 important to the Company's business continuity planning?

A. The Coos Bay RC is the Company's only facility along the southern coast, so it is essential for performing basic utility functions and serves as the center for Company regional emergency response in both Coos County and western Douglas County. As shown in Figure 1, the nearest NW Natural resource center to the Coos Bay RC is over 100 miles away, in Eugene, Oregon. The Coos Bay RC Project – Phase 2 will increase Company emergency response readiness by ensuring that the RC can remain operational following a seismic event. NW Natural also is constructing a fueling station that will be available for Company use during emergencies that impact retail fueling stations. During normal operations, the fueling station will improve productivity by allowing employees to fuel their Company vehicles and equipment while on site and at the beginning and end of their shifts, without having to take the time to travel to retail gas stations. In addition, installing backup power generation will ensure the resource center can

remain operational during power outages and emergencies that impact power in the area.

Figure 1: Proposed Updated Map of NW Natural Service Area Tariff Sheet[3]



Q. What alternatives did the Company consider to the Coos Bay RC Project – Phase 2?

A. The Company considered three alternatives to the Coos Bay RC Project – Phase 2. First, NW Natural considered purchasing a new site, either retrofitting or

[3] See the Direct Testimony of Kyle T. Walker, NW Natural/1200, Walker.

replacing the existing buildings/site, and selling the current NW Natural site to offset the costs. Second, the Company considered moving employees, vehicles, equipment, and materials to its Eugene RC. Finally, the Company considered the option of doing nothing.

The Company determined that moving operations to the Eugene RC or doing nothing were not viable options. Moving operations to the Eugene RC (over 100 miles away) would severely impact the Company's ability to timely respond to emergency calls in Coos County and west Douglas County. Furthermore, the Eugene RC is not large enough to accommodate the employees, equipment, materials, and vehicles from the Coos Bay RC. Doing nothing was not viable because the Coos Bay RC does not meet basic life safety performance objectives.

Purchasing a new site, while viable, would have been significantly more expensive, taken longer to address the identified issues, and carried more construction risk than retrofitting the current Coos Bay RC site.

Q. What is the current status of the Coos Bay RC Project – Phase 2?

A. The Company expects to begin construction on the Coos Bay RC Project – Phase 2 early in the second quarter of 2027 and to complete it and place it in service by October 2027.

Q. What is the estimated cost to complete the Coos Bay Project – Phase 2?

A. The total cost to complete the Coos Bay RC Project – Phase 2 is expected to be approximately $5.0 million.

B. Salem RC Project

Q. Please provide an overview of the Salem RC.

A. The Salem RC, which was originally constructed in 1966, is essential for supporting the delivery of safe and reliable service to the greater Salem area including Amity, Aumsville, Aurora, Canby, Charbonneau, Dallas, Donald, Gervais, Grand Ronde, Hubbard, Independence, Keizer, Lafayette, Lyons, McMinnville, Mill City, Molalla, Monmouth, Mt. Angel, Salem, Sheridan, Silverton, Stayton, Turner, Willamina, and Woodburn. The services provided out of the Salem RC include contract management, gas distribution, pipe and equipment corrosion, contact center, electronic technical services, emergency response, field engineering, field services, information technology, safety, system operations, gas transmission, transportation and utility support. The Salem RC also provides storage for vehicles, equipment, parts, and materials. There are currently 74 employees who work from the Salem RC. The Salem RC is comprised of an office and warehouse with multiple other outbuildings. The office and warehouse were mostly upgraded in 2014.

Q. Please describe the scope of the Salem RC Project.

A. The Company is installing a new decant system and truck scale to enable more efficient operations and ensure compliance with applicable requirements. Those functionalities were not included in the 2014 upgrades because the efficiency and safety of the associated technology at that time needed to mature to better meet the Company's operational standards.

Q. Please provide detail regarding the decant system that will be installed at the Salem RC.

A. The decant system separates liquids from soils removed during excavation work (also called "spoils") completed for utility operations. The spoils are placed in the decant system, which is a sloped containment bin that enables liquids to separate from the soil through settling of the heavier solid materials and evaporation and draining of the liquids. Once removed, the liquid is filtered through a filtration system before it passes into a stormwater drain. Finally, the dry residue is disposed of at an appropriate site. NW Natural can dispose of dry residue more efficiently because there are more sites available for dry residue disposal.

Q. Why is the decant system necessary?

A. The decant system is important to NW Natural's Salem 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 too many vehicles and pose safety concerns for our employees when entering sites, during spoil disposal, and exiting sites. Additionally, due to the limited availability of sites accepting spoils, NW Natural has needed to haul spoils offsite, which is an inefficient use of resources in terms of both fuel and employee time. Due to these issues, NW Natural is installing decant systems at all resource centers.

Q. Please provide detail regarding the truck scale that will be installed at the Salem RC and explain why it is necessary.

A. The truck scale is used to weigh NW Natural's semitrucks and trailers before they leave the facility for a delivery. This is an important compliance and safety measure to ensure that NW Natural's trucks and trailers meet applicable weight limitations and to avoid over-loading trucks with equipment and materials. NW Natural uses its trucks and trailers daily to haul excavation equipment and job supplies to job sites.

Q. Did the Company consider alternatives to installing the new decant system and truck scale at the Salem RC?

A. Yes. The alternatives to installing a decant system and truck scale are limited. As noted above, sites accepting spoils are becoming more limited. The Company also considered not installing these upgrades but rejected that alternative because it would not fulfill the operational needs and objectives discussed above. The absence of an onsite decant system at the Salem RC means employees must take an estimated 40-minute round trip to haul spoils to the closest available disposal site.

Q. What is the current status of the Salem RC Project?

A. The Company expects to begin construction on the Salem RC Project in the fourth quarter of 2027 and to complete it and place it in service by October 2028.

Q. What is the estimated cost to complete the Salem RC Project?

A. The total cost to complete the Salem RC Project is expected to be approximately $3.1 million.

C. Physical Security Upgrades

Q. Please summarize the security upgrades NW Natural is undertaking.

A. In response to increasing threats and ongoing direction from TSA, NW Natural is in the midst of a comprehensive, multi-year effort to enhance the physical security at the Company's facilities and field infrastructure, which began with a pilot in 2023. The Company is implementing improvements at multiple sites each year, with completed upgrades becoming operational and delivering security benefits as they are placed into service. The Company has made significant progress on its security upgrades and anticipates it will complete the remaining systemwide security enhancements by October 2028.

Q. How did NW Natural determine that security upgrades are necessary?

A. A variety of emerging threats and new requirements over the last decade 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 Company documented all physical security apparatuses, identified potential risks, and engaged consulting firm CH2M to develop a criticality ranking and asset protection recommendations.

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.[4] 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.[5]

Following the May 2021 ransomware attack on the Colonial Pipeline, TSA issued several directives mandating cybersecurity measures. 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. For more details on these directives, refer to the Direct Testimony of Brian E. Fellon (NW Natural/800, Fellon).

In June 2022, TSA conducted an audit of several NW Natural sites classified as "critical" infrastructure. The TSA audit recommendations also informed the Company's planned upgrades at other sites.

The United States in general has seen ongoing attacks on the energy system, including intentional destruction of critical infrastructure, unauthorized access to facilities, and instances of individuals using recording devices, taking pictures, and flying drones over refineries and other facilities. Over the last few

[4] Transportation Security Administration, *Pipeline Security Guidelines* (March 2018; updated April 2021), *available at:* https://www.tsa.gov/sites/default/files/pipeline_security_guidelines.pdf.

[5] *Id.,* at 8-15.

years, the Company has experienced break-ins and theft at the Company's resource centers and damage to regulator stations. Because of these continuing activities, it is imperative that NW Natural continue addressing physical security upgrades in a comprehensive way.

In 2023, NW Natural conducted a pilot program at five key sites to help the Company refine its choice of technology/equipment, procurement strategy, quality assurance, risk management, cost estimates, and efficient execution of security upgrades. The Company has used the insight gained from the pilot program to plan and execute ongoing security upgrades in an efficient and cost-effective manner.

Q. How will the security upgrades included in this case provide benefits?

A. Security upgrades provide several benefits: they help ensure the Company's system can continue providing safe and reliable service to customers without interruption; they improve employee safety; they protect property, plant and equipment; they improve cyber security at locations that are connected to our gas control system; and they also ensure NW Natural is compliant with requirements from regulators, specifically the TSA.

Q. What is the Company's forecasted cost and timing for these projects?

A. The broader upgrade program is expected to continue through 2028, with annual security upgrades placed in service on a rolling basis as they are completed. Various sites will be completed each year. The current budget for these projects is $2.5 million per year, or $2.2 million allocated to Oregon.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Wayne K. Pipes

FACILITIES
EXHIBIT 701

November 24, 2026

EXHIBIT 701 – FACILITIES

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ASCE 41-13 Tier 1 Seismic Evaluation of

NW Natural – Coos Bay

1625 N 7th Street
Coos Bay, OR 97420

August 5, 2016
KPFF Project No. 1600122



NW Natural – Coos Bay Service Center
ASCE 41-13 Tier 1 Seismic Evaluation

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Appendix ASCE 41-13 Summary Data Sheet & Checklists

Introduction

This report summarizes the findings of our seismic evaluation of the NW Natural Coos Bay Facility located at 1625 N 7th Street, Coos Bay, 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 Coos Bay Facility located in Coos Bay, Oregon. This evaluation is based on a site visit that was completed on May 13, 2016, the existing drawings dated March 11th 1964, 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 Coos Bay Facility is composed of three existing buildings: (1) the main concrete building, (2) a wood shed to the north, and (3) a combination steel and wood shed to the south currently being leased by others. Only the main concrete building is evaluated in this report.

Designed in 1964, the Coos Bay Main Building is an existing precast concrete tilt-up, one story building with a wood roof. A steel shed was later added immediately to the north (specific date is unknown) and appears to be connected to the main building. The main building measures 100 feet east-west by 140 feet north-south. The western half of the building is a 26-foot-tall bay currently used for equipment maintenance and includes a crane. The eastern half of the building is shorter (15 foot tall) and is divided into offices in the south and storage in the north.

Reinforced concrete columns bound precast concrete tilt-up panels at the exterior and longitudinally down the center of the building. Large glulam beams span the western maintenance bay and are supported by the reinforced concrete columns. Smaller glulam beams span the eastern half of the building and are supported both by concrete columns and steel posts. Beneath each column is a concrete spread footing while a concrete slab-on-grade exists for the entire building footprint. Wood purlins span between glulam beams and support plywood sheathing to form the roof.

The identified load path for seismic forces is the plywood roof diaphragm spanning to precast concrete tilt-up panels which deliver load to the ground; however, as with most precast tilt-up buildings, the connections between these structural elements are either lacking or insufficient.

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
$S_{X1,\ BSE\text{-}1E}$	0.228 g	Design spectral response acceleration parameter at 1 second for the BSE-1E seismic hazard level.
$S_{XS,\ BSE\text{-}1N}$	0.953 g	Design short-period (0.2 seconds) spectral response acceleration parameter for the BSE-1N seismic hazard Level.
T	0.200 s	Building fundamental period, as defined in Section 4.5.2.4.
S_a	0.715 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 determined to be “High” as defined by Section 2.5 of ASCE 41-13. Reference Appendix A for the full summary of the evaluation assumptions.

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 the 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. Additional tables of structural and nonstructural unknowns are also included and indicate items which, if evaluated, could become a deficiency. Reference Appendix A for the summary data sheet and completed checklists.

Structural Deficiencies

No.	Item	Tier 1 Ref.	Comments
1	Wall Anchorage	A.5.1.1	There are inadequate development of out-of-plane forces into diaphragm.
2	Adjacent Buildings	A.2.1.2	The steel shed immediately to the north is not sufficiently separated from main structure.
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 indicate that the site has a "High" 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 indicate that the site has a "Moderate - Landsliding Possible" hazard. This refers to the steep slope to the west of building.
5	Ties Between Foundation Elements	A.6.2.2	
6	Wall Thickness	A.3.2.3.5	6” thick precast walls.
7	Wood Ledgers	A.5.1.2	
8	Cross Ties in Flexible Diaphragms	A.4.1.2	
9	Diagonally Sheathed and Unblocked Diaphragms	A.4.2.3	There are unblocked plywood diaphragm spans more than 40ft.
10	Precast Wall Panels	A.5.3.6	
11	Girders	A.5.4.2	The purlin to wall connection only includes one anchor bolt.

Structural Unknowns

No.	Item	Tier 1 Ref.	Comments
1	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 not indicate that there are active faults immediately beneath the site.
2	Tsunami	N/A	A geotechnical report was not available for review. However, the Oregon Department of Geology and Mineral Industries (DOGAMI) Statewide Geohazards Viewer indicates that the site is just outside the tsunami inundation zone.

Nonstructural Deficiencies

No.	Item	Tier 1 Ref.	Comments
1	Independent Support	A.7.3.2	
2	Tall Narrow Contents	A.7.11.2	There are tall shelves and other narrow contents.
3	Fall Prone Contents	A.7.11.3	There are stored items on tall shelves.

Nonstructural Unknowns

No.	Item	Tier 1 Ref.	Comments
1	Crane	N/A	Crane and crane rail attachments potentially not suitable to prevent unseating or crane collapse.

Conceptual Seismic Upgrade Work

Structural deficiencies are identified in the Tier 1 Checklists, and are listed in the Structural Deficiencies table previously shown in this report. The following is a list of potential solutions to mitigate those deficiencies:

1. Wall Anchorage: Provide new anchors from precast wall to roof diaphragm or strengthen connection of existing anchors to diaphragm.
2. Adjacent Buildings: Provide new connections between existing steel shed and main structure or separate steel shed from main structure.
3. Liquefaction: Have a geotechnical study performed to determine if liquefaction is a potential hazard at this site. If so, geotechnical ground improvement is likely required.
4. Slope Failure: Have a geotechnical study performed to determine if liquefaction is a potential hazard at this site. If so, geotechnical slope stabilization is likely required.
5. Ties between Foundation Elements: Install new reinforced concrete tie beams between existing footings.

6. Wall Thickness: Perform additional analysis to demonstrate that wall thickness is sufficient for bearing walls. Alternatively, provide supplemental steel posts at locations where walls are providing gravity support.
7. Wood Ledgers: Provide new anchors or strengthen existing connections to remove cross-grain tension.
8. Cross Ties in Flexible Diaphragms: Add steel strap cross-ties, with blocking, between walls on opposite sides of the diaphragm.
9. Diagonally Sheathed and Unblocked Diaphragms: Provide diaphragm blocking for long-span condition or create sub-diaphragms.
10. Precast Wall Panels: Install new reinforced concrete grade beams or thickened slab below and provide connection to precast panels. Coordinate work with that proposed under "Ties Between Foundation Elements".
11. Girders: Strengthen existing connection or provide supplemental steel posts. If supplemental steel posts are provided, coordinate work with that proposed under "Wall Thickness".

Nonstructural deficiencies are identified in the Tier 1 Checklists, and are listed in the Nonstructural Deficiencies table previously shown in this report. The following is a list of potential solutions to mitigate those deficiencies:

1. Independent Support: Install diagonal wires for each light fixture that is part of a dropped ceiling per current code requirements.
2. 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.
3. Fall-Prone Contents: Brace or restrain contents on storage racks/shelves/etc., that weigh more than 20 pounds, and are located more than 4 feet above the adjacent floor level.

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 Coos Bay Facility. 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 higher of the BSE-1E seismic hazard or 0.75 times the BSE-1N seismic hazard (latter based on 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.

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 for a building constructed to modern building codes. The structural seismic upgrade work would primarily involve roof diaphragm strengthening, installing new connections between the roof diaphragm and precast concrete tilt-up walls, installing new connections from the precast concrete tilt-up walls to the foundation, and potentially thickening the existing slab-on-grade edge (depending on further analysis). If liquefaction and slope failure potential is determined to be a concern at the site based on a geotechnical study, ground and slope stability improvements may be necessary. Most of the nonstructural seismic upgrade work would relate to bracing and/or restraint of nonstructural components and contents. 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 - Coos Bay Date: 5/13/16
Building Address: 1625 N 7th Street, Coos Bay, OR 97420
Latitude: 43.379700 Longitude: -124.221039 By: RBZ

Year Built: 1964 Year(s) Remodeled: N/A Original Design Code: Unknown
Area (sf): 14,000 Length (ft): 140 Width (ft): 100
No. of Stories: 1 Story Height: Varies 15' to 26' Total Height: Varies 15' to 26'

USE ☐ Industrial ☐ Office ☑ Warehouse ☐ Hospital ☐ Residential ☐ Educational ☐ Other: _____

CONSTRUCTION DATA

Gravity Load Structural System: Combination of precast concrete bearing walls and steel pipe columns
Exterior Transverse Walls: Precast concrete walls Openings? Yes
Exterior Longitudinal Walls: Precast concrete walls Openings? Yes
Roof Materials/Framing: Wood beams, purlins and plywood decking
Intermediate Floors/Framing: Not applicable
Ground Floor: Concrete slab-on-grade
Columns: Steel pipe Foundation: Spread Footings
General Condition of Structure: Fair
Levels Below Grade? Not applicable
Special Features and Comments: Metal shed built immediately to the north (steel columns, steel roof beams, tension rods)

LATERAL-FORCE-RESISTING SYSTEM

	Longitudinal	Transverse
System:	Precast concrete shear walls	Precast concrete shear walls
Vertical Elements:	Concrete bearing walls and steel pipes	Concrete bearing walls and steel pipes
Diaphragms:	Plywood sheathing	Plywood sheathing
Connections:	Varies	Varies

EVALUATION DATA

BSE-1N Spectral Response Accelerations: S_{Ds}= 0.953 S_{D1}= 0.708
Soil Factors: Class= D (assumed)
BSE-1E Spectral Response Accelerations: S_{XS}= 0.362 S_{X1}= 0.228
Level of Seismicity: High Performance Level: Life Safety
Building Period: T= 0.20 sec
Spectral Acceleration: S_a= 0.71=max[0.75*min(Sd1/T,Sds),min(Sx1/T,Sxs)]
Modification Factor: $C_mC_1C_2$= 1.0 Building Weight: W= 750k
Pseudo Lateral Force: $V = C_mC_1C_2S_aW$= 530k

BUILDING CLASSIFICATION: PC1

REQUIRED TIER 1 CHECKLISTS

	Yes	No
Basic Configuration Checklist	☑	☐
Building Type PC1 Structural Checklist	☑	☐
Nonstructural Component Checklist	☑	☐

FURTHER EVALUATION REQUIREMENT: _____

Project Name NW Natural - Coos Bay
Project Number 1600122

ASCE 41-13 Tier 1 Checklists

FIRM:	KPFF Consulting Engineers
PROJECT NAME:	NW Natural - Coos Bay
SEISMICITY LEVEL:	High
PROJECT NUMBER:	1600122
COMPLETED BY:	RBZ
DATE COMPLETED:	May 13, 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 - Coos Bay
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)	plywood sheathing to anchor bolts in precast walls to concrete columns (shear friction) into concrete spread footings
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)	inadequate development of out-of-plane forces into diaphragm

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Project Name NW Natural - Coos Bay
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)	plywood sheathing to anchor bolts in precast walls to concrete columns (shear friction) into concrete spread footings
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)	steel shed immediately to the north is not sufficiently separated from main structure; not a major concern for life safety however
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)	

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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)	
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)	
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)	
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)	

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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)	
☒	☐	☐	☐	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. However, the Oregon Department of Geology and Mineral Industries (DOGAMI) Statewide Geohazards Viewer does indicate that the site has a "High" liquefaction hazard.
☐	☒	☐	☐	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. However, the Oregon Department of Geology and Mineral Industries (DOGAMI) Statewide Geohazards Viewer does indicate that the site has a "Moderate - Landsliding Possible" hazard. This refers to the steep slope to the west of building.

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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 review. However, the Oregon Department of Geology and Mineral Industries (DOGAMI) Statewide Geohazards Viewer does not indicate that there are active faults immediately beneath the site.

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)	

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Project Name NW Natural - Coos Bay
Project Number 21600122

ASCE 41-13 Tier 1 Checklists

FIRM:	KPFF Consulting Engineers
PROJECT NAME:	NW Natural - Coos Bay
SEISMICITY LEVEL:	High
PROJECT NUMBER:	21600122
COMPLETED BY:	RBZ
DATE COMPLETED:	May 13, 2016
REVIEWED BY:	IKE
REVIEW DATE:	August 5, 2016

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Project Name NW Natural - Coos Bay
Project Number 21600122

16.12LS Life Safety Structural Checklist for Building Types PC1: Precast or Tilt-Up Concrete Shear Walls with Flexible Diaphragms and PC1A: Precast or Tilt-Up Concrete Shear Walls with Stiff Diaphragms

Low Seismicity

Connections

RATING				DESCRIPTION	COMMENTS
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)	inadequate development of out-of-plane forces into diaphragm

Moderate Seismicity

Seismic-Force-Resisting System

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☒	☐	☐	☐	REDUNDANCY: The number of lines of shear walls in each principal direction is greater than or equal to 2. (Commentary: Sec. A.3.2.1.1. Tier 2: Sec. 5.5.1.1)	
☒	☐	☐	☐	WALL SHEAR STRESS CHECK: The shear stress in the precast panels, calculated using the Quick Check procedure of Section 4.5.3.3, is less than the greater of 100 lb/in.^{2} or $2\sqrt{f'_c}$. (Commentary: Sec. A.3.2.3.1. Tier 2: Sec. 5.5.3.1.1)	

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C	NC	N/A	U		
☒	☐	☐	☐	REINFORCING STEEL: The ratio of reinforcing steel area to gross concrete area is not less than 0.0012 in the vertical direction and 0.0020 in the horizontal direction. (Commentary: Sec. A.3.2.3.2. Tier 2: Sec. 5.5.3.1.3)	#5 @ 12" o.c. vertical; #5 @ 14" o.c. horizontal
☐	☒	☐	☐	WALL THICKNESS: Thicknesses of bearing walls shall not be less than 1/40 the unsupported height or length, whichever is shorter, nor less than 4 in. (Commentary: Sec. A.3.2.3.5. Tier 2: Sec. 5.5.3.1.2)	6" thick precast walls

Diaphragms

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☒	☐	TOPPING SLAB: Precast concrete diaphragm elements are interconnected by a continuous reinforced concrete topping slab with a minimum thickness of 2 in. (Commentary: Sec. A.4.5.1. Tier 2: Sec. 5.6.4)	

Connections

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☒	☐	☐	WOOD LEDGERS: The connection between the wall panels and the diaphragm does not induce cross-grain bending or tension in the wood ledgers. (Commentary: Sec. A.5.1.2. Tier 2: Sec. 5.7.1.3)	

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C	NC	N/A	U		
☒	☐	☐	☐	TRANSFER TO SHEAR WALLS: Diaphragms are connected for transfer of seismic forces to the shear walls. (Commentary: Sec. A.5.2.1. Tier 2: Sec. 5.7.2)	1/2"x6" anchor bolts @ 4'-0" o.c.
☐	☐	☒	☐	TOPPING SLAB TO WALLS OR FRAMES: Reinforced concrete topping slabs that interconnect the precast concrete diaphragm elements are doweled for transfer of forces into the shear wall or frame elements. (Commentary: Sec. A.5.2.3. Tier 2: Sec. 5.7.2)	
☒	☐	☐	☐	GIRDER–COLUMN CONNECTION: There is a positive connection using plates, connection hardware, or straps between the girder and the column support. (Commentary: Sec. A.5.4.1. Tier 2: Sec. 5.7.4.1)	steel hanger connections

High Seismicity

Seismic-Force-Resisting System

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☐	☒	☐	DEFLECTION COMPATIBILITY FOR RIGID DIAPHRAGMS: Secondary components have the shear capacity to develop the flexural strength of the components. (Commentary: Sec. A.3.1.6.2. Tier 2: Sec. 5.5.2.5.2)	

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C	NC	N/A	U		
☒	☐	☐	☐	WALL OPENINGS: The total width of openings along any perimeter wall line constitutes less than 75% of the length of any perimeter wall when the wall piers have aspect ratios of less than 2-to-1. (Commentary: Sec. A.3.2.3.3. Tier 2: Sec. 5.5.3.3.1)	north and south walls have wall piers around openings for maintenance bay that are more than 2-to-1 aspect ratio; elsewhere openings less than 75% of wall length

Diaphragms

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☐	☒	☐	☐	CROSS TIES IN FLEXIBLE DIAPHRAGMS: There are continuous cross ties between diaphragm chords. (Commentary: Sec. A.4.1.2. Tier 2: Sec. 5.6.1.2)	
C	NC	N/A	U		
☐	☐	☒	☐	STRAIGHT SHEATHING: All straight sheathed diaphragms have aspect ratios less than 2-to-1 in the direction being considered. (Commentary: Sec. A.4.2.1. Tier 2: Sec. 5.6.2)	
C	NC	N/A	U		
☒	☐	☐	☐	SPANS: All wood diaphragms with spans greater than 24 ft consist of wood structural panels or diagonal sheathing. (Commentary: Sec. A.4.2.2. Tier 2: Sec. 5.6.2)	

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C	NC	N/A	U		
☐	☒	☐	☐	DIAGONALLY SHEATHED AND UNBLOCKED DIAPHRAGMS: All diagonally sheathed or unblocked wood structural panel diaphragms have horizontal spans less than 40 ft and aspect ratios less than or equal to 4-to-1. (Commentary: Sec. A.4.2.3. Tier 2: Sec.5.6.2)	unblocked plywood diaphragm spans more than 40ft
☐	☐	☒	☐	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)	

Connections

RATING				DESCRIPTION	COMMENTS
C	NC	N/A	U		
☒	☐	☐	☐	MINIMUM NUMBER OF WALL ANCHORS PER PANEL: There are at least two anchors from each precast wall panel into the diaphragm elements. (Commentary: Sec. A.5.1.3. Tier 2: Sec. 5.7.1.4)	
☐	☒	☐	☐	PRECAST WALL PANELS: Precast wall panels are connected to the foundation. (Commentary: Sec. A.5.3.6. Tier 2: Sec. 5.7.3.4)	

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C	NC	N/A	U		
☐	☐	☒	☐	UPLIFT AT PILE CAPS: Pile caps have top reinforcement, and piles are anchored to the pile caps. (Commentary: Sec. A.5.3.8. Tier 2: Sec. 5.7.3.5)	
☐	☒	☐	☐	GIRDERS: Girders supported by walls or pilasters have at least two ties securing the anchor bolts unless provided with independent stiff wall anchors with adequate strength to resist the connection force calculated in the Quick Check procedure of Section 4.5.3.7. (Commentary: Sec. A.5.4.2. Tier 2: Sec. 5.7.4.2)	purlin to wall connection only includes one anchor bolt

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ASCE 41-13 Tier 1 Checklists

FIRM:	KPFF Consulting Engineers
PROJECT NAME:	NW Natural - Coos Bay
SEISMICITY LEVEL:	High
PROJECT NUMBER:	21600122
COMPLETED BY:	RBZ
DATE COMPLETED:	May 13, 2016
REVIEWED BY:	IKE
REVIEW DATE:	August 5, 2016

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Project Number 21600122

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)	
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)	
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)	
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)	

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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)	
☐	☐	☒	☐	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)	not required for life safety

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)	
☒	☐	☐	☐	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)	hazardous materials storage (yellow cabinet)

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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)	
☐	☐	☒	☐	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)	
☐	☐	☒	☐	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)	
☐	☐	☒	☐	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)	

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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)	
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)	
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)	
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)	not required for life safety

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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)	not required for life safety
☐	☐	☒	☐	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)	not required for life safety

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)	
☐	☐	☒	☐	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)	

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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)	not required for life safety
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)	not required for life safety
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)	not required for life safety
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)	not required for life safety

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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)	not required for life safety

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)	
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)	not required for life safety
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)	not required for life safety

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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)	
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)	
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)	
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)	

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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)	
☐	☐	☒	☐	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)	
☐	☐	☒	☐	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)	

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)	

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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)	
C	NC	N/A	U		
☐	☐	☒	☐	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)	
C	NC	N/A	U		
☐	☐	☒	☐	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)	
C	NC	N/A	U		
☐	☐	☒	☐	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)	

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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)	
☐	☐	☒	☐	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)	not required for life safety
☐	☐	☒	☐	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)	not required for life safety

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)	

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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)	
☒	☐	☐	☐	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)	vertical reinforcing present in precast panels
☐	☐	☒	☐	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)	

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)	

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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)	

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)	
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)	

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)	

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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)	tall shelves and other narrow contents
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)	stored items on tall shelves
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)	not required for life safety
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)	not required for life safety

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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)	not required for life safety

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)	
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)	
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)	

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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)	not required for life safety
☐	☐	☒	☐	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)	not required for life safety
☐	☐	☒	☐	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)	not required for life safety
☐	☐	☒	☐	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)	not required for life safety

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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)	not required for life safety
☐	☐	☒	☐	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)	not required for life safety

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)	not required for life safety
☐	☐	☒	☐	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)	not required for life safety

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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)	not required for life safety
C	NC	N/A	U		
☐	☐	☒	☐	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)	not required for life safety

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)	not required for life safety
C	NC	N/A	U		
☐	☐	☒	☐	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)	not required for life safety

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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)	not required for life safety

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)	
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)	
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)	not required for life safety

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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)	not required for life safety
☐	☐	☒	☐	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)	not required for life safety
☐	☐	☒	☐	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)	not required for life safety
☐	☐	☒	☐	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)	not required for life safety

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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)	not required for life safety
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)	not required for life safety

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Direct Testimony of Brian E. Fellon

INFORMATION TECHNOLOGY & SERVICES
EXHIBIT 800

REDACTED

November 24, 2026

EXHIBIT 800 – DIRECT TESTIMONY – INFORMATION TECHNOLOGY & SERVICES

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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 of Science in Business Administration from the University of Washington and a Master of Business Administration from Seattle University. I have nearly 30 years of experience in information technology, and 20-plus years of IT leadership at 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 the retail sectors.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe NW Natural's IT&S strategy and investments. First, I provide an overview of NW Natural's IT&S environment, including the continued need to migrate to cloud-based software, the corresponding increase in incremental operations and maintenance ("O&M")

expense, and the rapid evolution of IT&S systems. Second, I provide a brief update on the second phase of the Company's Horizon Program. Third, I describe the Company's ongoing work to comply with security directives from the Department of Homeland Security's Transportation Security Administration ("TSA Compliance Program"). Fourth, I detail the major IT&S investments for which the Company seeks cost recovery in this proceeding.[1]

Q. Please explain how the Company's major IT&S investments are organized.

A. The Company's major IT&S investments include both discrete, standalone projects and incremental work efforts associated with ongoing, multiyear initiatives or programs. This work is organized into the following functional categories:

1. **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 to collect various types of data related to these assets. These tools also allow NW Natural to create visual representations of facilities and assets, which are used both internally and externally for a range of purposes, including inspection, reporting, 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

[1] For a description of the Company's capital expenditures budgeting and forecasting processes, including management approval and project/program lifecycle phases, please see the Direct Testimony of Jorge O. Moncayo, NW Natural/500, Moncayo.

solutions. This category includes the Field and Web Mapping Phase II Project and the E-Maps Replacement Project.

2. **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 phased projects necessary to transition to an automated IGA software solution, and thus ensure consistent, secure monitoring and control of access and permissions.

3. **Gas Control Daily Operations Platform ("GCDOP"):** The GCDOP is a multi-phase 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.

4. **Customer Self-Service:** Customer Self-Service projects are part of a multi-year initiative to provide customers with new features and efficiencies to improve communication and accessibility, thereby 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. This category includes the Website Technology Project and the Customer Self-Service Enhancements Program.

5. **Lifecycle Management:** Lifecycle Management refers to work needed to update and maintain critical IT&S equipment, applications, and platforms. These lifecycle-based and maintenance-related investments are necessary to ensure the safe, secure, and reliable provision of service. Maintaining IT&S software and equipment allows NW Natural to receive critical system and security patches, apply up-to-date technology features, and maintain license compliance as defined by support agreements. While replacing and updating aging technology is a longstanding part of managing the Company's technical infrastructure, rising equipment costs have increasingly turned these efforts into major investments. As a result, this type of baseline, programmatic refresh work represents a significant share of the Company's projects in this case, including:
    - Application Lifecycle Management ("ALM") – Governance, Risk, and Compliance ("GRC") Project,
    - Physical Security Platform Modernization Project,
    - Network Lifecycle Management 2027 Project,
    - Telemetry Lifecycle Management Program,
    - Communications Towers Modernization 2027-2028 Project, and
    - Temetra Implementation Project.
6. **Back-Office Infrastructure:** Back-office represents 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 ServiceNow Implementation Project and the Data Center Resilience and Modernization Project.

Q. How are the Company's IT&S investments allocated to Oregon customers?

A. The Company's IT&S investments are allocated to Oregon and Washington customers using the allocation factor of total customers. The Oregon allocation factor for total customers in this case is 87.76 percent. The Direct Testimony of Kyle T. Walker (NW Natural/1200, Walker) addresses the topic of allocation factors and their associated methodology.

II. OVERVIEW OF IT&S ENVIRONMENT

Q. Please describe NW Natural's current IT&S environment.

A. NW Natural's IT&S environment touches every corner of the Company's operations, from communications and security to mapping and procurement. This integration is crucial for the safety, reliability, and responsiveness of modern utility operations. Thus, IT&S plays a critical and ever-evolving role in serving customers, reflecting the broader evolution of IT&S systems and solutions.

Q. What principles and priorities guide NW Natural's IT&S investments in a dynamic, fast-changing environment?

A. NW Natural focuses on maintaining reliable and secure systems through ongoing modernization, 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 adoption of cloud-based solutions?

A. Yes. Cloud-based solutions are now industry standard for most large enterprises' IT&S systems. Utilities often transition to cloud-based solutions when legacy systems reach end-of-life because these solutions have become the standard available offering—and sometimes the only available offering, depending on the system. Cloud-based platforms often provide enhanced scalability with resource demands, real-time data accessibility, and robust support and real-time cybersecurity updates from developers. Over the last several years, the Company has successfully migrated an array of IT&S solutions and platforms to Microsoft's Azure cloud platform, which is consistent with NW Natural's overarching goal of simplifying IT&S solutions.

Q. Does the Company's IT&S strategy continue to include locally hosted systems as well?

A. Yes. Cloud-based solutions are not yet appropriate for all systems from an operational or security perspective (e.g., SCADA or gas control systems). For life-safety utility control systems in particular, the Company expects to continue hosting such key systems in specialized, low-latency, climate-controlled data center facilities.

Q. Is NW Natural continuing to experience financial pressures associated with cloud-based solutions?

A. Yes. While cloud-based solutions are the right choice for the Company and our customers, the accounting rules associated with these solutions create new

financial pressures that do not fit neatly into existing ratemaking frameworks. First, unlike on-premises solutions, the utility can capitalize only the implementation costs of cloud-based assets, and the depreciable life of the asset is tied to the duration of the contract for the software service. Typically, in the IT&S field, these contracts are relatively short—averaging approximately five years. As such, the depreciable life of the asset is very fast compared to most of 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.

Additionally, cloud-based assets are a growing asset class for NW Natural. The Company did not have any cloud-based assets prior to 2020. As such, there is an increasingly urgent financial need to ensure that the Company is routinely recovering this relatively new asset class.

Finally, because cloud-based solutions entail ongoing subscriptions, the accounting rules require that subscription costs incurred beyond the integration period be accounted for as O&M expense. As noted above, with the system-wide migration to cloud-based solutions, NW Natural is continuing to experience increases in annual incremental O&M expense as the Company moves to more cloud-based tools.

Q. Is the Company experiencing incremental IT&S O&M expenses above inflation?

A. Yes. The Company's Test Year IT&S O&M expense is increasing approximately $1.8 million above the inflation-adjusted Base Year expense, for two main reasons. First, new projects entering service entail ongoing software subscription and

maintenance costs. Second, some multi-year contracts escalate above inflation. Nonetheless, multi-year contract arrangements are favored where feasible in order to secure more favorable renewal rates. This approach not only helps manage long-term costs, but also improves the accuracy and predictability of our forecasting process.

For instance, the ESRI Utilities Network project placed in service earlier this year entails incremental Test Year O&M costs associated with software licensing ($219 thousand), cloud hosting ($450 thousand), and ongoing administration, patching, and related support ($250 thousand).[2] This O&M increase is partially offset by $148 thousand decrease in annual O&M associated with the replaced applications. Other significant project-specific O&M increases are noted in the corresponding project discussions, below.

Q. How does the rapidly changing IT&S environment interact with project forecasting in a rate case?

A. Unlike many other utility infrastructure investments, IT&S systems evolve rapidly—which makes these projects more challenging to forecast. As noted above, IT&S projects frequently operate on shorter time horizons, meaning that available options and constraints can change in the lead-up to project implementation. Thus, for some projects that will enter service during the Test Year, the Company will continue to refine the projects' cost, scope, and alternatives closer to the

[2] The capital cost portion of ESRI Utilities Network was addressed in UG 527.

implementation date in order to ensure that decisions are made with the most up-to-date available information.

For example, the Company anticipates needing to replace the SAP GRC software in 2027, as part of the application lifecycle management program (the ALM – GRC Project, discussed in more detail below). SAP has set a December 31, 2027, end-of-support deadline for the current GRC product, meaning that key maintenance, security updates, and other support services will no longer be provided after that date. However, the new SAP product was released quite recently in 2026. As a result, the Company is performing due diligence to assess the efficacy, reliability, and impact of adopting the new SAP product, and will continue to explore available alternatives—including potentially purchasing extended maintenance, which would entail its own costs and risks—prior to this project's kick-off date.

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. How do the projects and programs in your testimony align with the Company's overarching strategic goals?

A. Each project and program in my testimony supports the Company's goal of serving customers through a secure and compliant system. These investments 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. As the Company modernizes and replaces key aspects of its physical and software technologies, 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 520, the Horizon Program is a multi-year, two-phase IT&S initiative to upgrade NW Natural's central technology architecture. Each phase 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. Horizon 1 was implemented on time and within reasonable budget parameters, providing valuable lessons learned for the Horizon Program's second major phase. The

second phase of the Horizon Program will comprehensively update the Company's outdated Customer Information System ("CIS") and other customer-facing functions and related services.

Q. What is the status of the Horizon Program?

A. In 2024, the Company completed the initial planning stage for the Horizon Program's second phase, 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 second phase's larger implementation components. 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 6-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.

Q. Please summarize the study recommendation.

A. The study recommended initiating the implementation of the new CIS in approximately 2030, while dedicating the intervening period to completing the prerequisite work. This approach was designed to mitigate the risks associated with the upcoming CIS replacement project and to level out costs leading up to the CIS implementation.

Q. Based on the study recommendation, how does NW Natural plan to proceed?

A. Based on the EY study, and after completing a formal evaluation process of the available alternatives, NW Natural intends to complete all peripheral and prerequisite work prior to initiating the CIS replacement project. This work will put the Company on track to replace the CIS within a reasonable 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 on the timing of the replacement of the CIS?

A. An additional consideration was 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 nearing retirement. These individuals possess detailed working knowledge of the CIS's architecture, operation, customizations, and integrations. Changes to the CIS therefore flow through a very narrow funnel of design and development capacity. By extending the lead-up time to CIS implementation, NW Natural can build up its CIS staffing,

execute the necessary peripheral projects, and prepare for the CIS replacement without overwhelming personnel capacity.

Q. Were there external factors in the market affecting the decision not to 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 near term. According to EY, many similarly sized or larger utilities are pursuing CIS replacement projects. There is a finite number 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. How is NW Natural planning to manage risks associated with the current CIS, given the estimated 2032 replacement date?

A. NW Natural is continuing to maintain the stability and performance of the existing CIS, while preparing for its eventual replacement. These efforts are strategically planned to keep the CIS components up-to-date and secure, ensuring consistent service reliability for customers within a well-managed budget.

Q. Is the Company seeking cost recovery associated with any major projects under the Horizon Program's second phase in this rate case?

A. No.

IV. TSA COMPLIANCE PROGRAM

Q. Please provide some context for the TSA Compliance Program.

A. The TSA Compliance Program is part of an industry-wide response to cybersecurity attacks on critical pipeline systems. In May 2021, a cyber-attack on Colonial Pipeline crippled pipeline operations for a week, disrupted service to

customers, and led to widespread panic buying, price increases, and fuel shortages. The pipeline company was also forced to pay millions of dollars in ransom to recover its data. Unfortunately, ransomware cyber-attacks are common, and constitute a pernicious and persistent threat to critical infrastructure functions.

Q. How has TSA responded to the threat of pipeline cyber-attacks?

A. TSA has responded with an evolving set of Security Directives that have required specific and far-reaching cybersecurity interventions. In 2021, TSA issued two Security Directives (Security Directive 2021-01 and Security Directive 2021-02, collectively referred to as the "2021 Security Directives"), requiring pipeline owners and operators to perform detailed gap assessments, submit a Cybersecurity Implementation Plan for TSA approval, and take additional responsive and preventative actions. However, the 2021 Security Directives were based on TSA's emergency powers to address urgent needs and have not gone through the federal rulemaking process. As a result, each Security Directive expires yearly unless it is reauthorized.

Q. Has TSA reauthorized the 2021 Security Directives each year?

A. Yes. To date, TSA has reauthorized both of the 2021 Security Directives at least annually. The most recent Security Directive applicable to NW Natural is Security

Directive 2021-02G.[3] TSA has stated that it will continue renewing these two Security Directives until a formal pipeline security rulemaking process is complete.

Q. Are the details of these various TSA Security Directives available to the public?

A. In large part, yes. TSA initially designated the Security Directive 2 series as Sensitive Security Information ("SSI") pursuant to 49 CFR § 1520.5. Accordingly, the contents of Security Directive 2 could be shared only on a need-to-know basis as defined by 49 CFR § 1520.11. However, TSA has since made a determination that the Security Directive 2 series, with the exception of parts of the original Security Directive 02 and Security Directive 02A, are no longer considered to contain SSI.[4] However, "information submitted by the Owner/Operator to TSA as a result of these requirements is protected as SSI per 49 CFR parts 15 and 1520."[5] As a result, NW Natural's responsive plans may be made available only to persons with a "need to know" as defined by 49 CFR § 1520.11.

[3] See TSA, Security Directives and Emergency Amendments, available at https://www.tsa.gov/sd-and-ea.

[4] See Security Directive Pipeline-2021-02G, Cover Memorandum at 1 (May 3, 2026), available at https://www.tsa.gov/sites/default/files/signed_security_directive_pipeline-2021-02g_and_transmittal_memo_508c.pdf ("Consistent with TSA's previous determination, this SD is not marked as Sensitive Security Information.").

[5] Security Directive Pipeline-2021-02C, Cover Memorandum at 1 (Jul. 27, 2022), available at https://www.tsa.gov/sites/default/files/tsa_sd_pipeline-2021-02-july-21_2022.pdf.

Q. What is the status of TSA's formal pipeline security rulemaking?

A. An Advance Notice of Proposed Rulemaking was issued on November 30, 2022,[6] and a Notice of Proposed Rulemaking ("NPRM") was issued on November 7, 2024.[7] The NPRM gives the Company additional insight into potential changes that could be required in the final rule. The proposed new or modified requirements include supply chain risk management, designating positions with additional compliance responsibilities, organizational training, and physical security incident reporting.

NW Natural has participated in the rulemaking proceeding in collaboration with the American Gas Association ("AGA").[8] AGA submitted comments on behalf of all AGA members to highlight potential areas of overreach, costs, compliance timelines, and potentially burdensome management of compliance expectations, with the goal of supporting reasonable and cost-effective final rules. The proposed timeline for issuance of the final rules has not been released, and no further action has yet been taken in this proceeding. However, during the July 2026 confirmation

[6] Enhancing Surface Cyber Risk Management, 87 Fed. Reg. 73,527 (proposed Nov. 30, 2022) (to be codified at 49 C.F.R. ch. XII), available at https://www.govinfo.gov/content/pkg/FR-2022-11-30/pdf/2022-25941.pdf.

[7] Enhancing Surface Cyber Risk Management, 89 Fed. Reg. 88,488 (proposed Nov. 7, 2024) (to be codified at 49 C.F.R. pts. 1500, 1503, 1520, 1570, 1580, 1582, 1584, 1586), available at https://www.govinfo.gov/content/pkg/FR-2024-11-07/pdf/2024-24704.pdf.

[8] Am. Gas Ass'n, Comments on Enhancing Surface Cyber Risk Management, Docket No. TSA-2022-0001 (Feb. 5, 2025), https://www.aga.org/wp-content/uploads/2025/02/TSA-Cyber-NPRM-AGA-Comments-Feb-5-2025_Mohamed-Moussi.pdf.

hearings for TSA Administrator David Cummins, both Chair Cruz and Ranking Member Kim noted the delays in rulemaking and encouraged TSA to act swiftly.[9]

Q. Does NW Natural plan for ongoing compliance work associated with TSA's Security Directives?

A. Yes. Since TSA plans to continue issuing Security Directives until the rulemaking is complete, NW Natural similarly plans for associated incremental compliance work. Each year's project is named according to the letter corresponding to the underlying Security Directive: Bloodhound (Security Directive 2B), Charlie (Security Directive 2C), and so on.

Q. Has the scope of the projects in the TSA Compliance Program changed over time?

A. Yes. More recent TSA Security Directives have contained more limited new compliance requirements, thus reducing the scope and cost of corresponding projects. As a result, the Company anticipates that future projects will follow a similar pattern. However, the precise incremental work required will depend on both the specific decisions of each future Security Directive, as well as the final scope of TSA's formal rule.

[9] "TSA Administrator Nominee David Cummins Testifies at Confirmation Hearing," C-Span (Jul. 16, 2026) video at 8:24, available at https://www.c-span.org/program/senate-committee/tsa-administrator-nominee-david-cummins-testifies-at-confirmation-hearing/682901 (Sen. Andy Kim: "Swiftly issuing the rule has a bipartisan mandate.").

Q. What portion of the TSA Compliance Program is included for cost recovery in this rate case?

A. In this case, the Company seeks cost recovery for the Echo Project, the Foxtrot Project, and the Golf Project.

Q. What is the status of each of these projects?

A. The Company completes each project in sequence annually. The Echo Project started in the fourth quarter of 2024, and was completed in January 2025. The Foxtrot Project began in December 2025, and will be completed in December 2026. The Golf Project will then begin in December 2026, and is expected to be placed in service in September 2027.

Q. What cost recovery is the Company requesting for the TSA Compliance Program?

A. The Company requests to recover its capital investment for the following three compliance projects:

- Echo Project: $1.4 million ($1.2 Oregon-allocated),
- Foxtrot Project: $966 thousand ($848 thousand Oregon-allocated), and
- Golf Project: $1.9 million ($1.7 million Oregon-allocated).

V. MAJOR IT&S PROJECTS

A. Field and Web Mapping

1. Field and Web Mapping Phase II Project

Q. Please provide some context for the Field and Web Mapping Phase II Project.

A. The Field and Web Mapping Phase II Project is part of a broader, 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. 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 Field and Web Mapping 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.

Q. Please describe the Field and Web Mapping Phase II Project.

A. The Field and Web Mapping Phase II Project continues to phase out end-of-life software tools and transition to a consolidated set of modern systems by a) updating IQGeo to a supported version; and (b) 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.

Q. Why is the Field and Web Mapping Phase II Project necessary?

A. The Field and Web Mapping Phase II Project is necessary to ensure that the existing tools remain reliable. The Company's current version of the IQGeo platform (6.5) is out of official support and must 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.

Q. Does the Field and Web Mapping Phase II Project provide additional benefits?

A. Yes. The project also provides a path for modernizing geospatial data capture and as-built mapping processes. Currently, NW Natural relies on IQGeo Capture for several business-critical workflows, including the reconciliation of geospatial information with field construction records. IQGeo has indicated that future product investments are being directed toward newer capabilities within the IQGeo product suite, including Network Manager Gas, and has identified those capabilities as the long-term strategic replacement for Capture functionality. While Capture remains supported under the vendor's extended maintenance program, NW Natural must evaluate and implement a sustainable long-term solution to ensure continued supportability, vendor alignment, and access to future product enhancements.

In addition, updating IQGeo allows NW Natural to evaluate opportunities to reduce customized software components, adopt vendor-supported capabilities where appropriate, and position the Company's geospatial platform for future updates with lower implementation risk and cost. IQGeo has indicated that many future enhancements, including mobile workforce improvements, data synchronization improvements, and platform modernization initiatives, will be delivered through more current software releases.

Q. Did NW Natural consider alternatives to the Field and Web Mapping Phase II Project?

A. Yes, and further analysis will be completed. To date, the Company has evaluated whether to maintain its current environment without significant investment. Based on this analysis, NW Natural has concluded that failing to act is not viable for two reasons.

First, the Company's existing IQGeo version (6.5) is outside the vendor's current software lifecycle and will require modernization to maintain access to vendor support, product updates, security enhancements, and ongoing product improvements. Continued reliance on aging software increases operational risk for systems that support critical field and geospatial business processes.

Second, NW Natural currently relies on IQGeo Capture for several key geospatial data capture and as-built mapping functions. IQGeo has indicated that future product investment is focused on successor capabilities, including Network Manager Gas, and that Capture is expected to remain under extended maintenance support only while customers transition to longer-term solutions. Accordingly, NW Natural must evaluate and implement a sustainable path forward for these business processes as part of the overall platform modernization effort.

A further alternatives analysis will be completed in mid-2027 before project work begins. As part of the alternatives analysis, the Company plans to evaluate IQGeo's Network Manager Gas solution, which the vendor has identified as its strategic long-term replacement for Capture functionality, as well as alternative approaches, including solutions built on Esri technology and offerings from Esri

partners. This evaluation will consider functionality, long-term vendor support, integration requirements, implementation costs, operational impacts, and the ability to meet NW Natural's business and regulatory record-retention requirements.

Q. What is the status of the Field and Web Mapping Phase II Project?

A. This Project is currently in the Intake/Initiate phase. NW Natural will complete its analysis of alternatives in 2027, prior to starting work. This project is expected to be placed in service in May 2028.

Q. What cost recovery is NW Natural requesting for the Field and Web Mapping Phase II Project?

A. NW Natural seeks to recover its capital investment of $3.2 million on a system-wide basis, or $2.8 million on an Oregon-allocated basis.

2. E-Maps Replacement Project

Q. Please describe the E-Maps Replacement Project.

A. The E-Maps Replacement Project modernizes how NW Natural provides public-facing geographical information to the jurisdictions and external partners it serves for planning, design, and pre-locate activities. The E-Maps Replacement Project will replace the decades-old legacy approach by adding new, secure functionality to NW Natural's existing ESRI platform.

Q. Why is the E-Maps Replacement Project necessary?

A. The E-Maps Replacement Project is necessary for several reasons. **First**, [**BEGIN CONFIDENTIAL**] [redacted]

[redacted]

[**END CONFIDENTIAL**].

Second, the current solution is highly inefficient and manual. When a third-party requests a map, GIS personnel must manually extract the relevant GIS information, convert it into static PDF maps, and publish the maps to the externally accessible website.

Third, the current system is also difficult to maintain or modify from a technical perspective because it is more than 20 years old. Indeed, the system source code is in a legacy program language that is no longer industry standard or supported.

The new ESRI-supported solution will provide secure access to GIS information, reduce reliance on internally hosted infrastructure, improve security, and eliminate many of the manual processes required to publish and maintain mapping information. The result is a more efficient, sustainable, and secure method for providing access to geographic information.

Q. Did NW Natural consider alternatives to the E-Maps Replacement Project?

A. Yes. NW Natural evaluated rebuilding the existing E-Maps solution using a similar architecture and functionality. This alternative was not selected because the cost

of redeveloping and maintaining a custom website was estimated to be comparable to, or greater than, the proposed solution, while providing fewer long-term benefits. Rebuilding the existing solution would address only the website component and would not eliminate the manual processes associated with preparing and publishing geographic information. As a result, many of the operational inefficiencies and support requirements that exist today would remain.

The E-Maps Replacement Project was selected because it leverages the Company's existing ESRI investment and adopts an industry-standard method for providing external access to geographic information. This approach improves sustainability, reduces operational effort, enhances security, and provides greater long-term value than rebuilding the legacy solution.

Q. Was it viable to adopt a non-ESRI software solution to replace the current E-Maps system?

A. No. Adopting a new, non-ESRI software solution to replace the current E-Maps system would have been necessarily more complex and inconsistent with the Company's overarching strategy of streamlining IT&S software solutions. Leveraging the existing ESRI platform provides the most efficient and effective option to replace the E-Maps system.

Q. In addition to addressing the needs described above, are there other benefits of the E-Maps Replacement Project?

A. Yes. The E-Maps Replacement Project will also improve the experience for external users and internal administrators, as the new system is more intuitive to navigate than the current system.

Q. What is the status of the E-Maps Replacement Project?

A. The E-Maps Replacement Project is now underway and is expected to be placed in service by October 2027.

Q. What cost recovery is NW Natural requesting for the E-Maps Replacement Project?

A. NW Natural seeks to recover its capital investment of $1.4 million on a system-wide basis, or $1.2 million on an Oregon-allocated basis.

B. Identity Governance and Administration (IGA)

Q. Please provide some context for the IGA Program as a whole.

A. As previously explained in Dockets UG 490[10] and UG 520,[11] 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 ("SOX"). This legislation requires NW Natural and other public companies to implement, among a range of

[10] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Direct Testimony of Jim R. Downing, NW Natural/700, Downing/37-41 (Dec. 29, 2023).

[11] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 520, Direct Testimony of Brian E. Fellon, NW Natural/700, Fellon/18-21 (Dec. 30, 2024).

other security-related controls, mechanisms to ensure that unauthorized individuals cannot access sensitive financial information.[12]

Previously, security access and other privileges were handled manually, with no centralized control point. As a result, there was no reliable mechanism to certify that an individual's access to security and other functions had been removed following offboarding or other role changes. By implementing an IGA system, NW Natural increased security of both customer and Company data while streamlining the staff management process.

Q. How is the IGA Program being implemented?

A. The IGA Program is being implemented in phases. 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 built 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.

[12] Sarbanes-Oxley Sections 302.2, 404.

1. 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 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. Did the Company evaluate alternative application integrations to include in the IGA Phase 3 Project?

A. Yes. The Company evaluated alternative application integrations according to several criteria: (1) degree of technical difficulty; (2) degree of user impact; (3) potential cost for additional licensing; and (4) application team availability. The latter criterion was necessary to ensure that an application's technical team has

the capacity to support integration. Based on this analysis, the Company selected three applications for IGA integration in this project: the CIS, SuccessFactors Learning Management System, and Genesys.

Q. What other alternatives did NW Natural consider for the IGA Phase 3 Project?

A. NW Natural also considered two additional alternatives: (a) deploying a new IGA solution and (b) declining to add additional IGA functionality. However, deploying a new IGA solution was not viable because switching vendors at this stage would be substantially more costly, labor-intensive, and time-consuming, without any assurance of achieving a better outcome. Similarly, declining to add additional IGA functionality would have failed to maximize the benefits of the existing IGA Program investments, and would not have addressed the ongoing risk concerns associated with existing manual access control processes.

Q. What is the status of the IGA Phase 3 Project?

A. The Project is currently underway and 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 $2.3 million on a system basis, or $2.1 million on an Oregon-allocated basis.

2. IGA Phase 4 Project

Q. Please describe the IGA Phase 4 Project and how this Project relates to the broader IGA effort.

A. The IGA Phase 4 Project continues to expand the integration of access certifications and permissions controls with additional software applications. Consistent with the application-specific evaluation process described above, the Company is identifying potential additional applications for integration in this project.

Q. What is the status of the IGA Phase 4 Project?

A. The IGA Phase 4 Project will begin following completion of the IGA Phase 3 Project in October 2027 and is expected to be placed in service by October 2028. Prior to beginning project work, NW Natural will evaluate available alternatives, including verifying the appropriate scope and priority of application integrations.

Q. What cost recovery is NW Natural requesting for the IGA Phase 4 Project in this case?

A. NW Natural seeks to recover its capital investment of $1.3 million on a system basis, or $1.1 million on an Oregon-allocated basis.

C. Gas Control Daily Operations Platform (GCDOP)

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 phases: (1) to plan for and implement the new SCADA platform (the "GCDOP Implementation Project"), (2) to implement

additional gas system data capabilities (the "GCDOP Consolidated Reporting Project"), and (3) to connect the modernized gas control platform to NW Natural's business systems in order to improve gas controller forecasting (the "GCDOP Business System Integration Project"). Only the GCDOP Implementation Project is included for recovery in this rate case.

1. GCDOP Implementation Project

Q. Please describe the GCDOP Implementation Project.

A. The GCDOP Implementation Project will transition the Company to a new SCADA platform. The SCADA platform is real-time software that provides monitoring and control capabilities for NW Natural's Gas Control team, which manages 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 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 was 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 (a) was 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—functionality that is now offered "off-the-shelf" by SCADA vendors.

Q. Why is the GCDOP Implementation Project necessary?

A. The GCDOP Implementation Project 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, which is 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. Outages also create safety concerns as they impact NW Natural's ability to monitor the system.

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, thereby 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 to the request for proposals ("RFP") from the following potential vendors: AspenTech ("AspenTech") and [**BEGIN CONFIDENTIAL**] [redacted] [redacted] [**END CONFIDENTIAL**].

NW Natural conducted substantial due diligence into the responsive bids, and selected AspenTech as the lowest-cost and best service option to provide a new SCADA software platform. AspenTech 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 the lowest-cost, does the AspenTech software solution provide other benefits for the Company's new SCADA platform?

A. Yes. AspenTech'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 and the GCDOP Business System Integration 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 globally recognized 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 on schedule to be placed in service in October 2027.

Q. What cost recovery is NW Natural requesting for the project?

A. NW Natural is requesting to recover its capital investment of approximately $16.7 million on a system basis, or $14.7 million on an Oregon-allocated basis. NW Natural also requests recovery of $347 thousand in incremental ongoing O&M ($258 thousand Oregon-allocated after administrative transfer) for software licensing.

D. Customer Self-Service

1. Website Technology Project

Q. Please describe the Website Technology Project.

A. The Website Technology Project will update the Company's website platform to enhance security, maintain stability, and improve customers' user experience. The project also includes interim stabilization work to ensure that this core system remains functional before and during the replatforming work.

Q. Why is the Website Technology Project necessary?

A. The Website Technology Project is crucial to ensure that the Company's key customer-facing system remains stable and secure. The website platform is NW Natural's key customer portal, supporting the majority of customer interactions across the Company's three service channels: (1) online through the website, (2) by phone through the interactive voice response system, and (3) directly through live phone calls. NW Natural's website alone accounts for over 1 million self-service transactions, 4.5 million account dashboard views, and 5 million online payments annually.

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. However, the platform is now 6 years old, and includes functions that, having been carried over from a prior website, are more than 13 years old. In comparison, Gartner indicates that an industry-typical effective lifespan for self-service websites is approximately 2-5 years.

Q. What is included in the interim stabilization work for the Website Technology Project?

A. Interim stabilization work involves updating certain foundational technology components of the website platform to address critical near-term security issues. These fixes will allow the Company's customer-facing website and online services to continue to operate reliably and securely until the replatform is complete.

Q. How was the scope of the Website Technology Project evaluated?

A. The Website Technology Project began with an initial assessment phase (Phase Zero) completed by Accenture to evaluate current functionalities, support, security gaps, and to identify a path forward that meets both technical and functional challenges. The results of Phase Zero guided cost-effective decision-making and resulted in the recommendation for a specific implementation path.

Q. What were Accenture's findings during the Phase Zero analysis?

A. Accenture's analysis identified 53 gaps and 27 risks, many of them critical or high-severity, that require action. Foundationally, core website components need to be upgraded to maintain vendor support and address security risks. From a user perspective, improvements are also needed to support evolving customer needs, and meet regulatory requirements for multi-language access under the Company's Language Access Plan. From a maintenance perspective, the improvements will allow NW Natural to more easily modify the website to include up-to-date information. In addition, extensive customizations have reduced platform stability and security, making even minor updates costly. These issues raise long-term viability concerns as vendors shift to cloud-based solutions and increasingly dictate update timing.

Q. What did the Phase Zero analysis recommend to address these gaps and risks?

A. The Phase Zero analysis recommended replatforming the Company's website, while making limited stabilization investments to maintain the current website over the intervening multi-year implementation period. Replatforming is a substantial,

multi-year effort, beginning with an RFP for a software and implementation partner in 2026, proceeding with implementation work starting in 2027, and concluding with an in-service date in June 2028.

Q. Did NW Natural consider alternatives to Accenture's recommendation?

A. Yes. NW Natural evaluated two alternatives to remediate the identified risks and close the documented gaps in the Company's web platform. Both alternatives assumed an eventual migration to a cloud-based platform, reflecting vendor product direction and broader market movement; and differ principally in the timing and sequencing of that investment. No action was not a viable alternative, as failing to act at all would leave the identified security and service gaps and risks unaddressed, while also resulting in the loss of vendor support for core components.

The first alternative would have involved stabilizing the existing platform beginning in 2026, adding limited self-service capabilities, and deferring the replatform to 2030, ahead of the planned CIS replacement. This approach addressed supportability and security exposure in the near term and spread expenditures across a ten-year horizon, but it entailed substantial duplicative investment—first in the current platform, and again in the new platform several years later. Meanwhile, this alternative left customer experience gaps in place until 2030.

The second alternative would have involved upgrading and redesigning the current website in 2026 and deferring the replatform to 2034, following completion of the CIS replacement. While this sequencing kept the two programs separate, it

was the most costly alternative due to the expanded investment needed to fix gaps and risks in the current system. It also required an additional platform upgrade in 2030 and extended exposure to platform risk for the longest period.

The chosen alternative offers the lowest total cost among the viable alternatives, while closing the identified gaps and risks earlier than the other options. This approach also ranked highest against the Company's evaluation criteria, making it the strongest path to address platform stability, security, customer experience, operational efficiency, and regulatory needs. Although this alternative concentrates expenditure in the first three years and requires near-term internal resources, those trade-offs are manageable and outweighed by the benefits of earlier risk reduction, lower overall cost, and stronger long-term platform viability.

Q. Does the Company expect to experience measurable benefits from the recommended approach?

A. Yes. The recommended approach is expected to produce measurable benefits for customers, based on metrics Accenture has observed with comparable clients on similar projects. Observed metrics include: (1) more successfully completed transactions, and (2) reduced customer call volume.

First, comparable clients have experienced a 111 percent increase in customers' completed transactions following a replatform project. For NW Natural, a reasonable goal is more than 600,000 additional transactions completed through the website each year—including service initiation, bill payment, and program enrollment—without the need for customer service agent involvement. This figure

represents an efficiency gain for customers seeking to conduct routine business online.

Second, the project is expected to increase effective website utilization and correspondingly reduce contact center calls. Comparable implementations have produced a 9 percent increase in first-time visitors and a 13 percent increase in repeat visits to company websites. Applied to the Company's metrics, these increases would correspond to more than 168,000 additional new visitors and approximately 59,000 additional repeat visitors annually. By improving website engagement, comparable implementations have significantly reduced the volume of contact center calls. Extrapolated to NW Natural's numbers, the new platform and customer enhancements could avoid approximately 30,000 contact center calls annually. Reduced call volume allows existing staff capacity to be directed to customers requiring live assistance, thus reducing wait times and improving service.

Q. Are there other benefits associated with the Website Technology Project?

A. Yes. In addition to the expected measurable benefits described above, the new platform will support the display of multiple languages natively. This functionality will enable the Company to fulfill Commission requirements for language access under the Company's Language Access Plan.

Q. What is the status of the Website Technology Project?

A. The Company has implemented the Website Technology Project's interim stabilization work, which was placed in service in August 2026. The broader replatforming effort is currently in the Planning phase. The Company anticipates

selecting a platform and implementation partner by the end of 2026 and placing the rest of this project in service in June 2028.

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 of $14.7 million on a system-wide basis, or $12.9 million on an Oregon-allocated basis.

2. Customer Self-Service Enhancements Program

Q. Please describe the Customer Self-Service Enhancements Program.

A. The Customer Self-Service Enhancements Program is a multi-year, multi-phase initiative to improve accessibility and convenience for customers, through improvements to NW Natural's web-based and phone-based systems. The program will also improve operational efficiency for the customer contact center's customer service representatives, thereby allowing the Company to serve customers more quickly and effectively.

Q. Please describe the first phase of the Customer Self-Service Enhancements Program.

A. The first phase of this program involves a series of enhancements focused on improving the Interactive Voice Response ("IVR") system, automating customer enrollment in paperless billing, strengthening the security of the customer password reset process, implementing a customer-facing chat bot in the online payment portal, and piloting AI call summarization. Each enhancement is designed to streamline customers' online experience, reduce the need for support

calls, and improve average call handling time. This initial phase is expected to be completed the end of 2026.

Q. Please describe the second phase of the Customer Self-Service Enhancements Program.

A. The second phase of the Customer Self-Service Enhancements Program will deploy an expanded set of self-service enhancements on a rolling basis between 2027 and 2028, such as:

- Adding a customer-facing chatbot on the online payment portal and website. This tool will answer common questions, reduce customer barriers to accessing necessary information, and improve after-hour self-service. According to vendor feedback, chatbots can handle 8,000 to 10,000 questions per month, with limited need for live-agent support. For NW Natural, a chatbot is expected to help ease peak Monday call volumes by providing 24/7 support, reducing wait times, and lowering average handle time. Companies using AI chatbots have reported 33 percent to 45 percent reductions in average call handle time and up to a 30 percent improvement in first-contact resolution.
- Enabling customer contact center co-browsing (also known as "collaborative browsing"), which allows customer service representatives to simultaneously view and interact with the same web page that customers are seeing in real-time. This function allows the customer service representative to more efficiently guide customers

through challenges and is particularly valuable for quickly resolving log-in and password issues.

- Presenting bills in a responsive format without the need for customers to log in to their account. This enhancement allows customers to view their current bill directly on mobile devices or in email when bill notifications are distributed, improving accessibility across digital channels, while also preserving existing bill content and regulatory requirements. More than 50 percent of customers access the Company's website on a mobile device.
- Implementing AI-assisted quality management scorecards within Genesys to automate portions of the call evaluation process and significantly increase the number of interactions reviewed. By providing faster, more consistent insight into customer conversations, this initiative will help identify service gaps, improve coaching, and support more consistent, effective customer interactions. Customers benefit from better-informed customer service representatives, more accurate issue resolution, and a more reliable service experience.
- Designing and implementing an improved method for routing and handling Spanish-speaking customer calls within the IVR and customer contact center environment. This enhancement will help customers reach appropriate language support more quickly, reduce unnecessary transfers, and make it easier to resolve questions or service needs in

customers' preferred language. Overall, this enhancement will improve accessibility, reduce customer effort, and provide a more consistent and inclusive service experience for Spanish-speaking customers.

- Improving Paymentus and IVR integration points to make the payment experience easier, faster, and more intuitive for customers. Improvements will focus on reducing redundant authentication, creating smoother transfers between systems, offering payment programs such as Auto Pay that are currently not available in the IVR, and increasing successful self-service payment completion. Customers will benefit from less friction, fewer repeated steps, shorter resolution paths, and greater confidence that their payments can be completed securely and efficiently.
- Creating a new self-service IVR experience that allows authenticated customers to retrieve their account number without assistance from a customer service representative. This enhancement gives customers faster, more convenient access to important account information, reduces the need to wait for live support, and supports customers who prefer or rely on phone-based self-service. It also reduces call demand by enabling customers to complete a common request independently.
- Deploying AI-generated in-call checklists and action recommendations based on customer conversations to help customer service representatives respond more quickly, accurately, and consistently.

This will reduce manual effort, shorten the path to customer service representative proficiency, and support better real-time decision-making during customer interactions. Customers will benefit from clearer guidance, fewer errors or missed steps, faster resolution, and a more consistent service experience across representatives.

- Integrating text messaging and enterprise-wide email capabilities for all customers' notifications. Offering text messaging for common customer communication is a much-desired feature asked for by customers in customer satisfaction surveys.
- Creating a standardized platform for managing customer email interactions by expanding Genesys Email to additional business teams. This initiative will provide customers with more timely, transparent, and consistent service by improving tracking, reporting, and workflow consistency across departments.

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 contact center calls. NW Natural currently experiences extended customer wait times, which can result in customer frustration. Extended customer wait times relate in part to lack of effective, accessible options for customers to complete their business or address their needs via self-service tools. The Customer Self-Service Enhancements Program will address these deficiencies by improving self-service options, thereby saving customers time and improving overall convenience. 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 representatives. Together, these self-service enhancements are designed to improve NW Natural's ability to provide timely, reliable, and convenient service to customers.

Q. Did NW Natural consider alternatives to the Customer Self-Service Enhancements Program?

A. Yes. NW Natural is considering alternatives for each phase of this program. For the first phase, the Company considered implementing AI call summarization features at scale (rather than through a pilot), developing a payment chatbot for the website (in addition to the payment portal), and pursuing direct conversion to paperless billing (rather than incorporating automatic enrollment). However, this broader scope of work would have entailed additional cost and deployment risk, particularly by requiring more extensive website work at the same time the Company is revising the website platform (discussed in the Website Technology Project, above). As a result, the Company determined to systematically implement the backlog of needed self-service enhancements, prioritized to maximize customer benefits.

For the second phase of work, the Company will complete a detailed alternatives analysis in early 2027.

Q. What is the status of the Customer Self-Service Enhancements Program and when is it expected to be placed in service?

A. The Company is currently deploying self-service enhancements on a rolling basis. The second phase of work will begin in early 2027, and the Company plans to place the identified series of enhancements in service incrementally over the following two years, beginning in the second half of 2027. 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 2027.

Q. What cost recovery is NW Natural requesting for the Customer Self-Service Enhancements Program in this case?

A. NW Natural seeks to recover its capital investment of $3.6 million on a system-wide basis, or $3.2 million on an Oregon-allocated basis

E. Lifecycle Management

1. Application Lifecycle Management – Governance, Risk, and Compliance Project

Q. Please provide some context on what the Company means by Application Lifecycle Management.

A. Application Lifecycle Management encompasses the work effort required to update and maintain key and critical IT&S application platforms. It is necessary to ensure ongoing availability, stability, security, technical currency, and vendor support. 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. The Application Lifecycle Management – Governance, Risk, and Compliance ("ALM-GRC") Project is part of this broader category of work.

Q. Please describe the ALM – GRC Project.

A. The ALM – GRC Project will update NW Natural's Governance, Risk, and Compliance platform to the current version supported by the software provider, SAP. The platform, known as "SAP GRC," is a critical enterprise application that supports the Company's SOX compliance program, including internal controls, risk management, audit support, and regulatory compliance activities. The project will ensure that the platform remains aligned with NW Natural's long-term application lifecycle management strategy and continues to support these business functions effectively.

Q. Why is it necessary to update the SAP GRC product?

A. 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 SAP GRC 12.0 version will no longer be fully supported by SAP at the end of 2027. Prior to that date, customers must either upgrade to a newer version, purchase an extended maintenance package available through December 31, 2030, or accept a risk of limited support without legal, regulatory, or compliance-related updates that are required for a compliance-focused application such as GRC. Therefore, upgrading to the SAP-supported successor platform reduces support, security, and compliance risks.

Q. Is NW Natural considering alternatives to the ALM - GRC Project?

A. Yes. NW Natural is currently evaluating the alternative of remaining on the current SAP GRC version and utilizing SAP's Extended Maintenance program. SAP advised that Extended Maintenance is available through December 31, 2030, but this option would require an additional maintenance fee. SAP has provided preliminary pricing information indicating an annual cost of approximately $42,000, although final maintenance terms and pricing have not yet been formally established. While Extended Maintenance would provide additional time, it would also increase ongoing operating costs without providing new functionality. Conversely, NW Natural is evaluating the potential risks of transitioning to the new SAP product, which was released quite recently in 2026. As previously discussed, NW Natural generally prefers not to adopt the latest software release until there has been sufficient time to address "bugs" or technical issues with new products.

Q. Could the ALM-GRC Project be postponed to 2030?

A. No. Selecting Extended Maintenance would allow the ALM-GRC upgrade to be postponed to 2028, but not to 2030 because this upgrade must be completed before an SAP ERP system upgrade will be required in 2029.

Q. What is the status of the ALM - GRC Project?

A. The project is in the Intake/Initiate phase and the Company expects to finalize its evaluation of alternatives in the first quarter of 2027. If the upgrade is selected, then the project would enter service by December 2027. If extended maintenance is selected, then the project would enter service in July 2028.

Q. What cost recovery is NW Natural requesting for the ALM – GRC Project?

A. NW Natural seeks to recover its capital investment of $3.1 million on a system-wide basis, or $2.7 million on an Oregon-allocated basis. This amount reflects the cost estimate for the ALM-GRC upgrade, which will be completed in either December 2027 or, if delayed, in July 2028.

2. Physical Security Platform Modernization Project

Q. Please describe the Company's Physical Security Platform Modernization Project.

A. The Physical Security Platform Modernization Project is part of an ongoing initiative to replace and modernize security equipment across the Company's operational locations. Specific locations include corporate offices, operational facilities, data centers, remote sites, and other specialized locations, each with varying levels of existing security infrastructure. Security infrastructure and equipment include video surveillance equipment, access controls, intercoms, environmental monitoring, and alarm systems. The project prioritizes upgrades based on security coverage, reliability of gas operations, and long-term manageability.

This project is being implemented incrementally, with equipment placed in service on a rolling basis. In 2026, for instance, the Company replaced legacy access control and video surveillance platforms, focusing on an initial tier of resource centers and liquefied natural gas ("LNG") plants. In 2027 and 2028, the Company will continue [**BEGIN CONFIDENTIAL**] [redacted]

[redacted] [**END CONFIDENTIAL**].

Q. Why is the Physical Security Platform Modernization Project necessary?

A. The Physical Security Platform Modernization Project is necessary because NW Natural's legacy system has been in place for more than 15 years. Aging cameras and security systems have experienced gaps in performance and lack valuable features of modern systems. New technology significantly improves the function and performance of physical security systems, allowing security investigations to occur in minutes versus hours. In particular, new analytic functions improve employee safety by providing real-time monitoring and feedback, which allows the Company to rapidly identify and mitigate security incidents. In sum, the upgraded system will provide a standardized, modern physical security platform, reduce technical debt, unify the Company's security systems, replace end-of-life hardware, improve reliability, simplify lifecycle management and improve protection and safety across NW Natural facilities.

Q. What are the benefits of the Physical Security Platform Modernization Project?

A. The primary benefits are a standardized, modern physical security platform; integration with IT systems to automate the onboarding and offboarding processes and streamline coordination between cyber and physical systems; a reduction in technical debt; a unified enterprise-wide approach to security systems; retiring aging, unsupported hardware and thereby lowering risk of failure; improved

reliability and simplified lifecycle management; and improved protection and safety across NW Natural facilities.

Q. Did NW Natural consider alternatives to the Physical Security Platform Modernization Project?

A. Yes. The Company considered three alternatives: (1) adopting the [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] enterprise physical security platform; (2) adopting the alternate [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] system; and (3) continuing to rely on legacy systems. The Company chose [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] as its enterprise physical security platform because it is a cloud-based SaaS solution that scales across all sites. While [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] offered somewhat lower subscription cost, this would have been offset by the need for additional recording devices, network infrastructure, and ongoing management at every location. The Company concluded that continuing to rely on legacy systems was not viable as this option represents an unacceptable risk to safety and security.

Q. What is the status of the Physical Security Platform Modernization Project?

A. The Physical Security Platform Modernization Project is currently underway. In 2026, the Company completed planning activities and began implementation at critical sites. The 2027 locations will be placed in service in October 2027. The 2028 locations will be placed in service in October 2028.

Q. What cost recovery is NW Natural requesting for the Physical Security Platform Modernization Project?

A. NW Natural seeks to recover its capital investment for the Physical Security Platform Modernization Project of $5.3 million on a system basis, or $4.6 million on an Oregon-allocated basis.

3. Network Lifecycle Management 2027 Project

Q. Please describe how the Network Lifecycle Management 2027 Project fits into the Company's broader Network Lifecycle Management Program.

A. NW Natural's Network Lifecycle Management Program is a coordinated initiative to replace end-of-life network infrastructure. Network infrastructure includes both the devices and software that move data between computers, connect a business to the internet, and secure traffic along the way. Relevant equipment includes routers, switches, wireless access points, firewall security appliances, and other supporting gear, cabling, and operating software. All of this equipment requires periodic updating to ensure reliability.

Q. Please describe the work included in the Network Lifecycle Management 2027 Project.

A. The Network Lifecycle Management 2027 Project will replace end-of-life equipment at a set of NW Natural facilities with modern, fully supported Cisco hardware and renew the associated software licenses, warranties, maintenance, and technical support services agreements. The Company's work is tracked in four categories:

1. Data Center IT: work supporting corporate IT applications and services at data centers.
2. Data Center OT: work supporting OT systems at NW Natural's data centers.
3. Other OT Sites: work supporting other OT sites.
4. Other IT Sites: work supporting other corporate and field IT locations.

Although the four project categories follow the same lifecycle-management strategy, NW Natural tracks these projects separately for planning, budgeting, management, and cost tracking purposes. Together, however, the project represents a coordinated effort to sustain NW Natural's network infrastructure.

Q. Why is the Network Lifecycle Management 2027 Project necessary?

A. The Network Lifecycle Management 2027 Project is necessary to address two critical risks to NW Natural's operations. First, the Company replaces network equipment as it reaches the end of vendor support during the year. Once devices are out of support, they no longer receive security updates, performance improvements, or technical assistance from the manufacturer, which increase the risk of operational issues, security vulnerabilities, and unplanned outages. Second, several essential software and hardware licenses are approaching their expiration dates. If these licenses lapse and the associated hardware therefore fails, then the Company could lose access to key tools and services that support daily operations.

Q. How does the Network Lifecycle Management 2027 Project relate to the Data Center Resilience and Modernization Project?

A. Depending on the results of the Data Center Resilience and Modernization Project's initial study, some of the equipment replacements may be delayed or avoided. To the extent that equipment replacements are still required to ensure operational continuity, some of this equipment could be migrated to a new data center location.

Q. Did NW Natural evaluate alternatives to the Network Lifecycle Management 2027 Project?

A. Yes. NW Natural considered both (1) migrating to another equipment vendor and (2) declining to refresh the end-of-life equipment. Migrating to an alternate vendor, such as [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**], was not selected due to cost, time, and operational risk. Project costs would be considerably higher due to the need to modify system architecture, substantially redesign and re-engineer the network, train operational teams on unfamiliar equipment platforms, and implement new operational support procedures. This alternative would also take considerably longer, and would carry significant risk of data center downtime and service disruption.

Declining to refresh the end-of-life equipment was considered not viable because failing to act would leave NW Natural exposed to significant operational, security, and compliance risks. As explained above, unsupported devices increase the likelihood of system failures, security vulnerabilities, and unplanned outages. Moreover, expiring software licenses threaten continued access to

critical tools needed for daily operations. Without timely action, these risks could disrupt the Company's provision of safe and reliable service.

Q. What is the current status of the Network Lifecycle Management 2027 Project?

A. The Network Lifecycle Management 2027 Project is currently in the Planning phase as individual equipment replacement needs are identified for 2027. This project is on track to be placed in service in October 2027.

Q. What cost recovery is NW Natural requesting for the Network Lifecycle Management 2027 Project?

A. NW Natural is requesting recovery of the capital investment and associated ongoing O&M costs as follows:

Project	Capital investment	Annual O&M
Data Center IT	$1.3 million	$215,000
Data Center OT	$1.5 million	$215,000
OT Sites	$1.5 million	$215,000
IT Sites	$1.3 million	$215,000
Combined total	**$5.7 million**	**$860,000 annually**

4. Telemetry Lifecycle Management Program

Q. As an initial matter, please explain the term "telemetry" in the context of NW Natural's provision of service.

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 ongoing 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.

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 systematically maintaining the Company's telemetry

systems, NW Natural can support the critical functionality of its telemetry systems while avoiding unnecessary cost spikes.

Q. How is the Telemetry Lifecycle Management Program implemented?

A. The Telemetry Lifecycle Management Program is implemented on a scheduled, incremental basis to allow for systematic maintenance across the Company's telemetry locations. As of November 2026, 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 15 sites per year, allowing the Company to maintain and update sites on approximately a 15-year rotating cycle.

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.

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 by the end of October each year. The Company plans to refresh another 15 sites in 2027 and 15 sites in 2028.

Q. What cost recovery is NW Natural requesting for the project?

A. The Company seeks to recover its capital investment of $10.3 million (including $5.7 million invested in 2027 and $4.6 million invested in 2028) on a system basis, or $9.1 million on an Oregon-allocated basis.

5. Communications Towers Modernization 2027-2028 Project

Q. Please provide context for the Communications Towers Modernization 2027-2028 Project.

A. The Communications Towers Modernization 2027-2028 Project is part of a multi-phase effort to assess, repair, and optimize the Company's communications towers and related infrastructure ("Communications Towers Modernization Program"). NW Natural has relied on these communications systems for decades as a reliable, non-wires alternative for transmitting information. Transmitted information is used as part of the Company's SCADA and Emergency Voice Radio systems, among other functions. Currently, NW Natural's communications systems include communications towers, rooftop installations, and in-building antennas across 24 total sites. These sites include 15 Company-owned towers, most which were built decades ago; the oldest was installed in 1957. Many of these towers are in remote locations, and the Company had not previously conducted a comprehensive towers site assessment.

Q. Please describe the Communications Towers Modernization Program as a whole.

A. The Communications Towers Modernization Program involves (a) conducting a detailed site assessment of the Company's communication towers; (b) addressing

identified operational challenges, interference issues, and safety hazards; and (c) transitioning away from a "daisy-chained" network architecture to a ring-based, "hub-and-spoke" network architecture. This final phase may involve replacing or expanding existing towers or collocating NW Natural equipment on existing third-party towers to reduce single points of failure. These phases are implemented on an annual basis, as follows:

- 2025 Assessment: In 2025, NW Natural engaged Gillespie, Prudhon & Associates, Inc. Telecommunications Engineers ("GP&A") to assess the condition, safety, and performance of the Company's communications locations. Based on this assessment, GP&A provided site-specific recommendations, which NW Natural then used to develop a multi-year modernization strategy.
- 2026 Critical Fixes & Further Assessment: In 2026, the Company addressed the most urgent safety remediation work, such as rusted climbing systems and inadequate ladder access, and assessed the sites' electrical grounding. Based on the initial GP&A assessment, there appeared to be inadequate electrical grounding at some proportion of the communications towers—the lack of which can result in significant safety concerns during inclement weather. This grounding assessment was then used to guide the scope of 2027 remedial work.

- 2027 Safety Remediation & Network Expansion: In 2027, the Company will continue to correct high-priority safety issues, will remediate identified electrical grounding issues, and will remove vegetation currently interfering with data transmission. In addition, the Company will evaluate options for strengthening the data transmission network, such as collocating NW Natural equipment on existing third-party towers, installing a new tower, or both.
- 2028 Network Expansion Implementation: In 2028, the Company will implement the results of the 2027 network expansion evaluation, including installing additional equipment to strengthen the data transmission network.

Q. Why is the Communications Towers Modernization 2027-2028 Project necessary?

A. The Communications Towers Modernization 2027-2028 Project is necessary (1) to ensure reliable communications and emergency preparedness and (2) to remediate safety hazards at NW Natural's towers. Non-wires information transmission is particularly crucial in emergency situations, such as "technician down" scenarios and natural disasters, which can result in cellular communications outages. Additionally, the Company is aware of five towers that do not reliably transmit information due to interference by tree and vegetation growth; this degraded functionality means that those areas currently lack reliable voice radio service, telemetry data reporting, and back-up SCADA transmission. Restoring full communications and information transmission in these areas is critical.

Q. Did NW Natural consider alternatives to the Communications Towers Modernization 2027-2028 Project?

A. Yes. NW Natural considered 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: Non-wires transport offers greater flexibility in reaching remote or hard-to-access areas where laying cables might be impractical or impossible.

- Interference and Maintenance: While non-wires 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.

Based on these factors, NW Natural evaluated specific sites for access to wires-based alternatives, and concluded that field resource centers could be effectively converted to fiber. This alternative reduces the overall cost of the Communications Towers Modernization 2027-2028 Project, but requires additional O&M expense associated with the fiber leases.

In addition, the Company is evaluating alternatives for strengthening the design and structure of the communications network with either a new tower, a new collation site, or both. This analysis is ongoing and is expected to complete in the first quarter of 2027.

Q. What is the status of the Communications Towers Modernization 2027-2028 Project?

A. The Communications Towers Modernization 2027-2028 Project is in the Planning phase. The Company is in the process of gathering information from new tower vendors and collocation tower owners. Project work will begin in the first quarter of 2027 and is expected to be placed in service in October 2028.

Q. What cost recovery is NW Natural requesting for the project?

A. NW Natural seeks to recover its capital investment for this project of $7.4 million on a system-wide basis, or $6.5 million on an Oregon-allocated basis.

6. Meter Modernization & Temetra Implementation ("Temetra") Project

Q. Please describe the Temetra Project.

A. The Temetra Project is part of the multi-year Meter Modernization Program, previously discussed in Docket UG 520.[13] The Meter Modernization Program is gradually replacing end-of-life metering assets and associated software. Meter assets rely on proprietary communication devices, meaning meters must have the same vendor's "head end" system to successfully relay metering data. NW Natural's current metering head end system is Field Collection System ("FCS"), which will reach end-of-life and will no longer be supported in 2028. The software associated with the modernized meters is called Temetra. The Temetra Project will implement and integrate the new Temetra software into the Company's systems. Modern meters and the Temetra software will allow the Company to retrieve data via both radio and cellular communication devices.

Q. Why is the Temetra Project necessary?

A. The Temetra Project is necessary because NW Natural's metering assets can communicate only with their single vendor's head end system, which is currently FCS. With the adoption of the modern metering system, it is necessary to migrate to a compatible software solution.

[13] Docket No. UG 520, Direct Testimony of Joe S. Karney, NW Natural/900, Karney/4-5 (Dec. 30, 2024).

Q. Did NW Natural consider alternatives to the Temetra Project?

A. Yes. NW Natural considered implementing Temetra with and without a supplemental technology called Utility IQ. Utility IQ can support future cellular-based meter reading. At this stage, the Company chose to move forward with Temetra *without* Utility IQ for several reasons. First, this option was lowest cost. Second, the Company is not yet well positioned to implement cellular-based meter reading functionality. Third, focusing on Temetra alone reduces implementation risk and minimizes impact on field personnel.

In addition, NW Natural considered switching to a different head end system. However, this alternative was not selected because switching to a different head end system would require replacing the current metering assets. As a result, this option far outstripped the other options in cost.

Q. What is the status of the Temetra Project?

A. The Temetra Project has undergone preliminary work to prepare third-party software systems for Temetra integration. The core Temetra software implementation effort is in the Planning phase. The Temetra Project is expected to be placed in service by September 2027.

Q. What cost recovery is NW Natural requesting for the Temetra Implementation Project?

A. NW Natural seeks to recover its capital investment of $5.9 million on a system basis, or $5.2 million on an Oregon-allocated basis. NW Natural also requests recovery of $296 thousand in incremental ongoing O&M ($260 thousand Oregon-allocated) for software licensing.

F. Back-Office Infrastructure

1. ServiceNow Implementation Project

Q. Please describe the ServiceNow Implementation Project.

A. The ServiceNow Implementation Project is a two-phase effort that will replace the Company's current fragmented and highly manual processes and tools for both IT service management ("ITSM") and asset management with a single integrated platform from ServiceNow. An ITSM system is a platform and set of processes for handling IT support and services, including fixing IT problems, fulfilling user requests, and maintaining a searchable record of known fixes.

The project includes two phases that will proceed sequentially: the first phase will implement a consolidated ITSM system, while the second phase will implement asset management system functions. Each phase of this Project is detailed below, though only the first phase is included for cost recovery in this case.

Q. Why is establishing a consolidated ITSM system necessary?

A. Establishing a consolidated ITSM system is necessary to address deficiencies in NW Natural's current ITSM environment. The Company's central ITSM software—Cireson/System Center Service Manager ("SCSM")—is an on-premises solution that cannot integrate or communicate with cloud-based solutions. As a result, the SCSM tool is largely used as a service ticket repository. The Company manually tracks and coordinates service management activities, configuration data, asset information, knowledge resources, and operational reporting across disparate systems. This manual process is not only laborious and error-prone, but also fails

to fully leverage the Company's substantial knowledge resources to improve IT service.

In addition to these core functionality concerns, the SCSM tool is also increasingly out of date and difficult to update and maintain. The tool is not widely used by large organizations and NW Natural must rely on a single small vendor for product support. As a result, service response times are quite slow and can take weeks. Thus, ongoing reliance on the SCSM tool presents a growing reliability and performance challenge.

Q. Are there other benefits associated with modernizing and standardizing NW Natural's ITSM system?

A. Yes. By establishing a unified system of records, ServiceNow will strengthen the Company's reporting, internal visibility, and operational decision-making. The new ITSM system will also significantly improve the end-user experience by providing faster resolution times, clearer communication, and more intuitive self-service capabilities. Lastly, by adopting an out-of-the-box software solution, NW Natural can effectively reduce its technical debt and continue to streamline its IT&S environment.

Q. Did NW Natural consider alternatives to establishing a consolidated ITSM system with ServiceNow?

A. Yes. NW Natural considered several ITSM software alternatives ([**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**]), as well as a "no action" alternative. The three software alternatives offered some of the functionality of ServiceNow, such as basic ticketing and service management, but did not have sufficient functionality to serve as the consolidated system of record for ITSM. Moreover, all three of these alternatives also had limited enterprise integration and smaller support ecosystems, meaning that the Company would likely have needed to supplement these solutions with additional products or custom tools to address the capability gaps. Thus, while these products' offered somewhat lower up-front investments, the overall value of ServiceNow was considerably higher. Notably, ServiceNow is by far the most widely used and supported ITSM tool across the IT industry.

Similarly, the "no action" alternative was not selected due to the increasing enterprise risk and operational burden associated with the current highly manual and fragmented ITSM system.

[14] [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**].

Q. What is the status of the first phase of the ServiceNow Implementation Project?

A. The first phase of the ServiceNow Implementation Project is currently underway. NW Natural has procured the software license and has selected a system integrator for implementation via a competitive RFP process. The consolidated ITSM system is on track to enter service in July 2027.

Q. Please provide more detail about the second phase of the ServiceNow Implementation Project.

A. The second phase of the ServiceNow Implementation Project plans to establish ServiceNow's platform as NW Natural's consolidated asset management system. An asset management system provides a central record and management system for all technology assets, including both hardware and software. For each asset, the platform tracks and assists with the whole asset lifecycle, including purchasing, assignment, configuration, maintenance, retirement, and disposal.

Q. Why is establishing a consolidated asset management system necessary?

A. Establishing a consolidated asset management system is necessary for several reasons: (1) security, (2) cost control, and (3) operational visibility.

First, an asset management system supports security by ensuring that all equipment and software is assigned, maintained, and used appropriately. Currently, the Company relies on a fragmented system of Excel spreadsheets and siloed software tools that fail to comprehensively track and record the Company's assets. For instance, NW Natural uses Microsoft's Intune software for certain limited asset management functions; however, this system tracks only laptops and

cell phones—and even these only when the assets are active and enrolled. Thus, for all assets other than laptops and cell phones, and for those assets that are inventoried or retired, the Company largely relies on manual spreadsheet systems that are inherently error-prone and laborious to maintain.

Second, an asset management system ensures that the Company is paying only for systems that are actively and fully utilized. For software, a system like ServiceNow tracks all licenses owned to ensure that any licenses purchased are being used—and if not, the system reclaims these licenses for retirement or reallocation. Similarly, such a system tracks usage for software licenses from Adobe, Microsoft, and AutoCAD to identify which portions of the license are being utilized, and will automatically suggest downgrades to better suit the scope of the user's need.

Third, an asset management system allows the Company to operate with fewer operational disruptions and greater visibility. Currently, for example, when an individual's laptop is nearing end-of-life and experiencing service quality disruptions, IT&S personnel work directly with that individual to arrange for replacement and manage the device roll-out. An asset management system streamlines this process by automatically identifying what device is reaching end-of-life, contacting the affected individual, ordering the appropriate device, and setting up the new device with the tools and systems needed for that individual's scope of work. By creating a more streamlined, predictable asset procurement process, the system also reduces the need for large batch ordering and the degree of product inventory.

Q. Is NW Natural evaluating alternatives for this second phase of the ServiceNow Implementation Project?

A. Yes. NW Natural will evaluate available alternatives for asset management systems before beginning work in the latter half of 2027. Based on currently available information, the Company anticipates that extending the use of ServiceNow's software system to include asset management functions will provide the least-cost, least-risk option, and therefore includes this work as part of the ServiceNow Implementation Project.

Q. What is the status of the second phase of ServiceNow Implementation Project?

A. The Company anticipates beginning work on the second phase of the ServiceNow Implementation Project after the first phase is placed in service in July 2027. However, the second phase of this project will not enter service until December 2028, which is after the Test Year. Thus, the Company seeks recovery of only the first phase of this project in this case.

Q. What cost recovery is NW Natural requesting for the Project?

A. The Company is requesting recovery of its capital investment of $4.1 million for the Project's first phase on a system basis, or $3.6 million on an Oregon-allocated basis. NW Natural also requests recovery of $450 thousand in incremental ongoing O&M ($395 thousand Oregon-allocated) for software licensing.

2. Data Center Resilience and Modernization Project

Q. Please describe the Data Center Resilience and Modernization Project.

A. The Data Center Resilience and Modernization Project is a three-year effort to migrate NW Natural to new data center infrastructure. This effort involves moving away from the Sherwood data center, migrating IT workloads to cloud-based platforms (where feasible), consolidating OT workloads into resilient collocated data center facilities, and modernizing supporting network and infrastructure services. To achieve these goals, the project will be executed over a three-year roadmap:

- **Phase 1 (Planning & Architecture):** The first stage will complete facility engineering evaluations and determine the dependencies, constraints, requirements, and facility options for a data center migration. This analysis will evaluate costs, risks, and implementation considerations relevant to designing and scoping the data center migration in a manner that supports operational continuity and regulatory obligations.
- **Phase 2 (Design & Staging):** The second stage will secure a regional colocation space, upgrade core network fabrics, and prepare the Company's primary utility software platforms for transition. Which colocation space (or spaces) will be secured, as well as the associated staging requirements, will depend on the results of the planning and architecture evaluation.

- **Phase 3 (Migration & Site Retirement):** The third and final stage will physically transfer utility control systems into reliable new facilities, validate disaster recovery capabilities, and fully decommission the Sherwood building. The scope and sequence of these implementation steps will depend on the results of the planning and architecture evaluation.

Q. Why is the Data Center Resilience and Modernization Project necessary?

A. The Data Center Resilience and Modernization Project is necessary to (a) ensure system reliability, (b) manage macro technology cost pressures, and (c) deliver long-term value for customers.

- **Ensuring System Reliability:** Systems that monitor and control natural gas distribution require instantaneous, guaranteed connectivity. The Company-owned Sherwood data center is no longer able to reliably support NW Natural's operations due to the physical limits of its aging power and cooling infrastructure. These limits reflect the fact that the structure was retrofitted to provide data center services, rather than being designed as a data center from the ground up. This distinction is evident in core physical design features: most data centers have raised floors and cooling on all sides to facilitate efficient heat transfer, and have rack-level cooling. At the Sherwood location, racks are floor-mounted with room-level cooling. Despite engaging HVAC contractors, overheating equipment at this location has resulted in persistent outages. These outages disrupt the stability and safety of our OT

platform, which monitors and controls real-time natural gas pipeline operations. Thus, moving to a modern, specialized data center facility (colocation) is necessary to ensure reliable operations. At the same time, this strategy ensures our essential IT systems and business applications that cannot be effectively supported in the cloud are more highly available and resilient to support daily operations. While general office software functions well in the public cloud, life-safety utility control systems belong in specialized, climate-controlled regional facilities that guarantee continuous power, backup cooling, and more automated backup functionality.

- **Managing Macro Technology Cost Pressures:** While the Company's Sherwood location lacks reliability, NW Natural's Bend data center lease is coming up for renewal in September 2027. At the same time, the global expansion of AI infrastructure has created unprecedented supply chain pressures across enterprise technology for self-hosted data centers. As a result, retrofitting our aging facility to support modern high-density hardware while absorbing these elevated market hardware costs would be financially inefficient. As a result, the Company is studying both short-term and long-term options to cost-effectively improve the resilience of its data center infrastructure. For instance, colocation options allow the Company to optimize component purchasing, right-size its hardware footprint, and leverage existing data center

infrastructure to moderate ratepayer impact from macro technology price spikes.

- **Delivering Long-Term Value for Customers:** As explained above, some systems are appropriately cloud-hosted (such as business-level IT functions), while some technologies (such as OT, GCDOP, and SCADA) are not currently well suited to be cloud-hosted due to latency and security concerns. Hosting high-volume, 24/7 core utility systems continuously in the public cloud often carries ongoing subscription and data transfer fees that are two to three times higher over a five-year period than utilizing dedicated physical hardware in a colocation facility. Utilizing specialized physical facilities for constant-use core systems keeps long-term costs lower for customers.

Q. Is NW Natural evaluating alternatives for the Data Center Resilience and Modernization Project?

A. Yes. NW Natural is carefully evaluating alternatives as part of the rigorous first-phase planning and architecture process. At this stage, the Company will evaluate all viable alternatives for ensuring the reliable provision of data hosting services.

Q. What is the status of the Data Center Resilience and Modernization Project?

A. The planning and architecture phase of this project is currently underway. Current active efforts include:

- System Mapping: Categorizing Company software into the safest, most cost-effective hosting environments based on speed, security, and reliability requirements.

- Facility Evaluations: Surveying high-reliability, specialized data center facilities in the Pacific Northwest (such as Hillsboro and Bend) and nationally, to verify their backup power, advanced cooling systems, and physical security, while also recognizing other regions' cost and latency tradeoffs.
- Financial Modeling: Building detailed multi-year cost analyses comparing public cloud hosting against specialized physical facilities to ensure the final strategy provides the lowest overall cost impact for our customers.

While the schedule may be further refined based on the study results, the Company currently anticipates placing the first phase of this project in service in October 2028.

Q. What cost recovery is NW Natural requesting for the project?

A. NW Natural is requesting to recover its capital investment of $3.9 million on a system-wide basis, or $3.4 million on an Oregon-allocated basis.

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Direct Testimony of Kyra M. Patterson

COMPENSATION & BENEFITS
EXHIBIT 900

REDACTED

November 24, 2026

EXHIBIT 900 – DIRECT TESTIMONY – COMPENSATION & BENEFITS

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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 Kyra M. Patterson. My title is Vice President, Chief People 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 Science in English from Prairie View A&M University in 1995 and my Masters in Labor and Human Resources from The Ohio State University in 2001. Prior to NW Natural, I was employed by Avangrid as the Chief Human Resources Officer. Before joining Avangrid, I served as the Chief Human Resources Officer of HAI Group. I was employed in other senior human resource roles and management positions at Diageo, C&S Wholesale Grocers, Sears, International Paper, Interliant, and The Ohio State University Medical Center for 16 years prior to joining HAI Group. I joined NW Natural in September 2025 and have been an officer for the Company since that time.

Q. Please summarize your testimony.

A. In my testimony, I:

- Explain the Company's compensation philosophy, which is to provide competitive total compensation—the combination of base pay, pay-at-risk, medical benefits, and retirement benefits—at the market median for comparable jobs, in order to attract, motivate, and retain the qualified

workforce needed to run a safe and reliable natural gas delivery business at a reasonable cost;

- Describe how the Company determines base pay for Non-Bargaining Unit ("NBU") employees, Bargaining Unit ("BU") employees, and officers, and demonstrate that NBU base pay midpoints are at the market median and officer compensation is within the market competitive range;
- Explain why pay-at-risk is a standard and necessary component of competitive total compensation that does not result in above-market compensation, and note that the Company is seeking recovery only of NBU short-term incentive and long-term restricted stock unit costs and is not seeking recovery of officer pay-at-risk in this case;
- Describe the medical and other health benefits offered by NW Natural, demonstrate that they are aligned with the market, and show that the Company has carefully managed these benefits to ensure reasonable costs;
- Describe the Company's retirement benefits, which provide market median retirement offerings, and explain that the Company is proposing no changes to retirement benefits in this case;
- Describe the overall level of compensation and benefits costs included in the Company's requested revenue requirement for the November 2027 through October 2028 test year ("Test Year"); and

- Describe the Company's requested employee headcount for Full-Time Equivalent positions ("FTE") in the Test Year, which is 1,253.3 gas utility FTEs.

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 (or "pay-at-risk"), 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 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 practices 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.*, pay-at-risk) that are not guaranteed and are not paid on a regular interval but are nevertheless a critical component of offering competitive total 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. NW Natural's most recent analysis, as completed by the Company in 2026, is attached as NW Natural/901, Patterson. 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 and the union jointly agree to utilize selected market survey data sources and union contracts, primarily of Northwest gas utility companies, as the points of comparison for setting BU wage steps. Using the agreed-upon sources of competitive pay data, the average is used to determine pay grades. Pay increase trend data and union contracts are consulted when negotiating annual wage increases throughout the term of the Collective Bargaining Agreement ("CBA"). 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, whereas previously the sharing was 80 percent/20 percent. Lastly, six jobs were re-graded, increasing the wages for those positions.

Q. How has the Company determined BU employees' base pay in this case?

A. The last pay adjustment in the current contract will occur in December 2027. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] .**[END HIGHLY CONFIDENTIAL]**.

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 pay-at-risk 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 Confidential NW Natural/902, Patterson, 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, as included in the Company's requested revenue requirement?

A. Table 1 below provides the cost of base pay for the Test Year. These amounts include only the cost for gas utility employees of NW Natural and represent the Oregon-allocated base pay for FTEs.

Table 1
Utility Employee Base Pay (Wages & Salaries)
(Oregon Allocated FTEs)

Type of Utility Employee	Cost of Base Pay
Bargaining Unit (BU) Employees	$60,201,148
NBU Employees	$80,203,518
Officers	$4,468,243
Total	$144,872,909

Q. How did NW Natural determine the cost of base pay in Table 1 for NBU employees and officers in the Test Year?

A. For NBU employees and officers, the amounts shown were determined by taking base pay costs for the Base Year (12-months ended June 30, 2026) and escalating them by 4.50 percent in 2025 and 4.50 percent in 2026. This reflects a 3.50 percent merit increase in 2025 and 2026, and an additional 1.00 percent in 2025 and 2026 to reflect promotions and equity adjustments. The merit percentages were derived using the anticipated 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.

Q. How did NW Natural determine the cost of base pay in Table 1 for BU employees in the Test Year?

A. For BU employees, NW Natural determined the cost of base pay by first including the annual wage increases specified in the CBA. Next, an additional 1.05 percent was added each year to account for movement through training progression step increases, movement from entry rate to the experienced rate, as well as promotions, transfers and other adjustments. This additional amount was determined based upon past experience. Taken together, BU employees' base pay will increase 5.05 percent annually, which NW Natural incorporated into Table 1 above.

IV. PAY-AT-RISK

Q. In describing competitive total compensation, you stated that "pay-at-risk" is an important component. Please define what you mean by this term.

A. Pay-at-risk is compensation made to employees only if certain performance goals are met within a defined timeframe. Pay-at-risk 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 "pay-at-risk" compensation a standard practice in your industry?

A. Yes, pay-at-risk is widely employed by our competitors for labor, and is expected by the professional workforce. Therefore, we believe we need to provide pay-at-risk (at different levels depending on the employee's position) in order to compete

and meet pay expectations of the workforce. Pay-at-risk 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 pay-at-risk or incentive plan (see Confidential NW Natural/903, Patterson*).*

Q. Does NW Natural's "pay-at-risk" compensation result in above-market median total compensation?

A. No, it does not. Our pay-at-risk 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 pay-at-risk, 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 the Company proposing to recover the costs of pay-at-risk pay for officers of the Company?

A. No, it is not. To mitigate the size of the rate request, NW Natural determined that it would not seek recovery of the costs of pay-at-risk pay for officers of the Company in this case, even though we continue to believe that these costs are prudently incurred.

Q. By excluding pay-at-risk pay for officers in this proceeding, is the Company taking the position that these costs are not recoverable?

A. No. While pay-at-risk is an important part of competitive total compensation for officers, drives operational and financial goals, and is a consistent practice among its peers, NW Natural is not seeking recovery of the costs of pay-at-risk pay for officers of the Company in this rate case. The Company has also not capitalized

any portion of pay-at-risk compensation for officers. NW Natural notes that its decision to not seek cost recovery only applies to this proceeding. The Company continues to believe that multiyear rate plans, which Oregon is transitioning to over the next several years, must give utilities the opportunity to recover all prudently incurred costs, including officer and employee compensation.

Q. Is pay-at-risk 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. Table 2 below represents the pay-at-risk for our short-term incentive program for NBU employees.

Table 2
Short-Term Incentive Pay-At-Risk

Incentive Program Type	Participants	Target Percent of Pay	Amount Requested in Test Year 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 describe the pay-at-risk that NW Natural provides to NBU employees.

A. NW Natural provides pay-at-risk as a proportion of competitive total compensation that is in line with industry practice. Pay-at-risk is offered through a few different programs depending on job classification. The Company offers a "Goals Incentive Program" to NBU non-officer employees. This program recognizes and rewards employees who have demonstrated strong individual performance and rewards

the performers for the plan year who achieve or exceed their annual performance objectives. The Company offers long-term restricted stock units ("RSUs") as well. More details on this program are discussed below.

Q. Does NW Natural offer pay-at-risk compensation to BU employees?

A. No. Short-term incentive pay-at-risk is not typically found in unionized employee roles and it is not included in the CBA.

Q. Please describe the operational goals that underlie the Company's short-term incentive programs for NBU employees and explain how customers benefit when the Company meets these goals.

A. The Company's short-term incentive program for NBU employees includes an operational component with the following goals: (1) customer satisfaction, (2) market 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.
- Market growth measures the number of total 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 percentage 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 to its customers.

Q. Please explain why NBU employees' long-term RSUs are eligible for full cost recovery.

A. The purpose of RSUs is to encourage key employees to remain with the Company, which is why they vest over time. The RSUs are not awarded to incentivize financial performance, and the number of RSUs will not increase in a good financial year. While RSUs will not vest if the Company has a very poor year, this does not

determine the purpose of the incentive, which is to ensure that NW Natural retains qualified employees rather than incurring incremental costs of employee turnover.

Q. What is the total cost of at-risk pay for NBU employees that NW Natural has sought to recover as part of its revenue requirement for the Test Year in this rate case?

A. The Company is proposing to recover $10,630,848 in total at-risk pay for NBU employees in this rate case.

Q. How do you propose that the Commission view pay-at-risk in a utility's total compensation package?

A. The Commission should treat the question of cost recovery for pay-at-risk on a case-by-case basis, with an evaluation to ensure that utilities are paying at market and that the at-risk pay programs are reasonable. This approach is in line with the general regulatory construct in Oregon that allows utilities to recover prudently incurred costs necessary for the provision of utility service.

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.

Q. What is the medical benefits expense proposed for recovery in this case?

A. The Company has included $25.1 million of medical benefits costs for the Test Year.

Q. Has the Company taken action to manage medical costs?

A. Yes. The Company actively manages health care costs through periodic market reviews, plan design evaluations, and ongoing collaboration with its health insurance providers. NW Natural regularly evaluates its medical and pharmacy programs to ensure they remain competitive while balancing affordability for employees and customers.

The Company also periodically conducts requests for proposals ("RFPs") from medical insurance providers to confirm that pricing and services remain competitive. NW Natural's most recent medical and pharmacy benefits RFP

resulted in a change from Cigna to Regence beginning in 2022, generating approximately $1.0 million in annual savings.

In addition, the Company reviews plan design features annually and implements changes, when appropriate, to help manage costs while maintaining competitive benefits. For example, changes to the Regence Preferred Provider Organization (PPO) plan design have included adjustments to participant cost-sharing features, resulting in lower overall plan costs.

NW Natural also works closely with its carriers, Regence and Kaiser Permanente, to manage health care costs through care management programs, chronic condition support, virtual care options, prior authorization requirements, negotiated provider discounts, pharmacy rebate arrangements, and ongoing review of new and emerging therapies. These efforts are intended to improve health outcomes while helping to control the growth in medical and pharmacy expenses.

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. Based on health care market data reviewed by IMA Financial Group (formerly Parker, Smith & Feek), including data from the 2026 Milliman Employee Benefits Survey, and renewal trend data from Regence, health care trend factors in the Pacific Northwest have continued to increase in recent years. Premium increases for mid-size and large employer groups continue to be at 11 to 13 percent for medical plans in 2026 (see NW Natural/904, Patterson).

NW Natural's active NBU employees' medical expenses have been increasing at a rate that has been at or below trend factors from Regence for the last four years (see NW Natural/904, Patterson). In the case of BU employees, medical increases have been below the trends for the last four years.

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 develops rates on our actual insured population and claims experience. Kaiser Permanente combines the NBU population with their broader book of business for renewal rates due to the size of our enrolled population. In addition to claims experience, other demographic factors influence medical costs, including age, gender, and family size. Based on Kaiser Permanente's and Regence's Clinical Utilization Reports, NW Natural's average age among pre-65 covered NBU participants was 48.9 years, compared to 48.2 years in the carriers' broader populations (see NW Natural/905, Patterson). In addition, NW Natural's covered population had an average of 2.4 dependents per enrolled employee, compared to 1.4 dependents in the carriers' broader populations (see NW Natural/905, Patterson). According to IMA Financial Group, an aging population and higher dependent enrollment contribute to increased healthcare costs for NW Natural, in addition to broader market factors affecting healthcare costs generally.

Finally, broader market conditions continue to significantly impact annual medical cost increases. According to information provided by IMA Financial Group, including benchmark data and market observations, health care costs in

the Pacific Northwest continue to be driven by increasing provider reimbursement rates, provider workforce shortages, consolidation among health care providers, increased utilization of health care services, and rising pharmacy expenses. Specialty medications and other high-cost prescription therapies have become a growing contributor to medical and pharmacy cost increases. These factors, combined with the Company's claims experience and demographics, influence the medical benefit costs reflected in this filing (see NW Natural/904, Patterson).

Q. How does the design of NW Natural's medical plans compare with that of other companies?

A. In 2026, IMA Financial Group, completed an analysis of the Company's medical benefits relative to 38 utilities in the Pacific Northwest utilizing data from the Milliman Employee Benefits Survey. See NW Natural/906, Patterson. In this comparison, the Company's medical benefits were evaluated against those of regional utility employers across a variety of plan design features, including deductibles, coinsurance, office visit copays, and prescription coverage. While ratings varied by specific benefit provision, the overall rating was "Equal." IMA Financial Group has subsequently confirmed that this conclusion remains valid and that NW Natural continues to maintain strong benefit levels relative to utility benchmarks both locally and nationally.

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 97.3 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 used to evaluate medical benefits also evaluated the market competitiveness of other health and welfare benefits, including dental, vision, life, and disability. Each of these benefit programs was found to be "Equal" to the utility market based on the 35 utility companies included in the survey. While individual plan provisions may vary, IMA Financial Group's analysis concluded that, overall, NW Natural's health and welfare benefits plan designs are comparable to those offered by other utilities. IMA Financial Group has confirmed that these conclusions remain valid, and that NW Natural continues to maintain benefit levels that are competitive with utility industry benchmarks. See NW Natural/906, Patterson.

Q. What is the total cost of medical benefits that NW Natural has sought to recover as part of its revenue requirement for the Test Year in this rate case?

A. That amount, by employee type, is shown in Table 3 below:

Table 3
Utility Employee Medical Benefits
(Oregon Allocated FTEs)

Type of Utility Employee	Test Year
Bargaining Unit (BU) Employees	$11,935,500
NBU Employees[1]	$13,206,900
Total	**$25,142,400**

[1] Including officers.

VI. RETIREMENT BENEFITS

Q. Please provide an overview of your retirement benefits.

A. Table 4 below shows the retirement income benefits programs, which provide market median retirement offerings to employees:

Table 4
Retirement Benefits

Retirement Program	Eligible Employees	Summary Description of Benefit
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 12/31/06 and BU employees hired after 12/31/09 (covers employees not eligible for pension benefits)	Contribution made by the 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 benefits plan that was closed to new NBU employees hired after 12/31/06 and BU hired after 12/31/09.

Q. Are there any 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 retirement benefits provided by other companies?

A. In 2026 the Company asked IMA Financial Group 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 "Better" for BU and NBU (4.3 percent median data vs. 4.8 percent Company match) employees when compared to the Utility database. The Enhanced 401(k), for those hired after the Pension Plan was closed, was found to be "Equal" when compared to the Utility database. See NW Natural/906, Patterson. The "Better" rating for the 401(k) match reflects one element of the Company's total compensation package and does not alter the overall market-positioning conclusion. Individual program components may vary above or below market, while the Company's overall total compensation philosophy remains targeted to the market median.

Q. Please explain the total retirement benefits included for recovery in the Test Year.

A. Table 5 below shows the amount requested for recovery in the Test Year.

Table 5
Utility Retirement Benefits
(Oregon Allocated FTE)

Component	Test Year
RKSP-Matching Contribution	$6,831,700
RKSP-Enhanced Contribution	$6,074,200
Western States Pension-withdrawal liability	$501,600
Total	**$13,407,500**

VII. EMPLOYEE HEADCOUNT

Q. What is NW Natural's FTE count at the end of the Base Year (June 30, 2026)?

A. On a system level, the FTE count at the end of the Base Year was 1,260.6.

Q. Is the Company proposing to adjust its Base Year system FTE count for the Test Year?

A. Yes. The Company includes in its request the FTEs at the end of the Base Year of 1,260.6 plus projected additional 49.5 additional FTEs the Company is in the process of hiring leading up to filing this case. This reflects positions in which a person has accepted the position but had not yet started, positions that had an outstanding offer to someone, or positions that were finishing up the interview process at the time of the end of the Base Year. The total system FTE counts included in this request is 1,310.1 FTEs.

Q. You stated that NW Natural will have a system-level count of 1,310.1 FTEs during the Test Year. In seeking rate recovery, did NW Natural reduce its system level count of 1,310.1 FTEs?

A. Yes. NW Natural has removed 56.8 FTEs allocated to non-gas utility activities. After these FTEs are removed, NW Natural has 1,253.3 gas utility FTEs during the Test Year. All amounts described in this testimony reflect gas utility-only costs, and not the costs of subsidiaries or affiliates.

Q. Is NW Natural seeking recovery of employees' compensation and benefits based on 1,253.3 FTEs?

A. Yes. NW Natural is seeking cost recovery of employees' compensation and benefits based on the 1,253.3 gas utility FTEs that NW Natural projects to have in the Test Year.

Since the Company serves customers in Oregon and Washington, it allocates a certain percentage (approximately 88 percent) of its employees' compensation and benefits costs to Oregon. Cost allocation between Oregon and Washington is further explained in the Direct Testimony of Kyle T. Walker (NW Natural/1200, Walker). All employees' compensation and benefits costs referenced in this testimony reflect Oregon-allocated values.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibits of Kyra M. Patterson

COMPENSATION & BENEFITS
EXHIBITS 901 – 906

November 24, 2026

EXHIBITS 901-906 – COMPENSATION & BENEFITS

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Kyra M. Patterson

COMPENSATION & BENEFITS
EXHIBIT 901

November 24, 2026

Exhibit 901 Base Pay Analysis

2026 Salary Structure - Base Pay Analysis

2026 Salary Structure		
NWN Grade	NWN 2026 Midpoint	NWN Midpoint vs. Market Median
14	$66,100	115.1%
15	$71,400	104.7%
16	$77,100	103.3%
17	$84,050	101.2%
18	$91,600	102.5%
19	$99,850	102.4%
20	$110,850	100.6%
21	$123,050	101.7%
22	$137,800	100.5%
23	$154,350	99.9%
24	$172,850	100.5%
25	$193,600	98.6%
26	$216,850	94.4%
	Overall	**102.0%**

Data Source: NW Natural Market Analysis 2025 for 2026

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Kyra M. Patterson

COMPENSATION & BENEFITS
EXHIBIT 902

REDACTED

Under General Protective Order No. 23-132, this exhibit is confidential in its entirety and has been redacted.

November 24, 2026

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Kyra M. Patterson

COMPENSATION & BENEFITS
EXHIBIT 903

REDACTED

Under General Protective Order No. 23-132, this exhibit is confidential in its entirety and has been redacted.

November 24, 2026

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

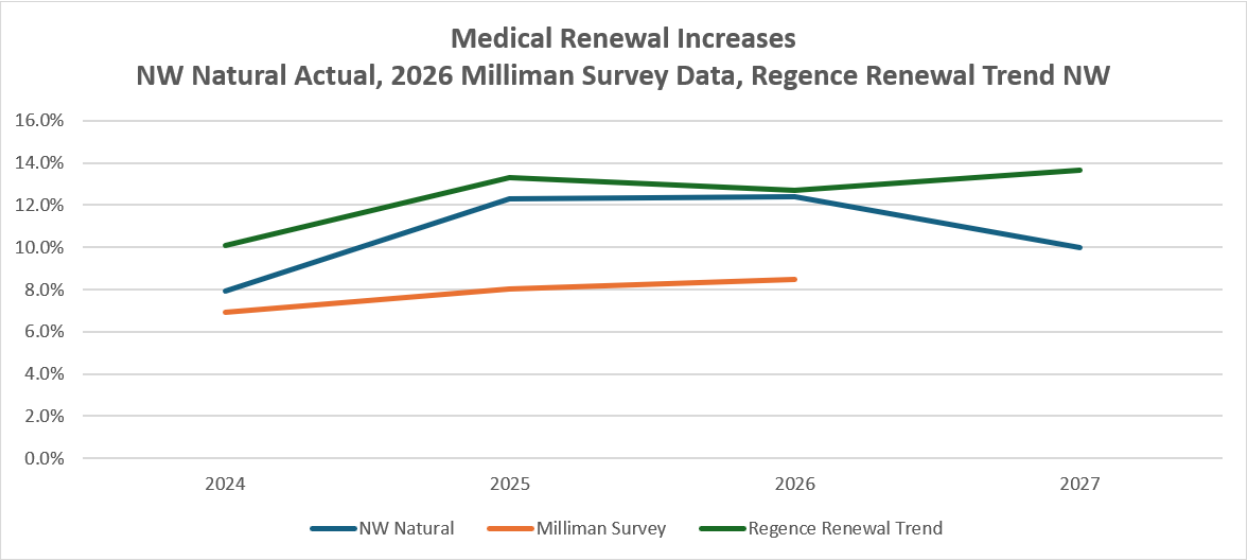
UG 532

NW Natural

Exhibit of Kyra M. Patterson

COMPENSATION & BENEFITS
EXHIBIT 904

November 24, 2026


Medical Renewal Increases
NW Natural Actual, 2026 Milliman Survey Data, Regence Renewal Trend NW
16.0%
14.0%
12.0%
10.0%
8.0%
6.0%
4.0%
2.0%
0.0%
2024
2025
2026
2027
NW Natural
Milliman Survey
Regence Renewal Trend

2027 RENEWAL – MARKET CONDITIONS

What's the current state of healthcare inflation (trend)?

- Medical continues to be high with local trend (Oregon/Washington) at 11 to 13% for medical and 13 to 15% for pharmacy or 11.5 to 13.5% combined
  - From a local perspective:
    - Increases to the Oregon Individual market filings for 2027 average 21.6%
    - Increases to the Oregon Small group market filings for 2027 average 15.5%
- National trend is lower for employer sponsored plans at between 8 and 11% combined
  - From a national perspective:
    - The median increase for individual and small groups combined is 14%



2027 RENEWAL – MARKET CONDITIONS

What's the current state of healthcare costs?

- Unit costs of medical care continues to increase
- Higher volumes of care; providers using AI to generate more billable care
  - Carriers are countering this with added review ("payment integrity")
- New specialty drugs coming to market; costly and effective
  - More diseases treated, more volume of patient's, higher cost
- Higher demand for GLP-1 medications to treat type 2 diabetes
- Recent PPO contract negotiations have resulted in higher reimbursements to providers, which increases cost to employers
  - Most recent for Regence was OHSU
- Continued consolidation of providers drives up cost due to less competition

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

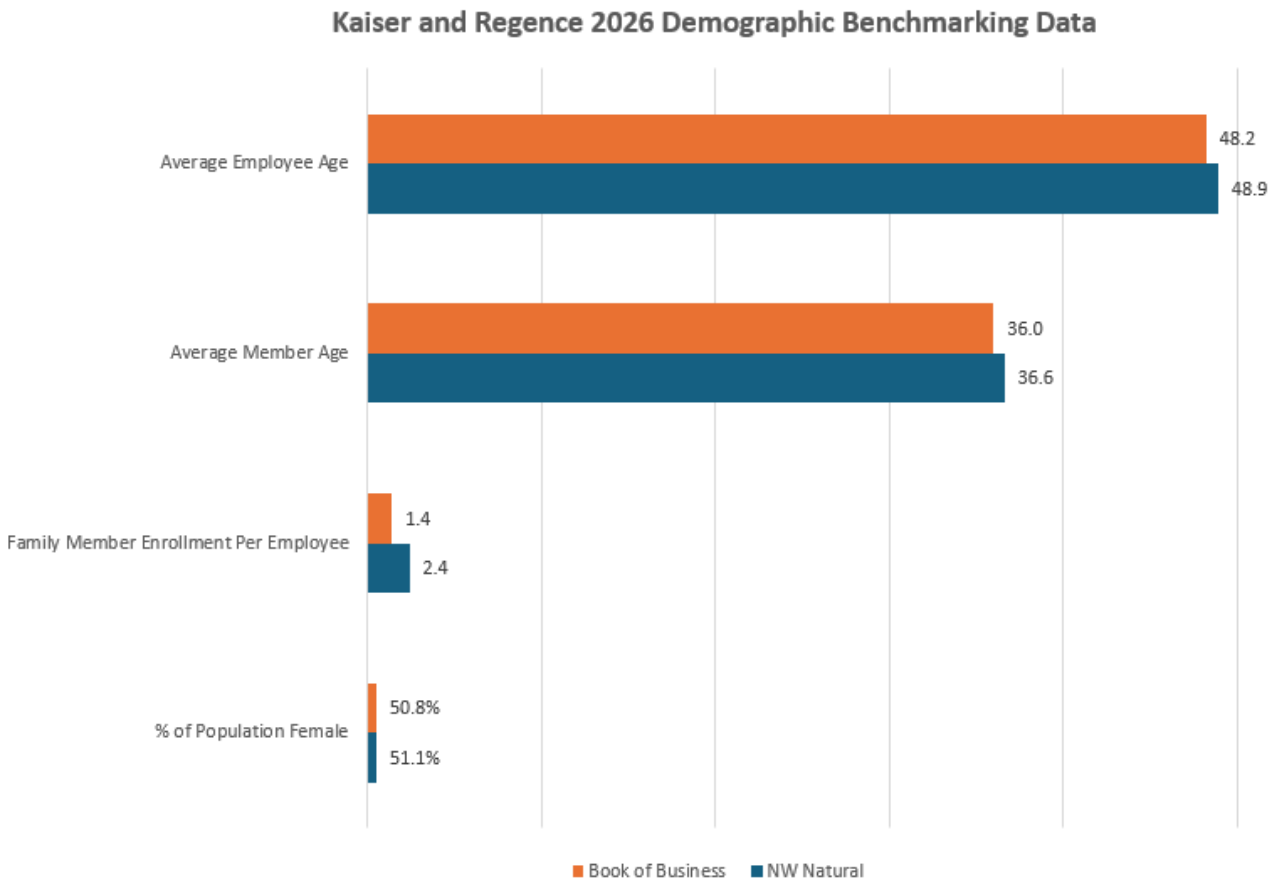
UG 532

NW Natural

Exhibit of Kyra M. Patterson

COMPENSATION & BENEFITS
EXHIBIT 905

November 24, 2026


Kaiser and Regence 2026 Demographic Benchmarking Data
Average Employee Age
48.2
48.9
Average Member Age
36.0
36.6
Family Member Enrollment Per Employee
1.4
2.4
% of Population Female
50.8%
51.1%
Book of Business
NW Natural

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Kyra M. Patterson

COMPENSATION & BENEFITS
EXHIBIT 906

November 24, 2026

Milliman 2026 Benchmarking Data

PPO Medical	Ranking as compared to 38 utilities in the PNW
Deductible	Equal
Out-of-Pocket Maximum	Worse
Coinsurance	Equal
Office Visit-Primary Care	Equal
Office Visit-Specialty Care	Better
Telehealth Visit	Equal
Pharmacy Copays	Equal
Employer Contributions	
Employee Only	Worse
Family	Equal

HSA Medical	Ranking as compared to 38 utilities in the PNW
Deductible	Better
Out-of-Pocket Maximum	Equal
Coinsurance	Equal
Telehealth Visit	Equal
Pharmacy	Equal
Employer Contributions	
Employee Only	Worse
Family	Better
HSA Contribution	
Employee Only	Worse
Family	Worse

Dental and Vision	Ranking as compared to 38 utilities in the PNW
Vision Exam	Equal
Vision Hardware	Better
Dental Deductible	Better
Dental Annual Maximum	Equal
Class 1: Preventive	Equal/Better PPO Provider
Class 2: Basic/Restorative	Equal/Better PPO Provider
Class 3: Major	Equal/Better PPO Provider
Orthodontia	Equal

Note: Dental compared to NW Natural's buy-up plan

Long Term Disability	Ranking as compared to 38 utilities in the PNW
Benefit Percentage	Equal
Montly Maximum	Equal
Elimination Period	Equal

Short Term Disability	Ranking as compared to 38 utilities in the PNW
Benefit Percentage	Better
Montly Maximum	Better
Elimination Period	Better

Milliman 2026 Benchmarking Data – Continued

Life Insurance	Ranking as compared to 38 utilities in the PNW
Employee Coverage	Worse
Dependent Coverage	Equal
Voluntary Life	Equal

Defined Contribution	Ranking as compared to 38 utilities in the PNW
Company Match	Better
Enhanced (Non-Match)	Equal

Other	Ranking as compared to 38 utilities in the PNW
Flexible Spending Accounts	Equal
Employee Assistance Program	Better

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Direct Testimony of Cory A. Beck

CUSTOMER COMMUNICATIONS
EXHIBIT 1000

November 24, 2026

EXHIBIT 1000 - DIRECT TESTIMONY - CUSTOMER COMMUNICATIONS

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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 Cory Beck, and I am the Director of Customer Experience Services at NW Natural. I lead customer, public, and customer program communications, including advertising, the company website, digital portals, and Interactive Voice Response ("IVR") services. My team also manages required regulatory communications, natural gas safety communications, bill discount program and language access plan communications, and NW Natural's federally mandated Public Safety Awareness Program. I have been with 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. Please summarize your testimony.

A. In my testimony, I:

- Present the Company's Category A (customer communications) proposed expense for the period November 2027 through October 2028 ("Test Year"), and explain why the proposed level is just $0.22 more per

customer than the level presumed just and reasonable under Oregon Administrative Rule ("OAR") 860-026-0022(3)(a), but still far below the amount deemed reasonable for electric utilities that share a similar service territory; and

- Present the Company's Test Year Category B proposed expense.

The Company is not seeking rate recovery of any expenses in Category C (corporate imaging), Category D (political/non-utility advertising) or Category E (energy efficiency/conservation advertising related to a program approved by the Public Utility Commission of Oregon [the "Commission"]) and, therefore, I do not address those categories in my testimony.

II. CATEGORY A – CUSTOMER COMMUNICATIONS

Q. Please describe Category A customer communications.

A. The Commission's administrative rules categorize utility customer communications and set forth ratemaking standards applicable to each category. Category A communications are defined as "Energy efficiency or conservation advertising expenses that do not relate to a Commission-approved program, utility service advertising expenses, and utility information advertising expenses."

Q. Under the Commission's rules, is there a level of Category A communications expense that is presumed just and reasonable?

A. Yes. Under OAR 860-026-0022(3)(a), expenditures for Category A customer communications up to 0.125 percent of gross retail operating revenues are presumed just and reasonable. In NW Natural's case, that percentage results in

$1,355,044 for Category A communications based on forecasted revenues and customer count, which is equivalent to about $1.90 per customer.

Q. How does NW Natural's proposed Category A communications expense for the Test Year compare with that presumed level?

A. The Company is requesting $2.12 per customer or $1,511,000 for the Test Year, or only $0.22 more per customer than the rate derived using the level presumed just and reasonable under OAR 860-026-0022(3)(a).

Q. How does NW Natural's Category A request compare to the amounts presumed reasonable for other utilities?

A. The existing revenue-based formula creates an imbalance by allowing natural gas utilities substantially less Category A expense presumed reasonable than electric utilities. NW Natural should be authorized to recover communication costs that are comparable to those incurred by Oregon electric utilities on a per-customer basis. NW Natural's request for $2.12 per customer for the Test Year is far less than electric utilities that serve most of the same customers as well. For example, based on 2025 data, Table 1 below shows that the revenue-based formula translates into an allowance of $3.69 per customer for PacifiCorp and $3.88 per customer for Portland General Electric Company compared to $1.75 per customer for NW Natural. This funding disparity is inequitable. Electric utilities receive approximately 74 percent more communications funding per customer than NW Natural, even though NW Natural serves the same communities, reaches many of the same customers, and has comparable customer communication obligations. Additionally, NW Natural has an expansive Oregon service territory that requires

purchasing media from multiple outlets: the Oregon coast from Astoria to Coos Bay, the Willamette Valley from Portland to Eugene, and the Columbia River Gorge.

Table 1

2025 Category A per Customer Based on Operating Revenues					
Utility	Year	Operating Revenue	CAT A 0.125%	Average # of Customers	CAT A Per Customer
NW Natural	2025	989,556,798	1,236,946	708,676	1.75
PGE	2025	2,969,346,620	3,711,683	955,654	3.88
PacifiCorp	2025	1,876,852,864	2,346,066	635,588	3.69

Q. How much would be presumed reasonable for NW Natural to recover in Category A according to the rule if the Company's per customer amount was equal to PGE?

A. Based on 2025 data, according to the rule, if NW Natural was allowed to recover $3.88 per customer, NW Natural would be allowed to recover $2,749,663 for Category A ($3.88 x 708,676 = $2,749,663).

Q. What is the difference between the amount NW Natural could recover for Category A if the per customer amount were equitable with the amount PGE is allowed to recover compared to the amount NW Natural is asking for in this case?

A. NW Natural believes closing the gap between Category A allowable amounts is highly reasonable for reasons mentioned above. With that in mind, in this case NW Natural is asking for $1,511,000, which remains $2,200,683 *less* for Category A than the amount that is equitable compared to PGE in our service territory ($3,711,683 - $1,511,000 = $2,200,683).

Q. What topics does the Company's Test Year Category A communications address?

A. The Company's Test Year Category A communications support the following topics:

- Payment options and programs for customers;
- Low-income programs such as low-income weatherization and the bill discount program;
- Energy and money-saving tips and resources;
- The efficient use of natural gas;
- Options to reduce natural gas consumption and save energy by installing high-efficiency appliances;
- Online customer service options and information;
- Customer safeguards and protections;
- Contemporary items of customer interest, such as business practices and involvement in the communities we serve; and
- Phone numbers and contact information.

Q. How does the Company plan to communicate with customers on these topics?

A. The Company plans to continue communicating with customers on bills, bill inserts and bill envelopes, letters, our website, on-hold messaging, customer e-newsletters, email, new customer information packets, telephone directory

advertising, digital advertising, community events, television, radio and streaming media.

Q. What is the Company's budget for its communication plan for Category A communications?

A. NW Natural plans to distribute Category A Test Year budget to address the following activities shown in Table 2 below:

Table 2

TOTAL CATEGORY A

Category A Channels		Total Budget		OR Test Year
Salaries/Overhead	$	852,000	$	747,715
Bill inserts	$	150,000	$	131,640
Brochures/ Customer Support Items	$	25,000	$	21,940
eNewsletter	$	20,000	$	17,552
Community Event Support	$	50,000	$	43,880
Welcome Letter Postage	$	90,000	$	78,984
Language Access Plan Support	$	195,000	$	171,132
Media - Production	$	100,000	$	87,760
Media - IVR	$	15,000	$	13,164
Media - Telephone directory	$	25,000	$	21,940
Media - Customer Service, Bill Discount Program, LAP	$	200,000	$	175,520
Category A Totals	**$**	**1,722,000**	**$**	**1,511,227**

Q. Why is the Company requesting an increase to the presumed just and reasonable amount for Category A?

A. The Company adjusted its request for Category A by $0.22 per customer above the amount presumed justified and reasonable by OAR 860-026-0022(3)(a) to support targeted communications and outreach to improve access to utility information for customers with limited English proficiency and English-proficient customers with limited literacy.

Q. Why are targeted communications necessary in addition to the Company's broader Test Year communications plan?

A. The Company's broader Test Year communications plan provides information to customers generally. However, certain customers face additional barriers to accessing and understanding utility information, including high energy burdens, limited English proficiency and limited literacy. Targeted communications help ensure these customers are aware of available bill assistance, customer protections, payment options, and other essential utility services.

Q. What are the components of the Company's proposed increase to Category A funding?

A. The driver of the proposed increase to Category A funding is the Company's Language Access Plan. The Plan identifies barriers that limit customers' ability to understand utility communications and access programs and services. To address these barriers, the Company proposes producing Spanish-language communications and outreach, funding translation services, providing customer service training, implementing website enhancements, and presenting visual communication tools. These activities will expand access to essential billing, assistance, safety, and account information for customers with limited English proficiency and improve comprehension for English-proficient customers with limited literacy. The Plan adds $171,132 to the overall consumer information budget, which is equivalent to about $0.22 per customer. See Table 3 below for the proposed Language Access Plan communications plan.

Q. What is the Company's Language Access Plan?

A. A Language Access Plan is a framework for improving and guiding how the Company communicates with customers who have limited English proficiency or limited literacy. It assesses customer language needs, evaluates existing language services, and identifies actions to improve access to important Company programs, services and communications. The Plan serves as a lasting framework that the Company can continue to reference when evaluating and enhancing future customer outreach and engagement efforts.

Additionally, NW Natural engaged its Community & Equity Advisory Group ("CEAG") during development of the Language Access Plan and has received positive, supportive feedback to date. The Company will continue working with CEAG, Community Action Agencies and others as appropriate to support the Language Access Plan's implementation in Oregon and help ensure outreach remains responsive to customer needs.

Q. How will the Company record feedback and update the Plan on an ongoing basis?

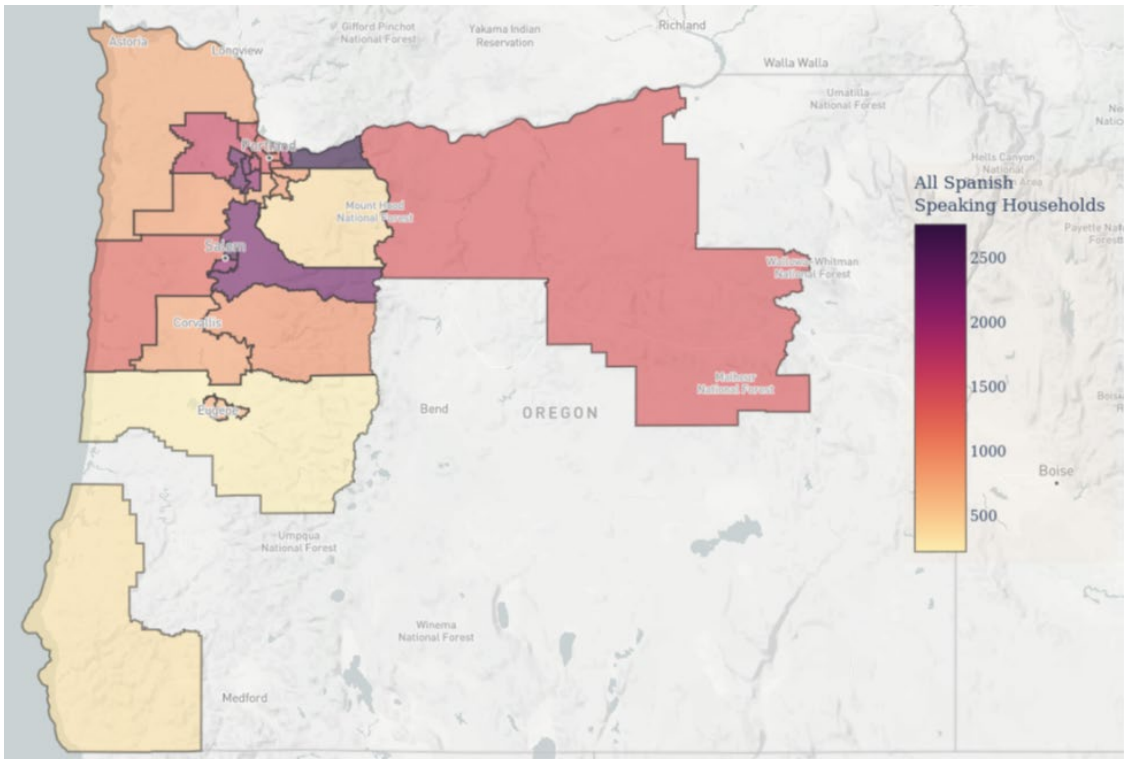
A. The Company will present the Language Access Plan to stakeholders, including CEAG, Community Action Agencies, and other organizations as appropriate, and will actively solicit feedback on the Plan and its implementation. The Company will document feedback received through stakeholder meetings, outreach activities, and ongoing discussions and use that input, along with available language service utilization data, to inform periodic updates to the Plan and related outreach

strategies. The Language Access Plan is intended to be a living framework that will evolve as customer needs and stakeholder feedback change over time.[1]

Q. How will the Company use data to support Language Access Plan outreach?

A. The Company will use data collected during development of the Language Access Plan to identify areas of its service territory where language and literacy barriers may limit customers' ability to access utility information and services. As shown in Figure 1, the Company can identify communities with higher concentrations of Spanish-speaking households and prioritize outreach in those areas through Spanish-language communications and translated materials.

Figure 1



[1] After the stakeholder process is complete and the Language Access Plan is finalized, NW Natural is willing to provide it to parties in response to a data request.

Q. What topics will be communicated through the Company's Language Access Plan outreach?

A. The Company's Test Year Category A communications support the Company's Language Access Plan. NW Natural Language Access Plan communications in other languages include topics related to:

- Bill assistance programs, including the Bill Discount Program;
- Late payment and disconnection communications;
- How to read and understand a bill;
- Ways to pay a bill;
- Rate changes and billing updates;
- Managing a gas account online with self-service options such as enrolling in paperless billing and automatic payment;
- Rebates for high-efficiency gas appliances and tune-ups that save energy;
- Schedule a free annual gas appliance inspection;
- Understand regulatory activities;
- Interpretation services are available free of charge;
- Contemporary items of customer interest, such as ways the Company works to keep costs low for customers and involvement in the communities we serve;
- Safety messaging, such as notifying 811 before digging and what to do if you detect a gas leak;

- Emergency preparedness messaging, such as how to operate natural gas appliances in a power outage;
- Required regulatory notices, such as customer Rights and Responsibilities;
- Natural gas price changes and rate change information; and
- Seasonal billing programs such as the Weather Adjusted Rate Mechanism ("WARM").

Q. Why is the Company communicating these topics to limited English proficiency and English-proficient customers with limited literacy?

A. These topics affect customers' ability to maintain service, manage their bills, access financial assistance, stay safe, and understand important utility information. The Company found that language and literacy barriers can make it more difficult for customers to understand utility communications and access programs and services. The Company communicates these topics to help customers avoid service interruptions, connect eligible customers with financial assistance and energy-saving programs, understand billing and payment requirements, and receive important safety, emergency and regulatory information.

Q. How will the Company use the Language Access Plan to support additional outreach?

A. The Company will use information developed through the Language Access Plan to identify areas of its service territory where language and literacy barriers may

limit access to utility information and services. Additionally, the Company will use these findings to implement targeted Spanish-language communications, translated customer resources, dedicated Spanish-language webpages, awareness of free interpretation services, and visual communication tools to select areas identified in the Language Access Plan.

Q. What additional targeted communications does the Company plan to undertake to support the Language Access Plan?

A. Table 3 below shows the targeted communications and outreach activities the Company proposes to reduce language and literacy barriers and improve customer access to billing, payment, assistance, safety, and other essential utility information.

Table 3

LAP CATEGORY A

Category A Channels		Total Budget		OR Test Year
Direct mail (Spanish)	$	35,000	$	30,716
Community Outreach Materials (Spanish flyers and multilingual materials for community-based organizations)	$	20,000	$	17,552
Media - Production (Spanish-language videos and creative assets)	$	40,000	$	35,104
Professional Services - Design, Writing, Translation Services	$	25,000	$	21,940
Media - Digital, Social Media, Community News, Radio	$	60,000	$	52,656
Community Events - Fees, Staffing, Materials	$	15,000	$	13,164
Category A Totals	**$**	**195,000**	**$**	**171,132**

Q. Why does the Company's proposed Language Access Plan outreach focus on Spanish-language communications?

A. The Company's proposed Language Access Plan identified Spanish as the most prevalent non-English language within the Company's service territory. As a result, the Company proposes targeted Spanish-language communications and

outreach to improve access to utility information and services for a significant portion of customers who may face language barriers.

Q. Are the proposed Language Access Plan communications consistent with the recommendations of the Company's Language Access Plan?

A. Yes. The proposed communications and outreach activities are based on recommendations identified in the Company's Language Access Plan, including Spanish-language communications, translated customer resources, awareness of interpretation services, website enhancements, community outreach, and visual communication tools. The activities shown in Table 3 above are designed to address identified language and literacy barriers and improve customer access to essential utility information and services.

Q. Are Language Access Plan communications appropriate for inclusion into Category A?

A. Yes. Language Access Plan communications are appropriate for inclusion in Category A because they help customers understand and manage their utility service. The proposed communications improve access to billing and payment information, customer protections, financial assistance programs, safety information, regulatory notices, and customer service resources for customers with limited English proficiency and English-proficient customers with limited literacy. These activities are consistent with the Commission's rules governing utility service advertising and utility information advertising expenses.

Q. What action does the Company request the Commission take with respect to Category A communications expense?

A. The Company requests that the Commission find that the proposed level of Test Year Category A communications expense is just and reasonable under OAR 860-026-0022. The proposed expense level is necessary to support customer communications energy efficiency or conservation advertising expenses, utility service advertising expenses, and utility information advertising expenses, including targeted outreach to customers in high-energy-burden communities and customers facing language and literacy barriers.

III. CATEGORY B – LEGALLY MANDATED COMMUNICATIONS

Q. What are legally mandated communications?

A. Legally mandated communications include required regulatory notices, bill inserts, and safety-related communications that the Company is obligated to provide to customers and the public through its Public Safety Awareness Program. Examples include customer rights and responsibilities, customer-owned gas service line maintenance information, WARM, natural gas safety, emergency preparedness, and underground utility damage prevention messages. These communications are classified as Category B communications under OAR 860-026-0022 and are presumed just and reasonable under OAR 860-026-0022(3)(b).

Q. Please describe the Company's Public Safety Awareness Program and Category B communications provided under that program and related activities.

A. Third-party damage to NW Natural pipelines still poses a significant threat to our system and public safety. Each year, the Company executes a robust Public Safety Awareness Program that distributes audience-specific pipeline safety information to required groups, including emergency officials, first responders, public officials, excavators, contractors, multi-family property managers, floating homes, and residents and businesses located along transmission pipelines, in high-consequence areas, or along rights-of-way. The Company's Category B communications are focused on damage prevention, emergency preparedness awareness, instructions for how to be safe around natural gas, and information to educate the public on the steps to follow if a gas incident is suspected.

Q. Please identify the legal mandates requiring expenditures under the Company's Public Safety Awareness Program and related activities.

A. NW Natural's Public Safety Awareness Program is required under the Federal Pipeline Safety Act, the United States Code of Federal Regulations Title 49 Parts 192 and 195, standards administered by the United States Department of Transportation, Pipeline and Hazardous Materials and Safety Administration including Recommended Practice API 1162 ("API RP 1162"), and OAR 860-024-0020. Please see NW Natural/1001, Beck, for a copy of API RP 1162. These legal mandates require pipeline operators such as NW Natural to establish continuing education programs to enable the public, appropriate government

organizations, and persons engaged in excavation-related activities to recognize a pipeline emergency and to report it to the operator and/or the police, or other appropriate public officials.

Furthermore, natural gas safety awareness messaging as defined in API RP 1162 is much more than only requiring a utility to publish advertising about preventing and detecting leaks from gas pipelines. Federal Pipeline Safety Regulations (49 CFR 192.616 and 49 CFR 195.440) require pipeline operators to develop and implement public awareness programs that follow the guidance provided by the API RP 1162, "Public Awareness Programs for Pipeline Operators". The scope of API RP 1162 provides guidance that states that "mainline pipe, pump and compressor stations, and other facilities that are associated with the pipeline should be considered to be included."

API RP 1162 also provides multiple recommendations for baseline messaging that is appropriate for the Affected Public (including customers) in addition to detecting and preventing leaks directly from pipelines including awareness of potential hazards and prevention measures and emergency preparedness. Importantly, "information materials may include supplemental information about the pipeline operator, pipeline operations, the safety record of pipelines and other information that an operator deems appropriate for the audience." NW Natural's Public Safety Awareness Program is charged to Category B under these legal mandates and is regularly audited by the Commission's Safety Division. In October 2023, Staff completed an inspection of the NW Natural Public Safety Awareness Program and communications, and

advertising distributed to support the program, and Staff concluded there were no issues or concerns and found that the Company followed state and federal regulations without infringement.

Q. Are there additional safety-related communications included in the Company Public Safety Awareness Plan that are necessary for customers?

A. Yes. The Company's Test Year Public Safety Awareness Plan includes natural gas and natural gas appliance safety communications and partners with and enhances the Category B Public Safety Awareness Plan through distribution of media across multiple channels, including TV, streaming media, radio, print, digital, social media, public relations, and community events. Media and event exposure increases the visibility and reach of the important safety messages and is more accessible to a wider audience.

Q. Why are natural gas and natural gas appliance safety messages important for customers?

A. For local natural gas distribution companies like NW Natural, safety messaging for distribution systems not only includes the mains that are usually located under city streets, but also the smaller service lines that connect to the mains and further distribute natural gas service to the local end users, including businesses and residential customers. Providing safety-related messages the Company deems appropriate to keep customers safe around natural gas in addition to messages to prevent damages to the pipeline, such as proper equipment operation, emergency preparedness, how to recognize a potential safety issue, how to respond, and properly operate gas appliances that are connected to these service lines and

prevention procedures, is of the utmost importance to customers. Additionally, when a gas appliance is not properly installed or operated, there could be a safety issue within the home. Accordingly, safety information is important for all customers to be educated about.

Q. Please describe the Company's regulatory-required customer communications.

A. Each year, the Company is required to send customers the following bill inserts:

- Houseline Maintenance: Information about customer responsibility for gas service line maintenance and available protection options;
- Customer Rights and Responsibilities: Information about customer protections, billing, payment options and utility service requirements; and
- WARM: Information about the Company's weather-normalized rate adjustment mechanism and its effect on customer bills.

Q. What Category B communications expenses are included in the Test Year?

A. The Company has included $996,076 for Category B communications for the Test Year.

Q. What is the Company's budget for its communication plan for Category B?

A. NW Natural plans to distribute Category B Test Year budget to address the following activities shown in Table 4 below.

Table 4

TOTAL CATEGORY B				
Category B Channels		**Total Budget**		**OR Test Year**
Salaries/Overhead	$	400,000	$	351,040
Bill inserts/Brochures - Safety and Regulatory	$	75,000	$	65,820
Professional Services - Design & Writing	$	40,000	$	35,104
Postage	$	85,000	$	74,596
Public Safety Awareness Program & Materials	$	185,000	$	162,356
Community Event Support	$	50,000	$	43,880
Media - Production	$	100,000	$	87,760
Media - Safety Education, Damage Prevention	$	200,000	$	175,520
Category B Totals	**$**	**1,135,000**	**$**	**996,076**

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Cory A. Beck

CUSTOMER COMMUNICATIONS
EXHIBIT 1001

November 24, 2026

EXHIBIT 1001 – CUSTOMER COMMUNICATIONS

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SLW updated version

Public Awareness Programs for Pipeline Operators

API RECOMMENDED PRACTICE 1162
FIRST EDITION, DECEMBER 2003





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Public Awareness Programs for Pipeline Operators

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FOREWORD

This document is a Recommended Practice (RP) for pipeline operators to use in development and management of Public Awareness Programs. Pipeline Operators have conducted Public Awareness Programs with the affected public, government officials, emergency responders and excavators along their routes for many years. The goal of this RP is to establish guidelines for operators on development, implementation, and evaluation of Public Awareness Programs in an effort to raise the effectiveness of Public Awareness Programs throughout the industry.

Representatives from natural gas and liquid petroleum transmission companies, local distribution companies, and gathering systems, together with the respective trade associations, have developed this Recommended Practice. The working group was formed in early 2002. Additionally, representatives from federal and state pipeline regulators have provided input at each step of development and feedback from all interested parties has been solicited through a wide variety of sources and surveys.

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Public Awareness Programs for Pipeline Operators

1 Introduction, Scope and Glossary of Terms

1.1 INTRODUCTION

This Recommended Practice (RP) provides guidance to be used by operators of petroleum liquids and natural gas pipelines to develop and actively manage Public Awareness Programs. This RP will also help to raise the quality of pipeline operators' Public Awareness Programs, establish consistency among such programs throughout the pipeline industry, and provide mechanisms for continuous improvement of the programs. This RP has been developed specifically for pipelines operating in the United States, but may also have use in international settings.

Public awareness and understanding of pipeline operations is vital to the continued safe operation of pipelines. Pipeline operators' Public Awareness Programs are an important factor in establishing communications and providing information necessary to help the public understand that pipelines are the major transportation system for petroleum products and natural gas in the United States, how pipelines function, and the public's responsibilities to help prevent damage to pipelines.

Public Awareness Programs should address the needs of different audiences within the community and be flexible enough to change as the pipeline system changes or as the public's needs for information change. When effectively and consistently managed, a Public Awareness Program can provide significant value to the pipeline operator in several areas: enhanced public safety, improved pipeline safety and environmental performance, building trust and better relationships with the public along the pipeline route, less resistance to pipeline maintenance and right-of-way activities, preservation of rights-of-way, enhanced emergency response coordination, and improved pipeline operator reputation.

Public awareness messages need to provide a broad overview of how pipelines operate, the hazards that may result from activity in close proximity to pipelines and those hazards possible due to pipeline operations, and the measures undertaken to prevent impact to public safety, property or the environment. These messages should be coupled with information regarding how pipeline operators prepare for emergencies in a way that minimizes the consequences of a pipeline incident.

This RP identifies for the pipeline operator four specific stakeholder audiences and associated public outreach messages and communication methods to choose from in developing and managing a successful Public Awareness Program. It also provides information to assist operators in establishing specific plans for public awareness that can be evaluated and updated.

This RP is comprised of a main body (Sections 1 – 8), and Appendices. The main body of this document contains the general, baseline program recommendations and the supplemental program components. Summary tables and diagrams are also provided in the main body. These summaries can be used as quick reference guides to assist operators when customizing their Public Awareness Programs to reflect the unique characteristics of their pipeline and facilities. The Appendices provide operators with additional, optional information and resources for further reference. The Appendices repeat many areas of the main body in order to provide the operator with comprehensive information.

1.2 SCOPE

This RP is intended as a resource that can assist pipeline operators in their public awareness efforts. Operators are urged to develop, implement and actively manage Public Awareness Programs within their companies. In implementing these programs, operators should select the most appropriate mix of audiences, message types, and delivery methods and frequencies, depending on their needs and the needs of the communities along a given pipeline segment. The guidance set forth in this RP establishes a baseline for Public Awareness Programs and describes considerations for program expansion that can further enhance specific public awareness outreach.

This RP provides guidance for the following pipeline operators:

- Intrastate and interstate hazardous liquid pipelines
- Intrastate and interstate natural gas transmission pipelines
- Local distribution systems, and
- Gathering systems.

This guidance is intended for use by pipeline operators in developing and implementing Public Awareness Programs associated with the normal operation of existing pipelines. The guidance is not intended to focus on public awareness activities appropriate for new pipeline construction or for communications that occur immediately after a pipeline-related emergency. Communication regarding construction of new pipelines is highly specific to the type of pipeline system, scope of the construction, and the community and state in which the project is located. Likewise, public communications in response to emergency situations are also highly specific to the emergency and location. This RP is also not intended to provide guidance to operators for communications about operator-specific performance measures that are

addressed through other means of communication or regulatory reporting.

The primary audience for this RP is the pipeline operator for use in developing a Public Awareness Program for the following stakeholder audiences:

- The affected public—i.e., residents, and places of congregation (businesses, schools, etc.) along the pipeline and the associated right-of-way (ROW)
- Local and state emergency response and planning agencies—i.e., State and County Emergency Management Agencies (EMA) and Local Emergency Planning Committees (LEPCs)
- Local public officials and governing councils
- Excavators.

DESCRIPTION OF PIPELINE INFRASTRUCTURE

To clarify the scope of the pipeline industry covered by this RP, a brief description of the affected infrastructure components is provided below. Mainline pipe, pump and compressor stations, and other facilities that are associated with the pipeline should be considered to be included. Unless otherwise noted, the use of the term "pipeline" in this RP will refer to all three of the following types of systems. The RP recognizes some differences between the three pipeline types and provides the operator flexibility based on the needs of the stakeholders along a particular pipeline.

1.2.1 Transmission Pipelines

The transmission pipeline systems for liquid petroleum and natural gas, move large amounts of liquids and natural gas from the producing and/or refining locations to local "outlets", such as bulk storage terminals (for liquids) and natural gas distribution systems. Transmission pipeline systems can be classified as either "intrastate pipelines", located within one state's borders, or "interstate pipelines" crossing more than one state's borders. Natural gas transmission pipelines deliver gas to direct-served customers and local distribution systems' stations, referred to as "city gates", where the pressure is lowered for final distribution to end users. Liquids transmission pipelines usually transport crude oil, refined products, or natural gas liquids. Transmission pipelines are generally the middle of the transportation link between gathering and distribution systems.

1.2.2 Local Distribution Systems

The local distribution systems for liquid petroleum and natural gas differ because of the nature and use of the products. Liquid petroleum products are distributed from bulk terminals by other modes of transportation, such as by rail cars and tank trucks. Local natural gas distribution companies (LDCs) receive natural gas at "city gates" and distribute it through distribution systems, These consist of "mains", which are usually located along or under city streets and smaller service lines that connect to the mains to further distribute natural gas service to the local end users - homes and businesses.

1.2.3 Gathering Systems

Gathering pipelines link production areas for both crude oil and natural gas to central collection points. Some gathering systems include processing facilities; others do not. Some gathering systems are regulated by the Office of Pipeline Safety, U.S Department of Transportation, while most are not. Gathering systems connect to transmission pipelines for long distance transportation of crude oil and natural gas to refinery centers and distribution centers, respectively.

1.3 GLOSSARY OF TERMS

1.3.1 Appendices: The Appendices' role is to provide a pipeline operator with additional information to develop and actively manage its Public Awareness Programs. The Appendices' mirror the main body of the RP while providing additional information such as: resources and contacts, examples of stakeholder audiences, public awareness messages, enhanced delivery methods and media, and program evaluation information.

1.3.2 Baseline Public Awareness Program: Refers to general program recommendations, set forth in Recommended Practice 1162, The baseline recommendations do not take into consideration the unique attributes and characteristics of individual pipeline operators' pipeline and facilities. Supplemental or enhanced program components are described in the RP to provide guidelines to the operator for enhancing its Public Awareness Programs. This is described more fully in Sections 2 and 6.

1.3.3 CFR: *Code of Federal Regulations*

1.3.4 Dig Safely: Dig Safely is the nationally recognized campaign to enhance safety, environmental protection, and service reliability by reducing underground facility damage. This damage prevention education and awareness program is used by pipeline companies, One-Call Centers, and others throughout the country. Dig Safely was developed through the joint efforts of the Office of Pipeline Safety and various damage prevention stakeholder organizations. Dig Safely is now within the purview of the Common Ground Alliance (CGA). For more information see www.commongroundalliance.com.

1.3.5 Enhanced Public Awareness Program: The concept developed in RP 1162 for assessing particular situations in which it is appropriate to enhance or supplement the Baseline Public Awareness Program. This is described more fully in Section 6.

1.3.6 High Consequence Areas (HCAs): A high consequence area is a location that is specially defined in pipeline safety regulations as an area where pipeline releases could have greater consequences to health and safety or the environment. Pipeline safety regulations require a pipeline operator to take specific steps to ensure the integrity of a pipeline for which a release could affect an HCA and, thereby, the protection of the HCA.

1.3.7 HVL (Highly Volatile Liquid): A highly volatile liquid, as defined in pipeline safety regulations, is a hazardous liquid that will form a vapor cloud when released to the atmosphere and has a vapor pressure exceeding 276kPa (40 psia) at 37.8 degrees C (100 degrees F).

1.3.8 Integrity Management Program (IMP): In accordance with pipeline safety regulations, an operator's integrity management program must include, at a minimum, the following elements:

- a process for determining which pipeline segments could affect a High Consequence Area (HCA)
- a Baseline Assessment Plan
- a process for continual integrity assessment and evaluation
- an analytical process that integrates all available information about pipeline integrity and the consequences of a failure
- repair criteria to address issues identified by the integrity assessment method and data analysis (the regulations provide minimum repair criteria for certain, higher risk, features identified through internal inspection)
- a process to identify and evaluate preventive and mitigative measures to protect HCAs
- methods to measure the integrity management program's effectiveness and
- a process for review of integrity assessment results and data analysis by a qualified individual.

1.3.9 IMP Overview: An overview of an operator's IMP program should include a description of the basic requirements and components of the program and does not need to include a summary of the specific locations or schedule of activities undertaken. The overview may only be a few pages and its availability could be mailed upon request or made available on the operator's website.

1.3.10 LDCs: Local Distribution Companies for natural gas

1.3.11 "may" versus "should": Clarification is necessary for RP 1162's use and definition of the words "may" versus "should":

- The use of the word "may" provides the operator with the option to incorporate the identified component into its Public Awareness Program.
- The use of the word "'should" provides the operator with the Public Awareness Program components that are recommended to be incorporated into the operator's Public Awareness Program.

1.3.12 NPMS: National Pipeline Mapping System (See Section 4.6.2)

1.3.13 One-Call Center: The role of the One-Call Center is to receive notifications of proposed excavations, identify possible conflicts with nearby facilities, process the information, and notify affected facility owners/operators.

1.3.14 Operator: All companies that operate pipelines that are within the scope of this RP.

1.3.15 OPS: Office of Pipeline Safety, part of the Research and Special Programs Administration (RSPA) of the U.S. Department of Transportation. OPS develops and enforces safety and integrity regulations for pipelines and pipeline operations.

1.3.16 Pipeline Right-of-Way (ROW): a defined strip of land on which an operator has the rights to construct, operate, and/or maintain a pipeline. A ROW may be owned outright by the operator or an easement may be acquired for specific use of the ROW.

1.3.17 Supplemental Public Awareness Program: Refer to the definition above, "Enhanced Public Awareness Program".

1.3.18 Third-Party Damage: outside force damage to underground pipelines and other underground facilities that can occur during excavation activities. Advanced planning, effective use of One-Call Systems, accurate locating and marking of underground facilities, and the use of safe digging practices can all be very effective in reducing third-party damage.

2 Public Awareness Program Development

The overall goal of a pipeline operator's Public Awareness Program is to enhance public environmental and safety property protection through increased public awareness and knowledge.

PUBLIC AWARENESS PROGRAM OBJECTIVES

2.1 OBJECTIVES

- **Public Awareness of Pipelines**

Public Awareness Programs should raise the awareness of the affected public and key stakeholders of the presence of

pipelines in their communities and increase their understanding of the role of pipelines in transporting energy. A more informed public along pipeline routes should supplement an operator's pipeline safety measures and should contribute to reducing the likelihood and potential impact of pipeline emergencies and releases. Public Awareness Programs will also help the public understand that while pipeline accidents are possible, pipelines are a relatively safe mode of transportation, that pipeline operators undertake a variety of measures to prevent pipeline accidents, and that pipeline operators anticipate and plan for management of accidents if they occur. Finally, a more informed public will also understand that they have a significant role in helping to prevent accidents that are caused by third-party damage and ROW encroachment.

- **Prevention and Response**

Public Awareness Programs should help the public understand the steps that the public can take to prevent and respond to pipeline emergencies. "Prevention" refers to the objective of reducing the occurrences of pipeline emergencies caused by third-party damage (versus other causes under the control of the operator) through awareness of safe excavation practices and the use of the One-Call System. "Response" refers to the objective of communicating to the public the appropriate steps to take into account in the event of a pipeline release or emergency.

These objectives, together with others that may be identified by individual pipeline operators, provide the foundation on which a pipeline Public Awareness Program is built. Two important objectives of this RP include:

- Assist each pipeline operator to develop a framework for managing its Public Awareness Program so that the quality of Public Awareness Programs can be continually improved throughout the pipeline industry and
- Provide the operator with considerations to determine how to enhance its program to provide the appropriate level of public awareness outreach for a given area and certain circumstances.

2.2 OVERVIEW FOR MEETING PUBLIC AWARENESS OBJECTIVES

In general, Public Awareness Programs should communicate relevant information to the following stakeholder audiences (as defined in Section 3):

2.2.1 The Affected Public

- Awareness that they live or work near a pipeline
- Hazards associated with unintended releases
- An overview of what operators do to prevent accidents and mitigate the consequences of accidents when they occur
- How to recognize and respond to a pipeline emergency
- What protective actions to take in the unlikely event of a pipeline release
- How to notify the pipeline operator regarding questions, concerns, or emergencies
- How to assist in preventing pipeline emergencies by following safe excavation/digging practices and reporting unauthorized digging or suspicious activity
- How community decisions about land use may affect community safety along the pipeline ROW
- How individuals can create undesirable encroachments upon a pipeline ROW
- How to contact the pipeline operator with questions or comments about public safety, additional overview information on Integrity Management Programs to protect High Consequence Areas located in their area, land use practices, emergency preparedness or other matters.

2.2.2 Local Public Officials

- Information regarding transmission pipelines that cross their area of jurisdiction
- Land use practices associated with the pipeline ROW that may affect community safety
- Hazards associated with unintended releases
- An overview of what operators do to prevent accidents and mitigate the consequences of accidents when they occur
- How to contact the pipeline operators with questions or comments about public safety, additional overview information on Integrity Management Programs to protect High Consequence Areas under their jurisdiction, land use practices, emergency preparedness or other matters.

2.2.3 Emergency Officials

- Location of transmission pipelines that cross their area of jurisdiction, and how to get detailed information regarding those pipelines
- Name of the pipeline operator and the emergency contact information for each pipeline
- Information about the potential hazards of the subject pipeline
- Location of emergency response plans with respect to the subject pipelines
- How to notify the pipeline operator regarding questions, concerns, or emergency
- How to safely respond to a pipeline emergency
- An overview of what operators do to prevent accidents and mitigate the consequences of accidents when they occur
- How to contact the pipeline operator with questions or comments about public safety, additional overview information on Integrity Management Programs to protect High Consequence Areas under their jurisdiction,

land use practices, emergency preparedness or other matters.

2.2.4 Excavators

- Awareness that digging and excavating along the ROW may affect public safety, pipeline safety and/or pipeline operations
- Information about one-call requirements and damage prevention requirements in that jurisdiction
- Information about safe excavation practices in association with underground utilities
- How to notify the operator regarding a pipeline emergency or damage to a pipeline
- Hazards associated with unintended releases
- Name of the pipeline operator and who to contact for emergency or non-emergency information.

This RP focuses on those four segments of the public, as listed above, that are most directly affected by or could have the most affect on pipeline safety. The general public is a larger audience for general pipeline awareness information. General knowledge about energy pipelines is useful to the general public and may be obtained through a variety of sources, including the Office of Pipeline Safety, US Department of Transportation, pipeline industry trade associations and pipeline operators.

2.3 REGULATORY COMPLIANCE

This RP is intended to provide a framework for Public Awareness Programs designed to help pipeline operators in their compliance with federal regulatory requirements found in 49 *CFR* Parts 192 and 195.

The three principal compliance elements include:

2.3.1 Public Education (49 *CFR* Parts 192.616 and 195.440):

These regulations require pipeline operators to establish continuing education programs to enable the public, appropriate government organizations, and persons engaged in excavation-related activities to recognize a pipeline emergency and to report it to the operator and/or the fire, police, or other appropriate public officials. The programs are to be provided in both English and in other languages commonly used by a significant concentration of non-English speaking population along the pipeline.

2.3.2 Emergency Responder Liaison Activities (49 *CFR* Parts 192.615 and 195.402):

These regulations require that operators establish and maintain liaison with fire, police, and other appropriate public officials and coordinate with them on emergency exercises or drills and actual responses during an emergency.

2.3.3 Damage Prevention (49 *CFR* Parts 192.614 and 195.442):

These regulations require pipeline operators to carry out written programs to prevent damage to pipelines by excavation activities.

2.4 OTHER RESOURCES

In addition to operator personnel, various other resources are available to assist pipeline operators in developing their Public Awareness Programs and related informational materials. These resources can often shorten development time and reduce the implementation cost of an operator's Public Awareness Program. Some of these other resources are described below.

2.4.1 Trade Associations

The major pipeline industry trade associations take an active role in sponsoring various efforts that can help operators meet public awareness objectives. These trade associations include the:

- American Petroleum Institute (API)
- Association of Oil Pipe Lines (AOPL)
- American Gas Association (AGA)
- Interstate Natural Gas Association of America (INGAA) and
- American Public Gas Association (APGA).

The websites of these associations provide a wide range of information to assist operators in developing and managing Public Awareness Programs, and developing information to use in implementing those programs. The trade associations also undertake specific efforts in public outreach, such as:

- Printing of pipeline safety brochures that can be customized by the operator
- Development and distribution of pipeline safety decals and materials
- Development of videos and brochures to aid in the education of public officials regarding pipeline emergency response
- Development of website information specifically for pipeline public awareness
- Distribution of periodic newsletters that provide additional guidance and information to operators on issues related to Public Awareness Programs
- Development and sponsorship of television and radio public service announcements (PSA)
- Participation in appropriate trade shows to inform excavators, regulators, legislators, and others.

For additional information on these efforts, contact the trade associations directly. Contact information and website addresses are provided in Appendix A.

2.4.2 One-Call Centers

The primary purpose of a One-Call System is to prevent damage to underground facilities, including pipelines, which could result from excavation activities. All states and the District of Columbia have established One-Call Systems (some states may have two or more One-Call Systems). State One-Call Centers may develop public awareness information materials and may be able to gather extensive information about excavation contractors. If available to the pipeline operator, this information will be useful to fulfill the requirements of 49 *CFR* Part 192.614 and 195.442 (Damage Prevention Programs). Many One-Call Systems perform their own public awareness outreach through public service announcements and other advertising. Some One-Call Systems may also sponsor statewide excavation hazard awareness programs. One-Call System contacts can be found at the "Dig Safely" website (see Appendix A).

2.4.3 Federal and State Agencies

Although pipeline operators are the primary sponsors of Public Awareness Programs on pipeline safety, some state agencies with regulatory authority for pipeline safety can provide training and materials. In addition, some state pipeline safety regulatory agencies sponsor or conduct pipeline public awareness efforts. The federal agency responsible for pipeline safety, the Office of Pipeline Safety of the U.S. Department of Transportation, is also a source of relevant information.

2.4.4 Common Ground Alliance

The Common Ground Alliance (CGA) is a nationally recognized nonprofit organization dedicated to shared responsibility in damage prevention and promotion of the damage prevention Best Practices identified in the landmark *Common Ground Study of One-Call Systems and Damage Prevention Best Practices*. This report is available online from CGA's website (see Appendix A). Building on the spirit of shared responsibility resulting from the Common Ground Study, the purpose of the CGA is to ensure public safety, environmental protection, and the integrity of services by promoting effective damage prevention practices. The "Dig Safely" campaign is now a component of the Common Ground Alliance.

The Common Ground Alliance is supported by its sponsors, member organizations, the Office of Pipeline Safety, and individual members. CGA sponsorship and membership is open to all stakeholder organizations that want to support the CGA's damage prevention efforts.

2.4.5 Outside Consultants

Many outside consultants are available to support an operators' Public Awareness Program. Direct-mail vendors are capable of producing pipeline safety materials and providing distribution services. These vendors can assist operators in identifying residents and special interest groups, such as excavators along the pipeline route, and can support the operator in production and distribution of the material. Public relations firms are also available to assist operators in developing material specifically geared to the intended audience. Their expertise can help heighten the readability of the public awareness materials and improve the operator's overall success in communicating the intended message.

2.4.6 Other Pipeline Companies

Pipeline companies have developed a variety of creative ways to meet their public awareness objectives. Cooperative information exchanges or shared public awareness activities between operators can be beneficial and economical.

2.4.7 Operator Employee Participation

As members of communities and community service organizations, informed employees of a pipeline operator can play an important role in promoting pipeline awareness. An operator should include in its Public Awareness Program provisions for familiarizing its employees with its public awareness objectives. Information and material used by the operator should be made available to employees who wish to promote pipeline awareness in their communities. Many Public Awareness Programs include components for key employee training in public awareness and specific communication training for specific key employees.

Operator employees can be a key part of public awareness efforts. Grass-roots employee contacts and communications can be particularly important in effectively reaching out to a community. Employees who are interested in and capable of performing a greater public communication role should be given the necessary training, communications materials and, as appropriate, be provided with opportunities for direct involvement with the community.

2.5 MANAGEMENT SUPPORT

For a Public Awareness Program to achieve its objectives, ongoing support within the operator's organization is crucial. Management should demonstrate its support through company policy, management participation, and allocation of resources and funding. Funding and resource requirements for an operator's Public Awareness Program development and implementation will vary according to the program's objectives, design, and scope. Full organizational support can make a marked difference in the way the Public Awareness Program is received and can affect the overall effectiveness and success of the program.

2.6 BASELINE AND SUPPLEMENTAL PUBLIC AWARENESS PROGRAMS

For the development of a Public Awareness Program, this RP recognizes that there are differences in pipeline conditions, release consequences, affected populations, increased development and excavation activities and other factors associated with pipeline systems. Accordingly, a "one-size-fits-all" Public Awareness Program across all pipeline systems would not be the most effective approach. For example, some geographic areas have a low population, low turn over in residents, and little development or excavation activity; whereas other areas have very high population, high turn over, and extensive development and excavation activity.

This RP provides the operator with the elements of a recommended baseline Public Awareness Program. It also provides the operator with considerations to determine when and how to enhance the program to provide the appropriate level of public awareness outreach. Details for assessing the need for program enhancement are presented in Section 6. The appropriateness of enhanced or supplemental messages, delivery frequency and methods, and/or geographic coverage area is also one aspect of program evaluation. Recommendations on the evaluation of Public Awareness Programs are presented in Section 8.

2.7 PROGRAM DEVELOPMENT GUIDE

It is recommended that pipeline operators develop a written Public Awareness Program. The following guide may be helpful to pipeline operators in the development and implementation of their Public Awareness Programs.

Overall Program Administration

Step 1. Define Program Objectives

- Define program objectives in accordance with Section 2 of this RP.

Step 2. Obtain Management Commitment and Support

- Develop a company Policy and "statement of support" for the Public Awareness Program. This should include a commitment of participation, resources, and funding for the development, implementation, and management of the program.
- Reference Section 2.5.

Step 3. Identify Program Administration

- Name program administrator(s)
- Identify roles and responsibilities
- Document program administration
- Reference Section 7.

Step 4. Identify Pipeline Assets to be Included within the Program

- The overall program may be a single Public Awareness Program for all pipeline assets, or may be divided into individual, asset-specific programs for one or more specific pipeline systems, one or more pipeline segments, one or more facilities, or one or more geographic areas. Smaller companies and LDCs may have just one overall program.
- Name an administrator for each asset specific program.
- Reference Section 7 for documentation.

Program Development (applied to each identified asset- specific program)

Step 5. Identify the Four Stakeholder Audiences

- Establish methods to be used in audience identification.
- Establish a means of contact or address list for each audience type:
  - Affected public
  - Emergency officials
  - Local public officials
  - Excavators.
- Document methods used and output.
- Reference Section 3 for detail on stakeholder audiences.

Step 6. Determine Message Type and Content for Each Audience

- Establish which message types are to be used with which audience(s).
- Determine content for each message type.
- Document message type and content selected.
- Reference Section 4 for details on message development.

Step 7. Establish Baseline Delivery Frequency for Each Message

- Suggested delivery frequencies are described in Section 2.8.
- Document delivery frequencies selected.

Step 8. Establish Delivery Methods to Use for Each Message

- Select appropriate methods.
- Utilize alternate methods as appropriate.
- Document delivery methods selected.
- Establish process for management of input/feedback/comments received.
- Reference Sections 2.8 and 5 for additional detail.

Step 9. Assess Considerations for Supplemental Program Enhancements

- Review the criteria in this RP for enhanced programs (e.g. supplemental activities).
- Assess pipeline assets contained in the program and apply supplemental program elements.
- Solicit input from appropriate pipeline personnel (e.g. pipeline operations and maintenance personnel, other support personnel, etc.).
- Apply identified supplemental program elements to the program.
- Document supplemental program elements (describes when, what, and where program enhancements are used).
- Reference Sections 2.8 and 6.

Step 10. Implement Program and Track Progress

- Develop resource and monetary budgets for program implementation.
- Identify, assign and task participating company employees needed to implement the program.
- Identify external resources or consultants needed.
- Conduct program activities (e.g. mass mailings, emergency official meetings).
- Periodically update the program with newly identified activities.
- Collect feedback from internal and external sources.
- Document the above. Reference Section 7 for documentation and record keeping recommendations.

Step 11. Perform Program Evaluation

- Establish an evaluation process.
- Determine input data sources (e.g. company surveys, industry surveys, reply cards, feedback from participating employees, and feedback from recipient audiences, etc.).
- Assess results and applicability of operator and/or industry-sponsored evaluations.
- Document evaluation results. Reference Section 8 for program evaluation recommendations.

Step 12. Implement Continuous Improvement

- Determine program changes or modifications based on results of the evaluation to improve effectiveness. Program changes may be areas such as: audience, message type or content, delivery frequency, delivery method, supplemental activities or other program enhancements.
- Document program changes.
- Determine future funding and internal and external resource requirements resulting from program changes made.
- Implement changes.

Return to Step 5; Initiate new cycle for updating the Public Awareness Program.

The figurative description of the program development process is shown below, highlighting the continuous nature of the development, implementation and evaluation process.

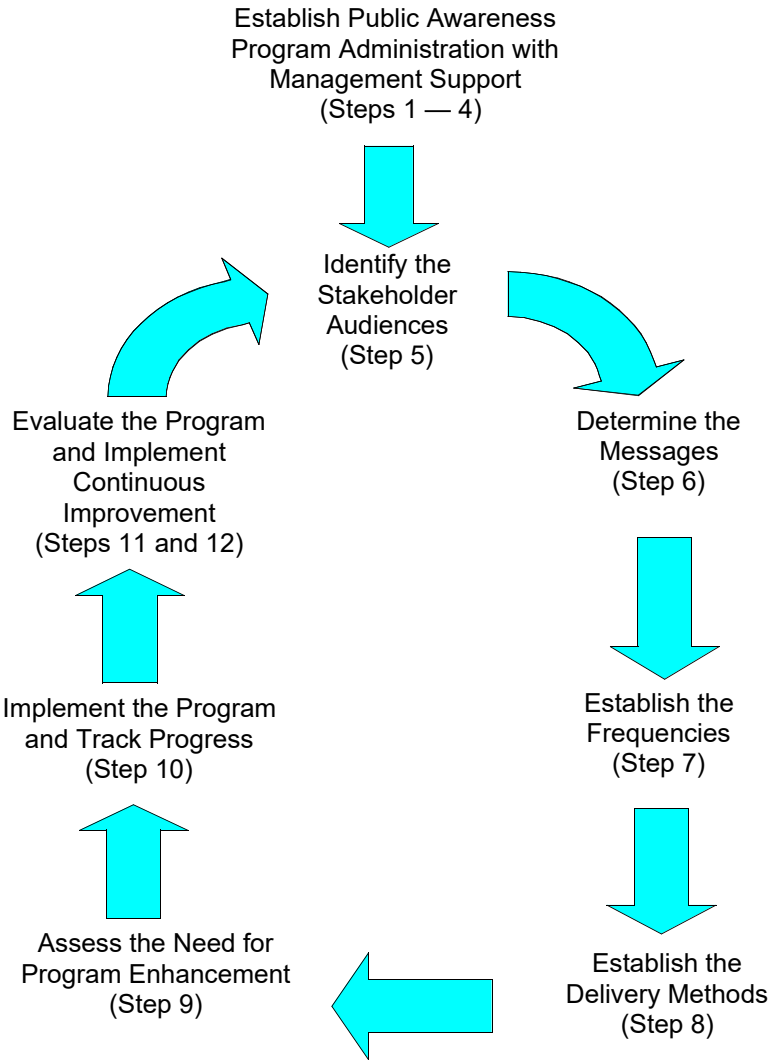

Figure 2-1—Public Awareness Program Process Guide

2.8 SUMMARY OF PROGRAM RECOMMENDATIONS

This RP has defined three categories of pipeline operators to which the RP applies. The three categories are:

1. Hazardous Liquid and Natural Gas Transmission Pipeline Operators (Table 2-1)
2. Local Natural Gas Distribution (LDC) Companies (Table 2-2)
3. Gathering Pipeline Operators (Table 2-3).

This RP recognizes that the communications and public awareness needs and activities may vary by the category of pipeline. Operators may customize their programs to best suit the needs of the stakeholder audiences and make them relevant to the type of potential hazards posed by their pipeline systems.

The tables 2-1 through 2-3 summarize the baseline recommendations for conducting public awareness for operators of Hazardous Liquid, Natural Gas Transmission, Local Natural Gas Distribution (LDC), and Gathering Pipelines. Guidance is also provided to assist the operators in determining if supplemental efforts affecting the frequency or method of message delivery and/or message content are called for, by evaluating the effectiveness of the program and the specifics of the pipeline segment or environment. Considerations for when and how an operator should implement program enhancements are described in Section 6. Further information of stakeholder audiences (Section 3); message types (Section 4); and message delivery methods (Section 5) may be found in their respective sections and related appendices.

Table 2-1 - Summary Public Awareness Communications for Hazardous Liquids and Natural Gas Transmission Pipeline Operators

Stakeholder Audience	Message Type	Delivery Frequency	Delivery Method and/or Media
2-1.1 Affected Public			
Residents located along transmission pipeline ROW **and** **Places of Congregation**	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • One-call requirements • Leak recognition and response • Pipeline location information • How to get additional information • Availability of list of pipeline operators through NPMS	**Baseline Frequency =** 2 years	**Baseline Activity:** • Targeted distribution of print materials • Pipeline markers
	Supplemental Message: • Information and/or overview of operator's Integrity Management Program • ROW encroachment prevention • Any planned major maintenance/construction activity	**Supplemental Frequency:** Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Print materials • Personal contact • Telephone calls • Group meetings • Open houses
Residents near storage or other major operational facilities	**Supplemental Message:** • Information and/or overview of operator's Integrity Management Program • Special incident response notification and/or evacuation measures *if* appropriate to product or facility • Facility purpose	**Supplemental Frequency:** Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Print materials • Personal contact • Telephone calls • Group meetings • Open houses

Table 2-1 - Summary Public Awareness Communications for Hazardous Liquids and Natural Gas Transmission Pipeline Operators (Continued)

Stakeholder Audience	Message Type	Delivery Frequency	Delivery Method and/or Media
2-1.2 Emergency Officials			
Emergency Officials	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Emergency Preparedness Communications • Potential hazards • Pipeline location information and availability of NPMS • How to get additional information	**Baseline Frequency =** Annual	**Baseline Activity:** • Personal contact (generally preferred) OR • Targeted distribution of print materials OR • Group meetings OR • Telephone calls with targeted distribution of print materials
	Supplemental Message: • Provide information and /or overview of Integrity measures undertaken • Maintenance construction activity	**Supplemental Frequency:** Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Emergency tabletop, deployment exercises • Facility tour • Open house
2-1.3 Local Public Officials			
Public Officials	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Emergency preparedness communications • One-call requirements • Pipeline location information and availability of NPMS • How to get additional information	**Baseline Frequency** = 3 years	**Baseline Activity:** • Targeted distribution of print materials
	Supplemental Message: • If applicable, provide information about designation of HCA (or other factors unique to segment) and summary of integrity measures undertaken • ROW encroachment prevention • Maintenance construction activity	**Supplemental Frequency:** • If in HCA, then annual contact to appropriate public safety officials • Otherwise, as appropriate to level of activity or upon request	**Supplemental Activity:** • Personal contact • Telephone calls • Videos and CDs

Table 2-1 - Summary Public Awareness Communications for Hazardous Liquids and Natural Gas Transmission Pipeline Operators (Continued)

Stakeholder Audience	Message Type	Delivery Frequency	Delivery Method and/or Media
2-1.4 Excavators			
Excavators / Contractors	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • One-call requirements • Leak recognition and response • How to get additional information	**Baseline Frequency =** Annual	**Baseline Activity:** • Targeted distribution of print materials • One-Call Center outreach • Pipeline markers
	Supplemental Messages: Pipeline purpose, prevention measures and reliability	**Supplemental Frequency:** Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Personal contact • Group meetings
Land Developers	**Supplemental Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage Prevention Awareness • One-call Requirements • Leak Recognition and Response • ROW Encroachment Prevention • Availability of list of pipeline operators through NPMS	**Supplemental Frequency:** Frequency as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Targeted distribution of print materials • Pipeline markers • Personal contact • Group meetings • Telephone calls
One-Call Centers	**Baseline Messages:** • Pipeline location information • Other requirements of the applicable One-Call Center	**Baseline Frequency:** • Requirements of the applicable One-Call Center	**Baseline Activity:** • Membership in appropriate One-Call Center • Requirements of the applicable One-Call Center • Maps (as required)
	Supplemental Messages: • One-Call System performance • Accurate line location information • One-Call System improvements	**Supplemental Frequency:** As changes in pipeline routes or contact information occur or as required by state requirements	**Supplemental Activity:** • Targeted distribution of print materials • Personal contact • Telephone calls

Table 2-2—Summary Public Awareness Communications for Local Natural Gas Distribution (LDC) Companies

Stakeholder Audience	Message Type	Suggested Frequency	Suggested Delivery Method and/or Media
2-2.1 Affected Public			
Residents along the Local Distribution System (LDC)	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • Leak recognition and response • How to get additional information	**Baseline Frequency** = Annual	**Baseline Activity:** • Public service announcements, OR • Paid advertising, OR • Bill stuffers (for combination electric & gas companies)
		Supplemental Frequency: • Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Targeted distribution of print materials • Newspaper and magazines • Community events or • Community neighborhood newsletters
LDC Customers	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage Prevention Awareness • Leak Recognition and Response • How to get additional information	**Baseline Frequency** = Twice annually	**Baseline Activity:** • Bill stuffers
		Supplemental Frequency: • Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Targeted distribution of print materials
2-2.2 Emergency Officials			
Emergency Officials	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Emergency preparedness communications • How to get additional information	**Baseline Frequency** = Annual	**Baseline Activity:** • Print materials, OR • Group meetings
		Supplemental Frequency: • Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Telephone calls • Personal contact • Videos and CDs
2-2.3 Local Public Officials			
Public Officials	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Emergency preparedness communications • How to get additional information	**Baseline Frequency** = 3 years	**Baseline Activity:** • Targeted distribution of print materials
		Supplemental Frequency: • Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Group meetings • Telephone calls • Personal contact

Table 2-2—Summary Public Awareness Communications for Local Natural Gas Distribution (LDC) Companies (Continued)

Stakeholder Audience	Message Type	Suggested Frequency	Suggested Delivery Method and/or Media
2-2.4 Excavators			
Excavators / Contractors	**Baseline Messages:** • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Leak recognition and response • One-call requirements • How to get additional information	**Baseline Frequency** = Annual	**Baseline Activity:** • One-Call Center outreach OR • Group meetings
		Supplemental Frequency: • Additional frequency and supplemental efforts as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Personal contact • Videos and CDs • Open houses
One-Call Centers	**Baseline Messages:** • Pipeline location information • Other requirements of the applicable One-Call Center	**Baseline Frequency:** • Requirements of the applicable One-Call Center	**Baseline Activity:** • Membership in appropriate One-Call Center • Requirements of the applicable One-Call Center • Maps (as required)
	Supplemental Messages: • One-Call System performance • Accurate line location information • One-Call System improvements	**Supplemental Frequency:** • As changes in pipeline routes or contact information occur or as required by state requirements	**Supplement Activity:** • Targeted distribution of print materials • Personal contact • Telephone calls • Maps (as required)

Table 2-3—Summary Public Awareness Communications for Gathering Pipeline Operators

Stakeholder Audience	Message Type	Delivery Frequency	Delivery Method and/or Media
2-3.1 Affected Public			
Residents, **and** **Places of Congregation within area of potential impact**	**Baseline Messages:** • Gathering pipeline purpose • Awareness of hazards • Prevention measures undertaken • Damage prevention awareness • One-call requirements • Leak Recognition and Response • How to get additional information	**Baseline Frequency** = 2 years	**Baseline Activity:** • Targeted distribution of print materials OR • Personal contact
	Supplemental Messages: • Planned maintenance construction activity • Special emergency procedures if sour gas or other segment specific reason.	**Supplemental Frequency:** • Annually for sour gas gathering lines • Additional frequency as determined by specifics of the pipeline segment or environment.	**Supplemental Activity:** • Pipeline markers • Print materials • Personal contact • Telephone calls • Group meetings • Mass media • Other activities described in Section 5

Table 2-3—Summary Public Awareness Communications for Gathering Pipeline Operators (Continued)

Stakeholder Audience	Message Type	Delivery Frequency	Delivery Method and/or Media
2-3.2 Emergency Officials			
Emergency Officials	**Baseline Messages:** • Gathering pipeline location and purpose • Awareness of hazards • Prevention measures undertaken • Emergency preparedness communications, company contact and response information • Specific description of products transported and any potential special hazards • How to get additional information	**Baseline Frequency** = Annual	**Baseline Activity:** • Personal contact (generally preferred) OR • Targeted distribution of print materials OR • Group meetings OR • Telephone calls with targeted distribution of print materials
	Supplemental Messages: • Planned maintenance construction activity • Special emergency procedures if sour gas or other segment specific reason		**Supplemental Activity:** • Emergency tabletop deployment exercises • Facility tour • Open house
2-3.3 Local Public Officials			
Public Officials	**Baseline Messages:** • General location and purpose of gathering pipeline • Awareness of hazards • Prevention measures undertaken • Copies of materials provided to affected public and emergency officials • Company contacts • How to get additional information	**Baseline Frequency** = 3 years	**Baseline Activity:** • Targeted distribution of print materials
	Supplemental Message: • ROW encroachment prevention • Maintenance construction activity • Special emergency procedures if sour gas or other segment specific reasons.	**Supplemental Frequency:** • If in HCA, then more frequent or annual contact with appropriate public safety officials • Otherwise as appropriate to level of activity or upon request	**Supplemental Activity:** • Personal contact • Telephone calls • Videos and CDs

Table 2-3—Summary Public Awareness Communications for Gathering Pipeline Operators (Continued)

Stakeholder Audience	Message Type	Delivery Frequency	Delivery Method and/or Media
2-3.4 Excavators			
Excavators / Contractors	**Baseline Messages:** • General location and purpose of gathering pipeline • Awareness of hazards • Prevention measures undertaken • Damage prevention awareness • One-call requirements • Leak recognition and response • How to get additional information	**Baseline Frequency** = Annual	**Baseline Activity:** • Targeted distribution of print materials • One-Call Center outreach • Pipeline markers **Supplemental Activity:** • Personal contact • Group meetings • One-Call Center outreach • mass media
Land Developers	**Supplemental Messages:** • General location and purpose of gathering pipeline • Awareness of hazards • Prevention measures undertaken • Damage prevention awareness	**Supplemental Frequency:** Frequency as determined by specifics of the pipeline segment or environment	**Supplemental Activity:** • Targeted distribution of print materials • Personal contact • Group meetings • Telephone calls
One-Call Centers	**Baseline Messages:** • Pipeline location information • Other requirements of the applicable One-Call Center	**Baseline Frequency:** • Requirements of the applicable One-Call Center	**Baseline Activity:** • Membership in appropriate One-Call Center • Requirements of the applicable One-Call Center • Maps (as required)
	Supplemental Messages: • One-Call System performance • Accurate line location information • One-Call System improvements	**Supplemental Frequency:** As changes in pipeline routes or contact information occur or as required by state requirements	**Supplement Activity:** • Targeted distribution of print materials • Personal contact • Telephone calls • Maps (as required)

3 Stakeholder Audiences

One of the initial tasks in developing a Public Awareness Program is to identify the audience(s) that should receive the program's messages. This section defines the intended audiences for the operator's Public Awareness Program and provides examples (not all inclusive) of each audience. Further explanation and examples are included in Appendix B. This information should help the operator clarify whom it is trying to reach with its program. The following audiences are considered "stakeholders" of the pipeline operator's Public Awareness Program. The four intended "Stakeholder Audiences" include:

- Affected public
- Emergency officials
- Local public officials
- Excavators.

The operator should consider tailoring its communication coverage area to fit its particular pipeline location and release consequences. The operator would be expected to consider areas of consequence as defined in federal regulations. Where specific circumstances suggest a wider coverage area for a certain pipeline location, the operator should expand its communication coverage area as appropriate.

The "Stakeholder Audience" definitions listed in the table below are used in the remaining sections of this RP, as applicable.

3.1 THE AFFECTED PUBLIC

Stakeholder Audience	Audience Definition	Examples
Residents located adjacent to the transmission pipeline ROW	People who live adjacent to a natural gas and/or hazardous liquid transmission pipeline ROW.	• Occupants or residents • Tenants • Farmers • Homeowners associations or groups • Neighborhood organizations
Residents located along distribution systems	People who live on or immediately adjacent to the land wherein gas distribution pipelines are buried.	• LDC customers • Non-customers living immediately adjacent to the land wherein distribution pipelines are buried
Gas transmission pipeline customers	Businesses or facilities that the pipeline operator provides gas directly to for end use purposes. This does not include LDC customers.	• Power plants • Businesses • Industrial facilities
LDC customers	People that are served by gas distribution facilities.	• LDC customers
Residents near liquid or natural gas storage and other operational facilities along transmission lines	People who live adjacent to or near a tank farm, storage field, pump/compressor station and other facilities.	• Occupants or residents tenants • Farmers • Homeowner associations or groups • Neighborhood organizations
Places of congregation	Identified places where people assemble or work on a regular basis—on or along a transmission pipeline ROW, unrelated to habitation.	• Businesses • Schools • Places of worship • Hospitals and other medical facilities • Prisons • Parks & recreational areas • Day-care facilities • Playgrounds
Residents located along rights-of-way for gathering pipelines	• People who live or work on land along which the gathering pipeline is located, and within the right-of-way. • For higher consequence gathering lines (e.g. H_2S), people who live or work a distance on either side of right-of-way that is based on the potential impact in the event of an emergency.	• Occupants or residents • Tenants • Farmers • Businesses • Schools

3.2 EMERGENCY OFFICIALS

Stakeholder Audience	Audience Definition	Examples
Emergency officials	Local, state, or regional officials, agencies and organizations with emergency response and/or public safety jurisdiction along the pipeline route.	• Fire departments • Police/sheriff departments • Local Emergency Planning Commissions (LEPCs) • County and State Emergency Management Agencies (EMA) • Other emergency response organizations • Other public safety organizations

3.3 LOCAL PUBLIC OFFICIALS

Stakeholder Audience	Audience Definition	Examples
Public officials	Local, city, county or state officials and/or their staffs having land use and street/road jurisdiction along the pipeline route.	• Planning boards • Zoning board • Licensing departments • Permitting departments • Building code enforcement departments • City and county managers • Public and government officials • Public utility boards • Includes local “Governing Councils” as defined by many communities • Public officials who manage franchise or license agreements

3.4 EXCAVATORS

Stakeholder Audience	Audience Definition	Examples
Excavators	Companies and local/state government agencies who are involved in any form of excavation activities.	• Construction companies • Excavation equipment rental companies • Public works officials • Public street, road and highway departments (maintenance and construction) • Timber companies • Fence building companies • Drain tiling companies • Landscapers • Well drillers
Land developers	Companies and private entities involved in land development and planning.	• Home builders • Land developers • Real estate sales
One-Call Centers	Excavation One-Call Centers relevant to the area.	• Each state, region, or other organization established to notify underground facility owner/operators of proposed excavations. Excavation One-Call Centers relevant to the area.

4 Message Content

An operator should select the optimum combination of message, delivery method, and frequency that meets the needs of the intended audience. Information materials may also include supplemental information about the pipeline operator, pipeline operations, the safety record of pipelines and other information that an operator deems appropriate for the audience. The operator is reminded that communications materials should be provided in the language(s) spoken by a significant portion of the intended audience.

The basic message conveyed to the intended audience should provide information that will allow the operator to meet the program objectives. The communications should include enough information so that in the event of a pipeline emergency, the intended audience will know how to identify a potential hazard, protect themselves, notify emergency response personnel, and notify the pipeline operator. Several components of these messages are discussed in this section.

4.1 PIPELINE PURPOSE AND RELIABILITY

Operators should consider providing a general explanation of the purpose of the pipeline and/ or facilities and the reliability of pipelines to meet the energy needs of the region, even though this is not a primary objective of pipeline public awareness. Operators should provide assurances that security is considered.

4.2 HAZARD AWARENESS AND PREVENTION MEASURES

Operators should provide a very broad overview of potential hazards, their potential consequences and the measures undertaken by the operator to prevent or mitigate the risks from pipelines (including, at the operator's discretion, an overview of the industry's safety record). Additionally, operators should provide an overview of their preventative measures to help assure safety and prevent incidents. The scope of the hazard awareness and prevention message should be more detailed for the emergency responder audience than for other audiences, and should include how to obtain more specific information upon request from the operator.

4.3 LEAK RECOGNITION AND RESPONSE

The pipeline operator should provide information in the following key subject areas to the affected public and excavator stakeholder groups.

4.3.1 Potential Hazards of Products Transported

Information about specific release characteristics and potential hazards posed by hazardous liquids or gases should be included.

4.3.2 How to Recognize a Pipeline Leak

Information should address how to recognize a pipeline leak through the senses of sight, unusual sound, and smell and describe any associated dangers as appropriate to the product type.

4.3.3 Response to a Pipeline Leak

Information should address an outline of the appropriate actions to take if a pipeline leak or release is suspected.

4.3.4 Liaison with Emergency Officials

Information should describe the ongoing relationship between the operator and local emergency response officials to help prevent incidents and assure preparedness for emergencies.

4.4 EMERGENCY PREPAREDNESS COMMUNICATIONS

Communicating periodically with local emergency officials is an important aspect of all Public Awareness Programs. Operators should provide a summary of emergency preparedness information to local public officials and should indicate that detailed information has been provided to emergency response agencies in their jurisdictions. The following information should be provided to the emergency officials stakeholder audience.

4.4.1 Priority to Protect Life

The operator's key messages to emergency officials should emphasize that public safety and environmental protection are the top priorities in any pipeline emergency response.

4.4.2 Emergency Contacts

Contact information for the operator's local offices and 24-hour emergency telephone line should be shared with local and state emergency officials. Operators should also use the contacts with emergency officials to confirm that both emergency officials and the operators have the current, correct contact information and calling priorities.

4.4.3 Emergency Preparedness Response Plans

Operators are required by federal regulations to have emergency response plans. These plans should be developed for use internally and externally, with appropriate officials, and in accordance with applicable federal and state emergency regulations. 49 *CFR* 192 and 195 and some state regulations outline the specific requirements for emergency response plans and who to contact for additional information. The operator should include information about how emergency officials

can access the operator's emergency response plans covering their jurisdiction.

4.4.4 Emergency Preparedness—Drills and Exercises

A supplemental means of two-way communication about emergency preparedness is to establish a liaison with emergency response officials through operator or joint emergency response drills, exercises or deployment practices. Information on "unified command system" roles, operating procedures and preparedness for various emergency scenarios can be communicated effectively and thoroughly through a hands-on drill or exercise.

4.5 DAMAGE PREVENTION

Because even relatively minor excavation activities can cause damage to a pipeline or its protective coating or to other buried utility lines, it is important that operators raise the awareness of the need to report any suspected signs of damage. Operators should keep their damage prevention message content consistent with the key "Dig Safely" messages developed by the Common Ground Alliance (CGA). CGA contact information is located in Appendix A.

The use of an excavation One-Call Notification system should be explained to the audience. Information on the prevalence of digging-related damage, also known as "third-party" damage, should be provided as appropriate. The audience should be requested to call the state or local One-Call System in their area before they begin any excavation activity. If the state or locality has established penalties for failure to use established damage prevention procedures, that fact may also be communicated, depending on the audience and situation. Additional information is located in Appendix C.

Additionally, third-party contractors are subject to the Occupational Safety and Health Administration's (OSHA) requirements. OSHA cites in its "General Duty Clause" possible regulatory enforcement action that could be taken against excavation contractors who place their employees at risk by not utilizing proper damage prevention practices. The lack of adequate damage prevention could subject the excavator to OSHA regulatory enforcement. OSHA contact information is located in Appendix A.

4.6 PIPELINE LOCATION INFORMATION

4.6.1 Transmission Pipeline Markers

The audience should know how to identify a transmission pipeline ROW by recognition of pipeline markers—especially at road crossings, fence lines and street intersections. The operator's awareness communications should include information about what pipeline markers look like, and the fact that telephone numbers are on the markers for their use if an emergency is suspected or discovered. Communications should also be clear that pipeline markers do not indicate the exact location or depth of the pipeline and may not be present in certain areas. As such, use of the One-Call Notification system should be encouraged. Additional detail is located in Appendix C.

4.6.2 Transmission Pipeline Mapping

Pipeline maps developed by transmission pipeline operators can be an important component of an operator's Public Awareness Program. The level of detail provided on the map should, at a minimum, include the line size, product transported and the approximate location of the pipeline, as well as any other information deemed reasonable and necessary by the operator. National energy infrastructure security issues should be considered in determining information and distribution related to pipeline maps. The public can also receive information about which pipelines operate in their community by accessing the National Pipeline Mapping System (NPMS). The NPMS will provide the inquirer a list of pipeline operators and operator contact information. Operators should include information on the availability of the NPMS within their public awareness materials. NPMS information is provided in Appendix A. Additional mapping information is provided in Appendix C.

4.7 HIGH CONSEQUENCE AREAS (HCAs) AND INTEGRITY MANAGEMENT PROGRAM OVERVIEW FOR TRANSMISSION OPERATORS

4.7.1 Message Content for Affected Public within HCAs

Public awareness materials should include a general explanation that, in accordance with federal regulations, some segments along transmission pipelines have been designated as High Consequence Areas (HCAs) and that supplemental hazard assessment and prevention programs (called Integrity Management Programs) have been developed. Information provided to the affected public should indicate where an overview of the operator's Integrity Management Programs can be obtained or viewed upon request.

4.7.2 Message Content for Emergency Officials within HCAs

For emergency official stakeholder audiences whose jurisdiction includes an HCA as defined by 49 *CFR* Parts 192 or 195, the operator should include an overview of the operator's Integrity Management Programs. Inclusion of this information during emergency official liaison interface will provide an opportunity for feedback from the emergency official on the operator's Integrity Management Programs.

4.7.3 Message Content for Public Officials within HCA's

For public official stakeholder audiences whose jurisdiction includes an HCA as defined by 49 *CFR* Parts 192 or 195, the operator should indicate where an overview of the operator's Integrity Management Programs can be obtained or viewed upon request.

4.8 CONTENT ON OPERATOR WEBSITES

Pipeline operators who maintain websites can include the following information (further examples of this information are provided in Appendix C):

- Company information
- General information on pipeline operations
- General or system pipeline map(s)
- Affected public information
- Emergency and security information
- Damage prevention awareness and One-Call Notification.

4.9 RIGHT-OF-WAY ENCROACHMENT PREVENTION

Pipeline operators should communicate that encroachments upon the pipeline ROW inhibit the operator's ability to respond to pipeline emergencies, eliminate third-party damage, provide ROW surveillance, perform routine maintenance, and perform required federal/state inspections. Stakeholder specific information is listed in Appendix D.

4.10 PIPELINE MAINTENANCE CONSTRUCTION ACTIVITIES

Pipeline maintenance-related construction activities should be communicated to the audience affected by the specific activity in a timely manner appropriate to the nature and extent of the activity.

4.11 SECURITY

Where applicable and in accordance with the national Homeland Security efforts, pipeline operators should communicate an overview pertaining to security of their pipelines and related facilities.

4.12 FACILITY PURPOSE

Where appropriate, communication with the affected public and emergency and public officials in proximity to major facilities (such as storage facilities, compressor or pump stations) should include information to promote understanding of the nature of the facility. Operators should communicate general information regarding the facility and product(s) stored or transported through the facility. Communication with emergency officials should also include emergency contact information for the specific facility.

5 Message Delivery Methods and/or Media

This section describes several delivery methods and tools available to pipeline operators to foster effective communications with the intended stakeholder audiences previously described. The operator is reminded that not all methods are effective in all situations. The content of the communication efforts should be tailored to:

- Needs of the audience
- Type of pipeline and/or facilities
- Intent of the communication, and
- Appropriate method/media for the content.

A more detailed discussion of the summary information below is provided in Appendix D.

5.1 TARGETED DISTRIBUTION OF PRINT MATERIALS

The use of print materials is an effective means of communicating with intended audiences. Because of the wide variety of print materials, operators should carefully select the type, language and formatting based on the audience and message to be delivered. Generally, an operator will use more than one form of print materials in its Public Awareness Program. While not all inclusive, several types are discussed below.

5.1.1 Brochures, Flyers, Pamphlets, and Leaflets

Brochures, flyers, pamphlets and leaflets are probably the most common message delivery methods currently used by the pipeline industry. These print materials can convey important information about the company, the industry, pipeline safety, or a proposed project or maintenance activity and should provide contact information where the recipient can obtain further information. These print materials also afford an effective opportunity to communicate content in a graphical or pictorial way.

5.1.2 Letters

Research has indicated that letters mailed to residents along the pipeline ROW are an effective tool to communicate specific information, such as how to recognize and what to do in the event of a leak, how to identify and report suspicious activity, and notification of planned operator activities.

5.1.3 Pipeline Maps

Pipeline maps can be an important component of an operator's Public Awareness Program and should be considered where they can enhance the appropriate stakeholder(s) aware-

ness of the operator's pipeline and facilities. Additional information regarding pipeline mapping is available in Appendix C.

5.1.4 Response Cards

Often referred to as either bounce back cards or business reply cards, these preprinted, preaddressed, postage paid response cards are often mailed to the affected public as an integral part of, or as an attachment to, other items. The inclusion of a response card can be used in a variety of ways (refer to Appendix D).

5.1.5 Bill Stuffers

Bill stuffers are printed brochures frequently used by local distribution companies (LDCs) in conjunction with customer invoices. Due to the nature of customers for transmission and gathering pipelines, bill stuffers are not considered an appropriate option. LDCs using bill stuffers can easily reach their customers with appropriate messages and can increase their effectiveness by using bill stuffers repeatedly. For those LDCs that are combined with other energy utilities such as electric or water systems, bill stuffers regarding pipeline safety and underground damage prevention can be delivered to virtually all surroundings residents, even those that may not be natural gas customers.

5.2 PERSONAL CONTACT

Personal contact describes face-to-face contacts between the operator and the intended stakeholder audience. This method is usually a highly effective form of communication and allows for two-way discussion. Personal contacts may be made on an individual basis or in a group setting. Some examples of personal contact communications are described further in Appendix D and include:

- Door-to-door contact along pipeline ROW
- Telephone calls
- Group meetings
- Open houses
- Community events
- Charitable contribution presentations by pipeline companies.

5.3 ELECTRONIC COMMUNICATION METHODS

5.3.1 Videos and CDs

There are a variety of approaches operators may use to supplement their public awareness efforts with videos and CDs. While considered a supplement to the baseline components of an effective Public Awareness Program, videos and CDs may be quite useful with some stakeholders or audiences in some situations. These media can show activities such as construction, natural gas or petroleum consumers, pipeline routes, preventive maintenance activities, simulated or actual spills and emergency response exercises or actual responses in ways that printed materials cannot.

5.3.2 E-mail

Electronic mail ("e-mail") can be a means of sending public awareness information to a variety of stakeholder audiences. The content and approach is similar to letters or brochures, but the information is sent electronically rather than delivered by postal mail or personal contact.

5.4 MASS MEDIA COMMUNICATIONS

5.4.1 Public Service Announcements

Public Service Announcements (PSAs) can be an effective means for reaching a large sector of the public. Radio and television stations occasionally make some airtime available for PSAs. They are no longer required by law to donate free airtime and as a result, there is great competition from various public interest causes for the small amount of time made available. If the operator is an advertiser with the radio or television station, this might be leveraged to gain advantage in acquiring PSA time.

5.4.2 Newspapers and Magazines

Newspaper and magazine articles don't have to be limited to the reactive coverage following an emergency or controversy. Pipeline companies can submit or encourage reporters to write constructive and informative articles about pipeline issues, such as local projects, excavation safety, or the presence of pipelines as part of the energy infrastructure.

5.4.3 Paid Advertising

The use of paid advertising media such as television ads, radio spots, newspapers ads, and billboards can be an effective means of communication with an entire community.

5.4.4 Community and Neighborhood Newsletters

Posting of pipeline safety or other information to community and neighborhood newsletters can be done in conjunction with other outreach to those communities and/or neighborhoods. This method can be particularly effective in reaching audiences near the pipeline, namely neighborhoods and subdivisions through which the pipeline traverses.

5.5 SPECIALTY ADVERTISING MATERIALS

Specialty advertising can be a unique and effective method to introduce a company or maintain an existing presence in a community. These materials also provide ways of delivering pipeline safety messages, project information, important phone numbers and other contact information. The main benefit of this type of advertising is that it tends to have a longer

retention life than printed materials because it is otherwise useful to the recipient. Because of the limited amount of information that can be printed on these items, they should be used as a companion to additional printed materials or other delivery methods. Examples are included in Appendix D.

5.6 INFORMATIONAL OR EDUCATIONAL ITEMS

Companies can develop informational and educational materials to heighten pipeline awareness. The cost-effectiveness of producing such materials can be increased through partnering with an industry association or group of other operators.

5.7 PIPELINE MARKER SIGNS

The primary purposes of aboveground transmission pipeline marker signs are to:

- Mark the approximate location of a pipeline
- Provide public awareness that a buried pipeline or facility exists nearby
- Provide a warning message to excavators about the presence of a pipeline or pipelines
- Provide pipeline operator contact information in the event of a pipeline emergency and
- Facilitate aerial or ground surveillance of the pipeline ROW by providing aboveground reference points.

Refer to Section 4 and Appendix C for additional information on marker sign types and information content.

Below-ground markers, such as warning tape or mesh, can also be effective warnings to excavators of the presence of buried pipe. When burying pipe following repairs, relocations, inspections, etc., operators should consider whether it is appropriate to add below-ground markers in the location.

5.8 ONE-CALL CENTER OUTREACH

Most state One-Call Centers provide community outreach or conduct public awareness activities about one-call requirements and damage prevention awareness, as discussed in Section 4. Pipeline operators should encourage One-Call Centers to provide those public awareness communications and can account for such communication as a part of their own Public Awareness Programs. Many One-Call Centers host awareness meetings with excavators to further promote the damage prevention and one-call messages. It is the operator's responsibility to request documentation for these outreach activities.

To enhance Dig Safely and one-call public awareness outreach by One-Call Centers, operators are required by 49 *CFR* Parts 192 and 195 to become one-call members in localities where they operate pipelines. Since all One-Call Center members share the center's public awareness outreach costs, the costs to an individual operator are usually comparatively low.

5.9 OPERATOR WEBSITES

Pipeline operators with websites can enhance their communications to the public through the use of a company website on the Internet. Additional information located in Appendix C.8 describes features for a company's pipeline operations that should fit into any corporate structure and overall website design. A company's website will supplement the other various direct outreach delivery tools discussed in this RP.

6 Recommendations for Supplemental Enhancements of Baseline Public Awareness Program

The pipeline operator has a number of stakeholder audiences for delivering messages regarding the safe operation of pipelines. The message content, the delivery medium, delivery frequency, and audience's retention of the delivered message should be carefully considered during the development and implementation of the operator's Public Awareness Program to achieve maximum effectiveness. Many of the communications should be available on demand or evergreen (e.g., websites, pipeline markers) and others are periodic in nature (e.g., mass mailings, public meetings, and advertisements). The combination of the specific messages, delivery methods, and delivery frequencies should be designed into the operator's program for each audience. These elements should allow each audience to develop and maintain an awareness of the pipeline's safe operation appropriate to the audience's responsibilities for pipeline awareness, response to pipeline emergencies, and its possible exposure to pipeline emergencies.

Section 2 includes summary tables of the overall Public Awareness Program recommendations. The summary tables include a baseline Public Awareness Program for the three pipeline categories. The tables also provide a recommended delivery frequency for each of the message types intended for the respective audiences. These frequencies are the suggested baselines and the pipeline operator should consider to what extent an enhanced, supplemental program is warranted.

The term "program enhancement" refers to the operator's decision to supplement its Public Awareness Program beyond the recommended baseline. Throughout this RP the terms "enhancement" and "supplemental" are used interchangeably and mean those communications measures added to the Public Awareness Program beyond the baseline program elements. To support this decision, the operator should consider external factors along the pipeline system and determine if some additional level of public awareness communications is warranted, beyond the recommended baseline program. Those supplemental aspects would then be incorporated into the Public Awareness Program for that pipeline segment or system. Supplemental enhancement considerations are discussed in detail on the following pages.

In addition, the operator should include in its Public Awareness Program Evaluation a periodic review and evaluation of its program (see Section 8), determine if supplemental public awareness efforts/activities are warranted and include those enhancements and related documentation into its program.

6.1 CONSIDERATIONS FOR SUPPLEMENTAL ENHANCEMENTS FOR THE BASELINE PROGRAM

This RP recognizes that there are differences in pipeline conditions, consequences, population, property development, excavation activities and other issues along pipeline systems. Accordingly, a "one-size-fits-all" Public Awareness Program across all pipeline systems would not be the most effective approach. This RP recommends that an operator enhance its baseline program with supplemental program components when conditions along the pipeline suggest a more intensive effort is needed.

Baseline program recommendations are established for each of the three pipeline categories. The following sections are provided for guidance when the operator's consideration of relevant factors along the pipeline route indicates that supplemental program enhancement is warranted. Three primary forms of enhancement are provided for consideration in the development and administration of each Public Awareness Program:

6.1.1 Increased Frequency (Shorter Interval)

Increased frequency refers primarily to providing communications to specific stakeholder audiences on a more frequent basis (shorter interval) than the baseline recommended components to reach the intended audience.

6.1.2 Enhanced Message Content and Delivery/ Media Efforts

Enhanced message content and delivery/media efforts refer to providing additional or supplemental communications activities beyond those identified in the baseline, using an enhanced or custom-tailored message content and/or different, or additional, delivery methods/media to reach the intended audience.

6.1.3 Coverage Areas

Coverage areas refer to broadening or widening the stakeholder audience coverage area beyond those contained in the baseline for delivery of certain communications messages. This can also be considered relative to widening the buffer distance for reaching the stakeholder audience along the pipeline route.

6.2 CONSIDERATIONS OF RELEVANT FACTORS

When the operator develops its Public Awareness Program and performs subsequent periodic program evaluations, it is recommended that a step for assessing relevant factors along the pipeline route be included to consider what components of the Public Awareness Program should be enhanced.

The operator should consider each of the following factors applied along the entire route of the pipeline system:

- Potential hazards
- High Consequence Areas
- Population density
- Land development activity
- Land farming activity
- Third-party damage incidents
- Environmental considerations
- Pipeline history in an area
- Specific local situations
- Regulatory requirements
- Results from previous Public Awareness Program evaluations
- Other relevant needs.

The presence of federally designated High Consequence Areas (HCAs) should prompt an operator to consider public awareness activity above the baseline level described in the RP. For natural gas transmission pipelines, 49 *CFR* Part 192.761 defines HCAs related to the population or places of congregation. For hazardous liquid transmission pipelines, 49 *CFR* Part 195.450 describes HCAs related to high population, Unusually Sensitive Areas (USAs) and navigable waterways.

Another factor to consider is the hazard associated with the pipeline as perceived by either the operator or the audience. For example, if a pipeline segment has experienced third-party damage, the operator could increase the frequency of messages to those third-parties and other relevant audiences. If the public's confidence in pipeline safety is undermined by a high profile emergency, even though an individual operator is experiencing no upward trend in incidents, that operator could consider expanding its public awareness communications to its public audiences to further increase awareness of its nearby pipeline system.

Further detail of considerations for program enhancement is discussed in the following sections.

6.3 HAZARDOUS LIQUID AND NATURAL GAS TRANSMISSION PIPELINE OPERATORS

Since Hazardous Liquids and Natural Gas Transmission pipelines are similar in many aspects with respect to public awareness, the two categories of pipelines have been combined.

Considerations for program enhancement for transmission pipelines could include, for example:

6.3.1 The Affected Public

Consideration should be given to *supplemental program enhancement* where:

- The occurrences indicate an elevated potential for third-party damage. Examples include:
  - A mailing to farmers along the right-of-way just prior to the deep plowing season where deep till plow methods are used
  - An additional or interim mass mailing to or face-to-face communications with residents of new housing developments in areas along the pipeline route that may not have previously been reached
  - Increasing the frequency of baseline communication efforts
- The pipeline runs through heavily developed urban areas that are more likely to have a frequently changing population than a more stable, less dense suburban or rural areas. Frequently changing population in an identified audience area should be considered when determining supplemental efforts to:
  - Residents in areas such as multi-family developments or densely populated urban areas
  - Increase the frequency of communications to residents
- Right-of-way encroachments have occurred frequently. Examples of supplemental efforts include:
  - Enhanced mailings to, face-to-face communications with, or increasing the frequency of communications to residents/developers/contractors in areas of right-of-way encroachment
- The potential for concern about consequences of a pipeline emergency is heightened. Consideration should be given to widening the coverage area for:
  - HVL pipelines in high population areas, extend the coverage area beyond the $^{1}/_{8}^{th}$ mile minimum distance each side of the pipeline
  - Large diameter, high pressure, high volume pipelines where a pipeline emergency would likely affect the public outside of the specified minimum coverage area—extend the coverage area to a wider distance as deemed prudent.

6.3.2 Public Officials

Consideration should be given to *supplemental program enhancement* where:

- Heightened public sensitivity to pipeline emergencies exists in the area, independent of cause or which operator was involved
- Significant right-of-way encroachments (such as new construction developments) are occurring.

6.3.3 Emergency Officials

Consideration should be given to *supplemental program enhancement* where:

- Emergency officials have heightened sensitivity to pipeline emergencies
- After post-emergency review, or where there's potential for enhanced "liaison activities" between the operator and emergency officials that could have improved the emergency response to a pipeline emergency
- Requested by emergency officials to provide additional communications.

6.3.4 Excavators/Contractors and One-Call Centers

Consideration should be given to *supplemental program enhancement* where:

- There are instances that indicate an elevated potential for third-party damage
- Developers and contractors are performing a high number of excavations along a pipeline route in developing areas
- There are instances of problems identified with excavators' use or lack of use of the One-Call System. In those cases the operator should also request that the one-call Center perform additional public awareness outreach activities

6.4 LOCAL NATURAL GAS DISTRIBUTION COMPANIES (LDCs)

Many of the aspects of Public Awareness Programs for LDCs are similar to liquid and transmission pipeline operators. However, there are some differences because LDCs serve a different audience. Unlike transmission pipeline operators, LDCs have many more individual customers and have existing communication paths with those customers through monthly billing statements and other customer relationships. Table 2-2, for LDCs, in Section 2, provides baseline and supplemental communication recommendations for each of the different audiences.

Among LDCs there may be some variability in the frequency of communications with specific audiences. Public officials and emergency response personnel in a small rural city will likely be more accessible to the LDC pipeline operators than those in a major metropolitan area. Therefore, LDC operators should tailor their programs based on specific local considerations.

6.5 GATHERING PIPELINE OPERATORS

Gathering pipelines are usually small in diameter and operate at low pressures. In general, the audiences involved in public awareness communications for gathering pipelines tend to be in rural areas. The operator should tailor the spe-

cific communication program to fit the needs of the audiences and the circumstances in the particular area. Table 2-3 for gathering pipeline operators provides baseline and supplemental recommended communication frequencies for different audiences.

7 Program Documentation and Recordkeeping

Each operator should establish policies and procedures necessary to properly document its Public Awareness Program and retain those key records for purposes of program evaluation.

7.1 PROGRAM DOCUMENTATION

Each operator of a hazardous liquid pipeline system, natural gas transmission pipeline system, gathering pipeline system or a natural gas distribution pipeline system should establish (and periodically update) a written Public Awareness Program designed to cover all required components of the program described in this RP.

The written program should include:

a. A statement of management commitment to achieving effective public/community awareness.
b. A description of the roles and responsibilities of personnel administering the program.
c. Identification of key personnel and their titles (including senior management responsible for the implementation, delivery and ongoing development of the program).
d. Identification of the media and methods of communication to be used in the program, as well as the basis for selecting the chosen method and media.
e. Documentation of the frequency and the basis for selecting that frequency for communicating with each of the targeted audiences.
f. Identification of program enhancements, beyond the baseline program, and the basis for implementing such enhancements.
g. The program evaluation process, including the evaluation objectives, methodology to be used to perform the evaluation and analysis of the results, and criteria for program improvement based on the results of the evaluation.

In addition, some operators are required to have an Operations and Maintenance Procedure (O&MP) manual under 49 *CFR* Part 192 or 195. While the overall written program will likely be too extensive and schedule-specific to be suitable for an O&MP manual, the operator should include in the manual an overall statement of management commitment, roles and responsibilities (by group or title), a requirement for a written program and evaluation process, and a summary of the operator's Public Awareness Program.

7.2 PROGRAM RECORDKEEPING

The operator should maintain records of key program elements to demonstrate the level of implementation of its Public Awareness Program. Record keeping should include:

a. Lists, records or other documentation of stakeholder audiences with whom the operator has communicated.
b. Copies of all materials provided to each stakeholder audiences.
c. All program evaluations, including current results, follow-up actions and expected results.

7.3 RECORD RETENTION

The record retention period for each category in Section 7.2 should be a minimum of five (5) years, or as defined in the operator's Public Awareness Program, whichever is longer.

8 Program Evaluation

This section provides guidance to operators on how to periodically evaluate their Public Awareness Programs. The overall written plan for the Public Awareness Program should include a section describing the operator's evaluation program that includes the baseline elements described in the following paragraphs. Also included are suggestions for operators to consider in periodically supplementing their evaluation efforts in a particular segment, with a selected stakeholder audience or to provide greater depth of evaluation. This section includes only a brief description of each element. Appendix E provides additional explanations and examples for operator personnel who are new to developing Public Awareness Program evaluations.

8.1 PURPOSE AND SCOPE OF EVALUATION

The primary purposes of the evaluation of the Public Awareness Program are to:

- Assess whether the current program is effective in achieving the objectives for operator Public Awareness Programs as defined in Section 2.1 of this RP, and
- Provide the operator information on implementing improvements in its Public Awareness Program effectiveness based on findings from the evaluation(s).

A secondary purpose for Public Awareness Program evaluation is to demonstrate to company management and regulators, for pipelines subject to federal or state pipeline safety jurisdiction, the status and validity of the operator's Public Awareness Programs.

8.2 ELEMENTS OF EVALUATION PLAN

A program evaluation plan should include the measures, means and frequency for tracking performance. The selected set of measures should reflect:

- Whether the program is being implemented as planned—**the process**
- Whether the program is effective—**program effectiveness**.

Based on the results of the evaluation addressing these two questions, the operator may need to make changes in the program implementation process, stakeholder identification effort, messages, means and/or frequency of delivery. The sections below suggest specific measures and methods recommended to complete a baseline evaluation of the Public Awareness Program.

8.3 MEASURING PROGRAM IMPLEMENTATION

The operator should complete an annual audit or review of whether the program has been developed and implemented according to the guidelines in this RP. The purpose of the audit is to answer the following two questions:

- Has the Public Awareness Program been developed and written to address the objectives, elements and baseline schedule as described Section 2 and the remainder of this RP?
- Has the Public Awareness Program been implemented and documented according to the written program?

Appendix E includes a sample set of questions that will aid an operator in auditing the program implementation process.

The operator should use one of the following three alternative methodologies when completing an annual audit of program implementation.

- Internal self-assessments using, for example, an internal working group, or
- Third-party audits where the evaluation is undertaken by a third-party engaged to conduct an assessment and provide recommendations for improving the program design or implementation, or
- Regulatory inspections, undertaken by inspectors working for federal or state regulators who inspect operator pipeline programs subject to pipeline safety regulations.

8.4 MEASURING PROGRAM EFFECTIVENESS

Operators should assess progress on the following measures to assess whether the actions undertaken in implementation of this RP are achieving the intended goals and objectives:

- Whether the information is reaching the intended stakeholder audiences
- If the recipient audiences are understanding the messages delivered
- Whether the recipients are motivated to respond appropriately in alignment with the information provided
- If the implementation of the Public Awareness Program is impacting bottom-line results (such as reduction in the number of incidents caused by third-party damage).

The following four measures describe how the operator should evaluate for effectiveness:

8.4.1 Measure 1—Outreach: Percentage of Each Intended Audience Reached with Desired Messages

This is a basic measurement indicating whether the operator's public awareness messages are getting to the intended stakeholders. A baseline evaluation program should establish a methodology to track the number of individuals or entities reached within an intended audience (e.g., households, excavating companies, local government, and local first responder agencies). Additionally, this measure should estimate the percentage of the stakeholders actually reached within the target geographic region along the pipeline. This measurement will help to evaluate the effectiveness of the delivery methods used.

- **Supplemental measures:** Other indicators that an operator may want to consider tracking as a supplement to measuring program outreach effectiveness include:
  - Track the number of inquiries by phone to operator-personnel or to the public awareness portions of an operator's website (however operators are cautioned that unless such information is specifically sought by the operator, this measure would not define if the caller or website viewer is a member of the target stakeholder audience nor whether this measure includes counts of repetitive website reviewers)
  - Track input received via feedback postcards (often called reply or bounce-back cards) from representatives of the stakeholder audience at events or meetings, sent by mail, or as a result of the operator's canvassing of the rights-of-way
  - Track the number of officials or emergency responders who attend emergency response exercises (this is an indicator of interest and the opportunity to gain knowledge).

8.4.2 Measure 2—Understandability of the Content of the Message

This measure would assess the percentage of the intended stakeholder audience that understood and retained the key information in the message received. This measurement will help to evaluate the effectiveness of the delivery media and

the message style and content. This measurement will also help to assess the effectiveness of the delivery methods used.

- **Pre-test materials:** Operators should pre-test public awareness materials for their appeal and the messages for their clarity, understandability and retain-ability before they are widely used. A pre-test can be performed using a small representative audience, for example, a small sample group of operator employees not involved in developing the Public Awareness Program, a small section of the intended stakeholder audience or others (often referred to as focus groups described more fully in Appendix E).
- **Survey target stakeholder audiences:** An effective method for assessing understandability is to survey the target stakeholder audience in the course of face-to-face contacts, telephone or written surveys. Sample surveys are included in Appendix E. Factors to consider when designing surveys include:
  - Sample size appropriate to draw general conclusions
  - Questions to gauge understandability of messages and knowledge or survey respondent
  - Retention of messages
  - Comparison of the most effective means of delivery.

Program effectiveness surveys are meant to validate the operator's methodologies and the content of the materials used. Upon initial survey, improvements should be incorporated into the program based on the results. Once validated in this initial manner, a program effectiveness survey is only required about every four years. However, when the operator introduces major design changes in its Public Awareness Program a survey to validate the new approaches may be warranted.

An operator may choose to develop and implement its own program effectiveness survey in-house; have a survey designed with the help of third-party survey professionals; or participate in and use the results of an industry group or trade-association survey. If the latter approach is used, the industry or trade-association survey should allow the operator to assess the results relevant to the operator's own pipeline corridors and Public Awareness Programs.

8.4.3 Measure 3—Desired Behaviors by the Intended Stakeholder Audience

This measure is aimed at determining whether appropriate prevention behaviors have been learned and is taking place when needed and whether appropriate response or mitigation behaviors would occur and have taken place. This is a measure of learned and, if applicable, actual reported behavior.

- **Baseline evaluation:** The survey conducted as the means of assessing Measure 2 (above) should be designed to include questions that ask respondents to report on actual behaviors following incidents.
- **Supplemental evaluation:** As a supplement to these measures, operators may also want to assess whether the Public Awareness Program successfully drove other behaviors. Operators may consider the following examples as a supplemental means of assessing this measure:
  - Whether excavators are following through on all safe excavation practices, in addition to calling the One-Call Center
  - The number of notifications received by the operator from the excavation One-Call Center (e.g. is there a noticeable increase following distribution of public awareness materials?)
  - An assessment of first responder behaviors, including the response to pipeline-related calls, and a post-incident assessment to determine whether their actions would be and were consistent with the key messages included in the public awareness communications. Assessments of actual incidents should recognize that each response would require unique on-scene planning and response to specifics of each emergency.
  - Measuring the appropriateness of public stakeholders' responses is also anecdotal but could include tracking whether an actual incident that affected residents was correctly identified and whether reported and personal safety actions undertaken were consistent with public awareness communication.

8.4.4 Measure 4—Achieving Bottom-Line Results

One measure of the "bottom-line results" is the damage prevention effectiveness of an operator's Public Awareness Program and the change in the number and consequences of third-party incidents. As a baseline, the operator should track the number of incidents and consequences caused by third-party excavators. This should include reported near misses; reported pipeline damage occurrences that did not result in a release; and third-party excavation damage events that resulted in pipeline failures. The tracking of leaks caused by third-party excavation damage should be compared to statistics of pipelines in the same sector (e.g. gathering, transmission, local distribution). While third-party excavation damage is a major cause of pipeline incidents, data regarding such incidents should be evaluated over a relatively long period of time to determine any meaningful trends relative to the operator's Public Awareness Program. This is due to the low frequency of such incidents on a specific pipeline system. The operator should also look for other types of bottom-line measures. One other measure that operators may consider is the affected public's perception of the safety of pipelines.

8.5 SUMMARY OF BASELINE EVALUATION PROGRAM

Table 8-1—Summary of Baseline Evaluation Program

The results of the evaluation need to be considered and revisions/updates made in the public awareness program plan, implementation, materials, frequency and/or messages accordingly

Evaluation Approaches	Evaluation Techniques	Recommended Frequency
Self Assessment of Implementation	Internal review, ***or*** third-party assessment ***or*** regulatory inspection	Annually
Pre-Test Effectiveness of Materials	Focus groups (in-house or external participants)	Upon design or major redesign of public awareness materials or messages
Evaluation of effectiveness of program implementation: • Outreach • Level of knowledge • Changes in behavior • Bottom-line results	1. Survey: Can assess outreach efforts, audience knowledge and changes in behavior • Operator-designed and conducted survey, or • Use of pre-designed survey by third-party or industry association, or • Trade association conducted survey segmented by operator, state or other relevant separation to allow application of results to each operator. 2. Assess notifications and incidents to determine anecdotal changes in behavior. 3. Documented records and industry comparisons of incidents to evaluate bottom-line results.	No more than four years apart. Operator should consider more frequent as a supplement or upon major redesign of program.
Implement changes to the Public Awareness Program as assessment methods above suggest.	Responsible person as designated in written Public Awareness Program	As required by findings of evaluations.

APPENDIX A—RESOURCE CONTACT INFORMATION

A.1 Trade Associations

American Petroleum Institute
www.api.org
1220 L Street, NW
Washington, DC 20005

Association of Oil Pipe Lines
www.aopl.org
1101 Vermont Avenue, NW, Suite 604
Washington, DC 20005

American Gas Association
www.aga.org
400 N. Capitol Street, NW
Washington, DC 20001

American Public Gas Association
www.apga.org
11094-D Lee Highway, Suite 102
Fairfax, VA 22030-5014

Interstate Natural Gas Association of America
www.ingaa.org
10 G Street NE, Suite 700
Washington, DC 20002

A.2 Government Agencies

Office of Pipeline Safety
www.ops.dot.gov
Research and Special Programs Administration,
U.S. Department of Transportation
400 Seventh Street, SW, Rm. 7128
Washington, DC 20590-0001

The National Pipeline Mapping System (OPS/DOT)
www.npms.rspa.dot.gov
Research and Special Programs Administration,
U.S. Department of Transportation
400 Seventh Street, SW, Room 7128
Washington, DC 20590-0001

Transportation Safety Institute
www.tsi.dot.gov
Research and Special Programs Administration,
U.S. Department of Transportation
6500 South MacArthur Blvd.
Oklahoma City, OK 73169

Occupational Safety and Health Administration
www.osha.gov
"Hazards Associated with Striking Underground Gas Lines"
www.osha.gov/dts/shib/shib_05_21_03_sugl.pdf

A.3 Private Organizations

Common Ground Alliance
www.commongroundalliance.com

Dig Safely
www.digsafely.com

A.4 Publications

The AGA's Gas Pipeline Technology Committee's GPTC Guide—ASC GPTC Z-380.1

APPENDIX B—EXAMPLES OF STAKEHOLDER AUDIENCES

When a Public Awareness Program is being developed, one of the initial tasks is to identify the audience(s) that should receive the program's messages. Section 3 identified the intended audiences for the operator's Public Awareness Program and included a "Stakeholder Audience Definition Table". This appendix will provide further examples. The four intended "Stakeholder Audiences" include:

- Affected public
- Emergency officials
- Local public officials
- Excavators.

B.1 Stakeholder Audience Identification

Identification of the individual stakeholder audiences (i.e., members of the four target audiences) may be done by any means available to the operator. Several methods are available. Operators may identify their stakeholder audiences on their own or may elect to hire outside consultants who specialize in audience identification. Where lists are developed, they should be kept current or redeveloped prior to effecting a particular communication.

B.1.1 AFFECTED PUBLIC

Some examples of how an operator may determine specific affected public stakeholder addresses along the pipeline, such as within a specified distance either side of the pipeline centerline, include the use of nine-digit zip code address databases and geo-spatial address databases. These databases generally provide only the addresses and not the names of the persons occupying the addresses. Broad communications to this audience are typically addressed to "Resident." It is important to note that when contacting apartment dwellers, individual apartment addresses should be used, not just the address of the apartment building or complex.

Some operators maintain "line lists" which provide current information on names and addresses of people who own property on which the pipeline is located. It should be noted, however, that not all property owners live on the subject property and that the program should address those people living on the property. Additionally, where the operator has a customer base, the operator can use its customer databases for identifying audience members.

For the sub-groups "Residents located along transmission pipeline ROW" and "Places of Congregation," it is recommended that transmission pipeline operators provide communications within a minimum coverage area distance of 660 feet on each side of the pipeline, or as much as 1000 feet in some cases. The transmission pipeline operator should tailor its communications coverage area (buffer) to fit its particular pipeline, location, and potential impact consequences. At a minimum, operators should consider areas of consequence as defined in federal regulations. Where specific circumstances suggest a wider coverage area for a certain pipeline location, the operator should expand the coverage area accordingly.

A sub-set of the affected public that the operator may desire to send specific public awareness materials to is farmers. Farmers engage in deep plowing and clearing activities that could impact pipelines. One method of determining names and addresses of farmers along a pipeline route is the use of third-party vendors who purchase periodicals databases related to the farming and agricultural community. Due to the size of farming operations in some areas and the proximity of farming residents, it is recommended that the operator increase its affected public awareness mailing coverage as appropriate.

B.1.2 EMERGENCY OFFICIALS

There are several methods used by operators to identify the names and addresses of emergency officials. Depending upon the size of the county or parish, this may include all emergency officials in the affected jurisdiction.

The means used by many operators is through the use of SIC (Standard Industrial Classification) code. Where SIC codes are utilized to identify emergency officials, the operator should include the list of code categories applicable to the emergency officials stakeholder group.

The pipeline operator should consider all appropriate emergency officials who have jurisdiction along the pipeline route and should communicate with any emergency officials that the operator deems appropriate for a given coverage area. This will generally include all emergency officials whose jurisdictions are traversed by the pipeline.

B.1.3 LOCAL PUBLIC OFFICIALS

Operators use several methods to identify names and addresses for specific public officials. These primarily include the use of local company resources, local phone books, and the Internet. Where SIC codes are used to identify public officials, the operator should include the categories applicable the public officials stakeholder group.

B.1.4 EXCAVATORS

While "excavators" is a broad category, its use here is intended to identify companies that perform or direct excavation work. Operators should identify, on a current basis, persons who normally engage in excavation activities in the areas in which the pipeline is located. There are several methods used by pipeline operators to identify specific excavator stakeholder names and addresses.

Where SIC codes are used to identify excavators, the operator should include the categories applicable to the Excavator stakeholder group. The SIC/NAICS list should be considered the minimum for excavator audience identification where those codes are used. The operator may add to or expand the list as other excavator information becomes available. Another source for identifying excavators is the One-Call Center that covers the area designated by the Public Awareness Program. Several One-Call Centers provide "excavator lists" to their members. This may also be accomplished by the use of a third-party vendor who specializes in this service.

APPENDIX C—DETAILED GUIDELINES FOR PUBLIC AWARENESS MESSAGES

Section 4 of this RP recommends that an operator should select the optimum combination of message, delivery method, and frequency that meets the needs of the intended audience. This appendix expands that recommendation by providing further explanation or examples of the content of messages to be communicated.

Information materials may include supplemental information about the pipeline operator, pipeline operations, the safety record of pipelines and other information that an operator deems appropriate for the audience. The operator is reminded that communications materials should be provided in the language(s) spoken by a significant portion of the intended audience.

The basic message is conveyed to the intended audience should provide information that will allow the operator to meet the program objectives set forth in Section 2. The communications should include enough information so that in the event of a pipeline emergency, the intended audience members will know how to identify a potential hazard, protect themselves, notify emergency response personnel, and notify the pipeline operator.

C.1 Pipeline Purpose and Reliability

While not a primary objective, pipeline operators should consider providing general information about pipeline transportation, such as:

- The role of pipelines in U.S. energy supply
- Pipelines as part of the energy infrastructure
- Efficiency and reliability of pipelines
- Positive messages about the energy transportation pipeline safety record
- The individual operator's pipeline safety actions and environmental record.

For local distribution companies:

- Typical distribution network (stations, mains, services, meters)
- How to detect a natural gas leak (e.g., how natural gas smells)
- Who uses natural gas and why.

Many of these messages are available in print and videos from the pipeline industry trade associations listed in Section 2 and Appendix A.

The operator should describe the purpose and function of the pipeline and/or associated facilities and the nature, uses, and purposes of the products transported. Where practical, it might be helpful to communicate the benefit(s) of the pipeline to the community. Examples of "benefits" include:

- "This pipeline provides gasoline to motorists at X gas stations in the area of Y."
- "This natural gas pipeline network provides gas to X thousands of homes and businesses in Y city or Z state."

Pipelines are a safe and reliable means of transporting energy. Where appropriate, operators should describe how pipelines are a reliable means of transporting energy products and point out that they are extensively regulated by Federal and State regulations with regard to design, construction, operation and maintenance. Operators may also describe applicable operational activities that promote pipeline integrity, safety and reliability, which could include initial and periodic testing practices, internal inspections and their frequency, patrolling types and frequencies, and other such information. Operators may also reference the National Transportation Safety Board finding that pipelines provide the highest level of public safety as compared to other transportation modes.

C.2 Hazard Awareness and Prevention Measures

C.2.1 OVERVIEW OF POTENTIAL HAZARDS

General information about the nature of hazards posed by pipelines should be included in the message, while also assuring the stakeholder audience that accidents are relatively rare. The causes of pipeline failures, such as third-party excavation damage, corrosion, material defects, worker error, and events of nature can also be communicated.

C.2.2 OVERVIEW OF POTENTIAL CONSEQUENCES

Information should identify the product release characteristics and potential hazards that could result from an accidental release of hazardous liquids or gases from the pipeline.

C.2.3 SUMMARY OF PREVENTION MEASURES UNDERTAKEN

The potential hazard message should be coupled with a general overview of the preventative measures undertake by the operator in the planning, design, operation, maintenance, inspection and testing of the pipeline. This message should also reinforce how the stakeholder audience can play an important role in preventing third-party damage and right-of-way encroachments.

C.2.4 OPTIONAL SUMMARY OF PIPELINE INDUSTRY SAFETY RECORD

Depending on the stakeholder audience and the delivery methods used, the operator may want to consider including a general overview of the industry's safety record.

Communication materials should also convey the qualification that the information provided on hazards, consequences and preventative measures is very general and that more specific information could be obtained from the operator or other sources (noting phone or website(s) for contacts). Information communicated to emergency responders needs to be more specific, provide an opportunity for two-way feedback and include additional details on the products transported, facilities located within the jurisdiction and the local emergency planning liaison. Operators may want to consider referring to publications or websites produced by the trade associations listed in Appendix A for specific example language developed to provide overviews of hazards, consequences and preventative measures tailored to each stakeholder audience.

C.3 Leak Recognition and Response

The pipeline operator should provide the following information to the affected public and excavator stakeholder groups. To accomplish this, operators may want to consider using generic or standard printed materials developed by trade associations as aides for their member companies. However, operators will need to ensure the materials used are specific to the type of pipeline and product(s) transported in their systems.

C.3.1 POTENTIAL HAZARDS

Specific information about the release characteristics and potential hazards posed by the accidental release of hazardous liquids or gases from the pipeline should be included in the operator's communications.

C.3.2 RECOGNIZING A PIPELINE LEAK

Operators should include in their communications information on how to recognize a pipeline leak through the senses of sight, unusual sound, and smell (as appropriate to the product type) and describe any associated dangers.

- By Sight—What to Look for...
- By Sound—What to Listen for...
- By Smell—What to Smell for...

C.3.3 RESPONDING TO A PIPELINE LEAK

Operators should include in their communications an outline of the appropriate actions to take once a pipeline leak or release is suspected. This information should include:

- What to do if a leak is suspected
- What not to do if a leak is suspected.

It is especially important to include specific information on detection response if the pipeline contains product that, when released, could be immediately hazardous to health (e.g. high concentration of hydrogen sulfide).

C.3.4 LIAISON WITH EMERGENCY OFFICIALS

This information should indicate that both the operator and the local emergency response officials have an ongoing relationship designed to prepare and respond to an emergency.

C.4 Emergency Preparedness Communications

Communicating periodically with local emergency officials is an important aspect of all Public Awareness Programs. The following information should be provided to the emergency officials stakeholder audience. Local public officials should be provided a summary of the information that is available in more detail from the emergency response agencies in their jurisdictions.

C.4.1 PRIORITY TO PROTECT LIFE

Operator emergency response plans and key messages relayed to emergency officials should emphasize that public safety and environmental protection are the top priorities in any pipeline emergency response.

C.4.2 EMERGENCY CONTACTS

Contact information on the operator's local offices and 24-hour emergency telephone numbers should be communicated to local and state emergency officials. Operators should also use the public awareness contact opportunity to confirm the contact information for the local and state emergency officials and calling priorities.

C.4.3 EMERGENCY PREPAREDNESS—RESPONSE PLANS

Operators are required by federal regulation to have emergency response plans. These plans should be developed for use internally and externally, with appropriate officials, and in accordance with applicable federal and state regulations. 49 *CFR* 192 and 194 and some state regulations outline the specific requirements for emergency response plans. In developing Emergency Response Plans, the operator should work with the local emergency responders to enhance communications and response to emergencies.

C.4.4 EMERGENCY PREPAREDNESS—DRILLS AND EXERCISES

A very effective means of two-way communication about emergency preparedness is the liaison with emergency officials through operator or joint emergency response drills, exercises or deployment practices. Information on "unified command system" roles, operating procedures and preparedness for various emergency scenarios can be communicated effectively and thoroughly through a hands-on drill or exercise.

C.5 Damage Prevention

Because even relatively minor excavation activities (for example: installing mail boxes, privacy fences and flag poles, performing landscaping, constructing storage buildings, etc.) can cause damage to a pipeline or its protective coating or to other buried utility lines, it is important that operators raise the awareness of the need to report any suspected signs of damage. Operators should keep their damage prevention message content consistent with the damage prevention best practices developed by the Common Ground Alliance (CGA).

The use of an excavation One-Call Notification system should be explained to the audience. The audience should be reminded to call the state or local One-Call System before beginning any excavation activity and that in most states it is required by law. Information on the prevalence of "third-party" damage should be provided as appropriate. If the state or locality has established penalties for failure to use established damage prevention procedures, that information may also be communicated, depending on the audience and situation.

As a baseline practice, excavation and one-call Information should include:

- Request that everyone contact the local One-Call System before digging
- Explain what happens when the One-Call Center is notified
- Provide the local or toll-free One-Call Center telephone numbers
- Explain that the one-call locate service is typically free (Note: Some exceptions by state)
- Remind, if applicable, that to call is required by law.

One-Call Center telephone numbers for all 50 states can be found at the Dig Safely website or by calling the Dig Safely national referral number at 1-888-258-0808.

The "Dig Safely" message should be included in public awareness materials distributed to the affected public and excavators by the operator in its communications:

- Call the One-Call Center before digging
- Wait for the site to be marked
- Respect the marks
- Dig with care.

For information see the "Dig Safely" website listed in Appendix A. Operators may also consider use of the widely recognized "No Dig" symbol in their materials.

C.6 Pipeline Location Information

C.6.1 TRANSMISSION PIPELINE MARKERS

The audience should know how to identify transmission pipeline rights-of-way by recognition of pipeline markers—especially at road crossings, fence lines and street intersections. Communications should include what pipeline markers look like, and the fact that telephone numbers are on the markers for their use if an emergency is suspected or discovered. Communications should also be clear that pipeline markers do not indicate the exact location or depth of the pipeline and may not be present in some areas.

Public awareness materials should include illustrations and descriptions of pipeline markers used by the operator and the information that the markers contain. Displaying the penalties for removing, defacing, or otherwise damaging a pipeline marker may also be beneficial.

In addition to meeting applicable federal and state regulations, transmission pipeline markers may:

- Indicate a pipeline right-of-way (not necessarily the exact pipeline location)
- Identify the product(s) transported
- Provide the name of the pipeline operator
- Provide the operator's telephone number, available 24-hours a day and 7-days a week
- Be brightly colored and highly visible
- Have weather resistant paint and lettering
- Include "Warning Petroleum Pipeline" or "Warning Gas Pipeline" and show the universal "No Dig" symbol
- Provide a one-call number.

Additional guidance for liquid pipeline marker design, installation, and maintenance is provided in API Recommended Practice 1109.

C.6.2 TRANSMISSION PIPELINE MAPPING

Transmission pipeline maps can be an important component of an operator's Public Awareness Program. The level of detail in the map provided will be relevant to the stakeholder's need, taking security of the energy infrastructure into consideration.

Members of the general public can also receive information about operators who have pipelines that might be located in their community by accessing the National Pipeline Mapping System (NPMS) on the Internet. The NPMS will provide the inquirer a list of pipeline operators and contact information for operators having pipelines in a specific area. Inquiries are made by zip code or by county and state. Operators should include information on the availability of the NPMS within their public awareness materials.

Following is a summary of the types of maps that are referred to in this RP in describing how operators can incorporate pipeline maps in their efforts to improve public awareness.

- *System Maps*—Typically system maps provide general depiction of a pipeline transmission system shown on a state, regional or national scale. This type of map generally is not at a scale that poses security concerns and is often used by operators in a number of publications available to the industry and general public. A system map generally depicts a portion of the pipeline system

shown in relationship to a region of the country. Generally these types of maps do not include any detail on the location of facilities.

- *General Maps*—General maps are another form of system map, which may be presented, in a more graphical format or smaller scale.
- *Local Maps*—Local maps are generally shown on a neighborhood, town, city or county level and usually do not show the entire pipeline system. Local maps are especially appropriate in communication with local emergency officials, One-Call Centers and elected public officials. Local maps should be distributed in accordance with regulatory or operator's company security guidelines. Local maps could include pipeline alignment maps, GIS-system produced maps, or other types of mapping that show more detail about the physical location of the pipeline system.
- *Community Pipeline Infrastructure*—Maps of communities that depict all of the natural gas and liquid transmission pipeline systems in the area. Available from the state or OPS to public and emergency officials.
- *National Pipeline Mapping System (NPMS)*—The U.S. Department of Transportation's Office of Pipeline Safety has developed the National Pipeline Mapping System, through which pipeline location maps are made available electronically to state and local emergency officials, in accordance with federal security measures.

Operators of transmission pipelines should make available appropriate system or general maps to the affected public and provide them guidance in how they can determine the location of the pipelines near where they live and work. Such maps should include company and emergency contact information and a summary of the type of products transported.

As part of the damage prevention program, all operators should also communicate the process for contacting the excavation One-Call System so that the specific location of the pipeline (and other nearby utilities) can be marked prior to excavation activity.

Operators of transmission pipelines should make available local maps to public and emergency officials in their effort to assure effective emergency preparedness and land use planning. In addition, operators must follow regulatory guidelines on providing such maps as required under 49 *CFR* Part 192 and 195. Maps should include company and emergency contacts, information on the type of products transported, and sufficient detail on landmarks, roads or location information relevant to the official's needs.

Operators should provide paper or digitized maps, or alternative information to the state or regional excavation One-Call Center, consistent with the One-Call System's requirements.

C.7 High Consequence Areas and Integrity Management Program (IMP) Overview for Transmission Pipelines

C.7.1 MESSAGE CONTENT FOR AFFECTED PUBLIC WITHIN HCAs

Information materials should include a message about where more information about High Consequence Area (HCA) designations and overviews of Integrity Management Program (IMP) Plans for transmission pipelines can be obtained. Guidelines for developing overviews of IMPs will be developed by the industry. The information should make system maps of HCAs available to the general or affected public. An overview of an operators IMP should include a description of the basic requirements and components of the program and does not need to include a summary of the specific locations or schedule of activities undertaken. The summary may only be a few pages long and its availability could be mailed upon request or made available on the operator's website.

C.7.2 MESSAGE CONTENT FOR EMERGENCY OFFICIALS WITHIN HCAs

When conducting liaison activities with emergency officials required by the public awareness plan, operators should include information on how the emergency official may gain access to the National Pipeline Mapping System for their jurisdiction through the Office of Pipeline Safety. In addition, the operator may supplement their messages and materials by including overviews of IMPs and specifically solicit feedback from the emergency official about local conditions or activities that may be useful and/or prompt changes to the operator's IMP for that area. For example, mitigation measures that may be included in a HCA segment's risk analysis and action plan is supplemental emergency response planning, staging area identification or equipment deployment. A two-way discussion with emergency officials of the components of the HCA risk mitigation plan would be helpful.

C.7.3 MESSAGE CONTENT FOR PUBLIC OFFICIALS WITHIN HCAs

Information materials should include a message about where more information about High Consequence Area (HCA) designations and overviews of IMPs for transmission pipelines can be obtained. Guidelines for developing overviews of IMPs will be developed by the industry.

An overview of an operator's IMP plan should include a description of the basic requirements and does not need to include a summary of the specific locations or schedule of activities undertaken. The overview may only be several pages long and its availability could be mailed upon request or made available on the operator's website.

C.8 Content on Company Websites

The information listed below will guide pipeline operators who maintain websites on the recommended informational components to be included on the website.

C.8.1 COMPANY INFORMATION

In addition to describing the purpose of the pipeline and markets served, the website should include a general description of the pipeline operator and system. This could include:

- Operator and owner name(s)
- Region and energy market served
- General office and emergency contacts telephone numbers and e-mail addresses
- Products being transported by pipeline
- System or general map and location of key offices (headquarters, region or districts).

C.8.2 INFORMATION ON PIPELINE OPERATIONS

A broad overview of the operator's pipeline safety and integrity management approach should be included describing the various steps the company takes to ensure the safe operation of its pipelines. While not specifically recommended, additional information to consider for the website includes:

- General pipeline system facts
- An overview of routine operating, maintenance and inspection practices of the system
- An overview of major specific inspection programs and pipeline control and monitoring programs.

C.8.3 TRANSMISSION PIPELINE MAPS

A general or system map (see previous section describing types of maps) should be on the website. Details on how to obtain additional information should be provided, including reference to the National Pipeline Mapping System ((NPMS).

C.8.4 PUBLIC AWARENESS PROGRAM INFORMATION

The operator should include a summary of its Public Awareness Program developed under the guidance of this RP and should consider including printed material used in these efforts on the website. The public should also be provided information on company contacts to request additional information.

C.8.5 EMERGENCY INFORMATION

The website should contain emergency awareness information from two aspects. First, it should contain a summary of the operator's emergency preparedness. Second, it should contain information about how the public, and residents along the pipeline rights-of-way, and/or public officials should help protect, recognize, report and respond to a suspected pipeline emergency. Emergency contact information should be prominent and accessible from anywhere on the pipeline portion of the website.

C.8.6 DAMAGE PREVENTION AWARENESS

Pipeline operators are encouraged to either provide or link the viewer to additional guidance on preventing excavation damage, such as "Dig Safely" program information, contact information for the One-Call System in each of the states in which the operator has pipelines, and the "Common Ground Alliance" website noted in Appendix A.

C.9 Right-of-way Encroachment Prevention

Pipeline operators should communicate that encroachments upon the pipeline right-of-way inhibit the operator's ability to reduce the chance of third-party damage, provide right-of-way surveillance and perform routine maintenance and required federal/state inspections. The communication can describe that in order to perform these critical activities, pipeline maintenance personnel must be able to access the pipeline right-of-way, as provided in the easement agreement. It should also describe that to ensure access; the area on either side of the pipeline contained within the right-of-way must be maintained clear of trees, shrubs, buildings, fences, structures, or any other encroachments that might interfere with the operator's access to the pipeline. It should also point out that the landowner has the obligation to respect the pipeline easement or right-of-way by not placing obstructions or encroachments within the right-of-way, and that maintaining a pipeline right-of-way free of encroachments is an essential element of maintaining pipeline integrity and safety.

Residents, excavators, and land developers should be requested to contact the pipeline operator if there are questions concerning the pipeline or the right-of-way, especially if property improvements or excavations are planned that might impact the right-of-way. These audiences should also be informed that they are required by state law to provide at least 48 hours advance notice, more in some states, to the appropriate One-Call Center prior to performing excavation activities. Longer lead times for planning major projects are advised and sometimes required by state law.

Operators should consider communicating with local authorities regarding information concerning effective zoning and land use requirements/restrictions that will protect existing pipeline rights-of-way from encroachment. Communications with local land use officials could include consideration of:

- How community land use decisions (e.g. planning, zoning,) can impact community safety
- Establishing setback requirements for new construction and development near pipelines

- Requiring prior authorization from easement holders in the permit process so that construction/development does not impact the safe operation of pipelines
- Requiring pipeline operator involvement in road widening or grading, mining, blasting, dredging, and other activities that may impact the safe operation of the pipeline.

C.10 Communication of Pipeline Maintenance Activities

When planning pipeline maintenance-related construction activities, operators should communicate to the audience affected by the activity in a manner that is appropriate to the nature and extent of the activity. For major maintenance construction projects (such as main-line rehabilitation or replacement projects) operators should also notify appropriate emergency and local public officials and include information on further communications appropriate to the nature or local impact of the maintenance or construction activity. Operators should communicate appropriately in accordance with requirements associated with the acquisition of permits.

C.11 Security

Operators should include in their communications, where applicable, appropriate information pertaining to security of their pipelines and related facilities. Communications messages could include:

- General information about the pipeline or aboveground facility security measures
- Increased public awareness about security
- Communications to pipeline and facility neighbors to:
  - Become familiar with the pipelines in their area (identification via pipeline marker signs)
  - Become familiar with the pipeline facilities in their area (identification via fence signs at gated entrances)
  - Record the operator name, contact information and any pipeline information from nearby pipeline marker signs or facility signs and keep in a permanent location near the telephone
  - Be observant for any unusual or suspicious activities and unauthorized excavations taking place within or near the pipeline right-of-way or pipeline facility. Report such activities to their local law enforcement and the pipeline operator.

Pipeline neighbors are the operator's first line of defense against unauthorized excavation and other such activity in the right-of-way, and they can help by contacting the operator or the proper local authorities of suspicious activities if they have contact information available.

C.12 Facility Purpose

Communication with the affected public, emergency and public officials in proximity of major facilities (such as storage facilities, compressor or pump stations) should include an understanding of the nature of the facility. Operators should include in their communications general information about the facility and the product(s) stored or transported through the facility. Liaison with emergency officials should also include an understanding of emergency contact information for the specific facility.

APPENDIX D—DETAILED GUIDELINES FOR MESSAGE DELIVERY METHODS AND/OR MEDIA

Section 5 describes the delivery methods and tools available to pipeline operators to foster effective communication programs with the stakeholder audiences previously described. This Appendix expands on those guidelines by providing further explanation or examples of delivery methods and/or media. This section does not imply that all methods are effective in all situations. The content of the communication efforts should be tailored to the needs of the audience and the intent of the communication. Refer to Section 4 for a detailed description of the message content that the following materials or delivery methods should contain for each intended audience.

D.1 Print Materials

The use of print materials is an effective means of communicating with intended audiences. Because of the wide variety of print materials, operators should carefully select the type, language and formatting based on the audiences and the message to be delivered. Generally, an operator will use more than one form of print materials in its Public Awareness Program. While not all inclusive, several types are discussed here.

D.1.1 TARGETED DISTRIBUTION OF PRINT MATERIALS

This is the most common message delivery mechanism currently used by the pipeline industry. Print materials can convey important information about the company, the industry, pipeline safety, or a proposed project or maintenance activity and should provide contact information where the recipient can obtain further information. Print materials also afford an effective opportunity to communicate content in a graphical or pictorial way. However, note that targeted distribution of print materials alone should not be considered effective communication with local emergency response personnel.

Consideration should be given to joining with other pipeline companies in a local, regional or national setting (including both the local distribution company and transmission pipelines) to produce common message materials that can be either jointly sponsored, (e.g., include all sponsors company names/logos) or used as a "shell" and then customized to each company's individual needs, to help ensure that a consistent message is being delivered. This approach can also effectively reduce the cost to individual operators.

Print materials can be mailed to residents or communities along the pipeline system or handed out at local community fairs, open houses, or other public forums. Operators can hire facilitators to organize mass mailings, using nine-digit zip codes or geo-spatial address databases; to designated residents in the community located along the pipeline, such as within an appropriate distance either side of the pipeline centerline. In this case it is often advisable to get information from the postal service or service provider on size, folding and closure requirements to minimize the postage costs for mass mailings. There are services that can handle the printing of materials, mailing address identification, mailing and documentation for the operator as a package.

D.1.2 LETTERS

Research has indicated that letters mailed to residents along a pipeline system are an effective tool for the operator to use to communicate specific information, such as what to do in the event of a leak, identification of suspicious activity or notification of planned maintenance activities within the right-of-way.

Notification letters are usually effective where there is a high likelihood for third-party damage such as in agricultural areas, new developments and where other types of ground-disturbing activities may take place. Similar letters may also be send to contractors, excavators and equipment rental companies informing them of the requirement to use One-Call Systems and providing other important safety information for their workers and the public.

Letters, along with other print materials, should provide information about where the recipient can obtain further information (such as website address, e-mail address, local phone numbers and one-call numbers).

D.1.3 PIPELINE MAPS

Pipeline maps can be presented as printed material and are an important component of an operator's Public Awareness Program. The operator should consider whether maps should be part of the communications to appropriate local stakeholder(s), and what type of maps should be used to accomplish the objective. See Appendix C.6.2 for further explanation of types and availability of maps.

D.1.4 RESPONSE CARDS

Often referred to as either bounce back cards or business reply cards, these preprinted, preaddressed, postage paid response cards are often mailed to the affected public as an integral part of, or as an attachment to, other print materials. When delivering public awareness information to nearby resi-

dents, public or emergency officials, the inclusion of response cards can be used in a variety of ways:

- To maintain/update current mailing lists. Response cards permit the recipients to notify the operator of any changes in address
- To provide a convenient venue for recipients to provide comments, request additional information, raise concerns or ask questions
- To help evaluate the effectiveness of the operator's Public Awareness Program.

D.1.5 BILL STUFFERS

Bill stuffers are printed materials frequently used by local distribution companies (LDCs) in conjunction with invoice mailings to their customers. Due to the nature of their customers, these are not an appropriate option for transmission and gathering pipelines. LDCs using bill stuffers can increase the effectiveness of their programs by communicating to their active customers frequently through the repeated use of bill stuffers. For those LDCs that are combined with other energy utilities such as electric or water systems, bill stuffers regarding pipeline safety and underground damage prevention can be delivered to virtually all surroundings residents, even when some may not be natural gas customers.

D.2 Personal Contact

Personal contact describes face-to-face contact between the operator and the intended stakeholder audience. This method is usually a highly effective form of communication, and it allows for two-way discussion. This may be done on an individual basis or in a group setting. Some examples of communications through personal contact are described below:

D.2.1 DOOR-TO-DOOR CONTACT ALONG PIPELINE RIGHT-OF-WAY

This method is often used to make contact with residents along the pipeline right-of-way to relay pipeline awareness information or information on upcoming pipeline maintenance. This method can help to build stakeholder trust, which is an integral part of communication and an enhancement to the long-term Public Awareness Program. Operator representatives conducting door-to-door contact should be knowledgeable and courteous, be prepared for these types of communications and be able to discuss and respond to questions relating to the communication materials provided so that contact is meaningful and positive. They should provide the landowner/resident with basic pipeline safety information and a means for future contact.

If pipeline safety is to be discussed in this forum, the operator representative should be generally knowledgeable about the company's pipeline integrity program and emergency response procedures. In addition to the general information described in Section 4, the following additional information should also be considered:

a. Description of facilities on or near the property (i.e., pipelines, meter/regulator stations, compressor/pump stations, wellheads, treating facilities, tankage, line markers, cathodic protection, communication, etc.)
b. Description of easement and property owner's rights and limitations within the easement
c. Name and phone number of local contact within company for further information and the operator's emergency notification number to report emergencies or suspicious activity
d. Information on damage prevention and local "Call Before You Dig" programs
e. What to do in case of emergency (fire, leak, noise, suspicious person)
f. Informational items (i.e., calendar, magnetic card, pens, hats, etc.) to retain important telephone numbers
g. As appropriate, additional local information such as upcoming maintenance, projects, events and/or company community involvement such as United Way, other charities, environmental projects, etc.

D.2.2 TELEPHONE CALLS

When the intended audience is small in number, the operator may find it effective to communicate by telephone. This personal form of contact allows for two-way discussion. The operator should decide which elements of their Public Awareness Program are suitable for conducting via telephone calls.

D.2.3 GROUP MEETINGS

Group meetings can be an effective way to convey the messages to selected audiences. Meetings may be between the operator (or group of operators) and an individual stakeholder audience or between the operator (or group of operators) and a number of the stakeholder audience groups at one time.

For example, the operator could conduct individual meetings with emergency response officials, combined industry meetings with emergency response officials, and participation by emergency response officials and personnel in the operator's emergency response tabletop drills and deployment exercises. Meetings are particularly effective in conducting liaison activities with the emergency official stakeholder group.

Another example is group meetings conducted by the operator in classrooms and with educators at local schools. Informational materials can be presented to school administrators and students and can contain important public awareness messages for students to take home to their parents. This method of personal contact can readily reach a large number of people with the operator's public awareness messages and reinforce positive messages about the operator and/or the pipeline industry.

Additional group meetings could include those with state One-Call System events, local excavators, contractors, land developers, and municipalities.

D.2.4 OPEN HOUSES

Operators often hold open houses to provide an informal setting to introduce an upcoming project, provide a "get to know your neighbor" atmosphere or to discuss an upcoming maintenance activity such as pipeline segment replacement. Tours of company facilities, question and answer sessions, videos, or presentations about pipeline safety and reliability do well in an open house environment. Even without formal presentations, allowing the public to see the facility can also be very effective. Often this type of forum would include refreshments and handouts (e.g. print material, trinkets, etc.) that attendees can take with them. Targeted or mass mailings can be used to announce planned open houses and can, in themselves, communicate important information.

D.2.5 COMMUNITY EVENTS

Community sponsored events, fairs, charity events, or civic events may provide appropriate opportunities where public awareness messages can be communicated to the event participants. Companies can participate with a booth or as a sponsor of the event.

These forums are generally used to remind the community of the operator's presence, show support for community concerns, and heighten public awareness about the benefits of pipeline transportation and about pipeline safety. Examples of community events include:

- County and state fairs
- Festivals and shows
- Job fairs
- Local association events
- Trade shows (Energy Fair)
- Chamber of Commerce events.

Operators should plan in advance and secure a large number of handout materials; as such events often include a large number of attendees and can take place over several days.

D.2.6 CHARITABLE CONTRIBUTIONS BY PIPELINE OPERATORS

While contributions to charities and civic causes are not in themselves a public awareness effort, companies should consider appropriate opportunities where public awareness messages can be conveyed as part of or in publicity of the contribution. Examples include:

- Contribution of gas detection equipment to the local volunteer fire department
- Donation of funds to acquire or improve nature preserves or green space
- Sponsorship to the community arts and theatre
- Support of scholarships (especially when to degree programs relevant to the company or industry)
- Sponsorship of emergency responders to fire training school.

D.3 Electronic Communications Methods

D.3.1 VIDEOS AND CDs

There are a variety of approaches companies may use to supplement their delivery tools with videos. While a supplement to the baseline components of an effective Public Awareness Programs, videos may be quite useful with some stakeholders or audiences in some situations. Videos can show activities such as construction, natural gas or petroleum consumers, pipeline routes, preventive maintenance activities, simulated or actual spills and emergency response exercises or actual response that printed materials often cannot. Companies may seek industry specific videos from trade organizations or develop their own customized version. Such videos can be used for landowner contacts, emergency official meetings, or the variety of community or group meetings described elsewhere in this section. Companies could also consider adding such videos to their company websites.

D.3.2 E-MAIL

Electronic mail ("e-mail") can be a means of sending public awareness information to a variety of stakeholders. The content and approach is similar to letters or brochures, but the information is sent electronically rather than delivered by mail, by person or in meetings.

E-mail contact information can be provided on company handouts, magazine advertisements, websites and other written communications. This provides an effective mechanism for the public to request specific information or to be placed on distributions lists for specific updates.

An advantage of e-mail is the ease of requesting and receiving return information from the recipient, similar to contact information, survey or feedback described in bounce-back cards explained above. Note that it is important for the operator to designate a response contact within the organization to handle follow-up responses to e-mail queries in a timely manner.

D.4 Mass Media Communications

D.4.1 PUBLIC SERVICE ANNOUNCEMENTS (PSAs)

Radio and television stations occasionally make airtime available for public service announcements. There is great competition from various public interest causes for the small amount of time available because the broadcast media is no longer required by law to donate free airtime for PSAs. Given the popularity of radio and television and the large areas cov-

ered by both, public service announcements can be an effective means for reaching a large sector of the public. Pipeline operators (or groups of pipeline operators) could consider contacting local stations along the pipeline route to encourage their use of the PSAs. The use of cable TV public access channels may also be an option.

D.4.2 NEWSPAPERS AND MAGAZINES

Newspaper and magazine articles don't have to be limited to the reactive coverage following an emergency or controversy. Pipeline operators can encourage reporters to write constructive stories about pipeline issues in various topics of relevance, such as local projects, excavation safety, or the presence of pipelines as part of the energy infrastructure. Even if the reporter is covering an emergency or controversial issue, pipeline operators can leverage the opportunity to reinforce key safety information messages such as damage prevention and the need to be aware of pipelines in the community. Trade magazines such as those for excavators or farmers often welcome guest articles or submission or assistance in writing a positive, safety-minded story for their readers. Local weekly newspapers and "metro" section inserts will sometimes include a news release verbatim at no cost to the sender.

D.4.3 PAID ADVERTISING

The use of paid advertising media such as television ads, radio spots, newspapers ads, and billboards can be an effective means of communication with an entire community. This type of advertising can be very expensive, but can be made more cost effective by joining with other pipelines, including the local utilities, to deliver a consistent message. One example is placement of a public awareness advertisement on a phone book cover, thus achieving repetitive viewing by the audience for a whole year. Another example is advertising in local shopping guides.

D.4.4 COMMUNITY AND NEIGHBORHOOD NEWSLETTERS

Information provided should be similar to that made available for newspapers and magazines. Posting of pipeline safety or other information to community and neighborhood newsletters can be done in conjunction with outreach to those communities and/or neighborhoods and is usually done for free. Operators can also develop their own newsletters tailored to specific communities. These newsletters can be used to highlight the operator's involvement in that community, provide the operator's public awareness messages, and to address any pipeline concerns that community may have.

This method can be particularly effective in reaching audiences near the pipeline, namely neighborhoods and subdivisions through which the pipeline traverses.

D.5 Specialty Advertising Materials

Company specialty advertising can be a unique and effective method to introduce a company or maintain an existing presence in a community. These tools also provide ways of delivering pipeline safety messages, project information, important phone numbers and other contact information. Many such materials or items exist, including refrigerator magnets, calendars, day planners, thermometers, key chains, flashlights, hats, jackets, shirts, clocks, wallet cards, and other such items containing a short message (i.e. "Call Before You Dig"), the company logo and/or contact information. The main benefit of this type of advertising is that it tends to have a longer retention life than printed materials because it is otherwise useful to the recipient. Because of the limited amount of information that can be printed on these items, they should be used as a companion to additional printed materials or other delivery methods.

D.6 Informational Items

Operators can develop (or participate in industry associations or along with other companies) informational materials for groups or schools that heighten pipeline awareness. Operators (and their industry associations) may also sponsor or develop training materials for emergency response agencies that are designed to increase knowledge and skills in responding to pipeline emergencies. Alternatively, local emergency officials will hold training as part of their own continuing education, and attendance by pipeline personnel at these sessions is often welcome and an ideal setting for relaying public awareness information about pipelines.

D.7 Pipeline Marker Signs

The primary purposes of above ground transmission pipeline marker signs are to:

- Mark the approximate location of a pipeline
- Provide public awareness that a buried pipeline or facility exists nearby
- Provide a warning message to excavators about the presence of a pipeline or pipelines
- Provide pipeline operator contact information in the event of a pipeline emergency
- Facilitate aerial or ground surveillance of the pipeline right-of-way by providing aboveground reference points.

Refer to Section 4 for additional information on marker sign types and information content.

Below ground markers are also effective warnings. While some may not consider this part of a proactive public awareness communication program, buried warning tape or mesh can be an effective reminder to excavators of the presence of underground utilities and have proven effective in preventing damage to pipelines and other buried utilities.

D.8 One-Call Center Outreach

Most state One-Call Centers provide community outreach or implement public awareness activities about the one-call requirements and the Dig Safely awareness messages, as discussed in Section 4. Pipeline operators should encourage One-Call Centers to provide those public awareness communications and can account for such Public Awareness Programs within their own Public Awareness Program. Some One-Call Centers focus on hosting awareness meetings with excavators to further promote the Dig Safely and One-Call Messages. It is the operator's responsibility to request documentation for these outreach activities.

In order to enhance Dig Safely and one-call public awareness outreach by One-Call Centers, operators are required by 49 *CFR* Parts 192 and 195 to become members of one-call organizations in areas where they operate pipelines. Since all underground facility members share One-Call Center public awareness outreach costs, the costs to an individual operator are usually comparatively low, and can demonstrate effectiveness by increased use of the One-Call Notification system.

D.9 Operator Websites

Pipeline operators with websites can enhance their communications to the public through the use of a company website on the Internet. Since corporate websites may vary in serving the business needs of the company (e.g. investor relations, marketing, affiliate needs), the guidance in Appendix C.8 describes features of the components of a website for a company's pipeline subsidiary or operations that should fit into any corporate structure and overall website design. Many pipeline operators may choose to place additional or more detailed information on their websites to supplement their public awareness and informational efforts.

An operator's website will supplement the other various direct outreach delivery tools discussed in this RP.

APPENDIX E—ADDITIONAL GUIDELINES FOR UNDERTAKING EVALUATIONS

This appendix provides additional explanation for several methods described in Section 8 for conducting program evaluations and provides a sample survey.

E.1 Focus Groups (Interview Panels)

A focus group is a group of people representative of one or more target audiences who are gathered to provide feedback about the materials or other aspects of a planned Public Awareness Program or to comment on an existing one.

Typically, a focus group has about 6 to 12 participants. While focus groups can be professionally facilitated, feedback about public awareness materials can be gained by an informal discussion run by individuals connected with the public education program. Often participants will be asked to review draft materials and to comment on what they understood from the materials and whether the materials would draw appeal when received by mail. Focus groups can also be used to provide input on the relative effectiveness of various means of delivery.

Focus group participants might be operator employees who are not familiar with the Public Awareness Program, citizens living along a stretch of pipeline or representatives of homeowner associations or business people along the right-of-way. Target stakeholder audiences should not be mixed. The participants usually are not chosen at random but rather are selected to be reasonably representative of their focus group and capable of articulating their reactions to the materials.

E.2 Sample Assessment of Program Implementation

Table E-1—Sample Audit of Program Implementation

I Program Development and Documentation: Has the Public Awareness Program been developed and written to address the objectives, elements and baseline schedule as described in Section 2 and the remainder of this RP?
1. Does the operator have a written Public Awareness Program?
2. Have all of the elements described in Section 2 of this RP been incorporated into the written program?
3. Does the written program address all of the objectives of this RP as defined in Section 2.1?
4. Does the documented program address regulatory requirements identified in Section 2.2 of this RP and other regulatory requirements that the operator must comply with?
5. Does the operator have a plan that includes a schedule for implementing the program?
6. Does the program include requirements for updating responsibilities as organizational changes are made?
II Program Implementation: Has the public awareness plan been implemented and documented according to the written plan?
1. Is the program updated and current with any significant organizational or major new pipeline system changes that may have been made?
2. Are personnel assigned responsibilities in the written program aware of their responsibilities and have management support (budget and resources) for carrying out their responsibilities on the program?
3. Has the program implementation been properly and adequately documented?
4. Have all required elements of the program plan been implemented in accordance with the written plan and schedule?
5. Does the operator have documentation of the results of evaluating the program for effectiveness?
6. Are the results of the evaluation of program effectiveness being used in a structured manner to improve the program or determine if supplemental actions (e.g. revised messages, additional delivery methods, increased frequency) in some locations?

E.3 Supplemental Information to Operators Conducting Surveys to Evaluate Effectiveness

E.3.1 Type of Survey—Surveys may be conducted in person, over the phone, or via mail questionnaires. Conducting them in person is more labor intensive and costly but yields the best result and the largest return. Mail surveys are least expensive but typically have only 10-20 percent of the forms returned, which raises questions about whether the results are representative. Incentives for completing mail surveys may improve participation. Telephone surveys are a good compromise for the modest size samples needed to draw broad conclusions, but any of the methodologies can be made to work.

E.3.2 Sample Size—Typically a survey is designed to reach a random number of the targeted stakeholder audience. A variation on the random sample when conducting surveys in person is a "cluster sample" in which a block may be chosen at random and then a cluster of several households on the block visited at the same time. That is a relatively efficient way to increase sample sizes and not sacrifice much in statistical validity. The telephone number for affected residents is typically not readily accessible to the operator, although a random survey in a designated zip code or geographic area may include questions on whether the respondent lives or works along the right-of-way (to ensure a sufficient number of the affected public is included in the survey). For conducting a survey in person, the operator can work with a random selection of homes or businesses drawn from aerial maps or simply by selecting segments at random to be visited near the right-of-way. Mail surveys might be sent to all in a census tract, all in a zip code, or sub-zip code area. Third-party experts in conducting surveys can readily assist, at least for the first time a survey is attempted.

E.3.3 Statistical Confidence—There is typically concern about being statistically reliable. Often this leads to needlessly expensive surveys when one really only needs to know the approximate percentage of the target group that has been reached and is knowledgeable.

In deciding sample size, one can keep in mind a simplification of a lot of statistical rules and tables:

The statistical error associated with a random survey is approximated by $1/\sqrt{n}$,where n is the size of the sample. A sample of 100 gives an accuracy of approximately $\pm 1/\sqrt{100}$, or about 10 percent.

There are a number of detailed assumptions behind that approximation, which is more valid the larger the total population to be surveyed. For smaller populations, the sampling error is actually even smaller than that approximation. Very modest-size surveys can be used for evaluating pipeline safety for public awareness and still have statistical validity to support broad conclusions that, in turn, drive changes (as necessary) or support continuation (when supported) to the Public Awareness Program.

E.3.4 Content—Different sets of questions are needed for different audiences. There obviously would be a different set of questions asked of households along a pipeline versus those asked of excavators. The survey questionnaire should be clear, brief and pre-tested to increase the participation and minimize the cost. Operators should try to keep their questions the same over time so that trends can be evaluated. The questions can be yes/no, multiple choice, or open-ended. It is easier to analyze data from multiple choice or yes/no questions than open-ended questions; the latter require someone to read and interpret them, and then complete computer-readable tallies or do a tally by hand. A combination of both open-end and multiple-choice questions can be used. A survey can focus on only one program element or several elements and can measure the following with one or more of the selected stakeholder audiences:

- **Outreach:** Surveys can determine whether the audience received the public awareness communication.
- **Knowledge:** Surveys can also inquire about what the person would do hypothetically in certain situations, such as "If you observed a suspected leak in a pipeline, what would you do?"
- **Behavior:** In addition to knowledge and attitudes, surveys can be designed to inquire of actual behaviors; e.g., "Have you ever called to inquire about the location of a pipeline," "Have you ever been involved in any way with a pipeline break or spill," etc.

As a supplement to the baseline survey, the operator or operators working in collaboration or with trade associations may also include information about general attitudes about pipelines and knowledge of their role in delivering energy.

Some thought is needed as to whether it is better to get open-ended responses that do not prompt the respondent, to avoid bias. A short example: One might be tempted to ask, "What number would you call if you saw a break in a pipeline," but that question already assumes somebody would look up a number, which may be what you are trying to determine. A less biased question would be "what would you do if you saw a break in a pipeline?"

E.3.5 Implementation—An operator can:

- Develop and conduct a survey on its own system using internal or external expertise
- Select a survey format designed by external parties or an industry association
- Adapt surveys designed by others and conduct on its own systems, or
- Join with others in a regional survey.

E.4 Sample Survey

E.4.1 Survey Questions—The content of the questions on the survey should reflect the goals of the public education program. The wording of questions is critical.

Developing appropriate wording is more difficult than it may appear to be on the surface. It is easy to inadvertently build in biases or confuse the person being interviewed. The questionnaires should be tested before use. A focus group or small sample can be used for that purpose. If the wording is changed, the questions should be retested.

Preferably, the same wording would be used for a group of operators if not all of the industry, to achieve comparability and be able to compare statistics for the industry or a region. Individual operators should try to keep their questions the same over time so that trends can be evaluated.

Where possible, it is preferable to use multiple-choice questions rather than open-ended questions, because the former are easier to analyze objectively. A combination of both open-end and multiple-choice questions can be used. Negative answers or problems raised by respondents preferably should be followed up by a diagnostic question to understand the respondent's point of view better, and to get insight for making improvements.

In the tables below are two sample sets of survey questions—one for the general public near pipelines, the other for excavators. These lists of questions can be used as menus from which to choose if there is time only for a few questions. The asterisked questions are the most important.

The questions may refer to the respondent's experience in the past six months, year, or two years; generally one does not ask about information older than one year because of memory problems, except for dramatic events likely to be remembered.

E.4.2 Introduction—In administering a survey, there should be a brief introduction to set the stage. For example:

> "Our company [or insert company name association] believes it is important to get feedback from people (excavators) such as you about pipeline safety. We would like to ask you a few questions and would greatly appreciate your candid answers. The information on your particular response will be kept confidential. Let me start by asking ...."

E.4.3 Venues—Basically the same questions can be asked during a formal survey, whether undertaken by mail, telephone, or in person. They also can be used during customer contacts or as part of contacts with appropriate personnel from excavators.

Tables

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Table E-2—Sample Survey Questions for Affected Public

Attribute Measured		Sample Questions (Asterisk * marks most important questions.)
Outreach	*1.	In the last year [or 2 years], have you seen or heard any information from [our company] relating to pipeline safety? *[Yes or No]* If yes: 1a. What was the source of the information (check all that apply): a. Written material (brochure, flyer, handout) b. Radio? c. TV? d. Newspaper ad or article? e. Face-to-face meeting? f. Posted information (e.g., on or near pipeline) g. Other: _____ 1b. About how many times did you see information on pipeline safety in the last year?_____
Outreach	2.	Have you or has or anyone in your household ever tried to obtain information about pipeline safety in the last 12 months? *[Yes or No]* _____ 2a. If yes, where did you try? Check all that apply: a. Internet b. Call c. Letter d. Visit e. Other: _____
Knowledge	*3.	Do you live close to a petroleum or gas pipeline? *[Yes, No, do not know]* 3a. If yes, where is it (or how close are you to it)?_____ _____
Knowledge	*4.	What would you do in the event you were first to see damage to a pipeline? *[Can check more than one]* a. Call 911 b. Call pipeline operator c. Flee area d. Nothing (not my responsibility) e. Other: _____
Knowledge	5.	What would you do if you saw someone intentionally trying to damage a pipeline? *[Can check more than one]* a. Call 911 b. Call pipeline operator c. Flee area d. Nothing (not my responsibility) e. Other: _____
Behavior	*6.	Have you ever called a pipeline operator, 911, or anyone else to report suspicious or worrisome activity near a pipeline? *[Yes or No]* 6a. If yes, what did you report: a. Break b. Product release c. Digging d. Other: _____

Table E-2—Sample Survey Questions for Affected Public (Continued)

Attribute Measured		Sample Questions (Asterisk * marks most important questions.)
Behavior	*7.	Have you or has anyone in your household [or company if a business] ever encountered a damaged pipeline or product released from a pipeline? *[Yes or No]* If yes, what did you do? _____
Behavior	8.	Have you ever passed information about pipeline safety to someone else? *[Yes or No]* If yes, what information and to whom: _____
Outcomes	9.	Has anyone in your household or have nearby neighbors ever had any injuries or damage associated with a pipeline break or spill? *[Yes or No]* 9a. If yes, describe event. _____
Attitude	10.	Do you agree or disagree that your local pipeline operator has been doing a good job of informing people like you about pipeline safety? a. Strongly agree b. Agree c. Disagree d. Strongly disagree If you disagree, why: _____

Table E-3—Sample Survey Questions for Excavators

The questions below could be worded for a specific operator or for any operator; some excavators may deal with more than one pipeline.

Outreach

*1. In the last 12 months, have you been contacted or received written information from [local pipeline operator] regarding pipeline safety? *[Yes or No]*

If yes, what was the source:
- a. Telephone call
- b. Mail
- c. Visit or in-person meeting
- d. E-mail
- e. Sign or billboard
- f. Other:_____

Outreach

2. Have you received information from any other sources about pipeline safety? *[Yes or no]*

2a. If yes, which? _____

Behavior

3. Have you contacted [pipeline operator name] in the past year to inquire about the location of pipelines? *[Yes or no]*

3a. If yes, about how many times? _____

3b. If yes, how did you make the contact:
- a. Telephone
- b. E-mail
- c. Letter
- d. In-person
- e. Other: _____

Behavior

*4. How often would you say your operator checks whether a pipeline exists before digging in a new spot?
- a. Always
- b. Usually
- c. Sometimes
- d. Rarely or Never
- e. Don't know.

4a. If not always: why not?
- a. Didn't know where to get information
- b. Not necessary
- c. Didn't think about it
- d. Takes too much time
- e. Think we can tell where pipeline is on our own
- f. Other: _____

Outreach

5. How do you make sure that all the right people in the company get the information on whom to call before digging? That is, how do you disseminate the information?
- a. Post it
- b. Discuss in meetings
- c. E-mail
- d. Calls
- e. Put in company's written procedures
- f. Put in company newsletter
- g. Other: _____

Outreach (Audience Size)

6. About how many people in your company actually determine where to dig? _____

Table E-3—Sample Survey Questions for Excavators (Continued)

6a. What jobs do they have (e.g., excavator equipment operator; executive; operations boss; etc.):

_____

Outreach

6b. How many of them probably have information on where to call before digging?
a. All
b. Most
c. Some
d. Few or None

Outcome

*7. Has your company ever unexpectedly encountered a pipeline while digging? *[Yes or No]*

7a. If yes, how often has this occurred? _____

Explain whether pipeline location was unknown and why. _____

_____

_____

7b. If yes, how many were "close calls"? _____

7c. How many resulted in damage: _____

Table E-4.1—Measuring Effectiveness of Pipeline Public Awareness Programs for Transmission or Liquid or Gathering Pipelines

Local Public Officials

The following are sample survey questions on pipeline safety for local government/public officials. They can be used when meeting one on one with such officials or when doing a more systematic survey in connection with evaluating Public Awareness Programs for pipeline safety.

Introduction if survey is in person:

I am _____representing _____

I would like to ask you a few questions regarding pipeline safety.

Knowledge

1. Do you have an oil or gas pipeline running through your community? _____(Y/N)
   If not yes, tell them. [Reviewers: Should we also ask if they know where it is?]
2. Do you know the name of your local pipeline operator? _____ (Y/N)

   2a. If yes, who? _____
   [This may be given away by the introductory line.]

Outreach

3. Have you heard or seen a message regarding pipeline safety in the last 12 months? _____ (Y/N)

   3a. If yes, about how many? _____
4. Before today, about when was your last contact with someone from the pipeline industry related to pipeline safety? _____ (If known, fill in approximate date or number of weeks, months, or years ago.)

Knowledge (again)

5. Do you have the number to call in the pipeline company if there is an incident or you need more information? _____(Y/N)
6. Have you heard of the Office of Pipeline Safety in the U. S. Department of Transportation? _____ (Y/N)
7. Do you know what precautions an excavator should take prior to digging, to avoid accidentally hitting a pipeline? _____ (Y/N)

   7a. If yes, what are they? _____
8. Are you familiar with the one-call line? _____ (Y/N)
   (If no, they should be informed about it.)
9. How would you rate the adequacy of information you have about pipeline safety (e.g., how to recognize a leak, what to do when there is a leak, what first responders should do, etc.)?
   a. About right? _____
   b. Too much? _____
   c. Not enough? _____

   [This question is essentially a self-assessment of knowledge for a measure such as "percent of local officials who felt they needed more information about pipeline safety."]

Behavior

10. Does your community have an emergency response plan to deal with a pipeline break (regard less of whether intentional or accidental)? _____(Y/N)

Outcome

11. Are you aware of any pipeline breaks that occurred in your community in the last 10 years? _____ (Y/N)

    11a. If yes, how many? _____

Table E-4.1—Measuring Effectiveness of Pipeline Public Awareness Programs for Transmission or Liquid or Gathering Pipelines (Continued)

11b. What were they? _____
[The interviewer should be prepared to tell the local official the correct answer.]

12. Have any of your local citizens or businesses expressed concern in the last 12 months about any issue regarding pipeline safety? _____ (Y/N)

12a. If yes, what was it? _____

13. Overall, do you feel the pipeline industry has an adequate public safety awareness program?
    a. Definitely yes _____
    b. Pretty much so _____
    c. Not sure _____
    d. Don't know _____
    e. Probably not _____
    f. Definitely not _____

[This is an overall perception of their awareness program. The operatory could use for measures such as "percent of local governments who rated the overall program as definitely or probably adequate."]

Table E-4.2—Measuring Effectiveness of Pipeline Public Awareness Programs for Transmission or Liquid or Gathering Pipelines

Emergency Officials

These questions are primarily for local first responders (e.g., fire, police, EMS officials), but could also be used for utility responders, and other emergency officials.

Knowledge

1. Do you know where the nearest oil or gas pipeline is in or near your community? _____(Y/N) [If not, tell them after the interview.]
2. Do you know the name of your local pipeline operator? _____ (Y/N)

   15a. If yes, who? _____

3. Do you know who to call in the pipeline company if there is an incident, or if you need more information? _____(Y/N)

Outreach

4. Have you seen, heard, or received any information regarding pipeline safety in any media in the last year? _____ (Y/N)

   17a. If yes, do you recall what? _____

5. Have you or anyone else in your department to your knowledge met with any representatives of the pipeline company to discuss pipeline safety within the last 12 months, prior to today? _____(Y/N)

   18a. If yes, when?_____

   18b. With whom? _____

Behavior

6. Do you have a response plan or SOPs for responding to a pipeline incident, such as a break? _____ (Y/N)
7. Have you done any practical training to deal with a break? _____(Y/N)

Outcome

8. Do you know if there were any pipeline incidents within the last ten years in your community? _____ (Y/N)

   8a. If yes, about when? _____

   8b. What was the incident? _____

   8c. Did the department respond? _____(Y/N)

   8d. If yes, Do you feel the department dealt with the incident in a satisfactory manner? [Self-assessment, if knowledgeable about the incident.]

_____

_____

_____

_____

Table E-5.1—Measuring Effectiveness of Pipeline Public Awareness Programs for Local Distribution Companies

Local Public Officials

The following are sample survey questions on pipeline safety for local government/public officials. They can be used when meeting one on one with such officials or when doing a more systematic survey in connection with evaluating Public Awareness Programs for pipeline safety.

Introduction if survey is in person:

I am _____representing _____

I would like to ask you a few questions regarding pipeline safety.

Knowledge

1. Do you have natural gas pipelines running through your community? _____(Y/N)
2. Do you know the name of your local natural gas company? _____ (Y/N)

   2a. If yes, who? _____
   [This may be given away by the introductory line.]

Outreach

3. Have you heard or seen a message regarding natural gas safety in the last 12 months? _____ (Y/N)

   3a. If yes, about how many? _____

4. Before today, about when was your last contact with someone from the natural gas industry related to pipeline safety? _____ (If known, fill in approximate date or number of weeks, months, or years ago.)

Knowledge (again)

5. Do you have the number to call the natural gas company if there is an incident or you need more information? _____(Y/N)
6. Do you know who regulates the natural gas company in this community? _____ (Y/N) (If no, they should be informed about it.)
7. Do you know what precautions an excavator should take prior to digging, to avoid accidentally hitting a natural gas pipeline? _____ (Y/N)

   7a. If yes, what are they? _____

8. Are you familiar with the one-call line? _____ (Y/N) (If no, they should be informed about it.)
9. How would you rate the adequacy of information you have about natural gas safety (e.g., how to recognize a leak, what to do when there is a leak, what first responders should do, etc.)?
   a. About right? _____
   b. Too much? _____
   c. Not enough? _____

   [This question is essentially a self-assessment of knowledge for a measure such as "percent of local officials who felt they needed more information about pipeline safety."]

Behavior

10. Does your community have an emergency response plan to deal with a natural gas leak (regardless of whether intentional or accidental)? _____(Y/N)

Table E-5.1—Measuring Effectiveness of Pipeline Public Awareness Programs for Local Distribution Companies (Continued)

Outcome

11. Are you aware of any pipeline leaks that occurred in your community in the last 2 years? _____ (Y/N)

    11a. If yes, how many? _____

    11b. What were they? _____
    [The interviewer should be prepared to tell the local official the correct answer.]

12. Have any of your local citizens or businesses expressed concern in the last 12 months about any issue regarding natural gas safety? _____ (Y/N)

    12a. If yes, what was it? _____

13. Overall, do you feel the natural gas industry has an adequate public safety awareness program?
    a. Definitely yes _____
    b. Pretty much so _____
    c. Not sure _____
    d. Don't know _____
    e. Probably not _____
    f. Definitely not _____

    [This is an overall perception of their awareness program. Could use for measures such as "percent of local governments who rated the overall program as definitely or probably adequate."]

Table E-5.2—Measuring Effectiveness of Pipeline Public Awareness Programs for Local Distribution Companies

First Responders/Emergency Officials

These questions are primarily for local first responders (e.g., fire, police, EMS officials), but could also be used for utility responders, and other emergency officials.

Knowledge

1. Do you have natural gas pipelines running through your community?? _____(Y/N) [If not, tell them after the interview.]
2. Do you know the name of your local natural gas company? _____ (Y/N)

   15a. If yes, who? _____
3. Do you know how to contact the local natural gas company if there is an incident, or if you need more information? _____(Y/N)

Outreach

4. Have you seen, heard, or received any information regarding natural gas safety in any media in the last year? _____ (Y/N)

   17a. If yes, do you recall what? _____
5. Have you or anyone else in your department to your knowledge met with any representatives of the natural gas company to discuss pipeline safety within the last 12 months, prior to today? _____(Y/N)

   18a. If yes, when?_____

   18b. With whom? _____

Behavior

6. Do you have a response plan or SOPs for responding to a natural gas incident, such as a leak? _____ (Y/N)
7. Have you done any practical training to deal with a leak? _____(Y/N)
8. Do you feel reasonably well prepared to deal with a natural gas leak, should one occur in your community? _____(Y/N) If not, in what areas are there deficiencies? (Check all that apply.)
   a. Training _____
   b. Special Equipment _____
   c. Knowledge about leaks _____
   d. Inherent dangers _____
   e. Other: (Write in.)_____
9. If you heard a report of a natural gas leak right now, what actions would you or your department take? [Write in the steps; someone should grade the responses to get a sense of whether there has been adequate training or preparation, or if the respondent just mentioned general procedures applicable to any kind of incident.]

   _____

   _____

Outcome

10. Do you know if there were any natural gas leaks within the last two years in your community? _____ (Y/N)

    10a. If yes, about when? _____

    10b. What was the incident? _____

    10c. Did the department respond? _____(Y/N)

    10d. If yes, Do you feel the department dealt with the incident in a satisfactory manner? [Self-assessment, if knowledgeable about the incident.] _____

    _____

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Direct Testimony of Tobin F. Davilla

OPERATIONS & MAINTENANCE COSTS
EXHIBIT 1100

November 24, 2026

EXHIBIT 1100 – DIRECT TESTIMONY – OPERATIONS & MAINTENANCE COSTS

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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 Tobin F. Davilla. I am the Director of Financial Planning and Budget at NW Natural. I am responsible for producing the annual operations and maintenance ("O&M") costs budget, the capital expenditures budget, and 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 business 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. In my testimony, I explain how the Company developed the O&M costs amount included in the revenue requirement, including how the Company used the base year costs in the 12-months ended June 30, 2026 ("Base Year") to develop the Oregon-allocated O&M costs for the test period consisting of the 12-months ending October 31, 2028 ("Test Year").

II. TEST YEAR OPERATIONS AND MAINTENANCE COSTS

Q. What is the Oregon-allocated O&M expense included in NW Natural's revenue requirement in this case?

A. The Oregon-allocated Test Year O&M expense included in the revenue requirement in this case is $249.0 million. This compares to a Company total of $279.6 million of O&M for the Test Year, which is adjusted for state allocations, and amounts that represent O&M for which the Company is not seeking cost recovery in this case. NW Natural/1101, Davilla shows the Base Year O&M expense and NW Natural/1102, Davilla shows the Test Year O&M expense by Federal Energy Regulatory Commission ("FERC") account.

Q. How were the Test Year O&M costs developed?

A. O&M costs are composed of three components: A) payroll costs; B) non-payroll costs; and C) other cost adjustments. The Company Base Year O&M costs were separated into these three components. Except for several specific items, non-payroll O&M costs were adjusted using the most current U.S. Urban Consumer Price Index ("CPI") as reported in the August 2026 Oregon Economic and Revenue Forecast, published by the Oregon Office of Economic Analysis ("OEA").[1] Other O&M cost adjustments were calculated specifically for the Test Year. Base Year O&M payroll costs were also adjusted for increases through the Test Year.

[1] NW Natural/1103, Davilla/51.

A. O&M Payroll Costs

Q. What was the first step in calculating Test Year O&M payroll costs based on the Base Year costs?

A. The forecasted number of the Company's full-time equivalent positions ("FTEs") in the Test Year is the largest factor in the Test Year payroll O&M cost estimate. The total system Base Year ended FTE count was 1,260.6 FTEs.

Q. Do you request rate recovery for any incremental FTEs added after the Base Year?

A. Yes. The Company is seeking recovery of the costs associated with 49.5 FTEs in the process of being hired at the time of the conclusion of the Base Year. These additional FTEs reflect positions in which a person has accepted the position but had not yet started, positions that had an outstanding offer to someone, or positions that were finishing up the interview process at the end of the Base Year. These FTE additions are roughly half union positions in the Customer Contact Center (Customer Service Representatives), Construction, and Customer Field Service (Customer Field Service Representatives). The other FTEs are non-bargaining unit employees, covering a broad range of support from human resources and accounting to safety and security. Additional testimony regarding these FTEs can be found in the Direct Testimony of Kyra M. Patterson (NW Natural/900, Patterson).

Q. Did the projected Test Year FTE count consider vacancies and FTEs allocated to non-utility activities?

A. Yes. NW Natural does not seek to recover in rates the costs for 55.0 vacant FTE positions for which the Company had not yet initiated the hiring process at the end of the Base Year and 56.8 FTEs allocated to non-gas utility activities (termed "non-regulated FTEs" in this testimony). Table 1 below illustrates the adjustments made to the total internally approved FTEs.

Table 1

	Test Year
Approved FTEs	1,365.1
Unfilled FTE Adjustment	(55.0)
Test Year FTEs requested	1,310.1
Non-Regulated FTE Removal	(56.8)
Regulated FTEs	**1,253.3**

Q. You state that NW Natural does not seek recovery for non-regulated FTEs in the Test Year. Please explain how non-regulated FTEs are determined.

A. Based on their historical work allocation, utility FTEs were assigned, either in part or in full, to gas-regulated or non-gas-regulated operations. A total of 56.8 FTEs were assigned to non-gas-regulated activities, which includes NW Natural employees who directly or indirectly charged time to NW Natural's affiliates. Table 2 below shows the calculated FTEs for which the Company does not seek cost recovery:

Table 2

	Test Year
Appliance Center	(9.4)
North Mist Storage	(8.3)
Interstate Storage	(8.1)
Affiliate and Other Non-Regulated Activity	(31.0)
Non-Regulated FTE Removal	**(56.8)**

Q. Please explain how FTEs are allocated to affiliates.

A. The Company has several departments that may provide services to affiliates that specifically benefit another entity. These departments direct-charge time incurred to the respective affiliate, known as "Shared Services." The Test Year allocation of FTEs to Shared Services reflects the historical number of FTEs allocated out of NW Natural to the affiliates during the Base Year.

In addition, the Company has several departments that perform administrative and general functions for the benefit of NW Natural, Northwest Natural Holding Company ("NW Holdings") and its affiliates. These departments' labor costs are indirectly charged via a corporate allocation to the affiliates that benefit from their service.

The two labor allocation mechanisms are described in more detail in the Company's Cost Allocation Manual ("CAM").[2]

[2] See *In the Matter of NW Natural Gas Company Affiliated Interest Annual Report and Revised Cost Allocation Manual in Compliance with OAR 860-027-0046(6),* NW Natural's 2025 Affiliated Interest Report and Cost Allocation Manual, Docket No. RG 8, Exhibit B at 4-5 (Apr. 30, 2026).

Q. Please explain your escalation methodology for payroll costs.

A. Bargaining unit ("BU") employee wage increases are set according to the Collective Bargaining Agreement ("CBA") with the Union. The current agreement commenced on June 1, 2024, and will run through May 31, 2028.[3] Under the agreement all bargaining unit employees are scheduled to receive a wage increase of 4.0 percent on December 1, 2026, and on December 1, 2027. The Company also applies an additional 1.05 percent per year for promotions, job reclassifications, and movements from entry rate to experienced rate as described in the CBA.

Similarly, payroll costs were escalated for expected salary increases for non-bargaining unit ("NBU") employees. These increases are expected to be 3.50 percent on March 1, 2027, and 3.50 percent on March 1, 2028. Based on historical trends, the Company also assumes an additional 1.00 percent per year for NBU employee promotions/equity adjustments. For more detail on the salary increases, see NW Natural/900, Patterson.

Payroll costs were also adjusted for expected changes in benefits costs. The Direct Testimony of Kyra M. Patterson (NW Natural/900, Patterson) discusses salary and benefits cost increases.

[3] See NW Natural/1104, Davilla.

Q. How did you determine the utility regulated payroll that is allocated to O&M activities?

A. Once the Company determines the regulated utility payroll costs, it allocates utility regulated payroll expenses to O&M and capital. NW Natural uses two approaches to allocate expenses and to charge time for various activities. In the first approach, most employees who directly work on capital activities will track and directly charge their time to capital. In the second approach, employees who are generally supportive of both capital and O&M projects, such as human resources, accounting, or finance, have a portion of their time applied to capital via an administrative transfer. The O&M payroll allocation used in the Test Year is 58.5 percent. The Company calculated this allocation using the historical O&M allocation for the trailing 12-month period ended June 2026 and incorporating the O&M allocation of expected FTEs after that date.

Q. How were payroll overhead expenses calculated for the Test Year?

A. Payroll overhead is used to allocate benefits expense. The payroll overhead expenses included in O&M are a calculated ratio of the total Test Year payroll overhead expense for executives and non-executives multiplied by the percentage of executive and non-executive labor allocated to O&M.

B. O&M Non-Payroll Costs

Q. Please explain your escalation methodology for non-payroll costs.

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 August 2026

Oregon Economic and Revenue Forecast, published by the OEA.[4] These escalation factors were applied to expenses occurring after the Base Year through the end of the Test Year. The Company also identified several items where the information available to the Company indicated that the growth projection should be greater or lesser than the escalation using CPI, and NW Natural adjusted these items with their specific increase or decrease, as discussed in more detail below.

Q. Why did NW Natural use the U.S. Urban CPI as the escalator for these accounts instead of the West Region All-Urban CPI as has been often proposed by the Company in past proceedings?

A. NW Natural believes that a regional CPI provides a better measure of aggregate price changes experienced than the national CPI because the Company's expenses are regional in nature, generated in Oregon or southwest Washington, and Oregon's higher cost of living has aligned much more with the states that make up the West Region CPI than the national average. However, recognizing that Staff has proposed using the U.S. Urban CPI in past cases,[5] the Company is amenable to using the U.S. Urban CPI in this rate case because: (1) the West Region CPI rate for August 2026 Oregon Economic and Revenue Forecast closely aligns to the U.S rate in 2027 and 2028 (10 basis points lower in 2027, and 10 basis points higher in 2028); and (2) the Company does not believe the marginal

[4] See NW Natural/1103, Davilla/51.

[5] *See, e.g.*, *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 520, Opening Testimony of Mitchell Moore, Staff/1400, Moore/7 (Apr. 2, 2025).

difference between the two inflation measures warrants extensive litigation in this case given the limited impact on Test Year revenue requirement.

Q. You state above that the Company adjusted for certain items in the Test Year instead of using a CPI growth rate applied to the Base Year. Please explain what these items are and why it is more appropriate to use these cost adjustments instead of the CPI escalation factor.

A. The Company made these adjustments to ensure that the Test Year expense is as accurate as possible. These items change because of either fluctuation of contractual agreements that are both known and measurable, or the Company knows that the expenses will increase or decrease at a rate that would not be best reflected using CPI as an escalation factor. An escalation factor should only be relied on where actual costs are unknown or otherwise fail to be indicative of future costs. The following Oregon-allocated expenses in the Test Year have been adjusted accordingly:

Company Headquarters ("HQ") Lease Expense and Leasehold Improvement Amortization (FERC 931): The headquarters lease expense contractually increases annually by 2.5 percent, which is lower than the collective impact of CPI escalation factors in this case (3.2 percent in 2026, 2.2 percent in 2027 and 2.3 percent in 2028). The contracted HQ lease is growing at a lesser rate than if CPI were applied through the Test Year. Additionally, the Company is not expecting to make any leasehold improvements between now and the end of the Test Year. Accordingly, the leasehold improvement amortization expense is not expected to grow and instead is expected to remain flat through the end of the

Test Year and should not be subject to the CPI escalation factor. As a result, an adjustment is made to reduce the Test Year expense to keep the leasehold improvement amortization flat and to grow the HQ lease expense at its contracted rate in the Test Year. The total expense adjustment decrease in the Test Year is $72 thousand, and the Oregon-allocated amount after administrative transfer is $41 thousand.

Well Casing Integrity Inspection Program (FERC 832): In December 2016, the Pipeline and Hazardous Materials Safety Administration (PHMSA) under the Department of Transportation published in the Federal Register an interim final rule (IFR) 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 CFR 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 baseline casing inspection program completed in 2025. The baseline casing inspection program work is capitalized. 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 192.12(d)(3). This reassessment work is an O&M expense. This expense can fluctuate from year to year based on the type of inspection and the required number of inspections being performed. Inspections take the form of either a mechanical integrity test performed at least once every 7 years that does not require a rig, or

a rig-based well intervention which is significantly more expensive and performed every 5, 10 or 15 years based on the results of the individual well risk assessment. During the Test Year, the expense for this program is close to the Base Year expense. The total expense adjustment increase for re-inspections in the Test Year is $178 thousand, and the Oregon-allocated amount is $158 thousand. The increase above CPI is not significant and would not typically be identified as an expense that warrants discussion in this proceeding. However, due to the fluctuating schedule of this required work, this expense had been discussed in recent rate case testimonies. As such, the Company included the small impact again in this filing, mostly to note to parties in this proceeding that the variability of this expense was considered and factored into the O&M expense.

Advertising Adjustment (FERC 913 & 909): The Company included advertising costs for Category A equivalent to $2.12 per customer, and $996,076 for Category B expense and removed expense for all other categories of advertising. The Direct Testimony of Cory A. Beck (NW Natural/1000, Beck) discusses in more detail the advertising expense decrease. The total expense adjustment increase in the Test Year is $780 thousand, and the Oregon-allocated amount is $685 thousand.

Contracted Customer Payment Processing Fees (FERC 903): The Company entered into an agreement with Paymentus[6] to provide electronic bill payment services in March 2019 that went into effect in October 2020. The

[6] See Confidential NW Natural/1105, Davilla.

Company has since signed a contract amendment and extension through May 4, 2027.[7] After that date, the Agreement will automatically renew for successive one-year periods unless either party provides at least six months' notice. The agreed-upon amendment included a new service fee schedule. The Company is expecting a service fee increase to occur between the Base Year and the Test Year. This fee increase is greater than the expected CPI rate of inflation in this case. Partially offsetting the service fee increase is the Company's projected adoption rate, which is projected to increase but at a rate lower than CPI. The number of transactions is expected to grow at a 2 percent compound annual growth rate from the Base Year to the Test Year. The total expense adjustment increase in the Test Year is $713 thousand, and the Oregon-allocated amount is $626 thousand.

Contracted Locating & Survey Services (FERC 874): The Company employs the services of a third-party contractor, Heath Consultants Incorporated ("Heath Consultants"), to provide locating and marking services to the Company, and survey and inspection services. The Company entered into an amended agreement with Heath Consultants effective September 1, 2023.[8] This agreement runs through December 31, 2026, which encompasses the Base Year. During 2026, the Company leveraged multiple contracts, competitors' pricing and potential purchases of equipment known at that time to reduce rates from existing

[7] See Confidential NW Natural/1106, Davilla.

[8] See Confidential NW Natural/1107, Davilla.

rates in its new agreement with Heath Consultants that will begin January 1, 2027, and run through December 31, 2029.[9]

This new agreement sets the rates per locate and hourly standby rates in the Test Year. These rates are set to increase by 3 percent annually throughout the contract. In addition to these increases in rates per locate in the Test Year, NW Natural has also experienced annual increases in the number of low-pressure locating service units it receives. This increase is due to customer education and customer growth. The Company expects that locating units will continue to increase 1.5 percent annually through the Test Year. In addition to the locating and marking services, Heath Consultants provide survey and inspection services to the Company. The Company and Heath Consultants have a contractual agreement that sets the rate per foot of inspection. This rate is set to increase at 3 percent annually throughout the contract. The total expense adjustment due to the benefit of the new reduced rates in the new contract for both locating and survey services in the Test Year is a reduction of $2.3 million, and the Oregon-allocated amount is a reduction of $2.1 million.

Information Technology and Services ("IT&S") (FERC 921): The Direct Testimony of Brian E. Fellon (NW Natural/800, Fellon*)* discusses in more detail the largest components of the IT&S O&M expense increase. The total expense adjustment increase in the Test Year is $2.4 million, and the Oregon-allocated amount after administrative transfer is $1.8 million.

[9] See Confidential NW Natural/1108, Davilla.

Insurance (FERC 924): The Company has incurred significantly higher insurance premium costs for the fiscal period 2026-2027 versus the cost embedded in rates. This is primarily due to higher excess liability and cybersecurity liability insurance costs, partially offset by a decrease in workers' compensation costs. These increased costs began on October 15, 2026.

The increase in excess liability costs is driven by three main factors. First, as described in our previous rate case, the Company continues to be behind its peers with respect to the levels of excess liability insurance limits purchased. Second, pricing for excess liability insurance has increased across insurance markets, particularly for gas and electric utilities as a result of increasing climate-related and physical risks. Third, contributing to both factors but separately notable are the 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 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, all these circumstances have resulted in higher premiums and reduced market capacity for excess liability. For the 2026-2027 insurance year, the Company saw a 10 percent increase in excess liability insurance premiums with 6 percent related to higher pricing on existing coverage and 4 percent related to increasing the excess coverage limit $25 million to move more in line with appropriate coverage for the risks facing the Company.

The increase in cybersecurity costs is primarily driven by the surge in cyber attacks targeting utilities, a utility's unique risk profile where a cyber breach can disrupt critical physical operations, and overall rising costs of attacks. In addition, the Company is behind its peers with respect to the level of cybersecurity insurance limits purchased and adding coverage related to cyber attacks. For the 2026-2027 insurance year, the Company saw a 45 percent increase in cyber insurance premiums with 2 percent related to higher pricing on existing coverage and 43 percent related to increasing coverage limits to move more in line with appropriate coverage for the risks facing the Company.

Offsetting these increases was a 41 percent decline in workers' compensation premiums due to strong historical management of claims, our strong safety culture and risk management practices, and insurers bidding competitively in order to gain greater market share.

The Company projects an 18 percent incremental increase for the 2027-2028 year, which begins on October 15, 2027. The increase is primarily based on higher overall premiums as elevated loss trends are expected to continue and the Company will continue to take measures to increase coverage associated with key emerging risks for cybersecurity and excess liability.

Q. Please explain why the Company decided that increased liability and cybersecurity coverage is necessary.

A. NW Natural's liability coverage limits are consistently below its peers. Specifically, NW Natural's limit of $200 million falls below the average coverage limit of approximately $250 million. NW Natural has increased coverage $25 million to

$225 million total coverage on October 15, 2026. The Company plans to increase its coverage by an incremental $25 million to $250 million total coverage on October 15, 2027, to fall in line with the industry standard.

NW Natural's cybersecurity coverage limits are below its peers in this emerging risk area. Specifically, NW Natural's limit of $10 million falls below the average coverage limit of approximately $30 million. NW Natural has increased coverage $5 million to $15 million total coverage on October 15, 2026. The Company plans to increase its coverage by an incremental $5 million to $20 million on October 15, 2027, to move closer to the industry standard.

Q. Please explain the insurance expense increase the Company is seeking in this case.

A. For premiums beginning October 15, 2026, the Company incurred a year-over-year increase of 5 percent in expense for the same levels of coverage and 10 percent overall increase with the incremental coverage.

For the forecasted premium beginning October 15, 2027, the Company is expecting an increase of 18 percent that considers increases for both higher pricing as well as the impact of the higher liability and cyber limits. The total expense adjustment increase in the Test Year is $3.4 million, and the Oregon-allocated amount after administrative transfer is $2.0 million.

Q. Returning to the specific items adjusted, please continue explaining other areas where the Company made specific adjustments to O&M expense.

A. **Pipeline Inspection Integrity Program (FERC 856)**: The Company is required by Code of Federal Regulations (CFR) Part 192 – subpart O to perform assessments on transmission system pipelines every seven years. The Company utilizes inline inspection technologies to assess the Company's 6-inch diameter through 24-inch diameter transmission pipelines that have been made piggable. 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 our transmission pipeline assessment vendor and internal labor costs. In summary, the Company's transmission assessment costs can vary due to the variability in pipeline, size, length and location of pipeline to be assessed. The Test Year is expected to inspect larger and longer pipelines than in the Base Year. The total expense adjustment increase in the Test Year is $660 thousand, and the Oregon-allocated amount is $652 thousand.

Legal Fees (FERC 921): NW Natural is subject to claims and litigation arising in the ordinary course of business. However, the Company has recently been experiencing an increasingly heightened level of litigation, particularly as a defendant. On October 11, 2024, NW Natural was added as a defendant to an ongoing lawsuit brought by Multnomah County in Multnomah County Circuit Court, *County of Multnomah v. Exxon Mobil Corp., et. al.*, against more than a dozen oil and gas producers seeking damages relating to climate change impacts. The

County asserts various causes of action, including negligence, fraud, trespass and public nuisance under Oregon law related to the refining, producing, and/or marketing of fossil fuels. Separately, on October 14, 2024, NW Natural was named as a defendant in another lawsuit filed in Multnomah County Circuit Court, *Blumm et al. v. Northwest Natural Gas Company*, that is seeking class certification on behalf of all Oregon NW Natural Smart Energy-enrolled customers during the past approximately six years. The lawsuit alleges claims under Oregon's Unlawful Trade Practices Act and for breach of contract with respect to NW Natural's Smart Energy program. The plaintiffs seek injunctive and equitable relief and damages. Both lawsuits have been designated as "complex litigation," are still in the initial motion phases, and have schedules including preliminary discovery expected to be extensive that are likely to extend into the Test Year and beyond. Lawsuits of this nature tend to last for multiple years.

Furthermore, the utility industry overall has been experiencing an increase in litigation, such as environmental litigation, against which utilities must defend themselves. Therefore, it is reasonable for NW Natural to expect that its own legal expenses will increase from what it experienced in the Base Year, even without accounting for the specific cases discussed above. It benefits customers for the Company to vigorously defend itself from such lawsuits because lawsuits have the potential to impose very significant costs on the Company if the plaintiffs prevail.

The Company also expects its legal expenses related to environmental and other types of compliance to increase in the Test Year. NW Natural must comply

with an increasing number of statutes and regulations and incurs legal costs to do so.

As such, the Company will incur incremental recoverable legal expense in the Test Year. The total expense adjustment increase in the Test Year is $500 thousand, and the Oregon-allocated amount after administrative transfer is $372 thousand.

Coos County Expenses (FERC 856): During the Base Year, all Coos County expenses were charged directly to Coos County and as a result no actual expense appeared in the Base Year in this case. The Company is requesting to include the projected on-going routine Test Year operations and maintenance expenses related to supporting Coos County customers previously charged to Coos County. The amount included in the Test Year is $403 thousand. The Company describes the nature of these expenses in the Direct Testimony of Daniel B. Kizer and Michael C. Hwang (NW Natural/600, Kizer-Hwang).

Q. Are Non-Payroll O&M costs adjusted to reflect services provided from NW Natural to its affiliates?

A. Yes. NW Natural's O&M costs are reduced to reflect a credit for expenses associated with services to affiliates. The non-payroll portion of Shared Services is calculated by imputing an administrative overhead of 17.7 percent to the payroll charges.[10] The Oregon-allocated credit amount during the Test Year is $604 thousand.

[10] See Docket No. RG 8, Exhibit B at 6 (Apr. 30, 2026).

In addition, the Company has several departments that perform administrative and general functions for the benefit of NW Natural, NW Holdings, and its affiliates. These departments' labor and non-labor costs are indirectly charged via a corporate allocation to the affiliates that benefit from their service. Payroll costs, along with a forecasted 17.7 percent non-payroll overhead factor, are credited through the allocation mechanism described in the CAM.[11] The Oregon-allocated indirect non-payroll allocated amount and 17.7 percent administrative overhead rate credited to the utility during the Test Year is $1.2 million.

Q. Does the Test Year include any other adjustments?

A. Yes. All Executive Incentive Compensation was removed from the Test Year (NW Natural/900, Patterson), as NW Natural is not seeking recovery for these costs.

C. O&M Other Cost Adjustments

Q. Once you have calculated O&M payroll and non-payroll expenses, do you perform any further adjustments?

A. Yes. Once payroll and non-payroll expenses are calculated, O&M is adjusted to reflect: a) the Commission-authorized amount of $5.0 million expense related to environmental remediation (see docket UM 1635, Order No. 15-049, where a tariff rider of $5.0 million was established to be applied toward recovery of environmental remediation expense[12]); b) the Commission-authorized amount of

[11] Docket No. RG 8, Exhibit B at 4-5 (Apr. 30, 2026).

[12] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Mechanism for Recovery of Environmental Remediation Cost*s, Docket No. UM 1635, Order No. 15-049 at 11 (Feb. 20, 2015).

$7.1 million expense related to pension balancing amortization (see docket UG 344 Phase II, Order No. 19-105[13]); c) Oregon Horizon amortization expense of $976 thousand (see docket UG 435, Order No. 22-388[14]); and d) corporate O&M adjustments.

Q. What items are included in the corporate O&M adjustments?

A. Listed below are the items included in the Oregon-allocated corporate O&M adjustments:

- Administrative Transfer: $25.9 million credit – The administrative transfer allocates a portion of payroll and non-payroll administrative expenses, such as the salaries and expenses of Accounting, Human Resources, Facilities, and general administration, from O&M to construction activities. These costs are categorized as indirect construction overhead because they are not charged directly to specific or individual construction projects.
- Payroll Tax: $8.0 million credit – This credit removes payroll tax expense from O&M and transfers it to the "Other Taxes" line of the revenue requirement. This adjustment is required by FERC accounting methodology. The payroll tax expense is included in the revenue

[13] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 344, Order No. 19-105, Appendix A at 5 (Mar. 15, 2019).

[14] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Order No. 22-388, Appendix A at 9-10 (Oct. 24, 2022)

requirement in this case under the "Other Taxes" area and is not included in O&M costs.

- Post-Retirement Medical Non-Service: $1.0 million expense – The total post-retirement medical plan expense (ASC-715-60) is forecasted by our actuary, Fidelity. The Company used the latest forecast provided to us prior to filing this rate case. The actuary forecasted total post-retirement medical plan costs in the Test Year to be $1.2 million. This is made up of a service component (Operating Cost) and a non-service component (Non-Operating Cost). The service expense forecasted in the Test Year is $50 thousand and is included in the payroll overhead rates that are allocated to O&M, capital, and non-utility work based on the payroll work mix. The total non-service expense projected by the actuary for the Test Year is $1.1 million, or $1.0 million Oregon-allocated. The non-service expense is an O&M expense.
- Pension Non-Service: $3.8 million expense – The total pension expense (ASC 715) is forecasted by our actuary, Fidelity. The Company used the latest forecast provided to us prior to filing this rate case. The actuary forecasted total system pension cost in the Test Year to be $6.9 million. This is made up of a service component and a non-service component. The system service expense forecasted in the Test Year is $2.7 million and is included in the payroll overhead rates that are allocated to O&M and capital based on the payroll work mix. The total non-service expense projected by the actuary for the Test Year is $4.1

million, or $3.8 million Oregon-allocated. This non-service portion of pension is an O&M expense.

- Claims and Damages: $80 thousand expense – This expense is based on a three-year historical average.
- Severance: $261 thousand expense – This expense is based on a three-year historical average.
- Non-Officer Stock Expense and Employee Stock Purchase Plan: $974 thousand expense – This expense includes the employee stock purchase plan for non-officer employees, as well as employee stock expense compensation for non-officer employees. The Direct Testimony of Kyra M. Patterson (NW Natural/900, Patterson) discusses this plan.

The overall Oregon-allocated effect of these corporate adjustments is a reduction to O&M of $27.7 million.

Q. How did NW Natural allocate O&M expenses to Oregon?

A. The Company converted its O&M forecast into FERC accounts based on actual historical FERC allocations to allow for a state allocation based on FERC accounts. For Test Year expenses that may not have been incurred in the historical period, the costs were allocated to the appropriate FERC account. NW Natural then applied the relevant Oregon allocation factor to each FERC account to calculate Oregon-allocated O&M. The Oregon FERC allocation factors are determined by considering the specific drivers, such as volumes or customers, that have a

causative effect on costs in that account. The allocation methodology is described in the Direct Testimony of Kyle T. Walker (NW Natural/1200, Walker).

Q. Does NW Natural have cost control protocols and practices in place?

A. Yes. Under the direction of the Chief Financial Officer and Chief Executive Officer, my department engages in an annual budgeting and financial planning process, through which we determine and manage to a Company-wide budget. This budget is informed by individual departmental needs, overall Company goals, and an ongoing focus on controlling costs. Throughout the year, we provide reporting on budgets to actuals for each department and engage with departments on their spending levels. We also require justifications for department budgets and significant departures from budgeted amounts.

Q. Please provide your view of NW Natural's O&M levels, and the amounts of O&M reflected in the Test Year.

A. NW Natural's O&M levels have grown at a reasonable rate, reflecting good cost management practices within the Company. As is true with most companies, much of the pressure on our O&M expense levels comes from inflation and its impact on goods and services, and salary and wage growth. In addition, as described above, the Company's O&M in the Test Year is increasing or decreasing based on contracted or known spend that represents "lumpier" impacts to O&M, such as increased insurance premium expense and a new contract lowering the locating and survey service expense.

Furthermore, as described in detail in the Direct Testimony of Brian E. Fellon (NW Natural/800, Fellon), NW Natural seeks to ensure the same

foundational level of service and reliability to customers, while allowing for the flexible adoption of evolving technological solutions such as cloud-based solutions. The Company works to balance the growing need for technological innovation, while preserving and extending the useful life of existing IT&S platforms and programs.

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibits of Tobin F. Davilla

OPERATIONS & MAINTENANCE
EXHIBITS 1101 – 1108

November 24, 2026

EXHIBITS 1101-1108 – OPERATIONS & MAINTENANCE

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE
EXHIBIT 1101

November 24, 2026

NW Natural
Base Year Twelve Months Ended June 30, 2026
Operations and Maintenance Expense

Line No.	FERC Acct.	Description	BASE YEAR System	BASE YEAR Oregon
			(a)	(b)
1		Natural Gas Storage		
2		Underground Storage Expense		
3		Operation		
4	816	Wells Expense	$386,433	$343,384
5	818	Compressor Station Expense	264,513	235,046
6	819	Compressor Station Fuel	0	0
7	820	Measuring and Regulator Station Expense	3,643,609	3,238,870
8	821	Purification Expense	-	-
9		Maintenance		
10	831	Maintenance of Structures and Improvements	8,759	7,687
11	832	Wells Expense	2,489,236	2,211,935
12	834	Compressor Station Expense	312,378	277,580
13		Total Underground Storage Expense	7,104,928	6,314,502
14		Other Storage Expense		
15		Operation		
16	840	Supervision and Engineering	17,588	15,629
17		Total Other Storage Expense	17,588	15,629
18		Liquified Natural Gas Expense		
19		Operation		
20	844	Supervision and Engineering	2,157,316	1,916,991
21	845	LNG Fuel	(36,479)	(32,415)
22		Maintenance		
23	847	Supervision and Engineering	1,697,380	1,508,292
24		Total Liquified Natural Gas Expense	3,818,217	3,392,868
25		Total Natural Gas Storage	10,940,733	9,722,999
26		Transmission Expense		
27		Operation		
28	856	Mains Expense	4,313,274	4,258,557
29		Maintenance		
30	863	Maintenance of Mains	-	-
31		Total Transmission Expense	4,313,274	4,258,557
32		Distribution Expense		
33		Operation		
34	870	Supervision and Engineering	3,963,129	3,651,890
35	874	Mains and Services Expense	24,634,507	21,787,334
36	875	Measuring and Regulator Station Expense - General	546,721	499,275
37	877	Measuring and Regulator Station Expense - City Gate	711,532	645,361
38	878	Meter and House Regulator Expense	7,939,826	6,967,991
39	879	Customer Installation Expense	13,048,701	11,453,138
40	880	Other Expense	3,261,868	2,944,681
41	881	Rents	367,415	315,327
42		Maintenance		
43	885	Supervision and Engineering	6,895,730	6,273,259
44	887	Mains	3,781,045	3,457,596
45	889	Measuring and Regulator Station Expense - General	2,594,199	2,359,596
46	891	Measuring and Regulator Station Expense - City Gate	83,727	76,692
47	892	Services	672,968	590,597
48	893	Meters and House Regulators	4,304,243	3,783,821
49	894	Other Equipment	1,913	1,679
50		Total Distribution Expense	72,807,523	64,808,237
51		Customer Accounts Expense		
52		Operation		
53	901	Supervision	2,180,557	1,913,657
54	902	Meter Reading Expenses	864,744	758,900
55	903	Customer Records and Collection Expense	24,557,109	21,579,043
56	904	Uncollectible Accounts	-	-
57		Total Customer Accounts Expense	27,602,411	24,251,599
58		Customer Service and Informational		
59		Operation		
60	906	Customer Service and Informational Expenses	1,464,171	1,284,956
61	907	Supervision	-	-
62	908	Customer Assistance Expense	2,186,426	1,915,504
63	909	Customer Information Expense	2,207,513	1,937,313
64	910	Miscellaneous Customer Service Expense	201,192	176,264
65		Total Customer Service and Informational	6,059,301	5,314,037
66		Sales Expense		
67		Operation		
68	911	Supervision	226,658	198,915
69	912	Demonstration and Selling Expense	1,624,611	1,425,677
70	913	Advertising	-	-
71	916	Miscellaneous Sales Expense	-	-
72		Total Sales Expense	1,851,269	1,624,592
73		Administrative and General Expense		
74		Operation		
75	920	Administrative and General Salaries	55,654,382	48,554,581
76	921	Office Supplies and Expense	48,427,193	42,431,860
77	922	Administrative Expenses Transferred - Credit	(36,781,372)	(32,339,790)
78	924	Property Insurance Premium	7,554,543	6,655,552
79	925	Injuries and Damages	120,673	106,313
80	926	Employee Pensions and Benefits	20,760,972	19,229,755
81	928	Regulatory Commission Expense	-	-
82	930	Miscellaneous General Expense	7,134,235	6,383,149
83	931	Rents	10,775,692	9,493,889
84		Maintenance		
85	932	Maintenance of General Plant	7,610,556	6,713,688
86		Total Administrative and General Expense	121,256,874	107,228,998
87		Total Operations and Maintenance Expense	244,831,385	217,209,019
88	407	Environmental Rider	5,000,000	5,000,000
85		Total O&M Expense including Environmental Rider	249,831,385	222,209,019

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE
EXHIBIT 1102

November 24, 2026

NW Natural
Test Year Twelve Months Ended October 31, 2028
Operations and Maintenance Expense

Line No.	FERC Acct.	Description	TEST YEAR System (a)	TEST YEAR Oregon (b)
1		Natural Gas Storage		
2		Underground Storage Expense		
3		Operation		
4	816	Wells Expense	$408,101	$362,638
5	818	Compressor Station Expense	279,538	248,397
6	819	Compressor Station Fuel	0	0
7	820	Measuring and Regulator Station Expense	4,222,436	3,753,243
8	821	Purification Expense	-	-
9		Maintenance		
10	831	Maintenance of Structures and Improvements	10,536	9,247
11	832	Wells Expense	2,839,513	2,523,191
12	834	Compressor Station Expense	333,751	296,571
13		Total Underground Storage Expense	8,093,875	7,193,288
14		Other Storage Expense		
15		Operation		
16	840	Supervision and Engineering	19,477	17,307
17		Total Other Storage Expense	19,477	17,307
18		Liquified Natural Gas Expense		
19		Operation		
20	844	Supervision and Engineering	2,511,921	2,232,093
21	845	LNG Fuel	(38,503)	(34,214)
22		Maintenance		
23	847	Supervision and Engineering	1,963,009	1,744,330
24		Total Liquified Natural Gas Expense	4,436,426	3,942,209
25		Total Natural Gas Storage	12,549,779	11,152,804
26		Transmission Expense		
27		Operation		
28	856	Mains Expense	5,935,319	5,860,026
29		Maintenance		
30	863	Maintenance of Mains	-	-
31		Total Transmission Expense	5,935,319	5,860,026
32		Distribution Expense		
33		Operation		
34	870	Supervision and Engineering	4,928,343	4,527,351
35	874	Mains and Services Expense	24,875,623	22,000,586
36	875	Measuring and Regulator Station Expense - General	688,061	626,343
37	877	Measuring and Regulator Station Expense - City Gate	831,383	752,051
38	878	Meter and House Regulator Expense	9,423,107	8,269,719
39	879	Customer Installation Expense	15,417,714	13,532,474
40	880	Other Expense	4,019,347	3,628,504
41	881	Rents	389,323	334,129
42		Maintenance		
43	885	Supervision and Engineering	8,507,135	7,739,152
44	887	Mains	4,497,400	4,112,670
45	889	Measuring and Regulator Station Expense - General	3,126,973	2,836,185
46	891	Measuring and Regulator Station Expense - City Gate	95,920	87,566
47	892	Services	772,979	678,367
48	893	Meters and House Regulators	5,121,649	4,502,396
49	894	Other Equipment	2,294	2,014
50		Total Distribution Expense	82,697,252	73,629,507
51		Customer Accounts Expense		
52		Operation		
53	901	Supervision	2,613,937	2,293,991
54	902	Meter Reading Expenses	1,033,017	906,576
55	903	Customer Records and Collection Expense	28,748,367	25,262,022
56	904	Uncollectible Accounts	-	-
57		Total Customer Accounts Expense	32,395,322	28,462,590
58		Customer Service and Informational		
59		Operation		
60	906	Customer Service and Informational Expenses	1,743,987	1,530,523
61	907	Supervision	-	-
62	908	Customer Assistance Expense	2,668,200	2,337,589
63	909	Customer Information Expense	3,280,317	2,878,806
64	910	Miscellaneous Customer Service Expense	241,661	211,719
65		Total Customer Service and Informational	7,934,165	6,958,637
66		Sales Expense		
67		Operation		
68	911	Supervision	272,151	238,839
69	912	Demonstration and Selling Expense	1,858,207	1,630,669
70	913	Advertising	-	-
71	916	Miscellaneous Sales Expense	-	-
72		Total Sales Expense	2,130,357	1,869,508
73		Administrative and General Expense		
74		Operation		
75	920	Administrative and General Salaries	61,146,724	53,346,267
76	921	Office Supplies and Expense	53,731,372	46,969,621
77	922	Administrative Expenses Transferred - Credit	(39,909,951)	(35,090,573)
78	924	Property Insurance Premium	11,391,695	10,036,083
79	925	Injuries and Damages	90,647	79,860
80	926	Employee Pensions and Benefits	17,804,357	17,017,152
81	928	Regulatory Commission Expense	-	-
82	930	Miscellaneous General Expense	6,812,791	6,198,297
83	931	Rents	11,329,704	9,982,000
84		Maintenance		
85	932	Maintenance of General Plant	8,519,372	7,514,362
86		Total Administrative and General Expense	130,916,710	116,053,068
87		Total Operations and Maintenance Expense	274,558,903	243,986,140
88	407	Environmental Rider	5,000,000	5,000,000
85		Total O&M Expense including Environmental Rider	279,558,903	248,986,140

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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EXHIBIT 1103

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Executive Summary

September 2026 — Stable Growth, Sticky Inflation

Resilience appears to be a recurring economic theme as the Office of Economic Analysis (OEA) evaluates and updates forecasts in quarter five of the biennium. National and state economic performance have withstood stiff headwinds from trade tariffs and elevated energy prices, in large part due to substantial fiscal support from the tax cuts embedded in H.R. 1.

State level economic growth, which has lagged the national trend for much of the post-pandemic period, largely closed the performance gap at the start of the year. Whether this gap remains closed is an open question—and the answer will have significant implications for the revenue forecast over the next several quarters.

Steady economic output appears to be translating into stabilizing conditions in the labor market, as reflected in the generally sideways movement in the unemployment rate nationally and in Oregon. A muted underlying rate of turnover in employment, characterized as 'low hire-low fire', appears to remain the status quo—and likely reflects muted economic confidence from both workers and employers.

At the state level, an ongoing decline in layoff announcements suggests the "low fire" dynamic should hold. Meanwhile, job posting data suggests tepid hiring demand is, at best, only mildly improving. As such, the dominant factors behind the largest source of tax revenue for the state—personal income taxes on wages and salaries—should be bolstered by relatively stable employment conditions and persistent, elevated wage inflation.

Another economic channel demonstrating resilience is stubbornly elevated inflation pressures. This recurring theme across the latest forecast is pumping up corporate profits, impacting the outlook for interest rates, and also driving wage trends. The downside of resilient economic performance appears to be a lack of progress toward price stability. Inflation has run "hot" for more than five years—for a multitude of reasons. Tariffs have contributed, but not exclusively. Industrial input prices in general, oil prices in particular, shelter costs, and wage pressures are all contributing to above-target inflation.

The longer this overshoot occurs, the more difficult it will be to correct as consumer and business inflation expectations become elevated and more entrenched. As a result, the duration and magnitude of overshoot will be directly proportional to the necessary dosage of antidote (i.e. restrictive monetary or fiscal policy).

Previously, the Office of Economic Analysis described the forecast profile for economic growth in this biennium as reminiscent of a hockey stick, i.e. showing faster momentum in the later stages of the biennium. The slope of the forecast profile became less steep due to rising oil prices in the first half of this year. This flatter upward slope remains intact in the latest forecast iteration, not only due to still-elevated energy prices, but now also in response to the risk of higher interest rates resulting from either renewed vigilance from inflation-fighting policymakers or more inflation-conscious investors.

A key theme at the start of 2026 was the notion that a growth acceleration relative to 2025 would also drive a firming of labor conditions, even amidst a nascent AI disruption. The wild card of geopolitics and rising energy prices appears to be sapping much of the vigor behind that projected economic pickup.

When the economy is hitting on all cylinders, revenue forecast revisions tend to be uniformly positive. Likewise, when the economy is weakening, revenue streams will exhibit mostly negative growth rates. However, under conditions like the current environment where the economy is transitioning from one paradigm (slowing) to another (accelerating), otherwise known as an inflection, indicators will vary from positive to negative with only marginal net consequences.

The latest forecast for General Fund revenues demonstrates such a mixed and modest result, increasing $55 million (0.2%) to $35.7 billion for the 2025-27 biennium. An increase in Personal Income Taxes is somewhat offset by a downward revision to Corporate Income Taxes while all other sources remain virtually unchanged. The latest projection for monies remaining in the General Fund at biennium's end has increased to $400 million with ten months left.

Beyond the General Fund, the revenue outlook is also mixed. Lottery earnings have been revised upward by $4 million due primarily to stronger-than-expected Video lottery sales. Corporate Activity Tax proceeds are down $95 million as payments over the preceding three months failed to match projections. As noted later in the publication, this is viewed primarily as a data processing issue as cash payments by corporate entities are exhibiting growth and indicators of economic activity remain strong. Finally, the Marijuana Tax forecast has been revised to reflect ongoing price declines and constant consumption patterns, a break from previous growth-oriented outlooks.

Economic Outlook

Macroeconomic Setting

Resilience means steady growth, but also sticky inflation

The national economy has endured multiple rounds of tariff increases, a sizable energy price shock, heightened geopolitical uncertainty and an ongoing, material disruption related to the build-out of artificial intelligence—yet the economic cycle has managed to persevere. A massive tax relief package provided a critical buffer, and the timing of tariff refunds also arrived mostly in the same period when the spike in energy prices was most extreme. To be sure, both served as economic stabilizers.

The overall resilience of the economy has been impressive, as reflected in both output growth and unemployment trends—but this has not occurred without cost. Economic resilience appears to have also fortified inflation pressures, which accelerated through midyear and have now run above policymakers' target for over five years.

Inflation serves as a tax on consumers and businesses, and now it also appears to be having an outsized impact on financial markets by contributing to higher interest rates. This can occur through two primary channels: Market-determined interest rates can rise as investors demand a higher inflation premium or short-term rates increase due to a more hawkish monetary policy stance from the Federal Reserve. The former appears to be the dominant driver of late. Either way, a higher cost of financing consumption and investment poses a material risk to the medium-term outlook, particularly for interest-sensitive sectors such as housing and business investment.

The trend in interest rates appears to be broadly higher at the moment due to a multitude of factors, some of which are global, but a core driver is the anticipation of continued elevated inflation. The cost of borrowing for the U.S. Treasury over a 30-year horizon (i.e. the long bond yield) has recently approached (5.31%), the highest level since 2002.

The perceived durability of the economic cycle has led the consensus of forecasters to further reduce recession risks (to 22% over the next 12 months). Economic signals pointing to sturdy, and possibly accelerating, domestic demand have led OEA's national forecast provider to raise the expected trajectory for corporate profits, which in turn appears to be contributing to ongoing gains in stock market valuations. (The S&P 500 index reached a new record high in mid-August.)

Taking the energy shock in stride (mostly)

A sharp increase in energy prices relating to the military conflict with Iran was a dominant theme embedded in the Q2 2026 forecast update. Fortunately, oil and gasoline prices did not reach the critical thresholds which OEA estimated would be sufficient to induce recession. Prices subsequently retraced, albeit only partially, with crude oil prices presently hovering about midway between the May peak and the December lows. Gasoline price increases have also moderated, to about 30% year-on-year compared to 45% as of May. The economic headwind from energy prices is still present but less severe compared to earlier this year.

Initial signals suggested the consumer response to this energy-driven inflation flare-up appeared to be extraordinarily limited. Inflation-adjusted consumer spending continued to expand even while inflation-adjusted personal incomes turned negative—meaning that for the first time since 2022 incomes were no longer outpacing inflation. More recently, the July retail sales data appeared to crack under this pressure, as the results fell meaningfully short of forecasters' expectations. However, tracking data through August suggests that demand is stabilizing, if not mildly recovering.

Hyperscalers and tariff refunds reduce energy price pain

Businesses which were exposed to lower- and middle-income consumer stress witnessed tepid economic conditions over the last few quarters. However, this was not reflected more broadly across the industrial base, where activity remained robust and quarterly earnings results were strong. Business capital investment continues to accelerate, lifted in particular by demand related to hyperscalers, data centers and AI investment.

Many trade-sensitive firms were also insulated from energy-related headwinds due to the U.S. Supreme Court ruling overturning significant portions of the 2025 tariff increases in February. Not only did the effective tariff rate initially drop sharply (albeit temporarily), but also the partial refunding of tariff revenues acted similarly to an unanticipated tax refund for many businesses. This two-pronged stimulus coincided serendipitously with a period where energy prices would have otherwise likely proved to be more onerous.

It is worth noting that the decline in the effective tariff rate proved to be short-lived, due to the administration of new tariffs using other sections of the trade code. Importantly, the impact of tariffs remains a prominent feature of the present economic landscape.

Due to the aforementioned factors, overall economic output barely flinched in response to a 70% increase in oil prices. Real GDP grew slower in Q2 (1.5% annualized) compared to the average

over the prior eight quarters (2.4%), but this was not an accurate depiction of underlying domestic demand. Rather, it reflected a surge in imports and a drawdown of nonfarm inventories, both of which count negatively toward topline GDP—but could actually be indicative of a pickup in domestic demand. The surge in imports also likely reflected a rush to take advantage of the temporary lull in tariff rates, not unlike what occurred before the initial tariff announcements in April 2025.

Removing the impact of inventory drawdowns and fluctuations in foreign trade from the GDP accounts allows for a clearer read of underlying domestic demand. This measure, which is referred to as final sales to domestic purchasers, actually accelerated last quarter (3.1% compared to an eight-quarter trailing average of 2.4%). Household consumption rose 3.2%, while businesses' investment rose 8.4%. The core message from these results is that the domestic economy is indeed on a sturdy footing at present. In a quarter marred by surging energy prices, profits appeared to hold up, stock market valuations ascended to new record highs, and domestic demand remained strong.

Labor market limp may be deceiving

Under normal circumstances, firming domestic economic output should also be reflected in labor market conditions—but the evidence appears mixed to date. The U.S. labor force saw net job losses in July, but the unemployment rate moved lower. The pace of hiring may not be as reliable of a gauge of hiring demand under current conditions, given aging demographics and stricter policies regarding foreign workers and immigration.

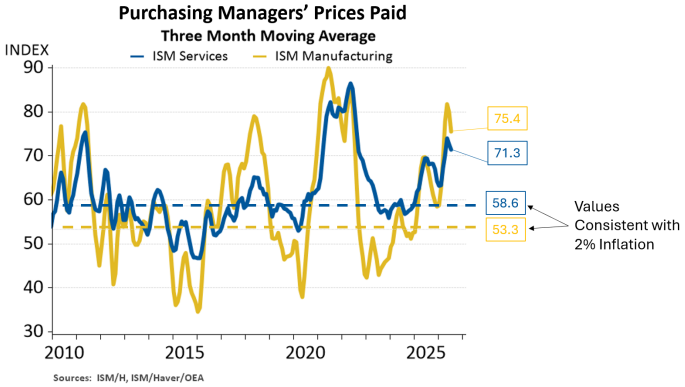
These factors are slowing the natural growth rate of the labor force, which means fewer jobs need to be created each month to hold the unemployment rate steady. In pre-pandemic times, the breakeven rate of job creation typically fluctuated between about 85k to 125k jobs per month. Over the last several quarters that breakeven rate has shifted much lower, and probably now stands closer to 20k to 25k. Importantly, while the pace of hiring remains low compared to recent history, the unemployment rate has held relatively steady for the most part and has even shown some signs of trending lower in recent months.

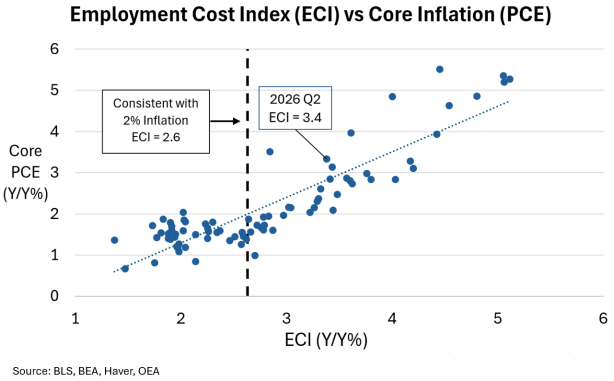
Notwithstanding net losses in July, job creation year-to-date has averaged about 60k per month, which is a measurable improvement relative to the 2025 average of 10k per month. This year's pace has been sufficient to shift the unemployment trajectory from an uptrend in 2025 to a downtrend more recently. To be sure, the low hire/low fire characterization which many economists have adopted to describe their current assessment of the labor situation still holds true, but the trend—while mild—points to at least some modest degree of improvement. Recent

data on job openings (up 2.2% year-on-year) suggests that the mild hiring acceleration in the first half of 2026 holds the potential for additional, incremental improvement.

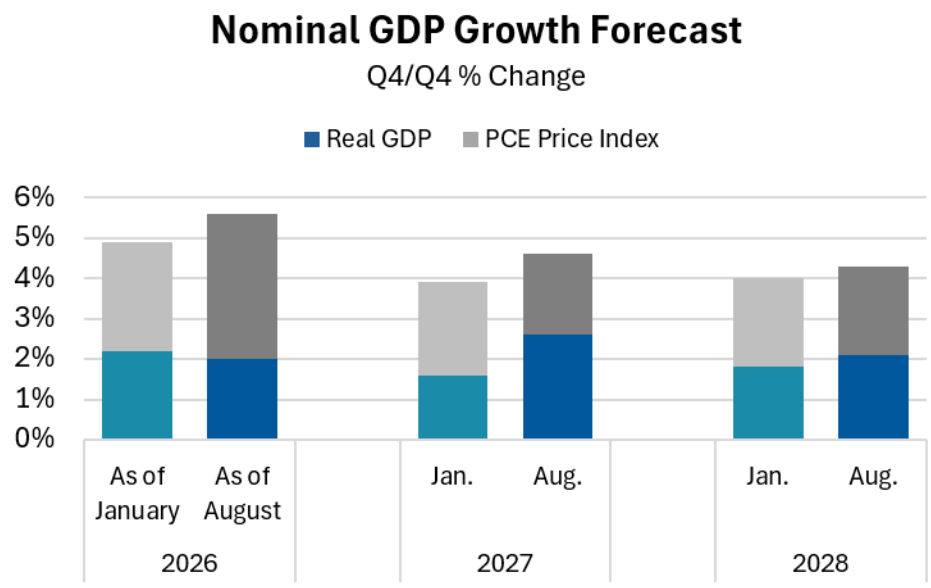
The outlook for inflation under the economic conditions described above is not particularly benign. The two dominant forces over longer-term inflation trends are the pace of economic growth relative to the natural (a.k.a. potential) rate and businesses' and households' expectations of future inflation. The economy has simply not cooled off sufficiently from its post pandemic surge to temper excessive price pressures.

As demonstrated in the following figures, the current elevated pace of inflation is not purely the result of tariffs and energy prices (although these are certainly contributing factors)—rather, the main drivers are still-high input prices, firm industrial pricing power and elevated wage pressures. These are all holding at paces which are inconsistent with a return toward the 2% inflation objective of policymakers. It remains an open question as to how aggressively the Federal Reserve is willing to act in order to tighten financial conditions in order to cool these input pressures.





While the economic reality for households and businesses is strained by a high inflation environment, the outlook for tax revenues actually benefits from the boost to topline economic activity from price and wage pressures. The fiscal trajectory at both the state and national level is largely directed by the trend in nominal economic activity. Nominal output, by definition, is real activity (i.e. inflation-adjusted) plus the change in the price level (i.e. the pace of inflation). As such, the fiscal trajectory is largely indifferent between a scenario of robust growth and low inflation compared to a scenario of low growth and robust inflation. Clearly, households and businesses would favor the former, but the tax collections between these two scenarios are similar. It is for this reason that economists describe inflation as a "hidden tax"—or as the Nobel Prize winning economist, Milton Friedman quipped, "Inflation is taxation without legislation."



In conclusion, while this forecast update shows some material changes to various components of the revenue outlook, there are large offsetting factors. Personal income taxes are revised higher, while corporate income and activity taxes are revised lower. Similarly, while corporate taxes are trimmed for the current biennium, they are lifted for the next biennium. The Office of Economic Analysis remains of the view that the current economic cycle remains in the middle stages, despite its age as measured by the calendar. If forecast expectations of stronger growth in 2027 are realized nationally, then the trend in state output and employment should be similarly firm.

Oregon's Economic Outlook

Last quarter, the Office of Economic Analysis highlighted that shifting energy and geopolitical conditions had dampened the outlook for the state economy. These factors had contributed to the flattening of the anticipated hockey-stick trajectory in Q2, which continues to be an appropriate characterization of the forecast profile of economic growth for Oregon. The state is still expected to grow, albeit at a slower pace broadly aligned with last year's performance, with modestly stronger momentum emerging in the late stages of the biennium. If forecast expectations of stronger growth in 2027 are realized, then the trend in state output and employment should firm.

Resilience has been a reoccurring feature of the U.S. economy, and this strength extends into Oregon as well. Although the state has been plagued by year-over-year job losses thus far into 2026, the state unemployment rate has remained unchanged. This suggests that the necessary number of new jobs to maintain steady unemployment—or the breakeven employment growth rate—has changed significantly from recent history. As such, the pace of hiring may not be as reliable of a gauge of hiring demand given the current circumstances. Slower population growth and an aging population have contributed to this changing labor market dynamic.

With monthly job growth in 2026 fluctuating between negative and positive and a stable unemployment rate (5.2%), the data suggest that breakeven employment growth is now likely near zero. While near-zero employment growth may be sufficient to maintain a stable unemployment rate in Oregon, stronger job growth would be necessary to meaningfully reduce it.

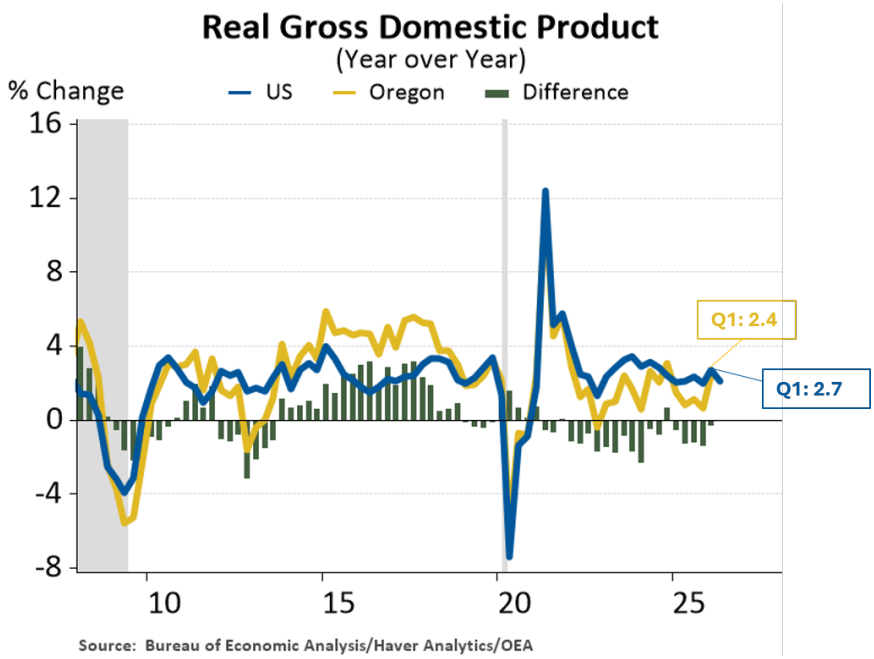
The recent declines in layoff announcements provides another encouraging indication for Oregon's labor market. The Worker Adjustment and Retraining Notification's (WARN) have declined noticeably from their peak in 2025, suggesting that the low fire dynamic appears to remain true and provides some evidence of continued labor market resilience in the state.

At the same time, state level economic growth, which has lagged the national trend through all of 2025, looks to have largely caught up to the U.S. in the beginning of the year. As shown in the chart below, year-over-year real GDP growth in Oregon for Q1 2026 was 2.4%, lagging the nation by a mere 0.3 percentage points.

For most of the pandemic recovery Oregon has lagged the national economy. Therefore, it is not unusual at this moment to see the state maintain its slight underperformance to national trends in

indicators such as unemployment. However, this pattern differs from what Oregon previously experienced before the pandemic, as the state consistently outpaced national GDP growth for four consecutive years between the two most recent recessions of 2008 and 2020.

Oregon may be in a situation similar to 2012 and 2013, when it also lagged national activity—albeit temporarily. It is too early to tell whether the recent narrowing of the US-Oregon output gap represents a similar turning point or a temporary convergence. The next state-level GDP release from the Bureau of Economic Analysis, scheduled for the end of this quarter, will be telling in this regard.

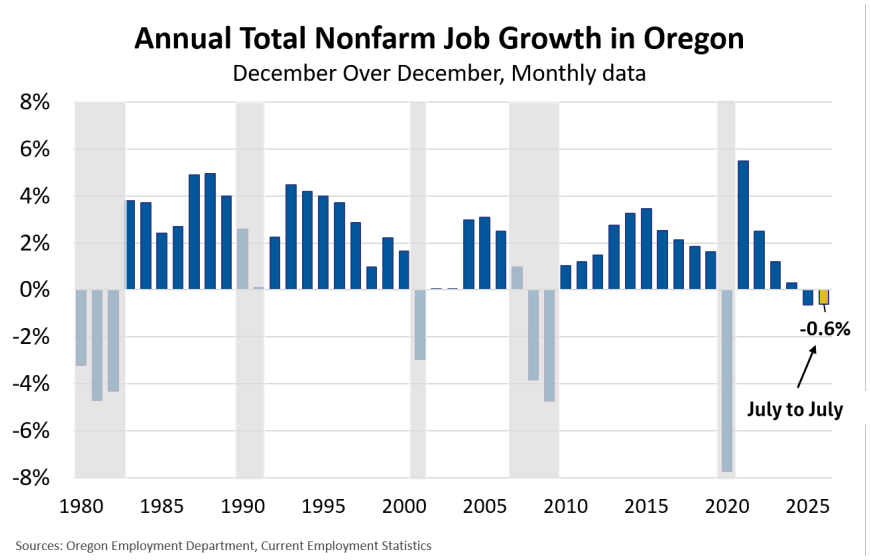


Employment flickers

In recent months, data published by the Oregon Employment Department (OED) have shown the state has continued to experience year-over-year job losses thus far into 2026, a trend that has persisted since 2025. This is quite unusual for the state as it has historically been the case to only see year-over-year payroll declines during recessionary periods, as shown in the chart below. With recent revisions going back to April 2025, there has been little change in the direction or magnitude of Oregon's labor market. As such, prior characterizations of the tepid job gains remain relevant.

Within the state, one sector has consistently stood out from the rest. The private education and health services sector continues to act as the state's primary driver of job creation, which is a pattern that mirrors national trends. This is in part due to the country's aging demographics and the need for more health services.

Although the state is net negative on payroll growth, the state's unemployment rate has held steady at 5.2% through 2026 thus far. The persistent job losses, alongside the unchanged unemployment rate, indicate that the labor market may be transitioning to a lower underlying growth trend. This is also the case for the U.S. economy, as migration patterns continue to shift and the population continues to age.



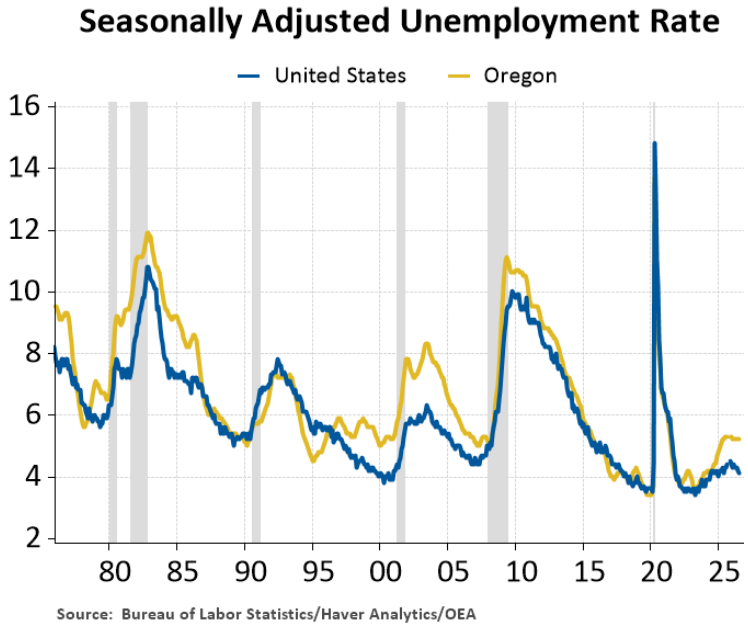
With the gap in economic activity growth between Oregon and the U.S. largely closing and a stable unemployment rate, the state's economic outlook has improved somewhat in the immediate near-term compared to the prior forecast iteration. Despite this, there remains some risk for the employment outlook as job gains have been concentrated in a limited number of industries, particularly healthcare and social assistance. A continuing decline in Affordable Care Act enrollment and cuts to Medicaid could result in a pause of the growth of health care employment that has supported much of Oregon and the U.S. economy.

Unemployment Steady



One leading indicator for Oregon's unemployment rate is the volume of WARN notices. As of July, the monthly number of implied layoffs in the state have considerably moderated from the peak experienced one year ago. Although the six-month moving average slightly increased from June to July, the overall continuing decline since the end of 2025 is an encouraging signal. The decreasing WARN notices experienced at the end of 2025 and thus far into 2026 have coincided with a slowly declining and stabilizing unemployment rate.

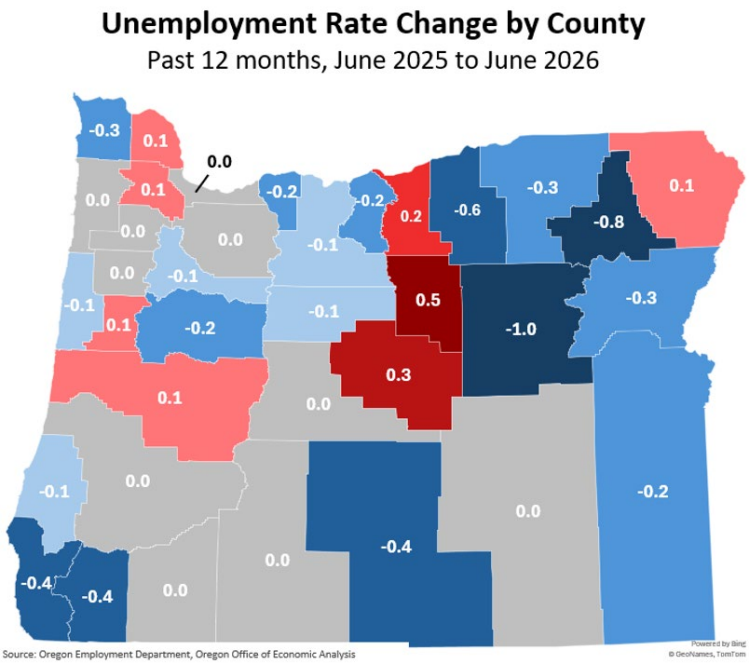
At the time of publication last quarter, the Local Area Unemployment Statistics (LAUS) data showed that Oregon had registered a 5.2% unemployment rate for the first three months of 2026. In the subsequent data releases, the rate has remained unchanged. This is welcome news, particularly when compared to the Q3 forecast of last year, when Oregon's unemployment rate had risen by 0.5 percentage points between January and July 2025. During this period, the U.S. was at 4.0% in January and increased to 4.3% in July.



Oregon's unemployment rate continues to remain elevated compared to the U.S. but has been stabilizing through the first two quarters of 2026. In contrast, the U.S. has seen a gradually decline in the unemployment rate. To be sure, it is not unusual for Oregon's unemployment rate to drift higher than the U.S., which is most often the case as illustrated in the historical data presented in the accompanying chart.

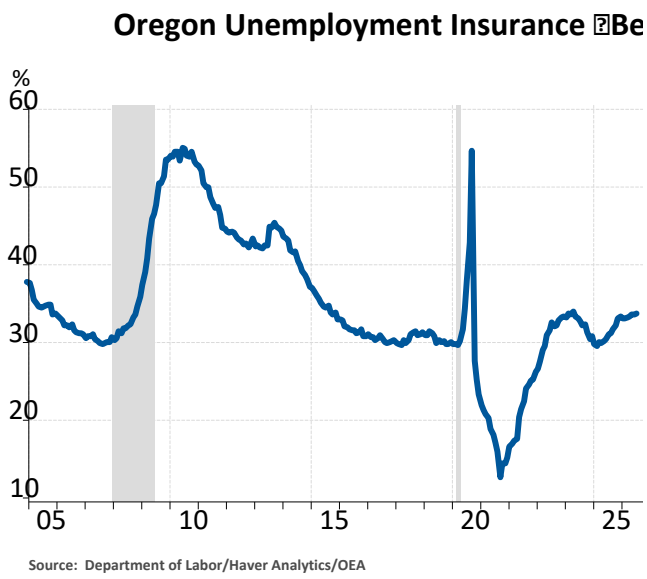
It is also important to note that Oregon has continued to perform similarly to its neighbors. California (5.1%), Washington (5.0%) and Nevada (5.0%) all registered unemployment rates above 5.0% for the month of July. Idaho (3.6%) is the only neighboring state to diverge meaningfully from Oregon.

Not only are there deviations between Oregon unemployment and the national trend, but also significant variation across counties within the state. The figure to the right shows the unemployment rate change by county over the past 12 months. The state overall is unchanged at 5.2% (from June 2025 to June 2026).



Nearly half of all counties in the state saw an improvement in their unemployment rate, with the other half remaining unchanged or slightly worsening over the past year. The largest increase in the unemployment rate during this period, 0.5 percentage points, was observed in Wheeler County. The county that saw the largest decrease in their unemployment rate was Grant County (1.0 percentage point change). The counties that saw no change in the unemployment rate are counties of metropolitan statistical areas with high population concentrations, such as Clackamas, Deschutes, Jackson, Multnomah, Polk, and Yamhill Counties.

While unemployment rate changes are a valuable barometer of labor market conditions, looking at how long individuals remain unemployed adds another layer of understanding. The unemployment benefit exhaustion rate measures the share of Oregonians who have received their maximum allotment of UI benefits (following 26 weeks). An elevated exhaustion rate is an indicator of labor market fragility and difficulties for displaced workers to find new sources of employment.



To date, the Oregon unemployment insurance benefit exhaustion rate has risen to a level reminiscent of the first half of 2024. Although the benefit exhaustion rate seems to have ticked up through 2025 and 2026, the rate is still low by historical standards. This is an indication that the labor market has slowed but remains functional. This echoes the "low hire-low fire" characterization that many labor economists have continued to apply to their assessment of national conditions and has been characterized in prior forecast iterations.

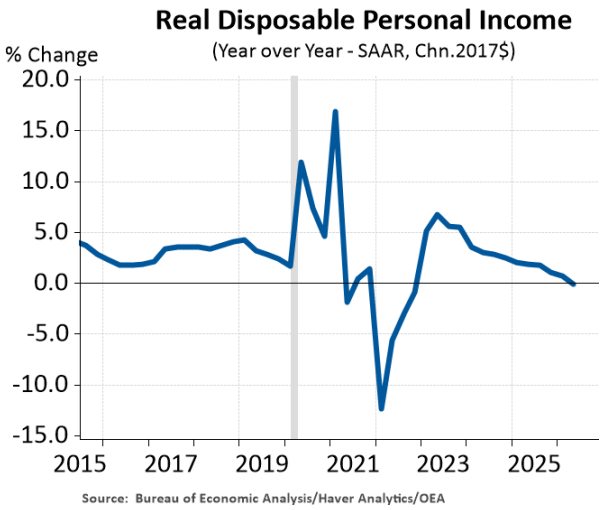
Topline Forecast Changes	
Labor Conditions	The unemployment rate is revised slightly higher across the forecast horizon as Oregon's unemployment rate has yet to come down substantially. Anticipated job creation is revised lower relative to the previous 2026 Q2 outlook in the long term but is revised up in the near term in large part due to recent tracking.
Personal Income	Total personal income is revised slightly lower across the forecast horizon. This forecast incorporates the most recent Q1 BEA release and prior revisions.
Population	Population growth has been revised slightly lower across the forecast horizon resulting from a reduction in growth from the employment forecast. This forecast incorporates the latest revisions released by PSU/PRC in December 2025. The population is expected to grow by an annual average of 0.4% through 2035.

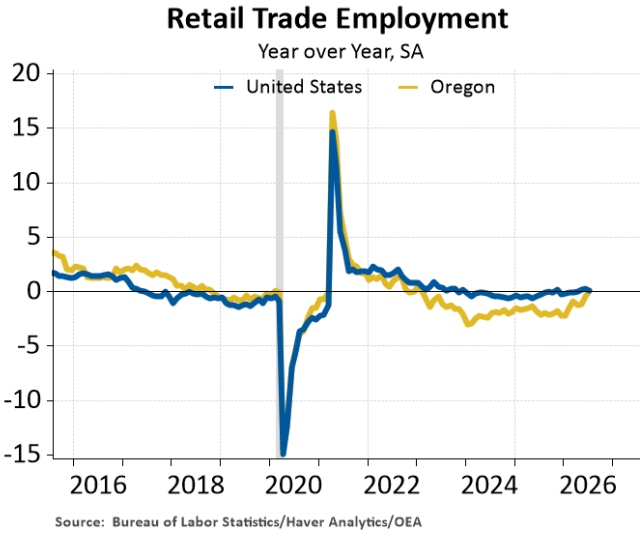
The economic and revenue forecasts are developed using inputs from a national forecast vendor, Standard & Poor's. Key assumptions included in their forecast are below.

Key Forecast Assumptions	
Federal Fiscal Policy	The forecast includes provisions in the One Big Beautiful Bill Act (OBBBA)/HR1.
State and Local Fiscal Policy	States are assumed to take on a larger share of provisions for Medicaid benefits in response to reduced federal grants.
Population	Net international migration assumptions are 500,000 lower per year, relative to Census projections, for the four years of the Trump presidency.
Monetary Policy	The Fed is expected to remain on hold until June 2027. The federal funds rate reaches a range of 3.00%-3.25% in December 2027, very close to estimates of the long-run "neutral" range.
Tariffs and Trade	The replacement of IEEPA tariffs that ranged from 10% to 50% with Section 122 tariffs expired last month and have now been replaced by Section 301 tariffs. The average effective tariff rate with both Section 301 and existing tariffs will converge to about 10%.
Oil Prices	Fallout from the ongoing war in Iran raises the spot price of Brent crude from an average of $69 per barrel over 2025 to an average of $87 in 2026, before it eases to an average of $80 by the end of 2027.

Industry Insight: Retail Trade

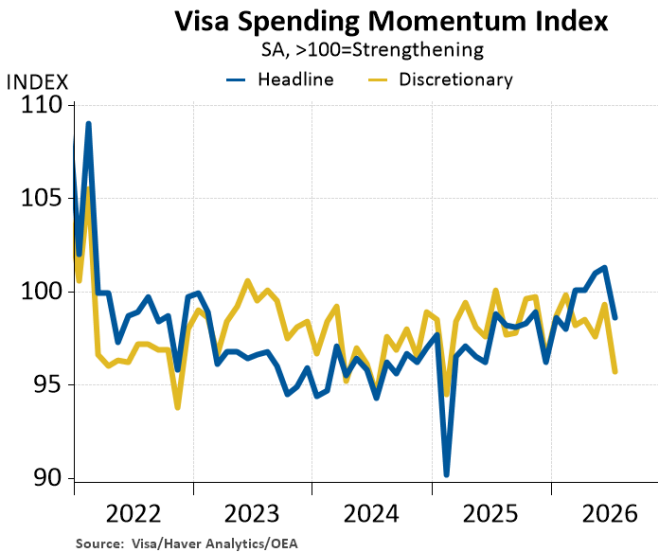
Elevated inflation stemming from energy prices and tariffs is evident through the slowing of national real disposable income growth, which can constrain the retail trade industry. Despite this, retail employment is showing some resilience as job losses appear to be slowing, both nationally and in Oregon. Card spending momentum shows that while headline spending strengthened for much of 2026, discretionary spending has been in decline.





Real disposable income is after tax income, adjusted for inflation. Despite the beginning of the war in the Middle East, the first quarter of 2026 saw income continue to grow, albeit at a slower pace. As inflation pressures persisted into the second quarter, income then saw a decline for the first time since 2023. Retail employment, conversely, has been in decline since 2023 and saw its first month of growth in July. Even if income has fallen, it remains strong enough that the demand for retail trade employees has not considerably declined in unison.

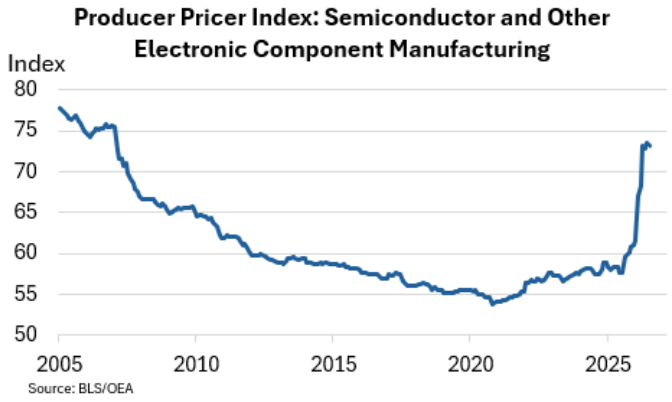
The Visa Spending Momentum index is a measure of year-over-year change to consumer spending. Headline spending includes spending at restaurants and gas stations, while discretionary spending does not. This partially explains why headline spending has continued to grow for much of 2026, as fuel is a relatively inelastic good. Discretionary spending has been falling, but not at a rate outside of the range seen in the last three years. This indicates while spending may be slightly hampered by inflation, consumers have not drastically altered their behavior in the current environment.



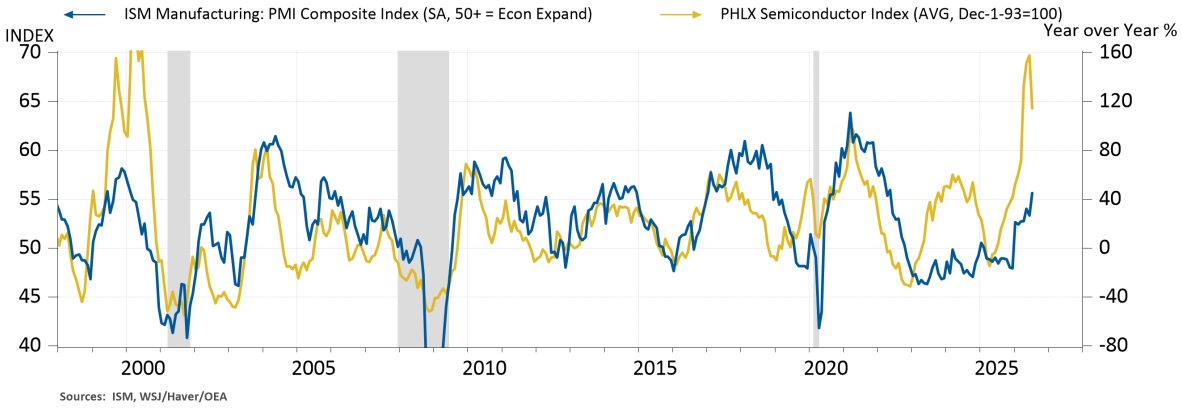
Industry Insight: Semiconductors

The proliferation of artificial intelligence has increased demand for semiconductors. Despite increasing selling prices for semiconductors, employment has been declining in Oregon. Recent strength in industry nationwide may be correlated with an uptick in manufacturing activity.

The producer price index (PPI) for semiconductors and other electronic component manufacturing is at its highest level since 2007. While the fall in prices bottoms out in 2020 and begins its upward trend, the index has grown by 27% in the last year alone. This is reflective of tightening supply as companies work to keep up with the quickly growing demand.



The Bureau of Labor Statistics (BLS) data estimates that Oregon semiconductor and electronic product manufacturing employment has fallen 28% from January of 2023 to June of 2026. While national employment numbers have also predominantly trended down in during this period, the United States has added approximately 4,100 jobs to the industry in the first half of 2026. However, that growth has not trickled down to Oregon, with the state losing an estimated 600 jobs in the same period. This indicates that while increased demand may be boosting the industry on a national level, at least in the short term, Oregon has not shared that same benefit.

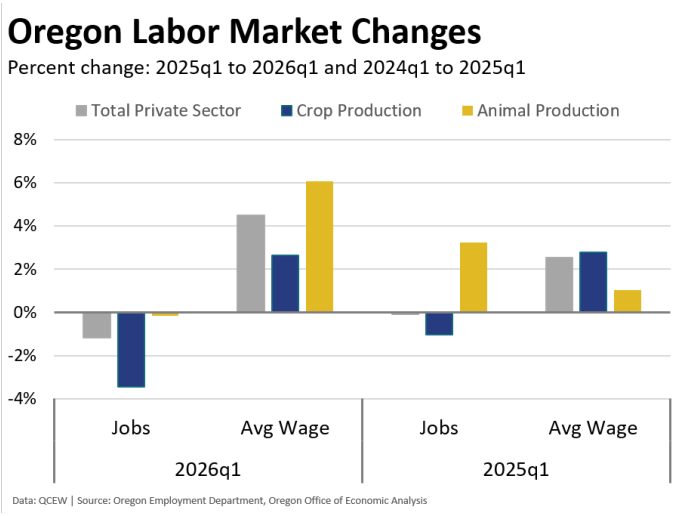


The expansion and contraction of the semiconductor industry can also provide strong signals for manufacturing. The chart above shows that the Philadelphia Stock Exchange Semiconductor Sector Index (SOX) often increases concurrently with the ISM Manufacturing Composite Index. It also serves as a meaningful leading indicator of manufacturing downturns with the SOX often showing slowdowns in growth months before they are observed in the ISM Index. Both have increased to start off 2026, with the SOX remaining elevated despite a drop in July. This is a potential positive sign that manufacturing may see improving conditions in the coming year.

Industry Insight: Agriculture

The Oregon Legislature passed HB 4002 (2022), which establishes maximum hour and overtime compensation requirements for agricultural workers. The law went into effect starting at the beginning of 2023. This office will continue to analyze and monitor the economic and labor market data to assess any impacts from the law. OEA will work to incorporate these changes, if any, in the broader context of the state's agricultural economy.

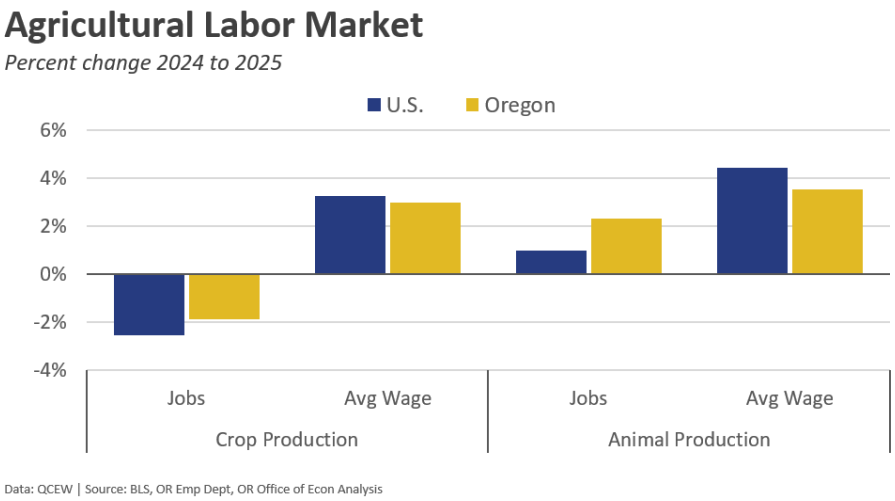
In prior quarters this office highlighted QCEW data, the nearly real-time data coming from businesses submitting records for unemployment insurance purposes. However, in Oregon, many agricultural employers are not subject to pay unemployment insurance taxes. As a result, the agricultural sector has a less robust employment representation in the covered employment statistics when compared to other sectors. It's also important to note that agricultural data is highly seasonal, which makes interpreting trends more challenging. However, OEA will continue to report on the latest information as it becomes available. As of this forecast, the first quarter of 2026 Oregon data and the fourth quarter of 2025 U.S. (all states) data are available.



As shown in the accompanying figure, Oregon experienced job losses in crop production employment —similar to total private employment, although to a greater degree — while animal production saw a minimal decline from Q1 2025 to Q1 2026. However, all saw an increase in their average wages over this period. This is a different dynamic than what was experienced from Q1 2024 to Q1 2025, as shown on the right-hand side of the chart. Over this time, animal and crop production experienced differing trends in job gains, with negative job growth in crop production and positive growth for animal production. Additionally, animal production saw employment growth outpace wage growth, while crop production experienced faster growth in average wages than in employment.

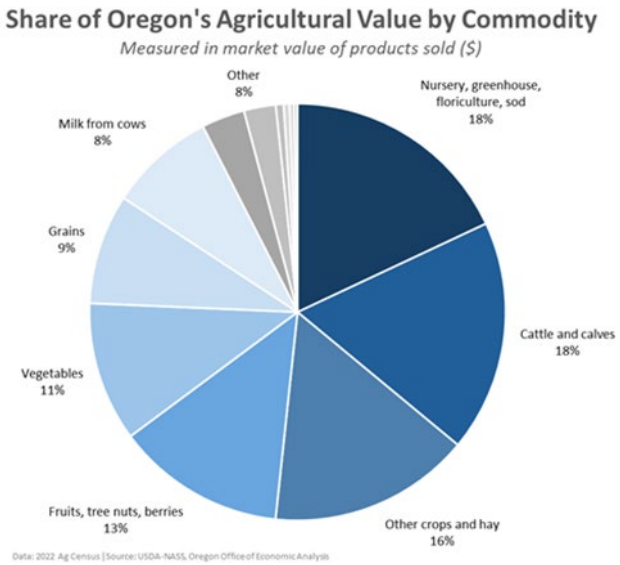
With the full data set available for 2025 for both Oregon and the U.S., changes can now be evaluated over the year to see how agricultural employment has fared. From 2024 to 2025, Oregon's average wage growth in crop and animal production has been slightly weaker than those

seen nationally, as shown in the accompanying chart. Interestingly, while average wages have increased for both of these industries, they have also experienced a mix of job gains and losses. Crop and animal production are doing slightly better than the U.S. in both their respective job declines and job growth. Crop production in Oregon experienced smaller declines than the U.S., and animal production saw more growth. The current trends in crop production appear to align with the expected effects of the law, namely, weaker employment alongside strong wage growth. The divergence between crop and animal production in terms of year-over-year employment gains have continued to occur through 2025, reflecting differing industry trends within the broader agricultural sector.



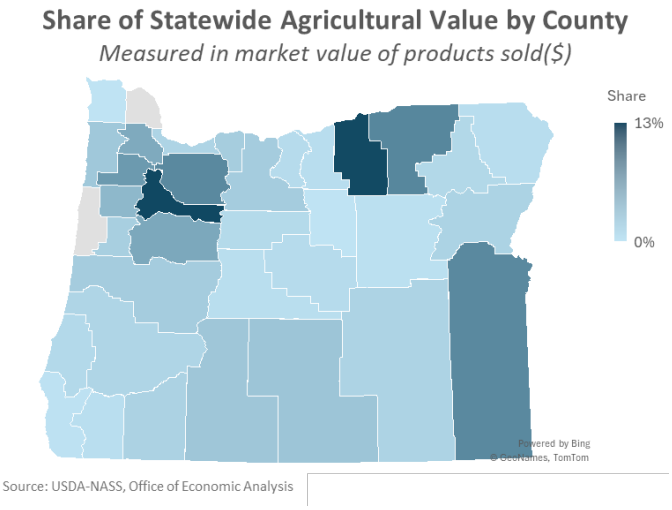
Keep in mind that this is still preliminary data and is far from enough information to make any strong assessments of how the law is impacting the state economy, given the changing dynamics. It is a big picture analysis using a simple year-over-year comparison. As such, it is hard to say whether Oregon's experiences are due to the new law or more a reflection of broader industry trends given commodity prices, tariffs and other factors.

According to the United States Department of Agriculture (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. The next census will not be conducted until 2027, so the available data on agriculture is significantly lagged.



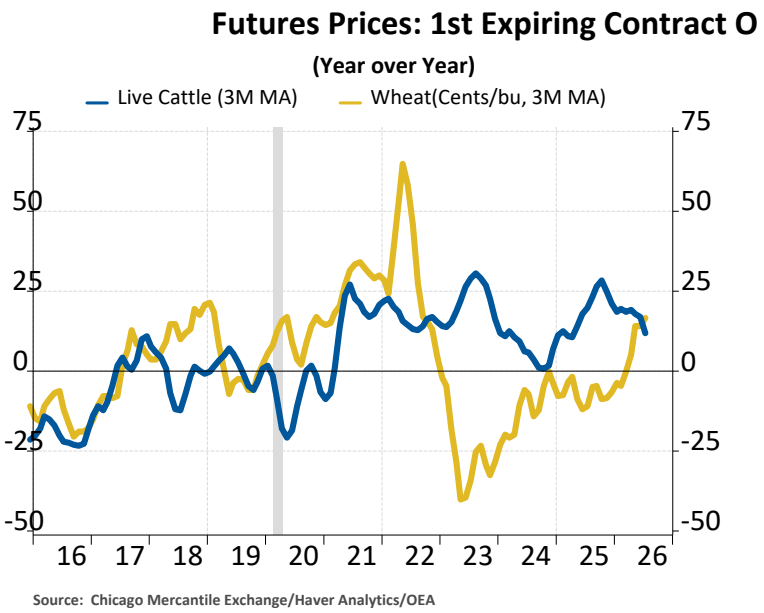
Although the agricultural industry is not large in terms of employment for the state, at about 3.1% of all private jobs in 2025, it remains a critical pillar of Oregon's economy. The state excels in

the production of a diverse range of crops, including berries, wine grapes, nursery plants and hay, as well as livestock and dairy.



Although Oregon is recognized for certain commodities, the state produces a wide array of agricultural products. These vary across the region as counties differ in 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. The eastern region focuses on hay, cattle and specialty crops like grains and oilseeds.

Live cattle and wheat are two of Oregon's largest agricultural staple goods. The Chicago Mercantile Exchange's data show that growth in wheat prices has been accelerating through 2026 and are now ahead of live cattle, which has not occurred since 2022. In contrast to wheat, the growth of live cattle prices has been gradually slowing in 2026, although still in positive territory. Decreasing prices on futures contracts can be a projection of continued hardships for farmers and those selling the commodities. With a mixed outlook for 2026 for these two staple goods, growth throughout the rest of the year may differ for those involved in animal and crop production.



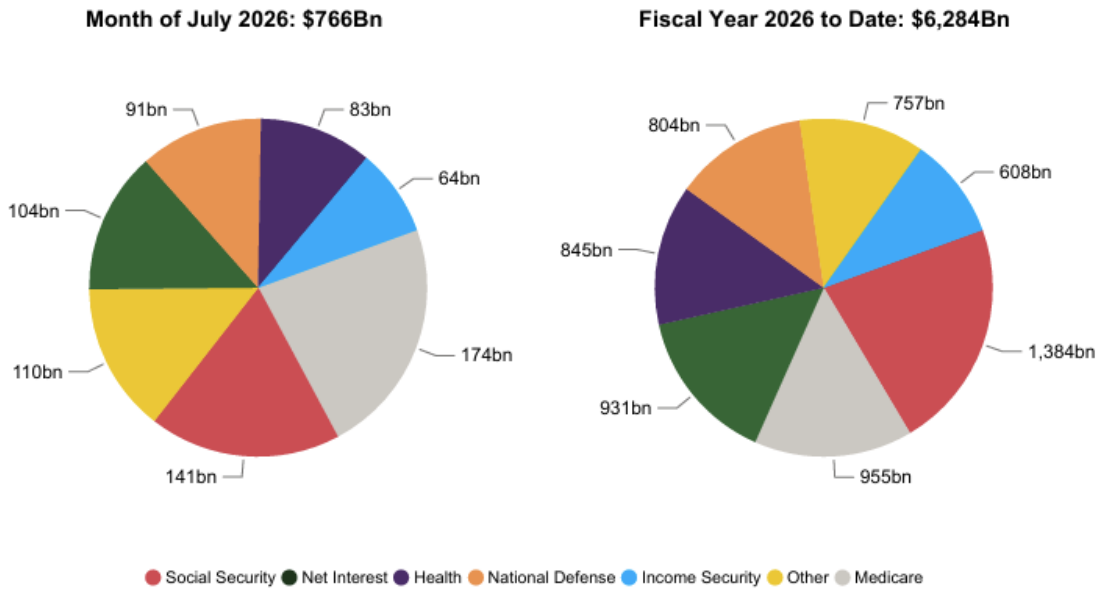
Near- to Medium-Term Forecast Risks

Oregon faces a multitude of near- to medium-term economic risks:

- *Financial Market Stress*: The previous 30 years have witnessed two asset price bubble-and-bust cycles – the 2001 technology sector bubble and the 2008 housing market bubble. Currently, the potential exists for an artificial intelligence (AI) bubble to be elevating valuations well above sustainable levels. The consequence of an ensuing crash in equity prices is not just economic; it has dramatic effects on Oregon's revenue streams as well. Capital gains income is currently estimated to contribute 7%, or $2.1 billion, of Oregon's $30 billion in personal income taxes in the current biennium. During the previous two bubble-bust cycles, capital gains income fell an average of 55% in the year of the crash. The full effect is even greater as falling incomes move taxpayers into lower tax brackets, affecting the resulting revenue from other sources, as well.

- *Elevated Federal Debt*: The total United States national debt has surpassed $40 trillion, higher than the 2026 Q2 estimate for total national Gross Domestic Product. In July, receipts were outpaced by outlays, adding $432 billion to the national debt. The United States has operated at a deficit of $1.8 trillion through fiscal year 2026. Net interest payments trail only Social Security and Medicare in the major federal expenditure categories. Elevated debt levels can slow economic growth by lowering private investment, raise interest rates and payments, and increase the risk of a financial crisis.

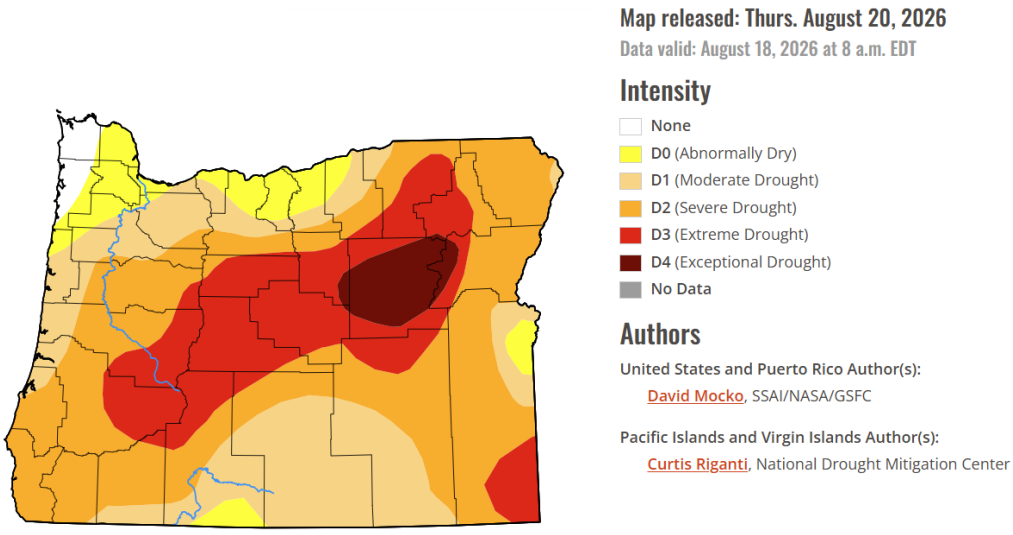
Outlays of the U.S Government, by Source, Fiscal Year 2026



Source: U.S. Treasury, July 2026 Monthly Treasury Statement

- *Cuts to SNAP/Medicaid*: In 2025, over 1.4 million Oregonians and 57% percent of children were enrolled in the Oregon Health Plan (Oregon's Medicaid program). House Resolution 1 (HR1) changed eligibility and work requirements, and OHA estimated that 200,000 Oregonians may lose coverage. Some individuals that remain covered will have higher co-pays and out-of-pocket costs. HR1 changes will also reduce hospital funding and potentially impact health care employment levels. In addition to Medicaid, HR1 changed eligibility requirements for the Supplemental Nutrition Assistance Program (SNAP), a program that an estimated 17% of Oregon households participate in. Effected individuals will include able-bodied adults without children, some immigrants still available for SNAP, and households that receive energy assistance. SNAP funding in its entirety is funded through September 2026 and will be at risk of being suspended if there is another government shutdown. The increased costs of medical care and food will increase non-discretionary expenses and lower purchasing power.

- Drought/Wildfires: Climate change is exacerbating weather extremes across the globe. From drought and wildfires to extreme temperatures and hurricanes, the consequences of changing weather patterns are becoming clearer. For Oregon, drought conditions are increasing according to the National Drought Mitigation Center at the University of Nebraska - Lincoln. Compared to one year ago, the percentage of Oregon land under "severe" drought conditions or worse has more than doubled to two thirds. The implications are significant: Harsher agricultural conditions limit feed supply and raise livestock and meat prices; changing water volumes and temperatures affect fish and waterfowl; reservoir volumes decrease, affecting water prices and availability; and, finally, dry vegetation and brush increase fire hazard and exacerbate the spread of fires, increasing damage and risk to life and property.



Source: National Drought Mitigation Center, University of Nebraska-Lincoln

Alternative Economic Scenarios

The baseline outlook characterizes the most likely path of the Oregon economy. However, as with any forecast, 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 37.

At the state level, the unemployment rate has remained unchanged during 2026 despite continued job losses and accelerating Oregon GDP growth. Baseline conditions continue to manifest, leaving less time for the impact of the alternative paths to be realized in the current biennium. Factors that were responsible for an increase in the recession probabilities last quarter have slightly subsided in recent months, namely energy prices and the conflict in Iran. The economic headwind from energy prices is still present but less severe compared to earlier this year.

Alternative Scenarios — September 2026

	2026	2027	2028	2029	2030
Employment					
Opt: Boom	0.1%	1.3%	1.1%	1.0%	1.0%
Opt: Solid Growth	-0.2%	1.0%	1.2%	1.1%	1.1%
Baseline	-0.5%	0.5%	0.5%	0.4%	0.6%
Pes: Moderate Recession	-1.7%	-0.4%	1.7%	0.7%	0.7%
Pes: Severe Recession	-1.1%	-5.1%	-2.7%	1.5%	3.7%
Unemployment Rate					
Opt: Boom	5.0%	4.7%	4.5%	4.5%	4.5%
Opt: Solid Growth	5.1%	4.8%	4.6%	4.7%	4.6%
Baseline	5.3%	5.3%	5.2%	5.3%	5.3%
Pes: Moderate Recession	6.7%	8.3%	6.6%	5.7%	5.3%
Pes: Severe Recession	6.8%	10.6%	11.2%	10.3%	8.0%
Personal Income					
Opt: Boom	3.6%	7.3%	6.7%	5.8%	5.2%
Opt: Solid Growth	3.1%	6.6%	6.6%	5.9%	5.5%
Baseline	3.0%	6.3%	6.1%	5.2%	4.8%
Pes: Moderate Recession	1.7%	4.7%	7.0%	5.4%	5.0%
Pes: Severe Recession	-0.3%	-1.1%	7.4%	8.0%	7.9%

Overall, there is an increase in confidence surrounding the baseline scenario, with the probability of upside risks being marked up from the prior quarter.

As such, the baseline forecast is assigned a 64% probability, which is slightly increased from the prior forecast. With the continued elevated recession risks, two additional alternative scenarios are included: an extreme upside/boom scenario and a severe recession.

Pessimistic Scenario: Moderate and Severe Recession

The distribution of economic outcomes for this forecast have marginally changed. While the weight of the baseline remains somewhat lower than is typical during normal times, it has

increased since the Q2 forecast. The optimistic scenarios have gotten incrementally more likely and are now equal to the potential downside. A notable shift from prior forecasts where the downside was larger than the upside scenarios.

Downside economic risk accounts for 18% of the distribution, compared to 22% previously. For now, the most likely pessimistic scenario is a moderate recession. This has a 16% chance of occurring. A severe recession is associated with a probability of 2%.

The moderate recession scenario is for a three-quarter decline in employment totaling 2.4%, followed by a five-quarter recovery period, more in line with the so-called jobless recoveries following the 1990 and 2001 cycles. The 2.4% decline in employment is a loss of roughly 47,000 jobs. The unemployment rate increases to a high of 8.6% in the first quarter of 2027. In the 2025-27 biennium, total personal income in Oregon is approximately 1.5% below the baseline.

The severe recession scenario is for a seven-quarter decline in employment totaling 7.7%, followed by a 12-quarter recovery period. The 7.7% decline in employment is a loss of about 150,000 jobs. The unemployment rate increases to a high of 12.1% in Q4 2027.

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, it can be an important contributor to higher employment levels. Oregon has experienced periods where employment growth has exceeded population growth, mainly 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 and total personal income are roughly 71,000 and 3.4% higher than in the baseline forecast, respectively.

Revenue Outlook

Revenue Summary

The summer is historically a light season for revenue news. Except for second quarter estimated payments for the major tax programs (Personal Tax, Corporate Income and Activity Tax) and normal month-to-month variation in withholding, the dog days rarely see significant movements in the General Fund forecast. For this 2026 Q3 iteration, the major story is withholding. Whereas the prior forecast assumed withholding would grow at a 4.5% clip for tax year 2026, that rate now looks closer to 6%. With withholding averaging a billion dollars a month, such a revision adds up fast. In addition, withholding has exceeded the prior forecast by over $100 million in the three months since the last release. With the Federal Reserve now likely to cut rates in 2027, a higher withholding base elevates the entirety of the forecast horizon - at least for Personal Income Tax. Corporate Income and Activity Tax are experiencing soft patches; however, it is unclear whether this is an anomaly with refunds and their application towards future liability or real economic weakness. Prevailing indicators would hedge towards the former explanation. This is elaborated

Table R.1

2025-27 General Fund Forecast Summary

(Millions)	2025 COS Forecast	June 2026 Forecast	September 2026 Forecast	Change from Prior Forecast	Change from COS Forecast
Structural Revenues					
Personal Income Tax	$30,247.1	$30,119.8	$30,257.6	$137.8	$10.6
Corporate Income Tax	$3,430.5	$3,587.8	$3,491.8	-$96.0	$61.3
All Other Revenues	$2,082.2	$2,205.5	$2,204.2	-$1.2	$122.1
Gross GF Revenues	$35,759.8	$35,913.1	$35,953.7	$40.6	$193.9
Offsets, Transfers, and Actions[1]	-$206.9	-$221.2	-$206.4	$14.7	$0.5
Beginning Balance	$2,243.1	$2,165.8	$2,165.8	$0.0	-$77.2
Net Available Resources	**$37,795.9**	**$37,857.7**	**$37,913.1**	**$55.4**	**$117.2**
Appropriations	$37,323.1	$37,513.1	$37,513.1	$0.0	$190.0
Ending Balance	**$472.8**	**$344.6**	**$400.0**	**$55.4**	**-$72.8**
Confidence Intervals					
67% Confidence	**+/- 2.2%**		**$791.0**	**$35.16B to $36.75B**	
95% Confidence	**+/- 4.4%**		**$1,582.0**	**$34.37B to $37.54B**	

1 Reflects personal and corporate tax transfers, Rainy Day Fund tranfer, and Dept of Ag transfer

in more detail below. Overall, the forecast is only marginally changed with a mix of ups and downs, indicative of economic inflection points.

Table R.1 presents the forecast for the current biennium by displaying revenues, appropriations, and the expected balance at biennium's end. General Fund revenues have increased $55 million from the prior forecast, driven primarily by the increase in personal income taxes elucidated elsewhere. Corporate Income Tax's $96 million downward adjustment offsets this increase. The rise in projected revenues elevates the ending balance estimate to $400 million with ten months remaining in the biennium.

Non-Corporate revenues, which determine the personal income tax kicker surplus (if any), are $526 below the kicker threshold. This is due to the impact of federal House Resolution 1, which dampened expected revenues relative to the Close-of-Session forecast. Corporate Income Taxes are a marginal $7 million below the kicker threshold. The net impact of HR1 and subsequent and related Oregon legislative tax law changes are estimated to have reduced Corporate Taxes by $191 million. Thus, without these changes, the Corporate Income Tax forecast would be well above the kicker threshold.

Except for the two major income tax streams, all other revenues are virtually unchanged from the prior forecast. Only Interest Earnings accruing to the General Fund have increased significantly, up $27 million. Estate Taxes have seen an off year in tax year 2025, possibly a consequence of randomly lower value estates appearing in the data to date. The forecast for Estate Taxes decreased $30 million. Liquor Apportionment is lower by $8 million as sales reflect ongoing consumption patterns. Cigarette and Tobacco Taxes continue to exhibit softness, edging down a combined $4 million from the Q2 forecast. It should be noted that fiscal year 2026 ended on June 30. Biennial forecast values and forecast-to-forecast comparisons include associated accounting adjustments.

2025-27 General Fund Revenues

The General Fund forecast for the third quarter of 2026 has only modestly increased, up $55 million from the second quarter. As noted above, this mixed and modest change is reflective of the summer cycle wherein less revenue and revenue data transpire. With a little more than ten months remaining in the biennium, potential error for this forecast remains significant: (1) the Fall extension filing season remains for tax year 2025, which is less consequential than the spring season but still can result in significant changes; and (2) reconciliation for tax year 2026 – tax filing season in the Spring of 2027 – is projected to net nearly $700 million in payments above refunds. Historically, tax filing seasons have resulted in the largest changes in the forecast. Not only do actual receipts impact the forecast directly, but the resulting change in the tax base affects the forecast throughout the forecast horizon.

Personal Income Tax

For 2025-27, the personal income tax forecast has increased $138 million. As noted above and described in detail in the following paragraph, burgeoning withholding receipts are the primary cause of the increase. In fact, as noted in Table B.8, withholding exceeded the Q2 forecast for May-July by $111 million. Offsetting errors in estimated and other payments and refunds resulted in a net forecast error of $27.9 million.

Elevated withholding levels have two consequences on the forecast, one real and one temporal. If withholding increases are viewed as signals of changing economic fortunes, these signals will cause changes in the income forecast (wages & salaries, pensions, etc.) and drive higher revenue projections throughout the forecast horizon. However, even if the increases are viewed as temporal shifts and commensurate increases in refunds occur, withholding bumps are immediate and refunds transact over ensuing years and even across biennia. The net result is an increase to the forecast in either case. The current Q3 forecast exhibits a little of both mechanisms. Due to there being only ten months remaining in the 2025-27 biennium, the current change is only a fraction of the increase realized in future biennia.

Corporate Income Tax

The outlook for corporate income taxes remains clouded by the impacts of House Resolution 1 and variation in refund processing timing that make historical trends less reliable. However, tracking shows that revenues are currently $167 million below the Q2 forecast. This negative signal is partially counteracted by positive economic indicators, namely an increase in the national corporate profits forecast. Sustained elevated inflation also results in higher nominal corporate profits, which in turn increases tax revenues. A balanced approach between economic and revenue indicators has resulted in a modest decrease of $96 million from the prior forecast for the 2025-27 biennium.

At the time of the Q2 forecast, the Department of Revenue had significantly more corporate tax refunds to review than when compared to the same period in the previous year. Because refunds are typically applied forward as estimated payments at a high rate, the expectation was that estimated payments would increase substantially when the refunds were issued. While most of those delayed refunds have been processed, data showed that they were applied forward at a rate below the historical average. The resulting weakness in estimated payments was a large contributor to revenue falling short of the Q2 forecast. The delayed refunds are associated with tax year 2024 and applied forward to tax year 2025, a year where corporations may be expecting lowered tax liability due to House Resolution 1. Because corporations are not required to file on a calendar year basis, the strength of tax year 2025 and the impact of House Resolution 1 will not come into clarity for several more quarters.

All Other Revenue

As noted above, the forecast outside of the two income tax streams is virtually unchanged from the previous forecast. Interest Earnings have increased significantly due to a revision to interest rate expectations. Most of the other elements, including Estate Taxes, Cigarette and Tobacco Taxes, and Liquor Apportionment, exhibit decreases. The Central Service Charge line, which should be known going into the biennium, was errantly coded at a gross level rather than the General Fund share. This correction resulted in a negative $4.5 million adjustment.

Extended General Fund Outlook

Table R.2 exhibits the long-run forecast for General Fund revenues through the 2033-35 biennium. The 2025-27 legislatively adopted budget is now being executed by agencies. The Office of Economic Analysis will release three more forecast updates and a final accounting for the current biennium's revenue picture. As such, the potential for the revenue figures presented here to fluctuate for any number of administrative and exogenous reasons is still significant.

Note that the large percentage changes between biennia are due to kicker credits affecting personal income tax collections. Beyond 2027-29, when these considerations are no longer in effect, growth reflects underlying economic assumptions characterized elsewhere in this document. Forecast error increases the further out one gets into the future.

Table R.2

General Fund Revenue Forecast Summary September 2026

Millions of Dollars, Current Law

Revenue Source	2025-27 Biennium	% Chg	2027-29 Biennium	% Chg	2029-31 Biennium	% Chg	2031-33 Biennium	% Chg	2033-35 Biennium	% Chg
Personal Income Taxes	30,257.6	*36.5%*	36,463.0	*20.5%*	41,019.6	*12.5%*	45,885.2	*11.9%*	51,451.0	*12.1%*
Corporate Income Taxes	3,491.8	*10.8%*	3,901.1	*11.7%*	4,168.2	*6.8%*	4,487.9	*7.7%*	4,893.4	*9.0%*
All Others	2,204.2	*-4.3%*	2,292.8	*4.0%*	2,767.0	*20.7%*	3,164.8	*14.4%*	3,641.1	*15.0%*
Gross General Fund	35,953.7	*30.2%*	42,656.9	*18.6%*	47,954.8	*12.4%*	53,537.9	*11.6%*	59,985.5	*12.0%*
Offsets and Transfers	*(206.4)*		*(297.6)*		*(293.4)*		*(288.5)*		*(309.8)*	
Net Revenue	35,747.2	*30.5%*	42,359.3	*18.5%*	47,661.4	*12.5%*	53,249.4	*11.7%*	59,675.6	*12.1%*

Corporate Activity Tax

Oregon's 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 at the outset. 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.

Corporate Activity Tax estimated payments are exhibiting signs of softness in tax year 2026. For the three-month period ending July 31, payments fell short of the prior forecast by $63 million. While payments are still increasing on a year-over-year basis, the growth rate is well below current estimates of economic activity in the state. Recent weakness is owed primarily to the rate at which refunds are being applied as subsequent year's estimated payments. While this rate can exhibit significant month-to-month volatility, the recent pattern is well below historical averages. With indicators of economic activity, such as state output, exhibiting signs of strength, this pattern is viewed as a temporary data anomaly rather than a systemic or structural issue.

Sizeable downward revisions regarding tax receipts for years currently in progress have significant consequences for 2025-27 revenue projections. The forecast has decreased by $95 million to $2.96 billion. Relative to the Close-of-Session forecast, expected revenues are now $88 million lower. The projected ending balance in the Fund for Student Success is $81 million. With focus shifting to the 2027-29 biennium, the forecast for next biennium is $26 million below the prior forecast and now stands at $3.4 billion.

Detailed forecast data are presented in Tables B.12 and B.13 in the Appendix. The personal income tax reductions are built into the General Fund forecasts shown in Tables B.1 and B.2.

Lottery Earnings Forecast

As presented in table R.3, this lottery revenue forecast is marginally increased from the prior forecast. The revision is divided between windfalls in the Powerball and Megamillions jackpot games and stronger-than-anticipated earnings in Video gaming. Total earnings projected for transfer to the Economic Development Fund in 2025-27 have increased $3.7 million to $1.8 billion. Compared to the original Close-of-Session forecast on which the current Legislatively Adopted Budget was based, the forecast is still down $36 million.

Table R.3

Lottery Earnings Forecast: 2026 Q3

	2025-27		2027-29		2029-31		2031-33		2033-35	
(millions)	Biennial Transfer	Forecast Change	Biennial Transfer	Forecast Change	Biennial Transfer	Forecast Change	Biennial Transfer	Forecast Change	Biennial Transfer	Forecast Change
Traditional Games	$200.0	$1.7	$164.6	$0.1	$168.8	$0.2	$174.1	$0.5	$181.1	$0.8
Video Lottery	1,561.0	2.1	1,676.0	3.3	1,789.1	3.5	1,916.0	3.8	2,067.6	4.0
Sports Betting	86.3	-0.1	88.5	0.1	92.6	0.7	95.5	0.0	97.6	-1.4
Administrative Actions	1.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Earnings	1,849.2	3.7	1,929.1	3.5	2,050.6	4.4	2,185.6	4.2	2,346.3	3.5
Bien/Bien %change	-0.1%		4.3%		6.3%		6.6%		7.4%	

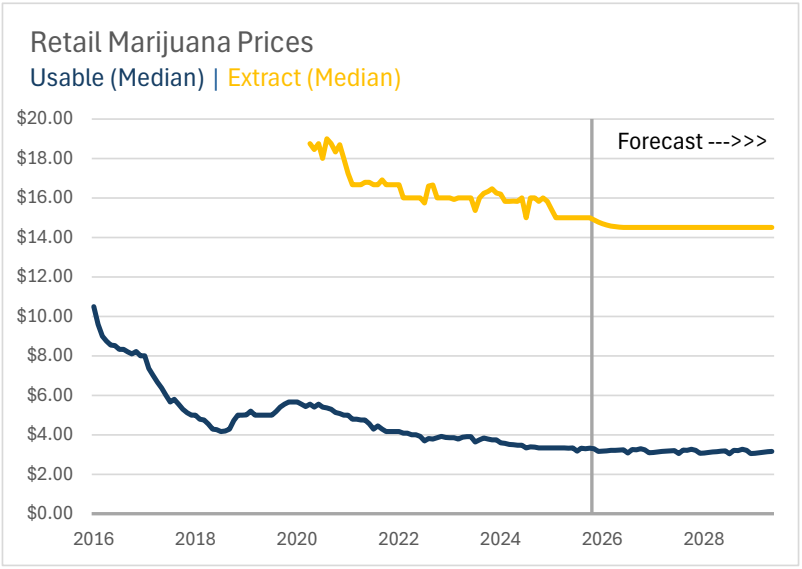
Video lottery sales rose 1.5% in fiscal year 2026 following a 1.9% decline in the prior year. Much of this turnaround occurred during the Spring 2026 tax filing season - when refunds fueled by federal tax cuts and a $1.4 billion Oregon kicker credit appear to have boosted sales. The Oregon Lottery is also replacing older, underperforming terminals with newer Sierra models, which is having a discernible impact, as well. The growth expectation built into the forecast has not changed, although a constant rate applied to an upwardly revised base does result in modestly higher sales projections throughout the forecast horizon.

With the Governor's Recommended Budget due to be published near year's end, focus is shifting to the 2027-29 biennium. The forecast for 2027-29 is also modestly increased, by $3.5 million to $2.1 billion. The forecast is 4.3% above the 2025-27 level, primarily reflecting anticipated growth in Video sales. The ban on courier sales of lottery products overseas, effective January 2026, softens the growth somewhat.

The full extended outlook for lottery earnings can be found in Table B.9 in Appendix B.

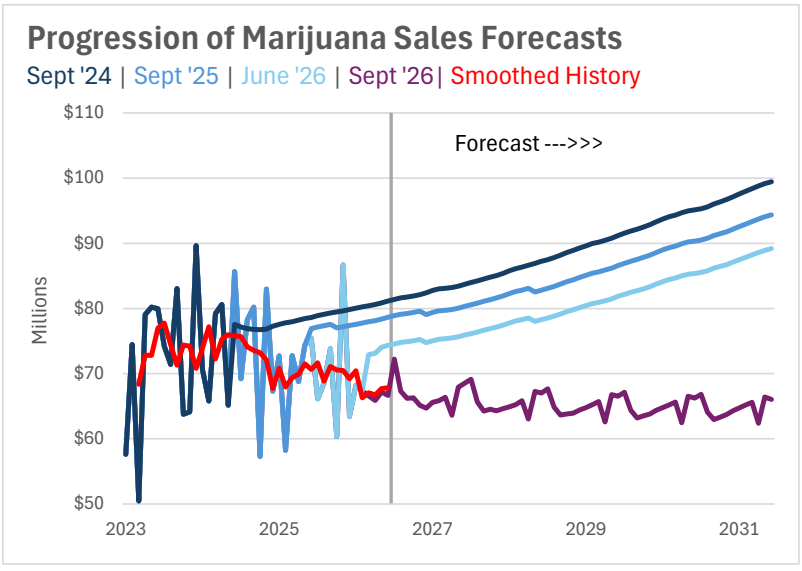
Recreational Marijuana Forecast

Chart R.1:



Prior marijuana revenue forecasts have exhibited moderate growth profiles even as revenues declined over six successive quarters. Following substantive conversation with members of the industry and analysts, the outlook for revenues needed a significant revision to account for strong ongoing production and consequent price declines. Chart R.2 presents these issues graphically, including the pronounced shift from the prior forecast (May 2026) to this 2026 Q3 outlook. Chart R.1 illustrates how prices for usable marijuana and extract have declined, as well as projections for how the rates of change are expected to slow over the next year or two. Given stable consumption trends, this results in revenues leveling off towards the end of next biennium.

Chart R.2:

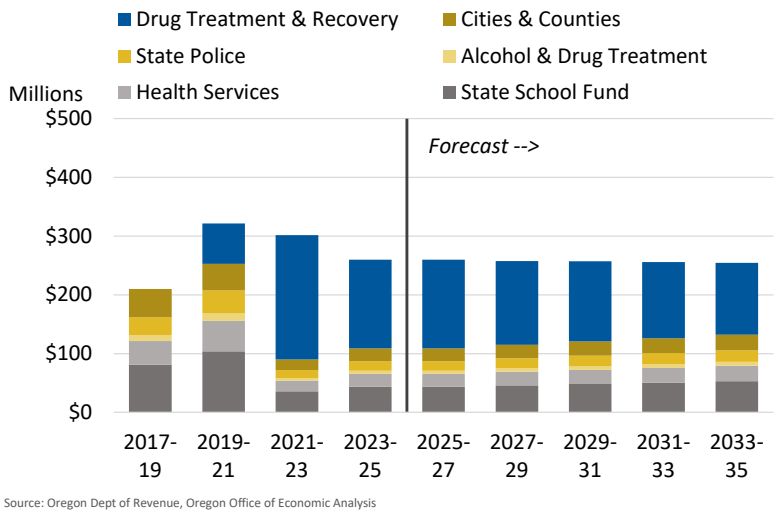


The consequence of this significant change in the outlook is a major decrease in projected revenues, with the impact increasing as time progresses into the future. For the current biennium, projected revenues have decreased $14.1 million to $261.7 million. As all other allocations are fixed in law, the decline is realized in a lower allocation to the Drug Treatment Fund. For the 2027-29 biennium, revenues are $51.5 million below the prior forecast. Chart R.3 presents the allocations from marijuana revenues graphically.

Marijuana remains classified as a Schedule I drug, preventing business owners from accessing traditional banking services and disallowing common business tax deductions. In December

2025, a presidential executive order directed the Attorney General to expedite the process or rescheduling marijuana to Schedule III. If finalized, the shift to Schedule III would relax restrictions and could improve access to banking and tax deductions for the industry — though the rulemaking process is ongoing.

Chart R.3:



Oregon does not currently tax medical marijuana; however, this exemption is set to expire at the end of 2027. Although this exemption could be extended by the Legislature, the current forecast assumes medical marijuana will be taxed per current law.

Table B.11 in Appendix B presents detailed revenue and allocation information for current and future biennia.

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. Most 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 nearly three years. The current forecast remains a work in progress; however, it is now based on the first three years 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 is expected to grow in the years ahead. As more data becomes available, this office will adjust its outlook accordingly.

The average product price reported is approximately $42. However, there is a wide range of values around that average. The average price is in line with previous conversations OEA 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.

Oregon Psilocybin Retail Sales Tax Revenue

	Biennium 2023-25	2025-27	2027-29	2029-31	2031-33	Sep-26 2033-35
No. of Session	28,000	34,500	38,000	38,000	38,000	38,000
Avg Product Price	$40	$42	$44	$45	$47	$49
Total Sales	$1,130,000	$1,451,000	$1,662,000	$1,729,000	$1,799,000	$1,871,000
Taxes	$169,000	$218,000	$249,000	$259,000	$270,000	$281,000

Note: Detailed entries may not add to totals due to rounding.

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 and historical data. 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.

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 largely relating 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

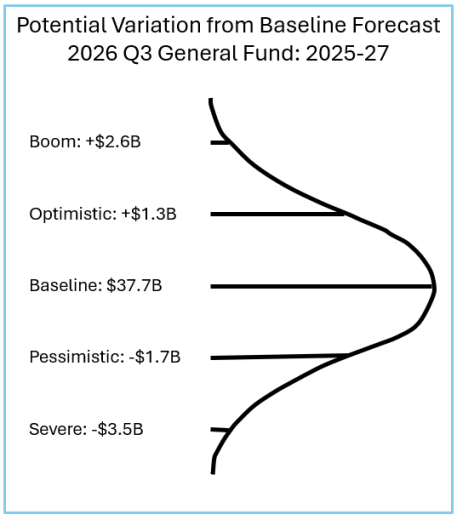
Given the degree of uncertainty present at the release of this forecast, the Office of Economic Analysis has analyzed historical forecast outcomes and revenue performance to produce a range of scenarios that could manifest throughout the forecast horizon. The four alternatives to the baseline (two upside 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.

Table R.4

General Fund Revenue* Scenarios

(millions)		2025-27	2027-29	2029-31	2031-33	2033-35
Boom (3%)	Revenues	$40,236.1	$45,788.7	$51,466.5	$57,745.4	$64,790.4
	Growth	*21.6%*	*13.8%*	*12.4%*	*12.2%*	*12.2%*
Optimistic (15%)	Revenues	$38,955.2	$44,136.3	$49,476.7	$55,364.5	$62,229.7
	Growth	*17.7%*	*13.3%*	*12.1%*	*11.9%*	*12.4%*
Baseline (64%)	Revenues	$37,674.3	$42,656.9	$47,954.8	$53,537.9	$59,985.5
	Growth	*13.9%*	*13.2%*	*12.4%*	*11.6%*	*12.0%*
Pessimistic (16%)	Revenues	$35,941.3	$40,398.0	$45,892.1	$51,215.6	$57,463.9
	Growth	*8.6%*	*12.4%*	*13.6%*	*11.6%*	*12.2%*
Severe (2%)	Revenues	$34,208.2	$38,210.6	$44,247.9	$49,513.4	$55,504.5
	Growth	*3.4%*	*11.7%*	*15.8%*	*11.9%*	*12.1%*

* Adjusted for kicker credits.

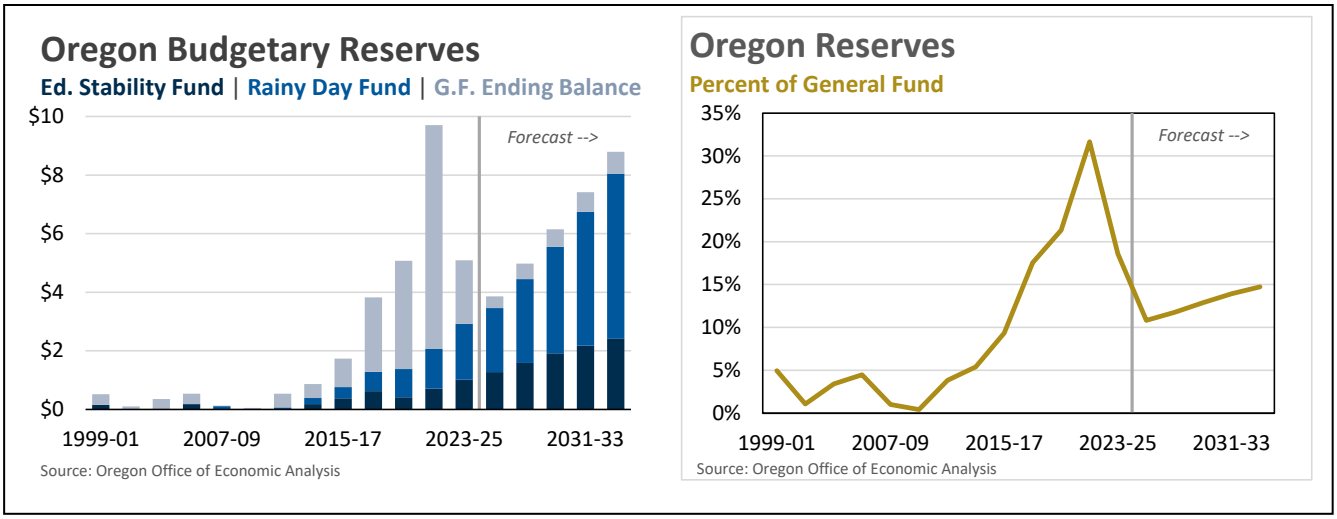


The first deviations are +3.4/-4.6% removed and are the traditional "optimistic" and "pessimistic" scenarios presented in past publications. The magnitudes of the deviations are diminishing as the biennium progresses, and baseline conditions continue to manifest. This leaves less time for the impact of the alternative paths to be realized. It should be noted that the two scenarios are not symmetric in terms of fiscal impact. 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 $1.3 billion, while the latter produces a $1.7 billion deficit.

The second pair of scenarios ("Boom" and "Severe") are +6.8/-9.2% removed from the baseline. The boom scenario has had 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 $2.6 billion, while the severe recession costs the General Fund $3.5 billion in 2025-27.

Budgetary Reserves

The state currently administers two general reserve accounts, the Oregon Rainy Day Fund[1] (ORDF) and the Education Stability Fund[2] (ESF). The current projection for the balance of the Education Stability Fund at the end of 2025-27 is $1,271 million, while the balance in the Rainy Day Fund is expected to equal $2,192 million. The total balance of $3,463 million would be 9.7% of the current General Fund forecast. It should be noted that Senate Bill 960 canceled the transfer of the lesser of 1% of the prior biennium's appropriation level or ending balance, which would have occurred early in 2026. House Bill 3920 diverted 20% of the interest earnings due to the Rainy Day Fund to other accounts. These legislative actions are reflected in the figures below.



As noted above, the current probability of an economic downturn is estimated at 18%. In the last 50 years, the worst decline in General Fund revenues relative to the Close-of-Session forecast was 15.6% during the 2001-03 biennium, which was associated with the tech industry boom-bust. The graphics above present the projected balances in the Oregon Rainy Day Fund and the Education Stability Fund under the baseline economic scenario. Total available reserves under this scenario would amount to 9.7% of General Fund revenues. It is quite likely that Oregon's reserves are adequate to weather a mild to medium downturn.

B.10 in Appendix B provides more details for Oregon's budgetary reserves.

[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. 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 12.5% of General Fund revenues in the prior biennium.

[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 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.

Tax Law Assumptions

The revenue forecast is tied to current state law. After each 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 outcome for federal law.

For a detailed treatment of the components of the 2025 Legislatively Enacted Budget, see:

Legislative Fiscal Office's 2025-27 Budget Summary[3]

[3] https://www.oregonlegislature.gov/lfo/Documents/2025-2%20LAB%20Summary%202025-27.pdf

Population and Demographic Outlook

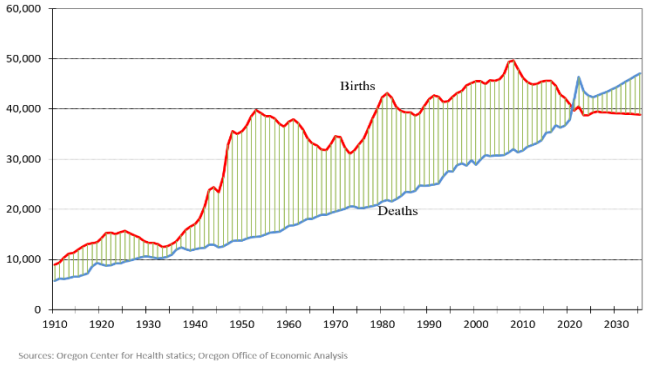
Population and Demographic Summary

Based on the most recent decennial census, Oregon's resident population on April 1, 2020, was 4.237 million. 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 a rare occurrence as it took 40 years for Oregon to gain one additional seat.

Oregon's population growth of 10.6% over the 2010-20 decade was the 11th highest in the nation, excluding Washington D.C. The growth rate for the decade lagged all of Oregon's neighboring states except California. Oregon's growth has experienced some turbulence since the 2020 census and the corresponding COVID-19 pandemic. At OEA, the PSU Population Research Center (PRC)'s recent postcensal estimate is used as the base for the office's population forecasts. The PRC's estimates show a loss of population between 2020 and 2021. Such a loss was very unusual for Oregon because this happened after nearly four decades. Since then, the recovery in population growth has been very slow.

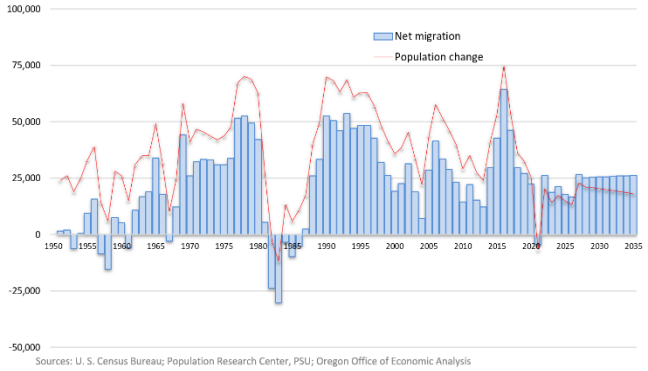
The estimates show Oregon's population growth has remained at a low level not seen since the mid-1980s, indicating timid economic recovery in the post-pandemic years. As the strict federal immigration policy continues to be enforced and Oregon's high-tech employment shows signs of stress, the population growth will be affected accordingly. The population growth is expected to show a slow positive increase in the future reaching 4.494 million in the year 2035 with an average annual rate of growth of 0.4% between 2025 and 2035.

New demographic reality: deaths outnumber births



Sources: Oregon Center for Health statics; Oregon Office of Economic Analysis

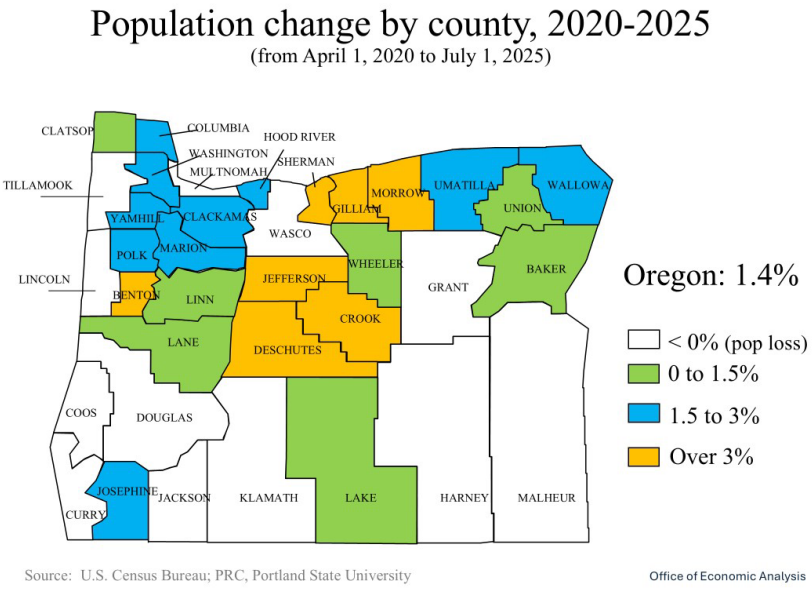
Population will decline without strong net migration



Sources: U. S. Census Bureau; Population Research Center, PSU; Oregon Office of Economic Analysis

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 an aging population — long-term growth will rely entirely on positive net migration.



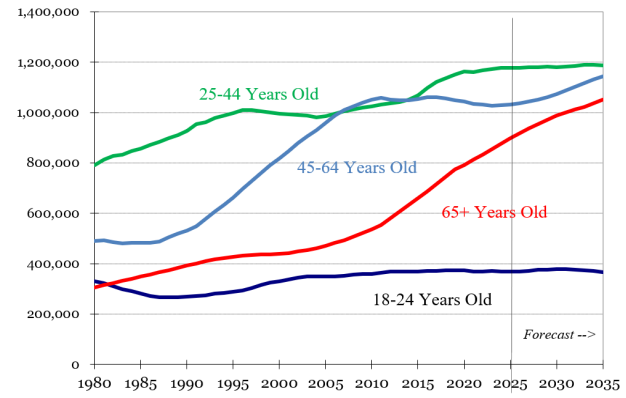
Population change by county in Oregon across recent years shows an interesting and challenging growth pattern. Population in Oregon increased by 1.4% between the 2020 Census and 2025 estimate. The county population growth ranged from a low of -1.3% in Multnomah County to a high of 13.5% in Crook County. In general, counties in the south, southeast, and coastal region lost population or grew very slowly. Oregon's largest county, Multnomah, lost the most. Population in central and northern Oregon increased faster than the state average. The 12 counties losing population were Multnomah, Harney, Wasco, Douglas, Jackson, Curry, Klamath, Malheur, Lincoln, Tillamook, Grant, and Coos in order of magnitude. The counties experiencing faster population growth exceeding 3% in recent years were Benton, Jefferson, Gilliam, Sherman, Deschutes, Morrow, and Crook.

Working-age adults move to Oregon as long as there are favorable economic and social conditions such as: job opportunities, affordable housing and childcare, a good educational environment, personal safety, 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 shrink or 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 of young-age adults contributing to an increase in the number of births. For decades, Oregon's population growth was well above the national average. However, due to the sluggish economy and employment situation, Oregon's population growth has been lagging well below the national average since 2021.

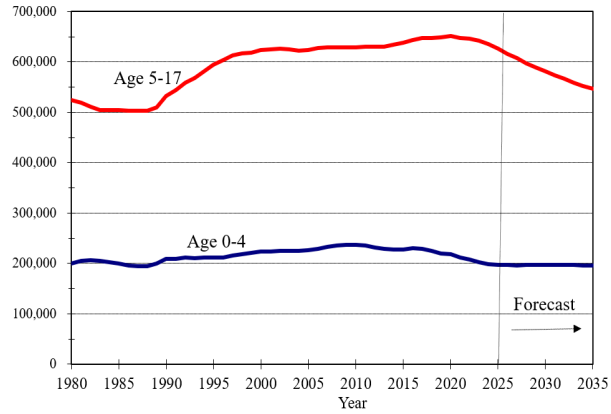
Age structure and its change affect employment, state revenue collection and tax expenditures. The demand for public services varies by age groups. Demographics are the major budget drivers, which are modified by policy choices on service coverage and delivery. Births, deaths and migration histories 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 over time.

Older adults will increase faster



Source: Census Bureau; Oregon Office of Economic Analysis

Number of children will decline



Source: Census Bureau; Oregon Office of Economic Analysis

Older Population (65+)

The overall older 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 65+ population picked up a faster pace of growth when the baby-boom cohort started maturing into the older age group. This age cohort has hit the plateau of high growth rates exceeding 4.0% annually between 2011 and 2018. The group will experience a high but diminishing rate of growth in the coming years. The average annual growth of the 65+ population will be 1.6% during the 2025-2035 forecast period, which is nearly four times the rate of growth of the overall population.

As a sign of the massive demographic structural change of Oregon's population, the population of people 65+ has exceeded the number of children under the age of 18 since 2023. To illustrate the contrast, in 2000 the older population numbered a little over half of the number of children in Oregon, and now they outnumber the children. This is due to the decline in the fertility rate, improvement in the life expectancy, as well as the aging of the large baby boom population. Different age groups among the 65+ population show quite varied and fascinating growth trends.

The youngest group of the 65+ population (aged 65-74), which was growing at an extremely fast pace in the recent past (averaging over 5.0% annually in 2010's), will taper off to negative growth after 2026 as a sign of the end of the baby boom generation transitioning to the older age group.

This high growth period will transition into a net loss of the youngest group in the older population resulting in a -0.7% annual average loss during the forecast period.

The next oldest 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 6.0% annually in this age group, in the recent past will transition into high but decelerating growth rate as the baby boom generation matures into and the depression era birth cohort exit out of this 75-84 age group. The annual average growth rate is expected to be unusually high at 3.0% during the forecast period.

The oldest population group (aged 85+) will grow at a very fast rate, steadily gaining momentum due to the combination of cohort change, historical positive net migration and improving life expectancies. The average annual rate of growth for this oldest elderly group over the forecast horizon will be 6.5%. An unprecedented annual growth exceeding 8.0% will commence after 2031.

Working Age and Young Adults (18-64)

The oldest working age population, aged 45-64, has also seen a dramatic demographic upheaval 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 had tapered off to negative growth. The growth rate is beginning to reverse to positive and will be gaining momentum over the forecast horizon with a 1.0% annualized rate of growth. The younger working-age population of the 25-44 age group will have slow growth of an annual average of 0.1% over the forecast period.

The young adult population, aged 18-24, will see no change, at a 0% annual rate, over the forecast period. The positive growth during the early years of the forecast period will disappear due to decline in the later years. Although the slow or no 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 (ages 5-17) was very slow during the last decade, turned negative in 2021, and is expected to decline consistently through the forecast years mainly due to the declining number of births and slower net migration over the years. This will translate into a

decline in school enrollments. We will see schools being considered for closing or merging as the enrollment will continue to decline. On average for the forecast period, this school-age population will decline by -1.4% annually. The growth rate for children under the age of five has remained below zero percent in the recent past and will show virtually no change over 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 economic wellbeing of legal guardians and parents.

Overall, the older population of 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 remain unchanged, whereas demand for care and services geared towards the older population will increase rapidly. Decline in the number of children may indicate smaller budget allocation for the pre-K and K-12 education. However, in the long-run, the state may suffer from a labor shortage and may lead to reliance on in-migration of working-age adults.

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 higher 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 modified for age heaping 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 June 30, 2025, 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 children 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 fertility levels. 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 the 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 80.6 years for men and 85.2 years for women by 2035.

Estimates of the number of net migrations are based on the residuals from the difference between population change and natural increase (births minus deaths). OEA’s migration forecast is done separately and 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 and the only way to grow for Oregon’s population is to bring in more people from other states/countries than those who leave the state. The net migration numbers in this forecast cycle are lower primarily due to a lower employment forecast. Between 2025 and 2035, net migration is expected to be in the range of 16,400 to 26,200, averaging 24,900 persons annually with net migration rates ranging between 3.8 to 5.8 per thousand population.

Appendix A: Economic Forecast Detail

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Table A.1 – Employment Forecast Tracking

Table A.1

Total Nonfarm Employment, 2nd quarter 2026

(Employment in thousands, Annualized Percent Change, Seasonally Adjusted)

	Preliminary Estimate (Q2)		Y/Y Change	Forecast (from Q2)	Forecast Error
	level	Q/Q SAAR	% ch	level	level
Total Nonfarm	1,974.4	(0.3)	(0.6)	1,968.6	5.8
Total Private	1,659.5	(0.2)	(0.6)	1,649.7	9.8
Mining and Logging	5.6	(2.3)	(5.6)	6.0	(0.3)
Construction	110.9	2.1	(2.1)	110.5	0.4
Manufacturing	172.4	(6.5)	(4.4)	174.4	(2.0)
Durable Goods	120.0	(4.0)	(4.6)	119.4	0.6
Wood Product	21.5	(2.2)	(3.0)	21.2	0.3
Metals and Machinery	36.1	(1.0)	(1.0)	35.5	0.6
Computer and Electronic Product	31.5	(8.7)	(11.3)	29.8	1.7
Transportation Equipment	11.3	(0.5)	4.0	10.7	0.5
Other Durable Goods	19.6	(5.4)	(5.5)	22.1	(2.4)
Nondurable Goods	52.4	(12.0)	(3.9)	55.0	(2.6)
Food	27.0	(5.5)	(3.4)	27.6	(0.6)
Other Nondurable Goods	25.4	(8.1)	(4.2)	27.4	(2.0)
Trade, Transportation & Utilities	350.9	(1.4)	(1.1)	351.6	(0.7)
Retail Trade	197.3	(1.3)	(1.8)	198.8	(1.5)
Wholesale Trade	74.2	0.5	(2.2)	74.2	0.1
Transportation, Warehousing & Utilities	79.4	(3.3)	1.8	78.7	0.7
Information	34.1	(4.6)	(1.2)	31.2	3.0
Financial Activities	99.2	(1.7)	(1.7)	95.1	4.1
Professional & Business Services	251.0	1.8	(1.7)	254.7	(3.7)
Educational & Health Services	362.1	3.3	3.6	353.6	8.6
Educational Services	36.9	4.8	2.8	34.9	2.0
Health Services	325.3	3.1	3.7	318.7	6.6
Leisure and Hospitality	205.5	(2.7)	(1.1)	208.0	(2.6)
Other Services	67.7	7.4	1.7	64.7	3.0
Government	314.9	(1.2)	(0.6)	318.9	(4.0)
Federal	26.8	(0.5)	(6.5)	26.3	0.5
State	49.1	(3.5)	(0.3)	48.8	0.3
State Education	1.3	(2.1)	3.4	1.0	0.3
Local	238.9	(0.8)	0.1	243.7	(4.8)
Local Education	134.8	0.0	(0.2)	138.0	(3.3)

Table A.2 – Short-Term Oregon Economic Summary

Table A.2.A

Oregon Forecast Summary - Personal Income and Other Indicators

	Quarterly						
	2026:1	**2026:2**	**2026:3**	**2026:4**	**2027:1**	**2027:2**	**2027:3**
	Personal Income ($ billions)						
Nominal Personal Income	321.0	322.6	324.0	328.3	336.2	341.6	347.2
% change yr/yr	3.9	2.9	2.1	3.0	4.7	5.9	7.2
% change relative to prior forecast	(0.4)	(0.6)	(1.3)	(1.4)	(1.3)	(1.2)	(1.0)
Real Personal Income (base year=2017)	247.6	245.7	245.9	247.3	251.9	254.6	257.5
% change yr/yr	0.8	(0.9)	(1.4)	(0.5)	1.7	3.6	4.7
% change relative to prior forecast	(0.5)	(0.7)	(1.4)	(1.6)	(1.4)	(1.2)	(1.0)
Nominal Wages and Salaries	156.2	157.9	159.7	161.5	163.9	166.3	168.8
% change yr/yr	3.3	3.4	3.2	4.1	4.9	5.3	5.7
% change relative to prior forecast	(1.5)	(1.7)	(2.1)	(2.1)	(2.2)	(2.2)	(2.1)
	Other Indicators						
Per Capita Income ($1,000)	74.5	74.8	75.1	76.0	77.7	78.8	80.0
% change yr/yr	3.6	2.7	1.8	2.7	4.2	5.3	6.6
% change relative to prior forecast	(0.4)	(0.6)	(1.3)	(1.4)	(1.3)	(1.2)	(1.0)
Average Wage rate ($1,000)	78.3	79.1	80.3	81.0	82.1	83.2	84.4
% change yr/yr	3.8	3.8	3.7	4.7	4.9	5.2	5.1
% change relative to prior forecast	(1.8)	(2.3)	(2.4)	(2.6)	(2.6)	(2.5)	(2.4)
Population (Millions)	4.3	4.3	4.3	4.3	4.3	4.3	4.3
% change yr/yr	0.3	0.3	0.3	0.3	0.5	0.5	0.6
% change relative to prior forecast	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Housing Starts (Thousands)	17.6	15.5	15.7	15.6	15.6	15.7	15.8
% change yr/yr	27.9	16.0	13.9	(2.0)	(11.2)	1.5	1.1
% change relative to prior forecast	(2.4)	(13.5)	(13.0)	(13.7)	(13.4)	(12.6)	(11.9)
Unemployment Rate	5.2	5.2	5.3	5.3	5.4	5.3	5.3
Percentage point change yr/yr	0.3	0.0	(0.0)	0.0	0.2	0.1	0.0
Percentage point change relative to prior forecast	0.0	(0.1)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)

Table A.2.B

Oregon Forecast Summary - Employment

	Quarterly						
	2026:1	**2026:2**	**2026:3**	**2026:4**	**2027:1**	**2027:2**	**2027:3**
Total Nonfarm	1,976.0	1,974.4	1,975.2	1,979.2	1,981.7	1,983.5	1,986.8
% change yr/yr	(0.6)	(0.6)	(0.4)	(0.4)	0.3	0.5	0.6
% change relative to prior forecast	0.4	0.3	0.3	0.5	0.4	0.3	0.3
Private Nonfarm	1,660.1	1,659.5	1,658.6	1,663.1	1,665.8	1,668.1	1,671.4
% change yr/yr	(0.7)	(0.6)	(0.4)	(0.4)	0.3	0.5	0.8
% change relative to prior forecast	0.4	0.6	0.5	0.7	0.7	0.6	0.5
Construction	110.3	110.9	110.4	110.3	110.7	111.0	111.4
% change yr/yr	(3.2)	(2.1)	(2.1)	(2.2)	0.4	0.1	0.9
% change relative to prior forecast	(1.2)	0.4	(0.6)	(0.6)	(0.4)	(0.3)	(0.1)
Manufacturing	175.3	172.4	170.3	170.7	170.5	170.1	170.3
% change yr/yr	(3.6)	(4.4)	(4.6)	(3.3)	(2.8)	(1.3)	0.0
% change relative to prior forecast	(1.0)	(1.1)	(2.7)	(2.4)	(1.9)	(2.2)	(2.1)
Durable Manufacturing	121.2	120.0	118.0	118.2	118.5	118.3	118.8
% change yr/yr	(4.7)	(4.6)	(4.6)	(3.3)	(2.2)	(1.3)	0.6
% change relative to prior forecast	(0.5)	0.5	(1.6)	(1.5)	(0.6)	(0.9)	(0.6)
Wood Product Manufacturing	21.6	21.5	21.3	21.1	21.3	21.0	21.0
% change yr/yr	(3.4)	(3.0)	(2.8)	(2.9)	(1.5)	(2.4)	(1.3)
% change relative to prior forecast	0.3	1.2	(1.3)	(2.3)	1.2	0.1	1.2
High Tech Manufacturing	32.3	31.5	29.9	30.0	30.2	30.4	30.6
% change yr/yr	(11.8)	(11.3)	(13.1)	(7.4)	(6.4)	(3.7)	2.6
% change relative to prior forecast	1.2	5.7	(0.4)	0.0	0.4	0.4	0.4
Transportation Equipment	11.3	11.3	11.3	11.4	11.4	11.4	11.4
% change yr/yr	6.0	4.0	6.7	6.9	1.2	1.4	1.0
% change relative to prior forecast	5.9	5.0	4.8	4.7	4.6	5.0	4.9
Nondurable Manufacturing	54.1	52.4	52.2	52.5	52.0	51.8	51.6
% change yr/yr	(0.9)	(3.9)	(4.6)	(3.2)	(4.0)	(1.2)	(1.3)
% change relative to prior forecast	(2.1)	(4.7)	(5.1)	(4.3)	(4.8)	(5.1)	(5.2)
Private nonmanufacturing	1,488.5	1,489.7	1,488.3	1,492.3	1,495.3	1,497.9	1,501.1
% change yr/yr	(0.1)	0.1	0.2	(0.1)	0.5	0.6	0.9
% change relative to prior forecast	0.8	1.0	0.9	1.1	1.0	0.9	0.8
Retail Trade	197.9	197.3	197.0	196.5	196.1	195.5	195.2
% change yr/yr	(1.8)	(1.8)	(1.4)	(1.4)	(0.9)	(0.9)	(0.9)
% change relative to prior forecast	(0.3)	(0.8)	(0.3)	(0.5)	(0.6)	(0.9)	(1.3)
Wholesale Trade	74.1	74.2	74.3	74.0	74.0	73.9	73.9
% change yr/yr	(3.0)	(2.2)	(1.0)	(1.1)	(0.2)	(0.4)	(0.5)
% change relative to prior forecast	0.3	0.1	0.3	0.3	0.1	0.1	(0.2)
Information	34.5	34.1	34.2	34.2	34.2	34.2	34.6
% change yr/yr	(1.9)	(1.2)	(1.8)	(2.4)	(1.0)	0.3	1.2
% change relative to prior forecast	6.1	9.5	9.6	8.4	7.4	6.8	6.7
Professional and Business Services	249.9	251.0	251.9	252.8	254.0	254.8	256.0
% change yr/yr	(3.0)	(1.7)	(0.0)	(0.1)	1.6	1.5	1.6
% change relative to prior forecast	0.6	(1.4)	(2.0)	(2.1)	(2.6)	(3.0)	(3.4)
Health Services	322.8	325.3	326.4	330.1	330.5	332.1	333.4
% change yr/yr	4.3	3.7	3.4	2.7	2.4	2.1	2.2
% change relative to prior forecast	1.1	2.1	3.1	4.6	4.6	4.9	5.2
Leisure and Hospitality	206.9	205.5	205.5	205.6	206.0	206.2	206.3
% change yr/yr	(0.3)	(1.1)	(0.8)	(1.3)	(0.4)	0.4	0.4
% change relative to prior forecast	(0.4)	(1.2)	(1.4)	(1.4)	(1.3)	(1.4)	(1.3)
Government	315.9	314.9	316.6	316.2	315.9	315.5	315.4
% change yr/yr	(0.3)	(0.6)	(0.6)	(0.1)	0.0	0.2	(0.4)
% change relative to prior forecast	0.6	(1.2)	(0.7)	(0.8)	(0.8)	(0.8)	(0.9)

Table A.3 – Oregon Economic Forecast Change

Table A.3

Oregon Forecast Change (Current vs Previous)

	Quarterly						
	2026:1	**2026:2**	**2026:3**	**2026:4**	**2027:1**	**2027:2**	**2027:3**
	Personal Income ($ billions)						
Nominal Personal Income	321.0	322.6	324.0	328.3	336.2	341.6	347.2
% change	(0.4)	(0.6)	(1.3)	(1.4)	(1.3)	(1.2)	(1.0)
Real Personal Income (base year=2017)	247.6	245.7	245.9	247.3	251.9	254.6	257.5
% change	(0.5)	(0.7)	(1.4)	(1.6)	(1.4)	(1.2)	(1.0)
Nominal Wages and Salaries	156.2	157.9	159.7	161.5	163.9	166.3	168.8
% change	(1.5)	(1.7)	(2.1)	(2.1)	(2.2)	(2.2)	(2.1)
	Other Indicators						
Per Capita Income ($1,000)	74.5	74.8	75.1	76.0	77.7	78.8	80.0
% change	(0.4)	(0.6)	(1.3)	(1.4)	(1.3)	(1.2)	(1.0)
Average Wage rate ($1,000)	78.3	79.1	80.3	81.0	82.1	83.2	84.4
% change	(1.8)	(2.3)	(2.4)	(2.6)	(2.6)	(2.5)	(2.4)
Population (Millions)	4.3	4.3	4.3	4.3	4.3	4.3	4.3
% change	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Housing Starts (Thousands)	17.6	15.5	15.7	15.6	15.6	15.7	15.8
% change	(2.4)	(13.5)	(13.0)	(13.7)	(13.4)	(12.6)	(11.9)
Unemployment Rate	5.2	5.2	5.3	5.3	5.4	5.3	5.3
Point Change	0.0	(0.1)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)
	Employment (Thousands)						
Total Nonfarm	1,976.0	1,974.4	1,975.2	1,979.2	1,981.7	1,983.5	1,986.8
% change	0.4	0.3	0.3	0.5	0.4	0.3	0.3
Private Nonfarm	1,660.1	1,659.5	1,658.6	1,663.1	1,665.8	1,668.1	1,671.4
% change	0.4	0.6	0.5	0.7	0.7	0.6	0.5
Construction	110.3	110.9	110.4	110.3	110.7	111.0	111.4
% change	(1.2)	0.4	(0.6)	(0.6)	(0.4)	(0.3)	(0.1)
Manufacturing	175.3	172.4	170.3	170.7	170.5	170.1	170.3
% change	(1.0)	(1.1)	(2.7)	(2.4)	(1.9)	(2.2)	(2.1)
Durable Manufacturing	121.2	120.0	118.0	118.2	118.5	118.3	118.8
% change	(0.5)	0.5	(1.6)	(1.5)	(0.6)	(0.9)	(0.6)
Wood Product Manufacturing	21.6	21.5	21.3	21.1	21.3	21.0	21.0
% change	0.3	1.2	(1.3)	(2.3)	1.2	0.1	1.2
High Tech Manufacturing	32.3	31.5	29.9	30.0	30.2	30.4	30.6
% change	1.2	5.7	(0.4)	0.0	0.4	0.4	0.4
Transportation Equipment	11.3	11.3	11.3	11.4	11.4	11.4	11.4
% change	5.9	5.0	4.8	4.7	4.6	5.0	4.9
Nondurable Manufacturing	54.1	52.4	52.2	52.5	52.0	51.8	51.6
% change	(2.1)	(4.7)	(5.1)	(4.3)	(4.8)	(5.1)	(5.2)
Private nonmanufacturing	1,488.5	1,489.7	1,488.3	1,492.3	1,495.3	1,497.9	1,501.1
% change	0.8	1.0	0.9	1.1	1.0	0.9	0.8
Retail Trade	197.9	197.3	197.0	196.5	196.1	195.5	195.2
% change	(0.3)	(0.8)	(0.3)	(0.5)	(0.6)	(0.9)	(1.3)
Wholesale Trade	74.1	74.2	74.3	74.0	74.0	73.9	73.9
% change	0.3	0.1	0.3	0.3	0.1	0.1	(0.2)
Information	34.5	34.1	34.2	34.2	34.2	34.2	34.6
% change	6.1	9.5	9.6	8.4	7.4	6.8	6.7
Professional and Business Services	249.9	251.0	251.9	252.8	254.0	254.8	256.0
% change	0.6	(1.4)	(2.0)	(2.1)	(2.6)	(3.0)	(3.4)
Health Services	322.8	325.3	326.4	330.1	330.5	332.1	333.4
% change	1.1	2.1	3.1	4.6	4.6	4.9	5.2
Leisure and Hospitality	206.9	205.5	205.5	205.6	206.0	206.2	206.3
% change	(0.4)	(1.2)	(1.4)	(1.4)	(1.3)	(1.4)	(1.3)
Government	315.9	314.9	316.6	316.2	315.9	315.5	315.4
% change	0.6	(1.2)	(0.7)	(0.8)	(0.8)	(0.8)	(0.9)

Table A.4 – Annual Economic Forecast

TABLE A.4.A

Sept 2026 - Other Economic Indicators

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Real GDP,										
Chain Weight (Bil of 2017$)	24,347.4	24,917.8	25,494.2	26,018.9	26,527.0	27,043.0	27,563.1	28,094.3	28,649.9	29,226.7
% Ch Yr/Yr	2.1	2.3	2.3	2.1	2.0	1.9	1.9	1.9	2.0	2.0
Price and Wage Indicators										
GDP Implicit Price Deflator,										
Chain Weight U.S., 2017=100	133.8	137.2	140.2	143.0	146.1	149.4	152.7	156.1	159.5	162.9
% Ch Yr/Yr	3.7	2.5	2.2	2.0	2.1	2.2	2.2	2.2	2.2	2.2
Personal Consumption Deflator,										
Chain Weight U.S., 2017=100	131.4	134.5	137.3	140.1	142.8	145.7	148.6	151.6	154.6	157.6
% Ch Yr/Yr	3.5	2.4	2.1	2.0	2.0	2.0	2.0	2.0	2.0	2.0
CPI, Urban Consumers,										
1982-84=100										
West Region	351.9	359.4	367.9	376.1	384.0	392.4	401.1	409.8	418.5	427.5
% Ch Yr/Yr	2.9	2.1	2.4	2.2	2.1	2.2	2.2	2.2	2.1	2.2
U.S.	332.3	339.6	347.5	355.2	362.6	370.6	378.8	387.0	395.2	403.6
% Ch Yr/Yr	3.2	2.2	2.3	2.2	2.1	2.2	2.2	2.2	2.1	2.1
Oregon Average Wage										
Rate (Thous $)	79.7	83.8	88.3	92.6	96.8	101.0	105.3	109.6	113.9	118.5
% Ch Yr/Yr	4.0	5.2	5.4	4.9	4.5	4.4	4.3	4.0	4.0	4.0
U.S. Average Wage										
Wage Rate (Thous $)	84.5	88.6	93.5	98.1	102.8	107.5	112.2	116.9	121.6	126.5
% Ch Yr/Yr	3.4	4.8	5.5	5.0	4.7	4.6	4.4	4.2	4.0	4.0
Housing Indicators										
FHFA Oregon Housing Price Index										
1991 Q1=100	630.3	644.1	668.0	694.3	720.1	748.1	780.6	812.2	845.3	872.0
% Ch Yr/Yr	0.4	2.2	3.7	3.9	3.7	3.9	4.3	4.1	4.1	3.2
FHFA National Housing Price Index										
1991 Q1=100	438.2	442.9	452.7	466.4	482.7	501.6	522.7	545.4	569.3	594.6
% Ch Yr/Yr	1.6	1.1	2.2	3.0	3.5	3.9	4.2	4.4	4.4	4.4
Housing Starts										
Oregon (Thous)	16.1	15.8	16.4	17.9	19.8	20.7	20.8	20.9	21.0	21.2
% Ch Yr/Yr	13.3	(1.9)	3.9	9.1	10.5	4.5	0.8	0.2	0.7	1.0
U.S. (Millions)	1.4	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.2	1.2
% Ch Yr/Yr	1.4	(3.0)	(1.3)	(0.8)	(0.8)	(0.4)	(0.9)	(2.0)	(2.2)	(2.2)
Other Indicators										
Unemployment Rate (%)										
Oregon	5.3	5.3	5.2	5.3	5.3	5.2	5.1	5.0	5.0	4.8
Point Change	0.1	0.1	(0.1)	0.0	0.0	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)
U.S.	4.3	4.4	4.3	4.3	4.3	4.3	4.3	4.2	4.2	4.2
Point Change	0.0	0.1	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Industrial Production Index										
U.S, 2017 = 100	102.5	103.5	104.8	106.1	107.1	108.1	109.0	109.7	110.6	111.5
% Ch Yr/Yr	1.2	1.0	1.2	1.3	0.9	1.0	0.8	0.7	0.8	0.8
Prime Rate (Percent)	6.8	6.6	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3
% Ch Yr/Yr	(8.4)	(2.3)	(5.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Population (Millions)										
Oregon	4.31	4.34	4.36	4.38	4.40	4.42	4.44	4.46	4.48	4.50
% Ch Yr/Yr	0.3	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4
U.S.	343.1	344.0	344.9	346.0	347.3	348.6	349.8	350.9	352.0	353.1
% Ch Yr/Yr	0.3	0.3	0.3	0.3	0.4	0.4	0.3	0.3	0.3	0.3
Timber Harvest (Mil Bd Ft)										
Oregon	3,338.5	3,423.7	3,490.7	3,531.9	3,563.7	3,589.1	3,608.2	3,625.3	3,640.3	3,649.8
% Ch Yr/Yr	7.1	2.6	2.0	1.2	0.9	0.7	0.5	0.5	0.4	0.3

TABLE A.4.B

Sept 2026 - Personal Income Indicators

(Billions of Current Dollars)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Personal Income*										
Oregon	324.0	344.6	365.6	384.6	403.0	422.2	441.9	462.1	482.9	504.5
% Ch Yr/Yr	3.0	6.3	6.1	5.2	4.8	4.8	4.7	4.6	4.5	4.5
U.S.	27,050.4	28,639.9	30,354.5	31,904.1	33,411.8	34,958.5	36,538.6	38,156.5	39,835.2	41,596.5
% Ch Yr/Yr	3.6	5.9	6.0	5.1	4.7	4.6	4.5	4.4	4.4	4.4
Wage and Salary										
Oregon	158.8	167.5	177.3	186.6	196.1	205.9	215.8	225.7	235.4	246.3
% Ch Yr/Yr	3.5	5.5	5.9	5.2	5.1	5.0	4.8	4.6	4.3	4.6
U.S.	13,434.9	14,117.8	14,946.4	15,746.0	16,556.6	17,379.0	18,200.3	19,010.5	19,832.0	20,681.3
% Ch Yr/Yr	3.7	5.1	5.9	5.3	5.1	5.0	4.7	4.5	4.3	4.3
Other Labor Income										
Oregon	39.1	41.2	43.6	45.9	48.3	50.7	53.1	55.5	57.9	60.4
% Ch Yr/Yr	3.2	5.3	5.8	5.3	5.1	5.0	4.8	4.5	4.2	4.3
U.S.	1,933.7	2,031.5	2,150.7	2,265.8	2,382.5	2,500.8	2,618.9	2,735.5	2,853.6	2,975.8
% Ch Yr/Yr	4.0	5.1	5.9	5.4	5.1	5.0	4.7	4.5	4.3	4.3
Nonfarm Proprietor's Income										
Oregon	25.2	27.5	29.4	31.1	32.6	34.2	35.9	37.8	39.7	41.6
% Ch Yr/Yr	3.0	9.2	7.0	5.6	5.0	4.9	4.8	5.3	5.1	4.9
U.S.	2,112.9	2,293.5	2,437.9	2,548.0	2,650.2	2,755.4	2,869.7	2,999.8	3,141.5	3,294.5
% Ch Yr/Yr	3.9	8.5	6.3	4.5	4.0	4.0	4.2	4.5	4.7	4.9
Dividend, Interest and Rent										
Oregon	65.5	69.8	75.0	78.5	81.2	84.0	86.8	90.0	93.3	97.0
% Ch Yr/Yr	1.2	6.6	7.4	4.7	3.4	3.4	3.4	3.7	3.7	3.9
U.S.	5,482.0	5,873.5	6,292.3	6,585.7	6,822.9	7,068.4	7,331.3	7,618.4	7,928.8	8,264.4
% Ch Yr/Yr	2.8	7.1	7.1	4.7	3.6	3.6	3.7	3.9	4.1	4.2
Transfer Payments										
Oregon	73.2	77.5	81.2	85.4	89.8	94.6	99.7	104.8	109.2	114.2
% Ch Yr/Yr	6.3	5.8	4.9	5.1	5.2	5.4	5.4	5.2	4.2	4.6
U.S.	5,073.0	5,321.7	5,557.0	5,827.7	6,117.1	6,427.9	6,749.0	7,079.8	7,423.6	7,783.6
% Ch Yr/Yr	4.7	4.9	4.4	4.9	5.0	5.1	5.0	4.9	4.9	4.8
Contributions for Social Security										
Oregon	29.2	30.8	32.4	34.0	35.6	37.4	39.2	40.9	42.7	44.5
% Ch Yr/Yr	5.9	5.3	5.1	4.9	4.9	5.0	4.7	4.4	4.4	4.2
U.S.	1,154.6	1,170.6	1,223.7	1,282.8	1,345.2	1,409.9	1,475.2	1,540.2	1,606.5	1,675.2
% Ch Yr/Yr	4.0	1.4	4.5	4.8	4.9	4.8	4.6	4.4	4.3	4.3
Residence Adjustment										
Oregon	(8.1)	(8.7)	(9.2)	(9.6)	(10.0)	(10.5)	(10.9)	(11.4)	(11.9)	(12.3)
% Ch Yr/Yr	7.8	7.2	5.0	4.6	4.6	4.4	4.4	4.4	4.3	3.0
Farm Proprietor's Income										
Oregon	0.2	0.3	0.5	0.6	0.6	0.7	0.7	0.7	0.7	0.7
% Ch Yr/Yr	(28.9)	35.5	42.0	21.7	9.8	3.6	1.9	2.2	2.2	2.4
Per Capita Income (Thousands of $)										
Oregon	75.1	79.4	83.9	87.8	91.6	95.5	99.5	103.6	107.9	112.2
% Ch Yr/Yr	2.7	5.8	5.6	4.7	4.3	4.3	4.2	4.1	4.1	4.0
U.S.	78.8	83.3	88.0	92.2	96.2	100.3	104.5	108.7	113.2	117.8
% Ch Yr/Yr	3.4	5.6	5.7	4.8	4.3	4.3	4.2	4.1	4.1	4.1

* Personal Income includes all classes of income minus Contributions for Social Security

TABLE A.4.C

Sept 2026 - Employment By Industry

(Oregon - Thousands, U.S. - Millions)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Nonfarm										
Oregon	1,976.2	1,985.2	1,995.1	2,003.1	2,014.6	2,026.1	2,037.3	2,048.1	2,057.5	2,067.3
% Ch Yr/Yr	(0.5)	0.5	0.5	0.4	0.6	0.6	0.6	0.5	0.5	0.5
U.S.	158.9	159.4	159.9	160.4	161.1	161.6	162.2	162.6	163.1	163.5
% Ch Yr/Yr	0.3	0.3	0.3	0.3	0.4	0.3	0.3	0.3	0.3	0.3
Private Nonfarm										
Oregon	1,660.3	1,669.8	1,680.7	1,689.5	1,700.7	1,713.3	1,724.8	1,735.9	1,745.5	1,755.5
% Ch Yr/Yr	(0.5)	0.6	0.7	0.5	0.7	0.7	0.7	0.6	0.6	0.6
U.S.	135.6	136.0	136.4	136.8	137.3	137.9	138.3	138.7	139.1	139.4
% Ch Yr/Yr	0.5	0.3	0.3	0.3	0.4	0.4	0.3	0.3	0.3	0.3
Mining and Logging										
Oregon	5.6	5.7	5.7	5.7	5.7	5.7	5.6	5.6	5.5	5.5
% Ch Yr/Yr	(4.4)	0.3	0.7	0.8	0.2	(0.7)	(1.3)	(1.0)	(0.9)	(0.7)
U.S.	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
% Ch Yr/Yr	(0.6)	5.3	3.1	2.5	(1.2)	(1.9)	(0.4)	0.5	0.6	0.6
Construction										
Oregon	110.5	111.2	112.5	114.1	115.8	117.4	119.1	120.8	122.7	124.6
% Ch Yr/Yr	(2.4)	0.7	1.2	1.4	1.5	1.4	1.4	1.5	1.6	1.6
U.S.	8.3	8.4	8.5	8.7	8.8	8.9	8.9	9.0	9.2	9.3
% Ch Yr/Yr	0.8	1.0	1.6	1.6	1.2	0.8	0.9	1.2	1.4	1.3
Manufacturing										
Oregon	172.2	170.2	170.2	171.0	171.0	170.9	171.5	172.2	172.5	172.0
% Ch Yr/Yr	(3.9)	(1.1)	(0.0)	0.5	(0.0)	(0.0)	0.4	0.4	0.2	(0.3)
U.S.	12.6	12.5	12.3	12.1	12.0	12.0	12.0	11.9	11.8	11.6
% Ch Yr/Yr	(0.2)	(0.8)	(1.8)	(1.3)	(0.6)	(0.3)	(0.3)	(0.6)	(1.1)	(1.4)
Durable Manufacturing										
Oregon	119.4	118.6	119.0	119.7	119.4	119.2	119.4	119.6	119.9	119.4
% Ch Yr/Yr	(4.3)	(0.7)	0.4	0.5	(0.2)	(0.2)	0.1	0.2	0.2	(0.4)
U.S.	7.8	7.8	7.7	7.6	7.5	7.4	7.4	7.4	7.3	7.1
% Ch Yr/Yr	0.1	(0.0)	(1.8)	(1.8)	(1.0)	(0.4)	(0.4)	(0.8)	(1.3)	(1.7)
Wood Products										
Oregon	21.4	21.0	20.7	20.9	20.7	20.8	21.4	21.9	22.4	22.5
% Ch Yr/Yr	(3.0)	(1.8)	(1.2)	0.8	(1.1)	0.6	2.8	2.5	2.4	0.0
U.S.	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5
% Ch Yr/Yr	(2.9)	3.8	1.2	0.5	2.7	3.6	3.2	1.4	0.0	(0.8)
Metal and Machinery										
Oregon	36.0	36.1	36.2	36.2	36.1	35.8	35.4	35.2	35.0	34.9
% Ch Yr/Yr	(0.9)	0.1	0.2	0.0	(0.2)	(0.8)	(1.1)	(0.7)	(0.5)	(0.3)
U.S.	2.9	2.9	2.8	2.8	2.7	2.7	2.7	2.7	2.7	2.6
% Ch Yr/Yr	0.4	(0.5)	(2.2)	(2.3)	(1.4)	(0.3)	(0.3)	(0.7)	(1.1)	(1.5)
Computer and Electronic Products										
Oregon	30.9	30.5	31.5	32.3	32.8	33.0	33.2	33.2	33.2	33.2
% Ch Yr/Yr	(11.0)	(1.3)	3.2	2.6	1.5	0.7	0.5	0.2	0.0	(0.0)
U.S.	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
% Ch Yr/Yr	(0.1)	1.4	0.6	0.0	(0.6)	(0.4)	(0.1)	(0.1)	(0.1)	(0.1)
Transportation Equipment										
Oregon	11.3	11.4	11.5	11.5	11.4	11.4	11.4	11.4	11.4	11.4
% Ch Yr/Yr	5.9	1.1	0.5	0.2	(0.7)	(0.3)	(0.3)	0.2	0.2	(0.3)
U.S.	1.7	1.7	1.7	1.7	1.6	1.6	1.6	1.6	1.5	1.5
% Ch Yr/Yr	(0.1)	0.3	(2.3)	(2.4)	(1.6)	(1.6)	(1.3)	(1.5)	(2.6)	(3.7)
Other Durables										
Oregon	19.7	19.5	19.1	18.7	18.4	18.2	18.0	17.9	17.8	17.5
% Ch Yr/Yr	(5.7)	(0.8)	(2.0)	(2.1)	(2.0)	(1.1)	(0.7)	(0.7)	(0.7)	(1.8)
U.S.	2.2	2.2	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
% Ch Yr/Yr	(0.2)	(0.3)	(1.9)	(1.5)	(0.2)	0.2	0.0	(0.6)	(1.0)	(1.4)

Sept 2026 - Employment By Industry

(Oregon - Thousands, U.S. - Millions)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Nondurable Manufacturing										
Oregon	52.8	51.6	51.1	51.3	51.6	51.7	52.2	52.6	52.7	52.5
% Ch Yr/Yr	(3.1)	(2.3)	(1.0)	0.4	0.5	0.3	0.8	0.8	0.1	(0.3)
U.S.	4.8	4.7	4.6	4.6	4.6	4.6	4.6	4.5	4.5	4.5
% Ch Yr/Yr	(0.7)	(2.1)	(1.8)	(0.5)	0.1	(0.0)	(0.1)	(0.4)	(0.8)	(1.0)
Food Manufacturing										
Oregon	27.1	26.4	26.0	26.1	26.4	26.8	27.3	27.8	28.0	28.0
% Ch Yr/Yr	(2.5)	(2.4)	(1.7)	0.7	1.1	1.3	1.8	1.8	0.7	0.2
U.S.	1.8	1.7	1.7	1.7	1.8	1.8	1.8	1.9	1.9	1.9
% Ch Yr/Yr	(0.2)	(1.9)	(1.1)	1.0	2.0	1.8	1.7	1.2	0.4	0.2
Other Nondurable										
Oregon	25.6	25.2	25.1	25.2	25.1	24.9	24.9	24.8	24.7	24.5
% Ch Yr/Yr	(4.4)	(1.4)	(0.3)	0.0	(0.1)	(0.7)	(0.2)	(0.2)	(0.5)	(0.8)
U.S.	3.0	2.9	2.9	2.8	2.8	2.8	2.7	2.7	2.6	2.6
% Ch Yr/Yr	(1.0)	(2.2)	(2.2)	(1.4)	(1.1)	(1.2)	(1.3)	(1.4)	(1.7)	(1.8)
Trade, Transportation, and Utilities										
Oregon	351.0	349.0	350.0	350.3	352.5	354.0	355.5	357.6	359.9	362.5
% Ch Yr/Yr	(1.1)	(0.6)	0.3	0.1	0.6	0.4	0.4	0.6	0.6	0.7
U.S.	28.7	28.5	28.1	27.8	27.7	27.7	27.7	27.6	27.6	27.5
% Ch Yr/Yr	(0.2)	(0.7)	(1.4)	(0.9)	(0.4)	(0.1)	(0.1)	(0.1)	(0.2)	(0.3)
Retail Trade										
Oregon	197.2	195.5	195.8	195.7	197.5	198.5	199.5	201.0	202.6	204.8
% Ch Yr/Yr	(1.6)	(0.8)	0.1	(0.0)	0.9	0.5	0.5	0.7	0.8	1.1
U.S.	15.4	15.3	14.9	14.8	14.8	14.8	14.9	15.0	15.0	15.1
% Ch Yr/Yr	(0.1)	(0.9)	(2.4)	(1.1)	0.1	0.3	0.5	0.5	0.3	0.3
Wholesale Trade										
Oregon	74.2	74.0	74.3	74.7	74.9	75.2	75.4	75.7	75.9	76.0
% Ch Yr/Yr	(1.8)	(0.3)	0.5	0.4	0.4	0.4	0.3	0.3	0.3	0.1
U.S.	6.1	6.0	6.0	5.9	5.9	5.8	5.8	5.8	5.7	5.7
% Ch Yr/Yr	(0.1)	(0.5)	(0.5)	(0.9)	(1.2)	(0.5)	(0.5)	(0.7)	(0.7)	(0.7)
Transportation and Warehousing, and Utilities										
Oregon	79.7	79.5	79.9	79.9	80.1	80.3	80.5	80.9	81.3	81.7
% Ch Yr/Yr	0.8	(0.2)	0.4	0.1	0.1	0.3	0.3	0.5	0.5	0.5
U.S.	7.2	7.2	7.2	7.1	7.1	7.0	7.0	6.9	6.8	6.7
% Ch Yr/Yr	(0.6)	(0.5)	(0.0)	(0.6)	(0.8)	(0.5)	(0.8)	(1.0)	(1.0)	(1.4)
Information										
Oregon	34.3	34.5	35.3	35.5	35.7	35.8	35.9	36.0	36.3	36.1
% Ch Yr/Yr	(1.8)	0.6	2.4	0.6	0.5	0.3	0.1	0.4	0.7	(0.5)
U.S.	2.8	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.6
% Ch Yr/Yr	(3.2)	(2.2)	0.4	0.2	0.4	(0.2)	(0.4)	(0.2)	(1.4)	(1.8)
Financial Activities										
Oregon	99.2	99.8	99.8	99.7	100.0	100.3	100.9	101.7	102.1	102.7
% Ch Yr/Yr	(1.3)	0.6	0.0	(0.1)	0.3	0.3	0.6	0.8	0.5	0.5
U.S.	9.1	9.1	9.1	9.0	9.0	9.0	9.1	9.2	9.2	9.2
% Ch Yr/Yr	(0.9)	(0.5)	0.0	(0.3)	(0.4)	0.2	0.8	0.6	0.3	0.0
Professional and Business Services										
Oregon	251.4	255.4	259.5	263.7	267.7	272.6	274.8	275.0	275.0	276.5
% Ch Yr/Yr	(1.2)	1.6	1.6	1.6	1.6	1.8	0.8	0.1	(0.0)	0.5
U.S.	22.5	23.0	24.0	24.4	24.8	25.2	25.4	25.5	25.8	26.2
% Ch Yr/Yr	0.4	2.3	4.1	1.8	1.8	1.3	0.8	0.7	1.1	1.5

Sept 2026 - Employment By Industry

(Oregon - Thousands, U.S. - Millions)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Education and Health Services										
Oregon	362.9	369.4	371.3	371.9	373.5	375.0	375.8	376.7	377.5	378.3
% Ch Yr/Yr	3.4	1.8	0.5	0.2	0.4	0.4	0.2	0.3	0.2	0.2
U.S.	28.0	28.1	28.2	28.3	28.5	28.8	29.0	29.2	29.4	29.5
% Ch Yr/Yr	2.3	0.4	0.6	0.4	0.6	0.9	0.8	0.8	0.7	0.3
Educational Services										
Oregon	36.7	36.8	36.7	36.4	36.1	35.8	35.4	35.1	34.7	34.3
% Ch Yr/Yr	2.0	0.2	(0.4)	(0.7)	(0.8)	(0.9)	(1.1)	(0.9)	(1.1)	(1.0)
U.S.	4.1	4.0	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.0
% Ch Yr/Yr	0.0	(0.4)	1.7	1.0	(0.2)	(0.3)	(0.4)	(0.5)	(0.5)	(1.4)
Health Care and Social Assistance										
Oregon	326.1	332.6	334.6	335.4	337.3	339.2	340.3	341.6	342.8	344.0
% Ch Yr/Yr	3.5	2.0	0.6	0.2	0.6	0.6	0.3	0.4	0.3	0.4
U.S.	23.9	24.0	24.1	24.2	24.4	24.6	24.9	25.1	25.4	25.5
% Ch Yr/Yr	2.7	0.6	0.4	0.3	0.7	1.1	1.0	1.0	0.9	0.5
Leisure and Hospitality										
Oregon	205.9	206.2	207.2	207.9	208.6	210.8	214.4	218.3	221.3	223.8
% Ch Yr/Yr	(0.9)	0.2	0.5	0.3	0.3	1.0	1.7	1.8	1.4	1.1
U.S.	17.0	17.0	16.7	16.8	16.9	16.8	16.8	16.7	16.7	16.8
% Ch Yr/Yr	0.6	0.2	(1.9)	0.9	0.3	(0.4)	(0.3)	(0.1)	(0.1)	0.7
Other Services										
Oregon	67.5	68.5	69.1	69.7	70.2	70.7	71.3	72.0	72.6	73.5
% Ch Yr/Yr	1.2	1.5	1.0	0.8	0.7	0.8	0.9	0.9	0.9	1.2
U.S.	6.0	6.0	6.1	6.2	6.2	6.2	6.2	6.1	6.1	6.1
% Ch Yr/Yr	0.7	0.0	1.6	0.8	(0.1)	(0.1)	(0.3)	(0.5)	(0.4)	(0.5)
Government										
Oregon	315.9	315.4	314.4	313.6	313.9	312.8	312.5	312.2	312.0	311.8
% Ch Yr/Yr	(0.4)	(0.1)	(0.3)	(0.3)	0.1	(0.3)	(0.1)	(0.1)	(0.1)	(0.1)
U.S.	23.4	23.4	23.5	23.6	23.8	23.8	23.8	23.9	24.0	24.1
% Ch Yr/Yr	(0.7)	0.4	0.4	0.3	0.6	0.1	0.3	0.3	0.3	0.3
Federal Government										
Oregon	26.7	26.4	26.3	26.2	27.0	26.1	26.1	26.2	26.2	26.2
% Ch Yr/Yr	(5.8)	(1.0)	(0.4)	(0.3)	2.8	(3.2)	0.1	0.1	0.1	0.1
U.S.	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
% Ch Yr/Yr	(7.5)	(0.0)	(0.0)	0.0	2.3	(2.2)	0.0	0.0	0.0	0.0
State Government, Oregon										
Total	49.2	49.9	51.1	51.9	52.6	53.1	53.5	53.8	54.1	54.4
% Ch Yr/Yr	(0.2)	1.4	2.3	1.6	1.2	1.1	0.8	0.6	0.5	0.5
Education	1.3	1.2	1.2	1.2	1.3	1.4	1.5	1.5	1.6	1.7
% Ch Yr/Yr	(2.7)	(7.8)	(0.6)	4.4	6.3	6.3	6.5	5.0	5.1	3.5
Non-Education	48.0	48.8	49.9	50.7	51.3	51.7	52.0	52.3	52.5	52.7
% Ch Yr/Yr	(0.1)	1.7	2.4	1.5	1.1	0.9	0.6	0.4	0.4	0.4
Local Government, Oregon										
Total	240.0	239.1	237.0	235.5	234.3	233.6	232.9	232.3	231.7	231.2
% Ch Yr/Yr	0.2	(0.4)	(0.9)	(0.7)	(0.5)	(0.3)	(0.3)	(0.3)	(0.2)	(0.2)
Education	135.3	130.8	126.0	122.9	120.7	119.1	117.9	117.0	116.2	115.3
% Ch Yr/Yr	0.4	(3.4)	(3.6)	(2.5)	(1.8)	(1.3)	(1.0)	(0.8)	(0.7)	(0.8)
Non-Education	104.7	108.3	111.0	112.6	113.7	114.4	114.9	115.3	115.5	115.9
% Ch Yr/Yr	0.0	3.5	2.5	1.5	0.9	0.7	0.4	0.3	0.2	0.3

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Table B.1a – General Fund Revenues – 2025-27

Table B.1a

General Fund Revenue Statement -- 2025-27

September 2026

		Previous Forecast			Current Forecast			Difference	
	Estimate at COS 2025	2025-26	2026-27	Total 2025-27	2025-26	2026-27	Total 2025-27	Current vs. Previous	Current vs. COS
Taxes									
Personal Income Taxes	30,247,069,114	13,981,639,000	16,138,155,000	30,119,794,000	13,966,648,000	16,290,977,000	30,257,625,000	137,831,000	10,555,886
Transfers & Offsets	(67,046,000)	(33,233,000)	(34,569,000)	(67,802,000)	(28,384,000)	(28,785,000)	(57,169,000)	10,633,000	9,877,000
Corporate Income Taxes	3,430,536,105	1,643,169,000	1,944,625,000	3,587,794,000	1,570,037,000	1,921,779,000	3,491,816,000	(95,978,000)	61,279,895
Transfer to Rainy Day Fund (Minimum Tax)	(139,874,000)	0	(153,366,000)	(153,366,000)	0	(149,263,000)	(149,263,000)	4,103,000	(9,389,000)
Insurance Taxes	195,920,000	105,021,000	108,658,000	213,679,000	115,686,000	114,495,000	230,181,000	16,502,000	34,261,000
Estate Taxes	936,573,000	442,152,000	496,347,000	938,499,000	417,736,000	490,631,000	908,367,000	(30,132,000)	(28,206,000)
Transfer to PERS UAL	0	0	0	0	0	0	0	0	0
Cigarette Taxes	32,795,000	15,951,000	15,548,000	31,499,000	15,584,000	14,967,000	30,551,000	(948,000)	(2,244,000)
Other Tobacco Products Taxes	47,273,000	25,199,000	24,172,000	49,371,000	24,487,000	22,253,000	46,740,000	(2,631,000)	(533,000)
Other Taxes	1,106,000	803,000	803,000	1,606,000	890,000	803,000	1,693,000	87,000	587,000
Fines and Fees									
State Court Fees	115,510,000	53,836,000	54,615,000	108,451,000	53,710,000	55,578,000	109,288,000	837,000	(6,222,000)
Secretary of State Fees	92,653,000	48,283,000	47,864,000	96,147,000	48,235,000	47,707,000	95,942,000	(205,000)	3,289,000
Criminal Fines & Assessments	0	0	0	0	0	0	0	0	0
Securities Fees	28,650,000	14,657,000	15,383,000	30,040,000	14,541,000	14,861,000	29,402,000	(638,000)	752,000
Central Service Charges	17,768,000	12,870,000	12,870,000	25,740,000	10,620,000	10,620,000	21,240,000	(4,500,000)	3,472,000
Liquor Apportionment	290,250,493	140,509,000	139,076,000	279,585,000	134,806,000	137,223,000	272,029,000	(7,556,000)	(18,221,493)
Interest Earnings	263,391,000	182,609,000	129,634,000	312,243,000	182,920,000	156,623,000	339,543,000	27,300,000	76,152,000
One-time/Miscellaneous Revenues	60,293,340	34,450,000	74,343,000	108,793,000	33,232,000	74,343,000	107,575,000	(1,218,000)	47,281,660
Reversions[1]	0	9,821,000	0	9,821,000	11,689,000	0	11,689,000	1,868,000	11,689,000
Gross General Fund Revenues	35,759,788,051	16,710,969,000	19,202,093,000	35,913,062,000	16,600,821,000	19,352,860,000	35,953,681,000	40,619,000	193,892,949
Total Transfers	(206,920,000)	(33,233,000)	(187,935,000)	(221,168,000)	(28,384,000)	(178,048,000)	(206,432,000)	14,736,000	488,000
Net General Fund Revenues	35,552,868,051	16,677,736,000	19,014,158,000	35,691,894,000	16,572,437,000	19,174,812,000	35,747,249,000	55,355,000	194,380,949
Plus Beginning Balance	2,243,051,122			2,165,830,351			2,165,830,351	0	(77,220,771)
Less Anticipated Administrative Actions*	0			0			0	0	0
Less Statutory Transfers**	0			0			0	0	0
Available Resources	37,795,919,173			37,857,724,351			37,913,079,351	55,355,000	117,160,178
Appropriations	37,323,112,893			37,513,112,979			37,513,112,979	0	190,000,086
Estimated Ending Balance	472,806,280			344,611,372			399,966,372	55,355,000	(72,839,908)

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 2025-27 biennium.

** "Statutory Transfers" amounts to the Rainy Day Fund transfer. SB 960 eliminated the statutory transfer to the Rainy Day Fund for 2025-27.

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 – 2027-29

Table B.1b

General Fund Revenue Statement -- 2027-29

September 2026

	Prevous Forecast			Current Forecast			Difference
	2027-28	2028-29	Total 2027-29	2027-28	2028-29	Total 2027-29	Current vs. Previous
Taxes							
Personal Income Taxes	17,385,857,000	18,602,405,000	35,988,262,000	17,663,272,000	18,799,732,000	36,463,004,000	474,742,000
Transfers & Offsets***	(34,772,000)	(34,670,000)	(69,442,000)	(61,551,000)	(69,317,000)	(130,868,000)	(61,426,000)
Corporate Income Taxes	1,853,162,000	1,975,045,000	3,828,207,000	1,914,067,000	1,987,014,000	3,901,081,000	72,874,000
Transfer to Rainy Day Fund (Minimum Tax)	0	(163,642,000)	(163,642,000)	0	(166,758,000)	(166,758,000)	(3,116,000)
Insurance Taxes	110,470,000	112,420,000	222,890,000	111,320,000	114,610,000	225,930,000	3,040,000
Estate Taxes	545,635,000	596,966,000	1,142,601,000	539,458,000	596,030,000	1,135,488,000	(7,113,000)
Cigarette Taxes	14,628,000	13,710,000	28,338,000	14,086,000	13,137,000	27,223,000	(1,115,000)
Other Tobacco Products Taxes	22,946,000	22,083,000	45,029,000	19,860,000	19,109,000	38,969,000	(6,060,000)
Other Taxes	803,000	803,000	1,606,000	803,000	803,000	1,606,000	0
Fines and Fees							
State Court Fees	55,404,000	56,206,000	111,610,000	56,967,000	58,391,000	115,358,000	3,748,000
Secretary of State Fees	48,508,000	49,153,000	97,661,000	49,049,000	50,391,000	99,440,000	1,779,000
Criminal Fines & Assessments	0	0	0	0	6,340,000	6,340,000	6,340,000
Securities Fees	15,442,000	15,894,000	31,336,000	15,017,000	15,409,000	30,426,000	(910,000)
Central Service Charges	15,444,000	15,444,000	30,888,000	12,213,000	12,213,000	24,426,000	(6,462,000)
Liquor Apportionment	122,775,000	123,570,000	246,345,000	113,210,000	113,943,000	227,153,000	(19,192,000)
Interest Earnings	127,455,000	131,245,000	258,700,000	172,293,000	167,197,000	339,490,000	80,790,000
One-time/Miscellaneous Revenues	10,000,000	11,000,000	21,000,000	10,000,000	11,000,000	21,000,000	0
Reversions[1]	0	0	0	0	0	0	0
Gross General Fund Revenues	20,328,529,000	21,725,944,000	42,054,473,000	20,691,615,000	21,965,319,000	42,656,934,000	602,461,000
Total Transfers	(34,772,000)	(198,312,000)	(233,084,000)	(61,551,000)	(236,075,000)	(297,626,000)	(64,542,000)
Net General Fund Revenues	20,293,757,000	21,527,632,000	41,821,389,000	20,630,064,000	21,729,244,000	42,359,308,000	537,919,000
Plus Beginning Balance**			344,611,372			399,966,372	55,355,000
Less Anticipated Administrative Actions*			0			0	0
Less Statutory Transfers**			(344,611,372)			(375,131,130)	(30,519,758)
Available Resources			41,821,389,000			42,384,143,242	562,754,242

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 2027-29 biennium.

** "Statutory Transfers" is the Rainy Day Fund transfer based on the previous biennium's expenditures and ending balance. A negative ending balance projected for the prior biennium is assumed balanced by June 30, resulting in no transfer to the Rainy Day Fund.

*** "Transfers & Offsets" includes the transfer of estimated income taxes related to Moda Center activities per SB 1501 (2026). LRO estimates of the impact are newly included for this Q3 forecast.

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.2 – General Fund Revenues by Fiscal Year

TABLE B.2

General Fund Revenue Forecast

September 2026

Millions of dollars

Fiscal Years	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	2033-34 Fiscal Year	2034-35 Fiscal Year
Taxes												
Personal Income	9,128.4	13,041.0	13,966.6	16,291.0	17,663.3	18,799.7	19,897.4	21,122.1	22,233.3	23,651.9	25,017.8	26,433.3
Offsets and Transfers	(70.5)	(34.5)	(28.4)	(28.8)	(61.6)	(69.3)	(67.9)	(47.3)	(49.2)	(47.5)	(48.6)	(52.1)
Corporate Excise & Income	1,623.1	1,527.7	1,570.0	1,921.8	1,914.1	1,987.0	2,055.0	2,113.2	2,197.2	2,290.7	2,391.3	2,502.0
Offsets and Transfers	0.0	(133.8)	0.0	(149.3)	0.0	(166.8)	0.0	(178.2)	0.0	(191.8)	0.0	(209.2)
Insurance	55.5	97.7	115.7	114.5	111.3	114.6	117.1	120.6	124.4	128.4	132.5	136.8
Estate	339.0	422.8	417.7	490.6	539.5	596.0	655.3	719.5	789.6	866.5	950.8	1,043.4
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	21.2	16.7	15.6	15.0	14.1	13.1	12.1	11.1	10.1	9.2	8.3	7.5
Other Tobacco Products	26.8	27.5	24.5	22.3	19.9	19.1	18.3	17.6	17.1	16.6	16.1	16.1
Other Taxes	1.4	0.9	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Other Revenues												
Licenses and Fees	112.6	112.5	116.5	118.1	121.0	130.5	127.0	136.8	133.1	143.1	139.3	149.6
Charges for Services	8.1	8.1	10.6	10.6	12.2	12.2	14.0	14.0	16.2	16.2	18.6	18.6
Liquor Apportionment	187.1	160.3	134.8	137.2	113.2	113.9	110.8	112.2	113.6	115.0	116.5	118.0
Interest Earnings	413.0	236.7	182.9	156.6	172.3	167.2	171.9	188.2	209.1	227.3	252.5	278.1
Others	32.8	22.4	44.9	74.3	10.0	11.0	12.0	13.0	14.0	15.0	16.0	17.0
Gross General Fund	11,948.9	15,674.2	16,600.8	19,352.9	20,691.6	21,965.3	23,191.7	24,569.3	25,858.5	27,480.7	29,060.5	30,721.2
Net General Fund	11,878.4	15,505.9	16,572.4	19,174.8	20,630.1	21,729.2	23,123.8	24,343.7	25,809.4	27,241.3	29,011.9	30,460.0

Biennial Totals	2023-25 BN	*Change (%)*	2025-27 BN	*Change (%)*	2027-29 BN	*Change (%)*	2029-31 BN	*Change (%)*	2031-33 BN	*Change (%)*	2033-35 BN	*Change (%)*
Taxes												
Personal Income	22,169.4	*-13.7%*	30,257.6	*36.5%*	36,463.0	*20.5%*	41,019.6	*12.5%*	45,885.2	*11.9%*	51,451.0	*12.1%*
Corporate Excise & Income	3,150.8	*-0.2%*	3,491.8	*10.8%*	3,901.1	*11.7%*	4,168.2	*6.8%*	4,487.9	*7.7%*	4,893.4	*9.0%*
Insurance	153.2	*-16.0%*	230.2	*50.3%*	225.9	*-1.8%*	237.7	*5.2%*	252.8	*6.3%*	269.3	*6.5%*
Estate Taxes	761.8	*22.3%*	908.4	*19.2%*	1,135.5	*25.0%*	1,374.8	*21.1%*	1,656.1	*20.5%*	1,994.2	*20.4%*
Cigarette	37.8	*-17.3%*	30.6	*-19.2%*	27.2	*-10.9%*	23.2	*-14.7%*	19.3	*-16.6%*	15.9	*-18.1%*
Other Tobacco Products	54.3	*-9.2%*	46.7	*-13.9%*	39.0	*-16.6%*	35.9	*-7.8%*	33.7	*-6.2%*	32.3	*-4.4%*
Other Taxes	2.2	*21.1%*	1.7	*-24.5%*	1.6	*-5.1%*	1.6	*0.0%*	1.6	*0.0%*	1.6	*0.0%*
Other Revenues												
Licenses and Fees	225.1	*0.0%*	234.6	*4.2%*	251.6	*7.2%*	263.8	*4.9%*	276.2	*4.7%*	288.9	*4.6%*
Charges for Services	16.2	*26.7%*	21.2	*31.5%*	24.4	*15.0%*	28.1	*15.0%*	32.3	*15.0%*	37.1	*15.0%*
Liquor Apportionment	347.4	*4.5%*	272.0	*-21.7%*	227.2	*-16.5%*	223.0	*-1.8%*	228.7	*2.5%*	234.4	*2.5%*
Interest Earnings	649.7	*114.8%*	339.5	*-47.7%*	339.5	*0.0%*	360.1	*6.1%*	436.4	*21.2%*	530.7	*21.6%*
Others	55.2	*-64.0%*	119.3	*116.2%*	21.0	*-82.4%*	25.0	*19.0%*	29.0	*16.0%*	33.0	*13.8%*
Gross General Fund	27,623.1	*-10.3%*	35,953.7	*30.2%*	42,656.9	*18.6%*	47,761.0	*12.0%*	53,339.2	*11.7%*	59,781.8	*12.1%*
Net General Fund	27,384.3	*-10.5%*	35,747.2	*30.5%*	42,359.3	*18.5%*	47,467.6	*12.1%*	53,050.7	*11.8%*	59,471.9	*12.1%*

Note: Detailed entries may not add to totals due to rounding

Table B.4 – Personal Income Tax Forecast

Table B.4 **September 2026**

Oregon Personal Income Tax Revenue Forecast

Quarterly tax receipts (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	2,926,174	3,132,725	3,123,902	3,007,930	12,190,731	3,101,456	3,285,034	3,354,763	3,271,844	13,013,097
Y/Y %ch	*5.2%*	*4.1%*	*4.1%*	*5.8%*	*4.8%*	*6.0%*	*4.9%*	*7.4%*	*8.8%*	*6.7%*
Est. Payments	713,044	609,622	550,049	953,592	2,826,307	698,973	708,457	621,467	1,058,048	3,086,946
Y/Y %ch	*13.9%*	*-2.7%*	*-4.9%*	*5.1%*	*3.2%*	*-2.0%*	*16.2%*	*13.0%*	*11.0%*	*9.2%*
Final Payments	208,518	281,895	331,768	1,630,774	2,452,955	170,522	302,100	334,691	2,370,874	3,178,188
Y/Y %ch	*15.0%*	*48.2%*	*-7.9%*	*-7.5%*	*-1.6%*	*-18.2%*	*7.2%*	*0.9%*	*45.4%*	*29.6%*
Refunds	(315,383)	(510,964)	(1,553,581)	(1,111,023)	(3,490,951)	(321,261)	(658,933)	(1,110,412)	(937,881)	(3,028,487)
Y/Y %ch	*-61.1%*	*-52.1%*	*41.5%*	*36.0%*	*-8.0%*	*1.9%*	*29.0%*	*-28.5%*	*-15.6%*	*-13.2%*
Other	(208,135)	-	-	195,740	(12,395)	(195,740)	-	-	236,973	41,233
Total	**3,324,217**	**3,513,279**	**2,452,138**	**4,677,014**	**13,966,648**	**3,453,950**	**3,636,658**	**3,200,510**	**5,999,859**	**16,290,977**
Y/Y %ch	*31.1%*	*27.3%*	*-13.7%*	*-4.6%*	*7.1%*	*3.9%*	*3.5%*	*30.5%*	*28.3%*	*16.6%*

	2027:3	2027:4	2028:1	2028:2	FY 2028	2028:3	2028:4	2029:1	2029:2	FY 2029
Withholding	3,315,545	3,526,696	3,569,107	3,477,849	13,889,196	3,524,278	3,748,679	3,799,820	3,703,240	14,776,017
%CHYA	*6.9%*	*7.4%*	*6.4%*	*6.3%*	*6.7%*	*6.3%*	*6.3%*	*6.5%*	*6.5%*	*6.4%*
Est. Payments	781,990	778,600	678,706	1,118,913	3,358,209	826,974	823,390	719,008	1,196,152	3,565,523
%CHYA	*11.9%*	*9.9%*	*9.2%*	*5.8%*	*8.8%*	*5.8%*	*5.8%*	*5.9%*	*6.9%*	*6.2%*
Final Payments	202,284	340,554	347,543	2,232,924	3,123,305	213,513	340,311	361,828	2,356,168	3,271,820
%CHYA	*18.6%*	*12.7%*	*3.8%*	*-5.8%*	*-1.7%*	*5.6%*	*-0.1%*	*4.1%*	*5.5%*	*4.8%*
Refunds	(270,294)	(533,130)	(1,061,561)	(900,279)	(2,765,264)	(247,693)	(505,311)	(1,143,980)	(972,371)	(2,869,355)
%CHYA	*-15.9%*	*-19.1%*	*-4.4%*	*-4.0%*	*-8.7%*	*-8.4%*	*-5.2%*	*7.8%*	*8.0%*	*3.8%*
Other	(236,973)	-	-	294,800	57,827	(294,800)	-	-	350,527	55,727
Total	**3,792,551**	**4,112,720**	**3,533,795**	**6,224,205**	**17,663,272**	**4,022,272**	**4,407,070**	**3,736,676**	**6,633,715**	**18,799,732**
%CHYA	*9.8%*	*13.1%*	*10.4%*	*3.7%*	*8.4%*	*6.1%*	*7.2%*	*5.7%*	*6.6%*	*6.4%*

Table B.4 – Personal Income Tax Forecast (cont.)

Table B.4 **September 2026**

Oregon Personal Income Tax Revenue Forecast

Quarterly tax receipts (thousands of dollars, not seasonally adjusted)

	2029:3	2029:4	2030:1	2030:2	FY2030	2030:3	2030:4	2031:1	2031:2	FY 2031
Withholding	3,752,683	3,991,635	4,033,320	3,929,602	15,707,240	3,982,057	4,235,598	4,267,681	4,156,790	16,642,126
%CHYA	*6.5%*	*6.5%*	*6.1%*	*6.1%*	*6.3%*	*6.1%*	*6.1%*	*5.8%*	*5.8%*	*6.0%*
Est. Payments	884,060	880,229	768,204	1,274,246	3,806,739	941,779	937,697	817,941	1,353,171	4,050,587
%CHYA	*6.9%*	*6.9%*	*6.8%*	*6.5%*	*6.8%*	*6.5%*	*6.5%*	*6.5%*	*6.2%*	*6.4%*
Final Payments	224,020	358,501	386,671	2,505,080	3,474,270	240,232	382,524	402,982	2,644,677	3,670,415
%CHYA	*4.9%*	*5.3%*	*6.9%*	*6.3%*	*6.2%*	*7.2%*	*6.7%*	*4.2%*	*5.6%*	*5.6%*
Refunds	(265,897)	(545,872)	(1,224,663)	(1,040,951)	(3,077,382)	(281,719)	(582,544)	(1,311,070)	(1,114,314)	(3,289,646)
%CHYA	*7.3%*	*8.0%*	*7.1%*	*7.1%*	*7.2%*	*6.0%*	*6.7%*	*7.1%*	*7.0%*	*6.9%*
Other	(350,527)	-	-	337,105	(13,421)	(337,105)	-	-	385,767	48,661
Total	**4,244,339**	**4,684,492**	**3,963,532**	**7,005,082**	**19,897,445**	**4,545,244**	**4,973,275**	**4,177,534**	**7,426,091**	**21,122,144**
%CHYA	*5.5%*	*6.3%*	*6.1%*	*5.6%*	*5.8%*	*7.1%*	*6.2%*	*5.4%*	*6.0%*	*6.2%*

	2031:3	2031:4	2032:1	2032:2	FY2032	2032:3	2032:4	2033:1	2033:2	FY 2033
Withholding	4,212,270	4,480,452	4,531,257	4,415,117	17,639,096	4,474,057	4,758,930	4,796,724	4,672,250	18,701,961
%CHYA	*5.8%*	*5.8%*	*6.2%*	*6.2%*	*6.0%*	*6.2%*	*6.2%*	*5.9%*	*5.8%*	*6.0%*
Est. Payments	1,000,111	995,776	869,178	1,442,867	4,307,932	1,066,404	1,061,782	926,231	1,532,772	4,587,189
%CHYA	*6.2%*	*6.2%*	*6.3%*	*6.6%*	*6.4%*	*6.6%*	*6.6%*	*6.6%*	*6.2%*	*6.5%*
Final Payments	249,009	400,130	425,608	2,790,559	3,865,307	263,032	422,495	450,632	2,956,072	4,092,231
%CHYA	*3.7%*	*4.6%*	*5.6%*	*5.5%*	*5.3%*	*5.6%*	*5.6%*	*5.9%*	*5.9%*	*5.9%*
Refunds	(301,093)	(623,248)	(1,400,300)	(1,190,076)	(3,514,716)	(321,758)	(665,713)	(1,500,905)	(1,275,666)	(3,764,042)
%CHYA	*6.9%*	*7.0%*	*6.8%*	*6.8%*	*6.8%*	*6.9%*	*6.8%*	*7.2%*	*7.2%*	*7.1%*
Other	(385,767)	-	-	321,468	(64,299)	(321,468)	-	-	355,980	34,512
Total	**4,774,531**	**5,253,111**	**4,425,743**	**7,779,935**	**22,233,320**	**5,160,267**	**5,577,494**	**4,672,682**	**8,241,409**	**23,651,851**
%CHYA	*5.0%*	*5.6%*	*5.9%*	*4.8%*	*5.3%*	*8.1%*	*6.2%*	*5.6%*	*5.9%*	*6.4%*

	2033:3	2033:4	2034:1	2034:2	FY2034	2034:3	2034:4	2035:1	2035:2	FY 2035
Withholding	4,734,611	5,036,052	5,072,114	4,940,124	19,782,902	5,006,058	5,324,776	5,364,349	5,224,892	20,920,074
%CHYA	*5.8%*	*5.8%*	*5.7%*	*5.7%*	*5.8%*	*5.7%*	*5.7%*	*5.8%*	*5.8%*	*5.7%*
Est. Payments	1,132,852	1,127,942	983,806	1,626,860	4,871,460	1,202,391	1,197,180	1,044,242	1,727,196	5,171,010
%CHYA	*6.2%*	*6.2%*	*6.2%*	*6.1%*	*6.2%*	*6.1%*	*6.1%*	*6.1%*	*6.2%*	*6.1%*
Final Payments	278,521	447,414	476,045	3,120,258	4,322,238	294,201	472,411	502,233	3,290,634	4,559,479
%CHYA	*5.9%*	*5.9%*	*5.6%*	*5.6%*	*5.6%*	*5.6%*	*5.6%*	*5.5%*	*5.5%*	*5.5%*
Refunds	(344,845)	(713,591)	(1,603,133)	(1,362,465)	(4,024,033)	(368,404)	(762,172)	(1,710,530)	(1,453,706)	(4,294,811)
%CHYA	*7.2%*	*7.2%*	*6.8%*	*6.8%*	*6.9%*	*6.8%*	*6.8%*	*6.7%*	*6.7%*	*6.7%*
Other	(355,980)	-	-	421,183	65,204	(421,183)	-	-	498,693	77,510
Total	**5,445,160**	**5,897,817**	**4,928,832**	**8,745,961**	**25,017,771**	**5,713,063**	**6,232,195**	**5,200,294**	**9,287,709**	**26,433,262**
%CHYA	*5.5%*	*5.7%*	*5.5%*	*6.1%*	*5.8%*	*4.9%*	*5.7%*	*5.5%*	*6.2%*	*5.7%*

Note: Other includes July withholding accrued to June (30 Day Number)

Table B.5 – Corporate Income Tax Forecast

Table B.5 **September 2026**

Oregon Corporate Income and Excise Tax Revenue Forecast

Quarterly tax collections (thousands of dollars, not seasonally adjusted)

	2023:3	2023:4	2024:1	2024:2	FY 2024	2024:3	2024:4	2025:1	2025:2	FY 2025
Advance Payments[1]	378,791	584,136	336,447	492,579	1,791,954	403,947	598,852	425,281	488,733	1,916,814
Y/Y %ch	*-11.5%*	*2.8%*	*-17.3%*	*5.1%*	*-4.3%*	*6.6%*	*2.5%*	*26.4%*	*-0.8%*	*7.0%*
Final Payments[1]	106,469	77,027	85,407	357,338	626,241	102,069	73,384	77,771	268,045	521,268
Y/Y %ch	*47.1%*	*51.3%*	*2.5%*	*17.4%*	*22.5%*	*-4.1%*	*-4.7%*	*-8.9%*	*-25.0%*	*-16.8%*
Refunds	-63,414	-297,105	-260,296	-175,571	-796,387	-102,686	-333,600	-346,919	-147,255	-930,461
Y/Y %ch	*-45.5%*	*19.9%*	*-18.7%*	*89.2%*	*2.4%*	*61.9%*	*12.3%*	*33.3%*	*-16.1%*	*16.8%*
Total[1]	**421,846**	**364,058**	**161,557**	**674,346**	**1,621,808**	**403,330**	**338,636**	**156,133**	**609,523**	**1,507,622**
Y/Y %ch	*9.8%*	*-1.9%*	*-4.8%*	*-0.9%*	*1.0%*	*-4.4%*	*-7.0%*	*-3.4%*	*-9.6%*	*-7.0%*

	2025:3	2025:4	2026:1	2026:2	FY 2026	2026:3	2026:4	2027:1	2027:2	FY 2027
Advance Payments[1]	326,652	500,498	202,207	418,252	1,447,609	444,172	663,345	380,149	477,078	1,964,744
Y/Y %ch	*-19.1%*	*-16.4%*	*-52.5%*	*-14.4%*	*-24.5%*	*36.0%*	*32.5%*	*88.0%*	*14.1%*	*35.7%*
Final Payments[1]	93,543	227,851	152,239	472,185	945,817	126,443	148,162	154,505	328,293	757,402
Y/Y %ch	*-8.4%*	*210.5%*	*95.8%*	*76.2%*	*81.4%*	*35.2%*	*-35.0%*	*1.5%*	*-30.5%*	*-19.9%*
Refunds	-71,195	-212,338	-138,599	-401,257	-823,389	-116,716	-326,671	-241,349	-115,631	-800,368
Y/Y %ch	*-30.7%*	*-36.3%*	*-60.0%*	*172.5%*	*-11.5%*	*63.9%*	*53.8%*	*74.1%*	*-71.2%*	*-2.8%*
Total[1]	**349,000**	**516,011**	**215,846**	**489,179**	**1,570,037**	**453,898**	**484,836**	**293,305**	**689,739**	**1,921,779**
Y/Y %ch	*-13.5%*	*52.4%*	*38.2%*	*-19.7%*	*4.1%*	*30.1%*	*-6.0%*	*35.9%*	*41.0%*	*22.4%*

	2027:3	2027:4	2028:1	2028:2	FY 2028	2028:3	2028:4	2029:1	2029:2	FY 2029
Advance Payments[1]	456,427	628,992	351,363	479,523	1,916,305	458,738	648,803	365,738	500,091	1,973,369
Y/Y %ch	*2.8%*	*-5.2%*	*-7.6%*	*0.5%*	*-2.5%*	*0.5%*	*3.1%*	*4.1%*	*4.3%*	*3.0%*
Final Payments[1]	130,079	177,607	134,778	360,492	802,956	110,217	146,268	142,092	375,339	773,916
Y/Y %ch	*2.9%*	*19.9%*	*-12.8%*	*9.8%*	*6.0%*	*-15.3%*	*-17.6%*	*5.4%*	*4.1%*	*-3.6%*
Refunds	-96,233	-342,944	-243,691	-122,326	-805,194	-93,205	-317,152	-230,306	-119,609	-760,271
Y/Y %ch	*-17.5%*	*5.0%*	*1.0%*	*5.8%*	*0.6%*	*-3.1%*	*-7.5%*	*-5.5%*	*-2.2%*	*-5.6%*
Total[1]	**490,273**	**463,655**	**242,450**	**717,690**	**1,914,067**	**475,750**	**477,919**	**277,524**	**755,820**	**1,987,014**
Y/Y %ch	*8.0%*	*-4.4%*	*-17.3%*	*4.1%*	*-0.4%*	*-3.0%*	*3.1%*	*14.5%*	*5.3%*	*3.8%*

Table B.5 – Corporate Income Tax Forecast (cont.)

Table B.5 **September 2026**

Oregon Corporate Income and Excise Tax Revenue Forecast

Quarterly tax collections (thousands of dollars, not seasonally adjusted)

	2029:3	2029:4	2030:1	2030:2	FY 2030	2030:3	2030:4	2031:1	2031:2	FY 2031
Advance Payments[1]	478,413	676,895	381,675	522,652	2,059,634	499,996	707,728	399,231	548,450	2,155,405
Y/Y %ch	*4.3%*	*4.3%*	*4.4%*	*4.5%*	*4.4%*	*4.5%*	*4.6%*	*4.6%*	*4.9%*	*4.6%*
Final Payments[1]	124,134	146,111	142,231	379,848	792,325	119,961	144,753	146,797	391,934	803,446
Y/Y %ch	*12.6%*	*-0.1%*	*0.1%*	*1.2%*	*2.4%*	*-3.4%*	*-0.9%*	*3.2%*	*3.2%*	*1.4%*
Refunds	-92,894	-336,541	-243,483	-124,054	-796,972	-98,032	-357,926	-258,353	-131,335	-845,646
Y/Y %ch	*-0.3%*	*6.1%*	*5.7%*	*3.7%*	*4.8%*	*5.5%*	*6.4%*	*6.1%*	*5.9%*	*6.1%*
Total[1]	**509,653**	**486,465**	**280,423**	**778,446**	**2,054,987**	**521,925**	**494,555**	**287,676**	**809,049**	**2,113,204**
Y/Y %ch	*7.1%*	*1.8%*	*1.0%*	*3.0%*	*3.4%*	*2.4%*	*1.7%*	*2.6%*	*3.9%*	*2.8%*

	2031:3	2031:4	2032:1	2032:2	FY 2032	2032:3	2032:4	2033:1	2033:2	FY 2033
Advance Payments[1]	524,674	743,336	419,561	578,116	2,265,687	553,053	784,207	442,796	610,745	2,390,802
Y/Y %ch	*4.9%*	*5.0%*	*5.1%*	*5.4%*	*5.1%*	*5.4%*	*5.5%*	*5.5%*	*5.6%*	*5.5%*
Final Payments[1]	124,316	149,974	151,690	405,508	831,488	128,555	155,472	157,450	421,381	862,858
Y/Y %ch	*3.6%*	*3.6%*	*3.3%*	*3.5%*	*3.5%*	*3.4%*	*3.7%*	*3.8%*	*3.9%*	*3.8%*
Refunds	-103,524	-380,759	-275,558	-140,108	-899,948	-110,508	-407,509	-294,975	-149,952	-962,943
Y/Y %ch	*5.6%*	*6.4%*	*6.7%*	*6.7%*	*6.4%*	*6.7%*	*7.0%*	*7.0%*	*7.0%*	*7.0%*
Total[1]	**545,467**	**512,551**	**295,694**	**843,515**	**2,197,227**	**571,099**	**532,171**	**305,271**	**882,175**	**2,290,716**
Y/Y %ch	*4.5%*	*3.6%*	*2.8%*	*4.3%*	*4.0%*	*4.7%*	*3.8%*	*3.2%*	*4.6%*	*4.3%*

	2033:3	2033:4	2034:1	2034:2	FY 2034	2034:3	2034:4	2035:1	2035:2	FY 2035
Advance Payments1	584,268	828,699	468,025	646,499	2,527,491	618,471	877,576	495,732	685,289	2,677,068
Y/Y %ch	*3.6%*	*3.7%*	*3.8%*	*4.6%*	*5.7%*	*4.6%*	*4.9%*	*5.0%*	*5.3%*	*5.9%*
Final Payments1	133,456	161,665	163,869	438,758	897,749	138,853	168,477	170,962	458,056	936,348
Y/Y %ch	*2.5%*	*3.4%*	*3.4%*	*3.7%*	*4.0%*	*3.0%*	*4.3%*	*4.6%*	*5.1%*	*4.3%*
Refunds	-118,375	-437,674	-316,855	-160,997	-1,033,902	-127,144	-470,498	-340,647	-173,086	-1,111,375
Y/Y %ch	*3.1%*	*4.1%*	*4.0%*	*3.8%*	*7.4%*	*3.9%*	*3.9%*	*4.0%*	*4.1%*	*7.5%*
Total[1]	**551,548**	**445,184**	**163,708**	**870,654**	**2,391,339**	**575,751**	**471,072**	**175,201**	**917,962**	**2,502,042**
Y/Y %ch	*3.5%*	*3.1%*	*2.8%*	*4.2%*	*4.4%*	*4.4%*	*5.8%*	*7.0%*	*5.4%*	*4.6%*

Table B.6 – Cigarette and Tobacco Tax Distribution

TABLE B.6 **September 2026**

Cigarette & Tobacco Tax Distribution[1]

Millions of dollars

	Cigarette Tax Distribution								Other Tobacco Distribution				Inhalant Distribution			Oral Nicotine Distribution		
	Total	General Fund	Health Plan	Mental Health	Health Authority[2]	TURA[3] Old	TURA[3] New	Local	Total	General Fund	Health Plan	TURA	Total	Health Authority	OHA Regional	Total	Landscape Resiliency	Community Risk
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	**257.0**	17.0	66.2	11.6	138.9	2.7	15.4	5.3	**50.9**	27.4	21.2	2.4	**25.2**	22.7	2.5			
2023-25 BN	**551.1**	36.4	141.9	24.8	297.9	5.7	33.1	11.3	**100.5**	54.1	41.8	4.6	**54.9**	49.4	5.5			
2025-26	**240.9**	15.9	62.0	10.8	130.2	2.5	14.5	4.9	**45.3**	24.4	18.8	2.1	**24.0**	21.6	2.4	**6.3**	2.1	4.2
2026-27	**226.6**	15.0	58.3	10.2	122.5	2.4	13.6	4.7	**41.3**	22.3	17.2	1.9	**23.1**	20.8	2.3	**23.6**	7.9	15.8
2025-27 BN	**467.4**	30.9	120.3	21.1	252.6	4.9	28.1	9.6	**86.6**	46.7	36.0	4.0	**47.2**	42.4	4.7	**30.0**	10.0	20.0
2027-28	**213.2**	14.1	54.9	9.6	115.2	2.2	12.8	4.4	**36.9**	19.9	15.3	1.7	**20.4**	18.4	2.0	**21.1**	7.0	14.1
2028-29	**198.9**	13.1	51.2	9.0	107.5	2.1	11.9	4.1	**35.5**	19.1	14.7	1.6	**19.6**	17.6	2.0	**22.0**	7.3	14.7
2027-29 BN	**412.1**	27.2	106.1	18.6	222.7	4.3	24.7	8.5	**72.4**	39.0	30.1	3.3	**40.0**	36.0	4.0	**43.1**	14.4	28.7
2029-30	**183.2**	12.1	47.2	8.3	99.0	1.9	11.0	3.8	**34.1**	18.3	14.1	1.6	**18.9**	17.0	1.9	**23.9**	8.0	15.9
2030-31	**168.2**	11.1	43.3	7.6	90.9	1.8	10.1	3.5	**32.7**	17.6	13.6	1.5	**18.2**	16.4	1.8	**26.0**	8.7	17.3
2029-31 BN	**351.4**	23.2	90.4	15.8	189.9	3.7	21.1	7.2	**66.8**	35.9	27.7	3.1	**37.1**	33.4	3.7	**49.9**	16.6	33.3
2031-32	**153.3**	10.1	39.5	6.9	82.8	1.6	9.2	3.1	**31.7**	17.1	13.2	1.5	**17.6**	15.8	1.8	**28.3**	9.4	18.9
2032-33	**139.7**	9.2	35.9	6.3	75.5	1.5	8.4	2.9	**30.9**	16.6	12.8	1.4	**17.0**	15.3	1.7	**30.8**	10.3	20.5
2031-33 BN	**293.0**	19.3	75.4	13.2	158.3	3.1	17.6	6.0	**62.6**	33.7	26.0	2.9	**34.5**	31.1	3.5	**59.1**	19.7	39.4
2033-34	**126.0**	8.3	32.4	5.7	68.1	1.3	7.6	2.6	**30.0**	16.1	12.4	1.4	**16.4**	14.7	1.6	**33.5**	11.2	22.3
2034-35	**114.1**	7.5	29.4	5.1	61.7	1.2	6.9	2.3	**45.3**	16.1	12.1	1.3	**15.8**	14.2	1.6	**36.4**	12.1	24.3
2033-35 BN	**240.1**	15.9	61.8	10.8	129.7	2.6	14.4	4.9	**59.5**	32.3	24.5	2.7	**32.1**	28.9	3.2	**69.9**	23.3	46.6

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

4 "Local" includes Cities, Counties and Public Transportation

Table B.7 – Liquor Apportionment and Revenue Distribution to Local Government

TABLE B.7 **September 2026**

Liquor Apportionment and Revenue Distribution to Local Governments

Millions of dollars

	Liquor Apportionment Distribution								
	Total Liquor Revenue Available	General Fund (56%)	Mental Health[1]	Oregon Wine Board	City Revenue Sharing Regular	City Revenue Sharing	City Revenue Sharing Total	Counties	Cigarette Tax Distribution[2]
2023-24	315.282	179.102	9.682	0.324	57.461	40.083	97.544	28.631	6.041
2024-25	264.508	151.630	7.954	0.292	47.500	33.383	80.882	23.750	5.278
2023-25 Biennium	**579.790**	**330.731**	**17.635**	**0.616**	**104.961**	**73.466**	**178.427**	**52.381**	**11.319**
2025-26	243.159	138.637	9.275	0.374	43.124	30.187	73.311	21.562	4.927
2026-27	240.679	137.223	9.180	0.371	42.684	29.879	72.563	21.342	4.779
2025-27 Biennium	**483.838**	**275.860**	**18.454**	**0.745**	**85.808**	**60.066**	**145.874**	**42.904**	**9.706**
2027-28	211.395	113.210	8.863	0.371	40.432	28.302	68.735	20.216	4.510
2028-29	212.764	113.943	8.921	0.374	40.694	28.486	69.180	20.347	4.237
2027-29 Biennium	**424.160**	**227.153**	**17.784**	**0.745**	**81.126**	**56.788**	**137.914**	**40.563**	**8.747**
2029-30	207.103	110.809	8.859	0.370	39.575	27.702	67.277	19.787	3.925
2030-31	209.707	112.203	8.970	0.375	40.072	28.051	68.123	20.036	3.612
2029-31 Biennium	**416.810**	**223.012**	**17.829**	**0.745**	**79.647**	**55.753**	**135.400**	**39.824**	**7.538**

[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 Previous Forecast

Table B.8 Track Record for the Quarter 2 2026 Forecast[1]

Millions of Dollars; Period May 2026 through July 2026

Personal Income Tax

	Revenues		Difference		Year-over-Year Change		
	Actuals	Forecast	$ Diff.	% Diff.	Year Ago	$ Change	% Change
Withholding	$3,027.4	$2,915.9	$111.5	3.8%	$2,842.2	$185.2	6.5%
Estimated Payments	$637.2	$667.8	-$30.6	-4.6%	$580.3	$56.9	9.8%
Other Payments	$182.3	$196.3	-$14.0	-7.1%	$206.6	-$24.3	-11.8%
Refunds	-$404.4	-$365.4	-$39.0	10.7%	-$289.0	-$115.4	39.9%
Other	$0.0	$0.0	$0.0		$0.0	$0.0	
Total	**$3,442.5**	**$3,414.6**	**$27.9**	**0.8%**	**$3,340.0**	**$102.5**	**3.1%**

Corporate Income Tax

	Revenues		Difference		Year-over-Year Change		
	Actuals	Forecast	$ Diff.	% Diff.	Year Ago	$ Change	% Change
Estimated Payments	$338.2	$477.4	-$139.2	-29.2%	$392.2	-$54.0	-13.8%
Other Payments	$364.5	$66.2	$298.3	450.7%	$117.3	$247.2	210.9%
Refunds	-$421.9	-$95.5	-$326.4	341.8%	-$108.7	-$313.3	288.2%
Total	**$280.7**	**$448.1**	**-$167.3**	**-37.3%**	**$400.7**	**-$120.0**	**-29.9%**

Corporate Activity Tax

	Revenues		Difference		Year-over-Year Change		
	Actuals	Forecast	$ Diff.	% Diff.	Year Ago	$ Change	% Change
Estimated Payments	$308.8	$371.4	-$62.6	-16.8%	$308.4	$0.4	0.1%
Other Payments	$88.7	$85.5	$3.2	3.7%	$86.5	$2.2	2.6%
Refunds	-$60.6	-$76.2	$15.6	-20.5%	-$21.3	-$39.3	184.4%
Total	**$336.9**	**$380.7**	**-$43.8**	**-11.5%**	**$373.6**	**-$36.7**	**-9.8%**

Estate Tax

	Revenues		Difference		Year-over-Year Change		
	Actuals	Forecast	$ Diff.	% Diff.	Year Ago	$ Change	% Change
All Payments	$108.2	$148.9	-$40.7	-27.3%	$113.0	-$4.7	-4.2%
Refunds	-$7.5	-$2.7	-$4.8	175.5%	-$3.4	-$4.2	122.9%
Total	**$100.7**	**$146.2**	**-$45.5**	**-31.1%**	**$109.6**	**-$8.9**	**-8.1%**

Notes:
1 Previously referred to as the June forecast.
2 Previous tracking reports aligned with calendar quarters. This report covers months since the last forecast to reflect new information incorporated into the latest forecast.

Table B.9 – Lottery Forecast

TABLE B.9
Summary of Lottery Resources

September 2026 Forecast

(in millions of dollars)	2025-2027 Current Forecast	2025-2027 Change from previous	2025-2027 Change from COS	2027-29 Current Forecast	2027-29 Change from previous	2029-31 Current Forecast	2029-31 Change from previous	2031-33 Current Forecast	2031-33 Change from previous	2033-35 Current Forecast	2033-35 Change from previous
LOTTERY EARNINGS											
Traditional Lottery	199.953	1.745	15.794	164.590	0.067	168.818	0.175	174.136	0.514	181.099	0.837
Video Lottery	1,561.021	2.088	(66.270)	1,675.981	3.308	1,789.136	3.537	1,916.025	3.782	2,067.617	4.044
Sports Betting	86.337	(0.093)	12.495	88.484	0.086	92.637	0.678	95.484	(0.050)	97.591	(1.401)
Administrative Actions	1.915	0.000	1.915	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Available to Transfer	**1,849.226**	3.740	(36.066)	**1,929.056**	3.461	**2,050.591**	4.390	**2,185.645**	4.246	**2,346.307**	3.479
ECONOMIC DEVELOPMENT FUND											
Beginning Balance	45.086	0.000	0.000	37.907	2.451	0.000	0.000	0.000	0.000	0.000	0.000
Transfers from Lottery	1,849.226	3.740	(36.066)	1,929.056	3.461	2,050.591	4.390	2,185.645	4.246	2,346.307	3.479
Other Resources[1]	10.757	0.000	8.757	2.000	0.000	2.000	0.000	2.000	0.000	2.000	0.000
Total Available Resources	**1,905.069**	3.740	(27.309)	**1,968.963**	5.912	**2,052.591**	4.390	**2,187.645**	4.246	**2,348.307**	3.479
ALLOCATION OF RESOURCES											
Constitutional Distributions											
Education Stability Fund[2]	292.268	0.665	37.910	347.230	0.623	369.106	0.790	245.706	0.614	311.012	0.496
Oregon Capital Matching Fund[2]	33.827	0.007	(37.002)	0.000	0.000	0.000	0.000	123.092	0.125	92.770	0.109
Parks and Natural Resources Fund[3]	277.384	0.561	(5.410)	289.358	0.519	307.589	0.659	327.847	0.637	351.946	0.522
Veterans' Services Fund[4]	27.738	0.056	(0.541)	28.936	0.052	30.759	0.066	32.785	0.064	35.195	0.052
Other Distributions											
Outdoor School Education Fund[5]	48.061	0.000	0.000	63.171	0.000	66.187	0.000	69.227	0.000	72.598	0.000
County Economic Development	59.784	0.000	0.000	64.257	0.127	68.595	0.136	73.460	0.145	79.272	0.155
HECC Collegiate Athletic & Scholarships[6]	18.853	0.000	0.000	19.291	0.035	20.506	0.044	21.856	0.042	23.463	0.035
Gambling Addiction [6]	18.721	0.000	(0.132)	19.291	0.035	20.506	0.044	21.856	0.042	23.463	0.035
County Fairs	5.744	0.000	0.000	19.291	0.035	20.506	0.044	21.856	0.042	23.463	0.035
Other Legislatively Adopted Allocations[7]	1,084.782	0.000	(20.042)	287.141	0.000	236.879	0.000	186.892	0.000	156.867	0.000
Employer Incentive Fund (PERS)	0.000	0.000	0.000	57.957	0.056	60.677	0.444	63.618	(0.034)	64.694	(0.929)
Total Distributions	**1,867.162**	1.289	(25.216)	**1,195.922**	1.481	**1,201.311**	2.226	**1,188.196**	1.678	**1,234.742**	0.509
Ending Balance/Discretionary Resources	**37.907**	2.451	(2.093)	**773.041**	4.431	**851.280**	2.164	**999.449**	2.568	**1,113.565**	2.971

Note: Some totals may not foot due to rounding.

1. Includes interest earnings on Economic Development Fund and reversions.
2. 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.
3. The Parks and Natural Resources Fund Constitutional amendment requires 15% of net proceeds be transferred to this fund.
4. Per Ballot Measure 96 (2016), 1.5% of net lottery proceeds are dedicated to the Veterans' Services Fund
5. 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.
6. Approximately one percent of net lottery proceeds are dedicated to each program. Certain limits are imposed by the Legislature.
7. 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 **September 2026**

Budgetary Reserve Summary and Outlook

Rainy Day Fund

(Millions)	2021-23	2023-25	2025-27	2027-29	2029-31	2031-33	2033-35
Beginning Balance	$962.2	$1,353.5	$1,911.2	$2,192.0	$2,868.6	$3,634.8	$4,563.4
Interest Earnings[6]	$43.6	$159.2	$131.5	$134.7	$169.5	$266.9	$331.9
Deposits[1]	$347.2	$398.5	$149.3	$541.9	$596.7	$661.7	$734.3
Triggered Withdrawals	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Ending Balance[2]	**$1,352.9**	**$1,911.2**	**$2,192.0**	**$2,868.6**	**$3,634.8**	**$4,563.4**	**$5,629.6**

Education Stability Fund[3]

(Millions)	2021-23	2023-25	2025-27	2027-29	2029-31	2031-33	2033-35
Beginning Balance	$414.6	$710.8	$1,012.1	$1,271.4	$1,583.9	$1,916.1	$2,137.2
Interest Earnings[4]	$21.9	$85.1	$93.8	$97.1	$116.3	$137.0	$153.1
Deposits[5]	$294.0	$299.9	$263.0	$312.5	$332.2	$221.1	$279.9
Distributions	$19.8	$83.7	$97.6	$97.1	$116.3	$137.0	$153.1
Oregon Opportunity Grant	$19.8	$83.7	$97.6	$97.1	$116.3	$137.0	$153.1
Withdrawals	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Ending Balance	**$710.8**	**$1,012.1**	**$1,271.4**	**$1,583.9**	**$1,916.1**	**$2,137.2**	**$2,417.1**

Total Reserves

(Millions)	2021-23	2023-25	2025-27	2027-29	2029-31	2031-33	2033-35
Ending Balances	**$2,063.7**	**$2,923.4**	**$3,463.3**	**$4,452.5**	**$5,550.9**	**$6,700.6**	**$8,046.7**
Percent of General Fund Revenues	6.7%	10.7%	9.7%	10.5%	11.7%	12.6%	13.5%

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 7.2% for the biennium are deposited on or before Jun 30 of each odd-numbered year. Deposits are made until the RDF balance exceeds 12.5 percent of the prior biennium's General Fund revenue total.
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. Quarterly contributions are made until the ESF balance exceeds five percent of the prior biennium's General Fund revenue total.
6. Per House Bill 3940 (2025), 20 percent of RDF interest earnings are distributed to the the Landscape Resiliency Fund (6.7 percent) and the Community Risk Reduction Fund (13.3 percent).

Table B.11 – Recreational Marijuana Forecast

TABLE B.11 **September 2026**

Summary of Marijuana Resources

(in millions of dollars)	2025-27 Current Forecast	2025-27 Change from Jun-26	2025-27 Change from COS 2025	2027-29 Current Forecast	2027-29 Change from Jun-26	2029-31 Current Forecast	2029-31 Change from Jun-26	2031-33 Current Forecast	2031-33 Change from Jun-26	2033-35 Current Forecast	2033-35 Change from Jun-26
MARIJUANA EARNINGS											
+ Retail Marijuana Tax Revenue [1]	280.437	*(14.078)*	*(39.560)*	267.538	*(49.515)*	264.618	(78.586)	263.643	(110.405)	262.968	(142.126)
+ Medical Marijuana Tax Revenue [2]	0.000	*0.000*	*0.000*	9.161	*(1.999)*	12.148	(3.860)	12.105	(5.341)	12.074	(6.778)
- Administrative Costs [3]	18.746	*0.000*	*(0.000)*	19.144	*0.000*	19.571	0.000	20.027	0.000	20.516	0.000
Net Available to Transfer	**261.691**	*(14.078)*	*(39.560)*	**257.555**	*(51.514)*	**257.195**	*(82.447)*	**255.721**	*(115.746)*	**254.526**	*(148.904)*
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	261.691	*(14.078)*	*(39.560)*	257.555	*(51.514)*	257.195	(82.447)	255.721	(115.746)	254.526	(148.904)
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	**261.691**	*(14.078)*	*(39.560)*	**257.555**	*(51.514)*	**257.195**	*(82.447)*	**255.721**	*(115.746)*	**254.526**	*(148.904)*
ALLOCATION OF RESOURCES [4]											
Drug Treatment & Recovery	150.895	*(15.952)*	*(41.436)*	142.502	*(51.514)*	136.562	(82.447)	129.693	(115.746)	122.331	(148.904)
State School Fund	43.569	*0.000*	*0.000*	46.021	*0.000*	48.253	0.000	50.411	0.000	52.878	0.000
Mental Health, Alcoholism, & Drug Services	21.784	*0.000*	*0.000*	23.011	*0.000*	24.127	0.000	25.206	0.000	26.439	0.000
State Police	16.338	*0.000*	*0.000*	17.258	*0.000*	18.095	0.000	18.904	0.000	19.829	0.000
Cities	10.892	*0.000*	*0.000*	11.505	*0.000*	12.063	0.000	12.603	0.000	13.220	0.000
Counties	10.892	*0.000*	*0.000*	11.505	*0.000*	12.063	0.000	12.603	0.000	13.220	0.000
Alcohol & Drug Abuse Prevention, Intervention & Treatment	5.446	*0.000*	*0.000*	5.753	*0.000*	6.032	0.000	6.301	0.000	6.610	0.000
Total Distributions	**259.817**	*(15.952)*	*(41.435)*	**257.555**	*(51.514)*	**257.195**	*(82.447)*	**255.721**	*(115.746)*	**254.526**	*(148.904)*
Ending Balance	**1.875**	*1.875*	*1.875*	**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) and HB 3000 (2019).

4. Per Measure 110 (2020), the first $11.25 million per quarter ($45m per year) is distributed via forumula to the initial recipient programs. Per HB 4056 (2022) the $11.25 million is indexed for inflation beginning in 2023. All revenues above these initial, fixed distributions go to the Drug Treatment & Recovery Fund.

Table B.12 – Fund for Student Success (Corporate Activity Tax)

TABLE B.12 **September 2026**

Summary of Corporate Activity Tax Resources

(in millions of dollars)	2025-27 Current Forecast	2025-27 Change from Jun-26	2025-27 Change from COS 2025	2027-29 Current Forecast	2027-29 Change from Jun-26	2029-31 Current Forecast	2029-31 Change from Jun-26	2031-33 Current Forecast	2031-33 Change from Jun-26	2033-35 Current Forecast	2033-35 Change from Jun-26
Corporate Activity Tax											
+ Tax Revenue	2,983.238	*(94.597)*	*(88.473)*	3,428.721	*(25.679)*	3,774.118	*(2.335)*	4,138.606	*2.423*	4,537.656	*12.360*
- Administrative Costs	23.656	*0.000*	*0.000*	26.259	*0.000*	28.689	*0.000*	31.234	*0.000*	33.702	*0.000*
Net Available to Transfer	**2,959.582**	(94.597)	(88.473)	**3,402.463**	(25.679)	**3,745.430**	(2.335)	**4,107.372**	2.423	**4,503.954**	*12.360*
Fund for Student Success											
Beginning Balance	136.449	*0.000*	*25.221*	0.000	*0.000*	0.000	*0.000*	0.000	*0.000*	0.000	*0.000*
Revenue Transfers	2,959.582	*(94.597)*	*(88.473)*	3,402.463	*(25.679)*	3,745.430	*(2.335)*	4,107.372	*2.423*	4,503.954	*12.360*
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	**3,096.031**	(94.597)	(63.252)	**3,402.463**	(25.679)	**3,745.430**	(2.335)	**4,107.372**	2.423	**4,503.954**	*12.360*
Distributions											
State School Fund	813.843	*4.891*	*(25.782)*	906.990	*7.985*	991.250	*7.364*	1,082.755	*6.438*	1,183.101	*5.428*
Student Investment Acc.	1,109.828	*0.000*	*0.000*	1,247.736	*(16.832)*	1,377.090	*(4.849)*	1,512.309	*(2.007)*	1,660.427	*3.466*
Statewide Ed. Initiative Acc.	541.288	*0.000*	*(18.156)*	748.642	*(10.099)*	826.254	*(2.910)*	907.385	*(1.204)*	996.256	*2.079*
Early Learning Account	550.385	*0.000*	*0.000*	499.095	*(6.733)*	550.836	*(1.940)*	604.923	*(0.803)*	664.171	*1.386*
Total Distributions	**3,015.344**	4.891	(43.938)	**3,402.463**	(25.679)	**3,745.430**	(2.335)	**4,107.372**	2.423	**4,503.954**	*12.360*
Ending Balance	**80.686**	(99.488)	(19.314)	**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. The 2025-27 distribution includes a -$8.56 million reconciling adjustment for the prior biennium.

Some totals may not foot due to rounding.

Table B.13 – Fund for Student Success Quarterly Revenues

Oregon Corporate Activity Tax Revenue Forecast

September 2026

Quarterly tax receipts (thousands of dollars, not seasonally adjusted)

	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	309,113	404,731	295,943	301,892	1,311,678
Y/Y %ch	*-1.1%*	*-18.9%*	*25.3%*	*5.8%*	*0.3%*	*6.9%*	*27.5%*	*-6.0%*	*-0.1%*	*7.2%*
Final Payments	41,981	53,324	65,943	185,622	346,870	47,701	53,540	71,841	219,666	392,748
Y/Y %ch	*-29.4%*	*-29.1%*	*1.2%*	*7.2%*	*-7.0%*	*13.6%*	*0.4%*	*8.9%*	*18.3%*	*13.2%*
Refunds	-29,313	-56,912	-101,932	-38,258	-226,416	-30,480	-136,480	-80,099	-40,845	-287,904
Y/Y %ch	*-29.5%*	*-66.7%*	*363.8%*	*88.3%*	*-11.2%*	*4.0%*	*139.8%*	*-21.4%*	*6.8%*	*27.2%*
Total	**301,708**	**313,753**	**278,972**	**449,555**	**1,343,988**	**326,333**	**321,790**	**287,686**	**480,714**	**1,416,523**
Y/Y %ch	*-2.8%*	*6.2%*	*-5.3%*	*2.5%*	*0.4%*	*8.2%*	*2.6%*	*3.1%*	*6.9%*	*5.4%*

	2025:3	2025:4	2026:1	2026:2	FY 2026	2026:3	2026:4	2027:1	2027:2	FY 2027
Estimated Payments	325,013	369,714	288,739	319,425	1,302,891	291,531	420,722	299,245	351,595	1,363,093
Y/Y %ch	*5.1%*	*-8.7%*	*-2.4%*	*5.8%*	*-0.7%*	*-10.3%*	*13.8%*	*3.6%*	*10.1%*	*4.6%*
Final Payments	62,739	75,489	89,044	270,743	498,015	69,877	81,213	94,469	254,994	500,553
Y/Y %ch	*31.5%*	*41.0%*	*23.9%*	*23.3%*	*26.8%*	*11.4%*	*7.6%*	*6.1%*	*-5.8%*	*0.5%*
Refunds	-52,650	-78,362	-91,387	-105,741	-328,139	-49,760	-149,409	-91,175	-62,831	-353,175
Y/Y %ch	*72.7%*	*-42.6%*	*14.1%*	*158.9%*	*14.0%*	*-5.5%*	*90.7%*	*-0.2%*	*-40.6%*	*7.6%*
Total	**335,102**	**366,841**	**286,396**	**484,427**	**1,472,767**	**311,648**	**352,527**	**302,539**	**543,758**	**1,510,471**
Y/Y %ch	*2.7%*	*14.0%*	*-0.4%*	*0.8%*	*4.0%*	*-7.0%*	*-3.9%*	*5.6%*	*12.2%*	*2.6%*

	2027:3	2027:4	2028:1	2028:2	FY 2028	2028:3	2028:4	2029:1	2029:2	FY 2029
Estimated Payments	352,130	442,428	311,094	369,588	1,475,241	370,377	465,878	327,685	387,938	1,551,878
Y/Y %ch	*20.8%*	*5.2%*	*4.0%*	*5.1%*	*8.2%*	*5.2%*	*5.3%*	*5.3%*	*5.0%*	*5.2%*
Final Payments	75,028	89,289	102,613	271,784	538,713	80,095	95,008	108,143	286,260	569,507
Y/Y %ch	*7.4%*	*9.9%*	*8.6%*	*6.6%*	*7.6%*	*6.8%*	*6.4%*	*5.4%*	*5.3%*	*5.7%*
Refunds	-52,091	-138,581	-85,830	-65,470	-341,972	-55,483	-147,948	-92,137	-69,078	-364,646
Y/Y %ch	*4.7%*	*-7.2%*	*-5.9%*	*4.2%*	*-3.2%*	*6.5%*	*6.8%*	*7.3%*	*5.5%*	*6.6%*
Total	**375,068**	**393,136**	**327,877**	**575,902**	**1,671,983**	**394,989**	**412,939**	**343,691**	**605,120**	**1,756,739**
Y/Y %ch	*20.3%*	*11.5%*	*8.4%*	*5.9%*	*10.7%*	*5.3%*	*5.0%*	*4.8%*	*5.1%*	*5.1%*

	2029:3	2029:4	2030:1	2030:2	FY2030	2030:3	2030:4	2031:1	2031:2	FY 2031
Estimated Payments	388,691	488,741	343,617	406,047	1,627,096	406,794	511,408	359,533	425,090	1,702,825
Y/Y %ch	*4.9%*	*4.9%*	*4.9%*	*4.7%*	*4.8%*	*4.7%*	*4.6%*	*4.6%*	*4.7%*	*4.7%*
Final Payments	84,495	100,161	114,418	301,372	600,447	88,956	105,350	120,024	315,625	629,956
Y/Y %ch	*5.5%*	*5.4%*	*5.8%*	*5.3%*	*5.4%*	*5.3%*	*5.2%*	*4.9%*	*4.7%*	*4.9%*
Refunds	-58,861	-156,231	-96,766	-72,133	-383,990	-61,158	-163,801	-101,562	-75,695	-402,215
Y/Y %ch	*6.1%*	*5.6%*	*5.0%*	*4.4%*	*5.3%*	*3.9%*	*4.8%*	*5.0%*	*4.9%*	*4.7%*
Total	**414,325**	**432,671**	**361,269**	**635,287**	**1,843,552**	**434,593**	**452,957**	**377,996**	**665,020**	**1,930,566**
Y/Y %ch	*4.9%*	*4.8%*	*5.1%*	*5.0%*	*4.9%*	*4.9%*	*4.7%*	*4.6%*	*4.7%*	*4.7%*

	2031:3	2031:4	2032:1	2032:2	FY2032	2032:3	2032:4	2033:1	2033:2	FY 2033
Estimated Payments	425,885	535,437	376,444	445,121	1,782,886	445,955	560,675	394,199	466,210	1,867,039
Y/Y %ch	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*
Final Payments	93,187	110,320	125,754	330,606	659,866	97,602	115,540	131,698	346,218	691,059
Y/Y %ch	*4.8%*	*4.7%*	*4.8%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*
Refunds	-64,191	-171,445	-106,294	-79,273	-421,202	-67,234	-179,503	-111,295	-83,010	-441,042
Y/Y %ch	*5.0%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*
Total	**454,881**	**474,312**	**395,904**	**696,454**	**2,021,550**	**476,323**	**496,713**	**414,601**	**729,419**	**2,117,056**
Y/Y %ch	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*

	2033:3	2033:4	2034:1	2034:2	FY2034	2034:3	2034:4	2035:1	2035:2	FY 2035
Estimated Payments	467,089	587,258	412,866	487,997	1,955,211	488,901	614,645	432,120	510,923	2,046,589
Y/Y %ch	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*
Final Payments	102,206	120,992	137,907	362,601	723,705	107,040	126,718	144,386	379,531	757,676
Y/Y %ch	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*
Refunds	-70,409	-187,965	-116,542	-86,931	-461,847	-73,737	-196,873	-122,058	-91,010	-483,678
Y/Y %ch	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*
Total	**498,886**	**520,285**	**434,231**	**763,666**	**2,217,069**	**522,205**	**544,490**	**454,448**	**799,444**	**2,320,587**
Y/Y %ch	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*	*4.7%*

Table B.14 – Oregon Estate Tax Revenue Forecast

Oregon Estate Tax Revenue Forecast

September 2026

Quarterly tax receipts (thousands of dollars, not seasonally adjusted)

	2023:3	2023:4	2024:1	2024:2	FY 2024	2024:3	2024:4	2025:1	2025:2	FY 2025
Payments	73,151	118,948	82,523	73,593	348,215	102,254	100,444	138,079	99,106	439,883
Y/Y %ch	*-19.0%*	*140.4%*	*-4.5%*	*-23.8%*	*7.9%*	*39.8%*	*-15.6%*	*67.3%*	*34.7%*	*26.3%*
Refunds	-1,084	-5,091	-1,359	-3,265	-10,798	-2,271	-4,447	-6,266	-3,438	-16,421
Y/Y %ch	*-82.6%*	*-30.0%*	*-39.8%*	*-62.7%*	*-55.9%*	*109.6%*	*-12.6%*	*361.1%*	*5.3%*	*52.1%*
Total	**72,067**	**113,857**	**81,164**	**70,328**	**337,416**	**99,983**	**95,997**	**131,814**	**95,668**	**423,462**
Y/Y %ch	*-14.3%*	*169.8%*	*-3.5%*	*-19.9%*	*13.1%*	*38.7%*	*-15.7%*	*62.4%*	*36.0%*	*25.5%*

	2025:3	2025:4	2026:1	2026:2	FY 2026	2026:3	2026:4	2027:1	2027:2	FY 2027
Payments	96,973	99,108	122,151	112,951	431,183	124,878	139,380	128,299	116,779	509,336
Y/Y %ch	*-5.2%*	*-1.3%*	*-11.5%*	*14.0%*	*-2.0%*	*28.8%*	*40.6%*	*5.0%*	*3.4%*	*18.1%*
Refunds	-3,305	-614	-3,612	-6,215	-13,745	-5,096	-5,964	-3,949	-3,752	-18,761
Y/Y %ch	*45.5%*	*-86.2%*	*-42.4%*	*80.8%*	*-16.3%*	*54.2%*	*871.9%*	*9.3%*	*-39.6%*	*36.5%*
Total	**93,669**	**98,494**	**118,540**	**106,736**	**417,438**	**119,782**	**133,416**	**124,350**	**113,027**	**490,575**
Y/Y %ch	*-6.3%*	*2.6%*	*-10.1%*	*11.6%*	*-1.4%*	*27.9%*	*35.5%*	*4.9%*	*5.9%*	*17.5%*

	2027:3	2027:4	2028:1	2028:2	FY 2028	2028:3	2028:4	2029:1	2029:2	FY 2029
Payments	139,210	148,373	142,684	129,842	560,109	155,662	163,712	157,207	142,952	619,534
Y/Y %ch	*11.5%*	*6.5%*	*11.2%*	*11.2%*	*10.0%*	*11.8%*	*10.3%*	*10.2%*	*10.1%*	*10.6%*
Refunds	-5,489	-6,570	-4,382	-4,210	-20,651	-6,255	-7,510	-4,987	-4,752	-23,504
Y/Y %ch	*7.7%*	*10.2%*	*11.0%*	*12.2%*	*10.1%*	*14.0%*	*14.3%*	*13.8%*	*12.9%*	*13.8%*
Total	**139,210**	**148,373**	**142,684**	**129,842**	**560,109**	**155,663**	**163,712**	**157,208**	**142,952**	**619,534**
Y/Y %ch	*16.2%*	*11.2%*	*14.7%*	*14.9%*	*14.2%*	*11.8%*	*10.3%*	*10.2%*	*10.1%*	*10.6%*

	2029:3	2029:4	2030:1	2030:2	FY2030	2030:3	2030:4	2031:1	2031:2	FY 2031
Payments	171,363	180,096	172,657	157,184	681,300	188,358	197,713	189,545	172,533	748,149
Y/Y %ch	*10.1%*	*10.0%*	*9.8%*	*10.0%*	*10.0%*	*9.9%*	*9.8%*	*9.8%*	*9.8%*	*9.8%*
Refunds	-6,949	-8,323	-5,512	-5,233	-26,017	-7,652	-9,171	-6,067	-5,762	-28,652
Y/Y %ch	*11.1%*	*10.8%*	*10.5%*	*10.1%*	*10.7%*	*10.1%*	*10.2%*	*10.1%*	*10.1%*	*10.1%*
Total	**171,363**	**180,096**	**172,657**	**157,185**	**681,300**	**188,358**	**197,713**	**189,545**	**172,533**	**748,150**
Y/Y %ch	*10.1%*	*10.0%*	*9.8%*	*10.0%*	*10.0%*	*9.9%*	*9.8%*	*9.8%*	*9.8%*	*9.8%*

	2031:3	2031:4	2032:1	2032:2	FY2032	2032:3	2032:4	2033:1	2033:2	FY 2033
Payments	206,736	216,991	208,012	189,337	821,076	226,870	238,120	228,266	207,770	901,027
Y/Y %ch	*9.8%*	*9.8%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*
Refunds	-8,405	-10,074	-6,660	-6,324	-31,464	-9,224	-11,057	-7,309	-6,941	-34,531
Y/Y %ch	*9.8%*	*9.9%*	*9.8%*	*9.8%*	*9.8%*	*9.7%*	*9.8%*	*9.7%*	*9.7%*	*9.7%*
Total	**206,736**	**216,991**	**208,012**	**189,338**	**821,076**	**226,870**	**238,120**	**228,266**	**207,771**	**901,027**
Y/Y %ch	*9.8%*	*9.8%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*

	2033:3	2033:4	2034:1	2034:2	FY2034	2034:3	2034:4	2035:1	2035:2	FY 2035
Payments	248,957	261,298	250,483	227,992	988,730	273,187	286,726	274,857	250,178	1,084,948
Y/Y %ch	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*
Refunds	-10,123	-12,134	-8,020	-7,616	-37,893	-11,108	-13,315	-8,801	-8,358	-41,581
Y/Y %ch	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*
Total	**248,957**	**261,298**	**250,483**	**227,992**	**988,730**	**273,187**	**286,726**	**274,857**	**250,178**	**1,084,948**
Y/Y %ch	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*	*9.7%*

Appendix C: Population Forecast Detail

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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	3,429,708	35,808	1.06	45,534	13.35	28,909	8.47	16,625	19,183	5.62
1995-2000		**245,308**		**222,239**		**145,431**		**76,808**	**168,500**	**10.15**
2000-01	3,467,937	38,229	1.11	45,536	13.20	29,934	8.68	15,602	22,627	6.56
2001-02	3,513,424	45,487	1.31	44,995	12.89	30,828	8.83	14,167	31,320	8.97
2002-03	3,547,376	33,952	0.97	45,686	12.94	30,604	8.67	15,082	18,870	5.35
2003-04	3,569,463	22,087	0.62	45,599	12.81	30,721	8.63	14,878	7,209	2.03
2004-05	3,613,202	43,739	1.23	45,892	12.78	30,717	8.55	15,175	28,564	7.95
2000-05		**183,494**		**227,708**		**152,804**		**74,904**	**108,590**	**6.16**
2005-06	3,670,883	57,681	1.60	46,946	12.89	30,771	8.45	16,175	41,506	11.40
2006-07	3,722,417	51,534	1.40	49,404	13.36	31,396	8.49	18,008	33,526	9.07
2007-08	3,768,748	46,331	1.24	49,659	13.26	32,008	8.55	17,651	28,680	7.66
2008-09	3,808,600	39,852	1.06	47,960	12.66	31,382	8.28	16,578	23,274	6.14
2009-10	3,837,609	29,009	0.76	46,256	12.10	31,689	8.29	14,567	14,442	3.78
2005-10		**224,407**		**240,225**		**157,246**		**82,979**	**141,428**	**7.57**
2010-11	3,872,651	35,042	0.91	45,381	11.77	32,437	8.41	12,944	22,098	5.73
2011-12	3,900,064	27,413	0.71	44,897	11.55	32,804	8.44	12,093	15,320	3.94
2012-13	3,924,055	23,991	0.62	44,969	11.49	33,168	8.48	11,801	12,190	3.12
2013-14	3,965,375	41,320	1.05	45,447	11.52	33,731	8.55	11,716	29,604	7.50
2014-15	4,018,453	53,078	1.34	45,660	11.44	35,318	8.85	10,342	42,736	10.71
2010-15		**180,844**		**226,354**		**167,458**		**58,896**	**121,948**	**6.22**
2015-16	4,093,165	74,712	1.86	45,647	11.25	35,339	8.71	10,308	64,404	15.88
2016-17	4,147,171	54,006	1.32	44,602	10.83	36,773	8.93	7,829	46,177	11.21
2017-18	4,183,398	36,227	0.87	42,906	10.30	36,268	8.71	6,638	29,589	7.10
2018-19	4,215,959	32,561	0.78	42,220	10.05	36,622	8.72	5,598	26,963	6.42
2019-20	4,241,467	25,508	0.61	40,920	9.68	37,821	8.94	3,099	22,409	5.30
2015-20		**223,014**		**216,295**		**182,823**		**33,472**	**189,542**	**9.13**
2020-21	4,234,736	-6,731	-0.16	39,654	9.36	41,893	9.88	-2,239	-4,492	-1.06
2021-22	4,255,112	20,376	0.48	40,470	9.53	46,351	10.92	-5,881	26,257	6.19
2022-23	4,269,152	14,040	0.33	38,756	9.09	43,521	10.21	-4,765	18,805	4.41
2023-24	4,286,443	17,291	0.41	38,789	9.07	42,667	9.97	-3,878	21,169	4.95
2024-25	4,301,164	14,721	0.34	39,330	9.16	42,357	9.86	-3,027	17,748	4.13
2020-25		**59,697**		**196,999**		**216,789**		**-19,790**	**79,487**	**3.73**
2025-26	4,314,400	13,236	0.31	39,468	9.16	42,708	9.91	-3,240	16,475	3.82
2026-27	4,337,300	22,900	0.53	39,318	9.09	43,063	9.95	-3,745	26,645	6.16
2027-28	4,358,300	21,000	0.48	39,284	9.04	43,460	10.00	-4,176	25,176	5.79
2028-29	4,379,000	20,700	0.47	39,238	8.98	43,914	10.05	-4,676	25,376	5.81
2029-30	4,399,300	20,301	0.46	39,170	8.92	44,386	10.11	-5,216	25,517	5.81
2025-30		**98,136**		**196,477**		**217,530**		**-21,053**	**119,189**	**5.48**
2030-31	4,419,100	19,800	0.45	39,095	8.87	44,909	10.19	-5,815	25,615	5.81
2031-32	4,438,500	19,400	0.44	39,050	8.82	45,454	10.26	-6,405	25,805	5.83
2032-33	4,457,500	19,000	0.43	39,024	8.77	45,994	10.34	-6,970	25,970	5.84
2033-34	4,476,000	18,500	0.42	38,978	8.73	46,538	10.42	-7,560	26,060	5.83
2034-35	4,494,000	18,000	0.40	38,882	8.67	47,075	10.50	-8,193	26,193	5.84
2030-35		**94,700**		**195,028**		**229,970**		**-34,942**	**129,642**	**5.83**

Sources: 1980-2019 intercensal population estimates by the U.S. Census Bureau; 2020-2025 population by Population Resear Center, PSU;

births and deaths 1990-2025: Oregon Center for Health Statistics. Forecaasts of population, births, deaths, and net migration are by the Oregon Office of Economic Analysis.

IMPORTANT: PRC/PSU has revised the estimates for the years 2020 through 2024. PSU's estimates for Oregon and its counties are here:

https://www.pdx.edu/population-research/population-estimate-reports

Table C.2 Population Forecasts by Age and Sex: 2010-2035

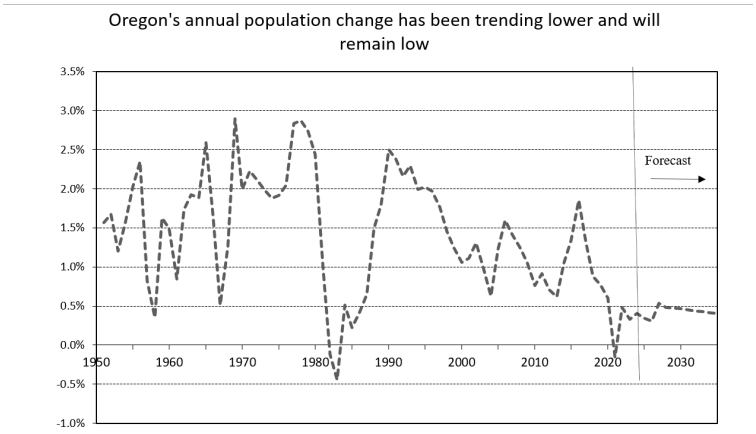
	2020			2021			2022			2023			2024			2025		
Age	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total
0-4	111,946	106,922	218,868	108,144	103,113	211,257	106,244	101,133	207,376	103,873	98,878	202,751	102,117	97,071	199,188	101,280	96,343	197,623
5- 9	124,674	118,428	243,102	122,900	117,231	240,131	121,562	115,874	237,436	119,586	113,870	233,456	117,226	111,510	228,736	114,035	108,167	222,202
10-14	132,232	125,152	257,383	131,456	124,461	255,916	130,832	123,477	254,309	129,455	121,898	251,352	128,240	120,680	248,920	127,253	119,863	247,115
15-19	130,581	125,598	256,179	129,466	123,122	252,589	131,334	124,327	255,661	133,258	126,096	259,354	134,662	127,286	261,948	135,345	127,818	263,162
20-24	135,159	132,143	267,302	134,716	132,667	267,383	135,055	133,373	268,428	134,771	132,670	267,440	134,275	131,406	265,681	133,374	129,092	262,466
25-29	145,643	142,048	287,691	140,975	137,674	278,649	139,057	135,326	274,383	137,792	133,816	271,608	137,806	134,004	271,810	138,042	135,282	273,324
30-34	152,715	148,944	301,659	152,623	149,116	301,739	154,834	150,571	305,404	155,312	150,517	305,829	154,432	149,300	303,732	151,659	146,619	298,278
35-39	150,310	148,123	298,434	150,698	147,883	298,582	151,459	148,495	299,955	152,237	149,077	301,314	153,581	150,161	303,742	155,449	151,495	306,944
40-44	138,193	136,528	274,721	141,234	139,834	281,068	144,407	143,550	287,956	146,708	146,504	293,212	148,670	148,749	297,419	150,202	149,935	300,137
45-49	130,076	127,351	257,427	128,404	126,092	254,497	128,830	127,183	256,013	130,937	129,647	260,584	134,022	133,083	267,105	137,564	137,210	274,774
50-54	125,577	125,808	251,385	127,789	127,325	255,114	129,623	128,811	258,433	130,109	129,116	259,225	129,509	128,484	257,993	128,147	127,127	255,274
55-59	128,368	134,727	263,095	125,058	130,445	255,503	122,360	127,117	249,477	120,396	124,446	244,842	120,243	123,722	243,965	122,158	125,063	247,221
60-64	130,378	143,027	273,406	128,786	141,072	269,858	127,418	139,627	267,045	125,972	137,656	263,629	124,615	135,460	260,075	122,595	132,538	255,132
65-69	125,171	139,242	264,413	125,334	140,335	265,669	125,244	140,971	266,215	124,346	140,506	264,852	123,103	139,555	262,658	122,043	138,522	260,565
70-74	102,952	114,512	217,464	107,059	119,671	226,730	109,236	122,950	232,186	110,688	125,600	236,288	112,436	128,615	241,051	113,893	131,241	245,134
75-79	65,329	75,572	140,902	68,614	79,557	148,170	73,442	85,175	158,617	78,561	91,222	169,783	83,205	96,872	180,077	88,001	102,750	190,751
80-84	38,042	46,674	84,716	39,694	48,766	88,460	41,762	51,525	93,287	44,585	55,085	99,670	47,467	58,848	106,315	49,916	62,186	112,102
85+	31,794	51,527	83,321	32,190	51,232	83,422	32,244	50,685	82,929	32,874	51,090	83,964	33,987	52,041	86,028	35,475	53,484	88,959
Total	2,099,139	2,142,328	4,241,467	2,095,140	2,139,596	4,234,736	2,104,944	2,150,168	4,255,112	2,111,458	2,157,694	4,269,152	2,119,596	2,166,847	4,286,443	2,126,429	2,174,735	4,301,164
Mdn. Age	38.9	40.8	39.8	39.2	41.2	40.2	39.4	41.4	40.4	39.7	41.8	40.7	39.9	42.1	41.0	40.2	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	101,165	96,238	197,403	100,707	95,779	196,486	101,070	96,109	197,179	101,374	96,384	197,757	101,343	96,343	197,686	101,173	96,178	197,351
5- 9	110,573	104,638	215,212	108,702	102,632	211,335	106,449	100,442	206,891	104,764	98,672	203,436	104,072	98,049	202,121	104,133	98,073	202,206
10-14	126,178	118,999	245,177	124,800	117,663	242,463	122,970	115,749	238,719	120,674	113,424	234,098	117,638	110,146	227,784	114,349	106,692	221,041
15-19	135,243	127,577	262,820	134,732	126,724	261,455	133,603	125,338	258,941	132,539	124,245	256,784	131,800	123,616	255,416	130,996	122,942	253,938
20-24	133,315	127,502	260,817	135,202	128,762	263,964	137,475	130,905	268,380	139,129	132,364	271,493	140,235	133,303	273,538	140,597	133,480	274,077
25-29	138,350	136,767	275,117	138,962	137,570	276,533	139,056	137,147	276,203	138,780	136,024	274,804	138,161	133,956	272,118	138,455	132,698	271,153
30-34	148,315	143,277	291,592	146,475	140,874	287,348	145,758	139,706	285,464	146,227	140,202	286,429	147,145	142,023	289,169	148,178	144,107	292,284
35-39	157,516	152,991	310,507	159,398	154,369	313,768	160,153	154,576	314,729	159,387	153,467	312,854	157,146	151,099	308,245	154,517	148,169	302,687
40-44	151,139	150,451	301,589	151,993	151,131	303,124	152,977	151,989	304,967	154,446	153,277	307,722	156,520	154,941	311,461	158,864	156,825	315,689
45-49	141,158	141,282	282,440	144,383	145,010	289,393	146,879	148,179	295,058	148,994	150,572	299,565	150,785	152,047	302,832	152,013	152,911	304,924
50-54	126,911	126,288	253,199	127,471	127,497	254,968	129,752	130,159	259,912	132,957	133,744	266,701	136,676	138,088	274,765	140,480	142,416	282,896
55-59	124,774	127,125	251,900	126,760	128,771	255,532	127,474	129,340	256,814	127,079	128,899	255,978	125,997	127,804	253,801	125,054	127,241	252,295
60-64	119,962	129,055	249,017	117,643	125,939	243,583	116,061	123,597	239,658	116,165	123,109	239,273	118,323	124,774	243,097	121,178	127,192	248,370
65-69	121,141	137,432	258,573	120,251	136,267	256,518	119,280	134,704	253,983	118,300	132,817	251,117	116,723	130,303	247,026	114,568	127,259	241,827
70-74	114,728	133,007	247,734	115,077	133,905	248,981	114,697	133,834	248,531	113,914	133,214	247,128	113,354	132,598	245,952	112,958	131,964	244,922
75-79	92,018	107,853	199,871	94,446	111,304	205,750	96,221	114,169	210,390	98,164	117,276	215,441	99,871	120,046	219,917	101,048	122,046	223,094
80-84	52,845	65,898	118,743	57,209	71,167	128,376	61,761	76,772	138,534	65,854	81,944	147,798	70,022	87,265	157,287	73,605	91,960	165,566
85+	37,190	55,498	92,688	39,383	58,339	97,722	42,096	61,850	103,947	45,016	65,605	110,621	47,822	69,266	117,087	51,144	73,637	124,781
Total	2,132,521	2,181,879	4,314,400	2,143,595	2,193,705	4,337,300	2,153,734	2,204,566	4,358,300	2,163,761	2,215,239	4,379,000	2,173,631	2,225,669	4,399,300	2,183,310	2,235,790	4,419,100
Mdn. Age	40.5	42.7	41.6	40.8	43.1	41.9	41.0	43.4	42.2	41.2	43.7	42.5	41.5	44.0	42.7	41.8	44.3	43.0

	2032			2033			2034			2035		
Age	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total
0-4	101,046	96,056	197,102	100,926	95,940	196,866	100,805	95,822	196,627	100,669	95,691	196,359
5- 9	103,640	97,591	201,231	104,029	97,936	201,965	104,356	98,224	202,580	104,337	98,190	202,527
10-14	112,383	104,631	217,014	110,072	102,407	212,479	108,344	100,609	208,953	107,643	99,979	207,622
15-19	129,541	121,551	251,091	127,674	119,603	247,277	125,316	117,223	242,538	122,185	113,853	236,038
20-24	140,017	132,541	272,557	138,885	131,123	270,007	137,815	130,005	267,820	137,084	129,373	266,457
25-29	140,391	133,967	274,358	142,799	136,228	279,026	144,561	137,770	282,330	145,762	138,775	284,537
30-34	148,802	144,914	293,716	148,984	144,512	293,496	148,743	143,356	292,099	148,134	141,208	289,342
35-39	152,530	145,638	298,168	151,855	144,480	296,335	152,429	145,048	297,477	153,489	146,988	300,477
40-44	160,767	158,221	318,988	161,580	158,476	320,056	160,858	157,376	318,234	158,644	154,984	313,628
45-49	152,890	153,587	306,478	153,939	154,501	308,440	155,479	155,854	311,333	157,639	157,599	315,238
50-54	143,737	146,194	289,931	146,298	149,446	295,744	148,482	151,913	300,394	150,349	153,454	303,803
55-59	125,695	128,496	254,191	128,057	131,255	259,312	131,331	134,943	266,274	135,120	139,401	274,521
60-64	123,217	128,885	252,102	124,042	129,542	253,584	123,793	129,191	252,985	122,891	128,196	251,087
65-69	112,515	124,277	236,793	111,192	122,102	233,294	111,483	121,759	233,243	113,747	123,550	237,297
70-74	112,350	130,998	243,348	111,685	129,678	241,363	110,997	128,034	239,031	109,742	125,779	235,521
75-79	101,659	123,118	224,778	101,650	123,333	224,983	101,280	123,041	224,322	101,113	122,751	223,864
80-84	75,937	95,259	171,196	77,810	98,138	175,948	79,808	101,209	181,018	81,604	103,971	185,575
85+	55,750	79,708	135,458	60,836	86,490	147,326	65,701	93,040	158,741	70,527	99,580	170,107
Total	2,192,867	2,245,633	4,438,500	2,202,310	2,255,190	4,457,500	2,211,582	2,264,418	4,476,000	2,220,678	2,273,321	4,494,000
Mdn. Age	42.1	44.6	43.3	42.4	44.9	43.6	42.7	45.2	43.9	42.9	45.5	44.2

Table C.3 Population of Oregon: 1990-2035

Year (July 1)	Total Population	% Change from previous decade/yr. Number	Percent
1980	2,641,200	---	---
1990	2,860,400	219,200	8.30%
2000	3,429,708	569,308	19.90%
2010	3,837,609	407,901	11.89%
2011	3,872,651	35,042	0.91%
2012	3,900,064	27,413	0.71%
2013	3,924,055	23,991	0.62%
2014	3,965,375	41,320	1.05%
2015	4,018,453	53,078	1.34%
2016	4,093,165	74,712	1.86%
2017	4,147,171	54,006	1.32%
2018	4,183,398	36,227	0.87%
2019	4,215,959	32,561	0.78%
2020	4,241,467	25,508	0.61%
2021	4,234,736	-6,731	-0.16%
2022	4,255,112	20,376	0.48%
2023	4,269,152	14,040	0.33%
2024	4,286,443	17,291	0.41%
2025	4,301,164	14,721	0.34%
2026	4,314,400	13,236	0.31%
2027	4,337,300	22,900	0.53%
2028	4,358,300	21,000	0.48%
2029	4,379,000	20,700	0.47%
2030	4,399,300	20,301	0.46%
2031	4,419,100	19,800	0.45%
2032	4,438,500	19,400	0.44%
2033	4,457,500	19,000	0.43%
2034	4,476,000	18,500	0.42%
2035	4,494,000	18,000	0.40%



Tables C.4, C.5, and C.6

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	223,147	13,509	6.44%	624,364	91,637	17.20%	329,918	61,784	23.04%
2010	237,446	14,299	6.41%	628,716	4,352	0.70%	359,288	29,370	8.90%
2011	235,556	-1,890	-0.80%	629,866	1,150	0.18%	364,590	5,302	1.48%
2012	232,025	-3,531	-1.50%	630,310	444	0.07%	368,018	3,428	0.94%
2013	228,836	-3,189	-1.37%	630,824	514	0.08%	368,277	259	0.07%
2014	228,317	-519	-0.23%	634,163	3,339	0.53%	369,576	1,299	0.35%
2015	228,272	-45	-0.02%	638,056	3,893	0.61%	368,355	-1,221	-0.33%
2016	229,780	1,508	0.66%	644,157	6,101	0.96%	370,466	2,111	0.57%
2017	228,794	-986	-0.43%	647,518	3,361	0.52%	371,232	766	0.21%
2018	224,720	-4,074	-1.78%	648,006	488	0.08%	372,808	1,576	0.42%
2019	219,637	-5,083	-2.26%	649,505	1,499	0.23%	372,356	-452	-0.12%
2020	218,868	-769	-0.35%	651,568	2,063	0.32%	372,398	42	0.01%
2021	211,257	-7,611	-3.48%	647,656	-3,912	-0.60%	368,363	-4,036	-1.08%
2022	207,376	-3,881	-1.84%	646,077	-1,579	-0.24%	369,756	1,393	0.38%
2023	202,751	-4,625	-2.23%	641,744	-4,334	-0.67%	369,859	103	0.03%
2024	199,188	-3,563	-1.76%	636,138	-5,606	-0.87%	369,147	-712	-0.19%
2025	197,623	-1,565	-0.79%	626,971	-9,166	-1.44%	367,974	-1,173	-0.32%
2026	197,403	-220	-0.11%	615,807	-11,164	-1.78%	368,218	244	0.07%
2027	196,486	-916	-0.46%	607,507	-8,300	-1.35%	371,710	3,492	0.95%
2028	197,179	692	0.35%	597,902	-9,606	-1.58%	375,029	3,319	0.89%
2029	197,757	579	0.29%	589,050	-8,852	-1.48%	376,761	1,732	0.46%
2030	197,686	-71	-0.04%	581,188	-7,861	-1.33%	377,670	909	0.24%
2031	197,351	-335	-0.17%	573,776	-7,412	-1.28%	377,485	-186	-0.05%
2032	197,102	-249	-0.13%	566,272	-7,504	-1.31%	375,621	-1,863	-0.49%
2033	196,866	-236	-0.12%	558,582	-7,690	-1.36%	373,146	-2,476	-0.66%
2034	196,627	-239	-0.12%	551,635	-6,948	-1.24%	370,257	-2,888	-0.77%
2035	196,359	-268	-0.14%	546,432	-5,202	-0.94%	366,212	-4,045	-1.09%

Tables C.7, C.8, and C.9

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)	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	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	616,548	71,810	13.18%	996,147	69,821	7.54%	817,150	285,969	53.84%
2010	651,471	34,923	5.66%	1,024,324	28,177	2.83%	1,050,717	233,567	28.58%
2011	653,895	2,424	0.37%	1,031,581	7,257	0.71%	1,058,929	8,212	0.78%
2012	656,364	2,469	0.38%	1,036,797	5,216	0.51%	1,052,118	-6,811	-0.64%
2013	658,501	2,137	0.33%	1,041,633	4,836	0.47%	1,048,629	-3,489	-0.33%
2014	665,301	6,800	1.03%	1,051,897	10,264	0.99%	1,049,041	412	0.04%
2015	674,965	9,664	1.45%	1,069,226	17,329	1.65%	1,055,051	6,010	0.57%
2016	691,815	16,850	2.50%	1,098,471	29,245	2.74%	1,062,345	7,294	0.69%
2017	701,759	9,944	1.44%	1,121,372	22,901	2.08%	1,062,119	-226	-0.02%
2018	707,710	5,951	0.85%	1,137,421	16,049	1.43%	1,055,716	-6,403	-0.60%
2019	711,861	4,151	0.59%	1,152,080	14,659	1.29%	1,048,772	-6,944	-0.66%
2020	714,408	2,547	0.36%	1,162,505	10,425	0.90%	1,045,313	-3,459	-0.33%
2021	708,478	-5,930	-0.83%	1,160,037	-2,468	-0.21%	1,034,971	-10,342	-0.99%
2022	711,739	3,261	0.46%	1,167,699	7,661	0.66%	1,030,969	-4,003	-0.39%
2023	713,369	1,630	0.23%	1,171,963	4,264	0.37%	1,028,280	-2,689	-0.26%
2024	714,756	1,387	0.19%	1,176,704	4,741	0.40%	1,029,138	859	0.08%
2025	713,868	-888	-0.12%	1,178,683	1,979	0.17%	1,032,401	3,263	0.32%
2026	712,738	-1,130	-0.16%	1,178,805	122	0.01%	1,036,556	4,155	0.40%
2027	714,769	2,030	0.28%	1,180,773	1,968	0.17%	1,043,476	6,920	0.67%
2028	716,046	1,278	0.18%	1,181,363	591	0.05%	1,051,442	7,966	0.76%
2029	716,062	15	0.00%	1,181,809	446	0.04%	1,061,518	10,076	0.96%
2030	714,487	-1,575	-0.22%	1,180,992	-817	-0.07%	1,074,494	12,977	1.22%
2031	712,742	-1,745	-0.24%	1,181,813	821	0.07%	1,088,485	13,990	1.30%
2032	711,281	-1,461	-0.21%	1,185,230	3,417	0.29%	1,102,702	14,217	1.31%
2033	710,196	-1,085	-0.15%	1,188,912	3,682	0.31%	1,117,080	14,378	1.30%
2034	708,864	-1,332	-0.19%	1,190,140	1,228	0.10%	1,130,986	13,906	1.24%
2035	706,653	-2,211	-0.31%	1,187,984	-2,156	-0.18%	1,144,648	13,662	1.21%

Table C.10 Older 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	438,982	11.88%	219,014	-2.56%	162,139	25.87%	57,829	49.11%
2010	537,118	22.36%	293,120	33.84%	165,668	2.18%	78,330	35.45%
2011	552,129	2.79%	306,047	4.41%	166,362	0.42%	79,720	1.77%
2012	580,796	5.19%	331,726	8.39%	168,240	1.13%	80,830	1.39%
2013	605,856	4.31%	353,255	6.49%	171,149	1.73%	81,452	0.77%
2014	632,381	4.38%	374,630	6.05%	175,830	2.74%	81,921	0.58%
2015	659,493	4.29%	396,125	5.74%	180,948	2.91%	82,420	0.61%
2016	687,946	4.31%	417,643	5.43%	187,528	3.64%	82,775	0.43%
2017	716,136	4.10%	437,586	4.78%	195,962	4.50%	82,588	-0.23%
2018	744,727	3.99%	453,507	3.64%	208,409	6.35%	82,811	0.27%
2019	773,609	3.88%	470,683	3.79%	219,976	5.55%	82,950	0.17%
2020	790,815	2.22%	481,876	2.38%	225,618	2.56%	83,321	0.45%
2021	812,451	2.74%	492,399	2.18%	236,630	4.88%	83,422	0.12%
2022	833,235	2.56%	498,401	1.22%	251,904	6.45%	82,929	-0.59%
2023	854,556	2.56%	501,139	0.55%	269,453	6.97%	83,964	1.25%
2024	876,129	2.52%	503,708	0.51%	286,393	6.29%	86,028	2.46%
2025	897,512	2.44%	505,699	0.40%	302,853	5.75%	88,959	3.41%
2026	917,611	2.24%	506,308	0.12%	318,615	5.20%	92,688	4.19%
2027	937,348	2.15%	505,500	-0.16%	334,126	4.87%	97,722	5.43%
2028	955,385	1.92%	502,514	-0.59%	348,924	4.43%	103,947	6.37%
2029	972,104	1.75%	498,245	-0.85%	363,238	4.10%	110,621	6.42%
2030	987,269	1.56%	492,978	-1.06%	377,203	3.84%	117,087	5.85%
2031	1,000,191	1.31%	486,749	-1.26%	388,660	3.04%	124,781	6.57%
2032	1,011,572	1.14%	480,141	-1.36%	395,973	1.88%	135,458	8.56%
2033	1,022,914	1.12%	474,657	-1.14%	400,932	1.25%	147,326	8.76%
2034	1,036,355	1.31%	472,274	-0.50%	405,339	1.10%	158,741	7.75%
2035	1,052,364	1.54%	472,818	0.12%	409,439	1.01%	170,107	7.16%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE
EXHIBIT 1104

November 24, 2026

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

Marci Lyn 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

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE
EXHIBIT 1105

REDACTED

Under General Protective Order No. 23-132, this exhibit is confidential in its entirety and has been redacted.

November 24, 2026

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE
EXHIBIT 1106

REDACTED

Under General Protective Order No. 23-132, this exhibit is confidential in its entirety and has been redacted.

November 24, 2026

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE
EXHIBIT 1107

REDACTED

Under General Protective Order No. 23-132, this exhibit is confidential in its entirety and has been redacted.

November 24, 2026

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Tobin F. Davilla

OPERATIONS & MAINTENANCE
EXHIBIT 1108

REDACTED

Under General Protective Order No. 23-132, this exhibit is confidential in its entirety and has been redacted.

November 24, 2026

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Direct Testimony of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS / RATE MECHANISMS
EXHIBIT 1200

November 24, 2026

EXHIBIT 1200 – DIRECT TESTIMONY – TEST YEAR / REVENUE REQUIREMENTS / TARIFFS / RATE MECHANISMS

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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 Kyle T. Walker. My current position is Senior Manager of Rates and Regulatory Affairs. My responsibilities for preparation of the revenue requirement for this rate case include development of Company revenues, calculation of gas costs, derivation of depreciation and amortization expense, rate base development, coordination of tax issues, and forecasting of miscellaneous revenues and other taxes.

Q. Please describe your education and employment background.

A. I received a Bachelor of Science Degree in Business Administration with an emphasis in Finance from Oregon State University and a Master of Business Administration from Willamette University. In addition, I received an accounting certificate from the University of Washington, and I am an active licensed certified public accountant in the State of Oregon. 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 February 2015, I started at NW Natural as a Rates/Regulatory Analyst and was later promoted to Manager and Senior Manager of Rates and Regulatory Affairs. In my current role, I am responsible for regulatory strategy, reporting, revenue requirement, rate design, rate spread, and other regulatory duties as assigned.

Q. Please summarize your testimony.

A. In my testimony, I:

- Provide an overview of how revenue requirement is calculated;
- Explain the historical base year of the 12-months ended June 30, 2026 ("Base Year") and the test year of November 1, 2027 to October 31, 2028 ("Test Year");
- Present the $90.1 million (9.1 percent) revenue requirement increase needed to achieve NW Natural's proposed overall rate of return ("ROR") of 7.374 percent and return on equity ("ROE") of 9.75 percent, compared to an ROE of 4.66 percent at current rates;
- Present the adjusted results of operations and explain the Company's projected revenues at current rates, including updated use per customer, and projected operations and maintenance ("O&M") expense, uncollectible expense, income taxes, property taxes, other taxes, and depreciation for the Test Year;
- Explain how rate base was calculated for the Test Year, including utility plant in service and cash working capital based on the lead-lag study from docket UG 520;
- Describe the allocation or assignment of revenues, costs, and rate base elements to the Oregon jurisdiction;
- Propose amortization of the Coos County deferral and removal of the Transportation Security Administration ("TSA") cost of service deferral;

- Provide routine updates to our weather adjustment rate mechanism ("WARM") and Decoupling mechanism;
- Propose a bridge mechanism for year-two rates and explain why temporary rates should not be included in base rates; and
- Present Company tariffs for the Test Year that are proposed to change due to the filing of this general rate case.

II. 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.[1] 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 also include Oregon's Corporate Activity Tax ("CAT"), the statutory Commission fee, and uncollectible revenues. Investment-related costs include the return of investment, or depreciation, and the return on investment,

[1] 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 Purchased Gas Adjustment ("PGA"), and not as part of the Company's base rates, which we seek to modify through this general rate case proceeding.

which includes the costs of long-term debt and equity to finance our investments.[2] Federal and State income taxes are also a cost to serve customers. The elements of the revenue requirement are shown below in Table 1.

Table 1 – 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

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 rate of return.

Q. Please summarize the components of rate base, to which the Company's investment costs relate.

A. The Company's rate base includes several components, but 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

[2] Investment-related costs also include income and property taxes associated with earnings and plant balances, respectively.

as gas inventory in storage, cash working capital, and supply inventories. 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 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 Company. Therefore, we 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 2 below shows the elements of rate base.

Table 2 – 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
+	Materials & Supplies
+	Accumulated Deferred Income Taxes
+	Cash Working Capital
=	Total Other Rate Base Items
Net Plant	
+ Total Other Rate Base Items	
= Total Rate Base	

Q. Please walk through the steps taken to compile the revenue requirement proposed in this case.

A. The first step in the revenue requirement calculation is to determine the amount of revenue that will be generated in the Test Year at current rates. 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.[3]

The second step is to forecast the operating costs and depreciation expense the Company will incur during the Test Year.[4]

The third step is to forecast rate base for the Test 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 the Test Year at current rates. Due to the rate of return being below recommended levels using forecasted revenue at current rates, the Company proposes to increase revenues in order to generate a reasonable return in the Test Year after paying for the forecasted operating

[3] See the Direct Testimony of Robert J. Wyman, NW Natural/1300, Wyman.

[4] 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 the Direct Testimony of Tobin F. Davilla, NW Natural/1100, Davilla.

revenues, 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.

Q. What is the Company's proposed increase to revenue requirement highlighting the steps above?

A. The proposed increase to revenue requirement is $90.1 million, as shown in Table 3 below.

Table 3 – Process Steps with Proposed Increase

($000)

Line No.	Base Year at Present Rates	STEP 1 STEP 2 Adjustments to Base Year	Test Year at Present Rates	STEP 4 Proposed Increase	Proposed Total
	(a)	(b)	(c)	(d)	(e)
Revenues	$943,442	$50,274	$993,715	**$90,061**	$1,083,776
Operating Expenses					
Gas Purchased	$329,013	$19,879	$348,893	$0	$348,893
Other Operating & Maintenance Expense	$224,479	$27,114	$251,593	$237	$251,830
Depreciation Expense	$146,241	$27,288	$173,529	$0	$173,529
Taxes					
Federal Income Tax	$21,586	($10,301)	$11,286	$16,878	$28,164
State Income Tax	$14,038	($3,624)	$10,414	$7,014	$17,427
Other Taxes	$66,443	$11,080	$77,523	$2,439	$79,962
Total Operating Revenue Deductions	$801,801	$71,437	$873,237	$26,568	$899,805
Net Operating Revenues	$141,641	($21,163)	$120,478	$63,493	$183,972
		STEP 3			
Average Rate Base					
Utility Plant in Service, Net	$2,614,169	$335,936	$2,950,105	$0	$2,950,105
Other Rate Base Items	($411,831)	($43,405)	($455,236)	$0	($455,236)
Total Rate Base	$2,202,338	$292,530	$2,494,868	$0	$2,494,868
Rate of Return	6.431%		4.829%		7.374%
Return on Common Equity	8.18%		4.66%		9.75%

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, NW Natural/1200, Walker.

Step two involves forecasts of operating expenses in the following pieces of testimony:

- Ms. Patterson's testimony (NW Natural/900, Patterson) demonstrates NW Natural's costs of labor, including compensation and benefits for our non-bargaining unit employees, bargaining unit employees, and executives.
- Mr. Beck's testimony (NW Natural/1000, Beck) describes the costs associated with our customer communications.
- Mr. Kizer's and Mr. Hwang's testimony (NW Natural/600, Kizer-Hwang) describes the operating expenses associated with the Company's safety and other regulatory compliance projects and programs.
- Mr. Fellon's testimony (NW Natural/800, Fellon) describes 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.
- Mr. Davilla's testimony (NW Natural/1100, Davilla) describes all other operations and maintenance expense, and the total level of expense the Company will incur in the Test Year.

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, is comprised of the following testimony:

- Mr. Kizer's and Mr. Hwang's testimony (NW Natural/600, Kizer-Hwang) describes the capital additions associated with the Company's distribution and storage projects.
- Mr. Pipes' testimony (NW Natural/700, Pipes) describes capital additions associated with the Company's facilities.
- Mr. Fellon's testimony (NW Natural/800, Fellon) describes the Company's capital additions related to IT&S and TSA's security directives, respectively.

In conjunction with these pieces of testimony, my calculations demonstrate NW Natural's rate base that is used in serving our Oregon customers.

Step four, NW Natural's required return on rate base, is established in the following testimonies:

- Mr. Wilson's testimony (NW Natural/300, Wilson) 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.

- Ms. Nelson's testimony (NW Natural/400, Nelson) 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 Test Year, displayed in NW Natural/1201, Walker.

III. BASE YEAR AND TEST YEAR

Q. Why did NW Natural use the 12-months ended June 30, 2026 as the Base Year?

A. The Company chose the 12-months ended June 30, 2026 as the Base Year because it is the most recent quarter-end 12 months ahead of the Company's filing given the amount of time the Company needs to prepare this case.

Q. Why did NW Natural choose the period of November 1, 2027 to October 31, 2028 as the Test Year?

A. The Company chose the 12-month period from November 1, 2027 to October 31, 2028 as the Test Year because it best reflects the conditions expected when new rates from this rate case will be in effect. Given a filing in November 2026, the assumed suspension period for the rate case process in this case would set rates effective by October 31, 2027 for residential customers and November 1, 2027 for non-residential customers. This matches the Test Year revenue requirement in this case and coincides with the effective date of the annual PGA rate change, which minimizes the frequency of rate changes for customers.

IV. TEST YEAR REVENUE REQUIREMENT

Q. What is the Test Year revenue requirement needed to achieve the rate of return proposed in this case?

A. To achieve the proposed rate of return of 7.374 percent in the Test Year, a revenue requirement increase of $90.1 million, or a 9.1 percent increase, is needed over the revenues expected for the Test Year at present rates.

Q. What would NW Natural's rate of return on equity be in the Test Year absent the proposed revenue increase?

A. At current rate levels, the Company's ROE would be 4.66 percent. This is significantly below the Company's currently authorized ROE of 9.50 percent and the 9.75 percent ROE proposed in this case.

Q. Please describe the changes to revenue requirement elements since the last rate case that combine to cause NW Natural to under-earn at current rates in the Test Year.

A. NW Natural/1202, Walker shows a side-by-side comparison of the results of operations from docket UG 520, the Company's last general rate case in 2024,[5] and the Test Year results from this general rate case. Of particular note in this detailed comparison are four specific areas:

1) Line 6 shows a decrease in margins (revenues net of cost of gas) of $5.9 million during the period;

[5] Docket UG 520 was completed, and rates became effective October 31, 2025. Due to the black box nature of the settlement and approved Commission Order, the presentation of NW Natural/1202, Walker does not match the presentation in any document from docket UG 520.

2) Line 9 shows total operating and maintenance expenses increasing by $31.7 million;

3) Line 14 shows an increase in depreciation expense of $19.1 million; and

4) Line 19 shows an increase in net plant of $225.3 million.

In summary, NW Natural has generated revenue growth over the period, but that growth has been insufficient to offset costs for O&M and investments in rate base.

Q. Please describe the cost-of-service schedule treatment in the revenue requirement.

A. All revenues, expenses, and rate base associated with Schedule 90 (North Mist) have been removed from the revenue requirement calculation. In addition, all Schedule 4 (multi-family), Schedule H (Compressed Natural Gas), Schedule 198 (renewable natural gas investments), and gas reserves revenues, expenses and rate base have been removed from the revenue requirement calculation. The ratemaking related to these schedules are self-contained and administered either through a cost-of-service schedule, including automatic adjustment clauses, or the PGA filing.[6] See Robert J. Wyman's Direct Testimony (NW Natural/1300, Wyman) regarding cost-of-service schedule changes.

[6] Gas reserves are included in the weighted average cost of gas, but they have no effect on incremental revenue requirement.

V. RESULTS OF OPERATIONS

Q. Please explain how NW Natural calculated the Test Year revenue requirement.

A. The Company began with actual and forecasted results from the Base Year. We made normalizing and known and measurable changes to Base Year revenues, expenses, and capital (rate base) to reflect conditions anticipated to be in effect during the Test Year. This testimony and the related exhibits explain how these adjustments are reflected in the Test Year revenue requirement.

Q. Have you prepared NW Natural's Oregon-allocated results of operations for the Test Year?

A. Yes. See NW Natural/1201, Walker for a summary of NW Natural's Oregon-allocated Results of Operations for the Test Year.

Q. Please describe Exhibit NW Natural/1201, Walker.

A. Column "a" of NW Natural/1201, Walker shows the Oregon-allocated results for the Base Year, including operating revenues, operating revenue deductions, taxes, and rate base. Column "b" shows the adjustments to Base Year results for each of these categories. Column "c" shows the Test Year results at present rates based on the adjustments to Base Year results. Column "d" indicates the proposed revenue increase necessary to reach the requested ROE. Finally, column "e" shows the Test Year results that reflect the requested ROE.

Q. Please explain the adjustments set forth in Column "b."

A. The amounts in Column "b" show the adjustments from the Base Year to the Test Year. These adjustments impact operating revenues, operating revenue deductions, including taxes, and changes in rate base.

A. Sales of Gas Revenues and Transportation Revenues

Q. Please explain the adjustments to Base Year operating revenues.

A. The first two adjustments to operating revenues are for Sale of Gas and Transportation revenues, shown on lines 1 and 2 of NW Natural/1201, Walker. These adjustments are calculated as the difference between Base Year and Test Year volumes and customers multiplied by current rates.[7]

Q. How did you calculate Base Year Sale of Gas and Transportation revenues?

A. Base Year revenues were projected using the latest available actual volumes and customers for the 12-months ended June 30, 2026, multiplied by rates that were effective during the applicable months. This calculation is shown in NW Natural/1203, Walker.

Q. How did you forecast the Test Year Sale of Gas and Transportation revenues?

A. Test Year revenues reflect normalized forecast volumes and customers multiplied by current rates. The volume forecast methodology is explained in Robert J. Wyman's Direct Testimony (NW Natural/1300, Wyman).

[7] Current rates became effective on October 31, 2026 (for residential customers) and November 1, 2026 (for non-residential customers), which include the most recent PGA and base rates from docket UG 527.

Q. What is the third adjustment to operating revenues?

A. The third adjustment is to remove the decoupling amount produced by the mechanism in the Base Year. This adjustment effectively creates no decoupling revenues in the Test Year, since test period revenues have been developed with newly created use per customer ("UPCs"), effectively normalizing usage that will become the baseline for the decoupling mechanism at the rate effective date of this proceeding. The revenue requirement UPC for residential premises connected to the system prior to January 1, 2018 is 641.76 therms per year while the revenue requirement UPC for residential premises that connected on or after January 1, 2018 is 430.67 therms per year.

Q. How do the updated UPC forecasts affect the Company's proposed $90.1 million revenue increase?

A. Approximately $19.8 million of the proposed $90.1 million revenue increase is attributable to the reduction in forecasted UPCs. The updated UPCs reduce the amount of distribution margin the Company expects to collect through existing base rates during the Test Year. Holding other factors constant, this reduction increases the additional revenue needed through base rates to recover the Company's proposed cost of service.

Importantly, this component of the request does not represent an additional $19.1 million of operating expenses or investment-related costs. Rather, it reflects an updated estimate of the gas volumes over which those costs will be recovered. For customers subject to decoupling, a shortfall in distribution margin associated with weather-normalized usage below the existing UPC baseline is addressed

through the decoupling mechanism. Updating the UPCs therefore better aligns recovery through base rates with expected customer usage and reduces reliance on subsequent decoupling adjustments.

Q. How does the Company's recent decoupling experience support updating the UPCs in this proceeding?

A. The Company's recent decoupling experience provides evidence that weather-normalized customer usage has been below the usage assumptions underlying existing rates. Under Schedule 190, the Company compares weather-normalized usage with the applicable baseline UPCs and defers the resulting distribution margin difference for subsequent recovery or refund. A decoupling balance recoverable from customers therefore reflects distribution margin that was not collected through usage-based rates relative to the established baseline.

Q. Does updating the UPCs result in recovery of the same distribution margin through both base rates and decoupling?

A. No. The Company proposes to update the UPCs used to establish base rates and the corresponding decoupling baselines consistently. As a result, the lower expected usage reflected in this case will be incorporated into both calculations. If weather-normalized usage equals the updated baseline, there would be no usage-related decoupling adjustment for that difference.

Q. What is the fourth adjustment to operating revenues?

A. The fourth adjustment is to remove the WARM revenue that was related to the Base Year. The Test Year is based on normal weather; therefore, no WARM amount is applicable.

B. Miscellaneous Revenues

Q. What is the fifth and last adjustment to operating revenues?

A. The last adjustment is to Miscellaneous Revenues, identified on line 5 of NW Natural/1201, Walker, and in detail on NW Natural/1204, Walker. The Company has proposed an adjustment that represents the difference between the Base Year and a three-year average ended June 30, 2026. This adjustment is used to forecast, or normalize to a three-year average, for the Test Year. The adjustment was calculated by adjusting specific categories of Miscellaneous Revenues to reflect levels of operating activity, based on three years of historical data. If the amounts for a particular category were trending upward or downward, the most recent year was taken as representative for the forecast. If there was no apparent trend to the historical amounts, a simple three-year average was used. The adjustments to specific categories of Miscellaneous Revenues are set forth in NW Natural/1204, Walker. Cost of service related to Schedule H, curtailment and entitlement revenues,[8] and all non-utility miscellaneous revenues have been removed.

C. Cost of Gas

Q. Please explain the adjustments to Operating Revenue Deductions.

A. The first adjustment to Operating Revenue Deductions is for Gas Purchased, shown on line 7 of NW Natural/1201, Walker. This adjustment reflects the

[8] Curtailment and entitlement revenues are given back to customers on Schedule 168 and do not impact Miscellaneous Revenues (see Order No. 20-364).

difference between Base Year and Test Year sales volumes multiplied by current commodity and demand rates.

Q. Is the cost of gas included in base rates?

A. No. The annual PGA filing revises billing rates to include the cost of gas for the upcoming year through a mechanism outside of base rates. As a result, the gas cost pricing issue is addressed in the PGA proceeding rather than in a general rate case. Although gas costs are not included in base rates, gas costs are included in the total revenue calculation to provide an appropriate expense level relative to the revenues that are forecasted for the rate case. This ensures that base rates in the rate case are calculated based on an accurate matching of costs and revenues.

Q. Please explain the Uncollectible Accrual for Gas Sales adjustment.

A. The expense amount for uncollectible accounts is shown on line 8 of NW Natural/1201, Walker in summary, and in detail in NW Natural/1205, Walker. NW Natural's forecasted uncollectible rate is expected to be 0.265 percent.

Q. What is uncollectible expense?

A. Uncollectible expense is the amount owed to NW Natural from customers that cannot be collected and the Company writes off. Because the revenue NW Natural collects each year varies, uncollectible expense is expressed as a percentage of revenue—the uncollectible rate.

Q. Please summarize your testimony on uncollectible expense.

A. NW Natural's goal is to forecast uncollectible expense accurately so that it collects in rates an amount that is as close as possible to the actual expense the Company writes off as uncollectible from customers. In recent history there have been

significant changes to collection rules. In 2022 the Division 21 rules strengthened customer protections concerning disconnections, and further enhancements to customer protections were enacted in late 2025. The Company expects that these changes along with macroeconomic conditions will cause the uncollectible rate to be higher than recent history and that the rate will remain volatile over the next several years given current economic conditions and the impact of the new rules. For these reasons, NW Natural proposes to depart from its past approach of using a three-year historical average and instead use the 2023 uncollectible rate of 0.265 percent.

Q. Please summarize how recent events have affected or are expected to affect the uncollectible rate.

A. As a result of macroeconomic trends and additional regulations, NW Natural's forecasted uncollectible rate is expected to be 0.265 percent. We expect the bad debt experience in 2027 and going forward will be comparable to the Company's experience in 2023. This is based on 2023 having a similar macro-environment to what Oregon and the Company are currently experiencing and are expected to experience through at least the Test Year. This includes high inflation, climbing interest rates, and increasing regulations around credit and disconnections.

Through rulemakings in dockets AR 667 and AR 671, Oregon materially expanded residential customer protections beginning in 2025, including longer severe-weather disconnection moratoriums, broader reconnection protections and longer payment arrangements. In 2026, NW Natural also implemented higher thresholds associated with payment-plan disconnections through the Company's

alternative rate mechanism proceeding in docket UG 527. As these protections were recently implemented, the full extent of the effect on uncollectible accounts cannot be determined. However, given they reduce the ability to collect payments, it is expected to increase bad debt expense.

One indicator of collections is recoveries from our collection agencies. Before 2020, collection agencies were able to successfully recover approximately 53 percent of the amounts owed. Today, about 31 percent are recovered.

Q. Please explain how NW Natural expects current economic conditions to impact the uncollectible rate.

A. Current economic conditions in NW Natural's service area are weaker than a year ago and contributing to an increasing uncollectible rate. Oregon's unemployment rate remains elevated at 5.1 percent (August 2026), the third highest rate in the country.[9] Oregon has lost nearly 20,000 private sector jobs (-1.2 percent) over the past two years (Q3 2024-Q3 2026), more than any other state in the United States ("U.S").[10] Wage growth has also slowed in Oregon and is no longer outpacing inflation with average hourly earnings up 3.5 percent year-over-year in Q3 2026, on par with year-over-year change in U.S. Urban Consumer Price Index ("CPI") for Q3 2026.[11,12]

[9] U.S. Bureau of Labor Statistics, Local Area Unemployment Statistics (September 18, 2026).

[10] U.S. Bureau of Labor Statistics, Current Employment Statistics (October 20, 2026).

[11] Ibid.

[12] U.S. Bureau of Labor Statistics (BLS).

During times of high unemployment and job loss, the Company experiences higher uncollectible rates. In previous recessions, the uncollectible rate has increased to 0.40 percent on average, up from 0.15 percent during non-recessionary periods.

NW Natural expects an increase in the uncollectible rate above historical average heading into 2027. Nationally, the personal savings rate continues to fall, while higher interest rates and inflation coupled with stagnant real wage growth will continue to be a drag on economic growth and customers' pocketbooks in 2027. U.S. real gross domestic product growth is forecasted to be lower in 2027 (1.8 percent) and remain low in 2028 (1.9 percent).[13]

D. Operations and Maintenance Expense

Q. Please explain the Other O&M Expenses adjustment.

A. The Oregon and System O&M expense excluding Uncollectible Accrual for Gas Sales is set forth in detail for the Base Year in NW Natural/1206, Walker, for the Test Year in NW Natural/1206, Walker, and in summary at line 9 of NW Natural/1201, Walker. The Direct Testimony of Tobin F. Davilla (NW Natural/1100, Davilla) explains in more detail how NW Natural calculated its Test Year O&M.

E. Income Taxes

Q. Please explain the adjustments to income taxes.

A. The first two adjustments to income taxes, included on lines 11 and 12 of NW Natural/1201, Walker, reflect changes to Federal and State Income Taxes between

[13] S&P Global, *Economic Outlook U.S. Q4 2026* (September 23, 2026).

the Base Year and Test Year. The adjustments are a function of the impact of statutory income tax rates on the changes to revenues and expenses from the Base Year to Test Year. The calculations of income tax expense are included in NW Natural/1207, Walker. The applicable statutory income tax rates are 21 percent for federal and 7.6 percent for Oregon. The combined statutory rate for both federal and Oregon State income taxes is 27 percent, derived by adding the federal rate to the state rate net of the federal tax benefit of the state income tax deduction. A summary of the tax rates used in the case is included in NW Natural/1208, Walker.

Q. What are the primary differences between income tax expense calculated using only the combined statutory rate and the income tax expense included in the Base Year and Test Year?

A. NW Natural has included historical regulatory income tax flow-through items related primarily to tax benefits that were originally flowed through to customers prior to 1981. NW Natural has also included the regulatory benefits of plant EDIT 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 schedule for the accelerated income tax depreciation benefits previously flowed through to customers was set in Accounting Order UM 1335 on December 8, 2008. The amortization schedule for the income tax cost of the plant removal costs was set in General Rate Case UG

221. The amortization of both items is anticipated to conclude in calendar year 2027 and are not present in the Test Year.

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 No. 19-105, which concluded NW Natural's general rate case docket UG 344 in March 2019, the Commission approved the agreement of all parties that NW Natural would provide three different categories of regulatory EDIT benefits to customers: Plant, Non-Plant, and Gas Reserves. The full benefit of Non-Plant EDIT was provided to customers in March 2019 consistent with Order No. 19-105. The Plant benefits continue to be provided to customers subject to the timing limitations of the average rate assumption method (ARAM) from Order No. 20-364 issued in NW Natural's docket UG 388 general rate case. The Gas Reserves benefits concluded on October 31, 2023, consistent with Order No. 20-364.

Q. Are the continuing regulatory benefits of Plant EDIT included in income tax expense for the Test Year the same annual dollar amounts documented in Order No. 22-388, issued in NW Natural's docket UG 435 general rate case?

A. No. The annual Plant EDIT amortization dollar amounts included in the income tax expense for the Test Year are proposed to increase $400 thousand to $3.6 million, prior to full revenue gross up.

F. Taxes Other than Income Taxes

Q. Please describe the property tax expense included in the Company's revenue requirement.

A. Property tax expense represents taxes imposed on the value of the utility operations and property used to provide natural gas service to customers. In Oregon, the Company's gas utility operations are valued under the State's central assessment process.

Q. How does central assessment differ from the property tax process that generally applies to other businesses?

A. Under the ordinary local assessment process, a county assessor may determine the value of the real and personal property located within that county. Under central assessment, the Oregon Department of Revenue develops an overall value for the centrally assessed utility operations. The resulting value is then apportioned to Oregon and allocated among the local tax code areas in which the Company operates. The applicable counties use those allocated values and the tax rates in effect in each tax code area to issue the Company property tax bills.

Q. How is the property tax expense included in this case connected to the provision of Oregon regulated utility service?

A. The property tax expense included in this case is limited to the amount attributable to the Company's core Oregon natural gas utility operations and the property used to provide regulated service to Oregon customers. Although the Oregon central assessment process values the Company's utility operations on a system-wide basis and includes certain non-core operations, the Company removes property

tax attributable to North Mist, Interstate Storage, other non-core operations, and property tax that is appropriately capitalized. The Company also excludes property taxes imposed outside Oregon. Accordingly, the amount included in the revenue requirement represents only the property tax expense associated with providing regulated natural gas service to Oregon customers.

Q. Why is property tax expense an appropriate cost of utility service?

A. Property tax is an unavoidable cost associated with owning and operating the property required to provide regulated natural gas service. The Company cannot provide service without substantial investments in mains, services, meters, storage facilities, buildings, equipment, and other utility infrastructure. Because the property tax obligation results from the Company's use of those assets to serve customers, the properly allocated and reasonably estimated expense is an appropriate component of the cost of service.

Q. What Oregon property tax expense has the Company included for the Test Year?

A. The Company has included approximately $41.5 million of Oregon property tax expense for the Test Year ending October 31, 2028, shown on line 19 of NW Natural/1209, Walker. The Test Year extends from November 1, 2027, through October 31, 2028. The Test Year amount, therefore, reflects two months of the forecast 2027 property tax amount and ten months of the 2028 forecast property tax amount.

Q. What is the starting point for the forecast?

A. The starting point is the most recent actual information available when the forecast was prepared. For 2026, the Oregon Department of Revenue determined a system-wide value of approximately $3.15 billion. The Department apportioned 91.58 percent of that value to Oregon. That apportioned value resulted in approximately $42.7 million of Oregon property tax paid in November 2026 after application of the available 3 percent early-payment discount.

Q. How did the Company forecast the 2027 and 2028 property tax amounts?

A. The Company began with the final 2026 system-wide assessed value of approximately $3.15 billion. For each forecast year, the Company increased the prior-year value for forecast system-wide utility plant additions and reduced the value for forecast depreciation expense. This produces an estimated system-wide value for each forecast year.

The Company then applied the Oregon apportionment percentage of 91.58 percent to estimate the portion of the system value attributable to Oregon. The composite effective property tax rate from 2026 of 1.48 percent was applied to the resulting Oregon value to estimate the total Oregon property tax. The composite effective property tax rate was derived from the 2026 Oregon property tax bills after reflecting the 3 percent payment discount. Finally, the Company removed amounts attributable to North Mist, Interstate Storage, other non-core operations, and property tax that is appropriately capitalized. The remaining amount represents the forecast Oregon property tax expense attributable to regulated gas utility operations.

Q. Why does the Company use plant additions less depreciation to develop the forecast assessed value?

A. The Company uses this methodology because changes in utility plant investment are a significant driver of changes in the utility's value. Beginning with the most recent actual value, adding forecast plant additions, and subtracting depreciation provides a reasonable baseline estimate of the change in value between assessment years. In recent assessment cycles, the Oregon Department of Revenue has considered changes in plant investment and depreciation when evaluating year-over-year changes in value. The Company uses those factors as a practical forecasting proxy, while recognizing that the Department's final appraisal may consider additional valuation evidence.

Q. How does the Company estimate the portion of the system value attributable to Oregon?

A. After estimating the total system value, the Company applies the actual 2026 Oregon apportionment percentage determined by the Oregon Department of Revenue. Oregon uses an apportionment formula that considers factors such as plant investment, sales, and gas volumes within and outside Oregon.

Q. Why did the Company use the 2026 composite effective property tax rate for the forecast period?

A. The Company used the most recent actual composite effective rate because it provides a reasonable and current measure of the combined effect of the geographic distribution of Oregon-assessed value, applicable local tax rates, and the 3 percent early-payment discount.

Q. What adjustments does the Company make after calculating the estimated total Oregon property tax?

A. The Company removes property tax attributable to North Mist, Interstate Storage, and other operations that are not part of the Oregon regulated gas revenue requirement. The Company also removes property tax that is appropriately capitalized. These adjustments are intended to ensure that the amount requested in this case includes only the expense attributable to providing regulated natural gas service to Oregon customers.

Q. How is the final Test Year property tax expense derived?

A. The Company calculates forecast regulated Oregon property tax expense for both 2027 and 2028. Because the Test Year runs from November 1, 2027, through October 31, 2028, the Test Year amount combines two-twelfths of the 2027 forecast and ten-twelfths of the 2028 forecast. This produces a Test Year expense of approximately $41.5 million.

Q. Why does the Company believe its property tax forecast is reasonable?

A. The forecast is reasonable for several reasons. First, it begins with the most recent actual assessed value and property tax payment available when the forecast was prepared. Second, the calculation applies an Oregon apportionment percentage and an effective rate based on the most recent actual central assessment outcome. Finally, the Company removes property taxes attributable to non-core operations and capitalized activities before determining the amount requested from Oregon gas customers.

Q. Does the Company simply accept the Oregon Department of Revenue's initially proposed value each year?

A. No. The Company reviews the Oregon Department of Revenue's proposed valuation and engages with the Department when the proposed value is not supported by the relevant valuation evidence. From 2017 through 2026, the Department's proposed annual valuation increases averaged approximately 10.7 percent. The final annual valuation increase was approximately 7.0 percent as a result of the Company engaging with the Department. Although the difference varies by year and may reflect several factors, the history shows that the Company reviews proposed values and engages with the Department by providing additional information or raising valuation concerns when appropriate.

Year	YoY Increase Proposed	YoY Increase Actual
2017	10.5%	6.2%
2018	7.4%	5.8%
2019	1.4%	1.4%
2020	13.7%	10.9%
2021	7.5%	7.5%
2022	16.1%	11.2%
2023	16.3%	2.0%
2024	1.4%	1.4%
2025	8.6%	8.6%
2026	24.5%	15.4%
	10.7%	7.0%
	Average	Average

Q. How does the Company's participation in the valuation process benefit customers?

A. A lower final assessed value results in lower property tax expense than would result from the Department's initial proposed value, all else being equal. By

reviewing and, where appropriate, challenging the proposed appraisal, the Company seeks to ensure that the final value is supportable and that customers do not bear property tax expense based on an overstated valuation.

Q. Will the forecast necessarily equal the property tax expense ultimately incurred?

A. No. The final property tax obligation depends on future valuation determinations by the Oregon Department of Revenue, the final Oregon apportionment, the allocation of value among tax code areas, and the tax rates imposed by the applicable local jurisdictions. Those elements are not all known when the rate case is filed. The Company therefore uses the most recent actual information and reasonable forecast assumptions to estimate the property tax expense attributable to the Test Year.

Q. What occurs after the Oregon Department of Revenue determines the Oregon value?

A. After determining the portion of the system value attributable to Oregon, the Oregon Department of Revenue allocates that value among the individual tax code areas in which the Company owns utility property. Pipe miles are a primary factor used to allocate value among the tax code areas. The Department communicates the allocated values to the counties, and each county applies the tax rates in effect for the relevant tax code areas and issues the corresponding property tax bills.

Q. How does the Company verify the property tax bills it receives?

A. The Company reconciles the values shown on the county tax bills to the values allocated by the Oregon Department of Revenue. The Company then reviews and

processes the bills for payment. This reconciliation helps ensure that the assessed values communicated by the Department have been properly reflected in the county billings.

Q. Does the Company take advantage of available payment discounts?

A. Yes. Oregon local jurisdictions provide a 3 percent discount when property taxes are paid in full on or before November 15. The Company pays its Oregon property tax bills in full by that date to obtain the discount. The property tax expense used in the rate-case forecast reflects that discount, so customers receive the benefit of the reduced payment amount.

Q. What is the Company requesting with respect to property tax expense?

A. The Company requests that the Commission approve the forecast Oregon property tax expense included in the Test Year revenue requirement as included on line 13 of NW Natural/1201, Walker. The amount represents the Company's reasonable estimate of the property tax expense attributable to its Oregon regulated natural gas utility operations during the Test Year.

Q. Please explain the adjustment to Other Taxes.

A. The adjustment to Other Taxes is shown on line 14 of NW Natural/1201, Walker. This adjustment was calculated as follows for the different categories within Other Taxes, the detail of which is shown in NW Natural/1209, Walker:

- Franchise fees were derived by applying the effective rate of 2.333 percent to gross revenue by using a three-year weighted average to provide a forecast for total franchise fees for both the Base Year and Test Year.

- Payroll taxes were tied to the payroll tax credit that is calculated within the O&M methodology. The credit within O&M is made to extract the payroll taxes associated with payroll for O&M, with the commensurate charge to the payroll tax expense line item under the Other Tax category.
- The regulatory fee was calculated using the current rate of 0.360 percent multiplied by total revenues for the Base Year and Test Year.
- The Oregon Department of Energy fee is calculated as a function of gross revenues. This fee was calculated using a three-year weighted average effective rate between gross revenue and actual fees paid. Total gross revenue for the Base Year and Test Year was multiplied by 0.099 percent to derive the fee.
- CAT is directly impacted by revenues the Company receives. Test Year amounts were calculated based on the total revenue requirement proposed in this proceeding.
- Other taxes, such as permit and licensing fees, were forecasted for the Test Year based on an average of 12-months ended June 2026, 2025, and 2024 amounts. The system-related other taxes were allocated to Oregon based on a three-factor allocation of 88.10 percent.

G. Depreciation and Amortization

Q. Please explain the adjustment to Depreciation and Amortization.

A. The Depreciation and Amortization adjustment is shown on line 15 of NW Natural/1201, Walker and in detail in NW Natural/1210, Walker. This adjustment reflects the difference in depreciation expense for the Base Year and Test Year. Depreciation expense was developed by using utility plant as of June 30, 2026, as a base and increasing plant accounts for capital expenditures from July 2026 through October 2028 for the Test Year. Applicable account balances were then decreased for expected retirements. Gross asset balances for each month of the Test Year multiplied by the current depreciation rates create depreciation expense for the Test Year.

Amortization of the GC 500 and GC 600 compressors at the Mist Storage Facility reflected in the Company's tariff under Schedules 122 and 124 are included in current base rates and their corresponding amortization expense is included on line 15 of NW Natural/1201, Walker.

Q. Please describe how depreciation rates for each asset category were determined.

A. The Company's current depreciation rates were implemented at the same time as rates from our last rate case in docket UG 520. The rates were approved in Order No. 25-344 issued in docket UM 2363 on September 2, 2025.

Q. Does the Company have any unique items related to depreciation?

A. Yes. The Company has acquired cloud-based software assets that are depreciated differently than other utility assets. The Company classifies these assets in FERC 303.7.

Q. How are cloud-based software assets depreciated?

A. Generally accepted accounting principles and FERC align on the guidance for cloud-based software assets.[14] The depreciation follows the contract length of the service provided. Therefore, each asset will depreciate consistent with the underlying service contract. The depreciation expense is derived by creating a weighted average depreciation rate based on current and projected cloud-based software assets and their underlying service contracts. Each month has a distinct depreciation rate due to retirements and additions of these assets. Please see Confidential NW Natural/1211, Walker for the cloud-based assets that are projected to be in FERC 303.7 during the Test Year.

VI. RATE BASE

Q. Please describe the calculation of rate base.

A. The components of rate base are shown in NW Natural/1201, Walker at lines 18-28 and at NW Natural/1210, Walker. Rate base is made up of Utility Plant in Service, net of Accumulated Depreciation, with additions and subtractions for Aid in Advance of Construction, Customer Deposits, Gas Inventory, Leasehold

[14] FERC order in Docket No. AI20-1-000, dated December 20, 2019.

Improvements, Materials and Supplies, Cash Working Capital, and Accumulated Deferred Income Taxes. These components are described in detail below.

Q. How were amounts for Utility Plant in Service calculated?

A. The Company starts with actual plant account balances as of June 30, 2026. We then forecast additions, retirements, transfers, and removal work in progress ("RWIP") for all FERC accounts.[15] Additions to plant reflect customer additions (mains, services, and meters) as well as recurring replacement of capital assets and larger planned projects through the Test Year. As future plant balances are developed, depreciation expense associated with each asset class can be calculated, which also provides for a projection of the accumulated depreciation reserve, net of RWIP. Consistent with mass-asset accounting, both the gross plant and accumulated depreciation amounts are lowered to reflect forecasted asset retirements. Utility plant in service is calculated using a 13-month average of monthly averages ("AMA") of the Test Year. Detail on the various capital projects that are included in the plant projection are described in the Direct Testimonies of Daniel B. Kizer and Michael C. Hwang (NW Natural/600, Kizer-Hwang), Wayne K. Pipes (NW Natural/700, Pipes), and Brian E. Fellon (NW Natural/800, Fellon).

[15] RWIP represents the net between the actual cost of removal and the release of the accrued removal cost liability that gets built up from the cost of removal portion of depreciation expense.

Q. What is Aid in Advance of Construction?

A. Aid in Advance of Construction, or customer contributions, represents money received from customers to install gas infrastructure on a new service. These funds represent a reduction to rate base.

Q. How did the Company calculate Aid in Advance of Construction for the Test Year?

A. Aid in Advance of Construction was calculated based on the line extension allowance in Schedule X of the Company's tariff and the average cost to connect a new system in 2025. For new residential customers added from July 2026 through October 2026, the allowance reflects two times the applicable margin factor. For new residential customers added from November 2026 through October 2027, the allowance reflects one times the applicable margin factor. Beginning November 1, 2027, no line extension allowance is provided for new residential customers. After 36 months, which is the period in which refunds of aid in advance of construction can be provided, the liability gets re-classified into rate base as negative gross plant with the associated negative, or offsetting, amortization included within the Depreciation expense. Prior to 36 months, the aid in advance of construction is accumulated into a liability which reduces rate base.

Q. Please define Cash Working Capital.

A. Cash working capital is the amount of investor-supplied capital required to fund the day-to-day operations of a company after accounting for the timing differences between accrued and cash revenue and expenses. It represents amounts funded

by investors to provide service prior to payment for such service by customers and, therefore, cash working capital typically is a component of a company's rate base.

Q. Did NW Natural perform a new study to determine its cash working capital requirements for the Base Year and Test Year?

A. No. The Company did not perform a new lead-lag study for this proceeding. Instead, the Company relied on the lead-lag study previously developed and approved in the Company's last general rate case, docket UG 520, which was based on calendar year 2023 data. The Company used the results of that study to calculate its Base Year and Test Year cash working capital amount.

Q. Why is it reasonable to rely on the lead-lag study developed in docket UG 520?

A. The lead-lag study developed using 2023 data remains representative of NW Natural's cash working capital because the Company's billing, collections and payment practices have not materially changed since the study was completed. Additionally, there have been no material changes in these processes that the Company believes would significantly affect the results of the lead-lag study. The Company believes the study continues to provide a reasonable basis for determining cash working capital for the Test Year.

Q. What is a lead-lag study?

A. A lead-lag study is an analysis designed to determine the funding required to operate a company on a day-to-day basis. The study compares 1) the timing difference between the receipt of service by customers and their subsequent payment for these services, and 2) the timing difference between incurred costs

and the subsequent payments of these costs. Therefore, a lead-lag study must compute both a revenue lag (or lead) and an expense lag (or lead). NW Natural/1212, Walker summarizes the 2023 lead-lag study results for NW Natural. The net lag days, 16.4 days, represents the average number of days the Company must fund operating expenses before it receives the revenues to cover those expenses.

Q. Were any adjustments made to the lead-lag study previously presented in docket UG 520?

A. Yes. During the docket UG 520 proceeding, the Company identified that the CAT was being double counted in the cash working capital calculation. Specifically, CAT was included in both the income tax component of the calculation and as a separate item. To eliminate the double count, the Company removed the separately identified CAT expense from the lead-lag study. The lead-lag study presented in this proceeding incorporates that adjustment. Additionally, although the Company's Base Year is 12-months ended June 30, 2026, the cash working capital Base Year calculation is based on calendar year 2025 information, consistent with standard annual reporting practices. This approach does not affect the calculation of Test Year cash working capital.

Q. How did the Company determine the lag days for operating revenues?

A. The number of lag days for operating revenues is the timing difference between the receipt of service by customers and their subsequent payment for these services for calendar year 2023. The measurement of revenue lag days consists of three components: 1) service lag, 2) billing lag, and 3) collection lag. Each of

these different components is a separate step in the collections process and, therefore, revenue lag is computed by adding together the total numbers of days associated with each component to determine revenue lag.

Q. Please describe how the Company calculated service lag.

A. The service lag represents the time from the midpoint of a customer's usage period to the meter read date. The Company bills all customers on a monthly basis and, therefore, the average service lag equates to approximately half of a given month or about 15.2 days.

Q. Please describe how the Company calculated billing lag.

A. The billing lag represents the time from the meter read date to the billing date. The Company reads and bills for service on the same day, so the Company's average billing lag was determined to be 0 days.

Q. Please describe how the Company calculated collection lag.

A. The collection lag represents the time from the billing date to the date payment is received. This lag was calculated by taking the average monthly accounts receivable balances in 2023 divided by the average daily sales to calculate the number of days, on average, it takes to turn over the accounts receivable balance. The Company's average collection lag was determined to be 25.7 days.

Q. What is the Company's total operating revenue lag?

A. The total operating revenue lag is the sum of the service lag, billing lag and collection lag. As shown on NW Natural/1212, Walker, the Company has an average operating revenue lag of 40.9 days.

Q. How did the Company determine the lag days for miscellaneous revenues?

A. For miscellaneous revenues, the lag was calculated using a 30-day service period, no billing lag and payment terms of net 30 days. Therefore, the average lag for miscellaneous revenues was determined to be 45 days (i.e., 30 days/2 + 30 days = 45 days). This is consistent with Company policy and experience for other operating revenues.

Q. What is the Company's total revenue lag?

A. Using a weighted average between revenue from customers and miscellaneous revenues, it is determined that the average revenue lag is 40.9 days.

Q. How did the Company determine the lag days for operating expenses?

A. For the purpose of this study, we first grouped operating expenses into two types: expenses for materials received and expenses for services rendered. The expense lag for materials received is calculated by comparing the invoice date with the payment date. The expense lag for services rendered is calculated by comparing the midpoint of the service period with the payment date. We then analyzed the following categories of operating expenses: Purchased Gas, Labor – Payroll, Employee Benefits, Prepaid Insurance, Prepaid Information Technology ("IT"), Regulatory Fees, Municipal Franchise Fees, Other O&M, Payroll Taxes and Other Taxes (Federal, State and Property Taxes).

Q. Please describe how the Company calculated the expense lag for Purchased Gas.

A. The Purchased Gas lag represents the time period from when the Company rendered service to its customers (i.e., supplied gas) to the time the Company

makes payments for the gas costs to deliver those services. There are two components to the Purchased Gas lag: the service lag and the payment lag. The service lag is calculated using the same methodology as that used for revenue collected from customers -- the time from the midpoint of service to the meter read date -- which is 15.2 days. The payment lag represents the time from the last day of the service period to the actual payment date for those gas costs. The industry standard is to pay these expenses on the 25th of the month, meaning that the payment lag is 25 days. The total lag for purchased gas, therefore, is 40.2 days (i.e., 15.2 days + 25 days = 40.2 days).

Q. Please describe how the Company calculated the expense lag for Labor – Payroll.

A. Labor – Payroll represents bi-weekly payroll paid to employees, as well as annual incentive pay. For bi-weekly payroll, the lag is the time from the midpoint of the service period to the time the Company pays its employees. Employees are paid every two weeks with a week lag for processing. On average, the bi-weekly payroll lag is 11.5 days. Annual incentive pay is paid once a year, after the end of the year. For this analysis we used 2023 as the service period and July 2, 2023, as the midpoint date. The payment was made to employees on March 5, 2024, and therefore there is a 247.0-day lag. On a weighted average basis, the average payroll lag is 27.1 days.

Q. Please describe how the Company calculated the expense lag for Employee Benefits.

A. Employee Benefits costs represent the expenses the Company pays for health benefits, health savings account, 401K, union dues and other employee benefits costs. These costs were analyzed in two groups to determine the average lag days for benefits expenses: the costs paid on the same day as payroll and those expenses treated like other accounts payable costs. To determine the costs paid on the same day as payroll, we used the bi-weekly payroll lag of 11.5 days. The second group was calculated by summarizing the invoice date and payment days for each of the vendors we pay for benefits costs. The Company's average employee benefits lag was determined to be 1.4 days. Therefore, the total lag for employee benefits is 12.9 days.

Q. Please describe how the Company calculated the expense lag for Prepaid Insurance.

A. Insurance premiums are generally prepaid, which means the Company outlays funds prior to the service period. This sequencing causes a negative lag (or lead) in calculated days. The insurance policies were analyzed based on service period and payment date which results in a lead (or negative lag) of 214.3 days. The Company does not forecast prepaid insurance expenses because it is not a usual revenue requirement item. Therefore, the Test Year amounts used for prepaid insurance is the Company's annual policy contracts and adjusted to the Test Year

using the most current CPI as reported in the August 2026 Economic and Revenue Forecast published by the Oregon Office of Economic Analysis (OEA).[16]

Q. Please describe how the Company calculated the expense lag for Prepaid IT.

A. Similar to prepaid insurance, prepaid IT contracts require the Company to outlay funds prior to the service period. The prepaid IT contracts were analyzed based on service period and payment date, which results in a lead (or negative lag) of 231.4 days. The Company also does not forecast prepaid IT because it is not a usual revenue requirement item; therefore, the Test Year amount used for prepaid IT is the balance as of December 31, 2025, and adjusted to the Test Year using the most current CPI as reported in August 2026.

Q. Please describe how the Company calculated the expense lag for Regulatory Fees.

A. NW Natural pays two entities for regulatory fees: the Public Utility Commission of Oregon and Washington Utilities and Transportation Commission. Payments for each calendar year are made in the spring, which creates a lead because the Company is making a payment for a service period (calendar year) that is not yet complete. On a weighted average basis, the average regulatory lead (or negative lag) is 91.3 days.

[16] NW Natural/1103, Davilla.

Q. Please describe how the Company calculated the expense lag for Municipal Franchise Fees.

A. Municipal franchise fees are paid monthly, quarterly, semi-annually and annually to 111 different entities. The fees were analyzed based on service period and payment dates, which results in an average lag of 90.9 days.

Q. Please describe how the Company calculated the expense lag for Other O&M.

A. Other O&M represents the remaining operating expenses the Company pays on a day-to-day basis. This analysis compares invoice dates and payment dates for nearly 30,000 items, which results in a lag of 33.2 days.

Q. Please describe how the Company calculated the expense lag for Payroll Taxes.

A. Payroll taxes are paid both quarterly, following the end of the quarterly payroll period, and through employee pay days. Service dates and midpoint dates were analyzed to determine quarterly payments, and the bi-weekly payroll lag, 11.5 days, was used for pay day payments. The total lag for payroll taxes is 79.4 days.

Q. Please describe how the Company calculated the expense lag for Other Taxes.

A. Federal and state taxes are paid on a quarterly basis on dates prescribed by the Internal Revenue Service. The total lag for federal and state income taxes is 36.5 days. The property tax year runs from July 1 through June 30 with payments being made November 15 of that same year. For example, for the July 1, 2025 through

June 30, 2026 tax year, taxes were paid on November 15, 2025. The total lead (or negative lag) for property taxes is 45.5 days.

Q. What are the overall results of the lead-lag study?

A. The results of the study show that NW Natural's daily cash working capital in Oregon for the Test Year is $33.2 million with a cash working capital factor of 4.48 percent. The Test Year revenue requirement amounts are derived from the Test Year expenses being multiplied by the net lag days and dividing it by 366 to get a daily amount of cash working capital. The net lag days (16.4 days) represents the average number of days the Company must fund operation expenses before the Company receives the appropriate revenues for those expenses. Please see NW Natural/1212, Walker for a summary of the lead-lag study.

Q. Please describe the remaining components of rate base.

A. The following components complete the calculation of total rate base:

- **Customer Deposits –** This reduction to rate base represents amounts that customers are required to provide to comply with credit requirements under our tariff. The Test Year balance is forecasted by using the June 30, 2026 balance as a proxy.
- **Gas Inventory –** This component of rate base includes a 13-month AMA[17] of stored gas supplies and is composed of two elements. The first element, cushion gas, assumes a continuation of the June 30, 2026

[17] Average rate base balances were calculated by utilizing monthly forecast amounts to construct a 13-month AMA for all rate base components.

balance. The second element, working gas inventory, was derived by starting with June 2026 storage volume and price balances and then by modeling injections and withdrawals monthly through the end of the Test Year. Withdrawals reflect the PGA pattern of cycling the gas facilities. Injections of gas volumes were priced at a mix of forward prices and IHS Markit Ltd. forecasts in June 2026.

- **Leasehold Improvements –** Leasehold improvements, primarily from the Company's headquarters building at 250 Taylor, have been included in rate base based on a 13-month AMA of the Test Year. Amortization of these balances are included in O&M expense.
- **Materials and Supplies –** The Test Year is derived using trended amounts using actual balances since October 2021 through September 2026. A 13-month AMA of balances is used for the Test Year.
- **Deferred Income Taxes –** The Test Year amount of deferred income tax is produced by taking the balances for plant and other utility deferred taxes on December 31, 2025, and forecasted forward for incremental amounts. For plant, new capital expenditures were considered as well as previous basis amounts in generating book-tax differences and consequent tax effects. These deferred income taxes are inclusive of EDIT, taking into account the amount of amortization from January 1, 2026 through October 31, 2028. The deferred income taxes also are inclusive of RWIP forecasted through October 31, 2028. For the other

utility federal and state deferred taxes, projections were made for various sub-categories of utility operations.

- **Order No. 22-388 Rate Base Adjustment** – Consistent with Order No. 22-388 in docket UG 435 and the first multi-party stipulation, NW Natural is reducing rate base by $4.5 million amortized over 15 years starting November 1, 2022. This adjustment offsets utility plant in service.

VII. STATE ALLOCATION

Q. Please describe NW Natural's state allocation methodology.

A. NW Natural has used the same state allocation methodology since 2000, approved in the Company's filing under Tariff Advice 00-18. Revenues, costs, and rate base are directly assigned, if applicable, and if elements are allocated, several different allocation factors are available to apply as needed. These factors are typically based on customers, volumes, plant, or labor. The allocation factors used in this case are presented in NW Natural/1213, Walker.

Q. How did you allocate revenues to Oregon?

A. Gas Sales and Transportation Revenues and Miscellaneous Revenues attributed to Oregon customers are directly assigned to Oregon.

Q. How did you allocate the various categories of expense to Oregon?

A. Gas costs correspond precisely with gas costs collected in billing rates over the Test Year, based on forecasted therms sold. The gas costs are the same as the rates currently in effect at the time of filing this rate case. Gas costs, including demand and commodity components, are changed every year in the PGA filing.

Because those costs have been fully approved in the PGA filing process, gas costs have not been an issue in general rate cases.

The allocation of O&M expense is accomplished by allocating common costs, along with a direct assignment of non-common costs, to the appropriate jurisdiction. The common costs are considered with respect to specific drivers, such as volumes or customers, that have a causative effect on costs. The O&M costs in this rate case were allocated to the appropriate jurisdiction by applying this methodology to the trailing 12-months ended June 30, 2026. The resulting jurisdictional allocation by FERC account was then applied to the forecasted O&M expenses developed for this case. For more information on O&M development, please see the Direct Testimony of Tobin F. Davilla *(*NW Natural/1100, Davilla*)*.

Q. Please describe the jurisdictional allocation of Utility Plant in Service, Depreciation Expense, and Accumulated Depreciation.

A. Intangible software is allocated between Oregon and Washington on the basis of the “all customers” allocation factor; other intangible, production, non-storage related transmission, and distribution plant are directly assigned; storage plant including related transmission plant has been allocated to both Oregon and Washington on the basis of firm volume deliveries; compressed natural gas and liquefied natural gas refueling facilities and most general plant are allocated using the three-factor allocation factor; and land and structures are allocated on a mix of direct and other allocation factors.

Q. Please explain the method for allocating other rate base items.

A. The allocation of rate base items differs by category. For aid in advance of construction, the rate base amount was derived specifically for Oregon. Gas inventory, including both cushion and working gas, was forecasted on a system basis and allocated using the firm volumes allocation factor. The Materials and Supplies amount was allocated using the gross distribution plant factor. Finally, deferred income taxes were allocated using an accumulated book depreciation factor since much of the deferred income tax balance is related to depreciation book-tax timing differences.

VIII. AMORTIZATION OF THE COOS COUNTY DEFERRAL

Q. Has the Company filed a deferral application for O&M expense associated with the Coos County pipeline?

A. Yes. The Company filed a deferral application on December 19, 2025, which was docketed as UM 2419. The Commission approved deferred accounting on February 3, 2026 in Order No. 26-035.

Q. What is the Company's specific proposal in this proceeding regarding the Coos County deferral amortization?

A. The Company proposes that the Commission authorize amortization of the June 30, 2027 deferral balance to be amortized to all rate schedules impacted by this rate case over one year starting October 31, 2027 for residential customers and November 1, 2027 for non-residential customers, on an equal percent of margin basis, coincident with the Company's PGA filings and the proposed rate effective date of this case. Furthermore, due to the ongoing repairs of the Coos County

pipeline, the Company proposes that amortization of the deferral continue the cadence of taking the June 30 balance and amortize that balance over one year coincident with future PGA filings until the balance is zero.

Q. What is the estimated deferral balance as of June 30, 2027?

A. We do not have an estimate at this time, however, we have included $350 thousand within the proposed tariff to represent the ongoing O&M costs of operating the pipeline, net with the estimated revenues from Coos County customers.

Q. Has the Company proposed a tariff to amortize these costs?

A. Yes. The Company has proposed a tariff (Schedule 125) to incorporate an estimate of the deferred amounts as of June 30, 2027.[18] The tariff includes netting the revenues received from Schedule 160 within this deferral. The Company will update the tariff with known costs as of June 30, 2027 in the compliance filing of this case.

IX. REMOVAL OF THE TSA COST OF SERVICE DEFERRAL

Q. What is the TSA cost of service deferral?

A. The TSA cost-of-service deferral was established to track the incremental costs associated with the Company's compliance with the TSA's security directives. The associated cost-of-service schedule (Schedule 189) provides a mechanism to recover the authorized costs from customers outside of base rates and to reconcile collections with the underlying costs.

[18] See NW Natural/1216, Walker.

Q. Why is the Company proposing to remove the deferral?

A. The Company proposes to remove the deferral because the costs associated with complying with the TSA security directives are now sufficiently established and have been included in the Test Year revenue requirement for recovery through base rates. Continuing the separate deferral after those costs are reflected in base rates would be unnecessary. Removing the deferral therefore simplifies the Company's rates while ensuring that the ongoing costs are recovered only once.

Q. When will the Company terminate TSA deferments?

A. The Company will cease deferring TSA costs on the rate-effective date in this case. Amounts deferred before that date will be amortized coincident with the PGA, consistent with historical practice.

X. ROUTINE UPDATES FOR DECOUPLING AND WARM

Q. Please provide a brief description of Decoupling and WARM and why routine updates are being proposed.

A. Decoupling and WARM are rate mechanisms that decouple the Company's revenue from usage caused by weather and any other impact that would cause customers to use more or less volume of gas from the normalized level proposed in this case under the Direct Testimony of Robert J. Wyman (NW Natural/1300, Wyman). The routine updates are outputs of Mr. Wyman's models that align the underlying normalized usage that builds revenue requirement and the two rate mechanisms.

Q. What outputs from Mr. Wyman's models referenced above are used in the mechanisms?

A. Both the decoupling mechanism and WARM use the heating statistical coefficient and normalized heating degree days (HDD) that are established in Mr. Wyman's models. It is important that both rate mechanisms are aligned with the UPC model output that builds revenue requirement for the Test Year. This alignment will ensure that the mechanisms will normalize customer usage back to the rate case UPCs derived in Mr. Wyman's model. The UPCs and statistical coefficients are shown in NW Natural/1214, Walker.

XI. BRIDGE MECHANISM FOR YEAR TWO RATES

Q. What is a bridge mechanism?

A. A bridge mechanism is a defined rate increase that takes effect one year after the rates approved in this case. It bridges the Company's cost recovery until the multi-year rate plan required by section 7 of House Bill ("HB") 3179, the Fair Act of 2025, begins.

Q. When does the Company plan to file its first multi-year rate plan ("MRP")?

A. Pursuant to OAR 860-022-081(3)(c), NW Natural will file its first MRP in the Fall of 2028, with residential rates effective prior to November 1, 2029.

Q. How is the bridge mechanism calculated?

A. The bridge mechanism increase equals the revenue requirement difference between the Test Year's 13-month average of monthly average plant in service and end-of-period plant in service as of October 31, 2028. This includes annualizing depreciation expense and uses end of period accumulated

depreciation as of October 31, 2028. See Confidential NW Natural/1215, Walker for the detailed calculation.

Q. What is the projected impact of the bridge mechanism?

A. The bridge mechanism will increase the Company's annual revenues by $11.6 million, or 1.2 percent. The corresponding increase for residential customers will be 1.0 percent.

Q. Will the bridge mechanism recover the cost of any investments that are not included in this proceeding?

A. No. The bridge mechanism will only recover the costs of investments that are included in this proceeding, and that enter service prior to the end of the Test Year. The bridge mechanism will not recover any increase to O&M expense, which is the Company's largest cost category that is recovered through a general rate case.[19]

Q. NW Natural's bridge mechanism would increase rates beyond the Test Year. Is NW Natural's bridge mechanism a multi-year rate plan?

A. No. As explained above, NW Natural is not seeking to include any additional capital projects or increased O&M expense in rates through the bridge mechanism. Instead, the bridge mechanism is very limited in scope. It is designed to accurately reflect the utility plant in service that has already been found to be prudent in this proceeding as of October 31, 2027. Therefore, using end-of-period rate base is

[19] The Company's largest overall cost category is the purchase of natural gas, which is recovered through the PGA.

appropriate because it reflects the utility plant in service that is providing safe and reliable service to customers.

Q. Does the bridge mechanism appropriately balance the customers' and the Company's interests?

A. Yes. The bridge mechanism is limited in scope and works in both directions. It updates accumulated depreciation, and moves it from the Test Year AMA to end-of-period utility plant in service, which reduces rate base. It also updates gross plant to end-of-period utility plant in service and annualizes the October 2028 depreciation expense. It does not include capital projects beyond those in this case or any increase to O&M or other expenses, despite continued inflationary pressure, so the Company remains subject to regulatory lag for projects that enter service after the Test Year. The bridge mechanism also limits rate volatility by smoothing the increase into the first MRP and avoiding additional cost recovery proceedings, while limiting the increase to 1.1 percent, which is below the forecasted rate of inflation.

Q. Why does NW Natural believe this is a fair, just, and reasonable proposal that is within the public interest?

A. NW Natural believes the proposed bridge mechanism is fair, just, and reasonable and in the public interest because it provides a limited and transparent means of aligning rates with the plant that will be serving customers at the end of the Test Year, while bridging the one-year period between the rate effective date in this case and the Company's first MRP. This approach supports timely recovery of investments made to provide safe and reliable service, reduces the regulatory

burden and expense that could otherwise result from an additional general rate case before the MRP begins, and provides customers and the Commission advance notice of the timing and basis of the year-two rate change.

XII. TEMPORARY RATE INCLUSION INTO BASE RATES

Q. What is the purpose of this section of your testimony, and what does the Company recommend?

A. This section responds to the MRP framework that Staff is developing in docket AR 676, the rulemaking implementing HB 3179. Staff's concepts in AR 676 include costs in the MRP on a comprehensive basis. That could result in amounts now recovered through separate temporary rates being incorporated into base rates. I describe temporary rates and the advantages and disadvantages of including them in base rates. For the reasons below, I do not recommend including temporary rates in base rates in this case. The Company recommends that they remain separate from base rates.

Q. What are temporary rates?

A. Temporary rates are charges or credits approved for a defined purpose and period. They commonly recover the costs of customer programs and other mechanisms that the Commission has approved for full cost recovery. Temporary rates are collected or returned amounts through a separate tariff schedule and are expected to end, change, or be reviewed when the applicable authorization expires or the underlying balance has been recovered or refunded, generally within one year.

Q. Why are temporary rates generally maintained separately from base rates?

A. Separate presentation identifies the amount attributable to each temporary mechanism and distinguishes it from the ongoing revenue requirement recovered through base rates. This treatment makes the purpose, authorized period, and eventual termination or revision of the temporary rate easier to administer and review.

Q. What are the potential advantages of including temporary rates in base rates?

A. Including temporary rates in base rates could simplify the tariff by reducing the number of separately identified adjustments. It may also reduce administrative work associated with maintaining multiple schedules and make the total rate appear more stable between rate proceedings.

Q. What are the disadvantages of including temporary rates in base rates?

A. Incorporating temporary rates into base rates would reduce transparency by combining time-limited amounts with revenues intended to recover ongoing costs. It could also make it more difficult to track collections against the authorized balance, determine when recovery or refund is complete, and remove or revise the amount at the appropriate time. In addition, temporary rates recover customer programs and mechanisms that the Commission has approved for full cost recovery. If those amounts were incorporated into base rates without a corresponding rate-design analysis, the Company's recovery could be limited. For example, a temporary cost currently recovered through a variable, usage-based rate could instead be embedded in the monthly fixed charge, or otherwise allocated

differently through base-rate design. Conversely, if the amount remained in a variable rate, actual collections could be higher or lower than the approved cost as customer usage varies. Unless a temporary cost has become a permanent, recurring component of the revenue requirement and is incorporated through an appropriate rate-design process, including it in base rates may create a mismatch between authorized costs and actual collections in the period in which the amount is collected and the period in which the related cost or credit applies, increasing the risk of over- or under-recovery.

Q. How does maintaining temporary rates outside base rates benefit customers?

A. Separate treatment allows customers and the Commission to see the amount collected or credited for each authorized purpose. It also preserves a clear process for reconciling actual results, adjusting the rate when necessary, and ending the charge or credit when its purpose has been fulfilled.

Q. What does the Company recommend?

A. The Company recommends continuing to maintain temporary rates outside base rates. Although incorporating them into base rates could simplify tariff presentation, the benefits of separate treatment are more important. Keeping temporary rates separate preserves transparency, supports accurate tracking and reconciliation, and facilitates timely modification or removal without obscuring the level of ongoing revenue requirement reflected in base rates. If a cost later becomes permanent and recurring, the Company can evaluate whether inclusion in base rates is appropriate in a future rate proceeding.

XIII. COMPANY TARIFFS

Q. Please describe the proposed Tariff changes that relate to the proposals in this case.

A. The Company is proposing Tariff changes in this case that affect the following sections of its Tariff: Index, General Schedules, Adjustment Schedules, and Rate Schedules. NW Natural/1216, Walker includes the proposed Tariff changes.

Q. Which Index tariff sheet does the Company propose to update in this case?

A. The Company proposes to update the service territory map on Original Sheet ii to reflect its current facilities. While preparing this case, the Company identified that the map was outdated. Over the past eight years, the Company has updated several service centers to improve employee safety and operational efficiency, including relocating some to adjacent cities.

Q. Which General Schedules are affected by the proposals in this case?

A. General Schedule H, related to compressed natural gas service, is being updated for the cost of capital inputs and is discussed in Robert J. Wyman's Direct Testimony (NW Natural/1300, Wyman).

Q. Which Adjustment Schedules are affected by the proposals in this case?

A. Schedule 167 shows the base rate changes proposed in this case. Schedules 122, 124, 175, 182, 196 and 197 are changing due solely to the billing determinants in this case. Schedules 190 and 195 update the routine inputs needed for the Decoupling and WARM mechanisms, respectively. Schedule 125 is being proposed to amortize the Coos County O&M deferral. The amount, $350 thousand, included in the tariff is an estimate of ongoing O&M, netted with Coos

County revenues received. Schedule 123 is being updated for the one-time bridge mechanism adjustment which will take effect on October 31, 2028 for residential customers and November 1, 2028 for non-residential customers.

Q. Which Rate Schedules are affected by the proposals in this case?

A. The following Rate Schedules are affected by the proposals in the case:

Schedule 2	Schedule 27
Schedule 3	Schedule 31
Schedule 4	Schedule 32
Schedule 15	Schedule 33

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibits of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS / RATE MECHANISMS
EXHIBITS 1201-1216

November 24, 2026

EXHIBITS 1201-1216 – TEST YEAR / REVENUE REQUIREMENTS / TARIFFS / RATE MECHANISMS

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS / RATE MECHANISMS
EXHIBIT 1201

November 24, 2026

NW Natural
UG 532 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2028
Base Year Twelve Months Ended June 30, 2026
Increase in Revenue Requirement
($000)

Line No.		Base Year at Present Rates (a)	Adjustments to Base Year (b)	Test Year at Present Rates (c)	Proposed Increase (d)	Proposed Total (e)
	Operating Revenues					
1	**Sale of Gas**	$857,704	$114,148	$971,853	$90,061	$1,061,914
2	**Transportation**	17,279	(4)	17,275	0	17,275
3	**Decoupling**	48,721	(48,721)	0	0	0
4	**WARM**	14,952	(14,952)	0	0	0
5	**Miscellaneous Revenues**	4,785	(198)	4,588	0	4,588
6	**Total Operating Revenues**	943,442	50,274	993,715	90,061	$1,083,776
	Operating Revenue Deductions					
7	**Gas Purchased**	329,013	19,879	348,893	0	348,893
8	**Uncollectible Accrual for Gas Sales**	2,270	337	2,607	237	2,844
9	**Other Operating & Maintenance Expenses**	222,209	26,777	248,986	0	248,986
10	**Total Operating & Maintenance Expense**	553,493	46,993	600,486	237	600,723
11	**Federal Income Tax**	21,586	(10,301)	11,286	16,878	28,164
12	**State Excise**	14,038	(3,624)	10,414	7,014	17,427
13	**Property Taxes**	34,339	7,197	41,536	0	41,536
14	**Other Taxes**	32,104	3,883	35,987	2,439	38,426
15	**Depreciation & Amortization**	146,241	27,288	173,529	0	173,529
16	**Total Operating Revenue Deductions**	801,801	71,437	873,237	26,568	899,805
17	**Net Operating Revenues**	$141,641	($21,163)	$120,478	$63,493	$183,972
	Average Rate Base					
18	**Utility Plant in Service**	4,207,418	598,900	4,806,318	0	4,806,318
19	**Accumulated Depreciation**	(1,593,249)	(262,964)	(1,856,213)	0	(1,856,213)
20	**Net Utility Plant**	2,614,169	335,936	2,950,105	0	2,950,105
21	**Aid in Advance of Construction**	(13,457)	(8,816)	(22,274)	0	(22,274)
22	**Customer Deposits**	(1,511)	(158)	(1,669)	0	(1,669)
23	**Gas Inventory**	47,711	(12,421)	35,290	0	35,290
24	**Leasehold Improvements**	17,852	(2,844)	15,008	0	15,008
25	**Materials & Supplies**	17,242	589	17,831	0	17,831
26	**Accumulated Deferred Income Taxes**	(508,266)	(24,373)	(532,639)	0	(532,639)
27	**Cash Working Capital**	28,599	4,619	33,217	0	33,217
28	**Total Rate Base**	$2,202,338	$292,530	$2,494,868	$0	$2,494,868
29	**Rate of Return**	6.431%		4.829%		7.374%
30	**Return on Common Equity**	8.18%		4.66%		9.75%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS / RATE MECHANISMS
EXHIBIT 1202

November 24, 2026

NW Natural
UG 532 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2028
Base Year Twelve Months Ended June 30, 2026
Comparison of Test Year to Prior Rate Case
($000)

Line No.		UG 520 Order 25-420 [1] (a)	Current Test Year at Present Rates (b)	Change from Last GRC (c)
	Operating Revenues (net of Cost of Gas)			
1	**Sale of Gas (net of Cost of Gas)**	$629,724	$622,960	($6,764)
2	**Transportation**	17,144	17,275	131
3	**Decoupling**	0	0	0
4	**WARM**	0	0	0
5	**Miscellaneous Revenues**	3,913	4,588	675
6	**Total Operating Revenues**	650,781	644,823	(5,958)
	Operating Revenue Deductions			
7	**Uncollectible Accrual for Gas Sales**	1,947	2,607	660
8	**Other Operating & Maintenance Expenses**	217,992	248,986	30,994
9	**Total Operating & Maintenance Expense**	219,939	251,593	31,654
10	**Federal Income Tax**	25,829	11,286	(14,544)
11	**State Excise**	16,283	10,414	(5,870)
12	**Property Taxes**	34,050	41,536	7,487
13	**Other Taxes**	38,622	35,987	(2,635)
14	**Depreciation & Amortization**	154,461	173,529	19,068
15	**Total Operating Revenue Deductions**	489,185	524,345	35,160
16	**Net Operating Revenues**	$161,596	$120,478	($41,118)
	Average Rate Base			
17	**Utility Plant in Service**	4,334,593	4,806,318	471,725
18	**Accumulated Depreciation**	(1,701,104)	(1,856,213)	(155,109)
19	**Net Utility Plant**	2,633,488	2,950,105	316,616
20	**Aid in Advance of Construction**	(8,414)	(22,274)	(13,860)
21	**Customer Deposits**	(739)	(1,669)	(930)
22	**Gas Inventory**	48,809	35,290	(13,519)
23	**Leasehold Improvements**	17,273	15,008	(2,266)
24	**Materials & Supplies**	22,697	17,831	(4,866)
25	**Accumulated Deferred Income Taxes**	(472,350)	(532,639)	(60,288)
26	**Cash Working Capital**	28,847	33,217	4,370
27	**Total Rate Base**	$2,269,612	$2,494,868	$225,256

[1] Order No. 25-420 approved a black box settlement. This column is for presentation purposes only and does not tie to any settlement or Commission Order.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS / RATE MECHANISMS
EXHIBIT 1203

November 24, 2026

NW Natural
UG 532 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2028
Base Year Twelve Months Ended June 30, 2026
Derivation of Forecasted Test Period Revenue

		BASE YEAR			TEST YEAR		
		Actual Therms Sales	Average Class Price Per Therm	Revenues and Margin at present rates	Normalized Therms Sales	Average Class Price Per Therm	Normalized Revenues and Margin
		(a)	(b)	(c)	(d)	(e)	(f)
Revenues							
	Sales Volumes and Revenues						
1	**Residential**	338,875,464	1.59094	$539,129,716	404,385,269	1.53003	$618,720,183
2	**Commercial**	219,271,395	1.20113	$263,372,702	262,627,073	1.14982	$301,973,775
3	**Industrial Firm**	37,670,429	0.77264	$29,105,765	38,449,417	0.72084	$27,715,786
4	**Interruptible**	48,173,619	0.54171	$26,096,273	49,505,472	0.47354	$23,442,926
5	**Total Sales of Gas Revenues**	643,990,908		$857,704,456	754,967,231		$971,852,670
	Transportation Volumes and Revenues						
6	**Firm**	93,916,306	0.10297	$9,670,190	94,713,032	0.10100	$9,566,362
7	**Interruptible**	160,833,205	0.03647	$5,866,188	167,565,795	0.03607	$6,044,260
8	**Special Contracts - Firm**	57,819,301	0.02510	$1,451,084	60,372,201	0.02314	$1,397,220
9	**Special Contracts - Interruptible**	12,593,196	0.02317	$291,832	13,724,206	0.01947	$267,171
10	**Total Transportation**	325,162,008		$17,279,295	336,375,234		$17,275,012
11	**Total Deliveries and Revenues**	969,152,916		$874,983,751	1,091,342,465		$989,127,682
12	**Decoupling Base Period**			$48,720,751			
13	**WARM Base Period**			$14,951,594			
14	**Total Revenue**			$938,656,096			$989,127,682
Gas Costs							
15	**Demand Charges**			$57,710,871			$79,301,317
16	**Commodity Charges**			271,302,539			269,591,256
17	**Total Cost of Gas**			$329,013,410			$348,892,573
18	**Total Margin**			$609,642,686			$640,235,109

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS / RATE MECHANISMS
EXHIBIT 1204

November 24, 2026

NW Natural
UG 532 - Oregon Jurisdictional Rate Case
Miscellaneous Revenues Detail
Twelve Months Ended September 2024, 2025 & 2026

Line No.		12 Months Ended June 2024 (a)	12 Months Ended June 2025 (b)	12 Months Ended June 2026 (c)	Test Year (d)		Test Year Method
1	FORFEITED DISCOUNTS-LATE PAYMENT CHARGE	2,761,292	2,643,740	2,607,271	2,607,271	-	trend down - take last year
2	MISC SERVICE REV-FIELD COLLECTION C	169,795	252,150	389,355	389,355	-	trend up - take last year
3	MISC SERVICE REV-GAS DIVERSIONS	64,377	45,528	49,072	52,992	-	no trend - 3 year average
4	MISC SERVICE REV-RECON CHG-CR-DURI	75,159	79,955	106,575	106,575	-	trend up - take last year
5	MISC SERVICE REV-RECON CHG-SEAS-DU	4,280	4,720	4,380	4,460	-	no trend - 3 year average
6	MISC SERVICE REV-DELINQ RECONN FEE	168,450	288,730	387,650	387,650	-	trend up - take last year
7	MISC SERVICE REV - SEAS RECONN FEE	5,400	5,650	13,200	13,200	-	trend up - take last year
8	MISC SERVICE REV-RETURNED CHECK CHA	505,497	548,129	547,175	533,600	-	no trend - 3 year average
9	MISC SERVICE REV-SUMMARY BILL SVCS	11,734	10,457	9,333	9,333	-	trend down - take last year
10	OTHER GAS REV-METER RENTALS	178,420	186,685	172,401	179,169	-	no trend - 3 year average
11	OTHER GAS REV-CNG METER RENTALS	834	837	842	-	-	Exclude Schedule H Activity
12	OTHER GAS REV-LNG SALES & OTHER MISC REV	104,162	215,867	99,023	139,684	-	no trend - 3 year average
13	OTHER GAS REV-NON AMR READ CHARGE	8,762	9,452	10,806	10,806	-	trend up - take last year
14	MISC SERVICE REV - NON-AMR INSTALL/REMOVE CHRG	860	860	1,376	1,376	-	trend up - take last year
15	OTHER GAS REV-MULTIPLE CALL OUT FEE	28,492	22,234	18,128	18,128	-	trend down - take last year
16	RENT FROM GAS PROP-SCHEUDLE H CNG REV	261,149	244,852	228,399	-	-	Exclude Schedule H Activity
17	RENT FROM GAS PROP-UTILITY PROP	81,847	84,667	74,996	80,503	-	no trend - 3 year average
18	MISC SERVICE REV-SCHEDULE CNG MAIN	20,742	32,432	53,569	53,569	-	trend up - take last year
20	MISC SERVICE REV - UNSCHEDLD CNG MAIN REV	7,008	9,464	11,909	-	-	Exclude Schedule H Activity
	Total Miscellaneous Revenues	**4,458,261**	**4,686,408**	**4,785,458**	**4,587,671**		

Note: Excludes Billing Amortization Offsets, WARM deferrals, Washington Misc Revenues

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS / RATE MECHANISMS
EXHIBIT 1205

November 24, 2026

NW Natural
UG 532 - Oregon Jurisdictional Rate Case
Uncollectible Accounts Adjustments
Twelve Months Ended December 2023
($000)

Line No.		2023 Total
		(a)
	Gas Revenues	
1	**Residential**	680,109
2	**Commercial**	322,257
3	**Industrial**	36,939
4	**Interruptible**	39,497
5	**Total**	1,078,802
	Net Write-Offs	
6	**Residential**	2,501
7	**Commercial**	353
8	**Industrial**	1
9	**Interruptible**	-
10	**Total**	2,855
	Write-Off % - 3-Year Average	
11	**Residential**	0.368%
12	**Commercial**	0.110%
13	**Industrial**	0.004%
14	**Interruptible**	0.000%
15	**Weighted Total**	0.265%
	Oregon Normalized Revenues (Test Year)	
16	**Residential**	618,720
17	**Commercial**	301,974
18	**Industrial**	27,716
19	**Interruptible**	23,443
20	**Total**	971,853
	Normalized Uncollectible	
21	**Residential**	$2,275
22	**Commercial**	331
23	**Industrial**	1
24	**Interruptible**	0
25	**Total Normalized Uncollectible**	$2,607
26	**In Base O&M**	$0
27	**Adjustment (Test Year)**	$2,607
28	**Uncollectible rate for normalizaing adjustments**	0.265%
29	**Uncollectible expense in Base Year (estimated)**	$2,270

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS / RATE MECHANISMS
EXHIBIT 1206

November 24, 2026

NW Natural
UG 532 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2028
Base Year Twelve Months Ended June 30, 2026
Operations and Maintenance Expense

Line No.	FERC Acct.	Description	BASE YEAR System	BASE YEAR Oregon
			(a)	(b)
1		Natural Gas Storage		
2		Underground Storage Expense		
3		Operation		
4	816	Wells Expense	$386,433	$343,384
5	818	Compressor Station Expense	264,513	235,046
6	819	Compressor Station Fuel	0	0
7	820	Measuring and Regulator Station Expense	3,643,609	3,238,870
8	821	Purification Expense	-	-
9		Maintenance		
	831	Maintenance of Structures and Improvements	8,759	7,687
10	832	Wells Expense	2,489,236	2,211,935
11	834	Compressor Expense	312,378	277,580
		Total Underground Storage Expense	7,104,928	6,314,502
12		Other Storage Expense		
13		Operation		
14	840	Supervision and Engineering	17,588	15,629
15		Total Other Storage Expense	17,588	15,629
16		Liquified Natural Gas Expense		
17		Operation		
18	844	Supervision and Engineering	2,157,316	1,916,991
19	845	LNG Fuel	(36,479)	(32,415)
20		Maintenance		
21	847	Supervision and Engineering	1,697,380	1,508,292
22		Total Liquified Natural Gas Expense	3,818,217	3,392,868
23		Total Natural Gas Storage	10,940,733	9,722,999
24		Transmission Expense		
25		Operation		
26	856	Mains Expense	4,313,274	4,258,557
27		Maintenance		
28	863	Maintenance of Mains	-	-
29		Total Transmission Expense	4,313,274	4,258,557
30		Distribution Expense		
31		Operation		
32	870	Supervision and Engineering	3,963,129	3,651,890
33	874	Mains and Services Expense	24,634,507	21,787,334
34	875	Measuring and Regulator Station Expense - General	546,721	499,275
35	877	Measuring and Regulator Station Expense - City Gate	711,532	645,361
36	878	Meter and House Regulator Expense	7,939,826	6,967,991
37	879	Customer Installation Expense	13,048,701	11,453,138
38	880	Other Expense	3,261,868	2,944,681
39	881	Rents	367,415	315,327

NW Natural
UG 532 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2028
Base Year Twelve Months Ended June 30, 2026
Operations and Maintenance Expense

Line No.	FERC Acct.	Description	BASE YEAR System	BASE YEAR Oregon
			(a)	(b)
40		Maintenance		
41	885	Supervision and Engineering	6,895,730	6,273,259
42	887	Mains	3,781,045	3,457,596
43	889	Measuring and Regulator Station Expense - General	2,594,199	2,359,596
44	891	Measuring and Regulator Station Expense - City Gate	83,727	76,692
45	892	Services	672,968	590,597
46	893	Meters and House Regulators	4,304,243	3,783,821
47	894	Other Equipment	1,913	1,679
48		Total Distribution Expense	72,807,523	64,808,237
49		Customer Accounts Expense		
50		Operation		
51	901	Supervision	2,180,557	1,913,657
52	902	Meter Reading Expenses	864,744	758,900
53	903	Customer Records and Collection Expense	24,557,109	21,579,043
54	904	Uncollectible Accounts (per adjustment calculation)	-	-
55		Total Customer Accounts Expense	27,602,411	24,251,599
56		Customer Service and Informational		
57		Operation		
58	906	Customer Service and Informational Expense	1,464,171	1,284,956
59	907	Supervision	-	-
60	908	Customer Assistance Expense	2,186,426	1,915,504
61	909	Customer Information Expense	2,207,513	1,937,313
62	910	Miscellaneous Customer Service Expense	201,192	176,264
63		Total Customer Service and Informational	6,059,301	5,314,037
64		Sales Expense		
65		Operation		
66	911	Supervision	226,658	198,915
67	912	Demonstration and Selling Expense	1,624,611	1,425,677
68	913	Advertising	-	-
69	916	Miscellaneous Sales Expense	-	-
70		Total Sales Expense	1,851,269	1,624,592
71		Administrative and General Expense		
72		Operation		
	920	Administration and General Salaries	55,654,382	48,554,581
73	921	Office Salaries and Expense	48,427,193	42,431,860
74	922	Administrative Expenses Transferred - Credit	(36,781,372)	(32,339,790)
75	924	Property Insurance Premium	7,554,543	6,655,552
76	925	Injuries and Damages	120,673	106,313
77	926	Employee Pensions and Benefits	20,760,972	19,229,755
78	928	Regulatory Commission Expense	-	-
79	930	Miscellaneous General Expense	7,134,235	6,383,149
80	931	Rents	10,775,692	9,493,889
81		Maintenance		
82	932	Maintenance of General Plant	7,610,556	6,713,688
83		Total Administrative and General Expense	121,256,874	107,228,998
84		Total O&M Expense	244,831,385	217,209,019
85	407	Environmental Rider	5,000,000	5,000,000
86		Total O&M Expense including Environmental Rider	249,831,385	222,209,019

NW Natural
UG 532 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2028
Base Year Twelve Months Ended June 30, 2026
Operations and Maintenance Expense

Line No.	FERC Acct.	Description	TEST YEAR System	TEST YEAR Oregon
			(a)	(b)
1		**Natural Gas Storage**		
2		**Underground Storage Expense**		
3		**Operation**		
4	816	**Wells Expense**	$408,101	$362,638
5	818	**Compressor Station Expense**	279,538	248,397
6	819	**Compressor Station Fuel**	0	0
7	820	**Measuring and Regulator Station Expense**	4,222,436	3,753,243
8	821	**Purification Expense**	-	-
9		**Maintenance**		
	831	**Maintenance of Structures and Improvements**	10,536	9,247
10	832	**Wells Expense**	2,839,513	2,523,191
11	834	**Compressor Expense**	333,751	296,571
		Total Underground Storage Expense	8,093,875	7,193,288
12		**Other Storage Expense**		
13		**Operation**		
14	840	**Supervision and Engineering**	19,477	17,307
15		**Total Other Storage Expense**	19,477	17,307
16		**Liquified Natural Gas Expense**		
17		**Operation**		
18	844	**Supervision and Engineering**	2,511,921	2,232,093
19	845	**LNG Fuel**	(38,503)	(34,214)
20		**Maintenance**		
21	847	**Supervision and Engineering**	1,963,009	1,744,330
22		**Total Liquified Natural Gas Expense**	4,436,426	3,942,209
23		**Total Natural Gas Storage**	12,549,779	11,152,804
24		**Transmission Expense**		
25		**Operation**		
26	856	**Mains Expense**	5,935,319	5,860,026
27		**Maintenance**		
28	863	**Maintenance of Mains**	-	-
29		**Total Transmission Expense**	5,935,319	5,860,026
30		**Distribution Expense**		
31		**Operation**		
32	870	**Supervision and Engineering**	4,928,343	4,527,351
33	874	**Mains and Services Expense**	24,875,623	22,000,586
34	875	**Measuring and Regulator Station Expense - General**	688,061	626,343
35	877	**Measuring and Regulator Station Expense - City Gate**	831,383	752,051
36	878	**Meter and House Regulator Expense**	9,423,107	8,269,719
37	879	**Customer Installation Expense**	15,417,714	13,532,474
38	880	**Other Expense**	4,019,347	3,628,504
39	881	**Rents**	389,323	334,129

NW Natural
UG 532 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2028
Base Year Twelve Months Ended June 30, 2026
Operations and Maintenance Expense

Line No.	FERC Acct.	Description	TEST YEAR System	TEST YEAR Oregon
			(a)	(b)
40		Maintenance		
41	885	Supervision and Engineering	8,507,135	7,739,152
42	887	Mains	4,497,400	4,112,670
43	889	Measuring and Regulator Station Expense - General	3,126,973	2,836,185
44	891	Measuring and Regulator Station Expense - City Gate	95,920	87,566
45	892	Services	772,979	678,367
46	893	Meters and House Regulators	5,121,649	4,502,396
47	894	Other Equipment	2,294	2,014
48		Total Distribution Expense	82,697,252	73,629,507
49		Customer Accounts Expense		
50		Operation		
51	901	Supervision	2,613,937	2,293,991
52	902	Meter Reading Expenses	1,033,017	906,576
53	903	Customer Records and Collection Expense	28,748,367	25,262,022
54	904	Uncollectible Accounts (calculated separately)	-	-
55		Total Customer Accounts Expense	32,395,322	28,462,590
56		Customer Service and Informational		
57		Operation		
58	906	Customer Service and Informational Expense	1,743,987	1,530,523
59	907	Supervision	-	-
60	908	Customer Assistance Expense	2,668,200	2,337,589
61	909	Customer Information Expense	3,280,317	2,878,806
62	910	Miscellaneous Customer Service Expense	241,661	211,719
63		Total Customer Service and Informational	7,934,165	6,958,637
64		Sales Expense		
65		Operation		
66	911	Supervision	272,151	238,839
67	912	Demonstration and Selling Expense	1,858,207	1,630,669
68	913	Advertising	-	-
69	916	Miscellaneous Sales Expense	-	-
70		Total Sales Expense	2,130,357	1,869,508
71		Administrative and General Expense		
72		Operation		
73	921	Office Salaries and Expense	61,146,724	53,346,267
74	922	Administrative Expenses Transferred - Credit	53,731,372	46,969,621
75	924	Property Insurance Premium	(39,909,951)	(35,090,573)
76	925	Injuries and Damages	11,391,695	10,036,083
77	926	Employee Pensions and Benefits	90,647	79,860
78	928	Regulatory Commission Expense	17,804,357	17,017,152
79	930	Miscellaneous General Expense	-	-
80	931	Rents	6,812,791	6,198,297
			11,329,704	9,982,000
81		Maintenance		
82	932	Maintenance of General Plant	8,519,372	7,514,362
83		Total Administrative and General Expense	130,916,710	116,053,068
84		Total O&M Expense	274,558,903	243,986,140
85	407	Environmental Rider	5,000,000	5,000,000
86		Total O&M Expense including Environmental Rider	279,558,903	248,986,140

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS / RATE MECHANISMS
EXHIBIT 1207

November 24, 2026

NW Natural
UG 532 - Oregon Jurisdictional Rate Case
Tax Provision
Test Year Twelve Months Ended October 31, 2028
Base Year Twelve Months Ended June 30, 2026
($000)

Line No.		BASE YEAR State Taxes (a)	BASE YEAR Federal Taxes (b)	TEST YEAR State Taxes (c)	TEST YEAR Federal Taxes (d)
1	**Operating Revenues**	$943,442	$943,442	$993,715	$993,715
2	**Operating Revenue Deductions**	553,493	553,493	600,486	600,486
3	**Property & Other Taxes**	66,443	66,443	77,523	77,523
4	**Book Depreciation**	146,241	146,241	173,529	173,529
5	**Interest (Rate Base * Cost of Debt)**	51,623	51,623	62,347	62,347
6	**Remove Equity Flotation**				
7	**State Tax Deduction**	4,282	14,038	4,527	10,414
8	**Subtotal**	121,360	111,604	75,304	69,417
9	**Permanent Differences 1/**	7,001	7,001	2,156	2,156
10	**Taxable Income**	128,361	118,605	77,460	71,573
11	**Tax Rate**	7.60%	21.00%	7.600%	21.000%
12	**Tax Before Credits**	9,755	24,907	5,887	15,030
13	**CAT Exp., Tax Credits, & EDIT Amortization 2/**	4,282	(3,321)	4,527	(3,745)
14	**Total Tax**	$14,038	$21,586	$10,414	$11,286

1/ Permanent tax items allocated using accumulated depreciation factor
2/ Oregon CAT expense, Oregon excess deferred income taxes (EDIT) amortization and Oregon allocated research credit

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS / RATE MECHANISMS
EXHIBIT 1208

November 24, 2026

NW Natural
UG 532 - Oregon Jurisdictional Rate Case
Base Year and Test Year Cost of Capital and Revenue Sensitive Costs

		BASE YEAR			TEST YEAR		
	Weighted Average Cost of Capital	**% of Total Capital**	**Average Cost**	**Weighted Cost**	**% of Total Capital**	**Average Cost**	**Weighted Cost**
1	**Long Term Debt**	50.0%	4.687%	2.344%	50.0%	4.997%	2.499%
2	**Common Stock**	50.0%	9.467%	4.733%	50.0%	9.750%	4.875%
3	**Total**	100.0%		7.077%	100.0%		7.374%
	Revenue Sensitive Costs						
4	**Gas Sales**		90.91%			97.80%	
5	**Transportation**		1.83%			1.74%	
6	**Other**		7.26%			0.46%	
7	**Subtotal**		100.00%			100.00%	
8	**O & M - Uncollectible**		0.26%			0.26%	
9	**Franchise Taxes**		2.35%			2.35%	
10	**OPUC Fee**		0.405%			0.360%	
11	**State Taxable Income**		96.98%			97.03%	
12	**State Income Tax**		7.37%			7.37%	
13	**Federal Taxable Income**		89.61%			89.65%	
14	**Federal Income Tax**		18.82%			18.83%	
15	**Utility Operating Income**		70.79%			70.83%	
16	**Total Revenue Sensitive Costs**		29.21%			29.17%	
17	**Net-to-gross factor**		141.26%			141.19%	
18	**Rate of Return on Equity**		9.47%			9.75%	
19	**Federal Tax Rate**		21.00%			21.00%	
20	**State Tax Rate**		7.60%			7.60%	
21	**Combined Tax Rate (Test Year)**		27.00%			27.00%	
22	**Franchise Fees**		2.348%			2.348%	
23	**Uncollectible Accounts**		0.265%			0.265%	
24	**Regulatory Fees**		0.405%			0.360%	
25	**Interest Coordination Factor**		2.344%			2.499%	

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS / RATE MECHANISMS
EXHIBIT 1209

November 24, 2026

NW Natural
UG 532 - Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2028
Base Year Twelve Months Ended June 30, 2026
Forecast of Other Taxes

Line No.		Actual 2026 (b)	Forecast 2027 (c)	Forecast 2028 (d)		Base Year Normalized (g)
	Property Taxes					
1	Prior Year Assessed Value		$3,150,000,000	$3,365,330,634		**34,338,956**
2	Add: Additions		$384,217,634	$358,167,728		
3	Less: Depreciation		($168,887,000)	($181,833,000)		
6	Estimated Value/1	$3,150,000,000	$3,365,330,634	$3,541,665,363		
7	Oregon Allocation/2	91.58%	91.58%	91.58%		
		$2,884,636,358	$3,081,827,017	$3,243,306,880		
8	Tax Rate/3	1.479%	1.479%	1.479%		
9	Estimated Tax/4	$42,671,695	$45,588,686	$47,977,417		
10	Less:					
11	North Mist	($2,218,063)	($2,300,000)	($2,381,937)		
12	Interstate Storage	($840,000)	($900,000)	($960,000)		
13	Other	($127,278)	($135,000)	($142,722)		
14	Total Before Capitalization	$39,486,353	$42,253,686	$44,492,758		
15	Less: Capital Portion	($2,400,000)	($2,500,000)	($2,600,000)		
16	Total Property Tax for Ratemaking	$37,086,353	$39,753,686	$41,892,758		
17	2027 Payment Forecast x 2/12				$6,625,614	
18	2028 Payment Forecast x 10/12				$34,910,632	
19	Test Period Expense				**$41,536,246**	

/1 Actual assessed system wide assessed value for 2026 by Oregon Department of Revenue
/2 Actual Oregon allocation in 2026 by Oregon Department of Revenue
/3 Tax Rate determined from actual 2026 taxes paid relative to Oregon value
/4 Actual Oregon tax paid in 2026

20	**Other Taxes**		
21	Franchise	$23,185,457	$20,526,855
22	Payroll	$8,046,323	$6,910,524
23	Regulatory Fee	$3,577,375	$3,563,065
24	Department of Energy	$984,311	$871,443
25	Other	$193,347	$232,232
26	Other Taxes Excluding Property Taxes	**$35,986,813**	**$32,104,120**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS / RATE MECHANISMS
EXHIBIT 1210

November 24, 2026

NW Natural
UG 532 - Oregon Jurisdictional Rate Case
Rate Base & Depreciation Expense - Oregon and System
Test Year Twelve Months Ended October 31, 2028
Base Year Twelve Months Ended June 30, 2026
($000)

Line No.	Rate Base	Test Year Oregon (a)	Test Year System (b)	Base Year Oregon (c)	Base Year System (d)
1	Utility Plant in Service	4,806,318	5,455,700	4,207,418	4,781,207
2	Accumulated Depreciation	(1,856,213)	(2,089,496)	(1,593,249)	(1,822,567)
3	Net Utility Plant	2,950,105	3,366,203	2,614,169	2,958,640
4	Aid in Advance of Construction [1]	(22,274)	(30,057)	(13,457)	(20,649)
5	Customer Deposits	(1,669)	(1,902)	(1,511)	(1,722)
6	Gas Inventory (Working and Cushion)	35,290	39,714	47,711	53,692
7	Leasehold Improvemets	15,008	17,035	17,852	20,263
8	Materials & Supplies	17,831	20,608	17,242	19,927
9	Accumulated Deferred Income Taxes - Depreciation	(530,576)	(583,075)	(504,643)	(560,166)
10	Accumulated Deferred Income Taxes - Other	(2,063)	(2,281)	(3,623)	(4,064)
12	Cash Working Capital	33,217	37,170	28,599	32,002
13	Total Rate Base	2,494,868	2,863,415	2,202,338	2,497,923

[1] Base Year Aid in Advance of Construction has been partially reclassified to Utility Plant in Service. New customer aid in advance of constructions has been added to this liability.

88.84% 87.42%

	Depreciation & Amortization Expense	Test Year Oregon	Test Year System	Base Year Oregon	Base Year System
14	Intangible - Software	35,867	40,291	28,902	32,453
15	Transmission	6,654	6,959	5,667	5,846
16	Distribution	92,202	104,825	83,336	94,864
17	General	20,637	23,502	14,857	17,163
18	Storage and Storage Transmission	15,443	17,263	12,024	13,438
19	Depreciation Subtotal	170,803	192,840	144,787	163,763
20					
21	GC 500 and 600 Amortization	2,726	2,726	1,454	1,454
22	Amortization Subtotal	2,726	2,726	1,454	1,454
23					
24	Total	173,529	195,566	146,241	165,217

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS / RATE MECHANISMS
EXHIBIT 1211

REDACTED

November 24, 2026

NW Natural
UG 532
Exhibit 1211 - Cloud Based Assets

Asset #	Project Description	Life (Months)	Depreciation Rate	Capitalized Date	Gross Plant Balance
1029756	SAP LMS - Phase 2 - Cloud Based SW	62	19.35%	Apr-21	$ -
1029757	Planview - Cloud Based SW	62	19.35%	Apr-21	$ -
1029837	Cloud Based SAP SF EC&OnBoarding	60	20.00%	Aug-21	$ -
1030597	QA Inspection Tool - Cloud Based SW	36	33.33%	Jul-24	$ -
9656970	Execution Labor Internal (Capital)	44	27.27%	Oct-22	$ -
9656973	Execution Labor External (Capital)	44	27.27%	Oct-22	$ -
9656978	Planning Labor Internal (Capital)	44	27.27%	Oct-22	$ -
9656981	Planning Labor External (Capital)	44	27.27%	Oct-22	$ -
9656984	Planning Software (Capital)	44	27.27%	Oct-22	$ -
9656987	Planning Hardware (Capital)	44	27.27%	Oct-22	$ -
9656990	Execution Labor Internal (Capital)	44	27.27%	Oct-22	$ -
9656993	Execution Labor External (Capital)	44	27.27%	Oct-22	$ -
9656996	Execution Software (Capital)	44	27.27%	Oct-22	$ -
9656999	Execution Hardware (Capital)	44	27.27%	Oct-22	$ -
9657002	Planning Labor External (Capital)	44	27.27%	Oct-22	$ -
9657005	Execution Labor External (Capital)	44	27.27%	Oct-22	$ -
9657113	Planning Labor External (Capital)	44	27.27%	Oct-22	$ -
9657116	Planning Software (Capital)	44	27.27%	Oct-22	$ -
9657119	Execution Labor External (Capital)	44	27.27%	Oct-22	$ -
9657152	Cloud Software (Capital)	44	27.27%	Oct-22	$ -
9657164	Cloud Software (Capital)	44	27.27%	Oct-22	$ -
10192713	Internal Labor Azure	45	26.67%	Sep-22	$ -
10427072	Q3 & Q4 2022 Sprints (Capital)	41	29.27%	Jan-23	$ -
10709735	Plan Cloud Roll Out 1 Labor Inter(Cap)	40	30.00%	Feb-23	$ -
10709738	Labor External (Capital)	40	30.00%	Feb-23	$ -
10709741	Execute Cloud MVC (Capital)	40	30.00%	Feb-23	$ -
10709744	Labor External (Capital)	40	30.00%	Feb-23	$ -
12930343	Execution External Labor (Capital)	36	33.33%	Oct-23	$ -
12930346	Reporting Gaps Phase 3 (Capital)	36	33.33%	Oct-23	$ -
12930380	Initiate Cloud Platform Enhance (Capital)	36	33.33%	Oct-23	$ -
12930383	Planning Cloud Platform Enhance (Capital)	36	33.33%	Oct-23	$ -
12930386	Execute Cloud Platform Enhance (Capital)	36	33.33%	Oct-23	$ -
13188469	Planning SCM Training Doc (Capital)	36	33.33%	Nov-23	$ -
13188472	Execute SCM Training Doc (Capital)	36	33.33%	Nov-23	$ -
13322836	Assess SecurityBridge 3 YR Cloud (Capital)	36	33.33%	Dec-23	$ -
13322839	Planning SecurityBridge 3 YR Cloud (Capital)	36	33.33%	Dec-23	$ -
13322842	Execute SecurityBridge 3 YR Cloud (Capital)	36	33.33%	Dec-23	$ -
13322856	Execute SAP Treasury Azure Cloud (Capital)	36	33.33%	Dec-23	$ -
13493778	Initiate Labor Internal (Capital)	36	33.33%	Feb-24	$ -
13493781	Initiate Labor External (Capital)	36	33.33%	Feb-24	$ -
13493784	Assess Labor Internal (Capital)	36	33.33%	Feb-24	$ -
13493787	Assess Labor External (Capital)	36	33.33%	Feb-24	$ -
13493790	Assess Software (Capital)	36	33.33%	Feb-24	$ -
13493793	Planning Labor Internal (Capital)	36	33.33%	Feb-24	$ -
13493796	Planning Other (Capital)	36	33.33%	Feb-24	$ -
13493799	Execution Labor Internal (Capital)	36	33.33%	Feb-24	$ -
13493802	Execution Labor External (Capital)	36	33.33%	Feb-24	$ -
13493805	Execution Software (Capital)	36	33.33%	Feb-24	$ -
14125327	Intune Cloud 2023	36	33.33%	Apr-24	$ -
14125330	Cloud Sharepoint 2023	36	33.33%	Apr-24	$ -
14125333	Microsoft EA 2023 True-Up	36	33.33%	Apr-24	$ -
14705231	Q3 2022 DRA Assets	120	10.00%	Sep-22	$ 13,894
14705234	Q4 2022 DRA Assets	108	11.11%	Dec-23	$ 1,782,623
14705237	Q1 2023 DRA Assets	120	10.00%	Mar-23	$ 1,295,046
14705240	Q2 2023 DRA Assets	123	9.76%	Mar-23	$ 1,698,405
14705243	Q3 2023 DRA Assets	120	10.00%	Sep-23	$ 2,805,232
14705246	Q4 2023 DRA Assets	120	10.00%	Dec-23	$ 1,757,094
14705249	Q1 2024 DRA Assets	120	10.00%	Mar-24	$ 2,361,146
14705358	Q4 2022 DRA Assets	120	10.00%	Dec-22	$ 28,628
14705361	Q1 2023 DRA Assets	117	10.26%	Mar-23	$ 155,347
14705364	Q2 2023 DRA Assets	120	10.00%	Jun-23	$ 4,164
14705367	Q3 2023 DRA Assets	120	10.00%	Sep-23	$ (197,955)
14705370	Q4 2023 DRA Assets	120	10.00%	Dec-23	$ 348,203
14705373	Q1 2024 DRA Assets	120	10.00%	Mar-24	$ (98,611)
14725687	Program Mgmt Labor Internal (Capital)	120	10.00%	Dec-22	$ 46,399
14725690	Labor External (Capital)	120	10.00%	Dec-22	$ 718,962
14725693	Software (Capital)	120	10.00%	Dec-22	$ 200,430
14725696	Other (Capital)	120	10.00%	Dec-22	$ 19
14725699	Plan Cloud Phase 3 Labor Inter(Cap)	120	10.00%	Dec-22	$ 1,393
14725702	Labor External (Capital)	120	10.00%	Dec-22	$ 1,184,472
14725705	Execute Cloud MVC Phase 3(Capital)	120	10.00%	Dec-22	$ 588
14725708	Labor External (Capital)	120	10.00%	Dec-22	$ 132,426
14725711	Software (Capital)	120	10.00%	Dec-22	$ 56,912
14725714	Labor External (Capital)	120	10.00%	Jun-23	$ 1,045
14725717	Execute Cloud MVC Phase 4(Capital)	120	10.00%	Jun-23	$ 1,219
14725720	Exe Cloud Phase 4 Labor Inter(Capital)	120	10.00%	Jun-23	$ 7,900
14725723	Labor External (Capital)	120	10.00%	Jun-23	$ 683,671
14725726	Other (Capital)	120	10.00%	Jun-23	$ 366
14725729	Cloud Software (Capital)	120	10.00%	Jun-23	$ 363

Asset #	Project Description	Life (Months)	Depreciation Rate	Capitalized Date	Gross Plant Balance
14725732	Plan DevSecOps Labor Inter(Capital)	60	20.00%	Jun-21	$ -
14725735	Labor External (Capital)	60	20.00%	Jun-21	$ -
15208843	Exe Clevest Opt Azure Cloud (Capital)	36	33.33%	Jul-24	$ -
15568051	Planning Labor Internal (Capital)	57	21.05%	Sep-21	$ -
15568054	Planning Labor External (Capital)	57	21.05%	Sep-21	$ -
15568057	Execution Labor Internal (Capital)	57	21.05%	Sep-21	$ -
15568060	Execution Labor External (Capital)	120	10.00%	Sep-21	$ 1,779,359
15568063	Execution Software (Capital)	57	21.05%	Sep-21	$ -
15933166	Initiate Website Portals (Capital)	60	20.00%	Sep-24	$ 155,482
15933169	Assess Website Portals (Capital)	60	20.00%	Sep-24	$ 939,727
15933172	Planning Website Portals (Capital)	60	20.00%	Sep-24	$ 544,126
15933175	Execute Website Portals (Capital)	60	20.00%	Sep-24	$ 1,077,894
15933184	Genesys Phase 1 9/30/2024	60	20.00%	Sep-24	$ 2,008,776
15933225	Execution Allocation of Study (Capital)	57	21.05%	Sep-21	$ -
15942546	Q2 2024 DRA Assets	120	10.00%	Jun-24	$ 1,893,790
15942549	Q3 2024 DRA Assets	120	10.00%	Sep-24	$ 1,396,192
16303368	Initiate Identity Gov & Admin Auto (Capital)	36	33.33%	Oct-24	$ -
16303371	Assess Identity Gov & Admin Auto (Capital)	36	33.33%	Oct-24	$ -
16303374	Planning Identity Gov & Admin Auto (Capital)	36	33.33%	Oct-24	$ -
16303377	Execute Identity Gov & Admin Auto (Capital)	36	33.33%	Oct-24	$ -
16303429	Hyperproof - GRC Cloud	36	33.33%	Oct-24	$ -
16649841	Sherwood CW Infra Tech Refresh IT DC '23	36	33.33%	Nov-24	$ -
16649856	Microsoft SCE 2023 True-Up	36	33.33%	Nov-24	$ -
16649911	Windows 11 Upgrade Cloud 2024	36	33.33%	Nov-24	$ -
16649914	Copilot 2024 Cloud	36	33.33%	Nov-24	$ -
16649917	AVD 2024 Cloud	36	33.33%	Nov-24	$ -
17103842	Q4 2024 DRA Assets (10 yr)	120	10.00%	Dec-24	$ 1,508,328
18562058	Cloud Azure East-West FW 2023	36	33.33%	Mar-25	$ -
18562086	Execute Genesys Replatform (Cap)	60	20.00%	Mar-25	$ 1,163,986
18562108	Initiate/Asses/Plan Resource Scheduling	60	20.00%	Mar-25	$ 579,279
18562111	Resource Scheduling Optimize 5 Yr (Capital)	60	20.00%	Mar-25	$ 1,107,006
18562128	Initiate/Asses/Plan SB 619 Comply	36	33.33%	Mar-25	$ -
18562161	Sherwood Tech Refresh Cloud 2024	36	33.33%	Mar-25	$ -
18574854	Q1 2025 DRA Assets (10 yr)	120	10.00%	Mar-25	$ 2,019,254
19997277	Q2 2025 DRA Assets (10 yr)	120	10.00%	Jun-25	$ 257,993
19997286	5 yr Initiate Planview Enhancements (Capital)	60	20.00%	Jun-25	$ 139,048
19997289	5 yr Planning Planview Enhancements (Capital)	60	20.00%	Jun-25	$ 349,771
19997292	5 yr Execute Planview Enhancements (Capital)	60	20.00%	Jun-25	$ 85,790
21345948	Initiate - Probabilistic Risk Model	36	33.33%	Sep-25	$ -
21345951	Assess - Probabilistic Risk Model	36	33.33%	Sep-25	$ -
21345954	Plan - Probabilistic Risk Model	36	33.33%	Sep-25	$ -
21345957	Execute - Probabilistic Risk Model	36	33.33%	Sep-25	$ -
21345960	Internal Labor	36	33.33%	Sep-25	$ -
21345963	JANA Implementation	36	33.33%	Sep-25	$ -
21345966	Licenses and hosting fee	36	33.33%	Sep-25	$ -
21346427	Initiate/Asses/Plan Fleet Driver (Capital)	36	33.33%	Sep-25	$ -
21346430	Exe Fleet Driver Management (Capital)	36	33.33%	Sep-25	$ -
21346445	Initiate/Asses/Plan Generative AI	36	33.33%	Sep-25	$ -
21346448	Execution Generative AI (Capital)	36	33.33%	Sep-25	$ -
21346488	Execute Cloud PCI standards 4.0 (Capital)	36	33.33%	Jul-25	$ -
21346495	Execute Genesys Enhance 5yr (Capital)	60	20.00%	Sep-25	$ 208,835
21346618	Q3 2025 DRA Assets (10 yr)	120	10.00%	Sep-25	$ 1,268,213
21346621	Initiate/Asses/Plan Water Federation	36	33.33%	Sep-25	$ -
21766709	Execute Cloud IGA 2.0 - Central Prov	36	33.33%	Oct-25	$ 792,649
21766761	Initiate/Asses/Plan LTIP - Stock Admin	60	20.00%	Oct-25	$ 54,309
21766764	Execute LTIP - Stock Admin (Capital)	60	20.00%	Oct-25	$ 33,229
22685380	Q4 2025 DRA Assets (10yr)	120	10.00%	Dec-25	$ 1,007,429
22685409	Initiate/Asses/Plan - Capital	36	33.33%	Dec-25	$ 5,083
22685412	Initiate/Asses/Plan Azure Security Enhan	36	33.33%	Dec-25	$ 236,601
22685415	Execution - Capital	36	33.33%	Dec-25	$ 8,673
22685418	Execute Azure Security Enhancement (Capital)	36	33.33%	Dec-25	$ 251,841
22685528	Execute Deepwatch 15% 3YR(2025)	36	33.33%	Dec-25	$ 146,666
22685542	Azure Kubernetes Website Enhancements	36	33.33%	Dec-25	$ 19,684
22685551	Initiate/Asses/Plan Self Service Enhance	36	33.33%	Dec-25	$ 424,312
22685554	Execute Self Service Enhancements	36	33.33%	Dec-25	$ 110,692
22685557	Initiate/Asses/Plan FOM Replatform	36	33.33%	Dec-25	$ 49,151
22685560	Execute FOM Replatform	36	33.33%	Dec-25	$ 124,492
23551678	Execute Deepwatch 15% 3YR(2026)	36	33.33%	Dec-25	$ 158,278
24060513	Q1 2026 DRA Assets (10 year)	120	10.00%	Mar-26	$ 1,453,289
24060579	Plan Q1 '26 Self Service Enhancements	36	33.33%	Mar-26	$ 586,038
24547416	Initiate/Asses/Plan Legal - Brightflag	36	33.33%	Apr-26	$ 182,242
24547419	Execute Legal - Brightflag	36	33.33%	Apr-26	$ 16,819
24547422	Exe Q1 '26 Self Service Enhancements	36	33.33%	Mar-26	$ 4,750
25410923	Initiate Resource Schdl Enhance 5year	60	20.00%	Jun-26	$ 64,507
25410926	Exec Resource Schdule Enhance 5year (Capital)	60	20.00%	Jun-26	$ 42,524
25410955	Initiate/Asses/Plan Splunk Arch Maturity	36	33.33%	May-26	$ 144,725
25410960	Exe Q2 '26 Self Service Enhancements	36	33.33%	Jun-26	$ 203,496
25410969	Execute Firewall Lifecycle Mgmt (Cloud)	36	33.33%	Jun-26	$ 3,322
25410972	Q2 2026 EDP DRA (10 yr)	120	10.00%	Jun-26	$ 783,013
25410975	Q1 2026 AI + Automation	36	33.33%	Jun-26	$ 31,894
25410978	Q2 2026 AI + Automation	36	33.33%	Jun-26	$ 470,407
25410993	Meter Mod Reporting Optimization	36	33.33%	May-26	$ 299,336
25455156	Q2 2026 DRA Assets (10 YR)	120	10.00%	Jun-26	$ 129,781
9498306	IT&S Execution Labor External (Capital)	120	10.00%	Sep-22	$ 28,847

Asset #	Project Description	Life (Months)	Depreciation Rate	Capitalized Date	Gross Plant Balance
9498345	Labor External (Capital)	120	10.00%	Sep-22	$ 185,012
9498357	Labor External (Capital)	120	10.00%	Sep-22	$ 23
9498366	Labor External (Capital)	120	10.00%	Sep-22	$ 18
9498369	Labor External (Capital)	120	10.00%	Sep-22	$ 19
9498378	Labor External (Capital)	120	10.00%	Sep-22	$ 15,937
9498387	DecSecOps Labor Inter (Capital)	120	10.00%	Sep-22	$ 9,293
9498396	Labor External (Capital)	120	10.00%	Sep-22	$ 260,646
9498408	Labor External (Capital)	120	10.00%	Sep-22	$ 20
9498414	Labor External (Capital)	120	10.00%	Sep-22	$ 29
9498423	Labor External (Capital)	120	10.00%	Sep-22	$ 71,625
9498435	Labor External (Capital)	120	10.00%	Sep-22	$ 39
9498444	Labor External (Capital)	120	10.00%	Sep-22	$ 29
9498456	Labor External (Capital)	120	10.00%	Sep-22	$ 28
9498465	Labor External (Capital)	120	10.00%	Sep-22	$ 13
9498474	Labor External (Capital)	120	10.00%	Sep-22	$ 32,577
9498483	Labor External (Capital)	120	10.00%	Sep-22	$ 78,474
9498492	Labor External (Capital)	120	10.00%	Sep-22	$ 6
9498495	DATA Labor Internal (Capital)	120	10.00%	Sep-22	$ 14,159
9498504	Labor External (Capital)	120	10.00%	Sep-22	$ 381,179
9498519	Labor External (Capital)	120	10.00%	Sep-22	$ 12
9498522	Labor External (Capital)	120	10.00%	Sep-22	$ 8
9498537	Mobility Test & QA Proc Labor Inter (Capital)	120	10.00%	Sep-22	$ 3,492
9498543	Labor External (Capital)	120	10.00%	Sep-22	$ 117,593
9498549	Labor External (Capital)	120	10.00%	Sep-22	$ 29
9498558	Project Management (Allocate)	120	10.00%	Sep-22	$ 73,691
9498567	Execution Labor Internal (Capital)	120	10.00%	Sep-22	$ 8,668
9498576	Execution Labor External (Capital)	120	10.00%	Sep-22	$ 939,113
9498636	EAM Labor Internal (Capital)	120	10.00%	Sep-22	$ 560,354
9498639	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 1,519,700
9498651	External Labor Other (Capital)	120	10.00%	Sep-22	$ 195,195
9498663	Supply Chain Labor Internal (Capital)	120	10.00%	Sep-22	$ 326,662
9498666	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 653,579
9498675	External Labor Other (Capital)	120	10.00%	Sep-22	$ 81,962
9498690	Finance Labor Internal (Capital)	120	10.00%	Sep-22	$ 349,957
9498699	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 2,051,134
9498705	External Labor Other (Capital)	120	10.00%	Sep-22	$ 32,055
9498714	IT&S Horizon 1 Labor Internal (Capital)	120	10.00%	Sep-22	$ 878,328
9498726	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 360,186
9498729	External Labor Other (Capital)	120	10.00%	Sep-22	$ 553,077
9498744	HCM Rel 1 Labor Internal (Capital)	120	10.00%	Sep-22	$ 16,074
9498747	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 279,106
9498762	HCM Rel 2 Labor Internal (Capital)	120	10.00%	Sep-22	$ 76,115
9498768	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 914,309
9498774	External Labor Other (Capital)	120	10.00%	Sep-22	$ 90,362
9498783	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 165,313
9498792	External Labor Other (Capital)	120	10.00%	Sep-22	$ 36,934
9498801	Data Migration Labor Internal (Capital)	120	10.00%	Sep-22	$ 33,351
9498813	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 178,674
9498819	External Labor Other (Capital)	120	10.00%	Sep-22	$ 86,544
9498834	Mobility Labor Internal (Capital)	120	10.00%	Sep-22	$ 50,367
9498837	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 29,443
9498852	Reporting & Analytics Labor Inter (Capital)	120	10.00%	Sep-22	$ 19,480
9498861	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 160,448
9498870	External Labor Other (Capital)	120	10.00%	Sep-22	$ 843,659
9498876	Security Labor Inter (Capital)	120	10.00%	Sep-22	$ 13,502
9498888	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 230,218
9498897	External Labor Other (Capital)	120	10.00%	Sep-22	$ 103,650
9498903	Dev Training Materials Labor Internal	120	10.00%	Sep-22	$ 10,002
9498912	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 265,550
9498918	External Labor Other (Capital)	120	10.00%	Sep-22	$ 294,367
9498927	Program Mgmt Labor Inter (Capital)	120	10.00%	Sep-22	$ 114,547
9498939	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 988,267
9498951	External Labor Other (Capital)	120	10.00%	Sep-22	$ 966,550
9498960	Development Labor Inter (Capital)	120	10.00%	Sep-22	$ 84,790
9498963	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 306,499
9498972	Testing Labor Internal (Capital)	120	10.00%	Sep-22	$ 66,041
9498981	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 231,042
9498996	External Labor Other (Capital)	120	10.00%	Sep-22	$ 319,972
9499002	Tech Arch Labor Internal (Capital)	120	10.00%	Sep-22	$ 129,576
9499008	Accenture Labor External (Capital)	120	10.00%	Sep-22	$ 276,595
9499020	External Labor Other (Capital)	120	10.00%	Sep-22	$ 7,248
9499029	Travel (Capital)	120	10.00%	Sep-22	$ 106,793
9499041	PWC (Capital)	120	10.00%	Sep-22	$ 205,774
9499044	On Prem SW SAP (Capital)	120	10.00%	Sep-22	$ 1,087,978
9499053	On Prem Clevest (Capital)	120	10.00%	Sep-22	$ 331,926
9499065	On Prem PowerPlan (Capital)	120	10.00%	Sep-22	$ 619,527
9499074	On Prem Other (Capital)	120	10.00%	Sep-22	$ 73,175
9499080	Cloud Based SAP (Capital)	120	10.00%	Sep-22	$ 1,016,295
9499095	Cloud Based Clevest (Capital)	120	10.00%	Sep-22	$ 138
9499101	Cloud Based PowerPlan (Capital)	120	10.00%	Sep-22	$ 61,534
9499107	Cloud Based SW Accenture (Capital)	120	10.00%	Sep-22	$ 15,392
9499116	Cloud Based SW Azure (Capital)	120	10.00%	Sep-22	$ 430,353
9499125	Cloud Other (Capital)	120	10.00%	Sep-22	$ 2,874
9499140	On Prem SW Maint SAP (Capital)	120	10.00%	Sep-22	$ 350,757

Asset #	Project Description	Life (Months)	Depreciation Rate	Capitalized Date	Gross Plant Balance
9499149	On Prem SW Maint Clevest (Capital)	120	10.00%	Sep-22	$ 110,377
9499152	On Prem SW Maint PowerPlan (Capital)	120	10.00%	Sep-22	$ 319,739
9499167	Cloud Based SW Maint Other (Capital)	120	10.00%	Sep-22	$ 153
9499173	Hardware (Capital)	120	10.00%	Sep-22	$ 109,116
9499179	Misc (Capital)	120	10.00%	Sep-22	$ 284,843
9499188	SLA Credit (Capital)	120	10.00%	Sep-22	$ (10,818)
9499197	IQGEO (Capital)	120	10.00%	Sep-22	$ 733,534
9657134	Execution Other (Capital)	120	10.00%	Sep-22	$ 2,339
9657429	Accenture Travel (Capital)	120	10.00%	Sep-22	$ (1,930)
9657480	Accenture Change Orders (Capital)	120	10.00%	Oct-22	$ 36,693
11545055	COMPUTER SOFTWARE	120	10.00%	Sep-22	$ 71,699
11545070	COMPUTER SOFTWARE	120	10.00%	Sep-22	$ 9
11545088	COMPUTER SOFTWARE	120	10.00%	Sep-22	$ 144,094
11545100	COMPUTER SOFTWARE	120	10.00%	Sep-22	$ 14,353
11545136	COMPUTER SOFTWARE	120	10.00%	Oct-22	$ 753,448
14125283	SuccessFactors Q1 2023	120	10.00%	Apr-24	$ 15,540
14125286	SuccessFactors Q3 2023	120	10.00%	Apr-24	$ 4,077
14125289	Workforce Q1 2023	120	10.00%	Apr-24	$ 5,885
10193070	Cloud SW Asset #2 (Nov) 3 year	42	28.57%	Dec-22	$ -
10193073	NMEP Cloud Asset Nov (3 year)	42	28.57%	Dec-22	$ -
10193095	Cloud SW Asset (Nov) 3 year	42	28.57%	Dec-22	$ -
10193107	Cloud Asset Nov	42	28.57%	Dec-22	$ -
10193122	Cloud SW Asset Dec	42	28.57%	Dec-22	$ -
10193125	NMEP SW Asset Dec	42	28.57%	Dec-22	$ -
10193134	Cloud SW Asset Dec	42	28.57%	Dec-22	$ -
10193143	Cloud SW Asset Dec	42	28.57%	Dec-22	$ -
12771848	COMPUTER SOFTWARE	48	25.00%	Oct-22	$ -
12779262	CLOUD SOFTWARE	48	25.00%	Oct-22	$ -
21766906	Hyperproof Cloud SW TSA 2E (Capital)	36	33.33%	Oct-25	$ 169,209

[BEGIN CONFIDENTIAL]

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[END C

10/31/28 TOTAL	$ 108,087,148

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS / RATE MECHANISMS
EXHIBIT 1212

November 24, 2026

NW Natural - Exhibit Page 1
Lead-Lag Test Year Summary

		Test Year Twelve Months Ended October 31, 2028				
		Year 1 Revenue Requirement $	Revenue Lag (Lead) Days	Expense Lag (Lead) Days	Net Lag (Lead) Days	Weighted $
3	**Total Revenue Lag**		40.92			
5	**Operations and Maintenance Expense**					
6	Purchased Gas	$ 348,892,573	40.9	40.2	0.7	$ 249,083,713
7	Labor - Payroll	$ 93,342,279	40.9	27.1	13.9	$ 1,294,683,953
8	Employee Benefits	$ 33,518,577	40.9	13.0	27.9	$ 936,673,000
9	Prepaid Insurance Expense	$ 8,071,726	40.9	-214.3	255.2	$ 2,060,169,741
10	Prepaid IT Expense	$ 14,260,839	40.9	-231.4	272.4	$ 3,884,195,063
11	Regulatory Fees	$ 3,577,375	40.9	-91.3	132.2	$ 472,853,430
12	Municipal Franchise Fees	$ 23,185,457	40.9	90.9	-50.0	$ (1,158,772,109)
13	Other O&M	$ 122,125,284	40.9	33.2	7.7	$ 936,980,138
15	**Payroll Taxes**	$ 8,046,323	40.9	79.4	-38.5	$ (309,644,548)
17	**Other Taxes**					
18	Federal/State	$ 45,590,823	40.9	36.5	4.4	$ 201,614,475
19	Property Taxes	$ 41,536,246	40.9	-45.5	86.4	$ 3,589,656,249
20	**Net of Revenue less Expense Lag**	**$ 742,147,503**	**40.9**	**24.5**	16.4	**$ 12,157,493,107**
21	Days					366
22	**Aver Daily Cash Working Capital Requirements - Oregon**					**$ 33,217,194**
23	**Aver Daily Cash Working Capital Requirements - System**					**$ 37,170,040**
24	**Cash Working Capital Factor**					**4.48%**

NW Natural - Exhibit Page 2
Revenue Test Year Summary

		Test Year Twelve Months Ended October 31, 2028	
1		Year 1	
2		Revenues Billed	Lag (Lead) Days
3	Sale of Gas	$ 1,061,913,781	
4	Transportation Revenues	$ 17,275,012	
5	Service Lag		15.2
6	Billing Lag		0.0
7	Collection Lag		25.7
8	**Grand Total Revenues**	**$ 1,079,188,793**	**40.9**
9	Misc Revenues	$ 4,587,671	
10	Service Lag		15.0
11	Billing Lag		0.0
12	Collection Lag		30.0
13	**Total Other Revenues**	**$ 4,587,671**	**45.0**
14			
15	**Total Revenue Lag**	**$ 1,083,776,464**	**40.9**

NW Natural - Exhibit Page 3
Expense Test Year Summary

			Test Year Twelve Months Ended October 31, 2028		
			Year 1		
			Revenue Requirement $		Lag (Lead) Days
1					
2					
3	**Operations and Maintenance Expense**				
4	Purchased Gas	$	348,892,573		40.2
5	Service Lag			15.2	
6	Payment Lag			25.0	
7	Labor - Payroll	$	93,342,279		27.1
8	Employee Benefits	$	33,518,577		13.0
9	Prepaid Insurance	$	8,071,726		-214.3
10	Prepaid IT	$	14,260,839		-231.4
11	Regulatory Fees	$	3,577,375		-91.3
12	Municipal Franchise Fees	$	23,185,457		90.9
13	Other O&M	$	122,125,284		33.2
14	**TOTAL O&M**	**$**	**646,974,110**		**27.5**
15					
16	**Payroll Taxes**	$	8,046,323		79.4
17					
18	**Other Taxes**				
19	Federal/State	$	45,590,823		36.5
20	Property Taxes	$	41,536,246		-45.5
21	**TOTAL TAXES**	**$**	**95,173,392**		**4.3**
22	**TOTAL REQUIRMENT**	**$**	**742,147,503**		**24.5**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS / RATE MECHANISMS
EXHIBIT 1213

November 24, 2026

NW Natural
UG 532 - Oregon Jurisdictional Rate Case
State Allocation Factors

Line No.	Allocation Factors - Summary	Oregon	Washington
1	**Customers-all**	87.760%	12.24%
2	**Customers-Residential**	87.610%	12.39%
3	**Customers-Commercial**	89.340%	10.66%
4	**Customers-Industrial**	92.180%	7.82%
5	**Customers-The Dalles**	74.850%	25.15%
6	**3-factor**	88.100%	11.90%
7	**firm volumes**	88.860%	11.14%
8	**sales volumes**	89.480%	10.52%
9	**sendout volumes**	91.520%	8.48%
10	**sales/sendout volumes**	90.500%	9.50%
11	**Payroll**	88.785%	11.22%
12	**Admin Transfer**	87.670%	12.33%
13	**Employee Cost**	88.765%	11.23%
14	**Regulatory**	70.000%	30.00%
15	**Telemetering**	88.235%	11.76%
16	**Direct-Wa**	0.000%	100.00%
17	**Direct-Or**	100.000%	0.00%
18	**Gross plant direct assign**	88.310%	11.69%
19	**Transmission**	98.731%	1.27%
20	**Accumulated Depreciation**	88.835%	11.16%
21	**Rate Base**	87.418%	12.58%
22	**Distribution**	86.526%	13.47%
23	**Perimeter**	93.056%	6.94%
24	**Environmental Admin Costs**	96.680%	3.32%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS / RATE MECHANISMS
EXHIBIT 1214

November 24, 2026

NW Natural
UG 532 - Exhibit 1214
Decoupling and WARM Updates

Decoupling Usage Baselines

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
02- Pre-2018 Residential	**Total**	105.9	88.3	75.9	52.8	31.0	19.2	13.5	13.5	17.6	40.5	77.5	106.0	**641.8**
02- Post-2018 Residential	**Total**	72.4	60.1	51.8	35.7	19.9	10.9	7.8	7.8	11.3	27.4	52.8	72.8	**430.7**
03 - Small Commerical	**Total**	486.7	426.2	392.0	279.2	176.9	108.5	90.0	89.8	100.6	187.0	334.2	481.8	**3,153.0**
31CSF - Commerical	**Total**	5,068.5	4,366.7	4,316.4	3,177.2	2,127.2	1,412.7	1,057.7	1,047.5	1,135.8	2,201.1	3,799.6	5,062.9	**34,773.3**

WARM and Decoupling Coefficients

02 - Residential	**0.15502**
03 - Small Commercial	**0.63180**
31CFS - Commerical	**6.45698**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS / RATE MECHANISMS
EXHIBIT 1215

REDACTED

November 24, 2026

NW Natural
UG 532 Exhibit NW Natural/1215
Bridge Mechanism

Gross Plant + Accumulated Depreciation



NW Natural
UG 532 Exhibit NW Natural/1215
Bridge Mechanism Revenue Requirement Calculation
($000)

Line No.		Bridge Mechanism
	Operating Revenues	
1	**Sale of Gas**	
2	**Transportation**	
3	**Decoupling**	
4	**WARM**	
5	**Miscellaneous Revenues**	
6	**Total Operating Revenues**	$0
	Operating Revenue Deductions	
7	**Gas Purchased**	
8	**Uncollectible Accrual**	$0
9	**Other Operating & Maintenance Expenses**	
10	**Total Operating & Maintenance Expense**	$0
11	**Federal Income Tax**	($1,372)
12	**State Excise**	($537)
13	**Property Taxes**	$0
14	**Adjustments [1]**	$59
15	**Depreciation & Amortization**	$5,437
16	**Total Operating Revenue Deductions**	$3,586
17	**Net Operating Revenues**	($3,586)
	Average Rate Base	
18	**Utility Plant in Service**	$144,200
19	**Accumulated Depreciation**	($81,187)
20	**Net Utility Plant**	$63,013
21	**Aid in Advance of Construction**	
22	**Customer Deposits**	
23	**Gas Inventory**	
24	**Leasehold Improvements**	
25	**Materials & Supplies**	
26	**EDIT Adjustments to Rate Base**	
27	**Accumulated Deferred Income Taxes**	
28	**Total Rate Base**	$63,013
29	**Interest Coordination**	$1,575
30	**Total Revenue Requirement**	$11,624

[1] This adjustment is used to tie to UG 532 - Exh. 1215 - WP2 - Bridge Mechanism - Revenue Requirements. Please see UG 532 - Exh. 1215 - WP2 - Bridge Mechanism - Revenue Requirements for exact calculation for the bridge mechanism revenue requirement.

NW Natural
Oregon Jurisdictional Rate Case
Test year Normalizing Adjustments
($000)

Line No.		Adjustment
1	**Book Revenues**	$0
2	**Book Expenses before Deprec. & Int.**	59
3	**State Tax Depreciation**	5,437
4	**Interest Expense (Income)**	1,575
5	**Book/Tax Differences (Sched. M)**	0
6	**State Taxable Income**	(7,070)
7	**State Excise Tax [1]**	(537)
8	**State Tax Credit**	0
9	**Net State Income Tax**	(537)
10	**Excess Book(Tax) Deprec.**	0
11	**Other Sched. M Differences**	0
12	**Federal Taxable Income**	(6,533)
13	**Federal Income Tax [2]**	(1,372)
14	**ITC**	0
15	**Current Federal Tax**	(1,372)
16	**Deferred Income Tax - Federal**	0
17	**Deferred Income Tax - State**	0
18	**ITC Restored (Deferred)**	0
19	**Total Federal Tax**	(1,372)
20	**Total State Tax**	(537)

[1] Statutory State Excise Tax Rate:
[2] Statutory Federal Income Tax Rate:

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Kyle T. Walker

TEST YEAR / REVENUE REQUIREMENTS / TARIFFS / RATE MECHANISMS
EXHIBIT 1216

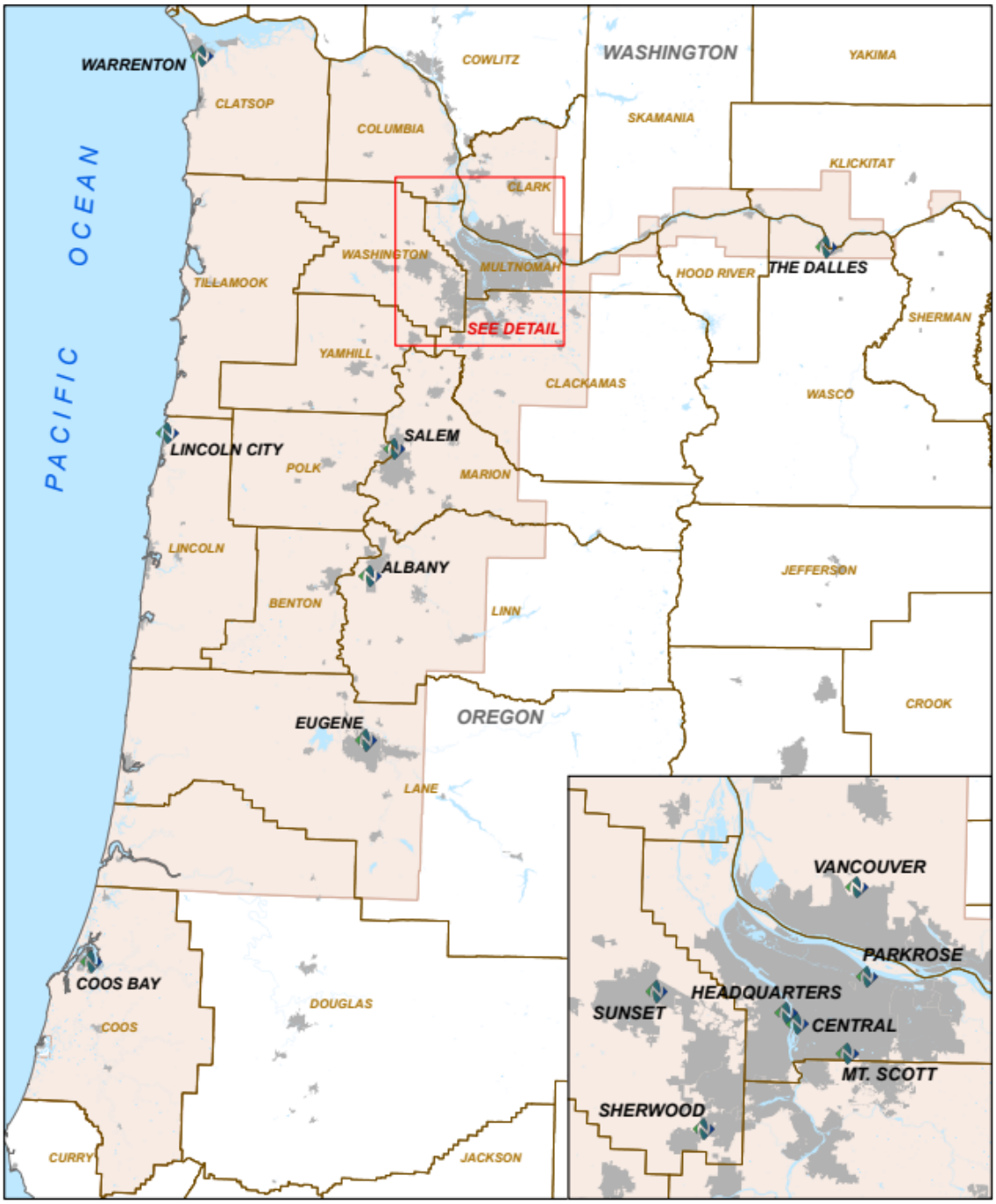
November 24, 2026

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25

First Revision of Sheet ii
Cancels Original Sheet ii

MAP OF SERVICE AREA

(C)



(C)

(continue to Sheet iii)

Issued November 24, 2026
NWN OPUC Advice No. 26-11

Effective with service on
and after December 24, 2026

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25

Eighth Revision of Sheet H-5
Cancels Seventh Revision of Sheet H-5

RATE SCHEDULE H
LARGE VOLUME NON-RESIDENTIAL
HIGH PRESSURE GAS SERVICE (HPGS) RIDER
(continued)

Monthly Billing Rate (continued)

Cost Recovery Factors Primary 10-Year Term Effective December 24, 2026			
Year	**No Bonus Depreciation**	**With Bonus Depreciation**	
Year 1	21.4%	20.8%	(C)(C)
Year 2	20.0%	19.0%	
Year 3	18.5%	17.9%	
Year 4	17.3%	16.8%	
Year 5	16.1%	15.7%	
Year 6	15.0%	14.7%	
Year 7	13.8%	13.7%	(C)
Year 8	12.8%	12.7%	(C)
Year 9	11.8%	11.8%	
Year 10	10.8%	10.8%	(C)(C)

Scheduled Maintenance Charge includes the costs associated with providing Scheduled Maintenance on HPGS Facilities as well as an annual charge of $10,087 per Customer for administrative services, which includes but is not limited to costs for managing the program, marketing, applying administrative and general overhead allocations, performing Customer credit evaluations, drafting the Customer agreements and site licenses, billing, warehousing and managing inventory of spare parts, monitoring, and dispatching. Scheduled Maintenance costs are initially based on expected labor and material costs known at the time the HPGS Agreement is executed. The labor component recovered through this charge includes the costs for administration. The Scheduled Maintenance Charge may be adjusted annually on the anniversary date of the execution of the HPGS Agreement to reflect any adjustments for differences between expected costs and actual costs, and to reflect any cost changes expected for the next 12-month period.

In addition to the Monthly Facility Charge and the Scheduled Maintenance Charge, the Company will bill and the Customer will be responsible to pay all actual costs associated with the Company's provision of Unscheduled Maintenance and Back-Up Services.

Unscheduled Maintenance will be billed as costs are incurred at actual costs for labor and materials plus overhead expenses.

(continue to Sheet H-6)

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25

Nineteenth Revision of Sheet 2-1
Cancels Eighteenth Revision of Sheet 2-1

RATE SCHEDULE 2
RESIDENTIAL SALES SERVICE

AVAILABLE:
To Residential Class Customers in all territory served by the Company under the Tariff of which this Rate Schedule is a part. Temporary Disconnection 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 X**.

SERVICE DESCRIPTION:
Service under this Rate Schedule is Firm Sales Service to gas equipment used for Domestic purposes by qualifying Residential Class Customers.

Service to a Vehicle Fueling Appliance is subject to the conditions set forth in Special Provisions 3 through 6 of this Rate Schedule.

MONTHLY RATE: Effective: December 24, 2026 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 100** for a list of applicable temporary adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **Schedule 160.** The rates for service to a Vehicle Fueling Appliance shall be further adjusted as set forth in Special Provision 6 of this Rate Schedule. “Multi-Family” shall mean attached dwelling units of two or more attached units (for example, duplexes, apartments, condominiums or townhomes) that are individually metered on this Rate Schedule 2.

Minimum Monthly Bill: Customer Charge plus charges under **Schedule C** or **Schedule 15** (if applicable)

	Customer Charge	Base Rate	Base Adjustment	Pipeline Capacity	Commodity	Temporary Adjustment	Total Billing
Charge Type (Fixed / Variable):	Fixed Charge	Volumetric Charges (per therm)					
Residential Single-Family	$10.00	$0.98871	$0.02259	$0.11482	$0.36778	$0.18695	$1.68085 (I)
Residential Multi-Family	$8.00	$0.98871	$0.02259	$0.11482	$0.36778	$0.18695	$1.68085 (I)

(continue to Sheet 2-2)

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25

Eighteenth Revision of Sheet 3-4
Cancels Seventeenth Revision of Sheet 3-4

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

MONTHLY RATE: Effective: December 24, 2026 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 100** for a list of applicable temporary adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **Schedule 160**. The rates for service to CNG vehicle fueling equipment shall be further adjusted as set forth in Special Provision 7 of this Rate Schedule.

FIRM SALES SERVICE CHARGES: (03CSF and 03ISF)						**Billing Rates [1]**	
Customer Charge (per month):						**$25.00**	(I)
Volumetric Charges (per therm):	Base Rate	Base Adjustment	Pipeline Capacity	Commodity Component [2]	Temporary Adjustment		
Commercial	$0.81034	$0.01781	$0.11482	$0.36778	$0.16865	$1.47940	(I)
Industrial	$0.56641	$0.01213	$0.11482	$0.36778	$0.13700	$1.19814	(I)
Standby Charge (per therm of MHDV) [3]:						**$10.00**	

[1] **Schedule C** and **Schedule 15** Charges shall apply, if applicable.
[2] The Commodity Component shown is the Annual Sales WACOG. The actual Commodity Component billed could be different for certain customers as described in the special provisions of this Rate Schedule
[3] Applies to Standby Sales Service only.

Minimum Monthly Bill. The Minimum Monthly Bill shall be the Customer Charge plus any **Schedule C** and **Schedule 15** Charges.

NORTHWEST NATURAL GAS COMPANY
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Sixth Revision of Sheet 4-1
Cancels Fifth Revision of Sheet 4-1

RATE SCHEDULE 4
RESIDENTIAL MULTI-FAMILY SERVICE

APPLICABLE:
To Residential tenants that reside in a Participant Multi-Family Building.

MONTHLY RATE: **$12.92** Effective: December 24, 2026 (I)(C)

The monthly rate for service under this Rate Schedule 4 may be adjusted from time to time for the effects of changes approved by the Commission in a general rate case proceeding.

SPECIAL PROVISIONS:

1. Low-use gas appliances include gas range or cooktop, gas clothes dryer, and gas barbecue. All Natural Gas usage associated with low-use gas appliances served under this Schedule 4 will be metered and billed from the master meter that serves the Participant Building and will be collected from tenants in accordance with General Rule 17 of this Tariff and with Participant Building policy.

2. Customers billed under this Rate Schedule 4 are not subject to Schedule 301 Public Purposes Funding Surcharges.

3. Customers billed under this Rate Schedule 4 are not eligible for the following programs:

   Schedule 310—Oregon Low-Income Gas Assistance (OLGA)
   Schedule 320—Oregon Low-Income Energy Efficiency Programs (OLIEE)
   Schedule 350—Energy Efficiency Services and Programs - Residential and Commercial

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

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Seventh Revision of Sheet 15-2
Cancels Sixth Revision of Sheet 15-2

RATE SCHEDULE 15
CHARGES FOR SPECIAL METERING EQUIPMENT, RENTAL METERS, AND METERING SERVICES (OPTIONAL)
(continued)

MONTHLY METER RENTAL RATES (Continued):
The following **diaphragm** meter sizes and associated monthly charges are retained under existing arrangements for billing purposes. These meters/charges are not available to new meter rental requests.

Applicable			
Meters Installed Prior to 9/24/2008	Meters Installed Prior to 4/26/2018	Meter Size (cf/hour)	Monthly Charge
XX		175	$0.81
	XX	200	$0.81
	XX	275	$1.00
XX		310	$1.00
	XX	415	$1.70
XX		425	$1.70
	XX	500	$1.70
XX		750	$4.07
XX		800	$4.07
		1400	$9.29
	XX	1450	$9.29
XX		2300	$14.68
	XX	2500	$14.68
	XX	3000	$23.33
XX		5000	$23.33
	XX	11000	$23.33
XX		16000	$23.33
	XX	18000	$23.33

The following **rotary** meter sizes and associated monthly charges are retained under existing arrangements for billing purposes. These meters/charges are not available to new meter rental requests. (T)

Applicable			
Meters Installed Prior to 4/26/2018	Meter Size	Meter Capacity (cf/hour)	Monthly Charge
XX	8C175	800	$ 13.00

METERING SERVICES AND CHARGES:

Metering Service	One Time Charge	Installation Charge	Monthly Charge
Rental Read	---	---	$0.76
Advanced Automated Meter Reading (AAMR) Device1	---	$1,270.53	$54.79 (I)
Remote Index	---	$50.00	$4.00
Pulse Output	---	$100.00	$8.00
Administrative Set-Up/Consultation Fee (all meters)	$145.00	---	---
Technical Assistance (Rotary meters only)	$145.00	---	---

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

(continue to Sheet 15-3)

NORTHWEST NATURAL GAS COMPANY

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Sixteenth Revision of Sheet 27-1
Cancels Fifteenth Revision of Sheet 27-1

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 Rate 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 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 2.**

MONTHLY RATE: Effective: December 24, 2026 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **Schedule 100** for a list of applicable temporary adjustments. Rates are subject to charges for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **Schedule 160**.

	Base Rate	Base Adjustment	Pipeline Capacity Rate	Commodity Rate	Temporary Adjustment	Billing Rate
Customer Charge:	$10.00	---	---	---	---	**$10.00**
Volumetric Charge (per therm)	$0.87370	$0.13760	$0.11482	$0.36778	$0.05703	$1.55093 (I)

Minimum Monthly Bill: Customer Charge, plus charges under **Schedule C** and **Schedule 15** (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, any other schedules that by their terms or by the terms of this Rate Schedule apply to service under this Rate Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25
Eighteenth Revision of Sheet 31-11
Cancels Seventeenth Revision of Sheet 31-11

RATE SCHEDULE 31
NON-RESIDENTIAL FIRM SALES AND FIRM TRANSPORTATION SERVICE
(continued)

MONTHLY RATES FOR COMMERCIAL CUSTOMER CLASS:

Effective: December 24, 2026 (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. **See Schedule 100** for a list of applicable temporary adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **Schedule 160**. The rates for service to CNG vehicle fueling equipment shall be further adjusted as set forth in Provision No. 2 of the "SPECIAL CONDITIONS FOR COMPRESSED NATURAL GAS ("CNG") SERVICE FOR VEHICULAR USE" of this Rate Schedule.

FIRM SALES SERVICE CHARGES (31 CSF) [1]:					Billing Rates	
Customer Charge (per month):					**$325.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment	Commodity Component [2]	Total Temporary Adjustments [3]		
Block 1: 1st 2,000 therms	$0.40858	$0.01136	$0.36778	$0.09010	**$0.87782**	(I)
Block 2: All additional therms	$0.37279	$0.01050	$0.36778	$0.08879	**$0.83986**	(I)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.11482**	
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.69**	
FIRM TRANSPORTATION SERVICE CHARGES (31 CTF):						
Customer Charge (per month):					**$325.00**	
Transportation Charge (per month):					**$250.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment		Total Temporary Adjustments [4]		
Block 1: 1st 2,000 therms	$0.38015	$0.00572		$0.08698	**$0.47285**	(I)
Block 2: All additional therms	$0.34755	$0.00488		$0.08634	**$0.43877**	(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 or Schedule 15.
[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 162 may not apply.
[4] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 162 may also apply.

(continue to Sheet 31-12)

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25

Sixteenth Revision of Sheet 31-12
Cancels Fifteenth Revision of Sheet 31-12

RATE SCHEDULE 31
NON-RESIDENTIAL FIRM SALES AND FIRM TRANSPORTATION SERVICE
(continued)

MONTHLY RATES FOR INDUSTRIAL CUSTOMER CLASS: **Effective: December 24, 2026** (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 100** for a list of applicable temporary adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **SCHEDULE 160**.

FIRM SALES SERVICE CHARGES (31 ISF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$325.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment	Commodity Component [2]	Total Temporary Adjustments [3]		
Block 1: 1st 2,000 therms	$0.29697	$0.00875	$0.36778	$0.13165	**$0.80515**	(I)
Block 2: All additional therms	$0.26771	$0.00805	$0.36778	$0.13063	**$0.77417**	(I)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.11482**	
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.69**	
FIRM TRANSPORTATION SERVICE CHARGES (31 ITF):						
Customer Charge (per month):					**$325.00**	
Transportation Charge (per month):					**$250.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment		Total Temporary Adjustments [4]		
Block 1: 1st 2,000 therms	$0.30849	$0.00538		$0.08553	**$0.39940**	(I)
Block 2: All additional therms	$0.27883	$0.00447		$0.08499	**$0.36829**	(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 15**.

[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 162** may not apply.

[4] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in **SCHEDULE 162** may also apply.

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Sixteenth Revision of Sheet 32-12
Cancels Fifteenth Revision of Sheet 32-12

RATE SCHEDULE 32
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES: **Effective: December 24, 2026** (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 100** for a list of applicable temporary adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **SCHEDULE 160**.

FIRM SALES SERVICE CHARGES [1]:					**Billing Rates**
Customer Charge (per month, all service types):					**$675.00**
	Base Rate	Base Rate Adjustment	Commodity Component [2]	Total Temporary Adjustments [3]	
32 CSF Volumetric Charges (per therm):					
Block 1: 1st 10,000 therms	$0.22719	$0.00828	$0.36778	$0.12956	$0.73281
Block 2: Next 20,000 therms	$0.19181	$0.00724	$0.36778	$0.12813	$0.69496
Block 3: Next 20,000 therms	$0.13300	$0.00551	$0.36778	$0.12580	$0.63209
Block 4: Next 100,000 therms	$0.07398	$0.00376	$0.36778	$0.12345	$0.56897
Block 5: Next 600,000 therms	$0.03159	$0.00252	$0.36778	$0.12176	$0.52365
Block 6: All additional therms	$0.01148	$0.00193	$0.36778	$0.12095	$0.50214
32 ISF Volumetric Charges (per therm):					
Block 1: 1st 10,000 therms	$0.16599	$0.00639	$0.36778	$0.12689	$0.66705
Block 2: Next 20,000 therms	$0.14014	$0.00565	$0.36778	$0.12600	$0.63957
Block 3: Next 20,000 therms	$0.09694	$0.00439	$0.36778	$0.12448	$0.59359
Block 4: Next 100,000 therms	$0.05388	$0.00315	$0.36778	$0.12297	$0.54778
Block 5: Next 600,000 therms	$0.02381	$0.00228	$0.36778	$0.12193	$0.51580
Block 6: All additional therms	$0.00867	$0.00184	$0.36778	$0.12141	$0.49970
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):					**$0.11482**
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV per month):					**$1.69**

(I) (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 or Schedule 15.
[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, the Account 191 Adjustments may apply.

(continue to Sheet 32-13)

NORTHWEST NATURAL GAS COMPANY
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Eighteenth Revision of Sheet 32-13
Cancels Seventeenth Revision of Sheet 32-13

RATE SCHEDULE 32
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES (continued): **Effective: December 24, 2026** (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 100** for a list of applicable temporary adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **SCHEDULE 160**

INTERRUPTIBLE SALES SERVICE CHARGES [1][4]:					**Billing Rates**	
Customer Charge (per month):					**$675.00**	
	Base Rate	Base Rate Adjustment	Commodity Component [2]	Total Temporary Adjustments [3]		
32 CSI Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	$0.17221	$0.00598	$0.36778	$0.10506	$0.65103	(I)
Block 2: Next 20,000 therms	$0.14540	$0.00530	$0.36778	$0.10420	$0.62268	
Block 3: Next 20,000 therms	$0.10064	$0.00415	$0.36778	$0.10273	$0.57530	
Block 4: Next 100,000 therms	$0.05587	$0.00302	$0.36778	$0.10127	$0.52794	
Block 5: Next 600,000 therms	$0.02902	$0.00233	$0.36778	$0.10039	$0.49952	
Block 6: All additional therms	$0.00936	$0.00183	$0.36778	$0.09975	$0.47872	(I)
Interruptible Pipeline Capacity Charge (per therm):					**$0.01366**	
32 ISI Volumetric Charges (per therm):						
Block 1: 1st 10,000 therms	$0.15039	$0.00530	$0.36778	$0.10490	$0.62837	(I)
Block 2: Next 20,000 therms	$0.12695	$0.00472	$0.36778	$0.10415	$0.60360	
Block 3: Next 20,000 therms	$0.08788	$0.00375	$0.36778	$0.10290	$0.56231	
Block 4: Next 100,000 therms	$0.04878	$0.00279	$0.36778	$0.10163	$0.52098	
Block 5: Next 600,000 therms	$0.02530	$0.00222	$0.36778	$0.10088	$0.49618	
Block 6: All additional therms	$0.00814	$0.00180	$0.36778	$0.10032	$0.47804	(I)
Interruptible Pipeline Capacity Charge (per therm):					**$0.01366**	

[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 or Schedule 15.
[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, the Account 191 Adjustments may apply.

(continue to Sheet 32-14)

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P.U.C. Or. 25

Sixteenth Revision of Sheet 32-14
Cancels Fifteenth Revision of Sheet 32-14

RATE SCHEDULE 32
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES (continued): **Effective: December 24, 2026** (C)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 100** for a list of applicable temporary adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in Schedule 160.

FIRM TRANSPORTATION SERVICE CHARGES (32 CTF or 32 ITF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$675.00**	
Transportation Charge (per month):					**$250.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment		Total Temporary Adjustments [2]		
Commercial						
Block 1: 1st 10,000 therms	$0.16429	$0.00040		$0.08254	$0.24723	(I)
Block 2: Next 20,000 therms	$0.13960	($0.00028)		$0.08207	$0.22139	
Block 3: Next 20,000 therms	$0.09856	($0.00141)		$0.08125	$0.17840	
Block 4: Next 100,000 therms	$0.05751	($0.00255)		$0.08044	$0.13540	
Block 5: Next 600,000 therms	$0.03283	($0.00323)		$0.07996	$0.10956	
Block 6: All additional therms	$0.01646	($0.00369)		$0.07964	$0.09241	
Industrial						
Block 1: 1st 10,000 therms	$0.15750	($0.00041)		$0.08237	$0.23946	
Block 2: Next 20,000 therms	$0.13386	($0.00097)		$0.08199	$0.21488	
Block 3: Next 20,000 therms	$0.09452	($0.00190)		$0.08139	$0.17401	
Block 4: Next 100,000 therms	$0.05516	($0.00283)		$0.08078	$0.13311	
Block 5: Next 600,000 therms	$0.03148	($0.00339)		$0.08041	$0.10850	
Block 6: All additional therms	$0.01581	($0.00376)		$0.08018	$0.09223	(I)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.49267**	
INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (32 CTI or ITI) [3][4]:						
Customer Charge (per month):					**$675.00**	
Transportation Charge (per month):					**$250.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment		Total Temporary Adjustments [2]		
Commercial						
Block 1: 1st 10,000 therms	$0.15944	($0.00134)		$0.08152	$0.23962	(I)
Block 2: Next 20,000 therms	$0.13552	($0.00176)		$0.08120	$0.21496	
Block 3: Next 20,000 therms	$0.09571	($0.00245)		$0.08062	$0.17388	
Block 4: Next 100,000 therms	$0.05581	($0.00316)		$0.08008	$0.13273	
Block 5: Next 600,000 therms	$0.03190	($0.00358)		$0.07977	$0.10809	
Block 6: All additional therms	$0.01601	($0.00386)		$0.07952	$0.09167	
Industrial						
Block 1: 1st 10,000 therms	$0.14093	($0.00110)		$0.08210	$0.22193	
Block 2: Next 20,000 therms	$0.11979	($0.00156)		$0.08178	$0.20001	
Block 3: Next 20,000 therms	$0.08459	($0.00231)		$0.08124	$0.16352	
Block 4: Next 100,000 therms	$0.04933	($0.00308)		$0.08069	$0.12694	
Block 5: Next 600,000 therms	$0.02822	($0.00353)		$0.08037	$0.10506	
Block 6: All additional therms	$0.01415	($0.00384)		$0.08016	$0.09047	(I)

[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 15.
[2] Where applicable, the Account 191 Adjustments shall apply.
[3] 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 15.

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NWN OPUC Advice No. 26-11

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NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25
Fifteenth Revision of Sheet 33-8
Cancels Fourteenth Revision of Sheet 33-8

RATE SCHEDULE 33
HIGH VOLUME NON-RESIDENTIAL
FIRM AND INTERRUPTIBLE TRANSPORTATION SERVICE
(continued)

MONTHLY RATE: Effective: December 24, 2026 (C)

The rates shown below may not always reflect actual billing rates. See **Schedule 100** for a list of applicable temporary adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM TRANSPORTATION SERVICE CHARGES (33 TF)					
					Billing Rates
Customer Charge:					**$38,000.00**
Transportation Charge:					**$250.00**
Volumetric Charge:		Base Rate	Base Rate Adjustments	Total Temporary Adjustment [1]	
Per therm, all therms:		$0.00574	($0.00814)	$0.07918	**$0.07678** (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 15**.					

INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (33 TI)					
					Billing Rates
Customer Charge:					**$38,000.00**
Transportation Charge:					**$250.00**
Volumetric Charge:		Base Rate	Base Rate Adjustments	Total Temporary Adjustment [1]	
Per therm, all therms:		$0.00574	($0.00814)	$0.07918	**$0.07678** (R)
Minimum Monthly Bill: Customer Charge, plus Transportation Charge, plus any other charges that may apply from **Schedule C** and **Schedule 15.**					

[1] Where applicable, as set forth in this Rate Schedule, the Account 191 portion of the Temporary Adjustments as set forth in **Schedule 162** shall apply.

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NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25

Fifteenth Revision of Sheet 100-1
Cancels Fourteenth Revision Sheet 100-1

SCHEDULE 100
SUMMARY OF TEMPORARY ADJUSTMENTS

PURPOSE:
To list the temporary adjustments included in billing rates.

DESCRIPTION:
The temporary adjustments to rates reflected in this Schedule are the result of the Commission's approval of an application by NW Natural to defer certain revenues or expenses for later amortization in customer rates under the authority of ORS 757.259, OAR 860-022-0070, and OAR 860-027-0300. The details specific to each adjustment can be found in the respective Adjustment Schedules.

All adjustment amounts identified in this Schedule shall be in effect for a 12-month period commencing with the stated effective date, or for such other period approved by the Commission.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Rate Schedule 2	Rate Schedule 27	Rate Schedule 32
Rate Schedule 3	Rate Schedule 31	Rate Schedule 33

All temporary adjustments are stated on a cent per therm basis.

Schedule 2: Residential Sales Service

TABLE OF TEMPORARY ADJUSTMENTS: **Effective: December 24, 2026** (C)

	Applicable	Firm Sales Residential	
Residential AMP (Schedule 120)	All Therms	$0.00159	
Thermostat Rewards Program Cost Recovery (Schedule 121)	All Therms	$0.00455	
Coos County Pipeline Amortization (Schedule 125)	All Therms	$0.00060	(N)
Meter Modernization (Schedule 151)	All Therms	$0.00730	
Deferred Gas Cost Amortization (Schedule 162)	All Therms	$0.02480	
Rate Mitigation (Schedule 166)	All Therms	$0.00000	
Net Curtailment and Entitlement Revenues (168)	All Therms	($0.00002)	
Transportation Customer Energy Efficiency Program Cost Recovery (Schedule 169)	All Therms	$0.00015	
Intervenor Funding (Schedule 172)	All Therms	$0.00105	
Covid-19 Deferral (Schedule 173)	All Therms	$0.00000	
Corporate Activity Tax (CAT) (Schedule 177)	All Therms	($0.00008)	
Regulatory Rate Adjustment (Schedule 178)	All Therms	$0.00000	
TSA Security Directive 2 Compliance Costs (Schedule 180)	All Therms	$0.00000	
Regulatory Fee (Schedule 181)	All Therms	($0.00152)	
Site Remediation Cost Recovery Mechanism (SRRM) (Schedule 183)	All Therms	$0.02338	(R)
TSA Capital and Cost of Service Recovery (Schedule 189)	All Therms	$0.00070	
Decoupling Adjustment (Schedule 190)	All Therms	$0.09638	
WARM True-up (Schedule 195)	All Therms	$0.02769	
Bill Discount Administrative Cost Recovery (Schedule 336)	All Therms	$0.00038	

Schedule 3: Basic Firm Sales - Non-Residential

TABLE OF TEMPORARY ADJUSTMENTS: **Effective: December 24, 2026** (C)

	Applicable	Firm Sales Commercial	Industrial	
Residential AMP (Schedule 120)	All Therms	$0.00123	$0.00078	
Thermostat Rewards Program Cost Recovery (Schedule 121)	All Therms	$0.00352	$0.00000	
Coos County Pipeline Amortization (Schedule 125)	All Therms	$0.00046	$0.00031	(N)(N)
Meter Modernization (Schedule 151)	All Therms	$0.00563	$0.00360	
Deferred Gas Cost Amortization (Schedule 162)	All Therms	$0.02480	$0.02480	
Net Curtailment and Entitlement Revenues (Schedule 168)	All Therms	($0.00001)	($0.00001)	
Transportation Customer Energy Efficiency Program Cost Recovery (Schedule 169)	All Therms	$0.00015	$0.00015	
Intervenor Funding (Schedule 172)	All Therms	$0.00000	$0.00061	
Covid-19 Deferral (Schedule 173)	All Therms	$0.00000	$0.00000	
Corporate Activity Tax (CAT) (Schedule 177)	All Therms	($0.00007)	($0.00006)	(R)
Regulatory Rate Adjustment (Schedule 178)	All Therms	$0.00000	$0.00000	
TSA Security Directive 2 Compliance Costs (Schedule 180)	All Therms	$0.00000	$0.00000	
Regulatory Fee (Schedule 181)	All Therms	($0.00124)	($0.00105)	
Site Remediation Cost Recovery Mechanism (SRRM) (Schedule 183)	All Therms	$0.01806	$0.01153	(R)
Industrial DSM (Schedule 188)	All Therms		$0.09582	
TSA Capital and Cost of Service Recovery (Schedule 189)	All Therms	$0.00056	$0.00033	
Decoupling Adjustment (Schedule 190)	All Therms	$0.07626		
WARM True-up (Schedule 195)	All Therms	$0.03901		
Bill Discount Administrative Cost Recovery (Schedule 336)	All Therms	$0.00029	$0.00019	

(continue to Sheet 100-2)

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25

Fifteenth Revision of Sheet 100-2
Cancels Fourteenth Revision of Sheet 100-2

SCHEDULE 100
SUMMARY OF TEMPORARY ADJUSTMENTS
(continued)

TABLE OF TEMPORARY ADJUSTMENTS (continued): **Effective: December 24, 2026**

Rate Schedule 27: Residential Heating Dry Out Service

	Applicable	FIRM SALES Commercial	
Residential AMP (Schedule 120)	All Therms	$0.00157	(I)
Thermostat Rewards Program Cost Recovery (Schedule 121)	All Therms	$0.00000	(N)
Coos County Pipeline Amortization (Schedule 125)	All Therms	$0.00062	(I)
Meter Modernization (Schedule 151)	All Therms	$0.00718	
Deferred Gas Cost Amortization (Schedule 162)	All Therms	$0.02480	
Net Curtailment and Entitlement Revenues (Schedule 168)	All Therms	($0.00002)	
Transportation Customer Energy Efficiency Program Cost Recovery (Schedule 169)	All Therms	$0.00015	
Intervenor Funding (Schedule 172)	All Therms	$0.00000	
Covid-19 Deferral (Schedule 173)	All Therms	$0.00000	
Corporate Activity Tax (CAT) (Schedule 177)	All Therms	($0.00008)	(R)
Regulatory Rate Adjustment (Schedule 178)	All Therms	$0.00000	
TSA Security Directive 2 Compliance Costs (Schedule 180)	All Therms	$0.00000	
Regulatory Fee (Schedule 181)	All Therms	($0.00146)	(R)
Site Remediation Recovery Mechanism (Schedule 183)	All Therms	$0.02302	(I)
TSA Capital and Cost of Service Recovery (Schedule 189)	All Therms	$0.00088	
Bill Discount Administrative Cost Recovery (Schedule 336)	All Therms	$0.00037	(I)

Schedule 31: Non-Residential Firm Sales and Firm Transportation

		FIRM SALES		FIRM TRANSPORTATION		
	Applicable	Commercial	Industrial	Commercial	Industrial	
Residential AMP (Schedule 120)	Block 1	$0.00074	$0.00052	$0.00077	$0.00057	
	Block 2	$0.00068	$0.00047	$0.00071	$0.00052	
Thermostat Rewards Program Cost Recovery (Schedule 121)	All Blocks	$0.00000	$0.00000			
Coos County Pipeline Amortization (Schedule 125)	Block 1	$0.00027	$0.00019	$0.00029	$0.00021	(N)(N)(N)(N)
	Block 2	$0.00025	$0.00018	$0.00027	$0.00019	(N)(N)(N)(N)
Meter Modernization (Schedule 151)	Block 1	$0.00340	$0.00238	$0.00355	$0.00263	
	Block 2	$0.00310	$0.00215	$0.00325	$0.00238	
Deferred Gas Cost Amortization (Schedule 162)	All Blocks	$0.02480	$0.02480			
Net Curtailment and Entitlement Revenues (168)	Block 1	($0.00001)	($0.00001)			
	Block 2	($0.00001)	$0.00000			
Transportation Customer Energy Efficiency Program Cost Recovery (Schedule 169)	Block 1	$0.00015	$0.00015	($0.00803)	($0.00591)	(I)(I)(R)(R)
	Block 2	$0.00015	$0.00015	($0.00735)	($0.00535)	(I)(I)(R)(R)
Transportation Customer Renewable Natural Gas Offtake Costs (Schedule 171)	All Blocks			$0.07910	$0.07910	
Intervenor Funding (Schedule 172)	All Blocks		$0.00061		$0.00061	
Covid-19 Deferral (Schedule 173)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	
Corporate Activity Tax (CAT) (Schedule 177)	Block 1	($0.00005)	($0.00004)	($0.00003)	($0.00003)	
	Block 2	($0.00004)	($0.00004)	($0.00003)	($0.00002)	
Regulatory Rate Adjustment (Schedule 178)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	
TSA Security Directive 2 Compliance Costs (Schedule 180)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	
Regulatory Fee (Schedule 181)	Block 1	($0.00086)	($0.00078)	($0.00056)	($0.00049)	
	Block 2	($0.00083)	($0.00075)	($0.00052)	($0.00045)	
Site Remediation Recovery Mechanism (SRRM) (Schedule 183)	Block 1	$0.01088	$0.00764	$0.01138	$0.00843	
	Block 2	$0.00995	$0.00690	$0.01043	$0.00764	
Industrial DSM (Schedule 188)	All Blocks		$0.09582			
TSA Capital and Cost of Service Recovery (Schedule 189)	Block 1	$0.00027	$0.00025	$0.00033	$0.00027	
	Block 2	$0.00025	$0.00023	$0.00031	$0.00025	
Decoupling Adjustment (Schedule 190)	All Blocks	$0.05033				
Bill Discount Administrative Cost Recovery (Schedule 336)	Block 1	$0.00018	$0.00012	$0.00018	$0.00014	
	Block 2	$0.00016	$0.00011	$0.00017	$0.00012	

(continue to Sheet 100-3)

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25

Fifteenth Revision of Sheet 100-3
Cancels Fourteenth Revision of Sheet 100-3

SCHEDULE 100
SUMMARY OF TEMPORARY ADJUSTMENTS
(continued)

TABLE OF TEMPORARY ADJUSTMENTS (continued): **Effective: December 24, 2026** (C)

Schedule 32: Large Volume Non-Residential Sales and Transportation

		FIRM SALES		FIRM TRANSPORTATION	
	Applicable	Commercial	Industrial	Commercial	Industrial
Residential AMP (Schedule 120)	Block 1	$0.00045	$0.00029	$0.00035	$0.00026
	Block 2	$0.00038	$0.00025	$0.00030	$0.00022
	Block 3	$0.00027	$0.00018	$0.00021	$0.00016
	Block 4	$0.00015	$0.00010	$0.00013	$0.00010
	Block 5	$0.00007	$0.00005	$0.00008	$0.00006
	Block 6	$0.00003	$0.00003	$0.00005	$0.00004
Thermostat Rewards Program Cost Recovery (Schedule 121)	All Blocks	$0.00000	$0.00000		
Coos County Pipeline Amortization (Schedule 125)	Block 1	$0.00018	$0.00012	$0.00012	$0.00011
	Block 2	$0.00015	$0.00010	$0.00010	$0.00009
	Block 3	$0.00010	$0.00007	$0.00007	$0.00006
	Block 4	$0.00006	$0.00004	$0.00004	$0.00004
	Block 5	$0.00003	$0.00002	$0.00002	$0.00002
	Block 6	$0.00001	$0.00001	$0.00001	$0.00001
Meter Modernization (Schedule 151)	Block 1	$0.00205	$0.00135	$0.00159	$0.00120
	Block 2	$0.00174	$0.00115	$0.00136	$0.00103
	Block 3	$0.00123	$0.00081	$0.00098	$0.00075
	Block 4	$0.00071	$0.00047	$0.00061	$0.00046
	Block 5	$0.00034	$0.00024	$0.00038	$0.00029
	Block 6	$0.00016	$0.00012	$0.00023	$0.00018
Deferred Gas Cost Amortization (Schedule 162)	All Blocks	$0.02480	$0.02480		
Net Curtailment and Entitlement Revenues (168)	Block 1	$0.00000	$0.00000		
	Block 2	$0.00000	$0.00000		
	Block 3	$0.00000	$0.00000		
	Block 4	$0.00000	$0.00000		
	Block 5	$0.00000	$0.00000		
	Block 6	$0.00000	$0.00000		
Transportation Customer Energy Efficiency Program Cost Recovery (Schedule 169)	Block 1	$0.00015	$0.00015	($0.00350)	($0.00262)
	Block 2	$0.00015	$0.00015	($0.00298)	($0.00222)
	Block 3	$0.00015	$0.00015	($0.00212)	($0.00157)
	Block 4	$0.00015	$0.00015	($0.00126)	($0.00092)
	Block 5	$0.00015	$0.00015	($0.00074)	($0.00053)
	Block 6	$0.00015	$0.00015	($0.00039)	($0.00027)
Transportation Customer Renewable Natural Gas Offtake Costs (Schedule 171)	All Blocks			$0.07910	$0.07910
Intervenor Funding (Schedule 172)	Block 1	$0.00000	$0.00061		$0.00061
	Block 2	$0.00000	$0.00061		$0.00061
	Block 3	$0.00000	$0.00061		$0.00061
	Block 4	$0.00000	$0.00061		$0.00061
	Block 5	$0.00000	$0.00061		$0.00061
	Block 6	$0.00000	$0.00061		$0.00061
Covid-19 Deferral (Schedule 173)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000
	Block 3	$0.00000	$0.00000	$0.00000	$0.00000
	Block 4	$0.00000	$0.00000	$0.00000	$0.00000
	Block 5	$0.00000	$0.00000	$0.00000	$0.00000
	Block 6	$0.00000	$0.00000	$0.00000	$0.00000
Corporate Activity Tax (CAT) (Schedule 177)	Block 1	($0.00004)	($0.00003)	($0.00002)	($0.00001)
	Block 2	($0.00004)	($0.00003)	($0.00001)	($0.00001)
	Block 3	($0.00003)	($0.00003)	($0.00001)	($0.00001)
	Block 4	($0.00003)	($0.00003)	($0.00001)	($0.00001)
	Block 5	($0.00003)	($0.00003)	($0.00001)	($0.00001)
	Block 6	($0.00003)	($0.00003)	($0.00001)	$0.00000
Regulatory Rate Adjustment (Schedule 178)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000
	Block 3	$0.00000	$0.00000	$0.00000	$0.00000
	Block 4	$0.00000	$0.00000	$0.00000	$0.00000
	Block 5	$0.00000	$0.00000	$0.00000	$0.00000
	Block 6	$0.00000	$0.00000	$0.00000	$0.00000
TSA Security Directive 2 Compliance Costs (Schedule 180)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000
	Block 3	$0.00000	$0.00000	$0.00000	$0.00000
	Block 4	$0.00000	$0.00000	$0.00000	$0.00000
	Block 5	$0.00000	$0.00000	$0.00000	$0.00000
	Block 6	$0.00000	$0.00000	$0.00000	$0.00000
Regulatory Fee (Schedule 181)	Block 1	($0.00073)	($0.00064)	($0.00029)	($0.00022)
	Block 2	($0.00070)	($0.00061)	($0.00026)	($0.00020)
	Block 3	($0.00065)	($0.00058)	($0.00021)	($0.00016)
	Block 4	($0.00059)	($0.00054)	($0.00016)	($0.00012)
	Block 5	($0.00055)	($0.00051)	($0.00013)	($0.00010)
	Block 6	($0.00053)	($0.00050)	($0.00011)	($0.00008)
Site Remediation Recovery Mechanism (Schedule 183)	Block 1	$0.00658	$0.00433	$0.00508	$0.00385
	Block 2	$0.00558	$0.00368	$0.00436	$0.00330
	Block 3	$0.00393	$0.00260	$0.00316	$0.00239
	Block 4	$0.00227	$0.00152	$0.00195	$0.00149
	Block 5	$0.00108	$0.00077	$0.00123	$0.00094
	Block 6	$0.00051	$0.00039	$0.00075	$0.00058
Industrial DSM (Schedule 188)	All Blocks	$0.09582	$0.09582		
TSA Capital and Cost of Service Recovery (Schedule 189)	Block 1	$0.00019	$0.00002	$0.00003	$0.00003
	Block 2	$0.00016	$0.00002	$0.00003	$0.00002
	Block 3	$0.00012	$0.00001	$0.00002	$0.00002
	Block 4	$0.00007	$0.00001	$0.00001	$0.00001
	Block 5	$0.00003	$0.00000	$0.00001	$0.00001
	Block 6	$0.00002	$0.00000	$0.00000	$0.00000
Bill Discount Administrative Cost Recovery (Schedule 336)	Block 1	$0.00011	$0.00007	$0.00008	$0.00006
	Block 2	$0.00009	$0.00006	$0.00007	$0.00005
	Block 3	$0.00006	$0.00004	$0.00005	$0.00004
	Block 4	$0.00004	$0.00002	$0.00003	$0.00002
	Block 5	$0.00002	$0.00001	$0.00002	$0.00002
	Block 6	$0.00001	$0.00001	$0.00001	$0.00001

(N)(N)(N)(N)
(N)(N)(N)(N)

(continue to Sheet 100-4)

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25

Fourteenth Revision of Sheet 100-4
Cancels Thirteenth Revision of Sheet 100-4

SCHEDULE 100
SUMMARY OF TEMPORARY ADJUSTMENTS
(continued)

TABLE OF TEMPORARY ADJUSTMENTS (continued): Effective: December 24, 2026 (C)

Schedule 32: Large Volume Non-Residential Sales and Transportation

		INTERRUPTIBLE SALES		INTERRUPTIBLE TRANSPORT		
	Applicable	Commercial	Industrial	Commercial	Industrial	
Residential AMP (Schedule 120)	Block 1	$0.00028	$0.00025	$0.00023	$0.00024	
	Block 2	$0.00024	$0.00021	$0.00020	$0.00020	
	Block 3	$0.00017	$0.00015	$0.00014	$0.00015	
	Block 4	$0.00010	$0.00009	$0.00009	$0.00009	
	Block 5	$0.00006	$0.00005	$0.00006	$0.00006	
	Block 6	$0.00002	$0.00002	$0.00003	$0.00004	
Thermostat Rewards Program Cost Recovery (Schedule 121)	All Blocks	$0.00000	$0.00000			
Coos County Pipeline Amortization (Schedule 125)	Block 1	$0.00011	$0.00010	$0.00019	$0.00008	(N)
	Block 2	$0.00010	$0.00009	$0.00016	$0.00007	
	Block 3	$0.00007	$0.00006	$0.00011	$0.00005	
	Block 4	$0.00004	$0.00003	$0.00006	$0.00003	
	Block 5	$0.00002	$0.00002	$0.00003	$0.00001	
	Block 6	$0.00001	$0.00001	$0.00001	$0.00001	(N)
Meter Modernization (Schedule 151)	Block 1	$0.00128	$0.00113	$0.00104	$0.00108	
	Block 2	$0.00109	$0.00096	$0.00090	$0.00093	
	Block 3	$0.00077	$0.00068	$0.00065	$0.00068	
	Block 4	$0.00045	$0.00040	$0.00040	$0.00042	
	Block 5	$0.00025	$0.00023	$0.00026	$0.00027	
	Block 6	$0.00011	$0.00010	$0.00016	$0.00017	
Deferred Gas Cost Amortization (Schedule 162)	All Blocks	$0.00377	$0.00377			
Transportation EE Deferral	Block 1	$0.00015	$0.00015	($0.00225)	($0.00235)	
	Block 2	$0.00015	$0.00015	($0.00191)	($0.00199)	
	Block 3	$0.00015	$0.00015	($0.00135)	($0.00141)	
	Block 4	$0.00015	$0.00015	($0.00078)	($0.00082)	
	Block 5	$0.00015	$0.00015	($0.00044)	($0.00047)	
	Block 6	$0.00015	$0.00015	($0.00022)	($0.00023)	
Transportation Customer Renewable Natural Gas Offtake Costs (Schedule 171)	All Blocks			$0.07910	$0.07910	
Intervenor Funding (Schedule 172)	All Blocks		$0.00061		$0.00061	
Covid-19 Deferral (Schedule 173)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 3	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 4	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 5	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 6	$0.00000	$0.00000	$0.00000	$0.00000	
Corporate Activity Tax (CAT) (Schedule 177)	Block 1	($0.00003)	($0.00003)	($0.00001)	($0.00001)	
	Block 2	($0.00003)	($0.00003)	($0.00001)	($0.00001)	
	Block 3	($0.00003)	($0.00003)	($0.00001)	($0.00001)	
	Block 4	($0.00003)	($0.00003)	($0.00001)	($0.00001)	
	Block 5	($0.00003)	($0.00003)	$0.00000	$0.00000	
	Block 6	($0.00003)	($0.00003)	$0.00000	$0.00000	(R)(R)
Regulatory Rate Adjustment (Schedule 178)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 3	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 4	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 5	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 6	$0.00000	$0.00000	$0.00000	$0.00000	
TSA Security Directive 2 Compliance Costs (Schedule 180)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 3	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 4	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 5	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 6	$0.00000	$0.00000	$0.00000	$0.00000	
Regulatory Fee (Schedule 181)	Block 1	($0.00062)	($0.00060)	($0.00020)	($0.00020)	
	Block 2	($0.00060)	($0.00058)	($0.00018)	($0.00018)	
	Block 3	($0.00056)	($0.00054)	($0.00015)	($0.00015)	
	Block 4	($0.00052)	($0.00051)	($0.00011)	($0.00011)	
	Block 5	($0.00049)	($0.00049)	($0.00009)	($0.00009)	
	Block 6	($0.00048)	($0.00047)	($0.00008)	($0.00008)	
Site Remediation Recovery Mechanism (Schedule 183)	Block 1	$0.00411	$0.00361	$0.00334	$0.00347	(R)
	Block 2	$0.00350	$0.00307	$0.00287	$0.00298	
	Block 3	$0.00246	$0.00217	$0.00208	$0.00217	(R)
	Block 4	$0.00143	$0.00127	$0.00130	$0.00135	
	Block 5	$0.00081	$0.00073	$0.00083	$0.00086	
	Block 6	$0.00036	$0.00033	$0.00051	$0.00053	
Industrial DSM (Schedule 188)	All Blocks	$0.09582	$0.09582			
TSA Capital and Cost of Service Recovery (Schedule 189)	Block 1	$0.00012	$0.00003	$0.00003	$0.00002	
	Block 2	$0.00010	$0.00003	$0.00002	$0.00002	
	Block 3	$0.00007	$0.00002	$0.00002	$0.00002	
	Block 4	$0.00004	$0.00001	$0.00001	$0.00001	
	Block 5	$0.00002	$0.00001	$0.00001	$0.00001	
	Block 6	$0.00001	$0.00000	$0.00000	$0.00000	
Bill Discount Administrative Cost Recovery (Schedule 336)	Block 1	$0.00007	$0.00006	$0.00005	$0.00006	
	Block 2	$0.00006	$0.00005	$0.00005	$0.00005	
	Block 3	$0.00004	$0.00004	$0.00003	$0.00003	
	Block 4	$0.00002	$0.00002	$0.00002	$0.00002	
	Block 5	$0.00001	$0.00001	$0.00001	$0.00001	
	Block 6	$0.00001	$0.00001	$0.00001	$0.00001	

(continue to Sheet 100-5)

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25

Second Revision of Sheet 122-1
Cancels First Revision of Sheet 122-1

SCHEDULE 122
AMORTIZATION OF GC 500 MIST COMPRESSOR REGULATORY ASSET

PURPOSE:
The purpose of this schedule is to reflect the rate effects of the amortization of the GC 500 Mist Compressor regulatory asset over an eight-year period beginning on October 31, 2025 and ending on October 31, 2033, subject to the terms of the First Partial Multi-Party Stipulation with a rate spread subject to the terms of the Second Partial All-Party Stipulation approved in Order No. 25-420 in Docket UG 520. These rates are included as Base Rate Adjustments in the rate schedules listed below and were first included in rates October 31, 2025, as filed with the Company's compliance filing in UG 520.

APPLICABLE:
To all Customers served under the following Rate Schedules of this Tariff:

Rate Schedule 2 Rate Schedule 3 Rate Schedule 27 Rate Schedule 31
Rate Schedule 32 Rate Schedule 33

APPLICATION TO RATE SCHEDULES:
The adjustment amounts shown below are embedded in the Base Rate Adjustment reflected in the respective Rate Schedules listed above. NO ADDITION TO RATES IS REQUIRED.

Effective: December 24, 2026 (C)

Rate Schedule/Class	Adjustment	
2	$0.00282	(I)

(C)

Effective: December 24, 2026

Rate Schedule/Class	Block	Adjustment		Rate Schedule/Class	Block	Adjustment	
				31 CSF	Block 1	$0.00126	(R)
03 CSF		$0.00217			Block 2	$0.00115	(I) (R)
03 ISF		$0.00142		31 CTF	Block 1	$0.00137	(I) (I)
27		$0.00293			Block 2	$0.00125	(I) (R)
				31 ISF	Block 1	$0.00088	
					Block 2	$0.00080	
				31 ITF	Block 1	$0.00099	
					Block 2	$0.00089	
32 CSF	Block 1	$0.00075		32 CSI	Block 1	$0.00048	(R)
	Block 2	$0.00064			Block 2	$0.00041	
	Block 3	$0.00044			Block 3	$0.00028	
	Block 4	$0.00025			Block 4	$0.00016	
	Block 5	$0.00011			Block 5	$0.00008	
	Block 6	$0.00004			Block 6	$0.00003	(R)
32 ISF	Block 1	$0.00050		32 ISI	Block 1	$0.00043	(R)
	Block 2	$0.00042			Block 2	$0.00036	
	Block 3	$0.00029			Block 3	$0.00025	
	Block 4	$0.00017			Block 4	$0.00014	
	Block 5	$0.00008			Block 5	$0.00008	(R)
	Block 6	$0.00003			Block 6	$0.00003	(I)
32 CTF	Block 1	$0.00054		32 CTI	Block 1	$0.00042	(I)
	Block 2	$0.00046			Block 2	$0.00035	
	Block 3	$0.00032			Block 3	$0.00025	
	Block 4	$0.00018			Block 4	$0.00014	(R)
	Block 5	$0.00010			Block 5	$0.00008	
	Block 6	$0.00004			Block 6	$0.00003	
32 ITF	Block 1	$0.00044		32 ITI	Block 1	$0.00038	
	Block 2	$0.00037			Block 2	$0.00032	
	Block 3	$0.00026			Block 3	$0.00022	
	Block 4	$0.00015			Block 4	$0.00013	
	Block 5	$0.00008			Block 5	$0.00007	
	Block 6	$0.00003			Block 6	$0.00003	(R)
				33		$0.00000	(R)

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.

Issued November 24, 2026
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Effective with service on
and after December 24, 2026

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25

First Revision of Sheet 123-2
Cancels Original Sheet 123-2

SCHEDULE 123
ADJUSTMENT FOR ALTERNATIVE RATE MECHANISM
(continued)

RATE ADJUSTMENTS:
The Total Adjustment amounts shown below are included in the Base Rate reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Rate Schedule/Class	Block	Adjustment		Rate Schedule/Class	Block	Adjustment
2		$0.00000		31 CSF	Block 1	$0.00000
					Block 2	$0.00000
03 CSF		$0.00000		31 CTF	Block 1	$0.00000
03 ISF		$0.00000			Block 2	$0.00000
27		$0.00000		31 ISF	Block 1	$0.00000
					Block 2	$0.00000
				31 ITF	Block 1	$0.00000
					Block 2	$0.00000
				32 CSI	Block 1	$0.00000
32 CSF	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		32 ISI	Block 1	$0.00000
32 ISF	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		32 CTI	Block 1	$0.00000
32 CTF	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		32 ITI	Block 1	$0.00000
32 ITF	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		33		$0.00000

(R) (R)
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Issued November 24, 2026
NWN OPUC Advice No. 26-11

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and after December 24, 2026

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25

First Revision of Sheet 124-1
Cancels Original Sheet 124-1

SCHEDULE 124
AMORTIZATION OF GC 600 MIST COMPRESSOR REGULATORY ASSET

PURPOSE:
The purpose of this schedule is to reflect the rate effects of the amortization of the GC 600 Mist Compressor regulatory asset over an eight-year period beginning on October 31, 2026 and ending on October 31, 2034, subject to the terms of the Partial Multi-Party Stipulation with a rate spread approved in Order No. 26-387 in consolidated Dockets UG 527 and UG 528. These rates are included as Base Rates in the rate schedules listed below and were first included in rates October 31, 2026 for residential 02 customers and November 1, 2026 for remaining rate schedules, as filed with the Company's compliance filing in consolidated Dockets UG 527 and UG 528.

APPLICABLE:
To all Customers served under the following Rate Schedules of this Tariff:

Rate Schedule 2	Rate Schedule 3	Rate Schedule 27
Rate Schedule 32	Rate Schedule 33	Rate Schedule 31

APPLICATION TO RATE SCHEDULES: **Effective: December 24, 2026** (C)
The adjustment amount shown below is embedded in the Base Rate Adjustment reflected in the respective Rate Schedules listed above. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Rate Schedule/Class	Block	Adjustment	
2		$0.00166	(I)

APPLICATION TO RATE SCHEDULES: **Effective: December 24, 2026** (C)
The adjustment amounts shown below are embedded in the Base Rate Adjustment reflected in the respective Rate Schedules listed above. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Rate Schedule/Class	Block	Adjustment		Rate Schedule/Class	Block	Adjustment	
				31 CSF	Block 1	$0.00074	
03 CSF		$0.00128			Block 2	$0.00068	(I) (I)
03 ISF		$0.00083		31 CTF	Block 1	$0.00081	(I) (I)
27		$0.00173			Block 2	$0.00074	(I) (I)
				31 ISF	Block 1	$0.00052	(R)
					Block 2	$0.00047	
				31 ITF	Block 1	$0.00058	
					Block 2	$0.00052	
32 CSF	Block 1	$0.00044		32 CSI	Block 1	$0.00028	(R)
	Block 2	$0.00038			Block 2	$0.00024	
	Block 3	$0.00026			Block 3	$0.00017	
	Block 4	$0.00015			Block 4	$0.00009	
	Block 5	$0.00006			Block 5	$0.00005	(R)(R)
	Block 6	$0.00003			Block 6	$0.00002	
32 ISF	Block 1	$0.00029		32 ISI	Block 1	$0.00025	(R)(R)
	Block 2	$0.00025			Block 2	$0.00021	
	Block 3	$0.00017			Block 3	$0.00015	
	Block 4	$0.00010			Block 4	$0.00008	
	Block 5	$0.00004			Block 5	$0.00004	(R)(R)
	Block 6	$0.00002			Block 6	$0.00002	
32 CTF	Block 1	$0.00032		32 CTI	Block 1	$0.00025	(R) (I)
	Block 2	$0.00027			Block 2	$0.00021	
	Block 3	$0.00019			Block 3	$0.00015	
	Block 4	$0.00011			Block 4	$0.00008	(I)
	Block 5	$0.00006			Block 5	$0.00004	
	Block 6	$0.00002			Block 6	$0.00002	
32 ITF	Block 1	$0.00026		32 ITI	Block 1	$0.00022	(R)
	Block 2	$0.00022			Block 2	$0.00019	
	Block 3	$0.00015			Block 3	$0.00013	(R)
	Block 4	$0.00009			Block 4	$0.00007	(R)
	Block 5	$0.00005			Block 5	$0.00004	(R)
	Block 6	$0.00002			Block 6	$0.00002	(R)
				33		$0.00000	(R)

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.

Issued November 24, 2026
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Effective with service on
and after December 24, 2026

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25 Original Sheet 125-1

(N)

SCHEDULE 125
COOS COUNTY PIPELINE AMORTIZATION

PURPOSE:
The purpose of this Schedule is to reflect the rate effects of the amortization of the Coos County Pipeline deferral (deferral docket UM 2419) subject to terms of the Partial Multi-Party stipulation approved in Order No. 26-387.

APPLICABLE:
To all classes of Customers taking service under the following Rate Schedules of the Tariff of which Schedule 125 is a part. Costs will be allocated on an equal percentage of margin basis.

Rate Schedule 2 Rate Schedule 3 Rate Schedule 27 Rate Schedule 31
Rate Schedule 32 Rate Schedule 33

APPLICATION TO RATE SCHEDULES:
The Temporary Adjustments in the applicable above-listed Rate Schedules include the adjustment shown below. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Effective: December 24, 2026

Schedule	Rate Adjustment
2	$0.00060

Effective: December 24, 2026

Schedule	Block	Rate Adjustment	Schedule	Block	Rate Adjustment
3 CSF		$0.00046	32 CSI	Block 1	0.00011
3 ISF		$0.00031		Block 2	0.00010
27		$0.00062		Block 3	0.00007
31 CSF	Block 1	$0.00027		Block 4	0.00004
	Block 2	$0.00025		Block 5	0.00002
31 CTF	Block 1	$0.00029		Block 6	0.00001
	Block 2	$0.00027	32 ISI	Block 1	0.00010
31 ISF	Block 1	$0.00019		Block 2	0.00009
	Block 2	$0.00018		Block 3	0.00006
31 ITF	Block 1	$0.00021		Block 4	0.00003
	Block 2	$0.00019		Block 5	0.00002
32 CSF	Block 1	$0.00018		Block 6	0.00001
	Block 2	$0.00015	32 CTI	Block 1	0.00019
	Block 3	$0.00010		Block 2	0.00016
	Block 4	$0.00006		Block 3	0.00011
	Block 5	$0.00003		Block 4	0.00006
	Block 6	$0.00001		Block 5	0.00003
32 ISF	Block 1	$0.00012		Block 6	0.00001
	Block 2	$0.00010	32 ITI	Block 1	0.00008
	Block 3	$0.00007		Block 2	0.00007
	Block 4	$0.00004		Block 3	0.00005
	Block 5	$0.00002		Block 4	0.00003
	Block 6	$0.00001		Block 5	0.00001
32 CTF	Block 1	$0.00012		Block 6	0.00001
	Block 2	$0.00010	33 (all)		$0.00000
	Block 3	$0.00007			
	Block 4	$0.00004			
	Block 5	$0.00002			
	Block 6	$0.00001			
32 ITF	Block 1	$0.00011			
	Block 2	$0.00009			
	Block 3	$0.00006			
	Block 4	$0.00004			
	Block 5	$0.00002			
	Block 6	$0.00001			

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 November 24, 2026
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NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25

Seventh Revision of Sheet 167-1
Cancels Sixth Revision of Sheet 167-1

SCHEDULE 167
GENERAL ADJUSTMENTS TO RATES

PURPOSE:
To identify adjustments made to the billing rates stated in the Rate Schedules listed below to reflect the effects of general rate changes approved by the Commission under the authority of ORS 757.210

DESCRIPTION:
The general rate changes shown in this Schedule 167 reflect the outcome of a Commission investigation in docket UG 532 initiated following a Company request to change rates due to increases or decreases in the cost of general utility operations. (C)

APPLICABLE:
To Customers taking service under the following Rate Schedules of this Tariff:

Rate Schedule 2	Rate Schedule 27	Rate Schedule 32
Rate Schedule 3	Rate Schedule 31	Rate Schedule 33

RATE ADJUSTMENTS: Effective: December 24, 2026 (C)
The Base Rates stated in the listed Rate Schedules were adjusted as follows:

	Adjustment Amount	
Schedule	**Customer Charge**	**Volumetric Charge**
02R	$0.00	$0.15107 (I)
02MF	$0.00	$0.15107 (I)

(C)

RATE ADJUSTMENTS: Effective: December 24, 2026
The Base Rates stated in the listed Rate Schedules were adjusted as follows:

	Adjustment Amount			Adjustment Amount	
Schedule	**Customer Charge**	**Volumetric Charge**	**Schedule**	**Customer Charge**	**Volumetric Charge**
27	$0.00	$0.15107	03 CSF	$10.00	$0.08214 (R)(I)(I)(I)
			03 ISF	$10.00	$0.07752 (I)(I)

Schedule	Block	Amount	Schedule	Block	Amount	Schedule	Block	Amount
31 CSF	Cust. Charge	$0.00	32 CSF	Cust. Charge	$0.00	32 CSI	Cust. Charge	$0.00
	Block 1	$0.05956		Block 1	$0.03882		Block 1	$0.01894 (I)(I)(I)
	Block 2	$0.05434		Block 2	$0.03278		Block 2	$0.01599 (I)
31CTF	Cust. Charge	$0.00		Block 3	$0.02273		Block 3	$0.01107
	Block 1	$0.06325		Block 4	$0.01264		Block 4	$0.00614 (I)
	Block 2	$0.05782		Block 5	$0.00540		Block 5	$0.00319 (I)
31ISF	Cust. Charge	$0.00		Block 6	$0.00196		Block 6	$0.00103 (I)(I)
	Block 1	$0.03251	32 ISF	Cust. Charge	$0.00	32 ISI	Cust. Charge	$0.00 (I)
	Block 2	$0.02930		Block 1	$0.02694		Block 1	$0.01704 (I) (I)(I)
31 ITF	Cust. Charge	$0.00		Block 2	$0.02274		Block 2	$0.01439
	Block 1	$0.03503		Block 3	$0.01573		Block 3	$0.00996 (I)
	Block 2	$0.03167		Block 4	$0.00874		Block 4	$0.00553 (I)
				Block 5	$0.00386		Block 5	$0.00286
				Block 6	$0.00140		Block 6	$0.00092 (I)(I)
			32 CTF	Cust. Charge	$0.00	32 CTI	Cust. Charge	$0.00
				Block 1	$0.02054		Block 1	$0.02944 (I)(I)
				Block 2	$0.01745		Block 2	$0.02502
				Block 3	$0.01232		Block 3	$0.01768
				Block 4	$0.00719		Block 4	$0.01031
				Block 5	$0.00411		Block 5	$0.00589
				Block 6	$0.00205		Block 6	$0.00296 (I)(I)
			32 ITF	Cust. Charge	$0.00	32 ITI	Cust. Charge	$0.00
				Block 1	$0.02253		Block 1	$0.01283 (I)(I)
				Block 2	$0.01914		Block 2	$0.01090
				Block 3	$0.01352		Block 3	$0.00770
				Block 4	$0.00789		Block 4	$0.00449
				Block 5	$0.00450		Block 5	$0.00257
				Block 6	$0.00226		Block 6	$0.00129 (I)(I)
						33	All	$0.00000

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, 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.

Issued November 24, 2026
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NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25

Fourth Revision of Sheet 175-1
Cancels Third Revision of Sheet 175-1

SCHEDULE 175
AMORTIZATION OF HORIZON 1 START-UP COST DEFERRAL

PURPOSE:
The purpose of this Schedule is to reflect the rate effects of the amortization of Horizon 1 Start-Up cost deferral (deferral docket UM 2132) over 10 years beginning November 1, 2022, subject to the terms of the stipulation approved in Order No. 21-246 with a rate spread as shown in Exhibit B of the Multi-Party Stipulation approved in Order No. 22-388 in dockets UG 435 and UG 411. These rates are included as Base Rate Adjustments in the rate schedules listed below and were first included in rates November 1, 2022, as filed with the Company's compliance filing in UG 435.

APPLICABLE:
To all Customers served under the following Rate Schedules of this Tariff:

Rate Schedule 2	Rate Schedule 3	Rate Schedule 27
Rate Schedule 32	Rate Schedule 33	Rate Schedule 31

APPLICATION TO RATE SCHEDULES:
The adjustment amounts shown below are embedded in the Base Rate reflected in the respective Rate Schedules listed above. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Effective: December 24, 2026 (C)

Rate Schedule/Class	Adjustment	
2	$0.00168	(R)

Effective: December 24, 2026

Rate Schedule/Class	Block	Adjustment	Rate Schedule/Class	Block	Adjustment	
03 CSF		$0.00127	31 CSF	Block 1	$0.00061	(R) (R)
03 ISF		$0.00092		Block 2	$0.00056	(I) (R)
27		$0.00174	31 CTF	Block 1	$0.00089	(R) (I)
				Block 2	$0.00082	
			31 ISF	Block 1	$0.00064	
				Block 2	$0.00058	
			31 ITF	Block 1	$0.00077	
32 CSF	Block 1	$0.00042		Block 2	$0.00070	(R)
	Block 2	$0.00036	32 CSI	Block 1	$0.00032	
	Block 3	$0.00025		Block 2	$0.00027	
	Block 4	$0.00014		Block 3	$0.00019	
	Block 5	$0.00006		Block 4	$0.00011	(I)
	Block 6	$0.00002		Block 5	$0.00006	
32 ISF	Block 1	$0.00005		Block 6	$0.00002	(R)
	Block 2	$0.00004	32 ISI	Block 1	$0.00010	(R) (I)
	Block 3	$0.00003		Block 2	$0.00008	
	Block 4	$0.00002		Block 3	$0.00006	
	Block 5	$0.00001		Block 4	$0.00003	
	Block 6	$0.00000		Block 5	$0.00002	(R) (I)
32 CTF	Block 1	$0.00009		Block 6	$0.00001	(R)
	Block 2	$0.00007	32 CTI	Block 1	$0.00014	(I)
	Block 3	$0.00005		Block 2	$0.00012	
	Block 4	$0.00003		Block 3	$0.00008	(R)
	Block 5	$0.00002		Block 4	$0.00005	
	Block 6	$0.00001		Block 5	$0.00002	(I)
32 ITF	Block 1	$0.00008		Block 6	$0.00001	(R)
	Block 2	$0.00006	32 ITI	Block 1	$0.00007	(I) (I)
	Block 3	$0.00004		Block 2	$0.00006	(I) (I)
	Block 4	$0.00003		Block 3	$0.00004	(I)
	Block 5	$0.00001		Block 4	$0.00002	(R)
	Block 6	$0.00001		Block 5	$0.00001	
				Block 6	$0.00001	
			33		$0.00000	(R)

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NWN OPUC Advice No. 26-11

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NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25

Sixth Revision of Sheet 182-1
Cancels Fifth Revision of Sheet 182-1

SCHEDULE 182
RATE ADJUSTMENT FOR ENVIRONMENTAL COST RECOVERY

PURPOSE:
The purpose of this Schedule is to reflect the rate effects of the collection of $5.0 million per year for the recovery of costs related to environmental remediation expenses, in accordance with Order No. 15-049 in Docket UM 1635 and UM 1706 entered by the Public Utility Commission of Oregon on February 20, 2015.

APPLICABLE:
To all Customers served under the following Rate Schedules of this Tariff:

Rate Schedule 2	Rate Schedule 3	Rate Schedule 27
Rate Schedule 32	Rate Schedule 33	Rate Schedule 31

APPLICATION TO RATE SCHEDULES:
The Adjustment amounts shown below are calculated based on equal percent of margin by Rate Schedule and Customer class. The adjustment amount is embedded in the Base Rate reflected in the respective Rate Schedules listed above. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Effective: December 24, 2026

Rate Schedule/Class	Base Rate Adjustment	
2	$0.00838	(I)

Effective: December 24, 2026

Rate Schedule/Class	Block	Base Rate Adjustment		Schedule	Block	Base Rate Adjustment	
				31 CSF	Block 1	$0.00374	(R)
					Block 2	$0.00342	
03 CSF		$0.00645		31 ISF	Block 1	$0.00262	(R)
03 ISF		$0.00421			Block 2	$0.00237	(R) (R)
27		$0.00872		31 CTF	Block 1	$0.00407	(R) (I)
					Block 2	$0.00372	(I)
				31 ITF	Block 1	$0.00293	(R)
					Block 2	$0.00264	
				32 CSI	Block 1	$0.00143	
32 CSF	Block 1	$0.00224			Block 2	$0.00121	(R)
	Block 2	$0.00189			Block 3	$0.00084	
	Block 3	$0.00132			Block 4	$0.00047	
	Block 4	$0.00074			Block 5	$0.00025	
	Block 5	$0.00032			Block 6	$0.00009	
	Block 6	$0.00013		32 ISI	Block 1	$0.00127	
32 ISF	Block 1	$0.00149			Block 2	$0.00107	
	Block 2	$0.00126			Block 3	$0.00075	
	Block 3	$0.00087			Block 4	$0.00042	
	Block 4	$0.00049			Block 5	$0.00022	
	Block 5	$0.00022			Block 6	$0.00008	(R)
	Block 6	$0.00009		32 CTI	Block 1	$0.00125	(I)
32 CTF	Block 1	$0.00161			Block 2	$0.00106	(I)
	Block 2	$0.00137			Block 3	$0.00074	
	Block 3	$0.00095			Block 4	$0.00042	(R)
	Block 4	$0.00054			Block 5	$0.00022	
	Block 5	$0.00029			Block 6	$0.00010	
	Block 6	$0.00013		32 ITI	Block 1	$0.00112	
32 ITF	Block 1	$0.00130			Block 2	$0.00095	
	Block 2	$0.00110			Block 3	$0.00066	
	Block 3	$0.00077			Block 4	$0.00037	
	Block 4	$0.00043			Block 5	$0.00020	
	Block 5	$0.00023			Block 6	$0.00008	
	Block 6	$0.00010		33 (all)		$0.00001	(R) (R)

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(C)

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NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25

Twentieth Revision of Sheet 190-1
Cancels Nineteenth Revision of Sheet 190-1

SCHEDULE 190
PARTIAL DECOUPLING MECHANISM

PURPOSE:
To (a) describe the partial decoupling mechanism established in accordance with Commission Order 12-408 in Docket UG 221, Commission Order 18-419 in Docket UG 344, Commission Order 20-364 in Docket UG 388; and Commission Order 24-359 in Docket UG 490, Commission Order 25-420 in Docket UG 520, and Commission Order 27-XXX in Docket UG 532; (b) identify the adjustment applicable to rates under the Rate Schedules listed below. (C)

APPLICABLE:
To Residential and Commercial Customers served on the following Rate Schedules of this Tariff:

Residential	Commercial
Rate Schedule 2	Rate Schedule 3 CSF
	Rate Schedule 31 CSF

ADJUSTMENT TO RATE SCHEDULES:
The Temporary Adjustments for Residential and Commercial Customers taking service on the above-listed Rate Schedules includes the following adjustment:

Effective: December 24, 2026 (C)

Residential Rate Schedule 2:	$0.09638

(C)

Effective: December 24, 2026

Commercial Rate Schedule 3:	$0.07626
Commercial Rate Schedule 31:	$0.05033

PARTIAL DECOUPLING DEFERRAL ACCOUNT:

1. As described in detail below, the Company will calculate the difference between weather-normalized usage and the calculated baseline usage for each Residential and Commercial Customer group. The Residential customer group is bifurcated by premises that were connected to the system prior to January 1, 2018, and for those connected on or after January 1, 2018. The resulting usage differential shall be multiplied by the per therm distribution margin for the applicable customer group.

   The Company shall defer and amortize, with interest, 100% of the distribution margin differential in a sub-account of Account 186. The deferral will be a credit (accruing a refund to customers) if the differential is positive, or a debit (accruing a recovery by the company) if the differential is negative.

(continue to Sheet 190-2)

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25
Fifteenth Revision of Sheet 190-2
Cancels Fourteenth Revision of Sheet 190-2

SCHEDULE 190
PARTIAL DECOUPLING MECHANISM
(continued)

PARTIAL DECOUPLING DEFERRAL ACCOUNT (continued):

2. The baseline use-per-customer is:

   Residential (premise connected prior to January 1, 2018): 641.76 (C)
   Residential (premise connected on or after January 1, 2018): 430.67 (C)

   Commercial (Schedule 3): 3153.02 (C)
   Commercial (Schedule 31): 34,773.28 (C)

3. Weather-normalized usage is calculated using the approach to weather normalization adopted in the Company's last general rate case, Docket UG 520. The weather data is taken from the stations identified in **Rule 24**.

   Step One. For the heating season months of December through March, usage is normalized by taking the difference between normal and actual heating degree days for each district using a base of 59 degrees for Residential and 58 degrees for Commercial. Usage for the heating season months of November, April and May will be normalized by the actual WARM effect attributable to the month that is included in customer bills for rate schedules 2 and commercial 3. For commercial schedule 31, no normalization will be done in November, April and May.

   Step Two. This step derives the per-therm customer variance by multiplying the heating degree-day difference by the usage coefficient of .15502 for Residential (Schedule 2) variances, .63180 for Commercial (Schedule 3) variances, and 6.45698 for Commercial (Schedule 31) variances. (C)(C) (C)

   Step Three. The per-therm customer variance is multiplied by the appropriate customer count, by district, with the sum of the district results representing the normalized therm amount.

4. Baseline usage will be adjusted to reflect actual customers billed each month.

5. The per therm distribution margins to be used in the deferral calculation effective December 24, 2026 is $0.85864 per therm for Residential (Schedule 2) customers and $0.74442 per therm for Commercial (Schedule 3) customers and $0.34596 per therm for Commercial (Schedule 31) customers. (C) (C)(I)(I) (I)

6. Coincident with the Company's annual Purchased Gas Cost and Technical Rate Adjustment filing, the Company shall apply an adjustment to Residential and Commercial rates to amortize over the following 12 months, the balance in the balancing account as of June 30.

7. This Schedule is an "automatic adjustment clause" as defined in ORS 757.210, and is subject to review by the Commission at least once every two (2) years.

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.

Issued November 24, 2026
NWN OPUC Advice No. 26-11
Effective with service on and after December 24, 2026

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25

Seventh Revision of Sheet 195-3
Cancels Sixth Revision of Sheet 195-3

SCHEDULE 195
WEATHER ADJUSTED RATE MECHANISM
(WARM Program)
(continued)

9. Upon request, the Company will provide Customer with historical billing information that reflects bills with and without the WARM adjustment for any month during the WARM Period.

10. Should a change to the margin rate occur during the WARM Period, the equivalent therms used in the calculation of the WARM adjustment will be based on the entire billing period, and then prorated based upon the number of days applicable to each margin rate. The pro-rated therms are then multiplied by the applicable margin rate to determine the WARM adjustment for each rate period. Example: If a margin rate change occurred on January 1, a bill with a bill period between December 25 and January 24 would be prorated based upon 6 days at the prior margin rate and 24 days at the new margin rate. The calculations performed under the provisions of Special Conditions 2 and 3 will apply to each prorated period separately, except that the total WARM adjustment for each bill will not exceed the maximum (increase or decrease) WARM adjustment specified in Special Conditions 2 and 3.

WARM FORMULA:

1. The Formula is: WARM Adjustment = $\sum_{1}^{T}(HDD_{n,t} - HDD_{a,t}) * B * Mrgn$

   Where:

   T = the days covered by the meter read dates for an individual customer's bill
   HDDn = the 25 year average of heating degree-days for each day determined using a 25-year average temperature published by the National Oceanic and Atmospheric Administration (NOAA) as adopted for use with the Company's most recent general rate proceeding.
   HDDa = the actual heating degree-days for each day based on the individual customer's actual beginning and ending meter read dates
   B = the statistical coefficient relating heating degree-days to therm use determined in the most recent general rate case, or other Commission authorized proceeding.
   Mrgn = the relevant Rate Schedule margin defined as the current Billing Rate less the current Commodity Rate, Pipeline Capacity Charge, and any Temporary Adjustments.

2. For purposes of calculating the WARM Adjustment, the following shall apply:

   a. A Heating Degree Day (HDD) is defined as the extent by which the daily mean temperature falls below a specified set point on a specified day. The HDD calculation uses a set point temperature of 59 degrees Fahrenheit for the **Rate Schedule 2** calculation, and 58 degrees Fahrenheit for the **Rate Schedule 3** calculation;

   b. The statistical coefficients to be used in the calculation of the WARM Adjustment Factor effective with the WARM Period commencing October 31, 2027 are: (C)

Rate Schedule 2:	0.15502	Rate Schedule 3:	0.63180

(C)(C)

(continue to Sheet 195-4)

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Effective with service on
and after December 24, 2026

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25

Eleventh Revision of Sheet 195-4
Cancels Tenth Revision of Sheet 195-4

SCHEDULE 195
WEATHER ADJUSTED RATE MECHANISM
(WARM Program)
(continued)

WARM FORMULA: (continued)

c. The applicable margins to be used in the calculation of the WARM Adjustment Factor effective December 24, 2026 are: (C)

Rate Schedule 2:	$0.85864	Rate Schedule 3:	$0.74442

(I)(I)

Weather data used in the calculation of HDD for each customer shall be from the same weather stations and weather zones that are used in the determination of thermal units as set forth in **Rule 24.**

WARM BILL EFFECTS:
The following table depicts the impact on Residential **Rate Schedule 2** and Commercial **Rate Schedule 3** customer bills, respectively, at specified variations in HDDs.

2R	RESIDENTIAL			COMMERCIAL	
HDD Variance (+ or -)	Equivalent therms		Total Monthly WARM adjustment (+ or -)	Equivalent therms	Total Monthly WARM adjustment (+ or -)
1	0.1550	$0.13		0.6318	$0.51
5	0.7751	$0.65		3.1590	$2.57
10	1.5502	$1.30		6.3180	$5.14
15	2.3253	$1.95		9.4770	$7.70
20	3.1004	$2.59		12.6360	$10.27
25	3.8755	$3.24		15.7950	$12.84
30	4.6506	$3.89		18.9540	$15.41
35	5.4257	$4.54		22.1130	$17.97
40	6.2008	$5.19		25.2720	$20.54
45	6.9759	$5.84		28.4310	$23.11
50	7.7510	$6.49		31.5900	$25.68

(I)(I)

(I)(I)

To calculate variations beyond or in-between specified levels, multiply the desired HDD variance by the applicable statistical coefficient, and then multiply that sum by the applicable margin.

To obtain the cent per therm effect of the Warm Adjustment, divide the WARM Adjustment by the number of therms used during the billing month.

(continue to Sheet 195-5)

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and after December 24, 2026

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25
Fifteenth Revision of Sheet 195-5
Cancels Fourteenth Revision of Sheet 195-5

SCHEDULE 195
WEATHER ADJUSTED RATE MECHANISM
(WARM Program)
(continued)

WARM BILL EFFECTS (continued):

Example Bill Calculation:

Here is the how the WARM adjustment is calculated for a residential **Rate Schedule 2** customer where the billing rate is $1.68085 cents per therm, the HDD variance is 50 HDDs colder than normal, and the monthly therm usage is 129 therms: (I)

HDD Differential:	Normal HDDs:	600 HDDs	
	Actual HDDs:	650 HDDs	
	HDD variance:	600 – 650 = -50 HDDs	
Equivalent Therms:	HDD variance:	-50 HDDs	
	Statistical coefficient:	0.15502	(C)
	Equivalent therms:	-50 x 0.15502 = -7.75100 therms	(C)
Total Warm Adjustment:	Equivalent therms:	-7.75100 therms	(C)
	Margin Rate:	$0.85864	(I)
	Total WARM Adj.:	-7.75100 x $0.85864 = ($6.65532)	(R)
Total WARM Adjustment converted to cents per therm:	Total WARM Adj.	($6.65532)	(R)
	Monthly usage:	129 therms	
	Cent/therm Adj.:	($6.65532) / 129 = ($0.05159)	(R)
Billing Rate per therm:	Current Rate/therm:	$1.68085	(I)
	WARM cent/therm Adj.	($0.05159)	(R)
	WARM Billing Rate:	$1.68085 + ($0.05159) = $1.62926	(I)
Total WARM Bill:	Customer Charge:	$10.00	
	Usage Charge:	$1.62926	(I)
	Total	(129 x $1.62926) + $10.00 = $220.17	(I)

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.

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NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25

Eighth Revision of Sheet 196-2
Cancels Seventh Revision of Sheet 196-2

SCHEDULE 196
ADJUSTMENT FOR CERTAIN EXCESS DEFERRED INCOME TAXES RELATED TO THE 2017 FEDERAL TAX CUTS AND JOBS ACT

(continued)

RATE ADJUSTMENTS:

The effect of this adjustment is included in the temporary rate and base rate for Plant. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED

The volumetric adjustment applicable to each Rate Schedule is shown in the tables below:

Effective December 24, 2026: (C)

Rate Schedule	Rate Adjustment (per therm)	
2	(0.00927)	(R)

Effective December 24, 2026: (C)

Rate Schedule	Block	Rate Adjustment (per therm)		Rate Schedule	Block	Rate Adjustment (per therm)	
				32 ITF	Block 1	(0.00138)	(R)
03 CSF		(0.00504)			Block 2	(0.00118)	(I)
03 ISF		(0.00476)			Block 3	(0.00083)	(R)
27		(0.00927)			Block 4	(0.00048)	(I)
31 CSF	Block 1	(0.00366)			Block 5	(0.00028)	(R)
	Block 2	(0.00334)			Block 6	(0.00014)	
31 CTF	Block 1	(0.00388)		32 CSI	Block 1	(0.00116)	
	Block 2	(0.00355)			Block 2	(0.00098)	
31 ISF	Block 1	(0.00199)			Block 3	(0.00068)	
	Block 2	(0.00180)			Block 4	(0.00038)	
31 ITF	Block 1	(0.00215)			Block 5	(0.00020)	(R)
	Block 2	(0.00194)			Block 6	(0.00006)	(I)
32 CSF	Block 1	(0.00238)		32 ISI	Block 1	(0.00105)	(R)
	Block 2	(0.00201)			Block 2	(0.00088)	
	Block 3	(0.00139)			Block 3	(0.00061)	
	Block 4	(0.00078)			Block 4	(0.00034)	
	Block 5	(0.00033)			Block 5	(0.00018)	(R) (R)
	Block 6	(0.00012)			Block 6	(0.00006)	
32 ISF	Block 1	(0.00165)		32 CTI	Block 1	(0.00181)	(R) (R)
	Block 2	(0.00140)			Block 2	(0.00154)	
	Block 3	(0.00097)			Block 3	(0.00108)	
	Block 4	(0.00054)			Block 4	(0.00063)	
	Block 5	(0.00024)			Block 5	(0.00036)	(R)
	Block 6	(0.00009)			Block 6	(0.00018)	
32 CTF	Block 1	(0.00126)		32 ITI	Block 1	(0.00079)	(R)
	Block 2	(0.00107)			Block 2	(0.00067)	
	Block 3	(0.00076)			Block 3	(0.00047)	
	Block 4	(0.00044)			Block 4	(0.00028)	
	Block 5	(0.00025)			Block 5	(0.00016)	(R) (R)
	Block 6	(0.00013)			Block 6	(0.00008)	
				33 (all)		0.00000	

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NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 25

Sixth Revision of Sheet 197-2
Cancels Fifth Revision of Sheet 197-2

SCHEDULE 197
AMORTIZATION OF PENSION BALANCING ACCOUNT
(continued)

R
RATE ADJUSTMENTS (continued):
The volumetric adjustment applicable to each Rate Schedule is shown in the table below:

Effective: December 24, 2026

Rate Schedule	Adjustment	
2	$0.01195	(I)

(C)

Effective: December 24, 2026

(C)

Rate Schedule	Block	Adjustment		Rate Schedule	Block	Adjustment	
				31 CSF	Block 1	$0.00534	(R)
					Block 2	$0.00487	
03 CSF		$0.00919		31 ISF	Block 1	$0.00374	(I)
03 ISF		$0.00600			Block 2	$0.00338	(I) (R)
27		$0.01243		31 CTF	Block 1	$0.00580	(I) (I)
					Block 2	$0.00530	
				31 ITF	Block 1	$0.00417	
					Block 2	$0.00377	
				32 CSI	Block 1	$0.00204	
32 CSF	Block 1	$0.00319			Block 2	$0.00173	(R)
	Block 2	$0.00270			Block 3	$0.00120	
	Block 3	$0.00188			Block 4	$0.00067	(I)
	Block 4	$0.00105			Block 5	$0.00036	(R)
	Block 5	$0.00046			Block 6	$0.00013	(R)
	Block 6	$0.00018		32 ISI	Block 1	$0.00181	(I)
32 ISF	Block 1	$0.00212			Block 2	$0.00153	
	Block 2	$0.00179			Block 3	$0.00106	
	Block 3	$0.00125			Block 4	$0.00060	(I)
	Block 4	$0.00070			Block 5	$0.00032	(R)
	Block 5	$0.00032			Block 6	$0.00012	(R)
	Block 6	$0.00013		32 CTI	Block 1	$0.00178	(I)
32 CTF	Block 1	$0.00230			Block 2	$0.00151	
	Block 2	$0.00195			Block 3	$0.00105	
	Block 3	$0.00136			Block 4	$0.00059	(I)
	Block 4	$0.00077			Block 5	$0.00032	(R)
	Block 5	$0.00041			Block 6	$0.00014	(R)
	Block 6	$0.00018		32 ITI	Block 1	$0.00160	(I)
32 ITF	Block 1	$0.00186			Block 2	$0.00135	
	Block 2	$0.00157			Block 3	$0.00094	
	Block 3	$0.00110			Block 4	$0.00053	
	Block 4	$0.00062			Block 5	$0.00028	(I)
	Block 5	$0.00033			Block 6	$0.00012	(R)
	Block 6	$0.00014		33 (all)		$0.00002	(R)(R)

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Direct Testimony of Robert J. Wyman

CUSTOMER AND NORMALIZED VOLUME FORECAST, LONG-RUN INCREMENTAL COSTS, AND RATE DESIGN/SPREAD EXHIBIT 1300

November 24, 2026

EXHIBIT 1300 – DIRECT TESTIMONY – CUSTOMER AND NORMALIZED VOLUME FORECAST, LONG-RUN INCREMENTAL COSTS, AND RATE DESIGN/SPREAD

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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 Regulatory Affairs Senior 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 Oregon and Washington 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 Rackham Graduate School. 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 over 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 rate classes, present the Long-Run Incremental Cost ("LRIC") study, and describe the Company's rate spread and rate design proposal. At the end of this testimony, I describe how the rate spread proposal will allocate incremental revenue requirement to each NW Natural Oregon Tariff rate schedule ("RS"), excluding RS 4, RS 15, RS 33, RS 90 and special contract schedules.

Q. Would you please summarize your testimony?

A. My testimony is made up of three distinct sections: (1) The Company's UPC forecasting methodology; (2) the LRIC study methodology and a summary of results; and (3) proposed changes to rate design, as well as the rate spread proposal to be applied to the incremental revenue requirement for this case.

UPC Forecast. First, I will detail the UPC forecasting methodology (referred to here as the "UPC Forecast") and explain how it is used in conjunction with the Company's customer forecast to create a short-term weather normalized volume forecast for the Residential and Commercial firm sales service rate classes. The normalized volume forecast is used to support the determination of the proposed revenue requirement presented in the Direct Testimony of Kyle T. Walker (NW Natural/1200, Walker). Second, I will outline NW Natural's LRIC study methodology, including additional study of the interruptible rate class, and will show the incremental cost inputs by capital investment and operations expense categories on a rate schedule basis. Third, I present and discuss proposed

modifications to rate design. Finally, I will describe how the Company proposes to spread the incremental revenue requirement across rate schedules, and the associated effect on rates.

My testimony explains how the UPC Forecast was 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 defined as the period November 1, 2027, through October 31, 2028 ("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.

LRIC study. Second, this testimony also explains how the LRIC study 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 LRIC study 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 (with the exception of one industrial rate schedule I note below). The study also indicates that the RS 2 Residential and 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, UG 520. Further, the study indicates that RS 3 Basic Firm Sales Service Non-Residential (Commercial) ("RS 3 General Commercial") is paying just below the

determined cost of service, whereas the Company's prior LRIC study presented in UG 520 indicated this schedule was paying slightly above its determined cost of service. Finally, the study indicates that RS 3 Basic Firm Sales Service Non-Residential (Industrial) ("RS 3 General Industrial") is paying less than its determined cost of service under present rates, whereas the UG 520 LRIC study indicated it paid over its determined cost of service.

I then describe the methodology by which NW Natural proposes to spread the incremental revenue requirement. The Company proposes to spread incremental revenue requirement in such a manner that is responsive to the results of the LRIC study. I describe in full the following four-step rate spread proposal and how it is applied to all rate schedules in my testimony. First, for RS 2 Residential and RS 27 Dry-Out, NW Natural proposes to use a cap that slightly moves both of these schedules' relative position closer to parity with respect to the LRIC study results, because these schedules are paying less than their cost to serve at current rates. The Company proposes a separate floor for RS 3 General Commercial and RS 3 General Industrial that allocates slightly more than the average margin increase to these schedules, because at current rates they also underpay their determined cost to serve. Second, the Company proposes to apply a cap that is set below the level that produces an equal percent of margin increment to all rate schedules with an LRIC study indicated parity ratio above 1.25 and/or those taking interruptible service.[1] As a result of the application of this cap,

[1] 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 LRIC study indicated cost of service, respectively.

the relative position to parity of the applicable rate schedules with respect to the overall indicated LRIC study results will decrease, reflecting the fact that these classes are paying more than their cost to serve at current rates. Third, the remaining revenue requirement is allocated to all remaining rate schedules to reflect the LRIC study results, which indicate that while those 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 1.25 and/or those taking interruptible service. This step allocates the remaining revenue requirement on an equal percent of margin basis among all remaining rate schedules. Fourth, the Company proposes to levelize and cap the margin increase allocated to the rate schedules for which the third step applies. I allocate the revenue requirement that is offset by this cap to two rate schedules that are underpaying the determined cost of service, RS 3 General Commercial and RS 3 General Industrial, on an equal percent of margin basis.

As a result of this four-step proposal, the RS 2 Residential, RS 3 General Commercial, RS 3 General Industrial, 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 (but less than the LRIC study indicated increase), with the greatest relative increase being applied to RS 3 General Industrial. The Large Commercial, Industrial, and Transportation rate classes will all receive a revenue spread less than an equal percent of margin share (with the exception of RS 3 General Industrial). The Company's proposal equitably distributes the incremental revenue requirement such that all rate classes

are moved closer to parity based on their indicated cost causation. The proposal described above is an incremental approach; it moves all rate classes closer to parity or generally maintains parity and does so in a manner that works to minimize rate shock.

Rate design and rate spread. Third, I describe proposed modifications to the Company's rate design. The Company proposes to increase the monthly fixed charges for RS 3 General Commercial and RS 3 General Industrial by $10.00 from $15.00 to $25.00 per month. Monthly fixed charges smooth bills for individual customers and businesses across the entire year, reduce variability in year-over-year decoupling deferral balances, and promote both intra- and inter-class rate equity whereby higher using individual customers or businesses subsidize the fixed system costs of lower users.

Finally, the rate spread section of this testimony shows the proposed spread of incremental revenue requirement by rate schedule and the corresponding average monthly bill impact.

Q. Are you introducing any exhibits with your testimony?

A. Yes. I am sponsoring Exhibits 1301, 1302, 1303, and 1304. NW Natural/1301, Wyman is a summary of the Company's long-run incremental cost study by rate schedule. NW Natural/1302, Wyman presents the rate spread allocation proposal methodology. NW Natural/1303, Wyman indicates the incremental revenue requirement allocation by rate schedule, as well as the bill impact and rate increase by rate schedule. NW Natural/1304, Wyman presents the proposed rates by rate schedule and rate block.

II. TEST YEAR CUSTOMER AND NORMALIZED VOLUME FORECAST

Q. What is the Test Year customer and normalized volume forecast?

A. The Test Year customers and volumes are forecasted separately. The volume forecast is a short-term, weather normalized load forecast that is built using the following steps:

1. Weather data are collected to produce a 25-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 UPC Forecast).
3. For these rate classes, the UPC Forecast is multiplied by the customer forecast to derive the weather normalized volume forecast.

The weather normalized volume forecast is used to calculate revenues at existing rates in the proposed revenue requirement presented in NW Natural/1201, Walker. In addition to being a revenue requirement input, the UPC Forecast is also used to create the design day load factor, which is an important input to the LRIC study.

Q. Please describe the customer forecast methodology.

A. For the Residential and Commercial firm sales service rate classes, Test Year 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 count forecast is also based on legislative and regulatory policy, such as the phase-out of the Company's line extension allowance ("LEA") policy. Specifically, for 2027 the Company has taken its estimate derived based on Oregon Office of Economic Analysis ("OEA") housing starts data and then adjusted that lower by 25 percent to account for not only Oregon building codes changes effective in the first two quarters of 2027, but the LEA step-down effective November 1, 2026. The 25 percent manual adjustment is estimated by Company subject matter experts based on observations of customer growth related to prior LEA step-downs as well as building code changes that have gone into effect previously in Washington. 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 Test Year rate base.

Q. Please describe the UPC Forecast methodology.

A. The purpose of the UPC Forecast is to estimate weather normalized usage for the Residential and Commercial firm sales service rate classes on a per customer basis. The forecast 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)[2], as well as economic factors which I describe in greater detail below. To develop the UPC Forecast, I:

- Collected daily high and low temperature data from weather stations identified in Rule 24, Sheet RR-24.1, of NW Natural's Oregon Tariff for the period June 1, 2001 through May 31, 2026 for two purposes: (1) to have recent actual weather data to statistically analyze against recent actual usage; and (2) to produce a 25-year historical benchmark for normal weather. Where gaps in the data are present, I use additional National Oceanic and Atmospheric Administration ("NOAA") observed weather stations as backups to the tariffed stations to estimate normalized heating degree days using a simple linear regression which estimates the relationship between temperature readings at like stations.
- Matched actual therm usage and actual HDDs for the period of January 2012 through May 2026. 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

[2] 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.

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 ("F") base for residential schedules and a 58-degree F base for Commercial schedules as temperature set points to convert temperature observations to HDDs. I discuss the selection process for these set points in greater detail below.

- 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 a model for each of the two Residential customer class Decoupling Mechanism baselines: Premises connected prior to January 1, 2018 and premises connected on and after January 1, 2018). 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 25-year weather data set.
- Used the econometrically estimated coefficients to build the weather normalized UPC Forecast on a daily basis using the 25-year HDD benchmark.

Q. Please describe the specification for the statistical forecast 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 have used an ARIMA time series model to calculate the UPC Forecast for the Company's four prior Oregon general rate cases, UG 388, UG 435, UG 490, and UG 520. In each proceeding, Staff supported the use of an ARIMA model specification for short-term normalized load forecasting purposes, noting that "ARIMA models are used by all Oregon regulated utilities and remain the standard approach."[3] Further, in its UG 435 Opening Testimony, Staff found "the Company's forecast methodology and revised data inputs to be accurate and the forecast to be reasonable."[4] In its UG 490 Opening Testimony, Staff noted that it "has no major concerns with [NW Natural's] overall load forecast methodology. In general, [NW Natural] uses industry standard methodologies and is receptive to feedback regarding model improvements."[5] Finally in UG 520, Staff made a similar conclusion with regards to the Company's overall methodology.[6]

[3] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Opening Testimony of Ryan Bain, Staff/400, Bain/4, lines 4-16 (Apr. 22, 2022).

[4] *Id.* at 9, lines 3-5.

[5] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Opening Testimony of Bret Stevens, Staff/1900, Stevens/2-3, lines 19-20, 1-2 (Apr. 18, 2024).

[6] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 520, Opening Testimony of Will Wheeler, Staff/1700, Wheeler/3, lines 17-21 (Apr. 2, 2025).

Q. Do you agree with Staff that the Company is receptive to feedback regarding UPC Forecast model improvements?

A. Yes. For UG 490, I implemented recommendations from the Oregon Citizens' Utility Board ("CUB") and Staff that they introduced in UG 435 testimony. CUB and Staff recommended employing more weather data beyond HDDs such as wind chill and solar radiation as a proxy for observed weather, including HDDs in multiple explanatory variables, controlling for days of the week, and continuing to examine how structural economic and social impacts related to the COVID-19 global pandemic (such as the continued prevalence of remote work) affects the UPC Forecast.[7] In UG 520, Staff noted that it "appreciates that the Company incorporated Staff and intervenor suggestions from past [NW Natural] rate cases and believes that these adjustments have improved the quality of the load forecast and the transparency of the model selection process."[8]

Q. In NW Natural's most recent rate case (UG 520), did Commission Staff make any recommendations regarding the UPC Forecast analysis methodology?

A. Yes. Staff made the following recommendations regarding the UPC Forecast analysis methodology, to be implemented with the Company's next general rate proceeding:

[7] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Direct Testimony of Robert J. Wyman, NW Natural/1800, Wyman/11-13 (Dec. 29, 2023).

[8] Docket No. UG 520, Staff/1700, Wheeler/3-4, lines 21,1-3 (Apr. 2, 2025).

1. Choose the HDD set point temperature based on the best fit of a regression of usage on HDDs;
2. Create separate UPC forecasts for single-family and multi-family residential customers; and
3. Incorporate analysis of the phase-out of the line extension allowance ("LEA") policy into customer count forecasts.[9]

Q. Did other intervenors to UG 520 recommend modifications to the UPC Forecast model specification?

A. No. The other UG 520 intervenors did not provide recommendations regarding the UPC Forecast.

Q. Did the Company examine Staff's recommendations for this general rate case filing?

A. Yes. I examined all of Staff's recommendations from UG 520 and address each one further below and explain how each is incorporated into the UPC Forecast analysis methodology in this proceeding. Staff's first recommendation, to analyze the choice of HDD set points, was also a condition to the UG 520 Second Partial All-Party Stipulation.[10] The discussion and analysis below is responsive to that condition.

[9] Docket No. UG 520, Staff/1700, Wheeler/4, lines 12-17 (Apr. 2, 2025).

[10] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 520, Order No. 25-420, Appendix B at 4 (Second Partial All-Party Stipulation) (Oct. 24, 2025).

Q. Did the Company choose the HDD set point temperatures based on the best fit of a regression of usage on HDDs?

A. Yes, as I explain below, the Company's HDD set points are statistically the most optimal for use in the UPC Forecast as determined through the Company's Integrated Resource Plan ("IRP") process.

Q. What is the Company's basis for using the HDD set points noted earlier?

A. HDDs are a common unit of measurement that allows for an analysis of increasing load demand as a function of increasingly colder weather. The set point is taken to be the temperature at which customers begin to use energy for heating purposes. For the purposes of the UPC Forecast, the Company adopted the 59 degree F and 58 degree F bases as the temperature set points for residential and commercial customers, respectively, because these values produced the best linear relationship between heating load and HDDs (i.e., that set points at these temperatures best estimated the average ambient outside temperature where customers begin using natural gas load for heating purposes). The Company has used these set points in every general rate case proceeding since they were first adopted with its 2002 proceeding. That rate case proceeding, UG 152, resulted in the adoption of the Company's Weather Adjusted Rate Mechanism ("WARM") program, which uses the normal-to-actual HDD variance as an input to the WARM adjustment calculation. Therefore, the 59 degree F and 58 degree F set points have been used in the calculation of WARM adjustments for the entire time the WARM program has been in effect.

Q. Has the Company examined whether these set points continue to adequately represent the relationship between ambient temperature and the beginning of observed heat load?

A. Yes. In UG 520, the Company stated it has continued to empirically examine the relationship between ambient temperature and the beginning of observed heat load. In discussing daily load demand drivers for development of the peak day planning standard, the Company's 2022 IRP states: "There is a structural break in this relationship at 58 degrees F as space heating equipment (e.g., furnaces) kicks on at temperatures less than 58 degrees F. To capture this relationship the daily system load model is estimated in two versions: average daily temperature less than 59 degrees F and average daily temperature greater than 59 degrees F."[11] Compared to other set points used by other utilities across the country, the Company argued that these set points are a more optimal statistical representation of its customers' space heating demand as a function of ambient temperature to optimize the performance and fit of the UPC Forecast. Building codes, materials, age, efficiency of building envelope and its thermal properties (insulation type and tightness), and appliance types and fuels vary significantly by geographic region and utility, which may make other set points more optimal elsewhere.

[11] *In the Matter of Northwest Natural Gas Company, dba NW Natural, 2022 Integrated Resource Plan*, Docket No. LC 79, 2022 Integrated Resource Plan at 97-98 (Sept. 23, 2022).

Q. In UG 520, did Staff agree that the Company's 58 and 59 degrees F set points best linearize the relationship between temperature and demand for space heating?

A. No. While Staff did agree that "the Company's set point temperatures are more appropriate than the 65-degree [F] temperature used by other utilities"[12] and "[i]n general, Staff supports the Company's use of set point temperatures below 65 degrees,"[13] Staff argued that data the Company supplied in a data request response suggested the R-squared value (a measure of model goodness-of-fit) is higher when using set points of 60 degrees F for residential schedules and 59 degrees F for commercial schedules.[14]

Q. In UG 520, did Staff make any recommendations regarding the HDD set points?

A. Yes. Based on Staff's analysis in UG 520, Staff recommended "the Company submit updated HDD set point temperature analyses in future rate cases to ensure the temperatures being used continue to be appropriate"[15] because Staff's analysis suggests "the possibility that the relationship between HDDs and usage has changed over time."[16]

[12] Docket No. UG 520, Staff/1700, Wheeler/7 (Apr. 2, 2025).

[13] *Id.* at 9.

[14] *Id.* at 8.

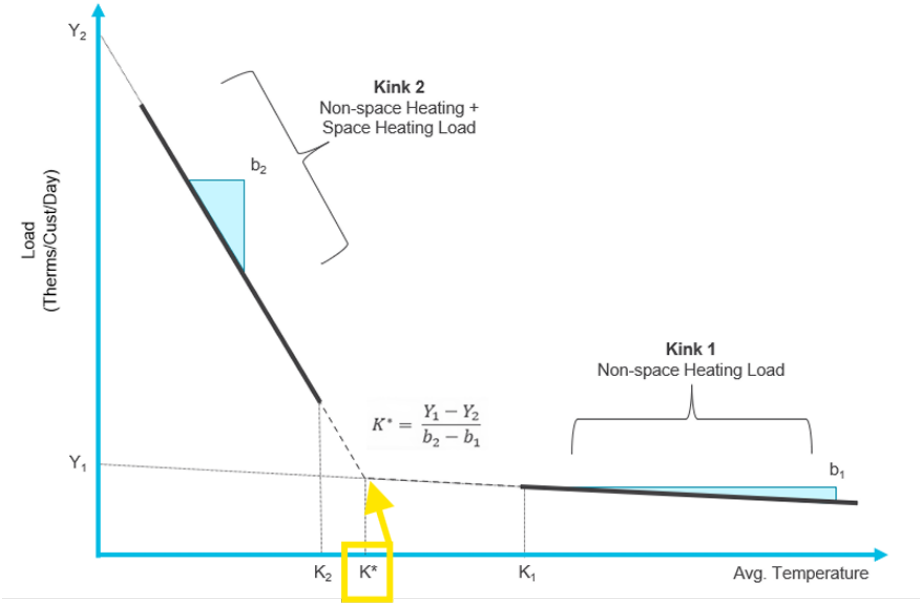
[15] *Id.* at 9.

[16] *Id.* at 9.

Q. Based on Staff's recommendation in UG 520, did the Company examine the HDD set points for future use?

A. Yes. The Company, in its 2025 IRP, updated its longer-term UPC forecasts for resource planning. For this analysis, the Company modeled the "temperature inflection point where space heating accelerates,"[17] which it refers to as "K*" using a piece-wise demand regression function. In other words, K* represents the statistical measurement of where the HDD set points should be set. Figure 1 below shows a theoretical UPC model where K* is located along the average temperature X-axis, at the inflection point between non-space heating load and space heating load (inclusive of non-space heating load).

Figure 1



[17] *In the Matter of Northwest Natural Gas Company, dba NW Natural, 2025 Integrated Resource Plan*, Docket No. LC 86, 2025 Integrated Resource Plan at 4-16/17 (Aug. 1, 2025).

The Company presented its estimated UPC piece-wise demand regression coefficients, including K*, in Appendix B of its 2025 IRP by load center and rate class (residential and small commercial).[18] The K* coefficients (expressed as degrees F) are shown in Figure 2 below by rate class. The weighted K* values for each rate class are based on customer counts in each identified load center.

Figure 2

	Load Center	Residential K*	Small Commercial K*
	Albany	58.3	57.2
	Astoria	59.1	57.5
	Coos Bay	59.4	59.7
	The Dalles	61.8	58.4
	Eugene	58.8	56.8
	Lincoln City	56.1	54.8
Portland	Central	60.9	57.9
Portland	East	60.6	60.6
Portland	West	57.2	57.0
	Salem	57.9	56.4
	Weighted	59.1	57.5

Figure 2 indicates the statistically derived K* coefficient for the residential and small commercial rate classes is 59.1 degrees F and 57.5 degrees F, respectively. Based on these results, the HDD set points of 59 degrees F and 58 degrees F for the residential and commercial rate classes, respectively, continue to be the best empirical representation of the relationship between ambient temperature and the beginning of observed heat load.

[18] *Id.*, Appendix B, Table B-5: Existing UPC Model Coefficient Estimates, at B-10.

Q. Are there other non-empirical reasons the Company has for maintaining these HDD set points?

A. Yes, the Company explained in UG 520 that "[c]hanging the HDD set point would result in administrative and technical burdens across the Company. It would result in inconsistent WARM adjustment methodologies across time periods, make comparisons of weather normalizing data difficult across the Company (such as comparing year-over-year changes in HDDs for financial reporting), and result in undue administrative burden (e.g., changes to accounting and reporting processes, modifications to Customer Information System coding to ensure correct WARM billing)."[19] Any changes to the set points, therefore, should be based on strong evidence of meaningful changes between ambient temperature and observed heat load. The weighted K* coefficients presented above are nearly identical to the HDD set points used across the Company for weather normalization, and the Company finds there is no evidence that they should be modified for the first time in almost a quarter of a century.

Q. Did the Company implement Staff's second recommendation, to create a separate UPC forecast for single- and multi-family residential customers, in this proceeding?

A. Yes. I created a separate UPC Forecast estimation for residential customers residing in single- and multi-family premises ("Single-Family Premises UPC" and

[19] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 520, Reply Testimony of Robert J. Wyman, Wyman/3300, Wyman/11 (May 21, 2025).

"Multi-Family Premises UPC") in this proceeding for the purpose of estimating average rate and bill impacts. As the Company noted in UG 520, "[u]nder its current LRIC study and rate design methodology, these forecasts [a separate single- and multi-family residential UPC forecast] would have no impact on proposed rates, but the UPCs would be useful for estimating average monthly bill impacts by cohort."[20] These impacts are reflected in NW Natural/1303, Wyman.

Q. Did the Company implement Staff's final recommendation, to incorporate analysis of the phase-out of the LEA policy into customer count forecasts, in this proceeding?

A. Yes, although it should be noted that the Company has incorporated the LEA phase-out already in prior rate case proceedings, specifically UG 490 and UG 520. As I discussed earlier, the Company's customer count forecast methodology includes, among other drivers, changes to legislative and regulatory policy that could influence future customer growth. To that end, the Company's customer count forecast has reflected the phase-out of its LEA in alignment with Public Utility Commission of Oregon ("Commission") Orders 22-388 in 2022 (UG 435) and 24-359 (UG 490) in 2024. Earlier, I discussed the specific methodological application of the LEA step-down on the customer count forecast in this proceeding.

[20] *Id*. at 13.

Q. In addition to Staff's UG 520 recommendations, did the Company also apply Staff's earlier recommendations from UG 490 to the ARIMA model specification and indicator variable selection process in this case?

A. Yes. I continue to implement many of Staff's recommended modifications from earlier general rate proceedings 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 for each rate schedule in the UPC Forecast. This command uses a Stata-adjusted Hyndman-Khandakar algorithm to automatically select an ARIMA(p,d,q) model parameterization for each rate class. I used the output of arimaauto as baseline model specification and note deviations later in this testimony.
2. Included non-linear weather terms, such as a squared HDD term.
3. Used monthly indicator (dummy) variables with no other interactions.
4. Dropped variables (mostly weather-related) with very small effects.

Below, I describe in greater detail my selection process for each firm sales service rate schedule in the UPC Forecast. Like Staff in UG 490, in some cases I used manual parameterization to introduce 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, which can account for the seasonal variation in rate class usage instead of the monthly indicator variables.

Q. Please describe the changes in the UPC Forecast methodology from NW Natural's latest rate case, UG 520.

A. I used consistent data collection, actual weather, load data alignment, and weighting methods to prepare the UPC Forecast. Similarly, I used an ARIMA time series model specification to produce the final UPC Forecast regression coefficients. I applied many of Staff's recommendations to the model specification process from UG 490, and for the Commercial rate schedules I continued to employ a macroeconomic variable (depending on the model), which I describe below. For the residential and small commercial rate classes, I used a separate model for the summer months of June, July, and August to address what I observed to be over-forecasting in these months when examining out-of-sample backcast testing conducted across varying historical data vintages.

Q. Please describe the weather variables included in the UPC Forecast in this case.

A. Consistent with UG 520, I evaluated the forecasting effectiveness of including weather variables that are in addition to the standard HDDs that I have included in all past iterations of the forecast, including: Effective temperature, precipitation, solar radiation, and wind speed and wind chill explanatory variables. The data used to create these variables are sourced from a third-party and are employed in the Company's IRP long-term resource planning forecast models.[21] The use of

[21] See, for instance, discussion of daily demand drivers in the NW Natural 2025 Integrated Resource Plan, Docket No. LC 86, at pages 4-35 to 4-39 (August 2025). 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.

multiple variables that measure HDDs is meant "to capture the dynamic nature of heat loss."[22] Using day-before HDDs, for instance, can help model how heat loss in a building from one cold weather day prior can impact natural gas consumption the following day. I have found that including such observations can make small improvements to the model forecast.

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.[23] The wind chill set point in this case is the temperature cut-off where any value higher produces no wind chill effect (i.e., 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.[24]

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

[22] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Opening Testimony of Sudeshna Pal, CUB/300, Pal/6-7, lines 11-14, 1-7 (Apr. 22, 2022).

[23] 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.

[24] *Id*.

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, however, that this factor did not improve the forecasting ability of the Residential or Commercial rate class models in this proceeding.

Consistent with UG 520, I found that a modeling approach where a "composite weather variable" is created by using a formula to combine multiple weather variables into one variable did not improve model efficacy relative to other model specifications I tested. Using the weather variables noted above as standalone variables while including interaction effects, as I describe below, is consistent with the Company's IRP resource planning forecast methodology.

Q. Please describe how HDDs are included in multiple explanatory variables within the UPC Forecast using interaction effects.

A. The UPC Forecast 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 UPC Forecast controls for monthly fixed effects and weekend days.

A. For this proceeding, I maintained a consistent methodology with UG 520 by using monthly fixed effects to control for seasonality for the Residential rate class[25] 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 as recommended by Staff in UG 490 to account for seasonal variation in usage, but did use the weekend days variable (depending on the model) 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 UPC Forecast.

A. For the Residential rate class, I chose to drop the constant term so that the UPC Forecast model produces one base load coefficient associated with each of the 12 months of the year, which is consistent with prior rate proceedings. This makes building the weather normalized UPC values on a daily and monthly basis

[25] Docket No. UG 490, Staff/1900, Stevens/4 (Apr. 18, 2024).

straightforward, because each model coefficient can be matched to a specific period of time 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 UPC Forecast estimates demand-side management ("DSM") savings.

A. Consistent with UG 520 methodology, for this UPC Forecast 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 UPC Forecast estimates macroeconomic effects.

A. I have included, consistent with UG 520, 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 Oregon 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 that indexes United States industrial production as a proxy measure of the year-over-year performance of the macro economy.

Q. Please describe the Company's ARIMA model specification selection process.

A. Per Staff's recommendation, 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 UPC Forecast. 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, mean absolute percentage error ("MAPE") and root mean squared error ("RMSE") results to assess model efficacy and choose appropriate ARIMA p and q terms.[26] I relied on the Augmented Dickey-Fuller test to determine the appropriateness of differencing load forecast data variables with the ARIMA d term to ensure model stationarity. Further, I plotted model residuals

[26] 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.

to check for non-uniformity. I consulted the Akaike Information Criterion ("AIC") and the Bayesian Information Criterion ("BIC") metrics, the AIC being the basis for the arimaauto module evaluation, to evaluate the performance of models under varying *p* and *q* term specifications against one another.[27] I also performed "backcast" tests as I describe below, to assess the forecasting abilities of the auto-parameterized models against non-auto-parameterized models.

Finally, as shown below, I plotted the forecast errors (residuals) for each UPC Forecast model against both a standard normal distribution and the residuals associated with the UG 520 model iteration. Residuals ideally should follow a standard normal distribution, which suggests there is not an obvious systematic tendency for the model to over- or under-predict actuals. This measurement alone does not indicate model efficacy because a model can have normally distributed residuals and still have large forecast errors; therefore, other metrics such as MAPE and RMSE are important for testing model performance and fit.

Q. Please describe the issue of non-stationarity and how it could impact the UPC Forecast model.

A. Non-stationarity in the UPC Forecast 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 UPC Forecast model could

[27] 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.

contain non-stationary inputs, 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 MAPE and RMSE, 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 both residential and commercial rate schedules. Models are evaluated against each other by calculating and comparing MAPE and RMSE values to test model accuracy and performance. I selected the model specifications with the lowest MAPE and RMSE for the UPC Forecast.

Q. Does the ARIMA model perform better at weather normalizing load compared to other types of models?

A. Yes. I have found in analysis for prior rate proceedings 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 model 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 25-year daily normal HDD values to derive a normalized use per customer per day by month.[28] 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.

[28] 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 and using the "dynamic" option to specify the forecast beginning month (May 2026).

Q. Please describe the model specification for each firm sales rate schedule modeled in the UPC Forecast.

A. Below, I describe the model specification for each rate schedule in the UPC Forecast and summarize the outputs.

A. RS 2 Residential Sales Service

For the class-wide RS 2 Residential model, I implemented Staff's recommendations from UG 490 to include monthly fixed effects to control for seasonality and a squared HDD term to control for non-linear effects of weather and exclude weather terms that did not produce meaningful coefficients.[29] The arimaauto auto-parameterization module suggested a non-differenced specification of ARIMA(1,0,0). I found that arimaauto suggested specification of ARIMA(1,0,0)(0,0,0)$_{[1]}$ does produce optimal test statistics and better backcast predictive fit compared to these other specifications.[30] The model is as follows, where *m* is month and *y* is year:

$$\frac{R2\ UPC}{Day}m,y = \beta_1\frac{R2\ HDD}{Day} + \beta_2\left(\frac{R2\ HDD}{Day}\right)^2 + \beta_3\frac{WindChill * EffectiveTemp}{Day} + \beta_4\frac{SolarRadiation}{Day} + \beta_5 Jan_{=1} \ldots$$
$$+ \beta_{16}Dec_{=1} + \beta_{17}SinceCovidMnths_{=1} + \beta_{18}\frac{ResidentialDSM}{Day} + \beta_{19}WeekendDays$$
$$+ ARIMA(1,0,0)(0,0,0)_{[1]}$$

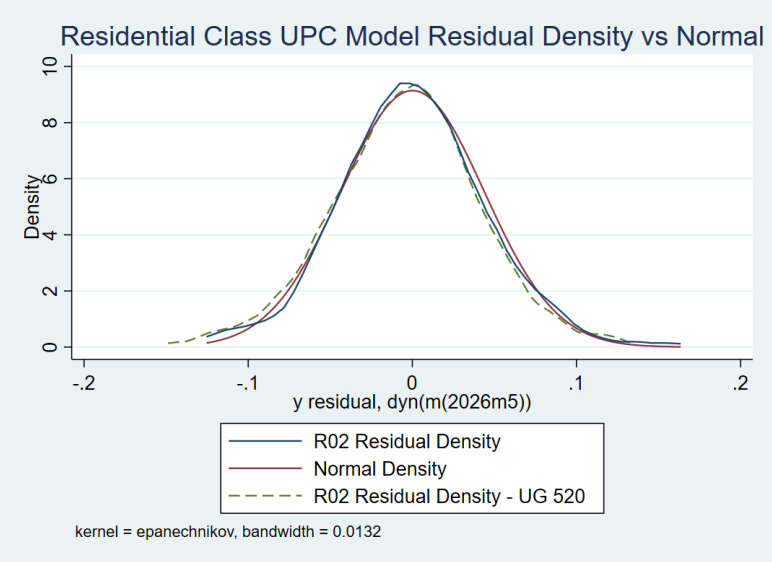
For the months of June, July, and August I used a separate simple regression model to estimate baseload in these months. The combined models

[29] Docket No. UG 490, Staff/1900, Stevens/4 (Apr. 18, 2024).

[30] 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.

produce a normalized UPC value of 631.3 therms annually, which is about 3.0 percent lower compared to the model specification used in UG 520. Figure 3 below indicates the residual errors density compared to both a normal distribution as well as the model specification from UG 520. As Figure 3 below indicates, this class-wide model, as well as the UG 520 model, both have residuals that closely align with a normal distribution.

Figure 3



B. RS 3 Basic Firm Sales Non-Residential Service - Commercial

I implemented Staff's recommendations from UG 490 for the RS 3 Basic Firm Sales Non-Residential Service – Commercial ("RS 3 General Commercial") model specification to remove the monthly fixed effects and instead control for seasonality in the ARIMA specification, include a squared HDD term to control for non-linear effects of weather, and exclude weather terms that did not produce

meaningful coefficients.[31] The arimaauto auto-parameterization module suggested a non-differenced specification of ARIMA(1,0,0)(1,0,0)$_{[12]}$. I found, for this proceeding, that a slightly different specification with the same order of multiplicative seasonal ARIMA periods of ARIMA(2,0,2)(2,1,2)$_{[12]}$ produces optimal test statistics and better backcast predictive fit compared to these other specifications. This parameterization is the same as the one the Company used in UG 520. The model is as follows:

$$\frac{C3\ UPC}{Day}m,y = \beta_1\frac{C3\ HDD}{Day} + \beta_2\left(\frac{C3\ HDD}{Day}\right)^2 + \beta_3\frac{WindChill * EffectiveTemp}{Day} + \beta_4\frac{SolarRadiation}{Day}$$
$$+ \beta_5 SinceCovidMnths_{=1} + ARIMA(2,0,2)(2,1,2)_{[12]}$$

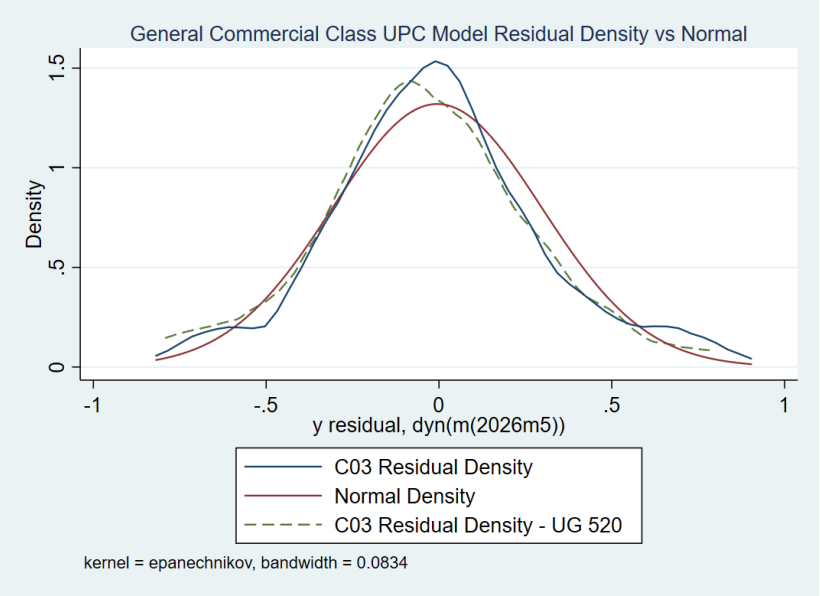
For the months of June, July, and August I used a separate simple regression model to estimate baseload in these months. The combined models produce a normalized UPC value of 3,153.0 therms annually, which is about 4.2 percent lower compared to the UG 520 model, and is still consistent with Staff's observation noted in UG 490 that the UPC Forecast in that proceeding of 2,973.5 therms was forecasting RS 3 General Commercial lower peak consumption in winter months compared to Staff's model.[32] Figure 4 below indicates the residual errors density compared to both a normal distribution as well as the model specification from UG 520. As Figure 4 indicates, while the UG 520 model aligns a little closer to the standard normal distribution, this model has residuals that have a higher concentration centered around zero which indicates a smaller cluster of

[31] Docket No. UG 490, Staff/1900, Stevens/9 (Apr. 18, 2024).

[32] *Id.* at 11. Staff observed: "Staff's forecast slightly increases the Test Year load forecast for commercial customers, primarily through a higher forecasted peak consumption in winter months."

forecast errors. For this reason, and the fact this model has lower MAPE and RMSE metrics, I find that this model is slightly more optimal compared to the UG 520 model.

Figure 4



C. RS 27 Residential Heating Dry-Out Service

I implemented Staff's recommendations from UG 490 for the RS 27 Residential Heating Dry-Out Service ("RS 27 Dry-Out") model specification to include monthly fixed effects and exclude weather terms "with a negligible effect on the model."[33] The arimaauto auto-parameterization module suggested a non-differenced specification of ARIMA(1,0,0)(0,0,0)$_{[12]}$. Staff, in UG 490, recommended an ARIMA(1,0,0) specification.[34] I found, for this proceeding, that Staff's recommended model specification produces optimal test statistics and

[33] *Id.* at 12.

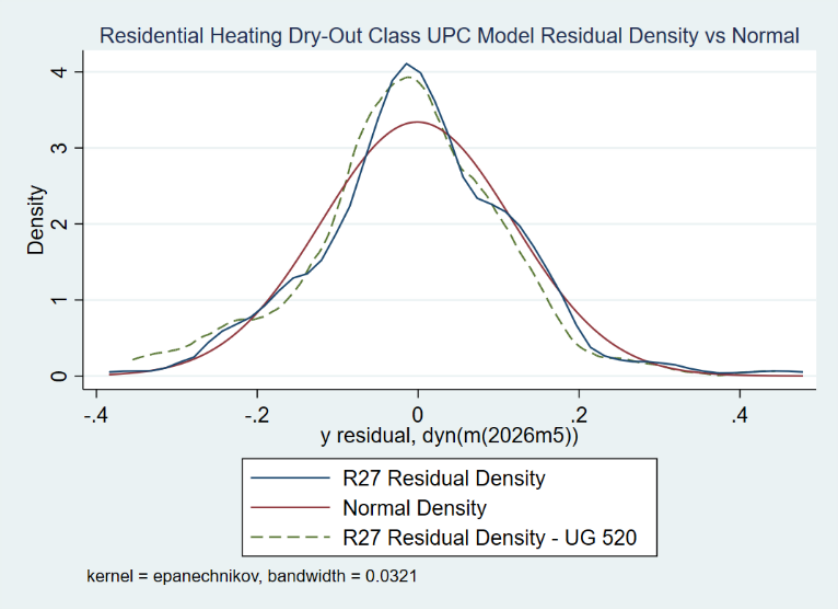
[34] *Id.* at 11.

better backcast predictive fit compared to these other specifications. The model is as follows:

$$\frac{R27\ UPC}{Day}m,y = \beta_1\frac{R27\ HDD}{Day} + \beta_2\frac{Precipitation}{Day} + \beta_3 Jan_{=1} + \beta_4 Feb_{=1} + \beta_5 Mar_{=1} + \beta_6 Apr_{=1} + \beta_7 May_{=1} + \beta_8 Jun_{=1}$$
$$+ \beta_9 SummerMnths_{=1} + \beta_{10} Oct_{=1} + \beta_{11} Nov_{=1} + \beta_{12} Dec_{=1} + ARIMA(1,0,0)$$

This model produces a normalized UPC value of 506.5 therms annually, which is just under 4.9 percent lower than the UPC value estimated for UG 520. Figure 5 below indicates the residual errors density compared to both a normal distribution as well as the model specification from UG 520. As Figure 5 below indicates, this model produces residuals similar to that of the UG 520 model, with a slightly higher concentration of forecast errors around zero.

Figure 5



D. RS 31 Non-Residential Firm Sales Service - Commercial

Staff recommended, in UG 490, a model specification for RS 31 Non-Residential Firm Sales Service – Commercial ("RS 31 Commercial Firm Sales")

load forecast that is the same as RS 27 Dry-Out.[35] I found in UG 520, however, that a model specification that implements the "substantive changes"[36] Staff recommended for RS 32 Large Volume Non-Residential Firm Sales Service – Commercial ("RS 32 Large Volume Commercial Firm Sales") produces more optimal test statistics and better backcast predictive fit. Therefore, for this proceeding and consistent with UG 520, I implemented a model that is close to that which Staff recommended for UG 490 for RS 32 Large Volume Commercial Firm Sales. I include no monthly fixed effects and instead control for seasonality in the ARIMA specification, include a squared HDD term to control for non-linear effects of weather, and exclude weather terms that did not produce meaningful coefficients. The arimaauto auto-parameterization module suggested a non-differenced specification of ARIMA(1,0,0)(1,0,0)$_{[12]}$. For this proceeding, I chose a model specification of ARIMA(1,0,1)(1,1,1)$_{[12]}$, which is the same specification I chose in UG 520 and similar to the specification Staff recommended for RS 32 Large Volume Commercial Firm Sales in UG 490. The model is as follows:

$$\frac{C31\ UPC}{Day}m,y = \beta_1\frac{C31\ HDD}{Day} + \beta_2\left(\frac{C31\ HDD}{Day}\right)^2 + \beta_3\frac{SolarRadiation}{Day} + \beta_4\frac{SolarRadiation * EffectiveTemp}{Day}$$
$$+ \beta_5 SinceCovidMnths_{=1} + \beta_6 WeekendDays_{=1} + \beta_7 IndustrialProductionIndex$$
$$+ ARIMA(1,0,1)(1,1,1)_{[12]}$$

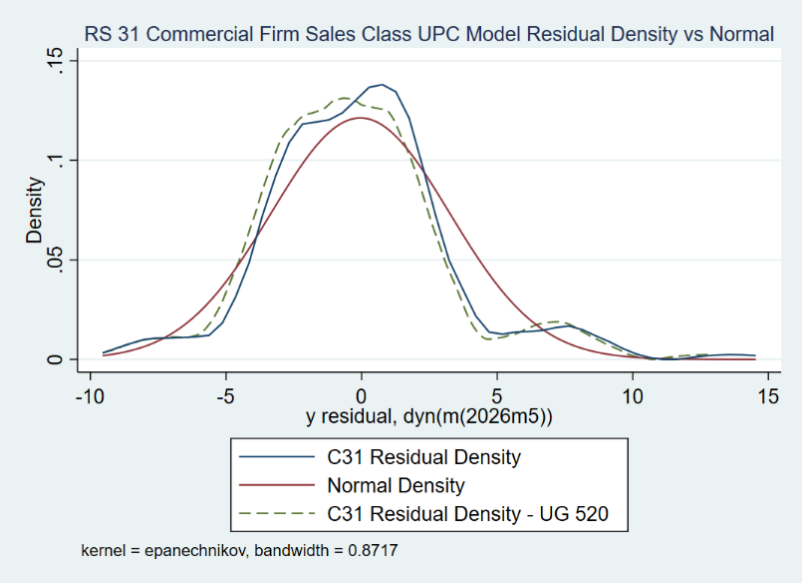
This model produces a normalized UPC value of 34,773.3 therms annually, which is about 3.9 percent lower than the UPC value estimated for UG 520. Figure 6 below indicates the density of residual errors compared to both a normal

[35] *Id.* at 14.

[36] *Id.* at 16.

distribution as well as the model specification from UG 520. As Figure 6 indicates, this model produces residuals similar to that of the UG 520 model, although this model has a higher concentration of slightly positive forecast errors (which indicate over-forecasting) while the UG 520 model indicates slightly more under-forecasting. The model for this proceeding produces a slightly more optimal RMSE compared to the UG 520 model, suggesting it is an improvement.

Figure 6



E. RS 32 Large Volume Non-Residential Firm Sales Service - Commercial

As noted above, Staff recommended in UG 490 "substantive changes" to the RS 32 Large Volume Commercial Firm Sales load forecast.[37] Per Staff's recommendations from that proceeding, I include no monthly fixed effects and instead control for seasonality in the ARIMA specification, include a squared HDD term to control for non-linear effects of weather, and exclude weather terms that

[37] *Id.* at 16.

did not produce meaningful coefficients. The arimaauto auto-parameterization module suggested a non-differenced specification of ARIMA(1,0,0)(1,0,0)$_{[12]}$. I found, for this proceeding, that a model specification of ARIMA(2,0,2)(2,1,2)$_{[12]}$ produces more optimal test statistics compared to a model of the same specification as RS 31 Commercial Firm Sales. The model is as follows:

$$\frac{C32\ UPC}{Day}m,y = \beta_1\frac{C32\ HDD}{Day} + \beta_2\left(\frac{C32\ HDD}{Day}\right)^2 + \beta_3\frac{SolarRadiation}{Day} + \beta_4\frac{SolarRadiation * EffectiveTemp}{Day}$$
$$+ \beta_5 SinceCovidMnths_{=1} + \beta_6 WeekendDays_{=1} + \beta_7 IndustrialProductionIndex$$
$$+ ARIMA(2,0,2)(2,1,2)_{[12]}$$

This model produces a normalized UPC value of 100,697.4 therms annually, which is about 8.9 percent higher than the UPC value estimated for UG 520. Figure 7 below indicates the residual errors density compared to both a normal distribution as well as the model specification from UG 520. As Figure 7 indicates, this model produces residuals that align similarly to a normal distribution compared to the UG 520 model, with a higher concentration of forecast errors centered around zero.

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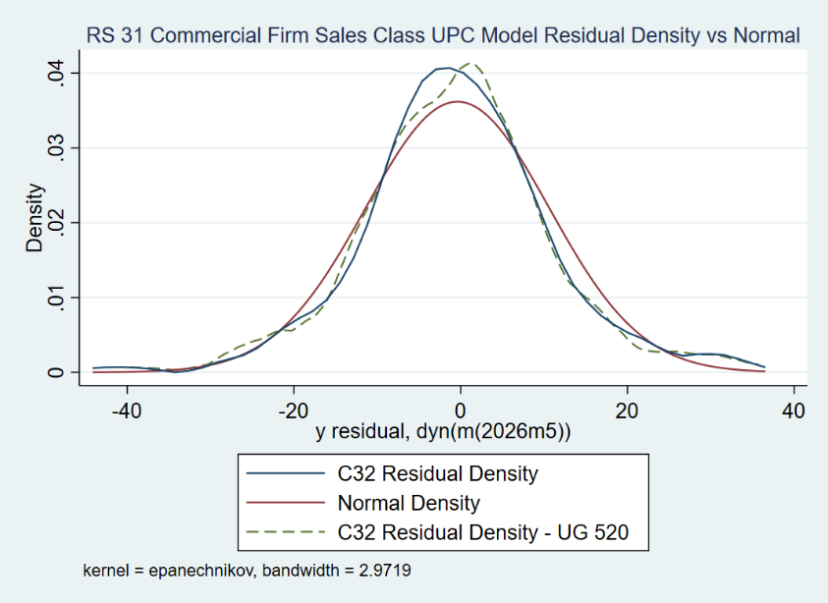
Figure 7



F. Additional UPC Analysis and UPC Forecast Results Summary

Q. Please describe the Single-Family Premises UPC and Multi-Family Premises UPC model parameters.

A. As I noted above, I also created a bifurcated residential UPC for Single-Family Premises and Multi-Family Premises for the purpose of estimating average rate and bill impacts. I used the same model specification parameters as the RS 2 Residential Sales Service class-wide model, which produces a Single-Family Premises UPC of 670.7 therms annually and Multi-Family Premises UPC of 340.9 therms annually.

Q. Have you calculated UPCs for the subset of residential premises taking service on RS 2 Residential that represent existing service connections ("Existing Premises UPC") and new service connections ("New Premises UPC") for purposes of creating a bifurcated baseline for the Company's Decoupling mechanism?

A. Yes. Per Order No. 24-359 in UG 490, the Commission directed the Company to bifurcate its decoupling revenue calculation based on whether each premises that is taking service on RS 2 Residential was connected to the Company's system on or after January 1, 2018.[38] Therefore, for this proceeding (and consistent with UG 520) I have calculated two additional UPCs for customers taking service on RS 2 Residential: (1) Existing Premises UPC for customers residing in premises connected before January 1, 2018; and (2) New Premises UPC for customers residing in premises connected on or after January 1, 2018. For premises connected before January 1, 2018, I use the same model specification as the residential class-wide model I presented above, but with an ARIMA specification of ARIMA(1,0,1)(1,0,0)$_{[1]}$. This produces an Existing Premises UPC of 641.8 therms annually, which is 3.5 percent lower than what I estimated for UG 520. For premises connected after January 1, 2018, I use the same model specification as the class-wide model. This model produces a New Premises UPC of 430.7 therms annually, which is 4.5 percent lower than what I estimated for UG 520. These two

[38] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Order No. 24-359 at 19 (Oct. 25, 2024).

weather normalized UPCs are used to set the Company's bifurcated Decoupling mechanism baselines.

Q. Please describe the Existing Premises UPC and New Premises UPC data collection and parameters.

A. I queried the Company's Customer Information System ("CIS") for all bills generated for Oregon residential premises that had a service connection initiated both before and on or after January 1, 2018. In developing the Company's Decoupling mechanism bifurcation proposal for UG 490, I found that in general there is about a four-month delay between when a service is initialized and when the bills show therm load. Therefore, I did not include load data for the period January 2018 through April 2018 for estimating the 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, I did not include load

data for the first four months after January 1, 2018 in my New Premises UPC analysis.

Q. Please summarize the results of the UPC Forecast.

A. The chosen ARIMA model specifications produce a weather normalized Test Year UPC Forecast of 631.3 therms annually for the Residential class (with bifurcated results of 641.8 and 430.7 therms annually for Existing and New Premises, respectively), and 4,136.2 therms annually for the Commercial Firm Sales class.

Q. How are the customer forecast and UPC Forecast 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 forecasted UPCs for each residential and commercial firm sales rate schedule by the forecasted monthly end-of-period customer counts.

Q. How are Test Year volumes built for the Industrial Sales as well as the Commercial and Industrial Transportation classes?

A. 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 detail by customer class as NW Natural/1203, Walker and is shown in summary at NW Natural/1201, Walker.

Q. What are the Company's other uses for the UPC Forecast?

A. The Company uses the UPC Forecast to develop the design day load factor for the LRIC study, as discussed below. The UPC Forecast is also used to estimate throughput volumes for the annual purchased gas adjustment ("PGA"). The methodology for calculating the UPC Forecast is consistent between the PGAs and rate case filings. Certain inputs and outputs of the UPC Forecast are also used for calculating the WARM and Decoupling rate mechanism adjustments, as described in Mr. Walker's Direct Testimony, NW Natural/1200, Walker.

Q. What are the statistical coefficient outputs produced by the UPC Forecast for WARM and Decoupling rate mechanism adjustments?

A. The formula for producing the statistical coefficient outputs that drive the WARM billing adjustment ("WARM Adjustment Factor") is described in the Company's Schedule 195 tariff. I produced the statistical coefficient outputs using the ARIMA model specification developed for the UPC Forecast, but with one weather variable to estimate HDD effects on heating load per the WARM Adjustment Factor formula presented in Schedule 195.[39] The statistical usage coefficients to be used in the

[39] NW Natural's Oregon Tariff, Sheet 195-3, Schedule 195 Weather Adjusted Rate Mechanism (WARM Program) (continued).

calculation of the WARM Adjustment Factor, defined in Schedule 195 as β, are 0.15502 for RS 2 Residential and 0.63180 for RS 3 General Commercial. These statistical usage coefficients, along with that of RS 31 Commercial Firm Sales, 6.45698, are also used to calculate the variance between weather normalized usage and actual usage for the Company's Decoupling mechanism, as described in Schedule 190.[40]

Q. Have you submitted work papers based on this section of your testimony?

A. Yes, I have submitted two work papers. The first is the normal weather model that derives the 25-year historical benchmark for normal weather. The second is the ARIMA analysis that derives the weather normalized UPC Forecast.

III. LONG-RUN INCREMENTAL COST (LRIC) STUDY

A. Long-Run Incremental Cost Study Purpose, Principles, and Inputs

Q. What purpose does a cost of service study serve?

A. The overall objective of a cost of service study, including an LRIC 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 embedded costs). Whereas an embedded cost study 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), a long run cost of service study evaluates the marginal (incremental) costs borne by each rate schedule as

[40] NW Natural's Oregon Tariff, Sheet 190-2, Schedule 190 Partial Decoupling Mechanism.

usage, throughput demand, and customer count change over time and how that impacts the on-going provision of utility service.[41] The Commission discussed the practical application of incremental- and marginal-cost pricing for utility ratemaking in Order No. 85-832 (docket No. UG 14), stating: "The marginal-cost theory generally applied to utility ratemaking actually is an incremental cost theory because it assumes additions or deletions of more than one therm. The result is an averaging of marginal costs over a range of output."[42]

By understanding the long run incremental costs by rate schedule, the LRIC study methodology is able 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. 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.

[41] 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 incremental cost study may use historical installed costs forecasted out to the Test Year as a basis to then allocate those costs to specific schedules based on the incremental costs of an additional customer to that schedule.

[42] *In the Matter of Revised Tariff Schedules Applicable to Gas Service in the State of Oregon Filed by Northwest Natural Gas Company, General Rate Increase*, Docket No. UG 14, Order No. 85-832 at 7 (Sep. 12, 1985).

Q. Has the Commission stated its preference for cost of service study methodology?

A. Yes. The Commission, in Order No. 85-832, directed that an LRIC study is "preferable" to an embedded cost approach because the methodology for developing long-run incremental costs better estimates the magnitude by which customers, either individually or as part of a rate class, are under- or over-paying the costs associated with their service. These estimates are used as the basis for price setting and the spreading of revenue requirement. While the Commission has stated its preference for an LRIC approach, it has not prescribed a specific methodology, stating: "We will not require a single marginal cost approach for all utilities" because "[w]e do not believe that mandating a single approach will advance the art of marginal cost analysis, and it could significantly impede progress."[43]

Q. Please describe the economic principles that underlie an LRIC study.

A. Incremental long run 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*

[43] *In the Matter of the Investigation of Methods for Estimating Marginal Cost of Service for Electric Utilities*, Docket No. UM 827, Order No. 98-374 at 10 (Sep. 11, 1998).

Optimality.[44] 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. 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 with economies of scale given that all customers are paying a portion of the fixed system costs where (Price > MC) while achieving equitable 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

[44] *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).

customers because customers would in theory be unwilling to take service (and/or move to the next best economic alternative) if prices exceed the 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 how the LRIC study evaluates incremental costs in the long-run.

As I noted earlier, the Commission has stated that the marginal cost theory as it pertains to evaluating the makeup of the entirety of the Company's revenue requirement for application of utility ratemaking is an incremental cost theory. The *long-run incremental costs* of capital assets identified in the Company's prior LRICs do not necessarily disappear because the *marginal cost* of those same assets is zero beginning with this proceeding. Certainly, due to ratemaking capital recovery conventions, the long run incremental costs identified in UG 520 have not expired simply because the Company has not yet reached the "long-run" when those assets have been fully depreciated. Commission Order No. 85-832 discusses why it is reasonable, albeit difficult, for an LRIC to consider long-run costs identified in prior rate cases:

> [A]ny method of allocating the cost of long-term assets among several reporting periods is inherently arbitrary. Expenditure of the entire cost is required to put the asset into service for the first period, but the benefits extend to other periods. A number of reasonable rationales exist for allocating the initial cost over time.[45]

[45] *In the Matter of Revised Tariff Schedules Applicable to Gas Service in the State of Oregon Filed by Northwest Natural Gas Company, General Rate Increase*, Docket No. UG 14, Order No. 85-832 at 8 (Sep. 12, 1985).

Therefore, it is reasonable to allocate the initial cost of long-run investments over reporting periods (i.e., multiple rate proceedings). A new rate proceeding does not necessarily reset every rate schedule to parity with prior period costs that are reasonably attributable to that rate schedule. Rate classes that enter a proceeding above or below their indicated cost of service may remain so after the proceeding when those differences in cost causation alignment are not fully addressed through rate spread, particularly where the adopted rate spread reflects considerations such as rate shock and gradualism, which I discuss later. Accordingly, this LRIC study not only addresses the incremental costs associated with the revenue requirement in this proceeding, but consistent with ratemaking conventions, it also recognizes the continuing cost responsibility for long-run investments reflected in rates established through prior proceedings.

Q. Please briefly summarize the LRIC study methodology and describe how the Company's incremental costs are assigned to rate schedules.

A. The LRIC study methodology presented in this testimony is an economics exercise that evaluates how much of the Company's incremental 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 LRIC study follow the Company's Test Year for the 12 months ended October 31, 2028.

The LRIC 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 is based on

Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts categorization. Incremental capital costs and O&M expenses are used as a basis for allocating the long-run incremental system cost to each rate schedule. The Test Year proposed cost allocation to each schedule is based on this incremental system cost and is further informed by the organization of the proposed Test Year revenue requirement into the following buckets of costs: commodity, meter reading and billing, meters and services, system core, transmission, and gas storage.

The next step, classification, splits the functionalized costs by each of three characteristics related to their underlying marginal cost driver: (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. Each functionalized-classified cost item is then assigned to each individual rate schedule through allocation factors which are measures of cost causation.

Allocation, the final step, assigns cost items through indirect or direct assignment. I describe below how costs that are directly assigned are allocated through special studies to specific rate schedules.

After allocating the entirety of the incremental revenue requirement, the LRIC study calculates the relative ratio of revenue to incremental costs for each rate schedule at present rates. This ratio is used to understand overall cost responsibility for each rate schedule, as well as 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 LRIC study 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 using indirect allocators. I describe how these special studies allocate costs in detail below.

Q. Please explain how the LRIC study is presented with this rate case.

A. The full Excel-based LRIC study model is submitted in its entirety as a Standard Data Request ("SDR") response and a work paper accompanying this rate case. Each of the special studies is similarly submitted as work papers; the output from each study is summarized in a tab in the LRIC study, with an index identifying the external spreadsheet file(s).

B. NW Natural's LRIC Study Inputs and Methodology

Q. Have you prepared an LRIC study for this proceeding?

A. Yes. NW Natural/1301, Wyman presents the results of NW Natural's LRIC study. The exhibit shows the indicated LRIC study summary results and the LRIC-indicated spread of NW Natural's proposed revenue requirement by rate schedule.

Q. Is your LRIC study methodology in this case, UG 532, similar to the methodology used in the Company's last rate case filing, UG 520?

A. Yes. Generally, NW Natural's LRIC study methodology is similar to the methodology used in the Company's last rate case filing, UG 520.

Q. Are there differing or additional aspects of your LRIC study methodology in this case that are noteworthy?

A. Yes. I made one modification as recommended by Staff, and I conducted an evaluation of interruptible rate schedules that I use to inform an update to the discount applied to some LRIC study allocators for these rate schedules. I describe the interruptible rate schedule cost of service evaluation in more detail later in this testimony. Finally, in this LRIC study I incorporate and allocate Coos County Pipeline assets which have been recorded in separate dedicated FERC sub-accounts. A summary of these modifications and updates is as follows:

- For the System Core Mains (less than four inches) Allocator labeled *Dist-5*, in response to Staff, I use the firm sales load factor in the calculation of this allocator instead of the sales load factor.
- Per the UG 520 Second Partial All-Party Stipulation, I conducted a cost of service study for interruptible rate schedules that evaluates the

system impacts of providing non-interruptible firm service to customers on such schedules. As I discuss later in this testimony, I use the results of this study to modify the interruptible rate schedule discounts that are applied to the demand and storage allocators *Dist-1, Dist-5, Dist-6, Trm-1, Trm-3,* and *Stor-1*. Whereas the factor that I applied for the discount was 0.50 in UG 520 (equating to a 50 percent allocation adjustment), I now use 0.58 for interruptible sales customers and 0.53 for interruptible transportation customers (equating to a 42 percent and 47 percent allocation adjustment, respectively).

- Per UG 527 and 528 Commission Order No. 26-387, as to the Coos County Pipeline assets recorded in FERC sub-accounts, I incorporate separate Coos County allocators that inform the LRIC study results and "adjust the overall rate spread factors between rate classes, incorporating the unique usage pattern in this area into our [the Commission's] standard approach to ratemaking."[46] These allocators are labeled as *Dist-8* and *Trm-3*.

Q. How is your discussion of the LRIC study methodology organized?

A. The individual LRIC study inputs and methodology discussion sections are organized as follows:

[46] *In the Matters of Northwest Natural Gas Company, dba NW Natural, Application for an Alternative Rate Mechanism, New Schedule 123 (Docket No. UG 527)*; *and Advice No. 25-23 (ADV 1789), Schedule 160, Cancellation of Changes for Coos County Pipeline (Docket No. UG 528)*, Order No. 26-387 at 13. (Oct. 13, 2026).

1. Design Day Load Factor
2. Functionalized Incremental Plant Investment Costs
3. Operations and Maintenance (O&M) Expense
4. Interruptible Rate Schedule Cost of Service Evaluation
5. LRIC Study 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 this LRIC study, I consider design day load on an Oregon basis and attributable to Oregon 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 LRIC study 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 LRIC study 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 this LRIC study?

A. I estimated the design day load factor for each rate schedule using the UPC Forecast for the Residential and Commercial sales customer classes, and the Company's Industrial Forecast for the remaining schedules.

The ARIMA-based UPC Forecast 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 the statistical software that produced these coefficients (Stata) to model the normalized load numerator for the load factor ratio using the historical 25-year HDD average. As part of its resource planning processes, the Company has estimated an 11.3

degree F design day temperature, which I converted to HDDs. Using the UPC Forecast derived coefficients, I then estimated the design day load factor denominator.[47]

Large Commercial interruptible and transportation service and Industrial schedules in rate classes RS 31 and RS 32 are not included in the UPC Forecast analysis, as well as schedule RS 3 Industrial. Customers in these classes were not included in the UPC Forecast 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 Test Year 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 beginning January 2016. I calculated a maximum daily delivery volume ("MDDV") for each customer by year and aggregated these volumes by rate schedule. Then, I weighted each year's MDDV values by Test Year customer counts for each rate schedule and used this factor to gross up (or down) each year's MDDV total. Finally, I took the average aggregate MDDV value from the period January 2019 through December 2025. This value is the basis for the design day load factor denominator.

[47] For NW Natural's 2025 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 11.3-degrees Fahrenheit.

Q. How did the Company weight the MDDV values in the design day factor calculation?

A. I weight each year's MDDV values by Test Year customer counts for each rate schedule, which is Staff's preferred approach.[48] This approach accounts for the full peak demand generated by new Test Year customers by adjusting demand for the years prior to their taking service for each rate schedule. Therefore, zero demand is not assumed for these new customers for the years prior to their taking service, helping to ensure that capacity factors are not overestimated, which would result in underestimating the capacity burden that some rate schedules may put on the system during peak days. I note that this approach is only valid when using customer counts incremental to the Test Year; simply using year-to-year customer count differences would risk overestimating the capacity burden as a business could close and be replaced the next year by a new business at the same location, resulting in zero incremental customers.

Q. What were the results of the design day load factor analysis?

A. For the purposes of this LRIC study, I estimate an overall load factor for Oregon rate schedules of 29.2 percent, with a firm load factor of 25.7 percent and a transportation load factor of 60.0 percent. The RS 2 Residential load factor is about 22.0 percent, meaning normal load for this schedule is a little more than one-fifth of its design day load. The RS 3 Commercial load factor is about 23.6 percent,

[48] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 435, Opening Testimony of Scott Gibbens, Staff/1600, Gibbens/11, lines 11-22 (Apr. 22, 2022).

while the Large Commercial rate schedules have estimated load factors ranging from 28.7 percent to 61.3 percent; the Industrial rate schedules have estimated load factors ranging from 32.8 percent to 60.9 percent. I use these load factors to estimate peak day deliveries, which with average deliveries makes up the basis for the weighted peak and average calculation that derives the Design Day Peak and Average Allocator (labeled *Dist-1*) in the LRIC study.

Q. Does the Company rely solely on the peak and average methodology for allocation of capacity costs in the LRIC study?

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 an "average and excess" and "winter to summer average excess" allocation methodologies in my LRIC study. The Company's natural gas system is built based on design day demands, which is why the design day load factor is a key input into the LRIC study cost causation modeling methodology. It follows, however, that cost causation for some investments such as a portion of distribution mains and transmission mains are allocated based on demand throughput based on a rate schedule's contribution to capacity needs. It also follows that cost causation for some investments, such as a portion of distribution (system core) mains and underground storage, are better allocated based on a rate schedule's contribution to capacity demands at peak times. 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.

Q. Did the Company estimate a separate peak and average allocator for allocation of Coos County Pipeline assets?

A. Yes. In alignment with Commission Order No. 26-387 (UG 527 and 528), I created a separate Coos County Pipeline Peak and Average Allocator that incorporates the unique usage pattern in this area to allocate mains of less than four inches, or greater than or equal to four inches, that have been recorded in Coos County FERC sub-accounts. I used 7 years of actual Coos County customer usage data to estimate a rate-class weighted contribution to average throughput and peak demand. This analysis results in an allocator that assigns costs by class as follows: Residential (22.6 percent), general and large commercial (32.6 percent), and industrial (44.8 percent).

2. Functionalized Incremental Plant Investment Costs

Q. Please outline the specific components of functionalized incremental 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 LRIC study 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) System core mains, which are the balance of mains not attributable to distribution mains. System core mains, for the purpose of this LRIC study, 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) System reinforcements, which are mains related to capacity increases.

d) Transmission mains, which constitutes the pipeline that transports gas from the interstate pipeline to delivery points on the Company's system.

e) Storage, which includes the costs associated with underground storage, a primarily winter peaking resource.

f) Service lines, which include 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 include the cost of the meter and regulator, as well as the pipe fittings, bracket assemblies labor, and shop time required for assembly.

h) General and Intangible Plant, which includes many of the assets used to serve all customers such as computers and software, as well as communications equipment.

i) Land and Structures, which 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. 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. I evaluated main extension costs using 12 calendar years (2014 – 2025) of historical accounting data of Oregon 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 I analyzed are as follows:

- Residential-single family new construction ("Residential New")
- Residential-single family conversion ("Residential Conversion")
- Commercial / Industrial ("Com/Ind")

In addition to the 12 years of job orders data, I used a main extension analysis that is produced annually by the Company's Business Analytics team, for actual and forecasted values from 2024 through roughly the Test Year (end of year 2028). This analysis 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. I use this

analysis to express actual and forecasted main extensions in terms of (by category) mains footage per meter and cost per foot.

Neither the main extension jobs order data nor does the forecast include a breakout by rate schedule. 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 median cost per foot and median main length installed by market segment over an 8-year period (2018-2025). Additionally, I used the same dataset to calculate the median 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").[49] The escalated values were used to create the median Test Year cost per foot input for the LRIC study.

[49] 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; and (2) Oregon Economic and Revenue Forecast, Table Other Economic Indicators: CPI Urban Consumers. Page 51, September 2026.

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 8-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.

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 31 and RS 32 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 customer forecasts. For the Commercial and Industrial schedules, I used median 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 Oregon 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.[50] Next, I used the historical GIS pipe size data to estimate what percentage of customers in each rate schedule are connected to

[50] 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.

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 unattributable feet were classified as system core 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 was classified as system core mains.

Q. How did you assign the system core mains costs to each rate schedule?

A. I used an average and excess method for distributing the system core mains costs to the rate schedules based on two allocations: total throughput and 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 "excess") and similarly distributes costs across all rate schedules.

Q. Did the Company update how system core mains are allocated?

A. Yes. As I noted earlier, for this proceeding I used the sales firm design day load factor for system core mains of less than four inches, which was originally intended

to be implemented in UG 520 (instead of the sales load factor), and used a load factor for the Commercial and Industrial rate classes for system core mains of greater than or equal to four inches. This methodology recognizes the differences in the design day load factor between customers who are more likely to be associated with system core mains of less than four inches and of those associated with system core mains of greater than or equal to four inches.

Q. Does the system core mains allocation make an adjustment for interruptible peak day deliveries?

A. Yes. The system core main allocation includes interruptible peak day deliveries, adjusted with a factor of 0.58 for interruptible sales customers and 0.53 for interruptible transportation customers. This equates to an allocation discount of 42 percent and 47 percent for each set of interruptible customers, respectively. This methodology represents an update from the Company's methodology in UG 520 and UG 490 (and implemented in response to Staff's recommendation in its UG 435 Opening Testimony which gave all interruptible customers a 50 percent core mains allocation discount).[51] The discount from these prior proceedings, as well as the updated discounts in this proceeding, continue to recognize that interruptible customers "receive tangible benefits from peak day planning investments" because they are "seldom, if ever interrupted" and therefore should be allocated a portion of these resource costs.[52] The updated discounts are based

[51] Docket No. UG 435, Staff/1600, Gibbens/15-17 (Apr. 22, 2022).

[52] Docket No. UG 435, Staff/1600, Gibbens/13, lines 11-14 (Apr. 22, 2022).

on an analysis (described later) of the system impacts of providing non-interruptible firm service to these customers, and are not based specifically on the number or timing of curtailment events. As the Company noted in UG 520, and continues to assert here, regardless of the number of curtailment events, interruptible customers do present a demand side resource for the sole reason they *can* be curtailed to alleviate supply and capacity constraints. As such, the allocation to interruptible customers at 42 percent and 47 percent of the standard firm demand allocation that is allocated to firm customers, and which is lower than the 50 percent discount Staff initially recommended in UG 435, is reasonable.

Q. Please elaborate why the Company finds using interruptible customer demand discounts for the system core mains allocator is reasonable.

A. The LRIC study is a theoretical economic costing exercise that attempts to estimate the point where customers, either individually or as part of a rate class, are paying the costs associated with their service as a basis for discussions of price setting and rate spread. The Company agrees that interruptible customers provide system planning benefits and these benefits are reflected in the rates that are charged to these customers. Valuing and assigning these benefits are not straightforward and raise the question of how (and to what extent) to allocate costs based on requirements and obligations in the tariffed rate compared to how the system is used in practice. On one hand, interruptible customers benefit from the reliability and capacity built for the design day standard of the system. Not all interruptions occur due to capacity constraints from peaking on the system under normal operating conditions; some occur for reasons outside the utility's control

(e.g., third-party damage to infrastructure). On the other hand, the Company notes that regardless of the number of demand response events, interruptible customers do present a demand side resource for the sole reason they *can* be interrupted to alleviate supply and capacity constraints. Later in this testimony, I will explain more about the benefits interruptible service provides the system as well as describe my methodology for valuing these benefits to arrive at the proposed interruptible discounts.

Q. How did the Company assign Coos County Pipeline costs assigned to mains FERC sub-accounts to individual rate schedules?

A. I used the Coos County Peak and Average Allocator, which allocates costs by rate class, and weighted each class's cost contribution by the Design Day Peak and Average Allocator to produce an allocation on a rate schedule basis. I assign both mains of less than four inches, or those greater than or equal to four inches in the same manner using this allocator which I labeled as *Dist-8*. Note that this results in interruptible rate schedules receiving the benefit of the interruptible allocation discounts.

c. System Reinforcements

Q. Please briefly describe system reinforcements.

A. System reinforcements are incremental infrastructure requirements when operating pressure is projected to drop below a certain level. The purpose of system reinforcements is to maintain safe and reliable pressure throughout the system, and to assure reliable service to firm customers.

Q. What are the methods used to calculate the incremental system capacity and reinforcement main investment?

A. I calculated incremental system reinforcement costs using over eight years of historical system reinforcement capital spend (January 2018 – July 2026), and forecasted spend from July 2026 through the Test Year. For each year, I multiplied the system reinforcement capital investment by an allocation factor based on Oregon volumes to calculate the Oregon-only system reinforcement expenditures.

I calculated an incremental investment cost per therm for all rate classes based on incremental estimated design day load added to the system over the same period. I applied this per therm investment cost only to those rate schedules that contributed to incremental design day load over the analysis period. Finally, I multiplied the per therm cost by each rate schedule UPC to estimate the total incremental capacity investment.

Q. How were the system reinforcement costs allocated?

A. Incremental system reinforcement investments are triggered by firm service commitments, but interruptible customers benefit from greater system resiliency which reduces the possibility of curtailment. For the same reasons explained above for system core mains, I allocated to interruptible customers that had incremental design day load 42 percent (for interruptible sales customers) and 47 percent (interruptible transportation customers) of the standard firm demand allocation on a per therm basis.[53] I allocated total costs based on the total

[53] Note that the UG 435 LRIC study methodology did not include any apportionment of system reinforcement costs to interruptible rate schedules.

weighted product of each schedule's incremental cost per customer and total customers.

d. Transmission Mains

Q. How were the transmission mains costs allocated?

A. I allocated transmission mains costs using an average of three allocators: design day peak and average allocator, system core mains allocator, and the capacity incremental investment (system reinforcement) allocator. For Coos County transmission mains assets, I used the Coos County Peak and Average Allocator and weighted each rate class's contribution by the overall transmission mains allocator to assign costs to each rate schedule. I labeled the Coos County specific allocator *Trm-3*.

e. Gas Storage

Q. How were underground gas storage costs allocated?

A. I allocated underground gas storage plant costs to sales customers only, using a ratio based on Test Year average winter sales that exceed Test Year average summer sales. This measure allocates costs based on contribution to average peak loads compared to a period of average base loads. I applied the interruptible allocation discount of 42 percent for interruptible sales customers based on the fact that interruptible service avoids the need for Mist storage recall and to acknowledge that service curtailments may not always coincide with a winter peaking event when storage assets are relied upon the most. Interruptible transportation customers receive a 100 percent discount.

Q. Were any underground storage costs classified as balancing and allocated to the Transportation class?

A. No. The LRIC study 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 8 years of historical accounting data of Oregon services job orders (2018 – 2025) for customer service installations by market segment. These data are very similar to those of the Oregon 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 12-year average of job costs per foot. Due to the small job sample size for the Commercial and Industrial schedules in the RS 31 and RS 32 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 median footage by median cost per foot. I used the Inflation Index to inflate nominal dollars to Test Year values.

Q. Does the Company apply its Service Line Cost Allocator consistently across all rate schedules?

A. Yes. In UG 490, AWEC recommended that service lines be allocated consistently across all rate schedules based on the Average Service Line Installed Cost Allocator methodology (labeled *Line-1* in the LRIC study). [54] I adopted AWEC's recommendation in UG 520 and, therefore, I now apply the *Line-1* methodology consistently across all rate schedules.

Q. How is the phase-out of the Company's residential LEA accounted for in the allocation of service line costs?

A. The phase-out of the Company's residential LEA is accounted for in the LRIC study based on the rate base treatment of Aid in Advance of Construction as explained in NW Natural/1200, Walker. The Aid in Advance of Construction allocated to RS 2 Residential by this LRIC study has increased to $13.8 million from $5.3 million in the UG 520 LRIC study, resulting in a direct reduction to total allocated rate base which, in turn, moves the indicated residential class parity ratio closer to unity.

[54] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, Reply Testimony of Robert J. Wyman, NW Natural/3900, Wyman/21 (Jun. 4, 2024).

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.

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 meters and regulators 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. Land and Structures

Q. How were land and structures allocated?

A. I allocated the general land and structures plant balances 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. O&M Expenses

Q. Please describe the categories of O&M expenses evaluated in the LRIC study.

A. Below, I describe how I allocate two categories of O&M expenses. The first category, 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. The second category, common O&M expenses, are associated with common cost items required to keep the entire system running, such as administrative and office expense, wages and salaries, and customer service and billing.

Q. How are O&M expenses associated with capital investments evaluated in the LRIC study for rate making and rate allocation purposes?

A. O&M expenses associated with capital investments (e.g., the on-going operations and maintenance costs associated with the gas storage assets, or the distribution system, for instance) are allocated to rate schedules in the LRIC study by applying an "investment carrying charge" to calculate the incremental revenue requirement associated with each category of investment. The carrying charge includes cost of capital (debt and equity), taxes, and depreciation to calculate the carrying percentage assigned to each category of investment. The investment carrying charge percentage is multiplied by each category of capital investment to calculate each rate schedule's annual revenue requirement. This indicated revenue requirement by rate schedule for each incremental capital investment category is weighted by each schedule's contribution to the overall cost and converted into an allocation factor. This allocation factor is used to apportion incremental O&M expenses (as well as, in some cases, the capital investment itself) associated with multiple capital investment categories to each rate schedule based on cost causation.

Q. What are the categories of common O&M expenses that were evaluated in the LRIC study?

A. The two major categories of common O&M expenses evaluated were: (a) Customer Service and Billing; and (b) Administrative and General. I discuss how these expenses were allocated to individual 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 LRIC study?

A. The LRIC study includes a special study based on the following categories of O&M customer service-related expenses for direct allocation:

- Gas Scheduling, which includes departments that schedule underground storage injections/withdrawals and 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. I evaluated the gas scheduling and gas planning cost centers 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 LRIC study, based on average hours spent on each customer at a calculated average labor rate.

The gas scheduling cost center is divided into two functions for the purposes of this study: 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.

I allocated the gas planning cost center 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 NW Natural evaluate Major Accounts Services costs?

A. I allocated Major Accounts Services costs only to the large RS 31 and RS 32 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 2024 and again in 2026, to reflect current operations and Accounts Services functions and labor costs. 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 this LRIC study.

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. These 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 LRIC study?

A. After identifying the incremental costs, the LRIC study broke 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 Oregon 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 were administrative and general expenses allocated?

A. I allocated most of the administrative and general expenses based on the customer-weighted customer services cost allocator described above. Some expenses, such as pension expense, I based on the allocation of salaries and wages cost components.

4. Interruptible Rate Schedule Cost of Service Evaluation

Q. What is the interruptible rate schedule cost of service evaluation?

A. In the Company's last general rate case proceeding, UG 520, the Company, Staff, and AWEC disagreed regarding the appropriate interruptible customer demand adjustment to apply in the Company's LRIC study. The Company applied a 50 percent adjustment, Staff recommended a 10 percent adjustment, and AWEC recommended a 100 percent adjustment. These adjustments are not a direct discount or credit applied to interruptible customers' bills. Rather, they are adjustments to selected LRIC study cost allocators that affect LRIC study indicated cost of service results and, ultimately, inform the Company's rate spread proposal. In the UG 520 Second Partial All-Party Stipulation, the Company agreed to "conduct a cost-of-service study for interruptible rate schedules that evaluates the system impacts of providing non-interruptible firm service to customers on such schedules."[55] The goal of this evaluation is to use these estimated impacts to

[55] Docket No. UG 520, Order No. 25-420, Appendix B at 3 (Second Partial All-Party Stipulation) (Oct. 24, 2025).

derive an interruptible class allocation adjustment for use in the LRIC study in this proceeding.

Q. Did the Company confer with the UG 520 parties prior to conducting this evaluation?

A. Yes. Consistent with the UG 520 Second Partial All-Party Stipulation, the Company held one workshop before initiating the cost of service study to discuss the methodology to be used for the study. This workshop was held on September 24, 2026.

Q. What is an interruptible service customer?

A. An interruptible-service customer agrees that the Company may curtail their natural gas usage under certain conditions. Under Rules 13 and 14 of the Company's Oregon tariff, interruptible customers are the first customers subject to curtailment when curtailment is necessary to meet firm-service requirements, balance available gas supply, preserve operational control, maintain distribution-system integrity, or respond to force majeure conditions. As of August 2026, the Company had 155 Oregon interruptible customers, consisting of 86 sales customers and 69 transportation customers all on large volume commercial or industrial rate schedules. These customers take service on rate schedules with lower billing rates to recognize the benefits they bring to the system. I estimate that on a curtailable schedule, an interruptible sales customer pays about 14.4 percent less than a firm sales customer using the same amount of gas while an interruptible transportation customer pays about 8.6 percent less than a firm transportation customer using the same amount of gas.

From a system-planning perspective, the service type distinction between interruptible and non-interruptible service (also referred to as firm service) is important. The Company plans its system capacity resources to meet design peak-day firm demand. Because interruptible load can be curtailed, that load is not included in the demand that the Company must plan to serve on a design peak day. If these customers instead received firm service, the Company would be obligated to plan for their peak-day demand and could be required to acquire additional commodity supply, capacity (demand response) resources, or reinforce portions of its distribution system.

Q. What type of resource is interruptible service and what is the system value of this type of resource?

A. Interruptible service functions as a demand response and a non-pipeline alterative resource. The intrinsic value of a demand-side resource is equal to the costs the Company avoids because that additional firm demand does not need to be served. These avoided costs can include system capacity resources as well as system reinforcement and capacity improvement costs in areas of the distribution system that experience constraints under cold-weather conditions. The value of curtailable load as a non-pipeline alternative resource is that it can reduce or defer the need to build pipelines (or, uprate existing pipelines) solely to meet peak demand.

Q. Is there a distinction between interruptible sales service and interruptible transportation service customers?

A. Yes. Both interruptible sales and transportation customers may be curtailed to address capacity constraints involving the Company's distribution system, upstream transmission capacity, or other conditions necessary to maintain system integrity. Interruptible sales customers, however, purchase their commodity supply from the Company. Curtailing these customers can therefore reduce both the capacity resources and the peak-day commodity supply resources the Company must procure. Interruptible transportation customers procure their own commodity supply, which is not included in the Company's sales-supply portfolio. Curtailing transportation customers therefore provides a capacity benefit but does not provide the same commodity supply benefit.

This distinction is relevant to the LRIC study because the value of interruptibility is ultimately tied to the system costs that are avoided. For the LRIC study, I evaluate the capacity benefit by estimating the incremental infrastructure and capacity resources that would be required if both interruptible sales and transportation customers instead received firm service. For interruptible sales customers, I separately evaluate the incremental peak-day commodity supply resources that would be required, in the form of reservoir capacity at the Company's Mist storage facility.

Q. What does the Company's interruptible customer usage data indicate about interruptible service?

A. The Company finds that interruptible customers represent a material amount of load that the Company is not obligated to serve during constrained system conditions. The Company modeled the peak-day load its existing interruptible customers would impose if those customers instead received firm service using the Synergi Customer Management Module ("CMM"). Oregon interruptible customers would be expected to account for roughly 717 thousand therms on a peak day under firm conditions, which would increase the Company's Oregon system peak by approximately 7.3 percent and 9.9 percent if measured against the coldest day within the past 40 years (February 3, 1989) or peak demand realized during the 2024 winter storm (on January 13, 2024), respectively.[56] Figure 8 below shows where these peak interruptible therms would be located geographically on the Company's Oregon system, broken down by sales or transportation service.

[56] Docket No. LC 86, 2025 Integrated Resource Plan at 4-43 (Aug. 1, 2025).

Figure 8

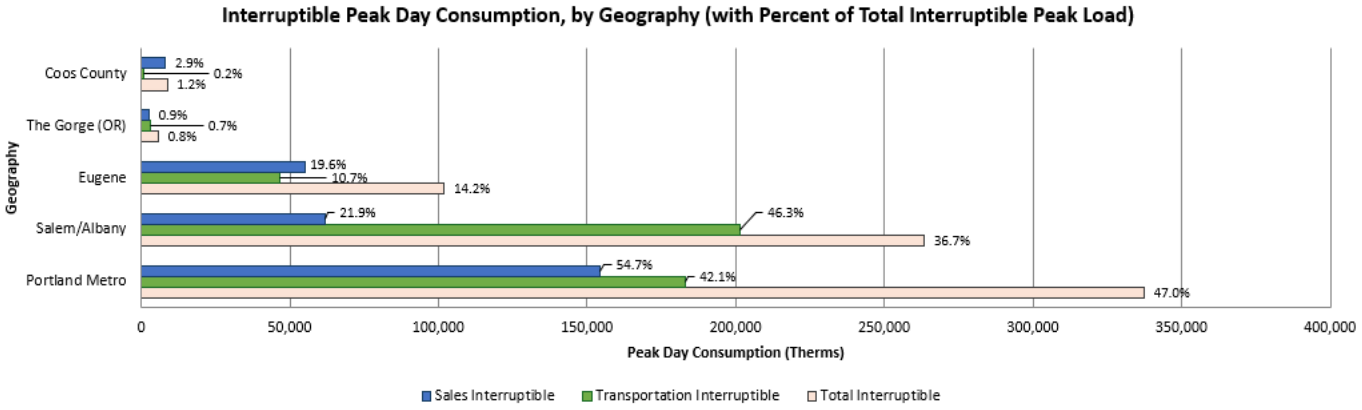


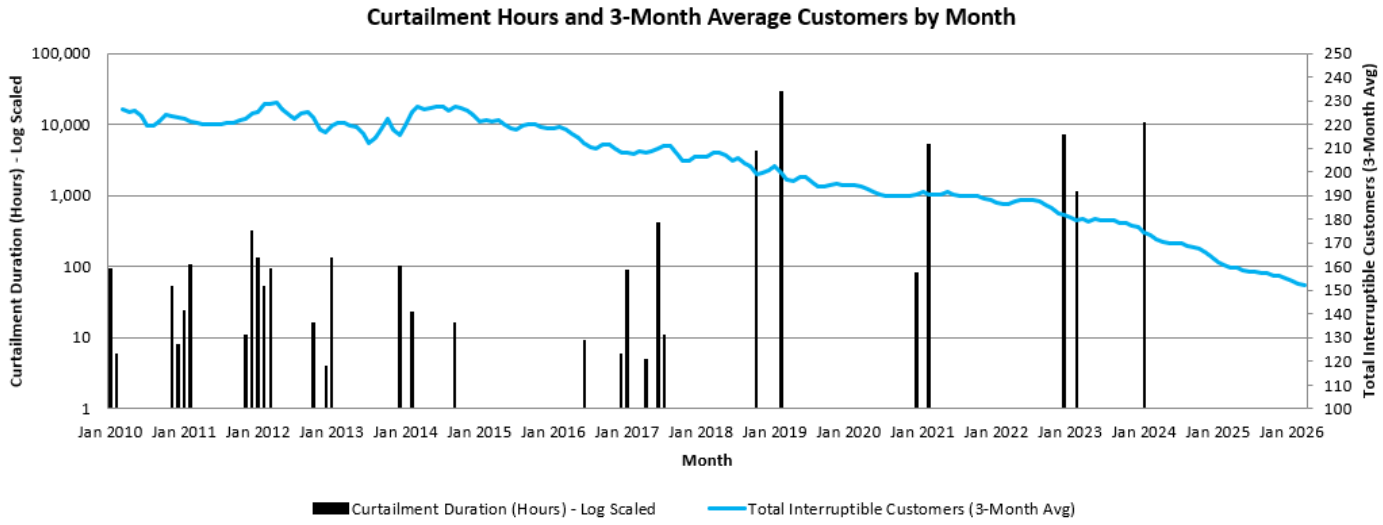
Figure 8 indicates that most of the overall benefits of interruptibility are tied to the Portland metro area. The Salem-Albany area, however, realizes a higher proportion of capacity-side benefits tied to avoided infrastructure costs from interruptible transportation customers; interruptibility in this area brings lower avoided sales-supply benefits. The geographic basis of estimated interruptible peak usage is important because the Company's interruptible cost of service evaluation measures avoided capacity and commodity-supply costs based on the location of interruptible customers and the CMM-modeled impact (e.g., localized pressure drops) of their hypothetically converting to firm service.

Q. What does the Company's interruptible customer historical curtailment data indicate about interruptible service?

A. Figure 9 below shows interruptible customer curtailment frequency from January 2010 through January 2026, with curtailment magnitude measured (on a log-scale) as cumulative duration in hours across all interruptible customers, with total number of interruptible Oregon customers on a separate axis. This figure shows that curtailment frequency can be variable, but the magnitude of total interrupted

hours for each curtailment event has been higher since January 2019. At the same time, the number of interruptible customers has steadily decreased, suggesting the possibility that the impact and magnitude of these curtailment events may incentivize some customers to forego the rate benefits of interruptibility and elect firm service.

Figure 9



Curtailment frequency alone, however, does not measure the system-planning benefit associated with interruptibility. Demand-side resources, such as interruptibility, have planning value when they reduce (or avoid) the Company's capacity and commodity supply requirements necessary to maintain satisfactory operating conditions under its design-day planning standard. That value does not depend on whether the resource has historically been called upon, but whether the resource can be relied upon to reduce demand under future design peak-day conditions. Further, the timing of curtailments is important: A few hours of curtailment during the coldest days of the year can provide greater system-

planning benefit than several days of curtailment during warmer periods when heating demand is low. For that reason, a measure of curtailment frequency or service downtime does not, by itself, quantify the system value of interruptibility.

Q. Has the Company examined whether system peaks coincide with interruptible customer curtailments?

A. Yes. Figure 10 below shows Oregon daily sendout for the period December 2016 through February 2024 compared to estimated curtailed usage for each of the curtailment events during that period (there have been no large curtailment events since February 2024). Figure 10 indicates that during this period, curtailment events have occurred and have resulted in avoided usage coinciding with peak and peak-adjacent days in five out of eight winter seasons. Curtailments coincided with sendout peak in January 2017, February 2021, December 2022, and January 2024. Additionally, curtailments coincided with the fourth highest peak sendout day in the winter of 2018/19 and the second highest sendout day in the winter of 2022/23. The estimated curtailment therms are based on reductions in interruptible usage during the curtailment days compared to average interruptible usage for the three days prior to curtailment or just after curtailment.

Figure 10

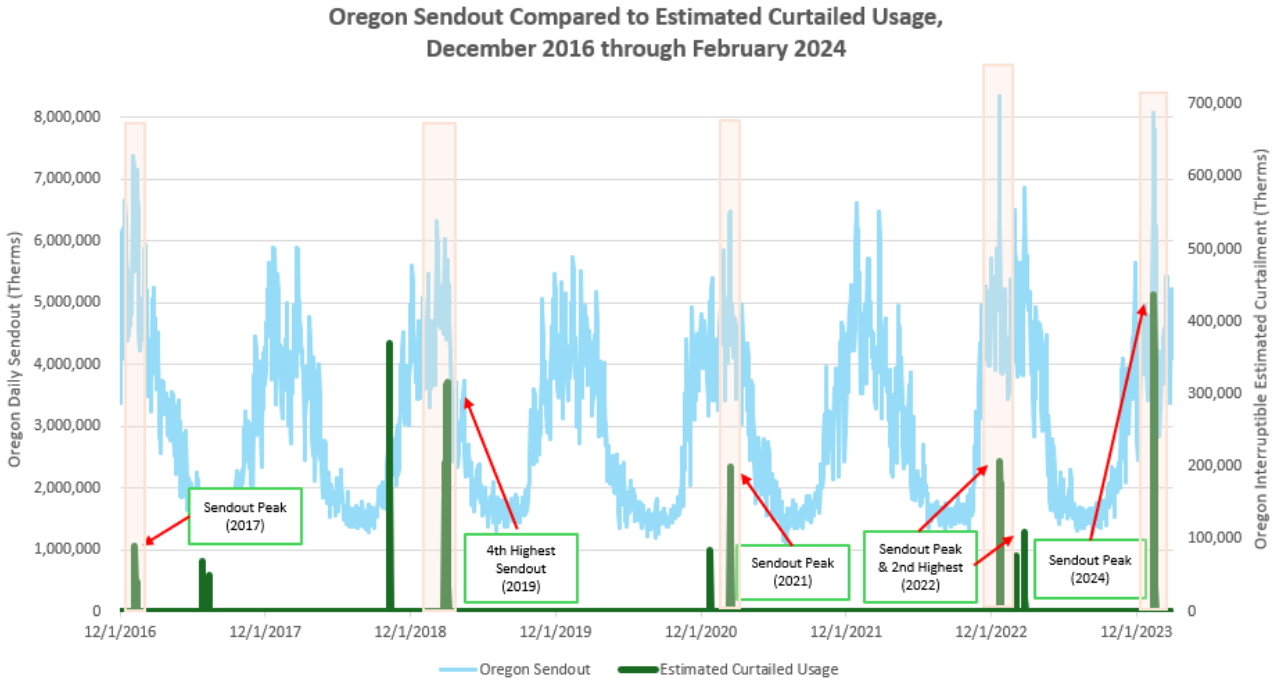


Figure 10 indicates that interruptible customers do act as an effective demand-side peaking resource during peak not just conceptually, but also in practice. For instance, for the curtailment period spanning January 13, 2024 through January 17, 2024, interruptible customers' usage dropped roughly 49 percent, 63 percent, 49 percent, and 43 percent on January 13th, 14th, 15th, and 16th, respectively, relative to January 12th. Across these days, interruptible customers' curtailed usage resulted in an estimated sendout reduction of about 5 percent coincident with firm customers' peaking usage. These data support the application of capacity and commodity-supply interruptible allocation adjustments in the LRIC study.

Q. What is the goal of the Company's interruptible cost of service study evaluation, and how did the Company perform its analysis?

A. The goals of this study are to better quantify the system costs the Company avoids because these customers take interruptible rather than firm service and use those avoided costs to evaluate the reasonableness of the interruptible allocation treatment in the Company's LRIC study. Rather than infer that value primarily from historical curtailment frequency and an assumption of avoided cost benefits, which formed the basis for the prior 50 percent interruptible allocator adjustment, this study estimates the incremental costs the system would incur under the counterfactual assumption that existing interruptible customers must instead be served on a firm basis.

Since interruptible sales and interruptible transportation customers bring different system benefits, as I discussed above, I separately evaluated capacity and commodity-supply avoided costs. For the avoided capacity cost analysis, the Company's Engineering team used the Synergi CMM to estimate interruptible customers' peak demands based on historical usage. The Company then modeled those customers as firm customers and evaluated impact on system pressures across the system which are based on each interruptible customer's geographic location and their peak usage. Where the firm-service scenario produced conditions outside the Company's system peak day operations and reinforcement standards, Engineering identified the pipeline additions, uprates, or other reinforcements necessary to serve that load and estimated the associated costs. For the commodity-supply analysis, I used modeled peak demands for only the

interruptible sales customers to estimate the incremental cost of firm peak-day gas supply, using Mist Recall as the avoided-cost reference resource.

Q. What were the avoided costs estimated by the Company's interruptible cost of service evaluation?

A. The Synergi CMM interruptible customers capacity analysis results in estimated avoided capacity and reinforcement costs of roughly $166 million that would immediately be required if all the Company's Oregon sales and transportation interruptible customers elected firm service. This includes capital investments in new mains and transmission mains, uprates or replacements of existing pipelines, new compressor stations, and new district regulators. Additionally, the Company estimates that it would need to recall existing interstate Mist storage capacity to core at a cost of about $15 million to meet the commodity-supply requirements of Oregon sales interruptible customers. Combined, I estimate total avoided capital costs of roughly $181 million.

Q. How did you incorporate this avoided cost estimate into your LRIC study to measure reasonable interruptible allocator adjustments?

A. First, I calculated the interruptible customers' cost causation using my standard LRIC study methodology, which estimates interruptible customers' overall cost causation given current rates and conditions that I refer to as the "main LRIC study." Then, I created an alternate LRIC study to more narrowly examine the system capacity and supply costs under a hypothetical system where these customers are taking firm service. To model this firm scenario "alternate LRIC study," I added the avoided capital costs identified above, into FERC accounts by

asset type in the tab labeled, “TY Plant Summary by FERC” and imputed reserve plant assuming half a month of depreciation. I adjusted O&M expenses and taxes commensurate with the additional hypothetical capital investment. I kept the capital investment and O&M expense allocators for the individual rate schedules consistent with my standard LRIC study methodology. These inputs and conditions act as if interruptibility was suddenly “switched” to firm service. Given these conditions, the alternate LRIC study indicates that the revenue requirement would be $29.7 million higher in this proceeding if all interruptible customers elected firm service. The $29.7 million, therefore, represents the estimated system costs avoided by providing these customers with interruptible rather than firm service.

I then used the firm and interruptible scenarios to determine reasonable allocation adjustments in three steps:

- First, in the alternative firm scenario LRIC study, which includes the additional $29.7 million of firm-service costs, I solved for the interruptible sales and interruptible transportation allocation adjustments that produce unity parity, or 1.00, for the interruptible class as a whole. This results in allocation factors of 0.63 for interruptible sales and 0.60 for interruptible transportation rate schedules. These factors represent the allocation adjustments under which interruptible customers, if served as firm customers, would collectively pay their modeled cost of service if it were aligned with their cost causation.

- Second, I applied the interruptible allocation factors from the first step to the main LRIC study and credited interruptible customers with their estimated $29.7 million avoided system cost. Under this condition, the parity ratio corresponding to the firm scenario alternative LRIC study 1.00 parity ratio calculated in the first step is equal to 1.10 in the main LRIC study. This calculation establishes the equivalent cost of service relationship after recognizing the system benefit provided by interruptibility.
- Finally, I reset the main LRIC study to the actual costs reflected in this proceeding by removing the estimated $29.7 million of firm-service costs because they are avoided through interruptibility. I then solved for the interruptible allocation adjustments that produce the equivalent 1.10 parity ratio for the interruptible class. This results in allocation factors of 0.58 for interruptible sales and 0.53 for interruptible transportation rate schedules, equivalent to allocation discounts of 42 percent and 47 percent, respectively.

Q. How do these interruptible allocation adjustments impact the main LRIC study allocation factors?

A. In the main LRIC study, the 0.58 interruptible sales factor impacts the demand and storage allocators *Dist-1, Dist-5, Dist-6, Trm-1, Trm-3,* and *Stor-1*. The 0.53 interruptible transportation factor impacts the same allocators except for *Stor-1*, where these rate schedules receive a factor of 0.00 (a 100 percent discount).

Q. What is the overall impact of the interruptible allocation adjustments on interruptible customers' indicated cost causality?

A. The overall impact of the interruptible allocation adjustments can be measured by comparing the proposed LRIC study results to a scenario in which these adjustments are removed, effectively reflecting a zero percent interruptibility discount. Under this scenario, the overall interruptible class parity falls from 1.10 to 0.77, indicating that absent recognition of the system avoided costs and benefits attributable to interruptible service, the class would appear to be significantly underpaying its cost to serve. Similarly, the LRIC study's indicated margin deficiency for the interruptible class increases from approximately 3.5 percent to 32.0 percent. Therefore, the proposed LRIC study interruptible allocation adjustments provide substantial recognition of the system benefits attributable to interruptible service customers.

Q. Are there other costs, risks, and benefits associated with interruptibility that are not readily quantified by this evaluation?

A. Yes. A business's willingness to take interruptible service, and thereby provide the associated system avoided cost benefits, depends in part on its tolerance for interruption risk. As AWEC testified in UG 520, "[Interruptible customers] plan their operations to accommodate a short notice shut down for major production facilities and are required to invest in protective systems and procedures. Shutting down a boiler used in an industrial process on moment's notice, if not planned for properly, can cause significant safety and production issues. Receiving interruptible service can be capital intensive and costly to customers that elect to take that service even

accounting for the slightly reduced gas distribution rate from interruptible service."[57] These considerations are not readily quantified in the LRIC study evaluation but are relevant to rate design because customers must be willing to elect to trade these costs and risks for the benefits of lower interruptible rates so that interruptibility remains available as a demand-side resource.

Q. Please summarize the results of your interruptible cost of service evaluation with parties' positions in UG 520.

A. The interruptible allocation discounts of 42 percent and 47 percent represent a slightly smaller discount compared to the Company's singular 50 percent discount from UG 520. These values continue to represent a middle-ground between the 10 percent allocator discount proposed by Staff and AWEC's proposed 100 percent allocator discount from that same proceeding.

5. LRIC Study Insights and Outcomes

Q. Upon what LRIC study model do you base your insights and outcomes to inform the rate spread in this proceeding?

A. Below, I base my LRIC study insights and outcomes on what I refer to as the main LRIC study above to inform my proposed rate spread in this proceeding. This LRIC study uses interruptible allocation discounts of 42 percent and 47 percent for interruptible sales and interruptible transportation customers, respectively. These discounts are applied to a few of many LRIC study allocators that help inform

[57] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 520, Opening Testimony of Brad Mullins, AWEC/100, Mullins/76, lines 6-12 (Apr. 2, 2025).

overall system cost causation for all rate classes and are ultimately used to guide my rate spread proposal below; they do not represent a direct adjustment on interruptible customers' bills.

Q. Upon what basis is margin revenue at current rates compared against the margin revenue with the proposed incremental revenue requirement?

A. The LRIC study compares the ratio of Margin Revenue at Current Rates (see line 20 of the LRIC study results, NW Natural/1301, Wyman) against the LRIC Based Target Margin (line 21), which is the margin revenue amount including the proposed incremental revenue requirement. This ratio is used to derive the Current Margin Revenue to LRIC Based Target Margin (line 23), and then the Parity Ratio at Present Rates (line 23a), which indicates each rate schedule's position relative to cost parity (i.e., the point that the schedule as a whole is neither over- nor under-paying its LRIC study determined cost of service).

Q. Does the Margin Revenue at Current Rates figure contain any commodity-related revenues for any of the rate schedules?

A. No. The Margin Revenue at Current Rates figure presented on line 20 does not contain any commodity-related revenues, including commodity cost related to "line loss" (e.g., unaccounted for gas). Commodity-related costs are pass-through costs and are therefore fully offset against commodity-related revenues, producing no net change to margin revenues.

Q. Does the Margin Revenue at Current Rates figure contain any emissions or environmental compliance, or renewable natural gas-related revenues, for any of the rate schedules?

A. No. The Margin Revenue at Current Rates figure presented on line 20 does not contain any revenues that the Company has collected for compliance with Oregon Department of Environmental Quality's Climate Protection Program ("CPP"). CPP-related costs are similar to commodity-related costs in that they are pass-through and are fully offset against revenues, producing no net change to margin revenues. Further, as explained in NW Natural/1200, Walker, all Schedule 198 renewable natural gas revenues, expenses, and rate base have been removed from the revenue requirement calculation and, accordingly, are not reflected in the LRIC study.

Q. What do the results of the LRIC study indicate?

A. The LRIC study-indicated Parity Ratio at Present Rates for each rate schedule is illustrated in Figure 11 below. A parity ratio below the value of 1.00 indicates that customers on a given schedule are underpaying their LRIC study 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 margin rates. Per Figure 11 below, the results of the LRIC study indicate that the RS 2 Residential, RS 3 General Commercial, RS 3 Industrial, and RS 27 Dry-Out rate schedules are paying less than their full cost of service at present rates while the remaining rate schedules are paying more than their cost to serve.

Figure 11
LRIC Study Parity Ratio at Present Rates, by Rate Schedule

RATE SCHEDULE	02R	03C	03I	27R	31CSF	31CTF	31ISF	31ITF
LRIC Study Determined Parity Ratio	0.99	0.98	0.88	0.94	1.24	1.12	1.28	1.62
RATE SCHEDULE	32CSF	32ISF	32CTF	32ITF	32CSI	32ISI	32CTI	32ITI
LRIC Study Determined Parity Ratio	1.22	1.12	1.36	1.08	1.18	1.04	1.98	1.05

The class-wide LRIC study indicated parity ratios are as follows: 0.99 for the Residential class; 0.98 for the General Commercial class; 1.19 for Large Commercial and Industrial Sales Firm class; 1.11 for the Large Commercial and Industrial Transportation Firm class; and 1.10 for the Large Commercial and Industrial Interruptible class.

Q. How do these results compare with the Company's last filed LRIC study?

A. This LRIC study and the Company's last study, filed with UG 520, both indicate that the RS 31 and RS 32 rate classes are paying more than their determined cost of service under present rates. Just as I observed in UG 520, the LRIC study in this rate case indicates that nearly all schedules have moved closer to parity. Both studies also indicate that RS 2 Residential and RS 27 Dry-Out customers are paying less than their determined cost of service. The RS 2 Residential parity ratio is slightly higher than the UG 520 indicated ratio (while still underpaying the determined cost of service, the LRIC study indicates the gap has narrowed which it has done so in each rate proceeding since UG 435). The RS 3 General Commercial parity ratio has moved from above parity in UG 520 (1.01) to a parity

ratio of 0.98 (which is close to the indicated parity ratio of 0.95 in UG 490). The movement from slightly below parity to above and back again indicates these customers are currently paying close to their determined cost of service. Of the rate schedules below parity, RS 27 Dry-Out had the largest move closer to parity, from 0.77 in UG 520 to 0.94 in this proceeding. Finally, based on the data and methods used to calculate incremental cost for this LRIC study, as described earlier in this testimony, I find that RS 3 General Service Industrial customers have the lowest Relative Margin-to-Cost Ratio at the Company's current rates, moving from a level above parity in UG 520.

Q. Why has RS 27 Dry-Out moved closer to parity?

A. The RS 27 Dry-Out has moved from a parity ratio of 0.77 in UG 520 to 0.94 in this proceeding. This large movement closer to parity is due to parties' agreement in the UG 520 Second Partial All-Party Stipulation which stated that the fixed and volumetric rate components of RS 27 Dry-Out "will be the same as the [RS 2 Residential] rate beginning at the rate effective date of NW Natural's next general rate case filing."[58] Per the UG 527 and 528 Partial Multi-Party Stipulation, parties agreed the rates would be set identical at the residential rate effective date of that proceeding, October 31, 2026.[59] These new identical rates, which result in a higher proportion of revenues attributable to RS 27 Dry-Out customers, are

[58] Docket No. UG 520, Order No. 25-420, Appendix B at 3 (Second Partial All-Party Stipulation) (Oct. 24, 2025).

[59] Docket Nos. UG 527, 528, Order No. 26-387, Appendix A at 8. (Oct. 13, 2026).

reflected in the Test Year revenues in this proceeding which, in turn, are reflected in the results of this LRIC study.

Q. Overall, are the rate classes moving closer to parity?

A. Yes. Although direct comparison of parity ratios across LRIC studies is not straightforward due to changes in investment mix, customer makeup and service elections, and changes to overall throughput and design day demand, the Company believes that its incrementalism approach to rate spread has helped to move all rate classes closer to parity over multiple rate proceedings. For instance, the UG 435 LRIC study indicated seven rate schedules having a parity ratio of above 1.75; the UG 520 LRIC study indicated just one schedule with a parity greater than this value and likewise this LRIC study also indicates just one. Further, the average parity ratio of 1.30 in UG 520 has lowered to 1.19 in this proceeding.

Q. Has the Company conducted a cost of service analysis for any other tariff schedule not included in the LRIC study?

A. Yes. The Company has updated the cost of capital components and the O&M assumptions (if necessary) of its cost of service analyses for tariff Schedule 4 – Residential Multi-Family Service ("Schedule 4"), tariff Schedule H – Large Volume Non-Residential High Pressure Gas Service Rider ("Schedule H"), and tariff Schedule 15 – Charges for Special Metering Equipment, Rental Meters, and Metering Services ("Schedule 15").

Q. What is tariff Schedule 4?

A. Tariff Schedule 4 is applicable only to residential tenants that reside in participating multi-family buildings. The tariff is based on the special provision that the service is for low-use gas appliances such as cooktops, and not for space heating. Customers taking service on this schedule are charged a base monthly rate.

Q. Please describe the Schedule 4 cost of service analysis.

A. The Company updated its Schedule 4 cost of service analysis to reflect the updated weighted average cost of capital as filed in this case. The analysis also updates the annual O&M expense to reflect the 2026 Meter-to-Cash study described earlier in my testimony.

Q. Please summarize the results of the Schedule 4 cost of service analysis.

A. The results of the analysis increase the Schedule 4 base monthly rate from $11.42 to $12.92, an increase of 12.5 percent.

Q. What is tariff Schedule 15?

A. Tariff Schedule 15 is an optional tariff schedule that enables customers to rent meters and metering services based on a monthly charge as determined by a cost of service formula specified in the tariff for both diaphragm and rotary meters (with some older meters charged a rate retained under existing arrangements). Schedule 15 includes the terms and conditions of meter rental, as well as various miscellaneous metering services and charges. Customers taking service under Schedule 15 enter into a rental meter agreement with the Company.

Q. Please summarize the results of the Schedule 15 cost of service analysis.

A. The Company proposes to update one Schedule 15 charge to reflect the updated weighted average cost of capital as filed in this case. Based on this update, the Company proposes to increase the monthly charge for installed advanced automated meter reading ("AAMR") devices from $54.04 to $54.79 per month (a 1.4 percent increase).

Q. Please summarize the results of the Schedule H cost of service analysis.

A. The Company updated the Schedule H "Cost Recovery Factors" found on Sheet H-5 to reflect the updated weighted average cost of capital as filed in this case. The Cost Recovery Factors are the factors applied each year to large volume non-residential high pressure gas service capital investments for recovery of capital-related costs including cost of capital, depreciation, interest, and taxes.

Q. Do the Company's proposed changes to Schedule 4, Schedule 15, or Schedule H 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 4, Schedule 15, and Schedule H to those customers only.

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, including its monthly fixed charge rate proposal;

- Summarize NW Natural's incremental revenue requirement request;
- Discuss the results of the LRIC study 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.

A. Rate Design

Q. Is the Company proposing any rate design changes in this proceeding?

A. Yes. The Company is proposing to increase the monthly fixed charge for the two Basic Firm Sales Service schedules, RS 3 General Commercial and RS 3 Industrial, by $10.00 per month from $15.00 to $25.00, which I discuss in more detail below. The Company is not proposing any other rate design changes in this proceeding, including to the residential monthly fixed charges.

Q. Is the Company proposing to maintain a uniform volumetric rate for both single-family and multi-family residential customers taking service under RS 2 Residential?

A. Yes. The proposed rate spread maintains a uniform volumetric rate for single-family and multi-family customers taking service under RS 2 Residential, even though the existing monthly fixed charge is $2.00 lower for the multi-family residential cohort ($8.00 compared to $10.00 for the single-family residential cohort). This rate design avoids arbitrariness in the residential volumetric price

signal on an intra-class basis while apportioning rates that recognize differing costs of service across premises types (single-family vs multi-family).

Q. How does the residential class rate design constitute sound rate design?

A. The Company's residential rate design maintains a uniform volumetric price signal for the residential rate class in order to promote a fair apportionment of revenue requirement across the Residential rate class, while avoiding different volumetric price signals on an intra-class level. 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)."[60] The Company's proposal avoids arbitrariness in the volumetric price signal on an intra-class basis while apportioning rates that recognize differing costs of service across residential premises types (single-family vs multi-family). The Company is, however, interested in seeing the results of Staff's differential rates workstream under docket UM 2211, which I understand will develop utility-specific recommendations.

[60] See: Bonbright, James C., Albert L. Danielsen, David R. Kamerschen. *Principles of Public Utility Rates* (Second Edition, 1988). Public Utilities Reports, pages 383-384.

Q. Please summarize the Company's monthly fixed charge rate design proposal.

A. The Company proposes to increase the monthly fixed charge for RS 3 General Commercial and RS 3 General Industrial customers by $10.00, from $15.00 to $25.00 per month. The monthly fixed charge is one of two components of the billing rates the Company uses to collect the fixed system costs associated with providing service to customers on these schedules. The second component is the volumetric rate which collects the remaining fixed system costs not collected by the monthly fixed charge, as well as costs that vary with customer usage.

The Company's rate design proposal is revenue neutral. The Company's rate spread proposal, as described below, determines the amount of overall revenue requirement to be spread to these rate schedules. The Company's rate design proposal only modifies how that revenue requirement is assigned between the fixed and volumetric rate components; it does not increase the total revenue requirement assigned to either schedule.

Q. Why is the Company proposing to increase the monthly fixed charge for these two rate schedules?

A. The Company's proposal more closely aligns the fixed monthly charge with the fixed system costs of serving each customer and promotes greater equity among customers taking service on the same rate schedule. Fixed system costs are incurred to connect and serve a customer regardless of how many therms that customer ultimately uses. These costs include investments and expenses associated with meters and regulators, service lines, distribution facilities, billing,

payment processing, and other customer-related functions. When a significant portion of fixed costs are collected through the volumetric rate component, a customer's contribution toward fixed system costs varies with usage. Higher-usage customers consequently contribute more toward those costs than lower-usage customers, even though many of the underlying costs do not vary proportionately with usage. Lower fixed monthly charges therefore place upward pressure on the volumetric rate and create intra-class subsidization that flows from higher-usage customers to lower-usage customers. A higher monthly fixed charge, on the other hand, 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. What is the current LRIC study indicated monthly fixed system cost attributable to these two rate schedules?

A. The LRIC study's indicated fixed monthly charge for RS 3 General Commercial and RS 3 General Industrial at the proposed rates in this proceeding is an estimated $164.61 and $379.82 per customer per month, respectively. At the current rate of $15.00, the Company would only collect less than 10 percent of its fixed costs through the fixed charge component of these rate schedules, relying on collection of over 90 percent through the volumetric rate component that produces revenues that vary year-to-year based on weather. By comparison, the Company currently collects about 30 percent (over three times as much) of its single-family residential fixed costs through the monthly fixed charge (a $10.00 per month charge compared to an estimated $34.50 in monthly fixed costs).

Q. How does the Company's monthly fixed charge for RS 3 General Commercial and RS 3 General Industrial compare to similar rate schedules charged by peer utilities?

A. Parties to UG 525, Cascade Natural Gas Corporation's most recent rate proceeding, agreed to a monthly fixed charge of $24.00 for Schedule 104 Commercial service and $70.00 for Schedule 105 Industrial service.[61] Avista currently charges a monthly fixed charge of $22.00 for small commercial and small industrial natural gas customers taking service on Schedule 420 in Oregon. Puget Sound Energy currently charges $65.72 per month for general commercial and industrial natural gas service on Schedule 31. Finally, Portland General Electric currently charges $24.00 or $33.00 per month for small non-residential electric service depending on phase. While these charges can vary among the peer utilities, especially for general industrial service, the Company's proposal is in line with similar existing general commercial service monthly fixed charges. The Company's existing monthly fixed charge of $15.00 is the lowest among the peer utilities (accounting for the stipulated agreement in UG 525), and substantially so for general industrial service.

[61] *In the Matter of Cascade Natural Gas Corporation, Request for a General Rate Revision*, Docket No. UG 525, Joint Testimony in Support of Second Stipulation, Stipulating Parties/100, Jacobson-Falconer-Finklea-Tran-Dougan-Apter-Prihoda/17, Table 1 (Aug. 7, 2026).

Q. How does the proposed monthly fixed charge promote equity within RS 3 as well as among the Company's other rate classes?

A. The Company's rate design proposal promotes equity in two related ways. First, within RS 3, it reduces the extent to which higher-usage customers pay fixed system costs on behalf of lower-usage customers. Each customer would make a larger and more consistent contribution toward the system costs attributable to maintaining that customer's connection and providing service. This reduces the gap between the contributions made by customers with different usage levels while still retaining a volumetric rate that varies with usage. The amount that is collected on the volumetric rate component 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 business characteristics: Square footage, hours of operation, tightness of building envelop, age of the building which influences standards and materials used in its construction. The Company's proposal puts downward pressure on the volumetric rate component which smooths bills across the entire year, resulting in lower bills where they are at their highest in the winter months.

Second, the Company's proposal supports equity among all rate classes. The LRIC study is designed to evaluate the incremental capital investment, carrying costs, and operating expenses attributable to each rate schedule. After allocating the revenue requirement, the LRIC study compares revenues with allocated incremental costs to identify cross-subsidies as measured by the parity ratio to inform rate design and rate-spread. A rate design that does not reasonably recover RS 3 fixed system costs from RS 3 General Commercial and RS 3 General

Industrial customers increases the risk that those costs will be borne by other rate classes. That result would be particularly inequitable for customers on schedules that the LRIC study indicates are already paying more than their cost of service.

Q. Do the higher monthly fixed charges proposed by the Company reduce the conservation price signal through the volumetric charge?

A. No. The Company adds an adjustment to the volumetric billing rate of each customer's bill for recovery of costs associated with the CPP 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.

Q. Do higher monthly fixed charges provide any additional benefits for customers?

A. Yes. Higher monthly fixed charges can reduce year-over-year variability in decoupling deferral balances and the resulting rate adjustments to customers. Recovering a greater proportion of fixed costs through the monthly fixed charge rather than the variable volumetric per therm rate reduces the amount of distribution margin collected that varies with customer usage. As explained in NW Natural/1200, Walker, the Company's decoupling mechanism reconciles differences in margin collections resulting when normalized customer usage differs from the usage assumptions underlying base rates, which can cause significant changes in decoupling mechanism collections or refunds. Higher monthly fixed charges can work to reduce these year-over-year changes.

Q. While the Company is not proposing any change to the residential monthly fixed charges in this case, can increasing the monthly fixed charge be beneficial for residential customers in future cases?

A. Yes. As I discussed in UG 490 and UG 520, the Company collects about one-fifth of its fixed costs through the fixed charge component of its RS 2 Residential rate, relying on collection of the remaining four-fifths through the volumetric rate component that produces revenues that vary seasonally and year-to-year based on weather.[62, 63] For the same reasons I discussed above, a higher monthly fixed charge for RS 2 Residential can promote rate equity for residential customers. As the Company explores further conservation and programs such as its recently proposed Hybrid Heating Program, such a rate design could be a key to fairness between residential customers with varying usages. The Company is also interested in understanding the outcomes and recommendations of docket UM 2211 as well as the Multi-Year Rate Plan docket AR 676.

B. Rate Spread

Q. What is NW Natural's total incremental revenue requirement?

A. NW Natural has filed for an incremental revenue requirement of $90.1 million in this proceeding. Please refer to NW Natural/1200, Walker, for more details regarding the incremental revenue requirement. Further, as explained in the Direct

[62] Docket No. UG 490, Direct Testimony of Robert J. Wyman, NW Natural/1800, Wyman/60 (Dec. 29, 2023).

[63] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 520, Direct Testimony of Robert J. Wyman, NW Natural/1600, Wyman/82-83 (Dec. 30, 2024).

Testimony of Kim A. Rush and Zachary D. Kravitz, NW Natural/100, Rush-Kravitz, however, $19.8 million of this amount does not represent new or additional costs but instead reflects the weather normalized UPC Forecast results I presented earlier and which underlie the base rates in this proceeding. These revenues are already authorized for recovery and would otherwise be collected through the Company's decoupling mechanism. Excluding this amount, the Company's net increase in revenue requirement is $70.3 million, or approximately 7.1 percent.

Q. Is any of the incremental revenue requirement 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.

Q. How does the LRIC study relate to rate spread?

A. The LRIC study provides the incremental capital investment costs and O&M expenses, 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 rate shock and smoothing, neither of which are in the Company's or the customers' interests. It is also important to balance the interests of rate equity with rate volatility. The LRIC study does, however, provide a baseline for incremental revenue requirement allocation by rate schedule.

Q. What are NW Natural's thoughts on using the LRIC study results to spread revenue requirement?

A. NW Natural values the LRIC study 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 long-run incremental costs (i.e., if all schedules were suddenly brought to parity with their indicated cost causality), such a shift would result in rate shock for many customers and perhaps inadvertently signal rate volatility. The Company does not have a rigid standard for what constitutes rate shock but rather analyzes its LRIC study 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.

Figure 12 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 long-run incremental costs per the results of this LRIC study. The sum total of the amounts in Figure 12 equals the full incremental revenue requirement in this proceeding. The values in this table are derived at line 19b of the LRIC Summary of Results, NW Natural/1301, Wyman.

Figure 12
LRIC Study Indicated Total Incremental
Revenue Requirement Deficiency (Sufficiency),
by Rate Schedule

RATE SCHEDULE	02R	03C	03I	27R	31CSF	31CTF	31ISF	31ITF
LRIC Study Target Revenue Change	$66,364,273	$24,481,882	$659,035	$170,381	($937,375)	$19,114	($348,619)	($38,067)
RATE SCHEDULE	**32CSF**	**32ISF**	**32CTF**	**32ITF**	**32CSI**	**32ISI**	**32CTI**	**32ITI**
LRIC Study Target Revenue Change	($1,040,543)	$87,454	($195,651)	$431,282	($79,296)	$268,106	($246,215)	$465,356

As seen in Figure 12 above, RS 2 Residential customers would bear the largest share of the incremental revenue requirement increase, if the Company were to adhere strictly to the indicated LRIC study results, followed by RS 3 General Commercial and RS 3 General Industrial. On a percent of total revenue basis, the indicated increase would be 10.7 percent, 10.3 percent, and 16.1 percent for the RS 2 Residential, RS 3 General Commercial, and RS 3 General Industrial rate schedules, respectively. The overall proposed total revenue increase is 9.1 percent. Seven of the twelve rate schedules within the RS 31 and RS 32 rate classes would realize rate reductions under such a scenario, with the remaining five rate schedules would receive increases below the overall total revenue increase.

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 LRIC study in this rate case, which would require higher rate increases for some schedules while others receive decreases. A strict

application of the LRIC 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."[64] Further, the Commission has stated that it is not inclined to raise some rates while reducing others without compelling evidence that immediate action is warranted.[65]

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 the incremental revenue requirement in such a manner that is responsive to the results of the LRIC study across all rate classes, using a methodology similar to what it proposed in its last general rate proceeding (UG 520). I describe the Company’s rate spread methodology in detail below. As I noted earlier, over multiple rate proceedings this approach has worked to narrow

[64] See: Bonbright, James C., Albert L. Danielsen, David R. Kamerschen. *Principles of Public Utility Rates* (Second Edition, 1988). Public Utilities Reports, page 383.

[65] *In the Matter of Avista Corporation, Request for a General Rate Revision*, Docket No. UG 284, Order No. 15-054 at 5 (Feb. 23, 2015).

the rate and differences of cost causation alignment as measured by LRIC study results.

First, for RS 2 Residential and RS 27 Dry-Out, I propose using a cap that slightly moves both of these schedules' relative position closer to parity with respect to the LRIC study results, because these schedules are paying less than their cost to serve at current rates. I use the same cap to keep consistent the volumetric rate component for both rate schedules, per UG 527 and 528 Order No. 26-387. I propose a separate floor for RS 3 General Commercial and RS 3 General Industrial that allocates slightly more than the average margin increase to these schedules because at current rates they also underpay their determined cost to serve. The floor allows an upward adjustment to the rate spread in a later step.

Second, I propose to apply a cap that is set below the level that produces an equal percent of margin increment to all rate schedules with an LRIC study indicated parity ratio above 1.25 and/or those taking interruptible service. As a result of the application of this cap, the relative position to parity of the applicable rate schedules with respect to the overall indicated LRIC study results will decrease, reflecting the fact that these classes are paying more than their cost to serve at current rates. The interruptible rate class is applied this cap to retain the same proportional rate difference as similarly situated firm rate schedules (i.e., so as not to reduce the actual current billing rate discount afforded to interruptible customers).

Third, I allocate the remaining revenue requirement to all remaining rate schedules to reflect the LRIC study results, which indicate that while those

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 1.25. For this step, I allocate the remaining revenue requirement on an equal percent of margin basis among the remaining rate schedules, which include RS 31 Commercial Transportation Firm, RS 31 and 32 Commercial Sales Firm, RS 32 Industrial Sales Firm, and RS 32 Industrial Transportation Firm.

Fourth, I levelize the rate schedules that received an equal percent of margin increase in the third step at a 12.0 percent margin increase cap to further recognize their LRIC study indicated cost causality (schedules with parities over 1.0 otherwise would have received a 13.3 percent increase). I allocate the revenue requirement offset by this cap to two rate schedules with below 1.0 parity ratios, RS 3 General Commercial and RS 3 General Industrial, on an equal percent of margin basis.

This proposal equitably distributes the incremental revenue requirement such that all rate classes are moved closer to parity based on their LRIC study-indicated cost causation. The proposal described above is an incremental approach; it moves all rate classes closer to parity but does so in a manner that works to minimize rate shock. It does this by balancing the impact to residential customers while making incremental steps toward the LRIC study indicated parity for larger volume customers who are farthest from parity. This approach continues a measured approach by the Company to work to bring all rate classes into alignment with their cost causation across multiple rate proceedings.

Q. Please describe the methodology NW Natural proposes to use to spread the incremental revenue requirement.

A. NW Natural proposes a multi-step process for spreading the incremental revenue requirement below. Note that the percentages represent margin changes only while the overall net increase in revenue requirement in this proceeding is 7.1 percent. The steps are:

1. Apply a cap equal to 1.01 times the overall incremental margin increase of 14.0 percent to RS 2 Residential and RS 27 Dry-Out. This cap is equal to a 14.1 percent margin increase. Apply an allocation equal to 1.02 times the overall incremental margin increase of 14.0 percent to RS 3 General Commercial. This allocation is equal to a 14.3 percent margin increase.
2. Apply a cap equal to 0.64 times the overall incremental margin increase of 14.0 percent to the Interruptible rate class plus any other rate schedules with an LRIC study indicated parity ratio above 1.25. This cap is equal to a roughly 9.0 percent margin increase.
3. After the allocations and caps have been applied, spread the remaining revenue requirement on an equal percent of margin basis among the remaining rate schedules. This step results in the same proposed margin increase for each of the remaining schedules, equal to roughly a 13.3 percent margin increase.
4. Cap the percent margin increase of those schedules in Step 3 at a 12.0 percent margin increase cap. Allocate the revenue requirement offset by the cap to RS 3 General Commercial and RS 3 General Industrial, on an

equal percent of margin basis. The effect of this step would be the same as applying a cap equal to 0.86 times the overall incremental margin increase to the Step 3 rate schedules.

The caps of 1.01 for RS 2 Residential RS 27 Dry-Out, as well as the initial allocations for RS 3 General Commercial and RS 3 General Industrial, represent an approximation of the inverse mathematical relationship between the parity ratio of each rate class and schedule and unit parity of 1.00. For instance, Residential class (0.99 parity ratio): 1.00/0.99≈1.01. The same logic is used to apply the cap for the rate schedules with parity ratios above 1.25, which have an average parity of 1.56 (1.00/1.56≈0.64).

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 NW Natural/1302, Wyman.

Q. Please describe how this rate spread proposal impacts each rate class relative to an equal percent of margin spread.

A. Under this proposal, the RS 2 Residential and RS 27 Dry-Out rate schedules receive a revenue spread slightly greater than an equal percent of margin share calculated across all rate schedules. RS 3 General Industrial receives the highest relative increase, followed by RS 3 General Commercial. The rate schedules with a parity ratio above 1.25 and/or taking interruptible service will receive a revenue spread less than an equal percent of margin share. The remaining rate schedules, as indicated above, will also receive revenue spread less than an equal percent of

margin share, but at a slightly higher rate relative to other rate schedules in the RS 31 and RS 32 rate classes.

Q. How does this rate spread proposal impact the LRIC study indicated parity ratios?

A. This rate proposal equitably distributes the incremental revenue requirement such that the parity ratios of all rate classes are moved closer to unity (i.e., to a value of 1.0) based on their indicated cost causation. The Parity Ratio at Proposed Rates is presented at line 26b of the LRIC Study Summary of Results, NW Natural/1301, Wyman.

Q. Are there any components of the revenue requirement that are already included, but are removed and spread separately?

A. Yes. I must first remove the temporary plant excess deferred income taxes ("EDIT") amortization credit of $5.1 million from the $90.1 million incremental revenue requirement to calculate a billing adjustment for Schedule 196.

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 rates that you propose to spread after the rate spread proposal for the base revenue requirement has been applied?

A. Yes, there are two. First, the Company proposes to spread the Coos County Pipeline O&M deferral of $360 thousand on an equal percent of margin basis (to be included as a temporary rate adjustment) to all rate schedules after the

proposed incremental base revenue requirement has been spread as described above. Second, the Company proposes to spread the bridge mechanism, effective October 31, 2028 for residential customers and November 1, 2028 for non-residential customers, in the same manner as the incremental base revenue requirement. For additional information about the Coos County Pipeline O&M deferral and the bridge mechanism, please refer to NW Natural/1200, Walker.

V. RESULTS AND BILL IMPACTS

Q. What is the rate impact to firm sales customers for the revenue requirement components?

A. Figure 13 below shows the proposed combined incremental revenue requirement of $90.1 million net of the $5.1 million plant EDIT credit (i.e., margin revenues only) including the effects of the Coos County Pipeline O&M deferral with average bill increase presented in this case for firm sales customers. These impacts are also presented in NW Natural/1303, Wyman. Of that amount of incremental revenue requirement, $19.8 million is already authorized for recovery and would otherwise be collected through the Company's decoupling mechanism, resulting in a net increase in revenue requirement of $70.3 million.

Figure 13
Incremental Revenue Requirement (Margin Revenues)
including Coos County Pipeline O&M deferral
and Average Bill Increase,
Firm Sales Customers Only

Rate Schedule	Revenue Req. Increase	Pct. Increase to Avg. Cust. Bill*
02 R	$ 61,333,114	8.8%
27	$ 106,175	9.3%
03 C	$ 22,307,374	8.3%
03 I	$ 356,754	7.7%
31 C Firm Sales	$ 1,418,312	5.6%
31 I Firm Sales	$ 290,953	3.3%
32 C Firm Sales	$ 1,925,085	4.4%
32 I Firm Sales	$ 540,418	3.2%
Total All Schedules**	$ 90,423,556	

* The average customer bill impact figure calculation excludes pipeline capacity charges for RS 31 and RS 32 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 NW Natural/1200, Walker. The total represents all rate schedules, not just the ones presented in Figure 13 above.

Q. What is the rate impact to firm sales customers for the bridge mechanism?

A. Figure 14 below shows the proposed incremental revenue requirement for the bridge mechanism and average bill increase of all the rate components presented in this case for firm sales customers.

Figure 14
Incremental Revenue Requirement
Bridge Mechanism
and Average Bill Increase,
Firm Sales Customers Only

Rate Schedule	Revenue Req. Increase	Pct. Increase to Avg. Cust. Bill*
02 R	$ 7,884,488	1.0%
27	$ 13,647	1.1%
03 C	$ 2,868,160	1.0%
03 I	$ 45,883	0.9%
31 C Firm Sales	$ 182,245	0.7%
31 I Firm Sales	$ 37,328	0.4%
32 C Firm Sales	$ 247,323	0.5%
32 I Firm Sales	$ 69,455	0.4%
Total All Schedules**	$ 11,623,902	

* The average customer bill impact figure calculation excludes pipeline capacity charges for RS 31 and RS 32 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 NW Natural/1200, Walker. The total represents all rate schedules, not just the ones presented in Figure 14 above.

Q. Does your testimony present the revenue and rate changes applicable to all other rate schedules as well?

A. Yes. NW Natural/1303, Wyman shows the revenue increases and average bill impacts by rate schedule for the revenue requirement effects and for the combined rate components shown in Figure 13 and Figure 14 above. NW Natural/1304, Wyman contains the volumetric rate increases by rate schedule and block.

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibits of Robert J. Wyman

CUSTOMER AND NORMALIZED VOLUME FORECAST, LONG-RUN INCREMENTAL COSTS, AND RATE DESIGN/SPREAD EXHIBITS 1301-1304

November 24, 2026

EXHIBITS 1301-1304 – CUSTOMER AND NORMALIZED VOLUME FORECAST, LONG-RUN INCREMENTAL COSTS, AND RATE DESIGN/SPREAD

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Robert J. Wyman

CUSTOMER AND NORMALIZED VOLUME FORECAST, LONG-RUN INCREMENTAL COSTS, AND RATE DESIGN/SPREAD EXHIBIT 1301

November 24, 2026

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2028
Long-Run Incremental Cost Study
Summary of Results
Exhibit NW Natural/1301, Wyman

Line No.			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
		CUSTOMER CLASS	Residential	Commercial	Industrial	Commercial	Commercial	Commercial	Industrial	Industrial	Commercial	Industrial	Commercial	Industrial	Commercial	Industrial	Transportation	Transportation	Transportation	
		SERVICE TYPE	Sales	Sales	Sales	Sales	Sales	Transportation	Sales	Transportation	Sales	Sales	Transportation	Transportation	Sales	Sales	Interruptible	Interruptible	Interruptible	Special
		RATE SCHEDULE -->	Firm 02R	Firm 03C	Firm 03I	Firm 27R	Firm 31CSF	Firm 31CTF	Firm 31ISF	Firm 31ITF	Firm 32CSF	Firm 32ISF	Firm 32CTF	Firm 32ITF	Interruptible 32CSI	Interruptible 32ISI	32CTI	32ITI	33T	Contracts
	STATISTICS	**Totals**																		
1	TY ANNUAL THERM DELIVERIES *(excl. special contract)*	1,017,246,058	404,385,269	184,979,746	4,073,419	699,948	24,584,706	2,013,647	9,528,982	353,055	52,362,673	24,847,016	6,289,527	86,056,803	22,532,666	26,972,806	7,354,115	160,211,680	0	74,096,407
2	TY AVG CUSTOMERS - END OF PERIOD	712,966	650,852	58,567	331	1,382	707	55	160	5	520	100	31	101	46	40	3	66	0	7
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER	1,427	621	3,158	12,306	506	34,773	36,612	59,556	70,611	100,697	248,470	202,888	852,048	487,030	678,824	2,424,062	2,428,693	0	10,585,201
	AVERAGE WINTER SALES	119,536,711	54,141,978	24,288,186	391,670	103,619	3,109,630	258,527	902,480	38,397	6,011,077	2,355,186	682,575	7,900,084	1,965,626	2,850,223	597,345	13,940,108	0	
	AVERAGE SUMMER SALES	50,618,766	13,357,217	6,808,294	298,556	12,069	961,900	84,520	706,758	17,155	2,662,295	1,808,194	384,590	6,374,400	1,743,309	1,753,878	605,554	13,040,077	0	
4	ESTIMATED DESIGN DAY LOAD FACTOR	*29.2%*	*22.0%*	*23.6%*	*32.8%*	*21.1%*	*28.7%*	*42.9%*	*43.1%*	*41.6%*	*35.8%*	*56.9%*	*52.1%*	*60.9%*	*60.4%*	*54.4%*	*61.3%*	*60.6%*	*0.0%*	
	4a Average Daily Deliveries	2,786,976	1,107,905	506,794	11,160	1,918	67,355	5,517	26,107	967	143,459	68,074	17,232	235,772	61,733	73,898	20,148	438,936	0	
	4b Peak Day Deliveries	9,471,986	5,036,486	2,145,079	34,039	9,098	234,595	12,869	60,601	2,328	401,155	119,666	33,043	387,213	102,137	135,911	32,894	724,872	0	
	LRIC Cost Allocation Factors - Capital Cost Indirect Allocators																			
5	Distribution Main Design Day Peak & Average	100.00%	52.59%	22.79%	0.40%	0.09%	2.62%	0.16%	0.77%	0.03%	4.80%	1.71%	0.46%	5.71%	0.87%	1.10%	0.26%	5.62%	0.00%	0.00%
6	System Core Mains	100.00%	52.03%	22.46%	0.38%	0.09%	2.56%	0.16%	0.74%	0.03%	4.62%	1.59%	0.43%	5.29%	1.03%	1.30%	0.61%	6.69%	0.00%	0.00%
7	Capacity Incremental (System Reinforcement)	100.00%	52.37%	23.97%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	6.79%	3.22%	0.81%	11.15%	1.69%	0.00%	0.00%	0.00%	0.00%	0.00%
8	Transmission Mains	100.00%	52.33%	23.07%	0.26%	0.06%	1.73%	0.11%	0.50%	0.02%	5.40%	2.18%	0.57%	7.39%	1.20%	0.80%	0.29%	4.11%	0.00%	0.00%
9	Storage Winter Sales / Summer Sales Excess Ratio	100.00%	62.31%	26.71%	0.14%	0.14%	3.28%	0.00%	0.30%	0.00%	5.12%	0.84%	0.00%	0.00%	0.20%	0.97%	0.00%	0.00%	0.00%	0.00%
10	Service Lines	100.00%	78.16%	19.86%	0.33%	0.11%	0.52%	0.05%	0.13%	0.00%	0.44%	0.09%	0.03%	0.12%	0.04%	0.04%	0.00%	0.08%	0.00%	0.00%
11	Meters Average Installed Cost	100.00%	73.16%	20.64%	0.56%	0.18%	1.57%	0.11%	0.43%	0.01%	1.64%	0.45%	0.12%	0.39%	0.22%	0.16%	0.02%	0.35%	0.00%	0.00%
12	Account Service Cost per Customer	100.00%	89.71%	8.60%	0.05%	0.19%	0.56%	0.04%	0.13%	0.00%	0.41%	0.08%	0.02%	0.08%	0.04%	0.03%	0.00%	0.05%	0.00%	0.00%
13	Common Cost (Administrative, General Plant, etc.)	100.00%	75.36%	19.64%	0.34%	0.15%	0.94%	0.10%	0.29%	0.01%	1.20%	0.36%	0.09%	0.62%	0.19%	0.22%	0.03%	0.49%	0.00%	0.00%
	**For all allocation factors, including direct allocators and incremental expense allocators, refer to the "LRIC Allocators" tab.*																			
14	Total Rate Base by Functional Classification																			
	14a Meter Reading & Billing Costs	$36,158,018	$22,492,698	$10,014,584	$111,155	$40,482	$590,560	$43,824	$136,110	$4,734	$913,889	$256,491	$71,388	$662,734	$124,382	$152,336	$35,984	$506,667	$0	$0
	14b Meters & Services Costs	$784,755,263	$488,170,102	$217,351,437	$2,412,453	$878,611	$12,817,224	$951,132	$2,954,066	$102,747	$19,834,581	$5,566,751	$1,549,369	$14,383,635	$2,699,514	$3,306,217	$780,982	$10,996,442	$0	$0
	14c Core Main Costs	$977,160,418	$607,858,938	$270,641,346	$3,003,935	$1,094,027	$15,959,732	$1,184,329	$3,678,340	$127,938	$24,697,595	$6,931,598	$1,929,242	$17,910,193	$3,361,377	$4,116,831	$972,462	$13,692,534	$0	$0
	14d Transmission Costs	$267,322,387	$166,292,350	$74,039,522	$821,788	$299,294	$4,366,114	$323,998	$1,006,286	$35,000	$6,756,536	$1,896,282	$527,784	$4,899,703	$919,574	$1,126,244	$266,037	$3,745,875	$0	$0
	14e Gas Storage Costs	$429,472,195	$277,325,388	$123,475,549	$1,370,494	$499,131	$7,281,359	$0	$1,678,181	$0	$11,267,861	$3,162,425	$0	$0	$1,533,572	$1,878,235	$0	$0	$0	$0
15	**Total Rate Base**	**$2,494,868,282**	**$1,562,139,477**	**$695,522,438**	**$7,719,825**	**$2,811,546**	**$41,014,990**	**$2,503,283**	**$9,452,983**	**$270,419**	**$63,470,462**	**$17,813,547**	**$4,077,783**	**$37,856,264**	**$8,638,419**	**$10,579,863**	**$2,055,464**	**$28,941,519**	**$0**	**$0**
16	**Proposed Rate of Return**	*7.374%*																		
17	**Total Return on Rate Base at 9.75% ROE**	**$183,971,587**	**$115,192,165**	**$51,287,825**	**$569,260**	**$207,323**	**$3,024,445**	**$184,592**	**$697,063**	**$19,941**	**$4,680,312**	**$1,313,571**	**$300,696**	**$2,791,521**	**$636,997**	**$780,159**	**$151,570**	**$2,134,148**	**$0**	**$0**
18	**Revenue at Current Rates** *(incl misc rev)*	**$993,715,353**	**$621,382,698**	**$238,537,485**	**$4,087,818**	**$1,109,389**	**$23,286,769**	**$1,017,036**	**$7,692,155**	**$128,158**	**$40,504,342**	**$16,127,150**	**$1,190,464**	**$7,296,746**	**$10,889,509**	**$12,715,257**	**$580,570**	**$5,505,416**	**$0**	**$1,664,390**
	18a Cost of Gas Commodity	$348,892,573	$189,482,809	$86,675,959	$1,908,685	$327,974	$11,519,656	$0	$4,464,993	$0	$24,535,578	$11,642,567	$0	$0	$8,344,973	$9,989,379	$0	$0	$0	$0
	18b O&M and Other Operating Revenue Deductions	$524,344,653	$364,471,785	$118,312,700	$2,076,866	$695,639	$8,122,927	$848,048	$2,293,984	$81,867	$10,614,506	$3,245,541	$756,918	$4,842,902	$1,857,778	$2,140,056	$258,950	$3,724,186	$0	$0
	18c Net Operating Revenues	**$120,478,127**	**$67,428,104**	**$33,548,825**	**$102,268**	**$85,776**	**$3,644,186**	**$168,988**	**$933,178**	**$46,291**	**$5,354,258**	**$1,239,042**	**$433,546**	**$2,453,843**	**$686,758**	**$585,823**	**$321,621**	**$1,781,230**	**$0**	**$1,664,390**
19	**Incremental Net Operating Revenue Deficiency (Sufficiency)**																			
	19a *Net-to-Gross Revenue Sensitive Factor:*	*141.2%*																		
	19b **Component LRIC Target Increase by Schedule**	**$90,061,116**	**$66,364,273**	**$24,481,882**	**$659,035**	**$170,381**	**($937,375)**	**$19,114**	**($348,619)**	**($38,067)**	**($1,040,543)**	**$87,454**	**($195,651)**	**$431,282**	**($79,296)**	**$268,106**	**($246,215)**	**$465,356**	**$0**	**$0**
	(incl. Corporate Activity Tax, credit for special contract revenues)																			
20	**Margin Revenue at Current Rates** *(incl misc rev)*	**$644,822,780**	**$431,899,889**	**$151,861,526**	**$2,179,133**	**$781,415**	**$11,767,113**	**$1,017,036**	**$3,227,162**	**$128,158**	**$15,968,764**	**$4,484,583**	**$1,190,464**	**$7,296,746**	**$2,544,536**	**$2,725,878**	**$580,570**	**$5,505,416**	**$0**	**$1,664,390**
21	**LRIC Based Target Margin**	**$734,883,896**	**$498,264,163**	**$176,343,408**	**$2,838,168**	**$951,796**	**$10,829,738**	**$1,036,150**	**$2,878,543**	**$90,091**	**$14,928,221**	**$4,572,037**	**$994,813**	**$7,728,028**	**$2,465,240**	**$2,993,985**	**$334,355**	**$5,970,772**	**$0**	**$1,664,390**
22	Current Revenue to Proposed Cost *(Includes Cost of Gas)*	**0.92**	**0.90**	**0.91**	**0.86**	**0.87**	**1.04**	**0.98**	**1.05**	**1.42**	**1.03**	**0.99**	**1.20**	**0.94**	**1.01**	**0.98**	**1.74**	**0.92**	**1.00**	**1.00**
23	Current Margin Revenue to LRIC Based Target Margin	**0.88**	**0.87**	**0.86**	**0.77**	**0.82**	**1.09**	**0.98**	**1.12**	**1.42**	**1.07**	**0.98**	**1.20**	**0.94**	**1.03**	**0.91**	**1.74**	**0.92**	**1.00**	**1.00**
	23a **Parity Ratio at Present Rates**	**1.00**	**0.99**	**0.98**	**0.88**	**0.94**	**1.24**	**1.12**	**1.28**	**1.62**	**1.22**	**1.12**	**1.36**	**1.08**	**1.18**	**1.04**	**1.98**	**1.05**	**1.00**	**1.00**
24	Target Increase as Percent of Total Present Revenue	**9.1%**	**10.7%**	**10.3%**	**16.1%**	**15.4%**	**-4.0%**	**1.9%**	**-4.5%**	**-29.7%**	**-2.6%**	**0.5%**	**-16.4%**	**5.9%**	**-0.7%**	**2.1%**	**-42.4%**	**8.5%**	**0.0%**	**0.0%**
	24a Target Increase as Percent of Present Margin Revenue *(less special contract revenue)*	**14.0%**	**15.4%**	**16.1%**	**30.2%**	**21.8%**	**-8.0%**	**1.9%**	**-10.8%**	**-29.7%**	**-6.5%**	**2.0%**	**-16.4%**	**5.9%**	**-3.1%**	**9.8%**	**-42.4%**	**8.5%**	**0.0%**	**0.0%**
25	Proposed Rate Revenue Increase (see: NW Natural/1300, Wyman)	**$90,061,116**	**$61,083,491**	**$22,222,368**	**$355,496**	**$110,515**	**$1,412,054**	**$122,044**	**$289,215**	**$11,485**	**$1,916,252**	**$538,150**	**$106,688**	**$875,609**	**$228,038**	**$244,290**	**$52,030**	**$493,389**	**$0**	**$0**
	25a *Proposed Increase as Percent of Present Margin Revenue*	**14.0%**	**14.1%**	**14.6%**	**16.3%**	**14.1%**	**12.0%**	**12.0%**	**9.0%**	**9.0%**	**12.0%**	**12.0%**	**9.0%**	**12.0%**	**9.0%**	**9.0%**	**9.0%**	**9.0%**	**0.0%**	**0.0%**
26	**Margin Revenue at Proposed Rates** *(incl misc rev)*	**$734,883,896**	**$492,983,381**	**$174,083,894**	**$2,534,630**	**$891,931**	**$13,179,167**	**$1,139,080**	**$3,516,376**	**$139,643**	**$17,885,015**	**$5,022,733**	**$1,297,152**	**$8,172,355**	**$2,772,574**	**$2,970,168**	**$632,601**	**$5,998,805**	**$0**	**$1,664,390**
	26a Revenue-to Cost Ratio at Proposed Rates	**1.00**	**0.99**	**0.99**	**0.89**	**0.94**	**1.22**	**1.10**	**1.22**	**1.55**	**1.20**	**1.10**	**1.30**	**1.06**	**1.12**	**0.99**	**1.89**	**1.00**	**1.00**	**1.00**
	26b **Parity Ratio at Proposed Rates**	**1.00**	**0.99**	**0.99**	**0.89**	**0.94**	**1.22**	**1.10**	**1.22**	**1.55**	**1.20**	**1.10**	**1.30**	**1.06**	**1.12**	**0.99**	**1.89**	**1.00**	**1.00**	**1.00**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Robert J. Wyman

CUSTOMER AND NORMALIZED VOLUME FORECAST, LONG-RUN INCREMENTAL COSTS, AND RATE DESIGN/SPREAD EXHIBIT 1302

November 24, 2026

NW Natural
Oregon Jurisdictional Rate Case - UG 532
Test Year Twelve Months Ended October 31, 2028
Rate Spread Allocation Proposal Methodology - Revenue Requirement Effects
Exhibit NW Natural/1302, Wyman

Steps 1-2 Allocation Factor		Margin %	
02R :	**1.01**	14.1%	
03C :	**1.02**	14.3%	
27R :	**1.01**	14.1%	*Set equal to Schedule 2*
03I :	**1.14**	16.0%	
CAP at 0.64x:	**0.64**	9.0%	

								Step 1	Step 2	Step 3	Step 4				
Line No.	Rate Schedule	Margin Revenue at Present Rates $	Total Revenue at Present Rates $	Target Increase (LRIC) %	Parity Ratio at Present Rates (Unit Parity = 1.0)	Target Margin Increase (LRIC) $	Equal % of Margin Increase $	Apply Allocation Factors: Parity Ratio Less than 1.0	Apply Cap: Transportation Class & Parity Ratio Over 1.25 &/or Interruptible	Apply Remainder: Remaining Schedules on Equal Percent of Margin Basis	Levelize Above Parity Schedules from Step 3 at 12.0% and Shift Incremental to 03C/03I	Total Proposed Revenue Requirement Increase $	Proposed Margin Increase %	Margin Revenue at Proposed Rates $	Parity Ratio at Proposed Rates (Unit Parity = 1.0) %
		A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	02R	$ 431,899,889	$ 621,382,698	15.4%	0.99	$ 66,364,273	$ 60,478,704	$ 61,083,491				$ 61,083,491	14.1%	$ 492,983,381	0.99
2	03CSF	$ 151,861,526	$ 238,537,485	16.1%	0.98	$ 24,481,882	$ 21,265,086	$ 21,690,388			$ 531,981	$ 22,222,368	14.6%	$ 174,083,894	0.99
3	03ISF	$ 2,179,133	$ 4,087,818	30.2%	0.88	$ 659,035	$ 305,143	$ 347,863			$ 7,634	$ 355,496	16.3%	$ 2,534,630	0.89
4	27R	$ 781,415	$ 1,109,389	21.8%	0.94	$ 170,381	$ 109,421	$ 110,515				$ 110,515	14.1%	$ 891,931	0.94
5	31CSF	$ 11,767,113	$ 23,286,769	-8.0%	1.24	$ (937,375)	$ 1,647,742			$ 1,568,704	$ (156,650)	$ 1,412,054	12.0%	$ 13,179,167	1.22
6	31CTF	$ 1,017,036	$ 1,017,036	1.9%	1.12	$ 19,114	$ 142,415			$ 135,584	$ (13,539)	$ 122,044	12.0%	$ 1,139,080	1.10
7	31ISF	$ 3,227,162	$ 7,692,155	-10.8%	1.28	$ (348,619)	$ 451,898		$ 289,215			$ 289,215	9.0%	$ 3,516,376	1.22
8	31ITF	$ 128,158	$ 128,158	-29.7%	1.62	$ (38,067)	$ 17,946		$ 11,485			$ 11,485	9.0%	$ 139,643	1.55
9	32CSF	$ 15,968,764	$ 40,504,342	-6.5%	1.22	$ (1,040,543)	$ 2,236,097			$ 2,128,837	$ (212,585)	$ 1,916,252	12.0%	$ 17,885,015	1.20
10	32ISF	$ 4,484,583	$ 16,127,150	2.0%	1.12	$ 87,454	$ 627,974			$ 597,851	$ (59,701)	$ 538,150	12.0%	$ 5,022,733	1.10
11	32CTF	$ 1,190,464	$ 1,190,464	-16.4%	1.36	$ (195,651)	$ 166,700		$ 106,688			$ 106,688	9.0%	$ 1,297,152	1.30
12	32ITF	$ 7,296,746	$ 7,296,746	5.9%	1.08	$ 431,282	$ 1,021,759			$ 972,748	$ (97,138)	$ 875,609	12.0%	$ 8,172,355	1.06
13	32CSI	$ 2,544,536	$ 10,889,509	-3.1%	1.18	$ (79,296)	$ 356,310		$ 228,038			$ 228,038	9.0%	$ 2,772,574	1.12
14	32ISI	$ 2,725,878	$ 12,715,257	9.8%	1.04	$ 268,106	$ 381,703		$ 244,290			$ 244,290	9.0%	$ 2,970,168	0.99
15	32CTI	$ 580,570	$ 580,570	-42.4%	1.98	$ (246,215)	$ 81,297		$ 52,030			$ 52,030	9.0%	$ 632,601	1.89
16	32ITI	$ 5,505,416	$ 5,505,416	8.5%	1.05	$ 465,356	$ 770,920		$ 493,389			$ 493,389	9.0%	$ 5,998,805	1.00
17	33T	$ 0	$ 0	0.0%	1.00	$ 0	$ 0					$ 0	0.0%	$ 0	1.00
	SPECIAL	$ 1,664,390	$ 1,664,390	0.0%	1.00							$ 0		$ 1,664,390	1.00
	Total	**$ 644,822,780**	**$ 993,715,353**	**14.0%**		**$ 90,061,116**	**$ 90,061,116**					**$ 90,061,116**	**14.0%**	**$ 734,883,896**	
		(1)	(1)				**Rev Req Applied:**	$ 83,232,257	$ 1,425,135	$ 5,403,723	$ (0)			(1)	
Proposed Rev Req:		**$ 90,061,116**					**Rev Req Remainder:**	$ 6,828,859	$ 5,403,723	$ 0	$ 0				

Note **(1)**: Includes special contract and miscellaneous revenues.

Avg Parity Ratio for schedules above 1.25: 1.56
Avg Parity Ratio of Step 4 adjusted down schedules: 1.15

12.0% *(Margin increase floor for schedules in Step 3)*
[13.3% with no adjustment]

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Robert J. Wyman

CUSTOMER AND NORMALIZED VOLUME FORECAST, LONG-RUN INCREMENTAL COSTS, AND RATE DESIGN/SPREAD EXHIBIT 1303

November 24, 2026

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2028
Incremental Revenue Requirement Allocation by Rate Schedule:
Combined Revenue Requirement Effects
UG 532 NW Natural Proposed Rates Effective October 31, 2027

UG 532 Revenue Requirement Combined Impacts
Impacts of UG 532 Revenue Requirement Items, including the application of the Plant EDIT Amortization Credit with Base Rate Adjustment for Coos County O&M Deferral

Line No.	Rate Schedule	Margin Revenue at Present Rates	Total Revenue at Present Rates	Revenue Requirement Base Rate Margin Increase ($) (1)	Plant EDIT Credit Base Rate Margin Decrease ($) (2)	Total: Rev. Req. Items Margin Increase ($)	Coos County Temporary Rate Adj Revenue Increase ($)	Margin Revenue at New Rates	Total Revenue at New Rates	Combined Revenue Requirement Effects: Margin Revenue Increase (%)	Total Revenue (In)(De)crease (%)	Average Bill (In)(De)crease (%)	Bridge Mechanism Base Rate Adjustment Margin Increase ($)	Margin Revenue at New Rates	Total Revenue at New Rates	Bridge Mechanism Effects: Margin Revenue Increase (%)	Total Revenue (In)(De)crease (%)	Average Bill (In)(De)crease (%)
		A	B	C	D	F = C+D+E	H	I = A+F	J = B+F+G+H	K	L	M	N	O = I+N	P = J+N	Q	R	S
1	02R	$ 431,899,889	$ 621,382,698	$ 64,839,134	$ (3,748,651)	$ 61,090,483	$ 242,631	$ 492,990,372	$ 682,715,812	14.1%	9.9%	8.9%	$ 7,884,488	$ 500,874,860	$ 690,600,300	1.6%	1.2%	1.0%
2	02R - SF	$ 386,070,336	$ 555,446,830	$ 57,818,523	$ (3,342,757)	$ 54,475,765	$ 216,360	$ 440,546,101	$ 610,138,961	14.1%	9.8%	8.9%	$ 7,030,776	$ 447,576,878	$ 617,169,738	1.6%	1.2%	1.0%
3	02R - MF	$ 45,829,553	$ 65,935,862	$ 7,020,611	$ (405,894)	$ 6,614,717	$ 26,271	$ 52,444,270	$ 72,576,850	14.4%	10.1%	8.4%	$ 853,712	$ 53,297,982	$ 73,430,562	1.6%	1.2%	1.0%
4	03C	$ 151,861,526	$ 238,537,485	$ 23,154,581	$ (932,298)	$ 22,222,283	$ 85,091	$ 174,083,809	$ 260,844,858	14.6%	9.4%	8.3%	$ 2,868,160	$ 176,951,969	$ 263,713,018	1.6%	1.1%	0.9%
5	03I	$ 2,179,133	$ 4,087,818	$ 374,881	$ (19,389)	$ 355,491	$ 1,263	$ 2,534,625	$ 4,444,572	16.3%	8.7%	7.7%	$ 45,883	$ 2,580,507	$ 4,490,455	1.8%	1.0%	1.1%
6	27R	$ 781,415	$ 1,109,389	$ 112,230	$ (6,489)	$ 105,741	$ 434	$ 887,156	$ 1,215,564	13.5%	9.6%	9.3%	$ 13,647	$ 900,804	$ 1,229,212	1.5%	1.1%	0.7%
7	31CSF	$ 11,767,113	$ 23,286,769	$ 1,498,643	$ (86,768)	$ 1,411,875	$ 6,437	$ 13,178,988	$ 24,705,081	12.0%	6.1%	5.6%	$ 182,245	$ 13,361,233	$ 24,887,327	1.4%	0.7%	1.2%
8	31CTF	$ 1,017,036	$ 1,017,036	$ 129,538	$ (7,490)	$ 122,048	$ 564	$ 1,139,084	$ 1,139,649	12.0%	12.1%	10.5%	$ 15,752	$ 1,154,836	$ 1,155,401	1.4%	1.4%	0.4%
9	31ISF	$ 3,227,162	$ 7,692,155	$ 306,951	$ (17,745)	$ 289,207	$ 1,746	$ 3,516,368	$ 7,983,108	9.0%	3.8%	3.3%	$ 37,328	$ 3,553,696	$ 8,020,436	1.1%	0.5%	0.9%
10	31ITF	$ 128,158	$ 128,158	$ 12,191	$ (704)	$ 11,487	$ 69	$ 139,645	$ 139,714	9.0%	9.0%	7.4%	$ 1,482	$ 141,128	$ 141,197	1.1%	1.1%	0.5%
11	32CSF	$ 15,968,764	$ 40,504,342	$ 2,033,712	$ (117,482)	$ 1,916,230	$ 8,855	$ 17,884,993	$ 42,429,427	12.0%	4.8%	4.4%	$ 247,323	$ 18,132,317	$ 42,676,750	1.4%	0.6%	0.4%
12	32ISF	$ 4,484,583	$ 16,127,150	$ 571,081	$ (33,052)	$ 538,029	$ 2,389	$ 5,022,612	$ 16,667,568	12.0%	3.4%	3.2%	$ 69,455	$ 5,092,067	$ 16,737,023	1.4%	0.4%	0.9%
13	32CTF	$ 1,190,464	$ 1,190,464	$ 113,243	$ (6,546)	$ 106,697	$ 617	$ 1,297,161	$ 1,297,778	9.0%	9.0%	7.1%	$ 13,770	$ 1,310,931	$ 1,311,547	1.1%	1.1%	1.0%
14	32ITF	$ 7,296,746	$ 7,296,746	$ 929,255	$ (53,797)	$ 875,458	$ 4,149	$ 8,172,203	$ 8,176,352	12.0%	12.1%	8.2%	$ 113,009	$ 8,285,213	$ 8,289,361	1.4%	1.4%	0.3%
15	32CSI	$ 2,544,536	$ 10,889,509	$ 242,003	$ (14,021)	$ 227,982	$ 1,409	$ 2,772,517	$ 11,118,900	9.0%	2.1%	2.4%	$ 29,431	$ 2,801,948	$ 11,148,331	1.1%	0.3%	0.3%
16	32ISI	$ 2,725,878	$ 12,715,257	$ 259,343	$ (15,022)	$ 244,321	$ 1,468	$ 2,970,199	$ 12,961,046	9.0%	1.9%	2.2%	$ 31,530	$ 3,001,729	$ 12,992,576	1.1%	0.2%	1.1%
17	32CTI	$ 580,570	$ 580,570	$ 55,231	$ (3,184)	$ 52,047	$ 280	$ 632,618	$ 632,897	9.0%	9.0%	9.1%	$ 6,716	$ 639,333	$ 639,613	1.1%	1.1%	0.5%
18	32ITI	$ 5,505,416	$ 5,505,416	$ 524,159	$ (30,529)	$ 493,630	$ 3,146	$ 5,999,047	$ 6,002,193	9.0%	9.0%	4.0%	$ 63,683	$ 6,062,729	$ 6,065,875	1.1%	1.1%	0.0%
19	33T	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	0.0%	0.0%	0.0%	$ 0	$ 0	$ 0	0.0%	0.0%	0.0%
	Total	**$ 643,158,390**	**$ 992,050,963**	**$ 95,156,176**	**$ (5,093,167)**	**$ 90,063,009**	**$ 360,547**	**$ 733,221,399**	**$ 1,082,474,519**	**14.0%**	**9.1%**		**$ 11,623,902**	**$ 744,845,301**	**$ 1,094,098,421**	**1.6%**	**1.1%**	
	(3)		(4)	(5)	(5)	(5)			(4)			(6)	(5)		(4)			(6)

NOTE **(1):** Revenue Requirement spread based on the Company's proposal described in Testimony NW Natural/1300, Wyman.
NOTE **(2):** Plant excess deferred income taxes (EDIT) amortization credit spread to all rate schedules based on the revenue requirement rate spread noted above.
NOTE **(3):** 02R indicates the entire Residential rate class. Below it are the two Residential sub-classes that make-up the class-wide total. They are as follow:
(1) 02R - SF: Residential Single-Family; and (2) 02R - MF : Residential Multi-Family.
NOTE **(4):** Total Revenues only includes margin (with miscellaneous revenues) and gas costs. It excludes temporaries associated with PGA filings. Therefore, for RS 31 and RS 32 rate classes, it is possible for margin revenues to exceed total revenues for new rates when rate case and PGA effects are combined.
NOTE **(5):** The 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.
NOTE **(6)**: The average customer bill percentage impact figure calculation excludes pipeline capacity charges for RS 31 and RS 32 rate classes, and thus the bill rate impacts for these schedules are overstated. In addition to the revenue requirement items, average bill increase or decrease can be impacted by changes in expected use per customer between current and new rates.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 532

NW Natural

Exhibit of Robert J. Wyman

CUSTOMER AND NORMALIZED VOLUME FORECAST, LONG-RUN INCREMENTAL COSTS, AND RATE DESIGN/SPREAD EXHIBIT 1304

November 24, 2026

NW Natural
Oregon Jurisdictional Rate Case
Test Year Twelve Months Ended October 31, 2028
Proposed UG 532 Base and Total Billing Rates by Rate Schedule and Block - Combined Effects
with Calculation of Effect on Customer Average Bill by Rate Schedule [1]
UG 532 NW Natural Proposed Rates Effective Oct. 31 / Nov. 1, 2027
UG 532 NW Natural Proposed Rates Effective Oct. 31 / Nov. 1, 2028 (Bridge Adj)

Includes Plant EDIT — *Clean County*

$1.51340 *802 Rate Less Temps*
$1.51340 *802 Rate Less Temps*

Line No.	Schedule	Block	Block Volumes	Test Year Volumes	Test Year Customers	Current Tariff	UG 532	Current Billing Rates	Proposed Increase: Base Rates	Proposed Base Rate	Proposed Increase: Temporary Rate Adjustment	Proposed Temporary Rate	UG 532 BILLING RATE Proposed Billing Rate	Base Rate	Base Rate Adjustment	Pipeline Capacity Rate (Demand)	Commodity Rate (WACOG)	Temporary Adjustment	Proposed Final Tariff Rate Effective: 10/31/27	Proposed Increase: Base Rate Adjustment	Base Rate	Base Rate Adjustment w/ Proposed Bridge	Pipeline Capacity Rate (Demand)	Commodity Rate (WACOG)	Temporary Adjustment	Proposed Final Tariff Rate Effective: 10/31/28	Current Average Bill [2]	Proposed Average Bill [2]	Change in Average Monthly Bill ($)	Change in Average Monthly Bill (%)	Current Average Bill [2]	Proposed Average Bill [2]	Change in Average Monthly Bill ($)	Change in Average Monthly Bill (%)
	A	B	C	D	E	F	G	M	N	O = M+N	P	Q = P	R = O+Q	S	T	U	V	W	X = S+...+W	Y	Z	AA	AB	AC	AD = Y+...+AC	AU	AV	AW	AX	AY	AZ	BA	BB
1	02R - SF		N/A	360,599,492	577,578	$ 10.00	$ 10.00	$1.52918	$0.15107	**$0.98871**	$0.00060	**$0.00060**	**$1.68085**	$0.98871	$0.02259	$0.11482	$0.36778	$0.18695	$1.68085	$0.01950	$0.98871	$0.04209	$0.11482	$0.36778	$0.18695	$1.70035	$95.47	$103.95	$8.48	8.9%	$103.95	$105.04	$1.09	1.0%
2	02R - NF		N/A	43,785,777	73,273	$ 8.00	$ 8.00	$1.52918	$0.15107	**$0.98871**	$0.00060	**$0.00060**	**$1.68085**	$0.98871	$0.02259	$0.11482	$0.36778	$0.18695	$1.68085	$0.01950	$0.98871	$0.04209	$0.11482	$0.36778	$0.18695	$1.70035	$51.44	$55.75	$4.31	8.4%	$55.75	$56.31	$0.56	1.0%
3	3C Firm Sales		N/A	184,979,746	58,567	$ 15.00	$ 25.00	$1.39680	$0.08214	**$0.81034**	$0.00046	**$0.00046**	**$1.47940**	$0.81034	$0.01781	$0.11482	$0.36778	$0.16865	$1.47940	$0.01551	$0.81034	$0.03332	$0.11482	$0.36778	$0.16865	$1.49491	$382.64	$414.38	$31.74	8.3%	$414.38	$418.46	$4.08	1.0%
4	3I Firm Sales		N/A	4,073,419	331	$ 15.00	$ 25.00	$1.12031	$0.07752	**$0.56641**	$0.00031	**$0.00031**	**$1.19814**	$0.56641	$0.01213	$0.11482	$0.36778	$0.13700	$1.19814	$0.01126	$0.56641	$0.02339	$0.11482	$0.36778	$0.13700	$1.20940	$1,163.92	$1,253.73	$89.81	7.7%	$1,253.73	$1,265.28	$11.55	0.9%
5	27 Dry Out		N/A	699,948	1,382	$ 10.00	$ 10.00	$1.39924	$0.15107	**$0.87370**	$0.00062	**$0.00062**	**$1.55093**	$0.87370	$0.13760	$0.11482	$0.36778	$0.05703	$1.55093	$0.01950	$0.87370	$0.15710	$0.11482	$0.36778	$0.05703	$1.57043	$69.06	$75.46	$6.40	9.3%	$75.46	$76.28	$0.82	1.1%
6	31C Firm Sales	Block 1	2,000	14,548,232	707	$ 325.00	$ 325.00	$0.93281	$0.05956	**$0.40858**	$0.00027	**$0.00027**	**$0.99264**	$0.40858	$0.01136	$0.11482	$0.36778	$0.09010	$0.99264	$0.00769	$0.40858	$0.01905	$0.11482	$0.36778	$0.09010	$1.00033								
7		Block 2	all additional	10,036,474		$0.90009	$0.05434	**$0.37279**	$0.00025	**$0.00025**	**$0.95468**	$0.37279	$0.01050	$0.11482	$0.36778	$0.08879	$0.95468	$0.00701	$0.37279	$0.01751	$0.11482	$0.36778	$0.08879	$0.96169	$2,998.90	$3,167.58	$168.68	5.6%	$3,167.58	$3,189.26	$21.68	0.7%
8	31C Firm Transpt	Block 1	2,000	1,034,844	55	$ 575.00	$ 575.00	$0.40931	$0.06325	**$0.38015**	$0.00029	**$0.00029**	**$0.47285**	$0.38015	$0.00572	$0.00000	$0.00000	$0.08698	$0.47285	$0.00816	$0.38015	$0.01388	$0.00000	$0.00000	$0.08698	$0.48101								
9		Block 2	all additional	978,803		$0.38068	$0.05782	**$0.34755**	$0.00027	**$0.00027**	**$0.43877**	$0.34755	$0.00488	$0.00000	$0.00000	$0.08634	$0.43877	$0.00746	$0.34755	$0.01234	$0.00000	$0.00000	$0.08634	$0.44623	$1,793.71	$1,981.85	$188.14	10.5%	$1,981.85	$2,006.02	$24.17	1.2%
10	31I Firm Sales	Block 1	2,000	3,117,617	160	$ 325.00	$ 325.00	$0.88727	$0.03251	**$0.29697**	$0.00019	**$0.00019**	**$0.91997**	$0.29697	$0.00875	$0.11482	$0.36778	$0.13165	$0.91997	$0.00420	$0.29697	$0.01295	$0.11482	$0.36778	$0.13165	$0.92417								
11		Block 2	all additional	6,411,365		$0.85951	$0.02930	**$0.26771**	$0.00018	**$0.00018**	**$0.88899**	$0.26771	$0.00805	$0.11482	$0.36778	$0.13063	$0.88899	$0.00378	$0.26771	$0.01183	$0.11482	$0.36778	$0.13063	$0.89277	$4,646.27	$4,799.02	$152.75	3.3%	$4,799.02	$4,818.61	$19.59	0.4%
12	31I Firm Transpt	Block 1	2,000	91,092	5	$ 575.00	$ 575.00	$0.36416	$0.03503	**$0.30849**	$0.00021	**$0.00021**	**$0.39940**	$0.30849	$0.00538	$0.00000	$0.00000	$0.08553	$0.39940	$0.00452	$0.30849	$0.00990	$0.00000	$0.00000	$0.08553	$0.40392								
13		Block 2	all additional	261,963		$0.33643	$0.03167	**$0.27883**	$0.00019	**$0.00019**	**$0.36829**	$0.27883	$0.00447	$0.00000	$0.00000	$0.08499	$0.36829	$0.00409	$0.27883	$0.00856	$0.00000	$0.00000	$0.08499	$0.37238	$2,610.01	$2,804.24	$194.23	7.4%	$2,804.24	$2,829.15	$24.91	0.9%
14	32C Firm Sales	Block 1	10,000	39,162,744	520	$ 675.00	$ 675.00	$0.80863	$0.03882	**$0.22719**	$0.00018	**$0.00018**	**$0.84763**	$0.22719	$0.00828	$0.11482	$0.36778	$0.12956	$0.84763	$0.00501	$0.22719	$0.01329	$0.11482	$0.36778	$0.12956	$0.85264								
15		Block 2	20,000	10,420,915		$0.77685	$0.03278	**$0.19181**	$0.00015	**$0.00015**	**$0.80978**	$0.19181	$0.00724	$0.11482	$0.36778	$0.12813	$0.80978	$0.00423	$0.19181	$0.01147	$0.11482	$0.36778	$0.12813	$0.81401								
16		Block 3	20,000	1,903,629		$0.72408	$0.02273	**$0.13300**	$0.00010	**$0.00010**	**$0.74691**	$0.13300	$0.00551	$0.11482	$0.36778	$0.12580	$0.74691	$0.00293	$0.13300	$0.00844	$0.11482	$0.36778	$0.12580	$0.74984								
17		Block 4	100,000	875,385		$0.67109	$0.01264	**$0.07398**	$0.00006	**$0.00006**	**$0.68379**	$0.07398	$0.00376	$0.11482	$0.36778	$0.12345	$0.68379	$0.00163	$0.07398	$0.00539	$0.11482	$0.36778	$0.12345	$0.68542								
18		Block 5	600,000	-		$0.63304	$0.00540	**$0.03159**	$0.00003	**$0.00003**	**$0.63847**	$0.03159	$0.00252	$0.11482	$0.36778	$0.12176	$0.63847	$0.00070	$0.03159	$0.00322	$0.11482	$0.36778	$0.12176	$0.63917								
19		Block 6	all additional			$0.61499	$0.00196	**$0.01148**	$0.00001	**$0.00001**	**$0.61696**	$0.01148	$0.00193	$0.11482	$0.36778	$0.12095	$0.61696	$0.00025	$0.01148	$0.00218	$0.11482	$0.36778	$0.12095	$0.61721	$7,460.21	$7,787.46	$327.25	4.4%	$7,787.46	$7,829.51	$42.05	0.5%
20	32I Firm Sales	Block 1	10,000	9,696,566	100	$ 675.00	$ 675.00	$0.75481	$0.02694	**$0.16599**	$0.00012	**$0.00012**	**$0.78187**	$0.16599	$0.00639	$0.11482	$0.36778	$0.12689	$0.78187	$0.00348	$0.16599	$0.00987	$0.11482	$0.36778	$0.12689	$0.78535								
21		Block 2	20,000	8,797,448		$0.73155	$0.02274	**$0.14014**	$0.00010	**$0.00010**	**$0.75439**	$0.14014	$0.00565	$0.11482	$0.36778	$0.12600	$0.75439	$0.00294	$0.14014	$0.00859	$0.11482	$0.36778	$0.12600	$0.75733								
22		Block 3	20,000	3,147,262		$0.69261	$0.01573	**$0.09694**	$0.00007	**$0.00007**	**$0.70841**	$0.09694	$0.00439	$0.11482	$0.36778	$0.12448	$0.70841	$0.00203	$0.09694	$0.00642	$0.11482	$0.36778	$0.12448	$0.71044								
23		Block 4	100,000	3,046,955		$0.65382	$0.00874	**$0.05388**	$0.00004	**$0.00004**	**$0.66260**	$0.05388	$0.00315	$0.11482	$0.36778	$0.12297	$0.66260	$0.00113	$0.05388	$0.00428	$0.11482	$0.36778	$0.12297	$0.66373								
24		Block 5	600,000	158,785		$0.62674	$0.00386	**$0.02381**	$0.00002	**$0.00002**	**$0.63062**	$0.02381	$0.00228	$0.11482	$0.36778	$0.12193	$0.63062	$0.00050	$0.02381	$0.00278	$0.11482	$0.36778	$0.12193	$0.63112								
25		Block 6	all additional			$0.61311	$0.00140	**$0.00867**	$0.00001	**$0.00001**	**$0.61452**	$0.00867	$0.00184	$0.11482	$0.36778	$0.12141	$0.61452	$0.00018	$0.00867	$0.00202	$0.11482	$0.36778	$0.12141	$0.61470	$16,055.07	$16,570.20	$515.13	3.2%	$16,570.20	$16,636.40	$66.20	0.4%
26	32C Firm Transpt	Block 1	10,000	2,910,130	31	$ 925.00	$ 925.00	$0.22657	$0.00054	**$0.16429**	$0.00012	**$0.00012**	**$0.24723**	$0.16429	$0.00040	$0.00000	$0.00000	$0.08254	$0.24723	$0.00265	$0.16429	$0.00305	$0.00000	$0.00000	$0.08254	$0.24988								
27		Block 2	20,000	1,932,014		$0.20384	$0.01745	**$0.13960**	$0.00010	**$0.00010**	**$0.22139**	$0.13960	($0.00028)	$0.00000	$0.00000	$0.08207	$0.22139	$0.00225	$0.13960	$0.00197	$0.00000	$0.00000	$0.08207	$0.22364								
28		Block 3	20,000	584,471		$0.16601	$0.01232	**$0.09856**	$0.00007	**$0.00007**	**$0.17840**	$0.09856	($0.00141)	$0.00000	$0.00000	$0.08125	$0.17840	$0.00159	$0.09856	$0.00018	$0.00000	$0.00000	$0.08125	$0.17999								
29		Block 4	100,000	799,290		$0.12817	$0.00719	**$0.05751**	$0.00004	**$0.00004**	**$0.13540**	$0.05751	($0.00255)	$0.00000	$0.00000	$0.08044	$0.13540	$0.00093	$0.05751	($0.00162)	$0.00000	$0.00000	$0.08044	$0.13633								
30		Block 5	600,000	63,622		$0.10543	$0.00411	**$0.03283**	$0.00002	**$0.00002**	**$0.10956**	$0.03283	($0.00323)	$0.00000	$0.00000	$0.07996	$0.10956	$0.00053	$0.03283	($0.00270)	$0.00000	$0.00000	$0.07996	$0.11009								
31		Block 6	all additional			$0.09035	$0.00205	**$0.01646**	$0.00001	**$0.00001**	**$0.09241**	$0.01646	($0.00369)	$0.00000	$0.00000	$0.07964	$0.09241	$0.00027	$0.01646	($0.00342)	$0.00000	$0.00000	$0.07964	$0.09268	$4,598.62	$4,926.44	$327.82	7.1%	$4,926.44	$4,968.50	$42.06	0.9%
32	32I Firm Transpt	Block 1	10,000	9,249,629	101	$ 925.00	$ 925.00	$0.21682	$0.02253	**$0.15750**	$0.00011	**$0.00011**	**$0.23946**	$0.15750	($0.00041)	$0.00000	$0.00000	$0.08237	$0.23946	$0.00291	$0.15750	$0.00250	$0.00000	$0.00000	$0.08237	$0.24237								
33		Block 2	20,000	13,404,392		$0.19565	$0.01914	**$0.13386**	$0.00009	**$0.00009**	**$0.21488**	$0.13386	($0.00097)	$0.00000	$0.00000	$0.08199	$0.21488	$0.00247	$0.13386	$0.00150	$0.00000	$0.00000	$0.08199	$0.21735								
34		Block 3	20,000	8,569,993		$0.16043	$0.01352	**$0.09452**	$0.00006	**$0.00006**	**$0.17401**	$0.09452	($0.00190)	$0.00000	$0.00000	$0.08139	$0.17401	$0.00174	$0.09452	($0.00016)	$0.00000	$0.00000	$0.08139	$0.17575								
35		Block 4	100,000	20,550,460		$0.12518	$0.00789	**$0.05516**	$0.00004	**$0.00004**	**$0.13311**	$0.05516	($0.00283)	$0.00000	$0.00000	$0.08078	$0.13311	$0.00102	$0.05516	($0.00181)	$0.00000	$0.00000	$0.08078	$0.13413								
36		Block 5	600,000	24,560,773		$0.10398	$0.00450	**$0.03148**	$0.00002	**$0.00002**	**$0.10850**	$0.03148	($0.00339)	$0.00000	$0.00000	$0.08041	$0.10850	$0.00058	$0.03148	($0.00281)	$0.00000	$0.00000	$0.08041	$0.10908								
37		Block 6	all additional	9,721,556		$0.08896	$0.00226	**$0.01581**	$0.00001	**$0.00001**	**$0.09223**	$0.01581	($0.00376)	$0.00000	$0.00000	$0.08018	$0.09223	$0.00029	$0.01581	($0.00347)	$0.00000	$0.00000	$0.08018	$0.09252	$12,844.08	$13,893.24	$1,049.16	8.2%	$13,893.24	$14,028.02	$134.78	1.0%
38	32C Interr Sales	Block 1	10,000	3,537,759	40	$ 675.00	$ 675.00	$0.64564	$0.01894	**$0.17221**	$0.00011	**$0.00011**	**$0.64469**	$0.17221	$0.00598	$0.01366	$0.36778	$0.10506	$0.66469	$0.00244	$0.17221	$0.00842	$0.01366	$0.36778	$0.10506	$0.66713								
39		Block 2	20,000	4,617,923		$0.62025	$0.01599	**$0.14540**	$0.00010	**$0.00010**	**$0.63634**	$0.14540	$0.00530	$0.01366	$0.36778	$0.10420	$0.63634	$0.00206	$0.14540	$0.00736	$0.01366	$0.36778	$0.10420	$0.63840								
40		Block 3	20,000	2,619,767		$0.57782	$0.01107	**$0.10064**	$0.00007	**$0.00007**	**$0.58896**	$0.10064	$0.00415	$0.01366	$0.36778	$0.10273	$0.58896	$0.00143	$0.10064	$0.00558	$0.01366	$0.36778	$0.10273	$0.59039								
41		Block 4	100,000	6,993,052		$0.53542	$0.00614	**$0.05587**	$0.00004	**$0.00004**	**$0.54160**	$0.05587	$0.00302	$0.01366	$0.36778	$0.10127	$0.54160	$0.00079	$0.05587	$0.00381	$0.01366	$0.36778	$0.10127	$0.54239								
42		Block 5	600,000	4,764,165		$0.50997	$0.00319	**$0.02902**	$0.00002	**$0.00002**	**$0.51318**	$0.02902	$0.00233	$0.01366	$0.36778	$0.10039	$0.51318	$0.00041	$0.02902	$0.00274	$0.01366	$0.36778	$0.10039	$0.51359								
43		Block 6	all additional			$0.49134	$0.00103	**$0.00936**	$0.00001	**$0.00001**	**$0.49238**	$0.00936	$0.00183	$0.01366	$0.36778	$0.09975	$0.49238	$0.00013	$0.00936	$0.00196	$0.01366	$0.36778	$0.09975	$0.49251	$29,326.40	$30,027.45	$701.05	2.4%	$30,027.45	$30,117.38	$89.93	0.3%
44	32I Interr Sales	Block 1	10,000	4,160,551	46	$ 675.00	$ 675.00	$0.62489	$0.01704	**$0.15039**	$0.00010	**$0.00010**	**$0.64203**	$0.15039	$0.00530	$0.01366	$0.36778	$0.10490	$0.64203	$0.00220	$0.15039	$0.00750	$0.01366	$0.36778	$0.10490	$0.64423								
45		Block 2	20,000	5,517,383		$0.60278	$0.01439	**$0.12695**	$0.00009	**$0.00009**	**$0.61726**	$0.12695	$0.00472	$0.01366	$0.36778	$0.10415	$0.61726	$0.00186	$0.12695	$0.00658	$0.01366	$0.36778	$0.10415	$0.61912								
46		Block 3	20,000	3,146,825		$0.56595	$0.00996	**$0.08788**	$0.00006	**$0.00006**	**$0.57597**	$0.08788	$0.00375	$0.01366	$0.36778	$0.10290	$0.57597	$0.00129	$0.08788	$0.00504	$0.01366	$0.36778	$0.10290	$0.57726								
47		Block 4	100,000	8,323,769		$0.52908	$0.00553	**$0.04878**	$0.00003	**$0.00003**	**$0.53464**	$0.04878	$0.00279	$0.01366	$0.36778	$0.10163	$0.53464	$0.00071	$0.04878	$0.00350	$0.01366	$0.36778	$0.10163	$0.53535								
48		Block 5	600,000	5,824,278		$0.50696	$0.00286	**$0.02530**	$0.00002	**$0.00002**	**$0.50984**	$0.02530	$0.00222	$0.01366	$0.36778	$0.10088	$0.50984	$0.00037	$0.02530	$0.00259	$0.01366	$0.36778	$0.10088	$0.51021								
49		Block 6	all additional			$0.49077	$0.00092	**$0.00814**	$0.00001	**$0.00001**	**$0.49170**	$0.00814	$0.00181	$0.01366	$0.36778	$0.10032	$0.49170	$0.00012	$0.00814	$0.00192	$0.01366	$0.36778	$0.10032	$0.49182	$29,655.58	$30,305.60	$650.02	2.2%	$30,305.60	$30,388.96	$83.36	0.3%
50	32C Interr Transpt	Block 1	10,000	253,166	3	$ 925.00	$ 925.00	$0.20999	$0.02944	**$0.15944**	$0.00019	**$0.00019**	**$0.23962**	$0.15944	($0.00134)	$0.00000	$0.00000	$0.08152	$0.23962	$0.00380	$0.15944	$0.00246	$0.00000	$0.00000	$0.08152	$0.24342								
51		Block 2	20,000	406,262		$0.18978	$0.02502	**$0.13552**	$0.00016	**$0.00016**	**$0.21496**	$0.13552	($0.00176)	$0.00000	$0.00000	$0.08120	$0.21496	$0.00323	$0.13552	$0.00147	$0.00000	$0.00000	$0.08120	$0.21819								
52		Block 3	20,000	290,470		$0.15608	$0.01768	**$0.09571**	$0.00011	**$0.00011**	**$0.17388**	$0.09571	($0.00245)	$0.00000	$0.00000	$0.08062	$0.17388	$0.00228	$0.09571	($0.00017)	$0.00000	$0.00000	$0.08062	$0.17616								
53		Block 4	100,000	864,158		$0.12236	$0.01031	**$0.05581**	$0.00006	**$0.00006**	**$0.13273**	$0.05581	($0.00316)	$0.00000	$0.00000	$0.08008	$0.13273	$0.00133	$0.05581	($0.00183)	$0.00000	$0.00000	$0.08008	$0.13406								
54		Block 5	600,000	1,360,309		$0.10217	$0.00589	**$0.03190**	$0.00003	**$0.00003**	**$0.10809**	$0.03190	($0.00358)	$0.00000	$0.00000	$0.07977	$0.10809	$0.00076	$0.03190	($0.00282)	$0.00000	$0.00000	$0.07977	$0.10885								
55		Block 6	all additional	4,179,749		$0.08870	$0.00296	**$0.01601**	$0.00001	**$0.00001**	**$0.09167**	$0.01601	($0.00386)	$0.00000	$0.00000	$0.07952	$0.09167	$0.00038	$0.01601	($0.00348)	$0.00000	$0.00000	$0.07952	$0.09205	$27,724.19	$30,238.23	$2,514.04	9.1%	$30,238.23	$30,560.76	$322.53	1.1%
56	32I Interr Transpt	Block 1	10,000	5,502,591	66	$ 925.00	$ 925.00	$0.20902	$0.01283	**$0.14093**	$0.00008	**$0.00008**	**$0.22193**	$0.14093	($0.00110)	$0.00000	$0.00000	$0.08210	$0.22193	$0.00166	$0.14093	$0.00056	$0.00000	$0.00000	$0.08210	$0.22359								
57		Block 2	20,000	8,828,796		$0.18904	$0.01090	**$0.11979**	$0.00007	**$0.00007**	**$0.20001**	$0.11979	($0.00156)	$0.00000	$0.00000	$0.08178	$0.20001	$0.00141	$0.11979	($0.00015)	$0.00000	$0.00000	$0.08178	$0.20142								
58		Block 3	20,000	6,318,799		$0.15577	$0.00770	**$0.08459**	$0.00005	**$0.00005**	**$0.16352**	$0.08459	($0.00215)	$0.00000	$0.00000	$0.08124	$0.16352	$0.00099	$0.08459	($0.00132)	$0.00000	$0.00000	$0.08124	$0.16451								
59		Block 4	100,000	18,805,995		$0.12242	$0.00449	**$0.04933**	$0.00003	**$0.00003**	**$0.12694**	$0.04933	($0.00308)	$0.00000	$0.00000	$0.08069	$0.12694	$0.00058	$0.04933	($0.00250)	$0.00000	$0.00000	$0.08069	$0.12752								
60		Block 5	600,000	29,632,804		$0.10248	$0.00257	**$0.02822**	$0.00001	**$0.00001**	**$0.10506**	$0.02822	($0.00353)	$0.00000	$0.00000	$0.08037	$0.10506	$0.00033	$0.02822	($0.00320)	$0.00000	$0.00000	$0.08037	$0.10539								
61		Block 6	all additional	91,122,696		$0.08917	$0.00129	**$0.01415**	$0.00001	**$0.00001**	**$0.09047**	$0.01415	($0.00384)	$0.00000	$0.00000	$0.08016	$0.09047	$0.00017	$0.01415	($0.00367)	$0.00000	$0.00000	$0.08016	$0.09064	$27,511.77	$28,602.17	$1,090.40	4.0%	$28,602.17	$28,742.04	$139.87	0.5%
62	33		-	N/A	-	$ 38,250.00	$ 38,250.00	$0.08092	$0.00000	**$0.00574**	$0.00000	**$0.00000**	**$0.08092**	$0.00574	($0.00400)	$0.00000	$0.00000	$0.07918	$0.08092	$0.00000	$0.00574	($0.00400)	$0.00000	$0.00000	$0.07918	$0.08092	$38,250.00	$38,250.00	$0.00	0.0%	$38,250.00	$38,250.00	$0.00	0.0%

NOTE: The two Residential sub-classes are as follow: (1) 02R - SF: Residential Single-Family; and (2) 02R - MF : Residential Multi-Family.
[1] Rate Schedule 31 and 32 customers may choose demand charges at a volumetric rate or based on MDDV. For convenience of presentation, demand charges are not included in the calculation for those rate schedules.
[2] Average bill rate calculated using the UG 532 rate case volumes and customer count.