NW Natural®

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July 31, 2025

NWN OPUC Advice No. 25-21 / UG 524
(UM 1496)

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attention: Filing Center
201 High Street SE, Suite 100
Salem, Oregon 97301-3398

Re: REQUEST FOR AMORTIZATION OF CERTAIN GAS COST DEFERRED ACCOUNTS RELATING TO: UM 1496 - Annual Purchased Gas Cost and Technical Rate Adjustments

Northwest Natural Gas Company, dba NW Natural (NW Natural or Company), files herewith revisions to its Tariff, P.U.C. Or. 25[1], stated to become effective with service on and after October 31, 2025, as follows:

Fifteenth Revision of Sheet P-2	Schedule P	Purchased Gas Cost Adjustments (continued)
Thirteenth Revision of Sheet P-3	Schedule P	Purchased Gas Cost Adjustments (continued)
Fourteenth Revision of Sheet P-5	Schedule P	Purchased Gas Cost Adjustments (continued)
Fourth Revision of Sheet 150-2	Schedule 150	Monthly Incremental Cost of Gas (continued)
Fifteenth Revision of Sheet 162-1	Schedule 162	Temporary (Technical) Adjustments to Rates
Fifteenth Revision of Sheet 162-2	Schedule 162	Temporary (Technical) Adjustments to Rates (continued)
Sixteenth Revision of Sheet 164-1	Schedule 164	Purchased Gas Cost Adjustments to Rates

This filing is made in accordance with OAR 860-022-0025, OAR 860-022-0030, and OAR 860-022-0070.

Please note that NW Natural is in the process of filing a motion for waiver relating to the request for an October 31 rate effective date due to previous Commission orders authorizing the current PGA guidelines.

[1] Tariff P.U.C. Or. 25 originated November 1, 2012 with docket UG 221; Order No. 12-408 as supplemented by Order No. 12-437 and was filed pursuant to ORS 767.205 and OAR 860-022-0005.

Purpose
The purpose of this filing is to:

1. Develop the temporary rate adjustments associated with the amortization of gas cost credit or debit balances in Federal Energy Regulatory Commission (FERC) Account 191, deferred under docket UM 1496 and proposed to be effective October 31, 2025, and to show the removal of temporary rate adjustments incorporated into rates effective November 1, 2024.
2. Develop the commodity (Weighted Average Cost of Gas or WACOG) and non-commodity (demand or pipeline capacity) purchased gas costs to be effective October 31, 2025.
3. Highlight that NW Natural proposes to continue to exclude the costs associated with Renewable Natural Gas (RNG) from the PGA sharing mechanism.

The Company revises rates for these purposes annually; its last filing was effective November 1, 2024.

The number of customers affected by the changes proposed in this filing is 644,678 residential customers, 62,124 commercial customers, and 795 industrial customers.

Background
Each year NW Natural seeks to change rates to reflect the projected cost of natural gas pursuant to tariff Schedule P, Purchased Gas Cost Adjustments. Schedule P sets forth the estimated purchased natural gas costs for the forthcoming year beginning October 31. The difference between the actual costs of natural gas purchased and the amount collected from customers are passed through to customers through Schedule 162. NW Natural follows the most recent Natural Gas Portfolio Development Guidelines adopted in OPUC Order No. 18-144 in docket UM 1286 issued on May 8, 2018.

Proposed Changes
In addition to the supporting materials submitted as part of this filing, the Company will separately submit work papers in electronic format, all of which are incorporated herein by reference.

1. Amortization of Gas Cost Deferrals (UM 1496) and removal of Temporary Rate Adjustments Currently in Effect

The net effect of this portion of the filing is to decrease the Company's annual revenues by $985,412, or about 0.10%; the effect of removing the Account 191 temporary adjustments placed into rates November 1, 2024, is an increase of $26,750,543; and the effect of applying the new Account 191 temporary rate adjustments for the amortization of gas costs deferred under docket UM 1496 is a decrease of $27,735,955.

The proposed adjustments to customer rates are comprised of the following: (1) a rate of ($0.04161) per therm for all sales service customers related to the 191 commodity accounts, and (2) a rate of $0.00643 per therm for all firm sales service customers and a rate of $0.00076 per therm for all interruptible sales service customers related to 191 demand accounts. The net effect of all Account 191 amortizations is a rate of ($0.03518) per therm for firm sales service customers and a rate of ($0.04085) per therm for interruptible sales service customers.

Gas cost deferrals also reflect amounts previously deferred and collected for RNG purchases under docket UM 2252 that were allocated to transport and special contract customers and have been reallocated to sales customers after the invalidation of the Climate Protection Program (CPP). Conversely, starting January 1, 2025, the Department of Environmental Quality started a revised CPP for which the company has deferring costs to the benefit of Sales customers. For more information, please refer to concurrently filed advice filings NWN OPUC Advice No. 25-15 and 25-18.

The Company has developed the adjustments to rates proposed in this filing in accordance with the PGA Filing Guidelines as prescribed by the most recent Commission Order in docket UM 1286. This portion of the filing is in compliance with ORS 757.259, which authorizes deferred utility expenses or revenues to be allowed (amortized) in rates to the extent authorized by the Commission in a proceeding to change rates. All of the deferrals included in this filing occurred with appropriate application by Commission authorization, as rate orders or under approved tariffs.

2. Purchased Gas Cost Adjustment (PGA)

The net effect of the PGA portion of this filing is to increase the Company's annual revenues by about $18,513,449, or about 1.97%; the change in commodity cost is an increase of $17,658,089 and the change in demand cost is an increase of $855,360.

The change in gas costs results in a proposed Annual Sales WACOG of $0.44246 per therm and a proposed Winter Sales WACOG of $0.47094. Revenue sensitive effects are applied for billing purposes, resulting in a proposed Annual Sales Billing WACOG of $0.45623 and a proposed Winter Sales Billing WACOG of $0.48560.

The change in demand costs results in a proposed firm service pipeline capacity charge of $0.09724 per therm, or $1.43 per therm of MDDV, and a proposed interruptible service pipeline capacity charge of $0.01157 per therm. Revenue sensitive effects are applied for billing purposes, resulting in a proposed firm service pipeline capacity charge of $0.10027 per therm, or $1.47 per therm of MDDV, and a proposed interruptible service pipeline capacity charge of $0.01193 per therm.

If there are material changes in the Company's gas supply costs or costs associated with pipeline services and charges from the levels used to develop the purchased gas adjustments included in this filing, then the Company will reflect such changes to Oregon gas customers in a manner approved by the Commission.

This filing applies the method for calculating the proposed Annual Sales WACOG that is set forth in a joint party stipulation approved by the Commission in Order No. 08-504, docket UM 1286, as modified by the approval of a stipulation affirmed in Order No. 11-176, dockets UM 1520/UG 204, and as further prescribed by the PGA Filing Guidelines, Section VI (1)(d) adopted in Commission Order No. 14-238 in docket UM 1286.

3. Renewable Natural Gas (RNG)

In compliance with OAR 860-150-0300, NW Natural has included about $40.6 million in costs for various offtake arrangements and related transaction costs in the commodity cost of this 2025-26 PGA. The renewable thermal certificates related to these offtakes will be tracked and accounted for in the M-RETS system and retired on behalf of sales customers to be counted toward the annual targets for a large natural gas utility established in ORS 757.396.

The details of these offtake transactions are included in Exhibit D. This exhibit provides support for the Company's RNG Portfolio which contains new RNG contracts, existing RNG contracts, historical data and forward gas curves, if applicable. The RNG support contained in Exhibit D originated from discussions during PGA quarterly meetings with Commission Staff, Oregon Citizens' Utility Board and Alliance of Western Energy Consumers. Some of the information in this exhibit is confidential and highly confidential, subject to the Modified Protective Order in docket UM 1286, Order No. 10-337. Highly confidential information will be distributed consistent with Commission procedures for filing this type of information.

In the 2020-21 PGA, NW Natural proposed, and the Commission approved, additional language in the PGA deferral calculation in Schedule P to clarify that RNG costs are excluded from the PGA sharing mechanism. In Commission Staff's public meeting memo for UG 410, Staff indicated support of excluding RNG costs from the PGA sharing mechanism for the 2020-21 gas year, as reasonable due to the difficulty in forecasting RNG purchases in an emerging and evolving RNG market.[2]

NW Natural maintains that the uncertainty with regard to the nascent RNG market continues. There is still no liquid trading market for RNG and the timing, cost and volumes related to RNG commodity procurement remains difficult to predict. In support of its proposal in docket UG 410, NW Natural provided the following example:

> For example, NW Natural may procure RNG several months after the WACOG for the upcoming gas year has been established. If, in this example, NW Natural did not forecast an RNG commodity procurement in the PGA, NW Natural would be subject to share in the costs of the procurement because the RNG procurement would be expected to be a higher cost than the WACOG, which would value those volumes on conventional natural gas prices. Removing this disincentive will support the Company's ongoing sourcing of RNG throughout the year. To be clear, in the above example, NW Natural would defer the costs of such procurement (as it does with similarly timed conventional natural gas purchases) and seek a prudency determination of the RNG commodity purchase in the subsequent PGA. Such additional language is also consistent with ORS 757.394(3)(b) and ORS 757.396(2), which state that a natural gas utility is entitled to recover all prudently incurred costs of purchasing RNG.

Additionally, this treatment protects customers. For example, if the Company were to include RNG in the forecasted WACOG, but the RNG was ultimately not delivered, NW Natural would otherwise benefit from this situation if not for the proposed exception to the sharing arrangement. Under that scenario, NW Natural could be in a position to substitute the RNG supply with conventional gas supply, which would likely be less expensive. This would create a situation where the Company's sharing mechanism would benefit the Company. The proposed exception prevents these flawed outcomes. Because these same conditions exist for the 2025-26 PGA year, NW Natural proposes to maintain the language in Schedule P that excludes RNG costs from the PGA sharing mechanism.

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[2] *In the Matter of Northwest Natural Gas Company dba NW Natural, Request for Amortization of Certain Deferred Accounts Related to Gas Costs, Schedules P, 162,164*, Docket No. UG 410, Order No. 20-360, Appendix A at 5 (Oct. 16, 2020).

4. Combined Effect on Customer Bills

The combined effect of this filing is to increase the Company's annual revenues by about $17,528,037, or about 1.87%; the change in purchased gas costs is an increase of $18,513,449 and the change in temporary adjustments to rates is a decrease of $985,412.

The average monthly bill impact of the changes proposed in this filing is shown in the table below:

Class	Rate Schedule	Average Monthly Bill Change ($)	Average Monthly Bill Change (%)
Residential	Schedule 2	$1.08	1.3%
Commercial	Schedule 3	$5.40	(1.6%)
Commercial Firm Sales	Schedule 31	$336.83	14.4%
Industrial Firm Sales	Schedule 32	$1,210.44	18.3%
Industrial Interruptible Sales	Schedule 32	$475.27	2.8%

The monthly bill effects for all other rate classes can be found in the separately provided work papers.

Please note that the monthly bill effects for Rate Schedule 31 and Rate Schedule 32 do not include the pipeline capacity charge due to the customer option to elect either an MDDV-based capacity charge or a volumetric-based capacity charge. If a customer served under Rate Schedule 32 Industrial Firm Sales Service elected the volumetric pipeline capacity option, the change in the monthly bill effective October 31, 2025 would be an increase of $1,186.08, or 15.53%.

UM 1286 Natural Gas Portfolio Development Guidelines
In addition to the supporting materials submitted as part of this filing as Exhibit A and Exhibit B, the Company provides Exhibit C.

Exhibit C contains data required by the Natural Gas Portfolio Development Guidelines Sections IV and V as adopted by the Commission in Order No. 11-196 in docket UM 1286. Some of the information in this exhibit is confidential and highly confidential and subject to the Modified Protective Order in docket UM 1286, Order No. 10-337. Confidential and highly confidential information will be distributed consistent with Commission procedures for these types of information.

Commission Staff's Attachment A through Attachment D, required by Section 5 of the PGA Filing Guidelines, are included in the Company's work papers, and incorporated herein by reference, which will be submitted under separate cover.

The Company requests that the tariff sheets filed herewith be permitted to become effective with service on and after October 31, 2025.

In accordance with ORS 757.205, copies of this letter and the filing made herewith are available in the Company's main office in Oregon and on its website at www.nwnatural.com.

Please address correspondence on this matter to Michael Lewis at Michael.Lewis@nwnatural.com with copies to:

eFiling
Rates & Regulatory Affairs
NW Natural
250 SW Taylor Street
Portland, Oregon 97204
Fax: (503) 220-2579
Telephone: (503) 610-7330
eFiling@nwnatural.com

Sincerely,

NW NATURAL

/s/ Kyle Walker, CPA

Kyle Walker, CPA
Rates/Regulatory Senior Manager

Attachments: Exhibit A – Purchased Gas Cost Deferral Amortizations
Exhibit B – Purchased Gas Costs
Exhibit C – PGA Portfolio Guidelines Sections IV and V
Exhibit D – RNG Support Documentation

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

DEFINITIONS (continued):

7. Estimated Annual Sales Weighted Average Cost of Gas (Annual Sales WACOG):
The estimated Annual Sales WACOG is the default Commodity Component for billing purposes, and is used for purposes of calculating the monthly gas cost deferral costs for entry into the Account 191 sub-accounts calculated by the following formula: (Forecasted Purchases at Adjusted Contract Prices) divided by forecasted sales volumes.
   a. "Forecasted Purchases" means November 1 – October 31 forecasted sales volumes, "weather-normalized", plus a percentage for distribution system LUFG.
   b. "Distribution system embedded LUFG" means the 5-year average of actual distribution system LUFG, not to exceed 2%.
   c. "Adjusted contract prices" means actual and projected contract prices that are adjusted by each associated Canadian pipeline's published (closest to August 1) fuel use and line loss amount provided for by tariff, and by each associated U.S. pipeline's tariffed rate.

Effective: October 31, 2025:		(C)
Estimated Annual Sales WACOG per therm (w/ revenue sensitive):	**$0.45623**	(I)
Estimated Annual Sales WACOG per therm (w/o revenue sensitive):	**$0.44246**	(I)

8. Estimated Winter Sales WACOG: The Company's weighted average Commodity Cost of Gas for the five-month period November through March.

Effective: October 31, 2025:		(C)
Estimated Winter Sales WACOG per therm (w/ revenue sensitive):	**$0.48560**	(I)
Estimated Winter Sales WACOG per therm (w/o revenue sensitive):	**$0.47094**	(I)

9. Estimated Non-Commodity Cost: Estimated annual Non-Commodity gas costs shall be equal to estimated annual Demand Costs, less estimated annual Capacity Release Benefits, plus or minus estimated annual pipeline refunds or surcharges.

10. Estimated Non-Commodity Cost per Therm – Firm Sales: The portion of the Estimated annual Non-Commodity Cost applicable to Firm Sales Service divided by November 1 – October 31 forecasted Firm Sales Service volumes.

Effective: October 31, 2025:		(C)
Estimated Non-Commodity Cost per therm-Firm Sales (w/revenue sensitive):	**$0.10027**	(R)
Estimated Non-Commodity Cost per therm-Firm Sales (w/o revenue sensitive):	**$0.09724**	(R)

(continue to Sheet P-3)

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

DEFINITIONS (continued):

11. Estimated Non-Commodity Cost per Therm – Interruptible Sales: The portion of the Estimated annual Non-Commodity Cost applicable to Interruptible Sales Service divided by November 1 – October 31 forecasted Interruptible Sales Service volumes.

Effective: October 31, 2025:		(C)
Estimated Non-Commodity Cost per therm-Interruptible Sales (w/revenue sensitive):	**$0.01193**	(R)
Estimated Non-Commodity Cost per therm-Interruptible Sales (w/o revenue sensitive):	**$0.01157**	(R)

12. Estimated Non-Commodity Cost per Therm – MDDV Based Sales: The portion of the Estimated annual Non-Commodity Cost applicable to MDDV Based Sales Service.

Effective: October 31, 2025:		(C)
Estimated Non-Commodity Cost per therm-MDDV Based Sales (w/revenue sensitive):	**$1.47**	(R)
Estimated Non-Commodity Cost per therm-MDDV Based Sales (w/o revenue sensitive):	**$1.43**	(R)

13. Actual Monthly Firm Sales Service Volumes: The total actual monthly billed Firm Sales Service therms, excluding MDDV based volumes, adjusted for estimated unbilled Firm Sales Service therms.

14. Actual Monthly Interruptible Sales Service Volumes: The total actual monthly billed Interruptible Sales Service therms, adjusted for estimated unbilled Interruptible Sales Service therms.

15. Actual Monthly MDDV Based Firm Sales Service Volumes: The total actual monthly billed Firm Sales Service Volumes for Rate Schedule 31 and Rate Schedule 32 customers billed under the Firm Pipeline Capacity Charge - Peak Demand option, adjusted for estimated unbilled MDDV Firm Sales Service Volumes.

16. Embedded Commodity Cost: The Estimated Annual Sales WACOG, updated for October 31 storage inventory prices, multiplied by the Total of the Actual Monthly Firm and Interruptible Sales Service Volumes.

17. Embedded Non-Commodity Cost per Therm – Firm Sales Service: The Estimated Non-Commodity Cost per Therm - Firm Sales Service multiplied by the Actual Monthly Firm Sales Service Volumes.

18. Embedded Non-Commodity Cost per Therm – Interruptible Sales Service: The Estimated Non-Commodity Cost per Therm – Interruptible Sales Service multiplied by the Actual Monthly Interruptible Sales Service Volumes.

(continue to Sheet P-4)

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

CALCULATION OF MONTHLY GAS COSTS FOR DEFERRAL PURPOSES (continued):

1. A debit or credit entry shall be made equal to 100% of the difference between the monthly Actual Non-Commodity Cost and the Monthly Embedded Non-Commodity Cost, net of revenue sensitive effects.
2. A debit or credit entry shall be made equal to 100% of any monthly difference between actual monthly fixed charge recoveries and Monthly Seasonalized Fixed Charges. The Monthly Seasonalized Fixed Charges for the period November 1, 2025 through October 31, 2026 are: (C)

November	2025	$7,896,890	(C)
December	2025	$10,892,111	
January	2026	$10,839,774	
February	2026	$9,380,513	
March	2026	$8,462,043	
April	2026	$6,123,490	
May	2026	$4,033,065	
June	2026	$2,721,869	
July	2026	$2,127,322	
August	2026	$2,081,168	
September	2026	$2,298,553	
October	2026	$4,404,099	
ANNUAL TOTAL		$71,260,897	(C)

3. A debit or credit entry shall be made equal to 90% of the difference between the Actual Commodity Cost, less the cost of renewable natural gas and renewable thermal certificates (including transaction costs and registration fees for a Commission-authorized renewable thermal credit tracking system), and the Embedded Commodity Cost. A debit or credit entry will also be made equal to 100% of the difference between storage withdrawals priced at the actual book inventory rate as of October 31 prior to the PGA year, storage withdrawals priced at the inventory rate used in the PGA filing and all costs associated with renewable natural gas and renewable thermal certificates. For any given tracker year, if the total activity subject to debit or credit entries that is related to the Gas Reserves transaction exceeds $10 million, amounts beyond $10 million will be recorded at 100%.
4. Monthly differentials shall be deemed to be positive if actual costs exceed embedded costs and to be negative if actual costs fall below embedded costs.
5. The cost differential entries shall be debited to the sub-accounts of Account 191 if positive, and credited to the sub-accounts of Account 191 if negative.
6. Interest – Beginning November 1, 2007, the Company shall compute interest on existing deferred balances on a monthly basis using the interest rate(s) approved by the Commission.

(continue to Sheet P-6)

SCHEDULE 150
MONTHLY INCREMENTAL COST OF GAS
(continued)

B. Compare the AECO, Sumas and Rockies city gate prices derived above and calculate the average of the highest two of those three prices.
C. The city gate price calculated in step B is then adjusted for the Company's revenue-sensitive effects, is converted from million Btus to Therms, and the Oregon Climate Protection Program Compliance Cost is added to the result to derive the Monthly Incremental Cost of Gas.
D. The Oregon Climate Protection Program Compliance Cost is as follows:

Effective October 31, 2025: $0.05360 per therm (C) (I)

E. The Company will post the Monthly Incremental Cost of Gas on its website as soon as it is available each month.

<u>GENERAL TERMS</u>:
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.

SCHEDULE 162
TEMPORARY (TECHNICAL) ADJUSTMENTS TO RATES

PURPOSE:
To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of balances in the Company's Account 191 deferred revenue and gas cost accounts.

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

APPLICATION TO RATE SCHEDULES: Effective: October 31, 2025 (C)

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

Schedule	Block	Account 191 Commodity Adjustment	Account 191 Pipeline Capacity Adjustment	Total Adjustment	
2		($0.04161)	$0.00643	**($0.03518)**	(R)
3 CSF		($0.04161)	$0.00643	**($0.03518)**	
3 ISF		($0.04161)	$0.00643	**($0.03518)**	
27		($0.04161)	$0.00643	**($0.03518)**	
31 CSF	Block 1	($0.04161)	$0.00643	**($0.03518)**	
	Block 2	($0.04161)	$0.00643	**($0.03518)**	(R)
31 CTF	Block 1	N/A	N/A	**$0.00000**	
	Block 2	N/A	N/A	**$0.00000**	
31 ISF	Block 1	($0.04161)	$0.00643	**($0.03518)**	(R)
	Block 2	($0.04161)	$0.00643	**($0.03518)**	(R)
31 ITF	Block 1	N/A	N/A	**$0.00000**	
	Block 2	N/A	N/A	**$0.00000**	

(continue to Sheet 162-2)

SCHEDULE 162
TEMPORARY (TECHNICAL) ADJUSTMENTS TO RATES
(continued)

APPLICATION TO RATE SCHEDULES (continued): Effective: October 31, 2025 (C)

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.

Schedule	Block	Account 191 Commodity Adjustment [1]	Account 191 Pipeline Capacity Adjustment	Total Adjustment	
32 CSF	Block 1	($0.04161)	$0.00643	**($0.03518)**	(R)
	Block 2	($0.04161)	$0.00643	**($0.03518)**	
	Block 3	($0.04161)	$0.00643	**($0.03518)**	
	Block 4	($0.04161)	$0.00643	**($0.03518)**	
	Block 5	($0.04161)	$0.00643	**($0.03518)**	
	Block 6	($0.04161)	$0.00643	**($0.03518)**	
32 ISF	Block 1	($0.04161)	$0.00643	**($0.03518)**	
	Block 2	($0.04161)	$0.00643	**($0.03518)**	
	Block 3	($0.04161)	$0.00643	**($0.03518)**	
	Block 4	($0.04161)	$0.00643	**($0.03518)**	
	Block 5	($0.04161)	$0.00643	**($0.03518)**	
	Block 6	($0.04161)	$0.00643	**($0.03518)**	(R)
32 CTF/ITF	Block 1	N/A	N/A	**$0.00000**	
	Block 2	N/A	N/A	**$0.00000**	
	Block 3	N/A	N/A	**$0.00000**	
	Block 4	N/A	N/A	**$0.00000**	
	Block 5	N/A	N/A	**$0.00000**	
	Block 6	N/A	N/A	**$0.00000**	
32 CSI	Block 1	($0.04161)	$0.00076	**($0.04085)**	(R)
	Block 2	($0.04161)	$0.00076	**($0.04085)**	
	Block 3	($0.04161)	$0.00076	**($0.04085)**	
	Block 4	($0.04161)	$0.00076	**($0.04085)**	
	Block 5	($0.04161)	$0.00076	**($0.04085)**	
	Block 6	($0.04161)	$0.00076	**($0.04085)**	
32 ISI	Block 1	($0.04161)	$0.00076	**($0.04085)**	
	Block 2	($0.04161)	$0.00076	**($0.04085)**	
	Block 3	($0.04161)	$0.00076	**($0.04085)**	
	Block 4	($0.04161)	$0.00076	**($0.04085)**	
	Block 5	($0.04161)	$0.00076	**($0.04085)**	
	Block 6	($0.04161)	$0.00076	**($0.04085)**	(R)
32 CTI/ITI	Block 1	N/A	N/A	**$0.00000**	
	Block 2	N/A	N/A	**$0.00000**	
	Block 3	N/A	N/A	**$0.00000**	
	Block 4	N/A	N/A	**$0.00000**	
	Block 5	N/A	N/A	**$0.00000**	
	Block 6	N/A	N/A	**$0.00000**	
33 TI/TF		N/A	N/A	**$0.00000**	

SCHEDULE 164
PURCHASED GAS COST ADJUSTMENT TO RATES

PURPOSE:
To identify the Commodity and Pipeline Capacity Components applicable to the Rate Schedules listed below.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Rate Schedule 2 Rate Schedule 3 Rate Schedule 27
Rate Schedule 31 Rate Schedule 32

APPLICATION TO RATE SCHEDULES: Effective: October 31, 2025 (C)

Annual Sales WACOG [1]	$0.45623	(I)
Winter Sales WACOG [2]	$0.48560	(I)
Firm Sales Service Pipeline Capacity Component [3]	$0.10027	(R)
Firm Sales Service Pipeline Capacity Component [4]	$1.47	
Interruptible Sales Service Pipeline Capacity Component [5]	$0.01193	(R)

[1] Applies to all Sales Service Rate Schedules (per therm) except where Winter Sales WACOG or Monthly Incremental Cost of Gas applies.
[2] Applies to Sales Customers that request Winter Sales WACOG at the September 15 Annual Service Election.
[3] Applies to Rate Schedules 2, 3, and Schedule 31 and Schedule 32 Firm Sales Service Volumetric Pipeline Capacity option (per therm).
[4] Applies to Rate Schedules 31 and 32 Firm Sales Service Peak Demand Pipeline Capacity option (per therm of MDDV per month).
[5] Applies to Rate Schedule 32 Interruptible Sales Service (per therm).

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 Rate Schedule apply to service under the Rate Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

EXHIBIT A

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

Purchased Gas Cost Deferral Amortizations

UM 1496

NWN OPUC Advice No. 25-21 / UG 524

July 31, 2025

NW NATURAL

EXHIBIT A

Supporting Materials

Purchased Gas Cost Deferral Amortizations

NWN OPUC ADVICE NO. 25-21 / UG 524

NW Natural
Rates & Regulatory Affairs
2025-26 PGA - Oregon: August Filing
Summary of TEMPORARY Increments

1			**Current Temporaries**	**WACOG Deferral**	**Demand Deferral - FIRM**	**Demand Deferral - INTERRUPTIBLE**	**Subtotal**
2							
3	Schedule	Block	**A**	**B**	**C**	**D**	**E**
4	2R		($0.01390)	($0.04161)	$0.00643	$0.00000	($0.03518)
5	3C Sales Firm		($0.06288)	($0.04161)	$0.00643	$0.00000	($0.03518)
6	3I Sales Firm		$0.03439	($0.04161)	$0.00643	$0.00000	($0.03518)
7	27 Dry Out		($0.01906)	($0.04161)	$0.00643	$0.00000	($0.03518)
8	31C Sales Firm	Block 1	($0.03470)	($0.04161)	$0.00643	$0.00000	($0.03518)
9		Block 2	($0.03542)	($0.04161)	$0.00643	$0.00000	($0.03518)
10	31C Trans Firm	Block 1	$0.01154	$0.00000	$0.00000	$0.00000	$0.00000
11		Block 2	$0.01067	$0.00000	$0.00000	$0.00000	$0.00000
12	31I Sales Firm	Block 1	$0.03140	($0.04161)	$0.00643	$0.00000	($0.03518)
13		Block 2	$0.03079	($0.04161)	$0.00643	$0.00000	($0.03518)
14	31I Trans Firm	Block 1	$0.00948	$0.00000	$0.00000	$0.00000	$0.00000
15		Block 2	$0.00873	$0.00000	$0.00000	$0.00000	$0.00000
16	32C Sales Firm	Block 1	$0.03026	($0.04161)	$0.00643	$0.00000	($0.03518)
17		Block 2	$0.02947	($0.04161)	$0.00643	$0.00000	($0.03518)
18		Block 3	$0.02811	($0.04161)	$0.00643	$0.00000	($0.03518)
19		Block 4	$0.02675	($0.04161)	$0.00643	$0.00000	($0.03518)
20		Block 5	$0.02578	($0.04161)	$0.00643	$0.00000	($0.03518)
21		Block 6	$0.02531	($0.04161)	$0.00643	$0.00000	($0.03518)
22	32I Sales Firm	Block 1	$0.02798	($0.04161)	$0.00643	$0.00000	($0.03518)
23		Block 2	$0.02757	($0.04161)	$0.00643	$0.00000	($0.03518)
24		Block 3	$0.02688	($0.04161)	$0.00643	$0.00000	($0.03518)
25		Block 4	$0.02621	($0.04161)	$0.00643	$0.00000	($0.03518)
26		Block 5	$0.02573	($0.04161)	$0.00643	$0.00000	($0.03518)
27		Block 6	$0.02549	($0.04161)	$0.00643	$0.00000	($0.03518)
28	32C Trans Firm	Block 1	$0.00506	$0.00000	$0.00000	$0.00000	$0.00000
29		Block 2	$0.00451	$0.00000	$0.00000	$0.00000	$0.00000
30		Block 3	$0.00358	$0.00000	$0.00000	$0.00000	$0.00000
31		Block 4	$0.00265	$0.00000	$0.00000	$0.00000	$0.00000
32		Block 5	$0.00210	$0.00000	$0.00000	$0.00000	$0.00000
33		Block 6	$0.00173	$0.00000	$0.00000	$0.00000	$0.00000
34	32I Trans Firm	Block 1	$0.00469	$0.00000	$0.00000	$0.00000	$0.00000
35		Block 2	$0.00426	$0.00000	$0.00000	$0.00000	$0.00000
36		Block 3	$0.00351	$0.00000	$0.00000	$0.00000	$0.00000
37		Block 4	$0.00277	$0.00000	$0.00000	$0.00000	$0.00000
38		Block 5	$0.00231	$0.00000	$0.00000	$0.00000	$0.00000
39		Block 6	$0.00202	$0.00000	$0.00000	$0.00000	$0.00000
40	32C Sales Interr	Block 1	$0.02823	($0.04161)	$0.00000	$0.00076	($0.04085)
41		Block 2	$0.02766	($0.04161)	$0.00000	$0.00076	($0.04085)
42		Block 3	$0.02671	($0.04161)	$0.00000	$0.00076	($0.04085)
43		Block 4	$0.02575	($0.04161)	$0.00000	$0.00076	($0.04085)
44		Block 5	$0.02518	($0.04161)	$0.00000	$0.00076	($0.04085)
45		Block 6	$0.02477	($0.04161)	$0.00000	$0.00076	($0.04085)
46	32I Sales Interr	Block 1	$0.02796	($0.04161)	$0.00000	$0.00076	($0.04085)
47		Block 2	$0.02749	($0.04161)	$0.00000	$0.00076	($0.04085)
48		Block 3	$0.02670	($0.04161)	$0.00000	$0.00076	($0.04085)
49		Block 4	$0.02591	($0.04161)	$0.00000	$0.00076	($0.04085)
50		Block 5	$0.02544	($0.04161)	$0.00000	$0.00076	($0.04085)
51		Block 6	$0.02509	($0.04161)	$0.00000	$0.00076	($0.04085)
52	32C Trans Interr	Block 1	$0.00387	$0.00000	$0.00000	$0.00000	$0.00000
53		Block 2	$0.00347	$0.00000	$0.00000	$0.00000	$0.00000
54		Block 3	$0.00283	$0.00000	$0.00000	$0.00000	$0.00000
55		Block 4	$0.00221	$0.00000	$0.00000	$0.00000	$0.00000
56		Block 5	$0.00183	$0.00000	$0.00000	$0.00000	$0.00000
57		Block 6	$0.00157	$0.00000	$0.00000	$0.00000	$0.00000
58	32I Trans Interr	Block 1	$0.00443	$0.00000	$0.00000	$0.00000	$0.00000
59		Block 2	$0.00401	$0.00000	$0.00000	$0.00000	$0.00000
60		Block 3	$0.00334	$0.00000	$0.00000	$0.00000	$0.00000
61		Block 4	$0.00266	$0.00000	$0.00000	$0.00000	$0.00000
62		Block 5	$0.00225	$0.00000	$0.00000	$0.00000	$0.00000
63		Block 6	$0.00197	$0.00000	$0.00000	$0.00000	$0.00000
64	33		$0.00127	$0.00000	$0.00000	$0.00000	$0.00000
65	Special Contracts			$0.00000	$0.00000	$0.00000	$0.00000
66							

Calculation of Increments Allocated on the EQUAL CENT PER THERM BASIS

ALL VOLUMES IN THERMS

Line	Schedule	Block	A		Multiplier B	Volumes C	Increment D	Multiplier E	Volumes F	Increment G	Multiplier H	Volumes I	Increment J	Multiplier AO	Volumes AP	Increment AQ
1					WACOG Deferral			Demand Deferral - FIRM			Demand Deferral - INTERRUPTIBLE			AWEC Deferral - Schedule 171 To Sales (WACOG)		
2			Oregon PGA	Proposed Amount:	(30,382,624) Temporary Increment			4,531,339 Temporary Increment			39,573 Temporary Increment			(1,087,169) Temporary Increment		
3			Volumes page,	Revenue Sensitive Multiplier:	3.018% add revenue sensitive factor			3.018% add revenue sensitive factor			3.018% add revenue sensitive factor			3.018% add revenue sensitive factor		
4			Column F	Amount to Amortize:	**(31,328,110)** to all sales			**4,672,351** to all firm sales			**40,805** to all interruptible sales			**(1,121,001)** to all sales		
5					Multiplier	Volumes	Increment	Multiplier	Volumes	Increment	Multiplier	Volumes	Increment	Multiplier	Volumes	Increment
6	Schedule	Block	A		B	C	D	E	F	G	H	I	J	AO	AP	AQ
7	2R		421,439,949		1.0	421,439,949	($0.04017)	1.0	421,439,949	$0.00643	0.0	0	$0.00000	1.0	421,439,949	($0.00144)
8	3C Firm Sales		191,560,213		1.0	191,560,213	($0.04017)	1.0	191,560,213	$0.00643	0.0	0	$0.00000	1.0	191,560,213	($0.00144)
9	3I Firm Sales		4,897,917		1.0	4,897,917	($0.04017)	1.0	4,897,917	$0.00643	0.0	0	$0.00000	1.0	4,897,917	($0.00144)
10	27 Dry Out		739,110		1.0	739,110	($0.04017)	1.0	739,110	$0.00643	0.0	0	$0.00000	1.0	739,110	($0.00144)
11	31C Firm Sales	Block 1	12,710,926		1.0	12,710,926	($0.04017)	1.0	12,710,926	$0.00643	0.0	0	$0.00000	1.0	12,710,926	($0.00144)
12		Block 2	11,231,948		1.0	11,231,948	($0.04017)	1.0	11,231,948	$0.00643	0.0	0	$0.00000	1.0	11,231,948	($0.00144)
13	31C Firm Trans	Block 1	1,171,263		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
14		Block 2	1,305,394		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
15	31I Firm Sales	Block 1	3,428,826		1.0	3,428,826	($0.04017)	1.0	3,428,826	$0.00643	0.0	0	$0.00000	1.0	3,428,826	($0.00144)
16		Block 2	7,225,968		1.0	7,225,968	($0.04017)	1.0	7,225,968	$0.00643	0.0	0	$0.00000	1.0	7,225,968	($0.00144)
17	31I Firm Trans	Block 1	12,735		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
18		Block 2	31,024		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
19	32C Firm Sales	Block 1	36,364,305		1.0	36,364,305	($0.04017)	1.0	36,364,305	$0.00643	0.0	0	$0.00000	1.0	36,364,305	($0.00144)
20		Block 2	11,181,417		1.0	11,181,417	($0.04017)	1.0	11,181,417	$0.00643	0.0	0	$0.00000	1.0	11,181,417	($0.00144)
21		Block 3	1,968,034		1.0	1,968,034	($0.04017)	1.0	1,968,034	$0.00643	0.0	0	$0.00000	1.0	1,968,034	($0.00144)
22		Block 4	888,550		1.0	888,550	($0.04017)	1.0	888,550	$0.00643	0.0	0	$0.00000	1.0	888,550	($0.00144)
23		Block 5	16,644		1.0	16,644	($0.04017)	1.0	16,644	$0.00643	0.0	0	$0.00000	1.0	16,644	($0.00144)
24		Block 6	0		1.0	0	($0.04017)	1.0	0	$0.00643	0.0	0	$0.00000	1.0	0	($0.00144)
25	32I Firm Sales	Block 1	8,628,593		1.0	8,628,593	($0.04017)	1.0	8,628,593	$0.00643	0.0	0	$0.00000	1.0	8,628,593	($0.00144)
26		Block 2	7,972,562		1.0	7,972,562	($0.04017)	1.0	7,972,562	$0.00643	0.0	0	$0.00000	1.0	7,972,562	($0.00144)
27		Block 3	2,916,083		1.0	2,916,083	($0.04017)	1.0	2,916,083	$0.00643	0.0	0	$0.00000	1.0	2,916,083	($0.00144)
28		Block 4	2,877,605		1.0	2,877,605	($0.04017)	1.0	2,877,605	$0.00643	0.0	0	$0.00000	1.0	2,877,605	($0.00144)
29		Block 5	443,011		1.0	443,011	($0.04017)	1.0	443,011	$0.00643	0.0	0	$0.00000	1.0	443,011	($0.00144)
30		Block 6	0		1.0	0	($0.04017)	1.0	0	$0.00643	0.0	0	$0.00000	1.0	0	($0.00144)
31	32C Firm Trans	Block 1	2,769,074		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
32		Block 2	2,051,764		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
33		Block 3	656,440		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
34		Block 4	951,036		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
35		Block 5	42,214		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
36		Block 6	0		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
37	32I Firm Trans	Block 1	11,405,325		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
38		Block 2	16,248,048		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
39		Block 3	9,930,036		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
40		Block 4	21,832,878		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
41		Block 5	22,413,473		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
42		Block 6	7,541,214		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
43	32C Interr Sales	Block 1	4,420,212		1.0	4,420,212	($0.04017)	0.0	0	$0.00000	1.0	4,420,212	$0.00076	1.0	4,420,212	($0.00144)
44		Block 2	6,619,668		1.0	6,619,668	($0.04017)	0.0	0	$0.00000	1.0	6,619,668	$0.00076	1.0	6,619,668	($0.00144)
45		Block 3	3,569,981		1.0	3,569,981	($0.04017)	0.0	0	$0.00000	1.0	3,569,981	$0.00076	1.0	3,569,981	($0.00144)
46		Block 4	5,246,915		1.0	5,246,915	($0.04017)	0.0	0	$0.00000	1.0	5,246,915	$0.00076	1.0	5,246,915	($0.00144)
47		Block 5	3,398,942		1.0	3,398,942	($0.04017)	0.0	0	$0.00000	1.0	3,398,942	$0.00076	1.0	3,398,942	($0.00144)
48		Block 6	0		1.0	0	($0.04017)	0.0	0	$0.00000	1.0	0	$0.00076	1.0	0	($0.00144)
49	32I Interr Sales	Block 1	4,783,726		1.0	4,783,726	($0.04017)	0.0	0	$0.00000	1.0	4,783,726	$0.00076	1.0	4,783,726	($0.00144)
50		Block 2	6,385,368		1.0	6,385,368	($0.04017)	0.0	0	$0.00000	1.0	6,385,368	$0.00076	1.0	6,385,368	($0.00144)
51		Block 3	3,622,167		1.0	3,622,167	($0.04017)	0.0	0	$0.00000	1.0	3,622,167	$0.00076	1.0	3,622,167	($0.00144)
52		Block 4	10,367,186		1.0	10,367,186	($0.04017)	0.0	0	$0.00000	1.0	10,367,186	$0.00076	1.0	10,367,186	($0.00144)
53		Block 5	4,928,689		1.0	4,928,689	($0.04017)	0.0	0	$0.00000	1.0	4,928,689	$0.00076	1.0	4,928,689	($0.00144)
54		Block 6	0		1.0	0	($0.04017)	0.0	0	$0.00000	1.0	0	$0.00076	1.0	0	($0.00144)
55	32C Interr Trans	Block 1	780,580		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
56		Block 2	1,586,918		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
57		Block 3	1,034,205		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
58		Block 4	3,340,006		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
59		Block 5	431,793		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
60		Block 6	0		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
61	32I Interr Trans	Block 1	5,825,488		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
62		Block 2	9,678,292		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
63		Block 3	6,123,269		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
64		Block 4	14,253,538		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
65		Block 5	29,505,433		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
66		Block 6	96,966,741		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
67	33		0		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
68	Special Contracts		74,098,618		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
69																
70	TOTALS		1,121,821,307			779,834,510	$ (0.04017)		726,491,658	$ 0.00643		53,342,852	$ 0.00076		779,834,510	$ (0.00144)
71	**Sources for line 2 above:**															
72	**Inputs page**				Line 33			Line 35			Line 37			Line 61		
73	**Tariff Schedules**															
74	**Rate Adjustment Schedule**				Sched 162			Sched 162			Sched 162			Sched 171		

NW Natural
Rates and Regulatory Affairs
2025-2026 PGA Filing - OREGON
Basis for Revenue Related Costs

Line		Twelve Months Ended 06/30/25		
1				
2				
3	Total Billed Gas Sales Revenues	$ 947,586,013		
4	Total Oregon Revenues	$ 952,494,446		
5				
6	Regulatory Commission Fees [1]	n/a	0.450%	Statutory rate
7	City License and Franchise Fees	$ 22,248,348	2.336%	Line 7 ÷ Line 4
8	Net Uncollectible Expense [2]	$ 2,209,884	0.232%	Line 8 ÷ Line 4
9				
10	Total		**3.018%**	Sum lines 6-8
11				
12				

13 **Note:**
14 [1] Dollar figure is set at statutory level of 0.450% times Total Oregon Revenues (line 4).
15 Because the fee changed since our last general rate case, the difference between the previous fee of 0.430%
16 and the new fee of 0.450%, as it affects our base rates, is being captured as a temporary deferral.
17 [2] Represents the normalized net write-offs based on a three-year average.

NW Natural
Rates & Regulatory Affairs
2025-2026 PGA Filing - Oregon: August Filing
PGA Effects on Revenue
Schedule 164: PGA Gas Costs and Gas Cost Deferrals

Line		Including Revenue Sensitive Amount
3	**Purchased Gas Cost Adjustment (PGA)**	
5	Commodity Cost Change	$17,658,089
7	Demand Capacity Cost Change	855,360
9	**Total Gas Cost Change**	**18,513,449**
11	**Temporary Increments**	
13	Removal of Current Temporary Increments	
14	Amortization of 191.xxx Account Gas Costs	26,750,543
16	Addition of Proposed Temporary Increments	
17	Amortization of 191.xxx Account Gas Costs	(27,735,955)
19	**Net Temporary Rate Adjustment**	**(985,412)**
21	**TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES**	**$17,528,037**
23	2024 Oregon Earnings Test Normalized Total Revenues	$939,254,783
25	Effect of this filing, as a percentage change (line 21 ÷ line 23)	1.87%
27	Effect of this filing, as a percentage change (line 19 ÷ line 23)	-0.10%
29	Effect of this filing, as a percentage change (line 9 ÷ line 23)	1.97%

NW Natural
Rates & Regulatory Affairs
2025-26 PGA Filing - September Filing
Summary of Deferred Accounts Included in the PGA

	Account	Balance 6/30/2025	Jul-Oct Estimated Activity	Jul-Oct Interest	Estimated Balance 10/31/2025	Interest Rate During Amortization	Estimated Interest During Amortization	Total Estimated Amount for (Refund) or Collection
	A	B	C	D	E	F1	F2	G
					E = sum B thru D	5.16%		G = E + F2
96	**Gas Cost Deferrals and Amortizations**							
97	151510 OREGON WACOG AMORTIZATION	(6,374,232)	3,459,622	(81,104)	(2,995,715)			
98	151505 OREGON WACOG DEFERRAL	(25,938,997)	-	(615,487)	(26,554,485)			
99	Total	(32,313,230)	3,459,622	(696,591)	(29,550,199)	5.16%	(832,425)	(30,382,624)
100								
101	151525 OREGON DEMAND AMORTIZATION	1,051,690	(518,930)	13,899	546,659			
102	151520 OREGON DEMAND DEFERRAL	(1,668,558)	-	(39,592)	(1,708,150)			
103	151535 COOS BAY DEMAND DEFERRAL	54,238	-	-	54,238			
104	151560 OREGON SEASONAL VOLUME DEMAND DEFERRAL	5,424,223	-	128,707	5,552,931			
105	Total	4,861,594	(518,930)	103,015	4,445,678	5.16%	125,234	4,570,912
106								
27	232092 CPP RS Allocation Sales RTC	(1,011,728)	(18,652)	(25,646)	(1,056,026)	0	(31,143)	(1,087,169)

Company:	Northwest Natural Gas Company
State:	Oregon
Description:	Amortization of Oregon WACOG Deferral
Account Number:	151510
Docket:	Dockets UM 1496, UG 518
	Amortization of deferral approved in Order No. 24-394

1 Debit (Credit)

2

3/4	Month/Year	Note	Amortization	Transfers	Interest	Interest rate	Activity	Balance
5	(a)	(b)	(c)	(d)	(e1)	(e2)	(f)	(g)
6								
7	Beginning Balance							
240	Jul-24		(93,518.78)		1,242.95	5.13%	(92,275.83)	245,232.57
241	Aug-24		(83,456.30)		869.98	5.13%	(82,586.32)	162,646.24
242	Sep-24		(91,711.52)		499.28	5.13%	(91,212.24)	71,434.01
243	Oct-24		(119,160.38)		50.68	5.13%	(119,109.70)	(47,675.69)
244	Nov-24	Old Rates	(117,495.10)		(454.96)	5.13%	(117,950.06)	(165,625.75)
245	Nov-24	New Rates (**1**)	1,144,696.46	(29,147,686.07)	(128,589.02)	5.40%	(28,131,578.63)	(28,297,204.38)
246	Dec-24		4,209,547.87		(117,865.94)	5.40%	4,091,681.93	(24,205,522.46)
247	Jan-25		4,529,190.03		(98,734.17)	5.40%	4,430,455.86	(19,775,066.59)
248	Feb-25		4,918,091.56		(77,922.09)	5.40%	4,840,169.47	(14,934,897.13)
249	Mar-25		3,469,580.60		(59,400.48)	5.40%	3,410,180.12	(11,524,717.01)
250	Apr-25		2,501,500.24		(46,232.85)	5.40%	2,455,267.39	(9,069,449.62)
251	May-25		1,513,622.68		(37,406.87)	5.40%	1,476,215.81	(7,593,233.81)
252	Jun-25		1,250,357.68		(31,356.25)	5.40%	1,219,001.43	(6,374,232.38)
253	Jul-25	*Forecasted*	*1,009,947.82*		(26,411.66)	5.40%	983,536.16	(5,390,696.22)
254	Aug-25	*Forecasted*	*913,240.40*		(22,203.34)	5.40%	891,037.06	(4,499,659.16)
255	Sep-25	*Forecasted*	*1,029,259.31*		(17,932.63)	5.40%	1,011,326.68	(3,488,332.48)
256	Oct-25	*Forecasted*	*507,174.25*		(14,556.35)	5.40%	492,617.90	(2,995,714.58)

257

258 **History truncated for ease of viewing**

259

260 **NOTES:**

261 **1** - Transferred in authorized balance from accounts 151505.

Company:	Northwest Natural Gas Company
State:	Oregon
Description:	Core Market Commodity gas cost deferral
Account Number:	151505
Docket:	Docket UM 1496
	Last deferral reauthorization was approved in Order 25-105
Narrative:	Deferral of customer's share of the difference between actual core commodity cost incurred and the Annual Sales WACOG embedded in customer rates. For the PGA year, the deferral election was 90%.

Debit (Credit)

Month/Year	Note	Commodity Deferral	Storage Adjustment	Hedge Adjustment	RTC Retirement	Interest	Interest Rate	Transfer	Activity	Balance
(a)	(b)	(c)	(d)	(e)	(g)	(h1)	(h2)	(i)	(j)	(k)
Beginning Bal										
Jul-24		(1,290,161.18)	(1,941.53)	(7,458.10)	(95,220.35)	(165,146.53)	6.836%		(1,559,928)	(29,852,566.09)
Aug-24		(1,544,732.68)	(2,050.37)	(8,988.20)	(100,606.36)	(174,778.03)	6.836%		(1,831,156)	(31,683,721.74)
Sep-24		(2,347,964.22)	(2,229.50)	(6,821.50)	313,483.77	(186,312.26)	6.836%		(2,229,844)	(33,913,565.45)
Oct-24		(6,918,578.19)	(4,476.20)	(63,290.40)	29,218.20	(213,010.49)	6.836%		(7,170,137)	(41,083,702.52)
Nov-24	**1**	471,008.29	(13,984.82)	6,595.10	(293,079.56)	(70,886.75)	7.056%	28,942,863.20	29,042,515	(12,041,187.06)
Dec-24		(229,958.09)	(18,856.10)	(127,051.00)	(1,277,589.19)	(75,663.34)	7.056%		(1,729,118)	(13,770,304.79)
Jan-25		(1,962,044.21)	(21,387.05)	(137,772.90)	(2,027,565.00)	(93,166.77)	7.056%		(4,241,936)	(18,012,240.72)
Feb-25		(481,925.62)	(18,376.19)	(48,645.20)	(2,141,275.91)	(113,821.23)	7.056%		(2,804,044)	(20,816,284.88)
Mar-25		2,530,678.87	(14,025.97)	39,363.70	1,201,742.78	(111,351.94)	7.056%		3,646,407	(17,169,877.44)
Apr-25		(4,981,485.74)	(8,617.60)	(21,213.80)	(346,607.17)	(116,711.18)	7.056%		(5,474,635)	(22,644,512.93)
May-25		(2,575,412.74)	(5,922.32)	(1,910.10)	69,496.58	(140,540.16)	7.056%		(2,654,289)	(25,298,801.67)
Jun-25		(733,123.68)	(4,479.43)	(770.30)	248,375.14	(150,197.55)	7.056%		(640,196)	(25,938,997.49)
Jul-25						(152,521.31)	7.056%		(152,521)	(26,091,518.80)
Aug-25						(153,418.13)	7.056%		(153,418)	(26,244,936.93)
Sep-25						(154,320.23)	7.056%		(154,320)	(26,399,257.16)
Oct-25						(155,227.63)	7.056%		(155,228)	(26,554,484.79)

History truncated for ease of viewing

NOTES:

1 -Transferred June balance plus July-October interest on June balance to account 151510 for amortization.

Company:	Northwest Natural Gas Company
State:	Oregon
Description:	Amortization of Oregon Demand Deferral
Account Number:	151525
Docket:	Dockets UM 1496, UG 518
	Amortization of deferral approved in Order No. 24-394

1 Debit (Credit)

Line	Month/Year	Note	Amortization	Transfers	Interest Rate	Interest Interest	Activity	Balance
5	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
6								
7	Beginning Balance							
202	Jul-24		75,825.83		5.13%	(2,405.57)	73,420.26	(527,199.23)
203	Aug-24		65,841.45		5.13%	(2,113.04)	63,728.41	(463,470.81)
204	Sep-24		73,304.70		5.13%	(1,824.65)	71,480.05	(391,990.76)
205	Oct-24		95,541.17		5.13%	(1,471.54)	94,069.63	(297,921.13)
206	Nov-24	Old Rates	109,187.35		5.13%	(1,040.22)	108,147.13	(189,774.00)
207	Nov-24	New Rates (**1**)	(171,202.79)	4,694,947.03	5.40%	20,742.06	4,544,486.30	4,354,712.31
208	Dec-24		(635,172.57)		5.40%	18,167.07	(617,005.50)	3,737,706.80
209	Jan-25		(683,392.92)		5.40%	15,282.05	(668,110.87)	3,069,595.93
210	Feb-25		(742,536.34)		5.40%	12,142.47	(730,393.87)	2,339,202.07
211	Mar-25		(523,181.27)		5.40%	9,349.25	(513,832.02)	1,825,370.05
212	Apr-25		(376,856.04)		5.40%	7,366.24	(369,489.80)	1,455,880.25
213	May-25		(227,496.35)		5.40%	6,039.59	(221,456.76)	1,234,423.50
214	Jun-25		(187,865.75)		5.40%	5,132.21	(182,733.54)	1,051,689.96
215	Jul-25	*Forecasted*	*(151,503.72)*		5.40%	4,391.72	(147,112.00)	904,577.96
216	Aug-25	*Forecasted*	*(136,796.24)*		5.40%	3,762.81	(133,033.43)	771,544.53
217	Sep-25	*Forecasted*	*(154,315.78)*		5.40%	3,124.74	(151,191.04)	620,353.49
218	Oct-25	*Forecasted*	*(76,314.72)*		5.40%	2,619.88	(73,694.84)	546,658.65

220 **History truncated for ease of viewing**

222 **NOTES:**

223 **1** - Transferred in authorized balances from accounts 151520, 151560 and 151535

Company:	Northwest Natural Gas Company
State:	Oregon
Description:	Core Market Demand cost deferral
Account Number:	151520
Docket:	Docket UM 1496 Last deferral reauthorization was approved in Order 25-105
Narrative:	Deferral of 100% of the difference between actual demand cost incurred and the demand cost embedded in customer rates.

Debit (Credit)

Month/Year	Note	Demand Deferral	Transfer	Interest	Interest Rate	Activity	Balance
(a)	(b)	(c)	(d)	(e1)	(e2)	(f)	(g)
Beginning Bal							
Jul-24		(65,050.84)		(4,737.31)	6.836%	(69,788.15)	(868,855.89)
Aug-24		(80,043.20)		(5,177.57)	6.836%	(85,220.77)	(954,076.66)
Sep-24		(71,364.18)		(5,638.33)	6.836%	(77,002.51)	(1,031,079.18)
Oct-24		(36,608.04)		(5,977.99)	6.836%	(42,586.03)	(1,073,665.21)
Nov-24	**1**	(624,803.59)	817,432.00	(3,343.57)	7.056%	189,284.84	(884,380.37)
Dec-24		(220,906.91)		(5,849.62)	7.056%	(226,756.53)	(1,111,136.90)
Jan-25		(485,619.02)		(7,961.20)	7.056%	(493,580.22)	(1,604,717.12)
Feb-25		(290,872.39)		(10,290.90)	7.056%	(301,163.29)	(1,905,880.41)
Mar-25		(17,044.62)		(11,256.69)	7.056%	(28,301.31)	(1,934,181.72)
Apr-25		143,079.64		(10,952.33)	7.056%	132,127.31	(1,802,054.41)
May-25		86,853.67		(10,340.73)	7.056%	76,512.94	(1,725,541.47)
Jun-25		66,933.17		(9,949.40)	7.056%	56,983.77	(1,668,557.70)
Jul-25				(9,811.12)	7.056%	(9,811.12)	(1,678,368.82)
Aug-25				(9,868.81)	7.056%	(9,868.81)	(1,688,237.63)
Sep-25				(9,926.84)	7.056%	(9,926.84)	(1,698,164.47)
Oct-25				(9,985.21)	7.056%	(9,985.21)	(1,708,149.68)

History truncated for ease of viewing

NOTES

1 -Transferred June balance plus July-October interest on June balance to account 151525 for amortization.

Company:	Northwest Natural Gas Company
State:	Oregon
Description:	Coos County Demand
Account Number:	151535
	Docket UM 1179 Order 04-702
Narrative:	Deferral of transportation charge payable by NW Natural for use of the natural gas transmission pipeline owned by Coos County.

1 Debit (Credit)

2

3

	Month/Year	Note	Deferral	Adjustment	Transfer	Activity	Balance
4	Month/Year	Note	Deferral	Adjustment	Transfer	Activity	Balance
5	(a)	(b)	(c)	(d)	(e)	(f)	(g)
6	Beginning Bal						
222	Jul-24		22,321.00	(6,268.08)		16,052.92	190,870.23
223	Aug-24		22,321.00	(5,889.54)		16,431.46	207,301.69
224	Sep-24		22,321.00	(6,373.25)		15,947.75	223,249.44
225	Oct-24		22,321.00	(8,399.50)		13,921.50	237,170.94
226	Nov-24	**1**	22,321.00	(11,258.90)	(174,817.31)	(163,755.21)	73,415.73
227	Dec-24		22,321.00	(13,339.80)		8,981.20	82,396.93
228	Jan-25		22,321.00	(14,372.97)		7,948.03	90,344.96
229	Feb-25		24,827.00	(15,081.22)		9,745.78	100,090.74
230	Mar-25		23,574.00	(13,707.98)		9,866.02	109,956.76
231	Apr-25		23,574.00	(11,898.39)		11,675.61	121,632.37
232	May-25		23,574.00	(11,111.59)		12,462.41	134,094.78
233	Jun-25		23,574.00	(103,430.73)		(79,856.73)	54,238.05
234	Jul-25					0.00	54,238.05
235	Aug-25					0.00	54,238.05
236	Sep-25					0.00	54,238.05
237	Oct-25					0.00	54,238.05

238

239

240 **History truncated for ease of viewing**

241

242 **NOTES**

243 **1** -Transferred June balance to account 151525 for amortization.

Company: Northwest Natural Gas Company
State: Oregon
Description: Seasonalized Demand Collection Deferral
Account Number: 151560
Docket: Docket UM 1496
Last deferral reauthorization was approved in Order 25-105
Narrative: Deferral of 100% of the difference between actual demand costs collected and the seasonalized imbedded demand costs embedded in customer rates.

1 Debit (Credit)

			Demand					
2-3	Month/Year	Note	Deferral	Interest	Interest Rate	Transfer	Activity	Balance
4	(a)	(b)	(d)	(e)	(f)	(g)	(i)	(j)
222	Jul-24		384,771.72	30,819.17	6.836%		415,590.89	5,633,239.97
223	Aug-24		(34,487.28)	31,992.46	6.836%		(2,494.82)	5,630,745.15
224	Sep-24		80,891.29	32,306.88	6.836%		113,198.17	5,743,943.32
225	Oct-24		55,737.25	32,880.09	6.836%		88,617.34	5,832,560.66
226	Nov-24	**1**	451,711.71	4,238.63	7.056%	(5,337,561.72)	(4,881,611.38)	950,949.28
227	Dec-24		835,234.89	8,047.17	7.056%		843,282.06	1,794,231.35
228	Jan-25		(383,625.06)	9,422.22	7.056%		(374,202.84)	1,420,028.51
229	Feb-25		(126,179.68)	7,978.80	7.056%		(118,200.88)	1,301,827.63
230	Mar-25		969,207.45	10,504.22	7.056%		979,711.67	2,281,539.30
231	Apr-25		1,778,261.87	18,643.54	7.056%		1,796,905.41	4,078,444.71
232	May-25		828,323.90	26,416.53	7.056%		854,740.43	4,933,185.14
233	Jun-25		460,676.56	30,361.52	7.056%		491,038.08	5,424,223.22
234	Jul-25			31,894.43	7.056%		31,894.43	5,456,117.65
235	Aug-25			32,081.97	7.056%		32,081.97	5,488,199.62
236	Sep-25			32,270.61	7.056%		32,270.61	5,520,470.23
237	Oct-25			32,460.36	7.056%		32,460.36	5,552,930.59

238

239 **History truncated for ease of viewing**

240

241 **<u>NOTES</u>**

242 **1** -Transferred June balance plus July-October interest on June balance to account 151525 for amortization.

Company:	Northwest Natural Gas Company
State:	Oregon
Description:	CPP RS Allocation Sales RTC
Account Number:	**232092**
Docket:	UM 2309

	Month/Year	Rates	Deferral	Transfers	Interest Rate	Interest	Activity	Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Beginning Balance							
1	Nov-23				6.836%	-	0.00	0.00
2	Dec-23		(3,769.57)		6.836%	(10.74)	(3,780.31)	(3,780.31)
3	Jan-24		(166,949.39)		6.836%	(497.06)	(167,446.45)	(171,226.76)
4	Feb-24		(166,563.27)		6.836%	(1,449.85)	(168,013.12)	(339,239.88)
5	Mar-24		36,970.03		6.836%	(1,827.23)	35,142.80	(304,097.07)
6	Apr-24		(145,336.46)		6.836%	(2,146.31)	(147,482.77)	(451,579.84)
7	May-24		(40,386.59)		6.836%	(2,687.53)	(43,074.12)	(494,653.96)
8	Jun-24		(86,326.07)		6.836%	(3,063.76)	(89,389.83)	(584,043.79)
9	Jul-24		(192,023.34)		6.836%	(3,874.05)	(195,897.39)	(779,941.18)
10	Aug-24		(186,380.13)		6.836%	(4,973.94)	(191,354.07)	(971,295.24)
11	Sep-24		14,335.22		6.836%	(5,492.31)	8,842.91	(962,452.33)
12	Oct-24		(68,414.71)		6.836%	(5,677.64)	(74,092.35)	(1,036,544.68)
13	Nov-24			1,036,545	7.056%	-	1,036,544.68	0.00
14	Dec-24				7.056%	-	0.00	0.00
15	Jan-25		(104,978.87)		7.056%	(308.64)	(105,287.51)	(105,287.51)
16	Feb-25		(24,046.63)		7.056%	(689.79)	(24,736.42)	(130,023.94)
17	Mar-25		(488,469.23)		7.056%	(2,200.64)	(490,669.87)	(620,693.81)
18	Apr-25		(118,131.77)		7.056%	(3,996.99)	(122,128.76)	(742,822.57)
19	May-25		(134,811.21)		7.056%	(4,764.14)	(139,575.35)	(882,397.92)
20	Jun-25		(123,777.61)		7.056%	(5,552.41)	(129,330.02)	(1,011,727.95)
21	Jul-25	*forecasted*	(80,225.86)		7.056%	(6,184.82)	(86,410.68)	(1,098,138.62)
22	Aug-25	*forecasted*	(26,468.33)		7.056%	(6,534.87)	(33,003.20)	(1,131,141.82)
23	Sep-25	*forecasted*	26,466.70		7.056%	(6,573.30)	19,893.40	(1,111,248.42)
24	Oct-25	*forecasted*	61,575.40		7.056%	(6,353.11)	55,222.29	(1,056,026.13)

EXHIBIT B

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

Purchased Gas Cost

NWN OPUC Advice No. 25-21 / UG 524

July 31, 2025

NW NATURAL

EXHIBIT B

Supporting Materials

Purchased Gas Cost

NWN OPUC ADVICE NO. 25-21 / UG 524

Commodity and Non-Commodity Costs	Page

NW Natural
2025-2026 PGA - SYSTEM: August Filing
Summary of Total Commodity Cost
ALL VOLUMES IN THERMS

OREGON COSTS

1	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
2			November	December	January	February	March	April	May	June	July	August	September	October	TOTAL
3			1	2	3	4	5	6	7	8	9	10	11	12	
4	**COSTS**														
5	**Commodity Cost from Supply**		$ 35,719,878	$46,409,437	$42,795,901	$34,010,774	$30,230,261	$19,832,404	$13,120,134	$9,397,880	$7,835,782	$7,751,360	$8,456,958	$15,524,161	$ 271,084,931
6	tab Commodity Cost from Supply, column DU, lines 101-112 plus Gen Input line D91 & P97; and														
7	tab Commodity Cost from Gas Reserve, column AG, lines 59-70														
8	**Volumetric Pipeline Charges**		$159,275	$180,423	$168,983	$148,424	$144,697	$114,156	$80,734	$58,282	$39,428	$39,058	$47,222	$90,796	$1,271,478
9	tab Commodity Cost from Vol Pipe, column F, line 78-89														
10	**Commodity Cost from Storage**		$68,139	$4,988,599	$6,483,543	$6,002,068	$4,068,600	$464,855	$0	$0	$0	$0	$0	$119,494	$22,195,298
11	tab Commodity Cost from Storage, column J, line 61-72														
12	**Commodity Cost from - Brown Gas**		$63,770	$65,897	$65,897	$59,519	$65,897	$63,770	$65,897	$63,770	$65,897	$65,897	$63,770	$65,897	$775,878
13	tab Commodity Cost from RNG, column M, line 61-72														
14	**Commodity Cost from RNG Supply/Offtakes**		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	tab Commodity Cost from RNG, column N, line 61-72														
16	**Commodity Cost from RNG RTCs**		$ 3,544,034	$ 3,535,209	$ 5,123,745	$ 5,119,899	$ 2,964,777	$ 3,020,115	$ 2,870,636	$ 2,879,718	$ 2,874,901	$ 2,885,240	$ 2,886,140	$ 2,873,855	$40,578,268
17	tab RNG RTC Costs, column L, line 1-12														
18	**Commodity Cost from Gas Reserves**		$768,544	$793,655	$792,937	$746,606	$757,991	$764,271	$777,736	$733,435	$747,870	$769,728	$752,610	$732,483	$9,137,867
19	tab Commodity Cost from Gas Reserve, column AF, line 59-70														
20	**Total Commodity Cost**		$ 40,323,639	$55,973,221	$55,431,006	$46,087,290	$38,232,223	$24,259,571	$16,915,137	$13,133,086	$11,563,877	$11,511,282	$12,206,701	$19,406,686	$ 345,043,720
21															
22	**VOLUMES**														
23	Commodity Volumes at Receipt Points		86,950,018	95,215,971	88,035,920	75,231,092	74,228,173	66,235,521	46,282,319	31,893,666	25,123,586	24,777,897	27,164,088	49,311,455	690,449,707
24	Pipeline Fuel Use		1,168,768	1,158,235	1,072,577	917,657	935,706	774,334	532,234	365,386	247,817	243,795	282,429	558,670	8,257,609
25	Gas Arriving at City Gate		85,781,250	94,057,736	86,963,343	74,313,435	73,292,467	65,461,187	45,750,085	31,528,280	24,875,769	24,534,103	26,881,659	48,752,785	682,192,098
26															
27	Brown Gas and Storage Gas Withdrawals		378,930.80	23,321,204	29,612,625	27,537,965	19,101,879	2,395,842	142,019	137,438	142,019	142,019	137,438	768,201	103,817,582
28	RNG Supply/Offtakes		-	-	-	-	-	-	-	-	-	-	-	-	0
29	Pipeline Fuel Use for Off-Site Storage		-	5,571	-	578	4,444	1,491	-	-	-	-	-	870	12,955
30	Storage Gas Deliveries at City Gate		378,931	23,315,633	29,612,625	27,537,387	19,097,435	2,394,351	142,019	137,438	142,019	142,019	137,438	767,331	103,804,626
31															
32	Total Gas At City Gate (Storage and Commodity)		86,160,181	117,373,369	116,575,968	101,850,822	92,389,902	67,855,538	45,892,104	31,665,718	25,017,788	24,676,122	27,019,097	49,520,116	785,996,725
33															
34	Unaccounted for Gas		774,858	849,620	785,536	671,270	662,048	591,309	413,258	284,794	224,702	221,615	242,821	440,382	6,162,213
35															
36	Load Served		85,385,323	116,523,749	115,790,432	101,179,552	91,727,854	67,264,229	45,478,846	31,380,924	24,793,086	24,454,507	26,776,276	49,079,734	779,834,512

NW Natural
2025-2026 PGA - SYSTEM: August Filing
Summary of Total Commodity Cost
ALL VOLUMES IN THERMS

WACOG Calculations

37	**Gas Reserves Supply:**													
38	Total cost (line 20 above)	$768,544	$793,655	$792,937	$746,606	$757,991	$764,271	$777,736	$733,435	$747,870	$769,728	$752,610	$732,483	$9,137,867
39	Load served by gas reserves	1,565,011	1,606,189	1,595,424	1,431,483	1,574,472	1,513,803	1,554,222	1,494,524	1,534,614	1,525,034	1,466,705	1,506,292	18,367,773
40														
41	**Total Load Served**													
42	Oregon	85,385,323	116,523,749	115,790,431	101,179,551	91,727,854	67,264,230	45,478,846	31,380,925	24,793,086	24,454,506	26,776,275	49,079,734	779,834,510
43	Total (same as line 36 +/- rounding)	85,385,323	116,523,749	115,790,431	101,179,551	91,727,854	67,264,230	45,478,846	31,380,925	24,793,086	24,454,506	26,776,275	49,079,734	779,834,510
44														
45	**Oregon WACOG Calculation**													
46														
47	Total Oregon commodity cost	$40,323,639	$55,973,221	$55,431,006	$46,087,290	$38,232,223	$24,259,571	$16,915,137	$13,133,086	$11,563,877	$11,511,282	$12,206,701	$19,406,686	$345,043,720
48	Total commodity cost for Oregon	$40,323,639	$55,973,221	$55,431,006	$46,087,290	$38,232,223	$24,259,571	$16,915,137	$13,133,086	$11,563,877	$11,511,282	$12,206,701	$19,406,686	$345,043,720
49														
50	**Oregon Sales WACOG (line 48 ÷ line 42)**	$0.47225	$0.48036	$0.47872	$0.45550	$0.41680	$0.36066	$0.37193	$0.41851	$0.46642	$0.47072	$0.45588	$0.39541	$0.44246
51														
52	**OREGON BILLING WACOG**	$0.48695	$0.49531	$0.49362	$0.46967	$0.42977	$0.37188	$0.38350	$0.43153	$0.48093	$0.48537	$0.47007	$0.40771	$0.45623

NW Natural
2025-2026 PGA - SYSTEM: August Filing
Summary of Total Demand Charges

SYSTEM COSTS

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		November	December	January	February	March	April	May	June	July	August	September	October	TOTAL
		30	31	31	28	31	30	31	30	31	31	30	31	365
Transport charges by transporter:														
Northwest Pipeline		$4,018,544	$4,152,496	$4,152,496	$3,750,641	$4,152,496	$3,927,859	$4,058,788	$3,927,859	$4,058,788	$4,058,788	$3,927,859	$4,058,788	$48,245,402
Alberta: NOVA		867,774	867,774	867,774	867,774	867,774	867,774	867,774	867,774	867,774	867,774	867,774	867,774	10,413,290
Alberta: Foothills		504,042	504,042	504,042	504,042	504,042	449,899	449,899	449,899	449,899	449,899	449,899	504,042	5,723,646
Alberta: GTN		404,282	417,758	417,758	377,330	417,758	340,228	351,569	340,228	351,569	351,569	340,228	417,758	4,528,034
BC: Southern Crossing														0
BC: Spectra (Westcoast)		3,191,632	702,082	702,082	670,732	702,082	1,295,877	1,314,117	1,295,877	1,314,117	1,314,117	1,295,877	1,314,117	15,112,709
KB Pipeline		18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	224,258
Shell Capacity Release Premium		(424,043)	(424,043)	(424,043)	(424,043)	(424,043)	(424,043)	(424,043)	(424,043)	(424,043)	(424,043)	(424,043)	(424,043)	(5,088,518)
Total System Demand		**$8,580,920**	**$6,238,797**	**$6,238,797**	**$5,765,165**	**$6,238,797**	**$6,476,282**	**$6,636,792**	**$6,476,282**	**$6,636,792**	**$6,636,792**	**$6,476,282**	**$6,757,124**	**$79,158,822**

NW Natural

2025-2026 PGA - SYSTEM: August Filing

Derivation of Oregon per therm Non-Commodity Charges

ALL VOLUMES IN THERMS

Oregon Derivation of Demand Increments

1			Without	WITH
2			Revenue Sensitive	Revenue Sensitive
3	(a)	(b)	(c)	(d)
4	System Demand		$79,158,822	
5	Oregon Allocation Factor 1/		88.88%	
6	Oregon Demand		$71,260,897	
7				
8	Oregon Firm Sales Forecasted Normal Volumes		726,491,658	
9	Oregon Interruptible Sales Forecasted Normal Volumes		53,342,852	
10				
11				
12	Proposed Firm Demand Per Therm 2/		$0.09724	$0.10027
13	Proposed Interruptible Demand 2/		$0.01157	$0.01193
14	Proposed MDDV Demand Charge		$1.43	$1.47
15				
16	Current Firm Demand Per Therm		$0.09962	$0.10274
17	Current Interruptible Demand		$0.01185	$0.01222
18	Current MDDV Demand Charge		$1.47	$1.52
19				
20	Percent Change in Firm Demand		-2.39%	
21				
22				
23	1/Allocation Factor: 2024-25 PGA forecast firm sales volumes:			
24		Washington	Oregon	System
25	Firm Sales	90,908,754	726,491,658	817,400,413
26		11.12%	88.88%	100.00%
27				
28	2/Calculation of Proposed Demand Rates:			
29				
30	Demand change factor		0.976	
31				
32	Firm Demand (line 16 * line 30)		$0.09724	$70,643,887
33	Interruptible Demand (line 17 * line 30)		$0.01157	$617,010
34				$71,260,897
35				$0.00

NW Natural

2025-2026 PGA - SYSTEM: August Filing

Calculation of Winter WACOG

Prices are per therm

1	Forecast price for AECO gas:			
2				
3		AECO/NIT		
4				
5	November	$0.23917		
6	December	$0.27175		
7	January	$0.27922		
8	February	$0.28031		
9	March	$0.25182		
10	April	$0.23369		
11	May	$0.22743		
12	June	$0.23210		
13	July	$0.23611		
14	August	$0.23781		
15	September	$0.23905		
16	October	$0.25310		
17				
18				
19	Average price, November-March		$0.26445	average lines 5-9
20				
21	Annual average price, November-October		$0.24846	average lines 5-16
22				
23	Ratio of winter to annual		1.06436	line 19 ÷ line 21
24				
25			Without Rev	WITH Rev
26			Sensitive	Sensitive
OR	Oregon Annual WACOG		$0.44246	$0.45623
OR	Oregon Winter WACOG		$0.47094	$0.48560
			line 23 * $0.44246	

NW Natural
2025-2026 PGA - OREGON: August Filing
Derivation of Oregon Seasonalized Fixed Charges

OREGON:

		Normalized Residential Volumes	Normalized Commercial Volumes	Firm Industrial Volumes	Interruptible Volumes	Total	Firm Demand Increment Eff. 11/01/25	Interr. Demand Increment Eff. 11/01/25	Seasonalized Fixed Charges
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
November	2025	49,295,017	27,650,535	3,701,333	4,738,438	85,385,323	$0.09724	$0.01157	$7,896,890
December	2025	68,697,629	38,909,428	3,796,957	5,119,734	116,523,749	$0.09724	$0.01157	$10,892,111
January	2026	68,648,665	38,513,585	3,729,875	4,898,306	115,790,431	$0.09724	$0.01157	$10,839,774
February	2026	57,404,239	34,700,302	3,727,239	5,347,771	101,179,551	$0.09724	$0.01157	$9,380,513
March	2026	50,073,110	32,738,912	3,575,171	5,340,661	91,727,854	$0.09724	$0.01157	$8,462,043
April	2026	35,283,375	23,781,110	3,329,246	4,870,499	67,264,230	$0.09724	$0.01157	$6,123,490
May	2026	21,154,995	16,834,456	2,945,453	4,543,941	45,478,846	$0.09724	$0.01157	$4,033,065
June	2026	13,713,112	11,148,542	2,671,948	3,847,322	31,380,925	$0.09724	$0.01157	$2,721,869
July	2026	10,299,729	8,652,482	2,531,105	3,309,770	24,793,086	$0.09724	$0.01157	$2,127,322
August	2026	9,930,211	8,527,119	2,532,970	3,464,206	24,454,506	$0.09724	$0.01157	$2,081,168
September	2026	11,320,226	9,143,565	2,750,432	3,562,053	26,776,275	$0.09724	$0.01157	$2,298,553
October	2026	25,619,639	16,061,109	3,098,835	4,300,151	49,079,734	$0.09724	$0.01157	$4,404,099
		421,439,949	266,661,145	38,390,564	53,342,852	779,834,510			$71,260,897

	Encana Gas Reserves Deal		Projected November 2025	Projected December 2025	Projected January 2026	Projected February 2026	Projected March 2026	Projected April 2026	Projected May 2026	Projected June 2026	Projected July 2026	Projected August 2026	Projected September 2026	Projected October 2026	Projected PGA Totals
1	**Therms Delivered (000s)**														
2	**Total Therms**		1,508.32	1,548.01	1,537.64	1,379.64	1,517.46	1,459.00	1,497.96	1,440.43	1,479.08	1,469.86	1,413.64	1,451.81	17,702.84
3	**Rate per Therm (Depletion Rate)**		0.13556	0.13556	0.13556	0.13556	0.13556	0.13556	0.13556	0.13556	0.13556	0.13556	0.13556	0.13556	0.13556
4	**Delivery Value**		204.47	209.85	208.45	187.03	205.71	197.79	203.07	195.27	200.51	199.26	191.64	196.81	2,399.85
5															0.1356
6	**Opex / Severance / Ad Valorem**														
7	**Operating Cost**		399.27	401.06	400.38	392.21	397.22	421.67	431.68	396.15	397.85	421.91	417.06	392.92	4,869.38
8	**Severance and Ad Valorem Taxes**		79.90	108.38	112.48	92.16	71.14	58.41	56.19	57.77	70.02	70.42	66.25	65.05	908.17
9	**Total**		479.17	509.44	512.86	484.38	468.36	480.08	487.87	453.92	467.87	492.33	483.31	457.97	5,777.55
10															0.3264
11	**Average Rate Base**		12,363.08	12,208.67	12,055.30	11,917.68	11,766.32	11,620.79	11,471.37	11,327.69	11,180.15	11,033.54	10,892.53	10,747.71	
12															
13	**Carrying Cost**														
14	**Equity**	**9.4000%**	48.42	47.82	47.22	46.68	46.08	45.51	44.93	44.37	43.79	43.21	42.66	42.10	
15	**Equity % of Cap Struct**	**50.0000%**													
16	**Equity Pretax**	**26.4193%**	37.42	26.48	24.21	30.69	37.36	41.11	41.10	39.77	34.64	33.71	34.44	34.10	
17	**Debt**	**4.2710%**	22.00	21.73	21.45	21.21	20.94	20.68	20.41	20.16	19.90	19.64	19.38	19.13	
18	**Total Carrying Cost**		59.42	48.21	45.66	51.90	58.30	61.79	61.51	59.93	54.53	53.35	53.83	53.23	661.66
19															0.0374
20	**Total Cost**		743.06	767.50	766.97	723.31	732.37	739.65	752.45	709.12	722.91	744.93	728.77	708.01	8,839.05
21	**Total Volume**		1,508.32	1,548.01	1,537.64	1,379.64	1,517.46	1,459.00	1,497.96	1,440.43	1,479.08	1,469.86	1,413.64	1,451.81	17,702.84
22	**Total Rate Per Therm**		0.493	0.496	0.499	0.524	0.483	0.507	0.502	0.492	0.489	0.507	0.516	0.488	0.499

Non-Carry Wells Gas Reserves Deal		**Projected November 2025**	**Projected December 2025**	**Projected January 2026**	**Projected February 2026**	**Projected March 2026**	**Projected April 2026**	**Projected May 2026**	**Projected June 2026**	**Projected July 2026**	**Projected August 2026**	**Projected September 2026**	**Projected October 2026**	**Projected PGA Totals**
Therms Delivered (000s)														
Total Therms		58.87	60.42	60.01	53.83	59.20	56.91	58.43	56.17	57.67	57.30	55.10	56.58	690.50
Rate per Therm (Depletion Rate)		0.3535	0.3535	0.3535	0.3535	0.3535	0.3535	0.3535	0.3535	0.3535	0.3535	0.3535	0.3535	0.3535
Delivery Value		20.81	21.36	21.21	19.03	20.93	20.12	20.66	19.86	20.39	20.26	19.48	20.00	244.11
														0.3535
Opex / Severance / Ad Valorem														
Operating Cost		14.62	14.72	14.70	14.40	14.54	15.11	15.36	14.48	14.54	15.13	15.03	14.42	177.05
Severance and Ad Valorem Taxes		3.12	4.23	4.39	3.60	2.78	2.28	2.19	2.25	2.73	2.75	2.58	2.54	35.43
Total		17.74	18.95	19.09	17.99	17.31	17.39	17.55	16.73	17.27	17.88	17.62	16.95	212.48
														0.3077
Average Rate Base		1,141.49	1,125.77	1,110.16	1,096.16	1,080.76	1,065.95	1,050.76	1,036.14	1,021.14	1,006.24	991.90	977.18	
Carrying Cost														
Equity	**9.4000%**	4.47	4.41	4.35	4.29	4.23	4.17	4.12	4.06	4.00	3.94	3.88	3.83	
Equity % of Cap Struct	**50.0000%**													
Equity Pretax	**26.4193%**	6.08	5.99	5.91	5.83	5.75	5.67	5.59	5.52	5.44	5.36	5.28	5.20	
Debt	**4.5290%**	2.15	2.12	2.09	2.07	2.04	2.01	1.98	1.96	1.93	1.90	1.87	1.84	
Total Carrying Cost		8.23	8.12	8.00	7.90	7.79	7.69	7.58	7.47	7.36	7.25	7.15	7.05	91.59
														0.1326
Total Cost		46.79	48.42	48.31	44.93	46.04	45.19	45.78	44.06	45.02	45.39	44.25	44.00	548.18
Total Volume		58.87	60.42	60.01	53.83	59.20	56.91	58.43	56.17	57.67	57.30	55.10	56.58	690.50
Total Rate Per Therm[1]		0.47250	0.47250	0.47250	0.47250	0.47250	0.47250	0.47250	0.47250	0.47250	0.47250	0.47250	0.47250	0.794

[1] Per Order 15-297

NW Natural
Rates & Regulatory Affairs
2025-26 PGA - Oregon: August Filing
Attachment C: 3% Test

Non-Gas Cost Amortizations [1]	**Surcharge**	**Credit**
WARM	$ 10,249,418	
Oregon Regulatory Fee	$ 182,566	
CAT Incremental		$ (96,683)
Net Curtailment and Entitlment		$ (332,625)
RNG Transport Allocation	$ 422,876	
Rate Mitigation	$ 63,389	
TSA Cost of Service	$ 1,095,891	
TSA O&M	$ -	
Residual Balances	12,723	
Lincoln City Sale		$ (124,864)
Total	$ 12,026,863	$ (554,172)
Net Proposed Amortizations (subject to the 3% test)		$ 11,472,691
Utility Gross Revenues (2024) [2]		$927,293,034
3% of Utility Gross Revenues		$ 27,818,791
Allowed Amortization		$ 11,472,691
Allowed Amortization as % of Gross Revenues		1.2%

Notes:

[1] Amortizations that are automatic adjustment clauses are not subject to the 3% test pursuant to ORS 757.259

[2] Unadjusted general revenues as shown in the most recent Results of Operations.

NW Natural
Rates & Regulatory Affairs
2025-26 PGA - Oregon: August Filing
Effects on Average Bill by Rate Schedule [1]
ALL VOLUMES IN THERMS

Advice 25-21
See note [15]

1			Oregon PGA		Normal				Proposed	Proposed	Proposed
2			Normalized		Therms	Minimum	11/1/2024	11/1/2024	10/31/2025	10/31/2025	10/31/2025
3			Volumes page,	Therms in	Monthly	Monthly	Billing	Current	Schedule 164 PGA	Schedule 164 PGA	**Schedule 164 PGA**
4			Column D	Block	Average use	Charge	Rates	Average Bill	Rates	Average Bill	**% Bill Change**
5								**F=D+(C * E)**		**AO = D+(C*AN)**	**AP = (AO-F)/F**
6	Schedule	Block	**A**	**B**	**C**	**D**	**E**	**F**	**AN**	**AO**	**AP**
7	2SF		374,907,494	N/A	54	$10.00	$1.33108	$81.88	$1.35109	$82.96	1.3%
	2MF		46,532,455	N/A	54	$8.00	$1.33108	$79.88	$1.35109	$80.96	1.4%
8	3C Firm Sales		191,560,213	N/A	270	$15.00	$1.18176	$334.08	$1.20177	$339.48	1.6%
9	3I Firm Sales		4,897,917	N/A	1,204	$15.00	$1.05417	$1,284.22	$1.07418	$1,308.31	1.9%
10	27 Dry Out		739,110	N/A	36	$8.00	$1.17668	$50.36	$1.19669	$51.08	1.4%
11	31C Firm Sales	Block 1	12,710,926	2,000	2,744	$325.00	$0.74499	**$2,346.69**	$0.86774	**$2,683.52**	14.4%
12		Block 2	11,231,948	all additional			$0.71467		$0.83742		
13	31C Firm Trans	Block 1	1,171,263	2,000	3,753	$575.00	$0.31490	**$1,709.33**	$0.31490	**$1,709.33**	0.0%
14		Block 2	1,305,394	all additional			$0.28781		$0.28781		
15	31I Firm Sales	Block 1	3,428,826	2,000	5,162	$325.00	$0.72950	**$4,008.94**	$0.85225	**$4,642.58**	15.8%
16		Block 2	7,225,968	all additional			$0.70365		$0.82640		
17	31I Firm Trans	Block 1	12,735	2,000	729	$575.00	$0.26830	**$770.59**	$0.26830	**$770.59**	0.0%
18		Block 2	31,024	all additional			$0.24243		$0.24243		
19	32C Firm Sales	Block 1	36,364,305	10,000	7,489	$675.00	$0.65293	**$5,564.79**	$0.77568	**$6,484.07**	16.5%
20		Block 2	11,181,417	20,000			$0.62396		$0.74671		
21		Block 3	1,968,034	20,000			$0.57579		$0.69854		
22		Block 4	888,550	100,000			$0.52745		$0.65020		
23		Block 5	16,644	600,000			$0.49273		$0.61548		
24		Block 6	0	all additional			$0.47626		$0.59901		
25	32I Firm Sales	Block 1	8,628,593	10,000	9,861	$675.00	$0.60345	**$6,625.62**	$0.72620	**$7,836.06**	18.3%
26		Block 2	7,972,562	20,000			$0.58223		$0.70498		
27		Block 3	2,916,083	20,000			$0.54675		$0.66950		
28		Block 4	2,877,605	100,000			$0.51141		$0.63416		
29		Block 5	443,011	600,000			$0.48672		$0.60947		
30		Block 6	0	all additional			$0.47429		$0.59704		
31	32C Firm Trans	Block 1	2,769,074	10,000	19,258	$925.00	$0.14137	**$3,449.47**	$0.14137	**$3,449.47**	0.0%
32		Block 2	2,051,764	20,000			$0.11998		$0.11998		
33		Block 3	656,440	20,000			$0.08442		$0.08442		
34		Block 4	951,036	100,000			$0.04883		$0.04883		
35		Block 5	42,214	600,000			$0.02745		$0.02745		
36		Block 6	0	all additional			$0.01327		$0.01327		
37	32I Firm Trans	Block 1	11,405,325	10,000	73,016	$925.00	$0.13314	**$7,174.60**	$0.13314	**$7,174.60**	0.0%
38		Block 2	16,248,048	20,000			$0.11308		$0.11308		
39		Block 3	9,930,036	20,000			$0.07964		$0.07964		
40		Block 4	21,832,878	100,000			$0.04622		$0.04622		
41		Block 5	22,413,473	600,000			$0.02609		$0.02609		
42		Block 6	7,541,214	all additional			$0.01279		$0.01279		
43	32C Interr Sales	Block 1	4,420,212	10,000	29,363	$675.00	$0.61838	**$18,374.36**	$0.63563	**$18,880.88**	2.8%
44		Block 2	6,619,668	20,000			$0.59472		$0.61197		
45		Block 3	3,569,981	20,000			$0.55521		$0.57246		
46		Block 4	5,246,915	100,000			$0.51568		$0.53293		
47		Block 5	3,398,942	600,000			$0.49198		$0.50923		
48		Block 6	0	all additional			$0.47465		$0.49190		
49	32I Interr Sales	Block 1	4,783,726	10,000	27,552	$675.00	$0.59896	**$16,815.80**	$0.61621	**$17,291.07**	2.8%
50		Block 2	6,385,368	20,000			$0.57835		$0.59560		
51		Block 3	3,622,167	20,000			$0.54400		$0.56125		
52		Block 4	10,367,186	100,000			$0.50962		$0.52687		
53		Block 5	4,928,689	600,000			$0.48899		$0.50624		
54		Block 6	0	all additional			$0.47389		$0.49114		
55	32C Interr Trans	Block 1	780,580	10,000	199,264	$925.00	$0.12838	**$11,569.70**	$0.12838	**$11,569.70**	0.0%
56		Block 2	1,586,918	20,000			$0.10895		$0.10895		
57		Block 3	1,034,205	20,000			$0.07661		$0.07661		
58		Block 4	3,340,006	100,000			$0.04425		$0.04425		
59		Block 5	431,793	600,000			$0.02486		$0.02486		
60		Block 6	0	all additional			$0.01194		$0.01194		
61	32I Interr Trans	Block 1	5,825,488	10,000	198,962	$925.00	$0.12678	**$11,474.60**	$0.12678	**$11,474.60**	0.0%
62		Block 2	9,678,292	20,000			$0.10765		$0.10765		
63		Block 3	6,123,269	20,000			$0.07583		$0.07583		
64		Block 4	14,253,538	100,000			$0.04395		$0.04395		
65		Block 5	29,505,433	600,000			$0.02486		$0.02486		
66		Block 6	96,966,741	all additional			$0.01213		$0.01213		
67	33		0	N/A	0.0	$38,000.00	$0.00465	$38,000.00	$0.00465	$38,000.00	
68	Special Contracts		74,098,618	N/A	0	$0	$0.00000	$0.00	$0.00000	$0.00	
69											
70	**Totals**		**1,121,821,307**								

NW Natural
Rates and Regulatory Affairs
2025-2026 PGA Filing - OREGON
Basis for Revenue Related Costs

Line		Twelve Months Ended 06/30/25		
1				
2				
3	Total Billed Gas Sales Revenues	$ 947,586,013		
4	Total Oregon Revenues	$ 952,494,446		
5				
6	Regulatory Commission Fees [1]	n/a	0.450%	Statutory rate
7	City License and Franchise Fees	$ 22,248,348	2.336%	Line 7 ÷ Line 4
8	Net Uncollectible Expense [2]	$ 2,209,884	0.232%	Line 8 ÷ Line 4
9				
10	Total		**3.018%**	Sum lines 6-8
11				
12				

13 **Note:**
14 [1] Dollar figure is set at statutory level of 0.450% times Total Oregon Revenues (line 4).
15 Because the fee changed since our last general rate case, the difference between the previous fee of 0.430%
16 and the new fee of 0.450%, as it affects our base rates, is being captured as a temporary deferral.
17 [2] Represents the normalized net write-offs based on a three-year average.

NW Natural
Rates & Regulatory Affairs
2025-2026 PGA Filing - Oregon: August Filing
PGA Effects on Revenue
Schedule 164: PGA Gas Costs and Gas Cost Deferrals

Line		Including Revenue Sensitive Amount
1		
2		
3	**Purchased Gas Cost Adjustment (PGA)**	
4		
5	Commodity Cost Change	$17,658,089
6		
7	Demand Capacity Cost Change	855,360
8		
9	**Total Gas Cost Change**	**18,513,449**
10		
11	**Temporary Increments**	
12		
13	Removal of Current Temporary Increments	
14	Amortization of 191.xxx Account Gas Costs	26,750,543
15		
16	Addition of Proposed Temporary Increments	
17	Amortization of 191.xxx Account Gas Costs	(27,735,955)
18		
19	**Net Temporary Rate Adjustment**	**(985,412)**
20		
21	**TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES**	**$17,528,037**
22		
23	2024 Oregon Earnings Test Normalized Total Revenues	$939,254,783
24		
25	Effect of this filing, as a percentage change (line 21 ÷ line 23)	1.87%
26		
27	Effect of this filing, as a percentage change (line 19 ÷ line 23)	-0.10%
28		
29	Effect of this filing, as a percentage change (line 9 ÷ line 23)	1.97%

EXHIBIT C

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

Purchased Gas Cost

REDACTED

NWN OPUC Advice No. 25-21 / UG 524

July 31, 2025

GUIDELINE REFERENCE	DATA REQUIREMENT	Page No.	STATUS
IV	General Information and Forecasting		
1	General Information		
a)	Definitions of all major terms and acronyms in the data and information provided.	4	
b)	Any significant new regulatory requirements identified by the utility that in the utility's judgment directly impacts the Oregon portfolio design, implementation, or assessment.	6	
c)	All forecasts of demand, weather, etc. upon which the gas supply portfolio for the current PGA filing is based should be based on a methodology and data sources that are consistent with the most recently acknowledged IRP or IRP update for the utility. If the methodology and/or data sources are not consistent each difference should be identified, explained, and documented as part of the PGA filing workpapers.	6	
2	Workpapers		
a)	PGA Summary Sheet	7	
b)	Gas Supply Portfolio and Related Transportation		
1	Summary of portfolio planning	9	
2	LDC sales system demand forecasting	10	
3	Natural gas price forecasts	10	
4	Physical resources for the portfolio	10	
	Supporting Tables	14-17	
5	Financial resources for the portfolio (derivatives and other financial arrangements).	13	
6	Storage resources.	13	
7	Forecasted annual and peak demand used in the current PGA portfolio, with and without programmatic and non-programmatic demand response, with explanation.	17	
8	Forecasted annual and peak demand used in the current PGA portfolio, with and without effects from gas supply incentive mechanisms, with explanation.	17	
9	Summary of portfolio documentation provided	17	
V.1	**Physical Gas Supply**		**HIGHLY CONFIDENTIAL**
a)	For each physical natural gas supply resource that is included in a utility's portfolio (except spot purchases) upon which the current PGA is based, the utility should provide the following:	18	
1	Pricing for the resource, including the commodity price and, if relevant, reservation charges.	18	
2	For new transactions and contracts with pricing provisions entered into since the last PGA: competitive bidding process for the resource. This should include number of bidders, bid prices, utility decision criteria in selecting a "winning" bid, and any special pricing or delivery provisions negotiated as part of the bidding process.	18	

GUIDELINE REFERENCE	DATA REQUIREMENT	Page No.	STATUS
3	Brief explanation of each contract's role within the portfolio.	18	
b)	For purchases of physical natural gas supply resource from the spot natural gas market included in the portfolio at the time of the filing of the current PGA or after that filing, the utility should provide the following:	20	
1	An explanation of the utility's spot purchasing guidelines, the data/information generally reviewed and analyzed in making spot purchases, and the general process through which such purchases are completed by the utility.	20	
2	Any contract provisions that materially deviate from the standard NAESB contract.	21	
V.2	**Hedging**		
	The utility should clearly identify by type, contract, counterparty, and pricing point both the total cost and the cost per volume unit of each financial hedge included in its portfolio.	22	**HIGHLY CONFIDENTIAL**
V.3	**Load Forecasting**		
a)	Customer count and revenue by month and class.	23	
b)	Historical (five years) and forecasted (one year ahead) sales system physical peak demand.	24	
c)	Historical (five years), and forecasted (one year ahead) sales system physical annual demand.	24	
d)	Historical (five years), and forecasted (one year ahead) sales system physical demand for each of following,	24	
1	Annual for each customer class	24	
2	Annual and monthly baseload.	24	
3	Annual and monthly non-baseload.	24	
4	Annual and monthly for the geographic regions utilized by each LDC in its most recent IRP or IRP update.	25	
V.4	**Market Information**		
	General historical and forecasted (one year ahead) conditions in the national and regional physical and financial natural gas purchase markets. This should include descriptions of each major supply point from which the LDC physically purchases and the major factors affecting supply, prices, and liquidity at those points.	26	
V.5	**Data Interpretation**		
	If not included in the PGA filing, please explain the major aspects of the LDC's analysis and interpretation of the data and information described in (1) and (2) above, the most important conclusions resulting from that analysis and interpretation, and the application of these conclusions in the development of the current PGA portfolio.	31	

GUIDELINE REFERENCE	DATA REQUIREMENT	Page No.	STATUS
V.6	**Credit Worthiness Standards**		
	A copy of the Board or officer approved credit worthiness standards in place for the period in which the current gas supply portfolio was developed, along with full documentation for these standards. Also, a copy of the credit worthiness standards actually applied in the purchase of physical gas and entering into financial hedges. If the two are one and the same, please indicate so.	32	
	NW Natural Gas Supply Risk Management Policies	33	CONFIDENTIAL
V.7	**Storage**		
	Workpapers should include the following information about natural gas storage included in the portfolio upon which that PGA is based.	74	
a)	Type of storage (e.g., depleted field, salt dome).	74	
b)	Location of each storage facility.	74	
c)	Total level of storage in terms of deliverability and capacity held during the gas year.	74	
d)	Historical (five years) gas supply delivered to storage, both annual total and by month.	74	
e)	Historical (five years) gas supply withdrawn from storage, both annual total and by month.	74	
f)	An explanation of the methodology utilized by the LDC to price storage injections and withdrawals, as well as the total and average (per unit) cost of storage gas.	76	
g)	Copies of all contracts or other agreements and tariffs that control the LDC's use of the storage facilities included in the current portfolio.	76	
h)	For LDCs that own and operate storage:		
a.	The date and results of the last engineering study for that storage.	91	CONFIDENTIAL
b.	A description of any significant changes in physical or operational parameters of the storage facility (including LNG) since the current engineering study was completed.	108	CONFIDENTIAL
V.8	**Attestation as to Consistency**	112	

Section IV. General Information and Forecasting

1. General Information

a) Definitions of all major terms and acronyms in the data and information provided.

AECO	The industry acronym used for Alberta sourced natural gas supply. It originally comes from Alberta Energy Company which was incorporated in 1973 by the Alberta government (fully divested in 1993).
Base Load gas (contract)	Purchase agreements in which NW Natural has to take a set amount of gas each day from a supplier for the term of the agreement. Usually involves paying for any gas not taken unless excused by reason of Force Majeure.
Base Rate	The portion of rates that does not change outside of a general rate case, except as allowed through a Commission approved base rate adjustment.
Base Rate Adjustment	A permanent adjustment to rates approved by the Commission outside of a general rate case process.
Btu	British thermal unit. 100,000 Btus is equivalent to one therm.
CGPR	Canadian Gas Price Reporter. This is the industry publication in Canada that is put out by Canadian Enerdata Ltd and is the exclusive source of Canadian natural gas storage and price forecasts and publishes first of month Canadian indices used in baseload purchase pricing.
Collar	Financial hedges that set ceiling and floor values on the price of gas purchases.
Commodity Component	The Tariff term used to refer to the cost of gas component of a customer’s billing rate, and which will equal either (a) the Annual Sales WACOG, (b) the Winter Sales WACOG, or (c) the Monthly Incremental Cost of Gas.
Dth	Dekatherm. A unit of measure equal to 10 therms or one million Btu.
Demand [Charge]	The term used to refer to Pipeline Capacity related costs.
Derivative products	Financial transactions related to gas supply, including but not limited to hedges, swaps, puts, calls, options and collars that are exercised to provide price stability/control or supply reliability for sales service customers.
EIA	U.S. Energy Information Administration
FERC	Federal Energy Regulatory Commission
Financial swaps	Transactions that involve an exchange of cash flows with a counterparty.

Financially hedged	Purchases that have associated financial swaps such that the price of the gas is fixed for a pre-determined period of time.
FOM	First of Month
Fuel-in-Kind (KIG)	The published fuel rate calculated based on the amount of fuel used on each pipeline to run the compressors and other equipment to move gas across their pipes. Fuel is taken in kind from all receipt shippers by reducing each shippers daily volumes in accordance to the pipelines estimated fuel requirements.
GMR-NWP Rockies	Inside FERC's Gas Market Report, a publication put out by Platts (a McGraw-Hill subsidiary) that is the source used for price forecasts and indices that used to set US baseload and some daily purchase prices.
IRP	Integrated Resource Plan
MDDV	Maximum Daily Delivery Volume
NWP	Northwest Pipeline
Off-system storage	Storage facilities located outside NW Natural’s service territory.
On-system storage	Storage facilities located inside NW Natural’s service territory.
PGA	Purchased Gas Adjustment
Peak day	The day in which volumes distributed or sold by NW Natural are at a maximum. May be theoretical (the “design day”) or actual.
Pipeline Capacity	The quantity (volume) of natural gas available on the interstate pipeline for the transportation of gas supplies to the Company's distribution system. Pipeline Capacity related costs are often referred to as "Demand".
RNG	Renewable Natural Gas (“RNG”)
Recallable gas supply/capacity	Refers to arrangements that allow NW Natural to use the upstream pipeline capacity and gas supplies held by third parties.
Revenue Sensitive	The amount by which rates are adjusted to reflect the effects of revenue related costs, such as uncollectible expense, regulatory fees, and city license and franchise fees.
Swing gas (contract)	Purchase agreements in which NW Natural has the right, but not the obligation, to take gas from a supplier on any given day.
Technical Rate Adjustments	Also referred to as Temporary Rate Adjustments.
Therm	A unit of heating value equivalent to 100,000 Btus. The amount of heat energy in approximately 100 cubic feet of Natural Gas.
Total Commodity Cost	The combined costs for all purchased gas supplies, excluding transportation costs.

Total Gas Cost	The combined costs of all purchased gas supplies and associated transportation costs.
Transportation Cost	The combined costs for all pipeline related demand, capacity or reservation charges.
Transportation Resources	The various upstream pipeline capacity agreements held by the company.
Upstream pipeline	Those pipelines that collect natural gas from the areas where it is produced in the British Columbia, Alberta and the U.S. Rocky Mountain supply regions and transport that gas to NW Natural's service territory.
Upstream pipeline capacity	Refers to the rights that NW Natural has obtained to transport gas on upstream pipelines.
WACOG	The Company's weighted average commodity cost of gas (excluding transportation cost), also referred to as Annual Sales WACOG.
Winter Sales WACOG	The Company's winter period weighted average commodity cost of gas (excluding transportation cost).

b) Any significant new regulatory requirements identified by the utility that in the utility's judgment directly impacts the Oregon portfolio design, implementation, or assessment.

There is one new source of regulatory requirements: 1) the reinstatement of the Climate Protection Program as of December 2024.

c) All forecasts of demand, weather, etc. upon which the gas supply portfolio for the current PGA filing is based should be based on a methodology and data sources that are consistent with the most recently acknowledged IRP or IRP update for the utility. If the methodology and/or data sources are not consistent each difference should be identified, explained, and documented as part of the PGA filing workpapers.

And

Attestation of verification of consistency

In accordance with the PGA Portfolio Guidelines at Section IV(1)(c), the Company acknowledges that all forecasts of demand, weather, etc., upon which the gas supply portfolio for this PGA filing is based, uses the methodology and data sources that are consistent with the Company's most recent 2022 IRP as well as its most recent Oregon rate case (UG 520).

Note, also that the supply portfolio for this PGA is based on a demand side management (DSM) savings forecast that is consistent with the forecast used in the 2022 IRP.

2. Workpapers

a) PGA Summary

NW Natural
Rates & Regulatory Affairs
2025-26 PGA - Oregon: August Filing
Attachment E: PGA Summary

	Amount	Location in Company Filing (cite)
1) Change in Annual Revenues		
(Per OAR 860-022-0017(3)(a))		
A) Dollars *(To .1 million)*	$49,313,875	Refer to workpaper "2025-26 PGA filing Summary Effects"
B) Percent *(To .1 percent)*	5.25%	"
2) Annual Revenues Calculation *(Whole Dollars)*		
A) PGA Cost Change *(Commodity & Transportation)*	18,513,449	Refer to workpaper "2025-26 PGA filing Summary Effects"
B) Remove Last Year's Temporary Increment Total	13,168,303	"
C) Add New Temporary Increment	18,808,295	"
D) Remove Last Year's Permanent Increment Total	(5,804,847)	
E) Add New Permanent Increment Total	4,628,676	
E) Total Proposed Change	49,313,875	Refer to workpaper "2025-26 PGA filing Summary Effects"
3) Residential Bill Effects Summary		
A) Residential Schedule 2 Rate Impacts		
1) Current Billing Rate per Therm	$1.33108	Refer to workpaper '2025-2026 PGA Rate Development'
2) Proposed Billing Rate per Therm	$1.39118	"
3) Rate Change Per Therm	$0.06010	"
4) Percent Change per Therm *(to .1%)*	$0.04515	"
B) Average Residential Bill Impact (forecasted weather-normalized annual)		
1) Average Residential Monthly Use	54.0	Refer to workpaper '2025-2026 PGA Rate Development'
2) Customer Charge	$10.00	"
3) Current Average Monthly Bill	$81.88	"
4) Proposed Average Monthly Bill	$85.12	"
5) Change in Average Monthly Bill	$3.24	"
6) Percent change in Average Monthly Bill *(to .1%)*	4.0%	"
C) Average January Residential Bill Impact		
1) Average January Residential Use *(forecasted weather-normalized)*	105.9	Refer to workpaper '2025-2026 PGA Rate Development'
2) Customer Charge	$10.00	"
3) Current Average January Bill	$150.83	"
4) Proposed Average January Bill	$157.20	"
5) Change in Average January Bill	$6.37	"
6) Percent change in Average January Bill *(to .1%)*	4.2%	"

NW Natural
Rates & Regulatory Affairs
2025-26 PGA - Oregon: August Filing
Attachment E: PGA Summary

	Amount	Location in Company Filing (cite)
4) Breakdown of Costs		
A) Embedded in Rates		
1) Total Commodity Cost	$320,249,632	NWN 2025-26 PGA OR Gas Cost Development_September Filing
a) Total Demand Cost (assoc. w/ supply)		
b) Total Peaking Cost (assoc. w/ supply)		
c) Total Reservation Cost (assoc. w/ supply)		
d) Total Volumetric Cost (assoc. w/ supply)	$768,122	"
e) Total Storage Cost (assoc. w/ supply)	$28,196,988	"
f) Other	$291,284,522	"
2) Total Transportation Cost *(Pipeline related)*	$71,291,272	"
a) Total Upstream Canadian Toll	$0	
i.Total Demand, Capacity, or Reservation Cost	$0	
ii. Total Volumetric Cost	$0	
b) Total Domestic Cost	$0	
i. Total Demand, Capacity, or Reservation Cost	$0	
ii. Total Volumetric Cost	$0	
3) Total Storage Costs	$0	
4) Capacity Release Credits	$0	
5) Total Gas Costs	$391,540,904	"
B) Projected For New Rates (Oregon Costs)		
1) Total Commodity Cost	$345,043,720	NWN 2025-26 PGA OR Gas Cost Development_August Filing
a) Total Demand Cost (assoc. w/ supply)		
b) Total Peaking Cost (assoc. w/ supply)		
c) Total Reservation Cost (assoc. w/ supply)		
d) Total Vaporization Cost (assoc. w/ supply)		
e) Total Volumetric Cost (assoc. w/ supply)	$1,271,478	"
f) Total Storage Cost (assoc. w/ supply)	$22,195,298	"
g) Other	$321,576,944	"
2) Total Transportation Cost *(Pipeline related)*	$71,260,897	"
a) Total Upstream Canadian Toll	$0	
i.Total Demand, Capacity, or Reservation Cost	$0	
ii. Total Volumetric Cost	$0	
b) Total Domestic Cost	$0	
i. Total Demand, Capacity, or Reservation Cost	$0	
ii. Total Volumetric Cost	$0	
3) Total Storage Costs	$0	
4) Capacity Release Credits	$0	
5) Total Gas Costs	$416,304,617	"
	Amount	**Location in Company Filing (cite)**
5) WACOG *(Weighted Average Cost of Gas)*		
A) Embedded in Rates		
1) WACOG *(Commodity Only)*		
a. With revenue sensitive	$0.43366	NWN 2025-26 PGA OR Gas Cost Development_August Filing
b. Without revenue sensitive	$0.42050	"
2) WACOG (Non-Commodity)		
a. With revenue sensitive	$0.10274	NWN 2025-26 PGA OR Gas Cost Development_August Filing
b. Without revenue sensitive	$0.09962	"
B) Proposed for New Rates		
1) WACOG *(Commodity Only)*		
a. With revenue sensitive	$0.45623	NWN 2025-26 PGA OR Gas Cost Development_August Filing
b. Without revenue sensitive	$0.44246	"
2) WACOG (Non-Commodity)		
a. With revenue sensitive	$0.10027	"
b. Without revenue sensitive	$0.09724	"
6) Therms Sold		"

NW Natural
Rates & Regulatory Affairs
2025-26 PGA - Oregon: August Filing
Attachment E: PGA Summary

7) Purchasing/ Hedging Strategies *Prepare 1-2 page summary of gas cost situation to include resources, purchasing strategy, hedging, and pipeline issues. Within the summary include:*		
A) Resources embedded in current rates and an explanation of proposed resources.		
1) Firm Pipeline Capacity		
a) Year-round supply contracts	N/A	Exhibit A, IV.2.b 1-7
b) Winter-only contracts	N/A	"
c) Reliance on Spot Gas/Other Short Term Contracts	N/A	"
d) Other - e.g. Supply area storage	N/A	"
2) Market Area Storage		
a) Underground-owned	N/A	"
b) Underground- contracted	N/A	"
c) LNG-owned	N/A	"
d) LNG-contracted	N/A	"
3) Other Resources		
a) Recallable Supply	N/A	"
b) City gate Deliveries	N/A	"
c) Owned-Production	N/A	"
d) Propane/Air	N/A	"

b) Gas Supply Portfolio and Related Transportation

1. Summary of Portfolio Planning Process

The gas supply planning process focuses on securing and dispatching gas supply resources to ensure reliable service to the Company's sales customers at a reasonable cost.

To ensure adequate reliability, NW Natural contracts for firm upstream pipeline capacity, firm off-system storage service and firm recallable gas supply/capacity arrangements with certain on-system customers, in addition to its development and use of on-system underground and LNG storage.

Upstream pipeline capacity has been contracted with the following objectives in mind:

(1) Diversify capacity sources so that disruptions in any one supply region, such as from a pipeline rupture, well freeze-offs, etc., have a minimal impact on NW Natural;

(2) Obtain upstream capacity along the path from NW Natural’s service territory to points generally recognized for their liquidity, such as AECO/NIT, to maximize buying opportunities and minimize price volatility; and,

(3) Find ways to minimize the cost of upstream capacity such as through optimization activities or committing to capacity only on a winter season basis, if possible.

Upstream gas supply contracts have been negotiated with the following objectives in mind:

(1) Use a diverse group of reliable suppliers as established by their asset positions, past performance and other factors;

(2) Try to match our year-round customer requirements to baseload (take-or-pay) year-round supply contracts to obtain the most favorable pricing and simplify administration;
(3) Use multiple month and bullet (single month) term contracts to match our rise in requirements during the heating season and shoulder months;

(4) Reduce spot purchase requirements during the winter due to the likely correlation of high requirements with high spot prices;

(5) Take advantage of favorable pricing opportunities to use supply-basin storage if and when possible;

(6) Use index-related pricing formulas in term contracts to enable easy evaluation of competitive offers and avoid the need for further price negotiation over the term of the contract;

(7) Structure the portfolio to provide some opportunity to take advantage when spot prices are favorable; and,

(8) Avoid over-contracting gas on a take-or-pay basis, which could result in excess gas supplies that must be sold at a loss if requirements fail to materialize such as during a warm winter.

2. LDC sales system demand forecasting

While the demand forecast reflects "normal" weather, the Company still plans for the possibility of extreme cold weather during the upcoming heating season. From a gas supply portfolio standpoint, the biggest impact of the two different load forecasts is in the dispatch of storage resources. That is, to handle the possibility of a cold winter, storage withdrawals are restrained in the resource dispatch during the early months of the winter in order to maintain maximum storage deliverability into early February, which historically has been the latest time period for extreme cold weather events to occur. This restraint around storage withdrawals is done in the PGA forecast even though it assumes normal weather for the upcoming winter, when such restraints would not be necessary. In this way the Company addresses the need to maintain reliability of service to firm customers should extreme cold weather arise during the coming winter, while at the same time complying with the PGA load forecast requirements.

3. Natural gas price forecasts

NW Natural relies on forecasts prepared by the US Energy Information Administration (EIA), the S&P Global Commodity Insights consulting firm, as well as NYMEX and Intercontinental Exchange (ICE) futures prices to help formulate its gas purchase and hedging strategies. Various other price forecasts and analyses also come to NW Natural by way of trade publications, consultant visits, oil/gas company presentations and other governmental sources. These provide opportunities to test assumptions and explore alternate viewpoints.

4. Physical resources for the portfolio

As mentioned above, NW Natural's physical portfolio on any given day includes gas supplies purchased and transported over the upstream pipeline system as well as supplies either placed into or withdrawn from a variety of gas storage facilities. The Company also has arrangements with two large on-system customers that allow it to call on their gas supplies on short notice for use by the company ("recall arrangements"). Finally, a very small portion of the company's gas supply (less than 1%) is produced on-system both from native gas produced from the Mist Field and renewable natural gas (RNG) from a few sources spread throughout the NW Natural system. These are the Company's only gas supplies that currently do not require transportation at one time or another over some portion of the interstate pipeline system.

Items to note regarding the physical supply portfolio as compared to last year's PGA filing:

(1) An annual analysis identified a resource need of approximately 15,000 Dth/day to meet the 2025-26 design peak day of approximately 1 million Dth/day. The Company's analysis led to a Mist recall of 15,000 Dth/d of deliverability.

(2) An electrical upgrade is needed at Portland LNG, which will not be in place this 2025-26 winter. This limits Portland LNG deliverability for this upcoming winter to 100,440 Dth/day.

Other physical resource items that do not represent changes but merit mention are:

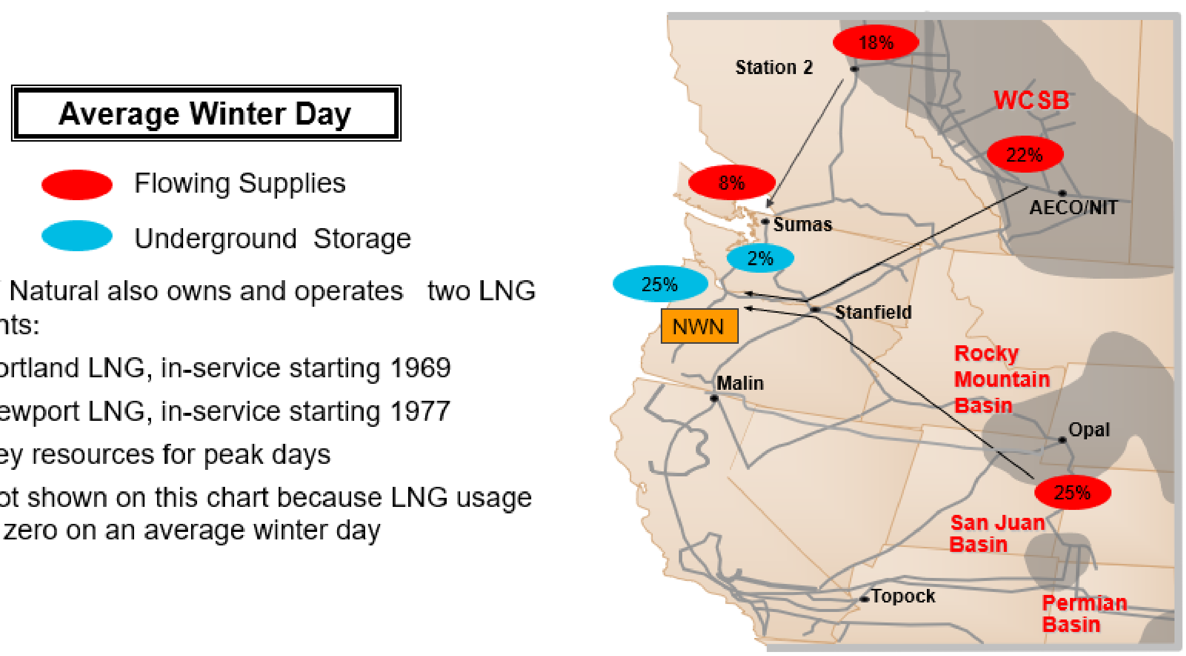
(i) A previously identified trend of higher heat content on the interstate pipeline system has not reversed, which means slightly higher deliverability from the Portland LNG and Newport LNG plants, along with slightly more working gas capacity for utility customers at Mist, continue to be maintained in the portfolio.

(ii) Seismic engineering evaluations of the Newport LNG and Portland LNG plants continue to restrict the working gas capacities of those two plants.

(iii) We continue to find opportunities to use segmented capacity as a resource during the winter, and its reliable performance justifies its continued inclusion in the Company's resource portfolio; however, the Enbridge T-South incident exposed concerns about supply liquidity at Sumas that may hamper the usefulness of segmented capacity in future years when new loads (such as the Woodfibre LNG project) begin to exert influence.

The Company's portfolio continues to reflect the gas reserves purchased under the agreement with Encana approved by the OPUC in 2011. That agreement was amended in March 2014 and seven new gas wells were drilled with the successor company Jonah Energy LLC. This PGA continues to reflect the approved regulatory treatment for both sets of reserves. As a reminder, the seven Jonah Energy wells have an approved regulatory treatment that is different from the reserves obtained under the original program with Encana, but all of the gas reserve volumes essentially function as a financial tool, i.e., they displace an identical volume of financial derivatives that the Company otherwise would have executed. For the purposes of this filing, the Encana and Jonah Energy gas reserve volumes have no impact on the company's physical supply portfolio.

Using its mix of transportation and storage resources, the company expects the following profile on a typical winter day:

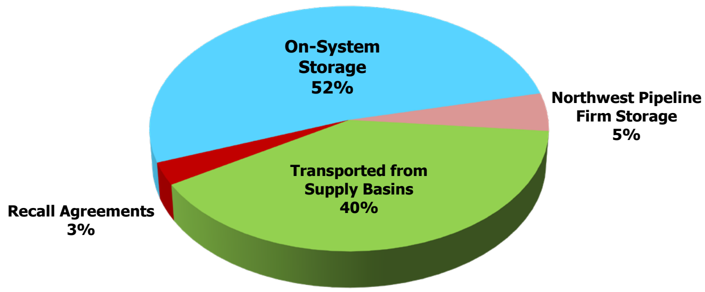


A summary of the Company's physical supply resources is provided in Tables 1 through 5.

Should its "design" peak day occur during the upcoming heating season, all physical resources would be used in the following proportions (607,000 therms/day of segmented capacity is included):

NW Natural

Peak Day Firm Supply
effective November 1, 2025



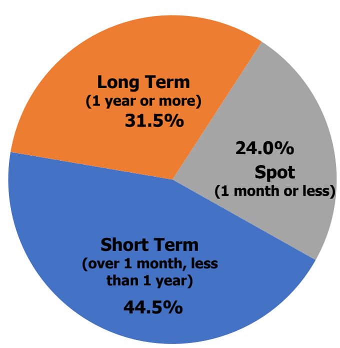
Total = 10.0 Million Therms
(includes Segmented Capacity)

Regarding physical supply purchasing, NW Natural will have baseload contracts with suppliers amounting to at least 800,000 therms per day of firm supply purchases on a daily basis throughout the upcoming November 2025 through October 2026 period. This reflects the relatively stable daily component of NWN's demand, i.e., water heater and other non-space heating loads that are not seasonal in nature.

Outside the non-heating season (June through September), additional baseload amounts are contracted to reflect likely heating demand. Rather than selecting a set amount for the entire heating season (November through March) as in past years, more variation in baseload quantities by month is being used to better reflect the ranges of heating loads that are likely to occur over the course of the heating season. The total baseload amount will range up to 2.93 million therms per day in December through February. The details by month are provided at the bottom of Table 1.

With slightly over 3.4 million therms per day of firm upstream pipeline capacity to its service territory, and potentially over 4.0 million therms per day if segmented capacity is included, this means substantial capacity is available for spot purchases (one month and shorter duration) as, and when, needed. During the 2024 calendar year, approximately one-quarter of the Company's purchases were made on the spot market as shown below, and depending on weather it could be similar again for the coming year.

Supply Diversity by Contract Duration
Calendar Year 2024



Total Purchases = 82.2 million Dths

5. Financial resources for the portfolio (derivatives instruments and other financial arrangements).

NW Natural “swaps” monthly index prices for fixed prices through the use of standard financial hedge instruments in order to increase price stability across the year. Volumes in storage, including any supply-basin storage arrangements, provide another form of hedging. That is, while the gas for storage injection is purchased on the spot market, its pricing is known to a very large extent in advance of the PGA filing and so can be reflected in the PGA rates. In addition, gas reserves provide a financial hedge for Oregon customers in a different form.

NW Natural currently estimates that it will financially hedge about 69% of the prices of its expected annual Oregon sales requirements for the upcoming PGA year commencing November 1, 2025. Gas reserves are expected to hedge about 3% of projected sales volumes. Storage gas, which again is gas purchased on the spot market, will account for approximately another 13%. On-system resources including Mist gas production and renewable natural gas production continue to add roughly 1% to the total requirements. Assuming normal weather, the remaining annual purchase volumes, when combined with our purchases for storage, means roughly 27% of NW Natural's total volumes would be purchased on an unhedged basis.

Financial hedging targets are set by an executive level oversight committee within the Company - the Gas Acquisition Strategy & Policies (GASP) Committee - and are reviewed on a monthly basis to determine if changes should be made in response to market conditions or other factors as the year progresses.

In addition to financial swaps, the Company’s derivative policies allow the use of financial options (puts and calls) to limit exposure to gas price fluctuations. For example, these instruments can be used in combination in order to “collar” the price of gas for specific purchases.

The Company’s Gas Supply department executes the actual derivative transactions, while separate individuals, reporting to different executives, oversee the risk management of the hedging program such as approving counterparties and determining credit limits.

6. Storage resources.

NWN relies on four storage facilities to balance its supply portfolio and meet customer requirements. Mist, Portland LNG (also known as Gasco) and Newport LNG are owned and operated by the company. NWN also contracts with Northwest Pipeline for service at the Jackson Prairie underground facility in Washington state.

Storage provides the following benefits to customers:

a. Avoids the need to subscribe to year-round interstate pipeline capacity to meet winter season loads. This benefit applies to the storage located on NW Natural's system, and partially applies to Jackson Prairie storage, which is eligible for a Northwest Pipeline transportation service that is less expensive than normal year-round firm service. This benefit does not apply to storage located in the supply basins such as Alberta.

b. Allows more gas purchasing during the non-heating season, when prices are typically lower, instead of heating season periods when prices typically peak. Supply-basin storage is pursued when this potential benefit is sufficient to offset the cost of the storage service.

c. Provides diversity of supply and gas movement to and through NWN’s service territory, improving overall reliability.

d. Helps balance daily demand with supplies, reducing the potential for imbalance penalties with upstream pipelines.

e. Provides flexibility to take advantage of daily, monthly and seasonal variations in gas pricing, either directly by NW Natural or through its third-party optimization arrangement.

Additional benefits attributable to Mist have been created through the development of an interstate storage service starting back in 2001. For example, rather than large “lumpy” resource additions requiring years of preparation, the “pre-build” of interstate storage service provides the ability to time and size incremental Mist capacity to a degree not achievable through typical resource development. Also, revisions to the customer load forecast have meant that previously planned storage additions for the utility could be deferred with multiple benefits to customers, e.g., rate base additions are deferred while revenue sharing from the interstate storage service continues.

More information on the company’s storage resources is provided in Table 3 and the workpapers.

Supporting information to IV.2.b.4

NW Natural
Firm Off-System Gas Supply Contracts
for the 2025/2026 Tracker Year

Supply Location	Duration	Baseload Qty (Dth/day)	Contract Termination Date
British Columbia:			
Canadian Natural Resources	Nov-Oct	5,000	10/31/2026
MacQuarie Energy Canada Ltd.	Nov-Oct	5,000	10/31/2026
Uniper Trading Canada Ltd.	Nov-Oct	5,000	10/31/2026
ConocoPhillips Canada Marketing	Nov-Mar	5,000	3/31/2026
J. Aron & Company	Nov-Mar	5,000	3/31/2026
MacQuarie Energy Canada Ltd.	Nov-Mar	10,000	3/31/2030
Powerex Corp	Nov-Mar	15,000	3/31/2030
IGI Resources	Nov-Mar	8,500	3/31/2030
IGI Resources	Nov-Mar	5,000	3/31/2026
Pacific Canbriam Energy Limited	Nov-Mar	5,000	3/31/2026
Uniper Trading Canada Ltd.	Nov-Mar	10,000	3/31/2026
MacQuarie Energy Canada Ltd.	Apr-May	10,000	5/31/2026
Canadian Natural Resources	Apr-Jun	5,000	6/30/2026
TD Energy Trading Inc	Sep-Oct	5,000	10/31/2026
Pending	Nov-Oct	5,000	10/31/2026
Pending	Nov-Mar	4,500	3/31/2026
Pending	Apr-May	5,000	5/31/2026
Pending	Oct	5,000	10/31/2026
Alberta:			
Suncor Energy Marketing Inc	Nov-Oct	5,000	10/31/2026
ConocoPhillips Canada Marketing	Nov-Oct	5,000	10/31/2026
ConocoPhillips Canada Marketing	Nov-Mar	10,000	3/31/2026
Suncor Energy Marketing Inc	Nov-Mar	5,000	3/31/2026
TD Energy Trading Inc	Nov-Mar	20,000	3/31/2026
Uniper Trading Canada Ltd.	Nov-Mar	5,000	3/31/2026
BP Canada Energy Group	Nov-Feb	5,000	2/28/2026
Suncor Energy Marketing Inc	Dec-Feb	5,000	2/28/2026
Castleton Commodities	Apr-Jun	5,000	6/30/2026
BP Canada Energy Group	Apr-Jun	5,000	6/30/2026
Suncor Energy Marketing Inc	Apr-May	5,000	5/31/2026
Suncor Energy Marketing Inc	Apr	10,000	4/30/2026
Castleton Commodities	Sep-Oct	5,000	10/31/2026
Direct Energy Marketing Limited	Oct	10,000	10/31/2026
Powerex Corp	Oct	5,000	10/31/2026
Pending	Nov-Oct	5,000	10/31/2026
Pending	Nov-Mar	15,000	3/31/2026
Pending	Apr-May	5,000	5/31/2026
Pending	Oct	10,000	10/31/2026
Rockies:			
MacQuarie Energy, LLC	Nov-Oct	10,000	10/31/2026
CIMA Energy LTD	Nov-Oct	10,000	10/31/2026
Concord Energy LLC	Nov-Oct	5,000	10/31/2026
Koch Energy Services, Inc	Nov-Oct	5,000	10/31/2026
CIMA Energy LTD	Nov-Mar	5,000	3/31/2026
Koch Energy Services, Inc	Nov-Mar	5,000	3/31/2026
MIECO LLC	Nov-Mar	5,000	3/31/2026
CIMA Energy LTD	Dec-Mar	15,000	3/31/2026
Citadel Energy Marketing, LLC	Dec-Mar	5,000	3/31/2026
Concord Energy LLC	Dec-Mar	5,000	3/31/2026
MacQuarie Energy, LLC	Dec-Mar	5,000	3/31/2026
MIECO LLC	Dec-Mar	5,000	3/31/2026
MacQuarie Energy, LLC	Dec-Feb	10,000	2/28/2026
ConocoPhillips Company	Dec-Feb	5,000	2/28/2026
Concord Energy LLC	Apr-May	5,000	5/31/2026
Concord Energy LLC	Apr	5,000	4/30/2026
MIECO LLC	Apr	5,000	4/30/2026
MacQuarie Energy, LLC	Oct	5,000	10/31/2026
J. Aron & Company	Oct	5,000	10/31/2026
Pending	Nov-Oct	15,000	10/31/2026
Pending	Nov-Mar	10,000	3/31/2026
Pending	Dec-Mar	5,000	3/31/2026
Pending	Apr	20,000	4/30/2026

Month	Baseload Qty (Dth/day)
Nov-25	233,000
Dec-25	293,000
Jan-26	293,000
Feb-26	293,000
Mar-26	268,000
Apr-26	165,000
May-26	125,000
Jun-26	95,000
Jul-26	80,000
Aug-26	80,000
Sep-26	90,000
Oct-26	130,000

Notes:
1. Contract quantities represent deliveries into upstream pipelines. Accordingly, quantities delivered into NW Natural's system are slightly less due to upstream pipeline fuel consumption.

Supporting information to IV.2.b.4

Table 2

NW Natural
Firm Transportation Capacity
for the 2025/2026 Tracker Year

Pipeline and Contract	Contract Demand (Dth/day)	Termination Date
Northwest Pipeline:		
Sales Conversion (#100005)	214,889	10/31/2033
1993 Expansion (#100058)	35,155	9/30/2044
1995 Expansion (#100138)	102,000	10/31/2033
Occidental cap. acq. (#139153)	1,046	10/31/2033
Occidental cap. acq. (#139154)	4,000	10/31/2033
International Paper cap. acq. (#138065)	4,147	10/31/2033
March Point cap. acq. (#136455)	12,000	12/31/2046
Total NWP Capacity	373,237	
less recallable release to -		
Portland General Electric	(30,000)	10/31/2026
Net NWP Capacity	343,237	
TransCanada - GTN:		
Sales Conversion (#00180)	3,616	10/31/2030
1993 Expansion (#00164)	46,549	10/31/2030
1995 Rationalization (#11030)	56,000	10/31/2030
Total GTN Capacity	106,165	
TransCanada - Foothills:		
1993 Expansion	47,727	10/31/2026
1995 Rationalization	57,417	10/31/2026
Engage Capacity Acquisition	3,708	10/31/2026
2004 Capacity Acquisition	48,669	10/31/2030
Total Foothills Capacity	157,521	
less release to -		
Shell Energy North America (Canada) Inc	(48,669)	10/31/2030
Net Foothills Capacity	108,852	
TransCanada - NOVA:		
1993 Expansion	48,135	10/31/2030
1995 Rationalization	57,909	10/31/2030
Engage Capacity Acquisition	3,739	10/31/2030
2004 Capacity Acquisition	49,138	10/31/2030
Total NOVA Capacity	158,921	
less release to -		
Shell Energy North America (Canada) Inc	(49,138)	10/31/2030
Net NOVA Capacity	109,783	
T-South		
Capacity (through Tenaska)	19,000	3/31/2029
2021 Expansion	25,511	10/31/2061
Capacity FI-3931	25,000	4/30/2028
Total T-South Capacity	69,511	

Notes:

1. All of the above agreements continue year-to-year after termination at NW Natural's sole option except for PGE, which requires mutual agreement to continue, and the T-South contract with Tenaska for 19,000 Dth/day, which has no renewal rights.
2. The numbers shown for the 1993 Expansion contracts on GTN and Foothills are for the winter season (Oct-Mar) only. Both contracts decline during the summer season (Apr-Sep) to approximately 30,000 Dth/day.
3. Segmented capacity has not been included in this table.
4. The 2004 Capacity Acquisition on NOVA and Foothills totaling about 49,000 Dth/day has been released to a third party through 10/31/2030. The revenues related to this arrangement are being credited back to customers as outlined in Schedule P.

Supporting information to IV.2.b.4

Table 3

NW Natural
Firm Storage Resources
for the 2025/2026 Tracker Year

Facility	Max. Daily Rate (Dth/day)	Max. Seasonal Level (Dth)	Termination Date
Jackson Prairie:			
SGS-2F	46,030	1,120,288	10/31/2033
TF-2 (primary firm portion)	23,038	839,046	10/31/2033
TF-2 (primary firm portion)	9,467	281,242	10/31/2033
TF-1	13,525	n/a	10/31/2033
Firm On-System Storage Plants:			
Mist (reserved for core)	340,000	13,701,780	n/a
Portland LNG Plant	100,440	511,574	n/a
Newport LNG Plant	78,000	1,097,346	n/a
Total On-System Storage	518,440	15,310,700	
Total Firm Storage Resource	564,470	16,430,988	

Notes:
1. The SGS-2F and TF-2 contracts have a unilateral annual evergreen provision (continuation at NW Natural's sole option), while the TF-1 contract requires mutual consent with Northwest Pipeline to continue after the indicated termination date.
2. The TF-2 contracts also contain additional "subordinated" firm service of 9,586 Dth/day on the first agreement listed above and 3,939 Dth/day on the second agreement. The subordinated service is NOT included in NW Natural's peak day planning.
3. On-system storage peak deliverability is based on design criteria, for example, Mist is at least 50% full.
4. Mist numbers pertain to the portion reserved for core utility service per the Company's Integrated Resource Plan. Additional capacity and deliverability at Mist have been contracted under varying terms to Interstate storage customers.
5. The Dth numbers for Mist, Newport LNG and Portland LNG are approximate in that they are converted from Mcf volumes, and so depend on the heat content of the stored gas. The current heat content used for Mist is 1092 Btu/cf. The current heat content used for Newport LNG is 1110 Btu/cf and Portland LNG is 1116 Btu/cf. An engineering study was conducted for Newport LNG peak deliverability for the 2024-25 winter supporting 78,000 Dth/d as the maximum daily rate. An electrical project at PLNG will not be finalized for the 2025-26 PGA year thus limiting daily sendout to 90 MMSCFD instead of 120 MMSCFD.
6. Newport LNG tank rated to 98.86% of the tank capacity.
7. Due to an Engineering analysis of the Portland LNG tank, liquifaction will be limited to 76.4% of the tank's capacity.
8. NW Natural has no supply-basin storage contract for the coming year.

Supporting information to IV.2.b.4

Table 4

NW Natural
Other Resources: Recall Agreements, Citygate Deliveries and Mist Production
for the 2025/2026 Tracker Year

Type	Max. Daily Rate (Dth/day)	Max. Availability (days)	Termination Date
Recall Agreements:			
PGE	30,000	30	10/31/2026
Georgia Pacific-Halsey mill	1,000	15	Upon 1-year notice
Total Recall Resource	31,000		
On-System Supplies:			
Renewable Natural Gas	≈500	n/a	Varying Terms
Mist Production	≈500	n/a	Life of the wells
Total On System Supplies	1,000		

Notes:
1. There are a variety of terms and conditions surrounding the recall rights under each of the above agreements, but they all include delivery of the gas to NW Natural's system.
2. Mist production is expected to flow at roughly the figure shown above. Flows vary as new wells are added and older wells deplete. NW Natural's obligation is to buy gas from existing wells through the life of those wells.
3. Assumes three Renewable Natural Gas (RNG) projects are online this PGA year.

Supporting information to IV.2.b.4

Table 5

NW Natural
Peak Day Resource Summary
for the 2025/2026 Tracker Year

Resource Type	Max. Daily Rate (Dth/day)
Net Deliverability over Upstream Pipeline Capacity	343,237
Off-System Storage (Jackson Prairie only)	46,030
On-System Storage (Mist, Portland LNG and Newport LNG)	518,440
Recallable Capacity and Supply Agreements	31,000
On-System Supplies	1,000
Segmented Capacity (not primary firm)	60,700
Total Peak Day Resources	1,000,407

Notes:

1. Per the 2025 IRP, Segmented Capacity is included as a firm resource through the 2026-27 gas year. Reliance for a peak event reduces to zero Dth/day beyond that poiont.

7. Forecasted annual and peak demand used in the current PGA portfolio, with and without programmatic and non-programmatic demand response, with explanation.

Forecasted DSM figures reflect new, additional savings for the gas year, and not the cumulative results of measures installed over time.

	2025/2026
Forecast Annual Demand (therms)	871,891,040
Forecast Peak Demand (therms) - Normal	4,462,947
Forecast Peak Demand (therms) - Design	10,385,450
Forecast DSM Annual (therms)	9,740,077
Forecast DSM Peak (therms) - Normal	56,006
Forecast DSM Peak (therms) - Design Peak	130,328
Forecast Annual Demand with Forecast DSM	862,150,963
Forecast Peak Demand with Forecast DSM - Normal	4,406,941
Forecast Peak Demand with Forecast DSM - Design	10,255,122

8. Forecasted annual and peak demand used in the current PGA portfolio, with and without effects from gas supply incentive mechanisms, with explanation.

Gas supply incentive mechanisms can lead to alternate uses of the resource portfolio, such as additional movements of gas in and out of storage, but the effects "net out" over the course of a year and so do not change the forecasted annual and peak demand used to develop the PGA portfolio.

9. Summary of portfolio documentation provided.

See Index.

Section V.1 - Physical Gas Supply

a) For each physical natural gas supply resource that is included in a utility's portfolio (except spot purchases) upon which the current PGA is based, the utility should provide the following:

1. Pricing for the resource, including the commodity price and, if relevant, reservation charges.

See Tables 1-4 below.

2. For new transactions and contracts with pricing provisions entered into since the last PGA: competitive bidding process for the resource. This should include number of bidders, bid prices utility decision criteria in selecting a "winning" bid, and any special pricing or delivery provisions negotiated as part of the bidding process.

See Tables 1-4 below.

3. Brief explanation of each contract's role within the portfolio.

See Tables 1-4 below**. [START HIGHLY CONFIDENTIAL]**

Table 1

Northwest Natural Gas Company
PGA Filing Guidelines CONFIDENTIAL

November 1, 2025 - October 31, 2026
Physical Natural Gas term contracts

All contracts are with Approved Counterparties per Exhibit "G" - NW NATURAL Gas Supply Risk Management Policies
Approved Counterparties all have executed NAESB contracts with NW Natural

Rocky Mountain Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dths	Contractual Conditions	Default Receipt Pt. Purchase Location	Internal Reference No.
MacQuarie Energy, LLC (1)	11/1/2025	10/31/2026	[redacted]	IFGMR-NWP Rockies FOM	5,000		Wyoming Pool	116742
MIECO LLC (2)	12/1/2025	3/31/2026		IFGMR-NWP Rockies FOM	5,000		Opal	116755
MacQuarie Energy, LLC (3)	12/1/2025	2/28/2026		IFGMR-NWP Rockies FOM	5,000		Rocky Mountain Pool	116764
Concord Energy LLC (4)	4/1/2026	5/31/2026		IFGMR-NWP Rockies FOM	5,000		Wyoming Pool	116770
J. Aron & Company (5)	10/1/2026	10/31/2026		IFGMR-NWP Rockies FOM	5,000		Opal	116795
ConocoPhillips Company (6)	12/1/2025	2/28/2026		IFGMR-NWP Rockies FOM	5,000		Opal	116867
CIMA Energy LTD (7)	12/1/2025	3/31/2026		IFGMR-NWP Rockies FOM	5,000		Wyoming Pool	116889
Koch Energy Services, Inc (8)	11/1/2025	10/31/2026		IFGMR-NWP Rockies FOM	5,000		Opal	116899
Concord Energy LLC (9)	12/1/2025	3/31/2026		IFGMR-NWP Rockies FOM	5,000		Wyoming Pool	116927
MIECO LLC (10)	11/1/2025	3/31/2026		IFGMR-NWP Rockies FOM	5,000		Opal	116942
CIMA Energy LTD (11)	12/1/2025	3/31/2026		IFGMR-NWP Rockies FOM	5,000		Opal	116949
MacQuarie Energy, LLC (12)	10/1/2026	10/31/2026		IFGMR-NWP Rockies FOM	5,000		Rocky Mountain Pool	116967
CIMA Energy LTD (13)	11/1/2025	3/31/2026		IFGMR-NWP Rockies FOM	5,000		Rocky Mountain Pool	116999
MacQuarie Energy, LLC (14)	12/1/2025	3/31/2026		IFGMR-NWP Rockies FOM	5,000		Opal	117073
MacQuarie Energy, LLC (15)	11/1/2025	10/31/2026		IFGMR-NWP Rockies FOM	5,000		Rocky Mountain Pool	117083
MIECO LLC (16)	4/1/2026	4/30/2026		IFGMR-NWP Rockies FOM	5,000		Opal	117090
CIMA Energy LTD (17)	11/1/2025	10/31/2026		IFGMR-NWP Rockies FOM	5,000		Wyoming Pool	117110
Citadel Energy Marketing, LLC (18)	12/1/2025	3/31/2026		IFGMR-NWP Rockies FOM	5,000		Wyoming Pool	117134
MacQuarie Energy, LLC (19)	12/1/2025	2/28/2026		IFGMR-NWP Rockies FOM	5,000		Rocky Mountain Pool	117175
Concord Energy LLC (20)	4/1/2026	4/30/2026		IFGMR-NWP Rockies FOM	5,000		Wyoming Pool	117207
Koch Energy Services, Inc (21)	11/1/2025	3/31/2026		IFGMR-NWP Rockies FOM	5,000		Opal	117217
CIMA Energy LTD (22)	11/1/2025	10/31/2026		IFGMR-NWP Rockies FOM	5,000		Rocky Mountain Pool	117230
CIMA Energy LTD (23)	12/1/2025	3/31/2026		IFGMR-NWP Rockies FOM	5,000		Wyoming Pool	117252
Concord Energy LLC (24)	11/1/2025	10/31/2026		IFGMR-NWP Rockies FOM	5,000		Wyoming Pool	117269

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids
(1) Wyoming Pool	8	[redacted]
(2) Opal	9	
(3) Rocky Mountain Pool	8	
(4) Wyoming Pool	8	
(5) Opal	7	
(6) Opal	8	
(7) Wyoming Pool	7	
(8) Opal	6	
(9) Wyoming Pool	6	
(10) Opal	8	
(11) Opal	7	
(12) Rocky Mountain Pool	8	
(13) Rocky Mountain Pool	9	
(14) Opal	6	
(15) Rocky Mountain Pool	8	
(16) Opal	6	
(17) Wyoming Pool	8	
(18) Wyoming Pool	8	
(19) Rocky Mountain Pool	8	
(20) Wyoming Pool	5	
(21) Opal	6	
(22) Rocky Mountain Pool	10	
(23) Wyoming Pool	7	
(24) Wyoming Pool	8	

[END HIGHLY CONFIDENTIAL]

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Table 2

Northwest Natural Gas Company
PGA Filing Guidelines

CONFIDENTIAL

November 1, 2025 - October 31, 2026
Physical Natural Gas term contracts

All contracts are with Approved Counterparties per Exhibit "G" - NW NATURAL Gas Supply Risk Management Policies
Approved Counterparties all have executed NAESB contracts with NW Natural

Huntingdon, BC Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dth's	Contractual Conditions	Default Receipt Pt. Purchase Location	Internal Reference No.
MacQuarie Energy Canada Ltd. (1)	11/1/2023	3/31/2030	[redacted]	IFGMR-NWP Canadian Border FOM	5,000		Huntingdon	113416
Powerex Corp (2)	11/1/2023	3/31/2030		IFGMR-NWP Canadian Border FOM	5,000		Huntingdon	113597
Uniper Trading Canada Ltd. (3)	11/1/2025	3/31/2026		IFGMR-NWP Canadian Border FOM	5,000		Huntingdon	116741
Uniper Trading Canada Ltd. (4)	11/1/2025	3/31/2026		IFGMR-NWP Canadian Border FOM	5,000		Huntingdon	116908
IGI Resources (5)	11/1/2025	3/31/2026		IFGMR-NWP Canadian Border FOM	5,000		Huntingdon	117005
Pacific Canbriam Energy Limited (6)	11/1/2025	3/31/2026		IFGMR-NWP Canadian Border FOM	5,000		Huntingdon	117091
Powerex Corp (7)	11/1/2025	3/31/2030		IFGMR-NWP Canadian Border FOM	10,000		Huntingdon	117317
IGI Resources (8)	11/1/2025	3/31/2030		IFGMR-NWP Canadian Border FOM	8,500		Huntingdon	117318
MacQuarie Energy Canada Ltd. (9)	11/1/2025	3/31/2030		IFGMR-NWP Canadian Border FOM	5,000		Huntingdon	117289

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids	Winning Bid Criteria
(1) Huntingdon	3	[redacted]	Price
(2) Huntingdon	4		Price
(3) Huntingdon	7		Price
(4) Huntingdon	9		Price
(5) Huntingdon	9		Price
(6) Huntingdon	9		Price
(7) Huntingdon	5		Price
(8) Huntingdon	4		Price
(9) Huntingdon	3		Price

Table 3

Northwest Natural Gas Company
PGA Filing Guidelines

CONFIDENTIAL

November 1, 2025 - October 31, 2026
Physical Natural Gas term contracts

All contracts are with Approved Counterparties per Exhibit "G" - NW NATURAL Gas Supply Risk Management Policies
Approved Counterparties all have executed NAESB contracts with NW Natural

Station 2, BC Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dth's	Default Receipt Pt. Purchase Location	Internal Reference No.
MacQuarie Energy Canada Ltd. (1)	11/1/2025	10/31/2026	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	116763
Canadian Natural Resources (2)	4/1/2026	6/30/2026		CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	116928
Canadian Natural Resources (3)	11/1/2025	10/1/2026		CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	116959
MacQuarie Energy Canada Ltd. (4)	4/1/2026	5/31/2026		CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	117031
ConocoPhillips Canada Marketing (5)	11/1/2025	3/31/2026		CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	117074
TD Energy Trading Inc (6)	9/1/2026	10/31/2026		CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	117129
Uniper Trading Canada Ltd. (7)	11/1/2025	10/31/2026		CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	117199
MacQuarie Energy Canada Ltd. (8)	4/1/2026	5/31/2026		CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	117268
J. Aron & Company (9)	11/1/2025	3/31/2026		CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	117307

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids.	Winning Bid Criteria
(1) Station 2	8	[redacted]	Price
(2) Station 2	8		Price
(3) Station 2	8		Price
(4) Station 2	8		Price
(5) Station 2	7		Price
(6) Station 2	7		Price
(7) Station 2	6		Price
(8) Station 2	6		Price
(9) Station 2	7		Price

[END HIGHLY CONFIDENTIAL]

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Table 4

Northwest Natural Gas Company
PGA Filing Guidelines

CONFIDENTIAL

November 1, 2025 - October 31, 2026
Physical Natural Gas term contracts

All contracts are with Approved Counterparties per Exhibit "G" - NW NATURAL Gas Supply Risk Management Policies
Approved Counterparties all have executed NAESB contracts with NW Natural

Aeco-NIT Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dth's	Contractual Conditions	Internal Reference No.
TD Energy Trading Inc (1)	11/1/2025	3/31/2026	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		116732
Castleton Commodities (2)	4/1/2026	6/30/2026	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		116747
ConocoPhillips Canada Marketing (3)	11/1/2025	10/31/2026	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		116756
Castleton Commodities (4)	9/1/2026	10/31/2026	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		116771
Suncor Energy Marketing Inc (5)	4/1/2026	4/30/2026	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		116789
ConocoPhillips Canada Marketing (6)	11/1/2025	3/31/2026	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		116860
BP Canada Energy Group (7)	4/1/2026	6/30/2026	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		116933
TD Energy Trading Inc (8)	11/1/2025	3/31/2026	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		116952
Suncor Energy Marketing Inc (9)	11/1/2025	10/31/2026	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		116966
Suncor Energy Marketing Inc (10)	4/1/2026	4/30/2026	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		116987
BP Canada Energy Group (11)	11/1/2025	2/28/2026	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		117047
Suncor Energy Marketing Inc (12)	4/1/2026	5/31/2026	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		117100
TD Energy Trading Inc (13)	11/1/2025	3/31/2026	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		117120
ConocoPhillips Canada Marketing (14)	11/1/2025	3/31/2026	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		117162
Suncor Energy Marketing Inc (15)	11/1/2025	3/31/2026	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		117163
Direct Energy Marketing Limited (16)	10/1/2026	10/31/2026	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		117172
Powerex Corp (17)	10/1/2026	10/31/2026	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		117173
Suncor Energy Marketing Inc (18)	12/1/2025	2/28/2026	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		117216
TD Energy Trading Inc (19)	11/1/2025	3/31/2026	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		117243
Uniper Trading Canada Ltd. (20)	11/1/2025	3/31/2026	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		117244
Direct Energy Marketing Limited (21)	10/1/2026	10/31/2026	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		117285

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids.	Winning Bid Criteria
(1) Aeco	8	[redacted]	Price
(2) Aeco	6	[redacted]	Price
(3) Aeco	7	[redacted]	Price
(4) Aeco	7	[redacted]	Price
(5) Aeco	6	[redacted]	Price
(6) Aeco	6	[redacted]	Price
(7) Aeco	8	[redacted]	Price/Diversity
(8) Aeco	7	[redacted]	Price/Diversity
(9) Aeco	7	[redacted]	Price
(10) Aeco	7	[redacted]	Price
(11) Aeco	7	[redacted]	Price
(12) Aeco	6	[redacted]	Price
(13) Aeco	9	[redacted]	Price
(14) Aeco	4	[redacted]	Price
(15) Aeco	4	[redacted]	Price
(16) Aeco	3	[redacted]	Price
(17) Aeco	3	[redacted]	Price
(18) Aeco	8	[redacted]	Price
(19) Aeco	4	[redacted]	Price
(20) Aeco	3	[redacted]	Price
(21) Aeco	9	[redacted]	Price/Diversity

[END HIGHLY CONFIDENTIAL]

b) For purchases of physical natural gas supply resources from the spot natural gas market included in the portfolio at the time of the filing of the current PGA or after that filing, the utility should provide the following:

1. An explanation of the utility's spot purchasing guidelines, the data/information generally reviewed and analyzed in making spot purchases, and the general process through which such purchases are complete by the utility.

1. The purchasing of baseload and spot supplies for the 2025-2026 PGA follows the Gas Acquisition Plan as prepared by the Gas Supply department and overseen by the company's Gas Acquisition Strategy and Policies (GASP) Committee. GASP members include the company's CFO and other senior company management.

2. In our gas purchasing for 2025-2026, we continue to strive for a diversity of supply on a regional basis and among approved counterparties, as listed in the company's Gas Supply Risk Management Policies. The advantage of regional diversity is the opportunity to manage purchases to capture the lowest cost while avoiding over-reliance on any one trading point or counterparty.

3. Diversity of contracts in the portfolio is determined by the forecasted usage of NW Natural customers.

    a. One year and greater baseload (take or pay) contract volumes are meant to meet the low end volume of sales requirements while avoiding the potential for excess supply that might have to be sold at a loss when sales volumes are low. Pricing is comparable to shorter term contracts and the administrative needs are a bit simpler.

    b. Shorter term contracts are aligned to meet the forecasted demand increase during the heating season and are typically divided between baseload and a small amount of winter call option ("swing") contracts. This helps minimize the exposure to purchasing large volumes of high priced spot gas during cold weather events.

    c. Spot purchases are used to fill in requirements on a very short-term basis, from one day up to one month, throughout the PGA year. One month spot purchases are negotiated to capture the best monthly index pricing using either the publication *Inside FERC's Gas Market Report* for Rockies and Sumas purchases, or the publication *Canadian Gas Price Reporter* for Canadian purchases in Alberta or at Station 2 in British Columbia. Daily spot purchasing utilizes either a daily index (e.g., Rocky Mountain or Sumas daily indices published in *Gas Daily*) or a fixed price in U.S. dollars as negotiated directly with the suppliers. The electronic trading platform Intercontinental Exchange (ICE) provides real-time price discovery for Rocky Mountain, Sumas, Station 2 and Alberta supplies as a reference tool for such price negotiations.

2. Any contract provisions that materially deviate from the standard NAESB contract.

None for the vast bulk of the company's purchases made in the Rockies, British Columbia and Alberta.

A small percentage (less than 1%) of the company's purchases are sourced from the Mist field. This is native gas that continues to be locally produced in Oregon. These purchases do not rely on a NAESB contract but instead on a custom-written contract that dates back to 1995. As an example, gas quality and measurement is a relatively simple matter in the NAESB contract because the gas already has to conform to the tariff provisions of one or more applicable interstate pipelines, but it requires a lot more attention for Mist production gas because there are no transporting interstate pipelines over which the gas is delivered to the company. In addition, this contract contains an option that allows the Company, in its sole discretion, to buy out the remaining gas in a production reservoir in order to convert it into a storage reservoir.

We now have renewable natural gas (RNG) projects in production on the NW Natural system, the volumes from which are purchased by the Company. We use standard NAESB contracts to buy the gas, not the environmental attributes, from these counterparties, with the particular transaction confirmations referencing the relevant interconnection agreements that contain additional requirements pertaining to gas quality, monitoring, and sampling.

Section V.2 – Hedging

The utility should clearly identify by type, contract, counterparty, and pricing point both the total cost and the cost per volume unit of each financial hedge included in its portfolio.

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Trade type	Contract	Counterparty	Pricing Point	Trade quantity	Total quantity	Cost per Dth	Total Cost	State
Financial Swap	100102	[redacted]	AECO	2,500	532,500	[redacted]	[redacted]	Oregon
Financial Swap	100102	[redacted]	Rockies	2,500	302,500	[redacted]	[redacted]	Oregon
Financial Swap	100102	[redacted]	Station 2	2,500	305,000	[redacted]	[redacted]	Oregon
Financial Swap	100102	[redacted]	Sumas	2,500	755,000	[redacted]	[redacted]	Oregon
Financial Swap	100101	[redacted]	AECO	2,500	377,500	[redacted]	[redacted]	Oregon
Financial Swap	100101	[redacted]	Rockies	2,500	6,010,000	[redacted]	[redacted]	Oregon
Financial Swap	100101	[redacted]	Station 2	2,500	1,667,500	[redacted]	[redacted]	Oregon
Financial Swap	100101	[redacted]	Sumas	2,500	1,510,000	[redacted]	[redacted]	Oregon
Financial Swap	100100	[redacted]	Rockies	5,000	605,000	[redacted]	[redacted]	Oregon
Financial Swap	100104	[redacted]	AECO	2,500	1,360,000	[redacted]	[redacted]	Oregon
Financial Swap	100104	[redacted]	Rockies	2,500	1,825,000	[redacted]	[redacted]	Oregon
Financial Swap	100104	[redacted]	Station 2	2,500	1,140,000	[redacted]	[redacted]	Oregon
Financial Swap	100104	[redacted]	Sumas	2,500	1,510,000	[redacted]	[redacted]	Oregon
Financial Swap	100106	[redacted]	AECO	2,500	530,000	[redacted]	[redacted]	Oregon
Financial Swap	100106	[redacted]	Rockies	3,571	2,270,000	[redacted]	[redacted]	Oregon
Financial Swap	100106	[redacted]	Sumas	2,500	377,500	[redacted]	[redacted]	Oregon
Financial Swap	100107	[redacted]	AECO	2,500	377,500	[redacted]	[redacted]	Oregon
Financial Swap	100107	[redacted]	Rockies	2,500	377,500	[redacted]	[redacted]	Oregon
Financial Swap	100170	[redacted]	AECO	2,500	77,500	[redacted]	[redacted]	Oregon
Financial Swap	100170	[redacted]	Rockies	2,500	377,500	[redacted]	[redacted]	Oregon
Financial Swap	100108	[redacted]	AECO	2,500	452,500	[redacted]	[redacted]	Oregon
Financial Swap	100108	[redacted]	Rockies	2,500	1,215,000	[redacted]	[redacted]	Oregon
Financial Swap	100108	[redacted]	Station 2	2,500	535,000	[redacted]	[redacted]	Oregon
Financial Swap	100108	[redacted]	Sumas	2,500	377,500	[redacted]	[redacted]	Oregon
Financial Swap	100109	[redacted]	AECO	2,763	3,180,000	[redacted]	[redacted]	Oregon
Financial Swap	100109	[redacted]	Rockies	2,500	2,355,000	[redacted]	[redacted]	Oregon
Financial Swap	100109	[redacted]	Station 2	2,500	1,290,000	[redacted]	[redacted]	Oregon
Financial Swap	100109	[redacted]	Sumas	2,500	377,500	[redacted]	[redacted]	Oregon
Financial Swap	100110	[redacted]	AECO	2,500	377,500	[redacted]	[redacted]	Oregon
Financial Swap	100111	[redacted]	AECO	2,500	5,002,500	[redacted]	[redacted]	Oregon
Financial Swap	100111	[redacted]	Rockies	2,500	2,045,000	[redacted]	[redacted]	Oregon
Financial Swap	100111	[redacted]	Station 2	2,500	2,737,500	[redacted]	[redacted]	Oregon
Financial Swap	100111	[redacted]	Sumas	2,500	377,500	[redacted]	[redacted]	Oregon
Financial Swap	100112	[redacted]	Station 2	2,500	377,500	[redacted]	[redacted]	Oregon
Financial Swap	100102	[redacted]	Rockies	3,000	453,000	[redacted]	[redacted]	Washington
Financial Swap	100102	[redacted]	Sumas	3,000	453,000	[redacted]	[redacted]	Washington
Financial Swap	100170	[redacted]	Rockies	1,500	226,500	[redacted]	[redacted]	Washington
Financial Swap	100110	[redacted]	Sumas	1,500	226,500	[redacted]	[redacted]	Washington

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Section V.3 - Load Forecasting

a. Customer count and revenue by month and class.

NW Natural

UM 1286 PGA Portfolio Guidelines
2025-2026 Oregon PGA

V.3.a Customer count and revenue by month and class.

	Customer Cnt Jul-24	Revenue Jul-24	Customer Cnt Aug-24	Revenue Aug-24	Customer Cnt Sep-24	Revenue Sep-24
Total	**801,943**	$ **50,828,150.99**	**801,047**	$ 36,470,651.80	**800,421**	$ 35,298,758.88
Oregon	704,288	45,348,403.65	703,480	32,445,635.17	703,061	31,452,702.69
Washington	97,655	5,479,747.34	97,567	4,025,016.63	97,360	3,846,056.19
Total Residential	731,497	29,323,259.75	730,716	19,612,408.80	730,236	18,467,843.02
Total Commercial	69,390	15,274,212.25	69,276	11,100,022.74	69,138	10,749,312.67
Total Industrial	654	2,385,765.14	654	2,200,670.91	647	2,428,679.35
Total Interruptible	97	2,196,649.76	96	1,934,115.82	95	2,040,163.83
Total Transportation - Commercial Firm	95	149,619.78	95	137,929.44	95	148,845.83
Total Transportation - Industrial Firm	123	829,230.09	123	814,466.92	123	800,814.72
Total Transportation - Interruptible	87	669,414.22	87	671,037.17	87	663,099.46
Unbilled Revenue		(10,458,002.81)		(2,969,230.84)		1,688,862.27
Agency Fees						
Net Balancing/Overrun						
Total Gas Operating Revenue		$ **40,370,148.18**		$ **33,501,420.96**		$ **36,987,621.15**

	Customer Cnt Oct-24	Revenue Oct-24	Customer Cnt Nov-24	Revenue Nov-24	Customer Cnt Dec-24	Revenue Dec-24
Total	**802,563**	$ 43,261,970.27	**803,883**	$ 82,548,942.91	**805,528**	$ 150,417,822.65
Oregon	704,693	39,109,800.76	705,869	74,401,594.52	707,351	136,625,234.53
Washington	97,870	4,152,169.51	98,014	8,147,348.39	98,177	13,792,588.12
Total Residential	732,331	23,556,441.55	733,636	52,236,993.36	735,117	99,363,032.04
Total Commercial	69,185	12,584,182.03	69,201	22,911,690.21	69,362	43,159,403.83
Total Industrial	648	2,793,418.24	647	2,850,637.22	648	3,214,969.65
Total Interruptible	94	2,576,916.46	94	2,830,557.72	90	2,939,659.84
Total Transportation - Commercial Firm	95	188,082.45	95	255,301.65	96	281,887.06
Total Transportation - Industrial Firm	123	873,267.31	126	872,629.13	129	889,533.98
Total Transportation - Interruptible	87	689,662.23	84	591,133.62	86	569,336.25
Unbilled Revenue		24,645,219.45		37,074,121.90		8,260,237.32
Agency Fees						-
Net Balancing/Overrun				-		
Total Gas Operating Revenue		$ **67,907,189.72**		$ **119,623,064.81**		$ **158,678,059.97**

	Customer Cnt Jan-25	Revenue Jan-25	Customer Cnt Feb-25	Revenue Feb-25	Customer Cnt Mar-25	Revenue Mar-25
Total	**806,679**	$ 164,985,358.73	**807,358**	$ 150,930,383.49	**807,426**	$ 127,737,464.25
Oregon	708,389	150,189,363.11	708,999	134,723,004.39	709,032	116,265,981.10
Washington	98,290	14,795,995.62	98,359	16,207,379.10	98,394	11,471,483.15
Total Residential	736,234	108,946,303.45	736,822	98,557,734.62	736,853	82,135,244.32
Total Commercial	69,399	47,668,506.00	69,493	45,422,352.36	69,526	38,024,032.39
Total Industrial	652	3,383,464.17	650	3,079,840.78	653	3,012,106.81
Total Interruptible	91	3,144,734.55	91	2,143,324.94	91	2,883,005.64
Total Transportation - Commercial Firm	92	305,844.33	92	279,552.73	92	246,776.43
Total Transportation - Industrial Firm	128	938,562.58	127	889,494.91	128	884,160.18
Total Transportation - Interruptible	83	597,943.65	83	558,083.15	83	552,138.48
Unbilled Revenue		(3,220,358.21)		(21,473,761.40)		(10,816,210.22)
Agency Fees		-				
Net Balancing/Overrun				-		-
Total Gas Operating Revenue		$ **161,765,000.52**		$ **129,456,622.09**		$ **116,921,254.03**

	Customer Cnt Apr-25	Revenue Apr-25	Customer Cnt May-25	Revenue May-25	Customer Cnt Jun-25	Revenue Jun-25
Total	**807,816**	$ 95,463,013.71	**807,339**	$ 58,152,565.35	**807,242**	$ 47,653,461.95
Oregon	709,333	87,219,430.30	708,837	52,667,625.78	708,666	43,261,635.98
Washington	98,483	8,243,583.41	98,502	5,484,939.57	98,576	4,391,825.97
Total Residential	737,260	60,603,776.84	736,912	34,590,223.95	736,849	27,290,279.50
Total Commercial	69,512	28,137,711.16	69,388	17,487,041.00	69,354	14,673,397.81
Total Industrial	652	2,675,466.91	649	2,344,018.18	651	2,271,097.72
Total Interruptible	91	2,423,356.86	90	2,177,509.53	89	1,962,129.45
Total Transportation - Commercial Firm	92	196,218.65	92	166,894.32	92	144,818.11
Total Transportation - Industrial Firm	126	834,970.53	125	812,920.74	124	757,383.48
Total Transportation - Interruptible	83	591,512.76	83	573,957.63	83	554,355.88
Unbilled Revenue		(18,558,610.20)		(9,620,316.98)		(6,171,235.36)
Agency Fees				-		-
Net Balancing/Overrun						
Total Gas Operating Revenue		$ **76,904,403.51**		$ **48,532,248.37**		$ **41,482,226.59**

b. Historical (five years) and forecasted (one year ahead) sales system physical peak demand.

	2025/2026 Forecasted	2024/2025	2023/2024	2022/2023	2021/2022	2020/2021
System peak demand (therms)	10,385,450	10,278,640	10,181,910	10,297,610	10,206,740	10,121,250

c. Historical (five years) and forecasted (one year ahead) sales system physical annual demand.

Gas Year	2025/2026 Forecasted	2024/2025	2023/2024	2022/2023	2021/2022	2020/2021
Annual Demand (therms)	871,891,040	853,772,745	862,272,608	838,438,962	817,385,916	792,118,472

d. Historical (five years) and forecasted (one year ahead) sales system physical demand for each of the following:

1. Annual for each customer class.

Gas Year	2025/2026 Forecasted	2024/2025	2023/2024	2022/2023	2021/2022	2020/2021
Residential (therms)	481,610,965	484,207,721	425,261,320	468,877,298	464,717,923	452,263,886
Commercial (therms)	294,593,318	274,360,540	249,474,803	262,893,049	260,799,176	254,805,654
Industrial Firm (therms)	41,196,130	41,794,756	36,674,198	34,384,194	37,380,657	37,032,338
Industrial Interruptible (therms)	54,490,627	53,409,728	59,686,337	83,987,152	54,488,159	48,016,595

2. Annual and monthly baseload.

Gas Year	2025/2026 Forecasted	2024/2025	2023/2024	2022/2023	2021/2022	2020/2021
November	31,492,592	24,616,239	21,521,199	32,008,982	30,709,933	29,969,601
December	35,312,131	28,903,191	24,388,941	36,240,142	33,590,735	31,307,203
January	39,531,899	33,358,807	27,694,685	42,189,006	36,168,000	34,107,108
February	37,915,213	30,978,735	26,267,236	38,815,909	33,929,102	32,215,083
March	39,345,425	31,479,838	26,937,910	39,913,157	36,509,535	33,569,472
April	35,105,033	27,507,205	24,771,735	35,710,634	33,156,039	30,395,597
May	32,488,564	23,914,784	22,974,153	32,711,512	30,364,879	28,937,453
June	29,338,484	22,113,670	20,932,483	29,402,280	28,541,575	28,169,111
July	25,622,804	18,968,054	18,792,979	26,827,120	25,960,692	25,359,279
August	23,738,677	16,878,121	16,536,474	24,490,204	24,016,589	23,386,015
September	24,133,603	19,206,265	18,238,335	25,090,116	23,815,161	23,625,511
October	29,086,319	22,202,856	20,486,173	30,016,148	28,784,191	28,841,952
Annual	**383,110,745**	**300,127,766**	**269,542,303**	**393,415,209**	**365,546,431**	**349,883,384**

3. Annual and month non-base load.

Gas Year	2025/2026 Forecasted	2024/2025	2023/2024	2022/2023	2021/2022	2020/2021
November	63,934,748	68,574,802	72,664,996	59,240,744	60,832,815	60,504,626
December	95,752,173	98,292,531	104,297,358	88,508,994	90,713,996	91,538,810
January	91,092,860	96,533,801	102,880,004	85,544,762	88,079,277	89,174,162
February	75,621,015	82,771,660	91,116,952	69,943,462	71,559,429	72,067,179
March	63,281,315	68,026,045	72,210,415	58,088,579	59,848,154	59,993,199
April	39,658,399	47,444,693	50,205,094	36,295,437	36,964,858	37,314,235
May	17,787,135	23,377,737	25,140,239	14,700,339	14,997,271	15,454,241
June	5,366,733	11,902,694	13,049,070	3,642,146	3,765,614	3,858,078
July	1,853,923	9,031,798	9,565,441	867,988	905,559	926,910
August	3,298,002	7,659,858	8,018,913	845,980	839,829	870,346
September	5,471,046	8,735,800	9,635,760	2,858,652	2,987,241	3,054,454
October	25,662,945	31,293,560	33,946,061	24,486,671	25,104,023	25,085,308
Annual	**488,780,295**	**553,644,979**	**592,730,305**	**445,023,753**	**456,598,067**	**459,841,547**

4. Annual and monthly for the geographic regions utilized by each LDC in its most recent IRP or IRP update.

2025/2026	Albany	Astoria	Coos Bay	The Dalles (OR)	The Dalles (WA)	Eugene	Newport	Portland	Salem	Vancouver	Total
November	6,050,244	1,702,433	400,599	1,252,637	287,741	6,950,733	1,246,569	54,116,875	14,111,992	9,493,730	95,613,553
December	8,126,134	2,335,044	523,466	1,724,822	413,865	9,437,467	1,679,476	77,267,554	18,756,052	13,835,433	134,099,311
January	8,098,328	2,325,773	518,129	1,679,552	415,097	9,243,781	1,677,702	77,237,363	18,590,685	14,304,578	134,090,990
February	6,992,738	2,107,603	490,866	1,447,599	345,682	8,270,324	1,542,156	65,545,113	16,085,896	11,998,955	114,826,932
March	6,317,951	1,987,525	487,353	1,249,384	294,689	7,482,225	1,500,390	56,702,029	14,535,043	10,592,793	101,149,383
April	4,607,598	1,462,821	385,668	874,672	198,012	5,599,793	1,155,966	39,870,873	10,619,157	7,303,488	72,078,048
May	3,115,787	978,520	299,965	605,533	127,281	3,944,064	798,579	26,486,731	7,261,989	4,771,679	48,390,127
June	2,124,043	661,849	214,161	451,453	86,803	2,829,254	547,599	18,997,643	5,180,272	3,406,985	34,500,062
July	1,651,906	539,633	172,856	352,702	69,392	2,289,322	417,481	15,231,714	4,177,456	2,765,807	27,668,268
August	1,650,263	533,423	166,012	343,288	67,417	2,443,428	415,262	14,849,466	4,015,424	2,659,537	27,143,519
September	1,815,552	558,574	188,378	384,278	74,424	2,380,644	480,531	15,982,274	4,547,466	2,893,382	29,305,504
October	3,444,916	1,028,204	270,030	688,964	153,423	4,013,903	832,184	28,918,581	8,178,802	5,496,334	53,025,342
Annual	53,995,459	16,221,401	4,117,484	11,054,884	2,533,827	64,884,939	12,293,893	491,206,216	126,060,234	89,522,703	871,891,040

2024/2025	Albany	Astoria	Coos Bay	The Dalles (OR)	The Dalles (WA)	Eugene	Newport	Portland	Salem	Vancouver	Total
November	5,987,783	1,656,759	380,435	1,263,506	292,376	6,873,297	1,198,373	53,134,505	13,922,471	9,409,207	94,118,713
December	8,017,318	2,256,887	500,691	1,715,260	398,346	9,279,573	1,608,472	76,207,872	18,497,840	13,203,046	131,685,304
January	8,208,907	2,304,774	514,413	1,728,060	408,646	9,371,493	1,643,957	78,042,224	18,850,840	13,979,885	135,053,201
February	7,080,260	2,117,638	481,662	1,473,858	350,923	8,326,306	1,536,991	66,486,638	16,277,795	12,092,281	116,224,352
March	6,184,726	1,920,459	470,197	1,216,073	294,586	7,296,574	1,448,448	54,826,193	14,231,198	10,497,498	98,385,953
April	4,637,856	1,486,976	387,156	863,253	208,018	5,586,326	1,189,483	39,071,048	10,628,728	7,575,973	71,634,816
May	2,884,464	938,897	284,522	532,293	132,966	3,620,242	816,017	23,352,092	6,601,903	4,931,845	44,095,242
June	2,032,144	657,951	210,532	414,145	92,073	2,682,739	607,001	17,658,727	4,878,645	3,569,473	32,803,430
July	1,589,284	520,950	172,239	331,097	82,268	2,193,331	480,040	14,663,889	4,027,333	3,259,980	27,320,412
August	1,430,632	454,968	149,748	291,084	69,825	2,159,886	413,607	12,761,663	3,511,127	2,688,362	23,930,902
September	1,686,022	522,374	180,749	354,261	76,614	2,208,786	485,339	14,565,179	4,230,642	2,903,003	27,212,969
October	3,376,822	1,012,647	256,885	692,831	161,087	3,948,798	823,005	27,574,398	7,967,757	5,493,222	51,307,451
Annual	53,116,218	15,851,280	3,989,228	10,875,721	2,567,729	63,547,351	12,250,732	478,344,429	123,626,280	89,603,776	853,772,745

2023/2024	Albany	Astoria	Coos Bay	The Dalles (OR)	The Dalles (WA)	Eugene	Newport	Portland	Salem	Vancouver	Total
November	6,093,201	1,674,096	370,424	1,325,668	303,677	7,048,039	1,190,781	53,769,434	14,293,412	9,544,800	95,613,532
December	8,186,516	2,270,081	488,842	1,803,024	409,044	9,560,075	1,592,624	77,884,669	19,099,663	13,304,741	134,599,277
January	8,356,057	2,301,047	499,067	1,804,165	417,179	9,620,006	1,603,198	79,174,199	19,423,010	13,887,067	137,084,996
February	7,354,465	2,196,005	479,342	1,569,506	368,177	8,701,747	1,565,052	69,088,715	17,095,594	12,486,075	120,904,678
March	6,208,629	1,946,923	459,274	1,244,004	292,146	7,356,580	1,455,856	54,615,879	14,411,681	10,224,813	98,215,785
April	4,676,872	1,525,328	386,929	877,075	204,438	5,663,243	1,220,807	38,454,569	10,792,953	7,333,207	71,135,423
May	2,982,834	984,640	302,720	551,893	123,404	3,838,686	876,104	22,785,727	6,859,608	4,465,990	43,771,604
June	2,022,655	687,783	215,432	413,482	88,096	2,701,522	674,570	16,732,754	4,816,197	3,402,141	31,754,633
July	1,606,842	548,522	184,014	344,366	77,445	2,260,167	564,276	14,653,169	4,114,745	3,104,670	27,458,214
August	1,432,343	467,541	155,906	299,017	68,664	2,190,884	477,694	12,647,464	3,539,440	2,629,038	23,907,990
September	1,659,386	538,044	185,367	356,479	75,212	2,194,438	546,551	13,728,997	4,168,446	2,784,235	26,237,155
October	3,476,597	1,041,606	259,786	736,414	164,631	4,114,924	842,418	27,246,068	8,289,815	5,417,061	51,589,321
Annual	54,056,397	16,181,616	3,987,104	11,325,093	2,592,111	65,250,310	12,609,930	480,781,644	126,904,564	88,583,839	862,272,608

2022/2023	Albany	Astoria	Coos Bay	The Dalles (OR)	The Dalles (WA)	Eugene	Newport	Portland	Salem	Vancouver	Total
November	5,689,560	1,535,318	319,342	1,088,570	274,132	6,318,249	1,128,054	52,304,343	13,410,457	9,250,013	91,318,038
December	7,682,272	2,109,693	425,939	1,513,403	374,950	8,712,922	1,520,832	74,342,317	17,920,088	12,788,427	127,390,841
January	7,844,959	2,150,334	431,394	1,494,863	387,318	8,730,432	1,559,978	76,239,873	18,258,083	13,612,643	130,709,879
February	6,598,595	1,894,948	384,117	1,243,356	324,808	7,536,212	1,390,432	63,667,195	15,315,056	11,502,009	109,856,729
March	5,956,062	1,752,770	376,158	1,046,900	270,126	6,778,149	1,325,201	55,375,919	13,859,684	9,967,746	96,708,714
April	4,356,269	1,275,070	297,187	713,633	189,346	5,086,934	1,012,398	39,205,009	10,191,327	7,236,769	69,563,941
May	2,896,744	792,155	228,344	466,631	114,554	3,504,686	646,594	25,689,767	6,935,692	4,550,644	45,825,813
June	1,961,921	539,639	155,960	339,092	79,010	2,449,277	458,430	18,610,240	4,892,514	3,409,400	32,895,484
July	1,610,732	469,265	135,624	275,702	65,818	2,111,864	369,427	15,724,920	4,189,604	2,925,976	27,878,931
August	1,512,975	434,279	120,874	251,021	57,537	2,164,136	333,760	14,341,359	3,767,680	2,514,549	25,498,169
September	1,681,025	447,890	143,931	292,879	66,777	2,090,510	394,967	15,562,090	4,349,712	2,847,367	27,877,150
October	3,394,053	933,616	217,399	594,544	146,709	3,757,657	762,823	29,396,189	8,198,024	5,514,259	52,915,273
Annual	51,185,167	14,334,976	3,236,268	9,320,595	2,351,086	59,241,029	10,902,896	480,459,223	121,287,920	86,119,802	838,438,962

2021/2022	Albany	Astoria	Coos Bay	The Dalles (OR)	The Dalles (WA)	Eugene	Newport	Portland	Salem	Vancouver	Total
November	5,490,502	1,663,249	260,243	1,054,807	266,864	5,987,815	1,209,582	53,996,945	12,566,251	9,163,220	91,659,477
December	7,476,494	2,229,213	349,124	1,464,088	363,913	8,081,469	1,602,501	75,953,806	17,038,097	12,598,702	127,157,405
January	7,385,839	2,224,847	347,324	1,444,983	375,865	7,940,218	1,592,279	76,153,517	16,861,249	13,234,908	127,561,028
February	6,150,476	1,958,152	304,583	1,165,903	310,969	6,653,952	1,421,564	63,244,324	14,234,356	11,244,993	106,689,273
March	5,625,952	1,878,674	308,345	995,035	264,793	6,078,750	1,418,387	55,516,355	12,977,216	9,858,640	94,922,147
April	4,151,196	1,411,431	241,487	659,492	178,068	4,439,725	1,109,972	38,944,609	9,440,459	6,890,455	67,466,893
May	2,687,032	893,325	159,351	407,059	109,843	2,893,479	746,999	25,270,820	6,004,999	4,434,772	43,607,679
June	1,924,347	600,865	107,211	295,723	81,576	2,089,897	502,686	18,738,877	4,413,314	3,366,300	32,120,796
July	1,587,531	505,008	89,451	257,517	68,268	1,737,672	414,719	15,861,749	3,710,237	2,811,514	27,043,665
August	1,512,244	468,116	82,434	241,374	62,281	1,636,170	386,120	14,636,144	3,438,589	2,557,154	25,020,628
September	1,614,061	507,023	89,364	255,150	67,875	1,717,196	419,524	15,504,936	3,745,858	2,772,076	26,693,064
October	3,184,569	1,013,852	165,241	550,735	148,345	3,482,797	789,620	30,153,000	7,320,382	5,393,904	52,202,444
Annual	48,790,243	15,353,754	2,504,159	8,791,865	2,298,661	52,739,140	11,613,951	483,975,081	111,751,006	84,326,638	822,144,498

2020/2021	Albany	Astoria	Coos Bay			Eugene	Newport	Portland	Salem	Vancouver	Total
November	5,417,614	1,641,176	244,661	1,043,842	242,381	5,903,847	1,193,283	53,368,623	12,315,393	9,420,252	90,791,072
December	7,367,820	2,192,496	325,790	1,453,447	336,992	7,956,784	1,581,665	75,078,885	16,691,467	13,067,534	126,052,881
January	7,297,435	2,194,480	327,273	1,440,533	346,460	7,848,958	1,578,568	75,534,760	16,548,142	13,455,958	126,572,568
February	6,068,715	1,930,141	286,063	1,163,153	285,785	6,577,048	1,402,497	62,549,199	13,980,449	11,116,995	105,360,046
March	5,466,225	1,829,178	285,584	972,716	243,036	5,894,920	1,383,778	54,067,843	12,518,709	9,518,275	92,180,265
April	4,014,878	1,370,228	221,961	637,549	166,237	4,271,617	1,089,502	37,625,313	9,065,639	6,595,067	65,057,991
May	2,631,816	879,779	147,899	394,183	104,196	2,810,430	741,521	24,810,018	5,848,058	4,197,580	42,565,479
June	1,916,930	598,166	103,229	291,737	75,996	2,071,115	503,933	18,688,556	4,367,584	3,083,215	31,700,459
July	1,559,964	495,319	85,342	250,615	62,995	1,700,089	410,040	15,595,683	3,624,140	2,539,848	26,324,035
August	1,479,180	457,366	78,097	233,362	57,371	1,591,654	380,079	14,360,679	3,346,283	2,308,352	24,292,422
September	1,618,047	507,636	87,370	254,697	62,638	1,718,869	423,636	15,517,733	3,735,911	2,522,838	26,449,375
October	3,225,528	1,022,272	161,517	558,539	130,144	3,531,312	798,411	30,419,460	7,378,628	5,152,529	52,378,340
Annual	48,064,152	15,118,237	2,354,785	8,694,372	2,114,232	51,876,643	11,486,914	477,616,752	109,420,403	82,978,443	809,724,932

2019/2020	Albany	Astoria	Coos Bay	The Dalles (OR)	The Dalles (WA)	Eugene	Newport	Portland	Salem	Vancouver	Total

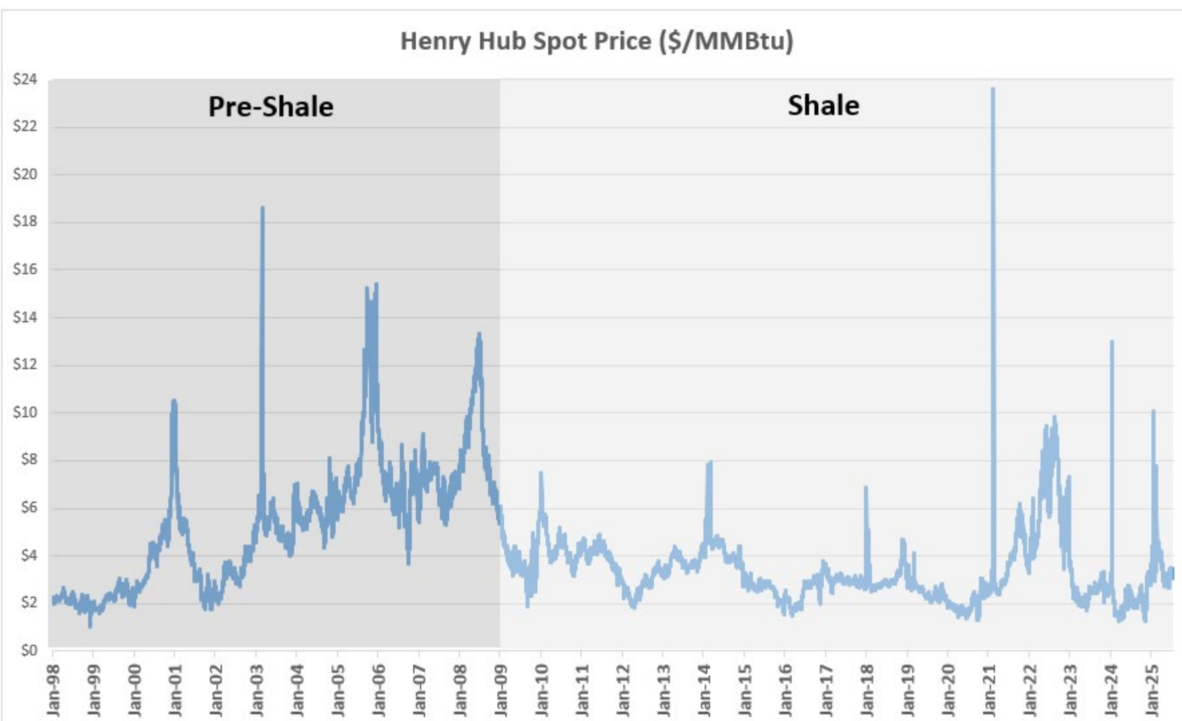
Section V.4 - Market Information

General historical and forecasted (one year ahead) conditions in the national and regional physical and financial natural gas purchase markets. This should include descriptions of each major supply point from which the LDC physically purchases and the major factors affecting supply, prices, and liquidity at those points.

Deregulation from the late 1970s to early 1990s was a response to perceived natural gas shortages. In the new unregulated environment, prices dropped due to competition, increased efficiencies, technological improvements, and the discovery of more natural gas.

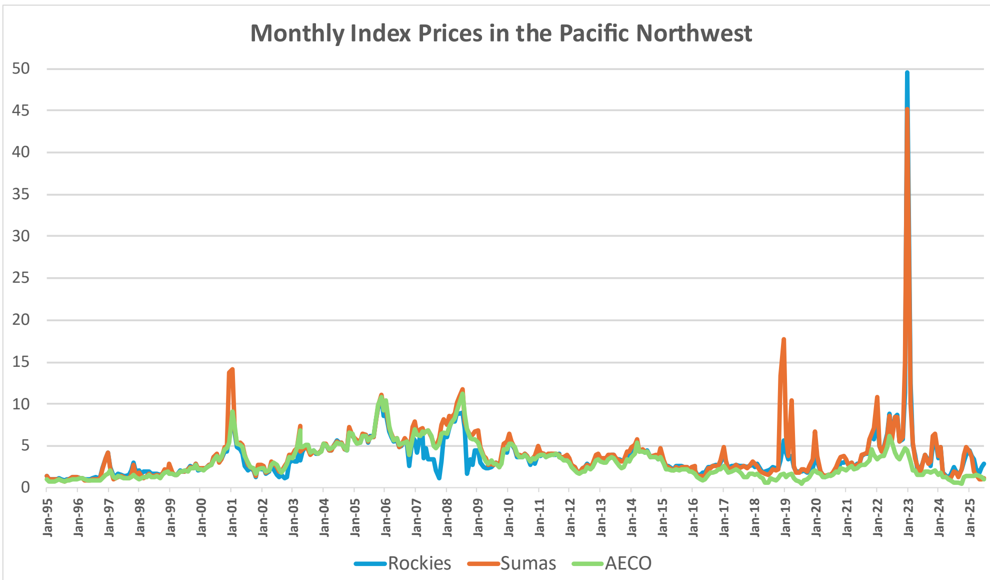
In the early 2000s, prices rose dramatically due to tightness in the supply/demand balance, a situation that Enron (and others) sought to exploit. This led to scandals, lawsuits, regulatory investigations, bankruptcies and other headline-making news that obscured the fact that gas supplies really were tightening and that demand growth would be dependent on bringing additional supplies to North America in the form of LNG imports. Catastrophic hurricanes (Katrina, Rita, et al) in 2005 interrupted natural gas supplies from the Gulf of Mexico and prices spiked again. Gas prices soared in the spring and summer of 2008 on the tail of predicted supply shortfalls. At that time, Henry Hub prices peaked at $13.31/Dth. Within months, the onset of a global economic recession reduced demand while the advent of horizontal drilling into shale formations unleashed a surge of production. Prices soon tumbled and remained quite low for over 10-years. More recently, extreme weather, LNG export growth, and infrastructure constraints, along with a variety of other factors, led to record volatility and a sharp rise in prices in 2022. While prices abated throughout 2023 and early 2024, they have since rebounded in 2025 amid tightening balances, with volatility returning as market fundamentals shift again. (Figure 1).

Figure 1



Historical prices into the Pacific Northwest at NW Natural's major supply points reflected national trends. As shown in Figure 2, prices initially bottomed out in spring 2012, then rose and fell again aided primarily by the weather. First there was the so-called "Polar Vortex" that swept the eastern half of the country in 2013/14 and again in 2014/15, then the exceedingly warm El Niño winter of 2015/2016. And then a non-weather event – the rupture of Enbridge's T-South pipeline on October 9, 2018 – was the dominant factor during the winter of 2018/19 due to its resulting shortfall of supply into the Pacific Northwest. Weather was generally mild October 2018 through January 2019; however, February 2019 was the third coldest on record in Portland and the coldest since 1989. As T-South directly supplies the Sumas market, very high prices resulted. By the winter of 2019/20, price parity around the Pacific Northwest supply hubs had resumed due to milder temperatures and the full return to service of the T-South pipeline in December 2019.

Figure 2



Prices fell in 2020 in the wake of the COVID-19 pandemic and its downward impact on energy demand. By April 20, 2020, the West Texas Intermediate crude oil price plunged into the negative for the first time in history. The drop in demand outpaced declines in production and led to a strong storage inventory. This economic uncertainty resulted in a decline in production that carried into 2022 as producers focused on reducing debt.

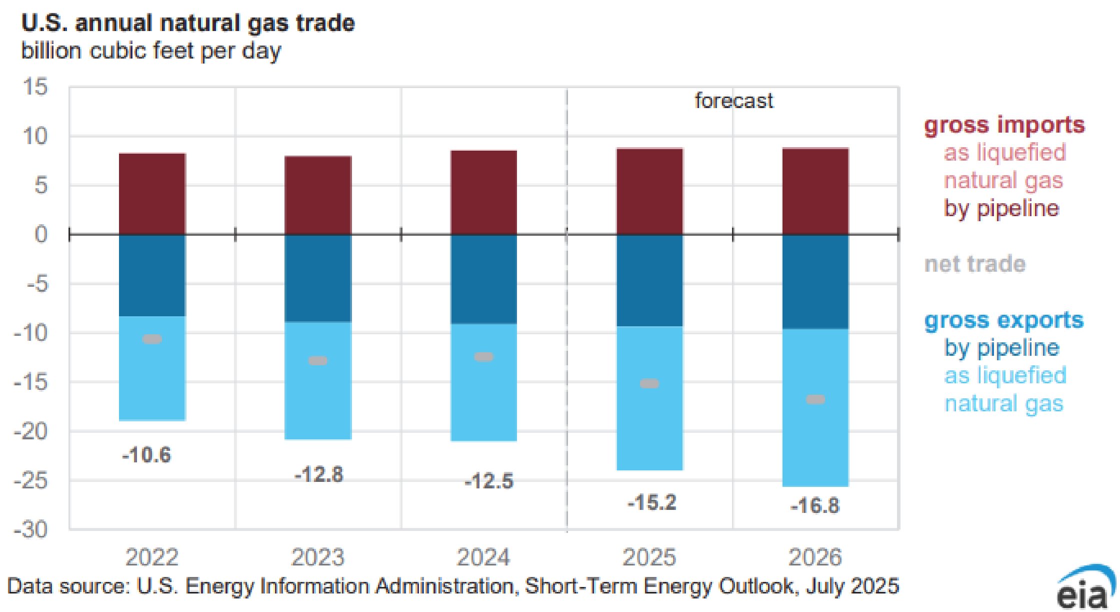
With production down and a colder-than-normal February in 2021, the storage draw was a February record and the second fastest withdrawal rate for any month on record. Well freeze-offs amplified the drop in production combined with increased consumption and supported a record Henry Hub spot price of $23.86/Dth on February 17, 2021. Storage ended the winter withdrawal season at 1.8 Tcf, slightly less than the five-year average. Demand continued to recover in 2021 with an increase in economic activity and easing of the COVID-19 pandemic.

Sluggish production growth combined with strong demand for natural gas generation and LNG and Mexico pipeline exports added to a tight market and created upward pressure on prices during the second half of 2021. LNG exports continued to grow in 2022 as two new facilities came online and there was additional global demand as a result of Russia's invasion of Ukraine(Figure 3). A June 8, 2022 fire at Freeport LNG took the facility offline into the first quarter of 2023 which added 2 Bcf/d of supply to the market and provided some relief. Prices remained high as a warmer-than-normal summer led to record gas-fired generation demand and the market anticipated the impact of demand outpacing supply in the winter of 2022/23. Nationally the U.S. saw price relief due to a warmer-than-normal winter in 2022/23; however, the West faced challenges including sustained colder-than-normal winter weather, pipeline constraints, and low storage inventory levels. The tight market led to extreme Sumas and Rockies prices.
Production began to increase in late 2022 and hit a new average monthly record of 107 Bcf/d in December 2023. With supply finally outpacing demand, the U.S. storage inventory recovered to above the five-year average.

Additionally, the consecutive mild winters of 2022/23 and 2023/24 in Europe provided relief to global LNG demand and prices. The additional supply led to lower prices in 2023 and resulted in a drop in both oil and gas rig counts. The outcome was seen in early 2024 as production began to decline and supply and demand came closer into balance.

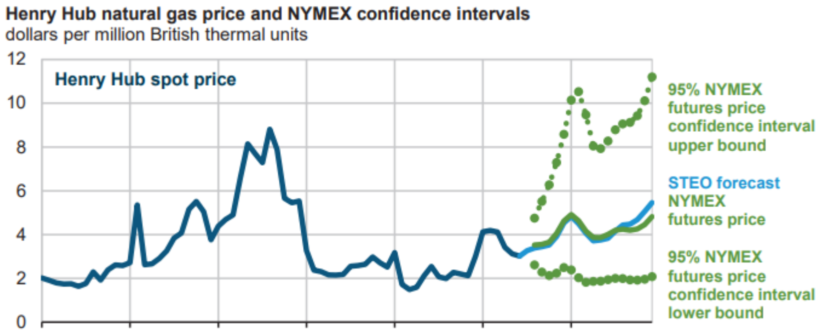
In 2025, continued strong inventory levels and modest demand have kept natural gas prices subdued. Above-average storage carryout from the prior winter and stable production have contributed to reduced price volatility, despite occasional regional imbalances. Gas-fired generation demand has weakened due to milder summer temperatures and increased renewable output.

Figure 3



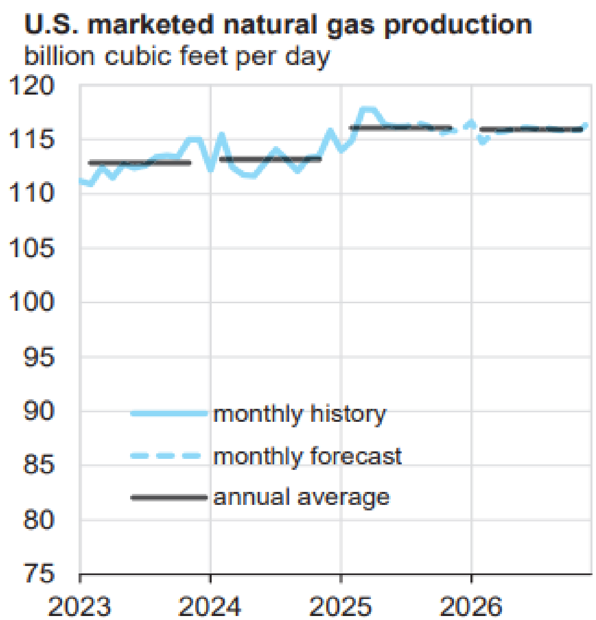
The US Energy Information Administration's (EIA) July 2025 Short-Term Energy Outlook has a baseline price forecast with upper and lower confidence intervals, as shown in Figure 4. These prices are for the Henry Hub, which is located in Louisiana and is one of the most traded natural gas futures contracts in the world. EIA, as well as the futures market represented by the NYMEX curve, indicate an expectation for prices to have a modest increase through 2025, driven by an anticipated slight production decline in 2026 combined with continued growth in LNG exports (Figure 5). The EIA expects storage inventory to end the 2025 injection season 3% above the five-year average (Figure 6).

Figure 4



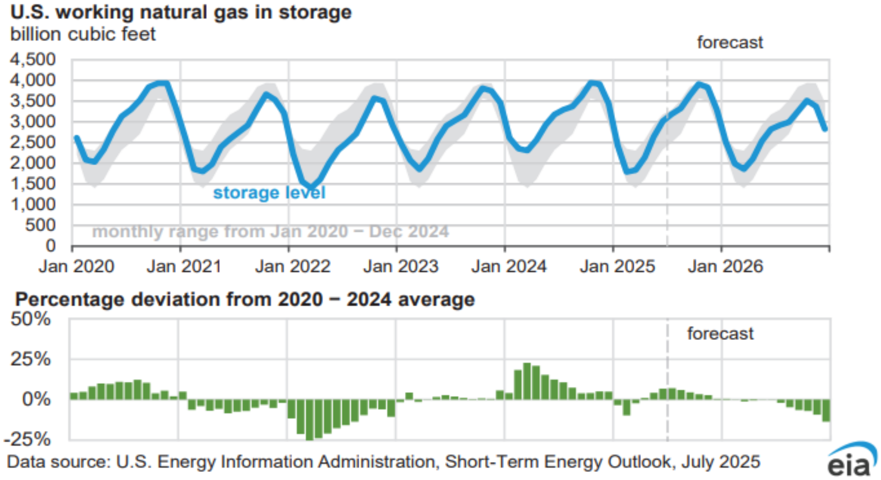
Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, July 2025, CME Group, and Refinitiv an LSEG Business
Note: Confidence interval derived from options market information for the five trading days ending July 2, 2025. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Figure 5



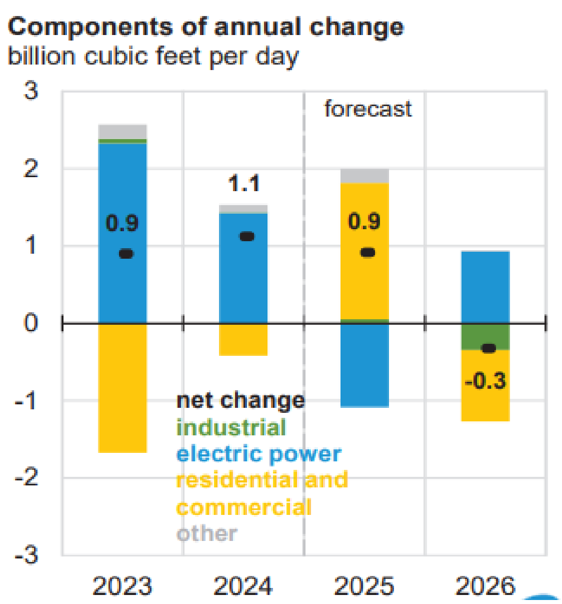
Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, July 2025

Figure 6



Gas-fired electric generation can be another big driver of natural gas consumption and pricing. Due to slower than expected renewable energy installation development, limited gas-to-coal switching flexibility, and warm summer temperatures, natural gas generation demand has grown over the past couple years. An increase in renewable energy is expected to reduce the need for natural gas generation in the future, though some renewable energy sources, such as wind, can work well in combination with natural gas generation to alleviate intermittency issues. On the whole, EIA expects an increase of natural gas for electric generation in 2026 compared to 2025 (Figure 7).

Figure 7



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, July 2025

Regarding liquidity at our major supply points in the Rockies and western Canada (AECO, Sumas and Station 2), it is likely to continue to be strong for the next couple of years. That is, Rockies and western Canadian gas that typically flowed to mid-Continent and East Coast markets will continue to be displaced by gas supplies from eastern shale plays such as Marcellus. It is likely, though, that demand growth in the Pacific Northwest - some combination of power generation, industrial loads and in particular regional LNG exports - will catch up with available supplies, spurring a strong price response. The Energía Costa Azul LNG export facility in Baja California, Mexico is expected to begin commercial operations in the spring of 2026, which will compete with California supply and could have an impact on regional prices. The LNG Canada export terminal located in British Columbia began commercial operations in June 2025 and the Woodfibre LNG export terminal is expected to be online in 2027. Woodfibre LNG will utilize 0.3 Bcf/d of capacity on the T-South pipeline. A 0.3 Bcf/d expansion of the T-South pipeline is planned to replace this heavily utilized capacity; however, it is anticipated that there will be liquidity issues at Sumas between the time Woodfibre LNG comes online in 2027 and the planned 2028 in-service date of the T-South expansion. The magnitude of the price response will also depend on the ability of gas producers to tap more supplies from western Canada (primarily BC shales) and the Rockies. These factors are not expected to have a major impact on the upcoming PGA year, whereas storage positions, the weather, and pipeline operations (maintenance activities, etc.) will continue, as they have in the past, to be the dominant factors influencing near-term prices.

Section V.5 - Data Interpretation

If not included in the PGA filing, please explain the major aspects of the LDC’s analysis and interpretation of the data and information described in (1) and (2) above, the most important conclusions resulting from that analysis and interpretation, and the application of these conclusions in the development of the current PGA portfolio.

See Exhibit C, IV.2.b

Section V.6 - Credit Worthiness Standards

A copy of the Board or officer approved credit worthiness standards in place for the period in which the current gas supply portfolio was developed, along with full documentation for these standards. Also, a copy of the credit worthiness standards actually applied in the purchase of physical gas and entering into financial hedges. If the two are one and the same, please indicate so.

IV. Credit Risk Management

The following steps are taken by the Front and Middle Offices to provide credit risk management:

	Procedure	Responsible Office
1	Analyzes the counterparty's profile to determine credit risk tolerances.	Mid Office
2	Sets counterparty maximum credit limits in accordance with company policy (see Exhibit "E" of the Gas Supply Risk Management Policies).	Mid Office
3	Monitors credit exposure, and reduces credit below policy maximums as necessary, and or halts future trading.	Mid Office
4	If the credit exposure amount exceeds the counterparty credit limit, verifies the limit violation amount, and after a risk analysis consults with Treasurer (or CFO) and Front Office to coordinate Company response	Mid Office
5	Follows GSRMP for policy exceptions for physical transactions and Treasurer (or CFO) for any financial policy exceptions not covered in policy.	Mid Office
6	Notifies Front Office Executive of limit violations in physical transactions, and Mid Office Executive of limit violations in financial transactions.	Mid Office
7	Determines any appropriate action, within the GSRMP guidelines, in response to physical transaction violations.	Front Office Executive
8	Communicates instructions for dealing with physical transaction violations to Front Office and submits copies of the instructions to the Mid Office.	Front Office Executive
9	Determines any appropriate action in response to financial transaction violations in coordination with the Treasurer and CFO.	Mid Office Executive
10	Communicates instructions for dealing with financial transaction violations to Front Office and submits copies of the instructions to the Mid Office.	Mid Office Executive
11	Monitors and analyzes various credit risk metrics to better understand the current and potential risks in the portfolio, including stochastic and scenario analysis, etc.	Mid Office
12	Reviews credit limits at least monthly, and additionally as needed, to assess whether changes should be made.	Mid Office
13	Monitors market and counterparty top news articles, Moody's and S&P rating and outlook actions, etc. daily for all counterparties with which the company has physical or financial gas commodity credit risk.	Middle Office
14	Daily monitor markets assessment credit risk (i.e. CDS spreads) on derivative counterparties.	Mid Office

Source: NW Natural General Procedure G-72; Physical and financial Commodity Transaction Procedures

Effective March 28, 2005; Last updated January 5, 2015

The entire text of NW Natural Gas Supply Risk Management Policies (pages 33-73) is confidential subject to Modified Protective Order No. 10-337 and has been redacted.

Section V.7 – Storage

Workpapers should include the following information about natural gas storage included in the portfolio upon which that PGA is based.

a) **Type of storage (e.g. depleted field, salt dome).**
See Table 1 below.

b) **Location of each storage facility.**
See Table 1 below.

c) **Total level of storage in terms of deliverability and capacity held during the gas year.**
See Table 1 below.

Table 1

Northwest Natural Gas Company
PGA Portfolio Guidelines
2025-2026 Oregon PGA

V.7	**Storage**
a)	Type of storage (e.g., depleted field, salt dome).
b)	Location of each storage facility.
c)	Total level of storage in terms of deliverability and capacity held during the gas year.

Facility	Max. Daily Rate (Dth/day)	Max. Seasonal Level (Dth)
Jackson Prairie - aquifer - Chehalis, WA	46,030	1,120,288
Mist (share allocated to Utility) - depleted field - Mist, OR	340,000	13,701,780
Portland LNG - LNG Plant - Portland, OR	100,440	511,574
Newport LNG - LNG Plant - Newport, OR	78,000	1,097,346

d) **Historical (five years) gas supply delivered to storage, both annual total and by month.**

See Table 2 below.

e) **Historical (five years) gas supply withdrawn from storage, both annual total and by month**

See Table 2 below.

Table 2

Northwest Natural Gas Company
PGA Portfolio Guidelines
2025-2026 Oregon PGA

NORTHWEST NATURAL GAS COMPANY
All Sites Therms Summary

MONTH	BEGINNING BALANCE THERMS	BEGINNING BALANCE AMOUNT	RATE	ISSUES (Withdrawals) THERMS	ISSUES (Withdrawals) AMOUNT	LIQUEFIED THERMS	INJECTIONS (Deliveries) AMOUNT	INJECTIONS (Deliveries) RATE	ENDING BALANCE THERMS	ENDING BALANCE AMOUNT	ENDING BALANCE RATE
Jan-20	132,823,074	$ 28,864,416.62	0.21731	10,198,737	$ 2,201,704.72	299,280	$ 64,173.00	0.21442	122,923,617	$ 26,726,884.90	0.21743
Feb	122,923,617	$ 26,726,884.90	0.21743	5,148,377	$ 1,112,277.52	-	$ -	-	117,775,240	$ 25,614,607.38	0.21749
Mar	117,775,240	$ 25,614,607.38	0.21749	2,421,591	$ 505,133.30	-	$ -	-	115,353,649	$ 25,109,474.08	0.21767
Apr	115,353,649	$ 25,109,474.08	0.21767	201,250	$ 43,943.40	2,948,736	$ 458,615.74	0.15553	118,101,135	$ 25,524,146.41	0.21612
May	118,101,135	$ 25,524,146.41	0.21612	217,195	$ 46,906.98	1,386,817	$ 253,956.25	0.18312	119,270,757	$ 25,731,195.69	0.21574
Jun	119,270,757	$ 25,731,195.69	0.21574	110,954	$ 24,511.80	1,817,787	$ 336,337.33	0.18503	120,977,590	$ 26,043,021.22	0.21527
Jul	120,977,590	$ 26,043,021.22	0.21527	298,733	$ 63,153.42	686,739	$ 109,795.08	0.15988	121,365,596	$ 26,089,662.88	0.21497
Aug	121,365,596	$ 26,089,662.88	0.21497	206,344	$ 42,686.24	3,249,076	$ 708,262.21	0.21799	124,408,328	$ 26,755,238.85	0.21506
Sep	124,408,328	$ 26,755,239.30	0.21506	317,164	$ 65,359.87	2,665,667	$ 476,066.34	0.17859	126,756,831	$ 27,165,945.77	0.21432
Oct	126,756,831	$ 27,165,945.77	0.21432	7,087,891	$ 1,434,728.83	1,630,897	$ 465,354.64	0.28534	121,299,837	$ 26,196,571.58	0.21597
Nov	121,299,837	$ 26,196,571.58	0.21597	154,113	$ 33,855.04	13,425,522	$ 3,849,976.20	0.28677	134,571,246	$ 30,012,692.73	0.22302
Dec	134,571,246	$ 30,012,692.73	0.22302	16,092,069	$ 3,573,068.87	-	$ -	-	118,479,177	$ 26,439,623.86	0.22316
TOTAL 2020 ACTIVITY				42,454,418	9,147,330	28,110,521	$ 6,722,536.78				
Jan-21	118,479,177	$ 26,439,623.86	0.22316	20,187,649	$ 4,486,480.80	-	$ -	-	98,291,528	$ 21,953,143.06	0.22335
Feb	98,291,528	$ 21,953,143.06	0.22335	32,056,999	$ 7,169,884.83	1,237,520	$ 2,237,530.40	1.80808	67,472,049	$ 17,020,788.63	0.25226
Mar	67,472,049	$ 17,020,788.63	0.25226	8,754,392	$ 2,231,412.59	1,068,806	$ 281,720.69	0.26358	59,786,463	$ 15,071,096.74	0.25208
Apr	59,786,463	$ 15,071,096.74	0.25208	192,781	$ 44,940.29	6,234,559	$ 1,582,117.90	0.25377	65,828,241	$ 16,608,274.34	0.25230
May	65,828,241	$ 16,608,274.34	0.25230	285,591	$ 69,434.67	6,485,525	$ 1,775,350.50	0.27374	72,028,175	$ 18,314,190.17	0.25426
Jun	72,028,175	$ 18,314,190.17	0.25426	252,285	$ 62,250.08	11,611,638	$ 3,519,482.59	0.30310	83,387,528	$ 21,771,422.69	0.26109
Jul	83,387,528	$ 21,771,422.69	0.26109	190,715	$ 47,213.41	16,337,851	$ 5,880,200.85	0.35991	99,534,664	$ 27,604,410.13	0.27733
Aug	99,534,664	$ 27,604,410.13	0.27733	113,879	$ 28,846.69	20,414,041	$ 7,646,427.28	0.37457	119,834,826	$ 35,221,990.72	0.29392
Sep	119,834,826	$ 35,221,990.72	0.29392	96,245	$ 25,894.38	11,937,862	$ 5,706,488.85	0.47802	131,676,443	$ 40,902,585.19	0.31063
Oct	131,676,443	$ 40,902,585.19	0.31063	2,299,888	$ 1,056,503.67	17,635,527	$ 8,822,437.24	0.50027	147,012,082	$ 48,668,518.76	0.33105
Nov	147,012,082	$ 48,668,518.76	0.33105	3,034,301	$ 1,390,726.33	4,290,036	$ 1,922,808.66	0.44820	148,267,817	$ 49,200,601.09	0.33184
Dec	148,267,817	$ 49,200,601.09	0.33184	28,923,938	$ 9,441,374.72	147,400	$ 44,726.45	0.30344	119,491,279	$ 39,803,952.82	0.33311
TOTAL 2021 ACTIVITY				96,388,663	$ 26,054,962.46	97,400,765	$ 39,419,291.41				
Jan-22	119,491,279	$ 39,803,952.82	0.33311	30,332,306	$ 9,764,472.15	495,770	$ 181,363.05	0.36582	89,654,743	$ 30,220,843.72	0.33708
Feb	89,654,743	$ 30,220,843.72	0.33708	21,782,705	$ 7,566,832.47	-	$ -	-	67,872,038	$ 22,654,011.25	0.33378
Mar	67,872,038	$ 22,654,011.25	0.33378	5,809,463	$ 1,870,379.81	-	$ -	-	62,062,575	$ 20,783,631.44	0.33488
Apr	62,062,575	$ 20,783,631.44	0.33488	13,717,798	$ 5,181,177.62	470,660	$ 296,905.84	0.63083	48,815,437	$ 15,899,359.66	0.32570
May	48,815,437	$ 15,899,359.66	0.32570	1,189,464	$ 404,147.40	17,594,964	$ 12,988,824.99	0.73821	65,220,937	$ 28,484,037.25	0.43673
Jun	65,220,937	$ 28,484,037.25	0.43673	104,489	$ 35,940.04	22,093,556	$ 15,626,716.14	0.70730	87,210,004	$ 44,074,813.35	0.50539
Jul	87,210,004	$ 44,074,813.35	0.50539	71,804	$ 31,570.78	16,766,575	$ 8,899,782.01	0.53081	103,904,775	$ 52,943,024.58	0.50953
Aug	103,904,775	$ 52,943,024.58	0.50953	43,995	$ 19,515.40	23,156,431	$ 15,118,342.40	0.65288	127,017,211	$ 68,041,851.58	0.53569
Sep	127,017,211	$ 68,041,851.58	0.53569	99,721	$ 40,802.29	15,810,366	$ 8,502,694.85	0.53779	142,727,856	$ 76,503,744.13	0.53601
Oct	142,727,856	$ 76,503,744.13	0.53601	1,045,005	$ 598,517.41	16,911,241	$ 7,980,458.99	0.47190	158,594,092	$ 83,885,685.72	0.52893
Nov	158,594,092	$ 83,885,685.72	0.52893	7,637,659	$ 4,087,081.91	3,223	$ 2,459.65	0.76316	150,959,656	$ 79,801,063.46	0.52863
Dec	150,959,656	$ 79,801,063.46	0.52863	26,378,774	$ 14,000,235.69	202,826	$ 295,977.33	1.45927	124,783,708	$ 66,096,805.10	0.52969
TOTAL 2022 ACTIVITY				108,213,183	$ 43,600,672.97	113,505,612	$ 69,893,525.25				
Jan-23	124,783,708	$ 66,096,805.10	0.52969	28,212,941	$ 14,979,987.33	249,200	$ 75,627.50	0.30348	96,819,967	$ 51,192,445.27	0.52874
Feb	96,819,967	$ 51,192,445.27	0.52874	31,775,058	$ 16,896,399.03	-	$ -	-	65,044,909	$ 34,296,046.24	0.52727
Mar	65,044,909	$ 34,296,046.24	0.52727	16,466,254	$ 8,881,623.71	897,780	$ 283,663.50	0.31596	49,476,435	$ 25,698,086.03	0.51940
Apr	49,476,435	$ 25,698,086.03	0.51940	6,788,869	$ 3,334,552.47	13,152,839	$ 4,245,399.24	0.32277	55,840,405	$ 26,608,932.80	0.47652
May	55,840,405	$ 26,608,932.80	0.47652	85,460	$ 33,176.43	19,426,664	$ 3,967,966.47	0.20425	75,181,609	$ 30,543,722.85	0.40627
Jun	75,181,609	$ 30,543,722.85	0.40627	19,150	$ 7,434.22	22,766,674	$ 4,844,647.54	0.21280	97,929,133	$ 35,380,936.17	0.36129
Jul	97,929,133	$ 35,380,936.17	0.36129	11,790	$ 4,341.90	21,024,456	$ 6,019,331.56	0.28630	118,941,799	$ 41,395,925.83	0.34804
Aug	118,941,799	$ 41,395,925.83	0.34804	131,230	$ 49,767.75	18,674,385	$ 5,722,370.74	0.30643	137,484,954	$ 47,068,528.82	0.34235
Sep	137,484,954	$ 47,068,528.82	0.34235	240,710	$ 90,343.78	13,699,121	$ 3,496,004.74	0.25520	150,943,365	$ 50,474,189.77	0.33439
Oct	150,943,365	$ 50,474,189.77	0.33439	4,249,460	$ 1,192,092.17	6,576,373	$ 2,038,775.80	0.31002	153,270,278	$ 51,320,873.40	0.33484
Nov	153,270,278	$ 51,320,873.40	0.33484	6,302,866	$ 2,091,031.97	3,233,700	$ 1,005,742.59	0.31102	150,201,112	$ 50,235,584.02	0.33446
Dec	150,201,112	$ 50,235,584.02	0.33446	3,625,981	$ 1,220,551.01	1,244,340	$ 226,008.97	0.18163	147,819,471	$ 49,241,041.98	0.33312
TOTAL 2023 ACTIVITY				97,909,769	$ 48,781,301.77	120,945,532	$ 31,925,538.65				
Jan-24	147,819,471	$ 49,241,041.98	0.33312	33,240,052	$ 10,878,497.62	1,169,510	$ 678,435.10	0.58010	115,748,929	$ 39,040,979.46	0.33729
Feb	115,748,929	$ 39,040,979.46	0.33729	5,512,390	$ 1,850,511.49	-	$ -	-	110,236,539	$ 37,190,467.97	0.33737
Mar	110,236,539	$ 37,190,467.97	0.33737	313,180	$ 116,315.06	9,580,965	$ 1,318,504.79	0.13762	119,504,324	$ 38,392,657.70	0.32127
Apr	119,504,324	$ 38,392,657.70	0.32127	288,400	$ 95,003.15	6,367,964	$ 770,870.59	0.12105	125,583,888	$ 39,068,525.14	0.31110
May	125,583,888	$ 39,068,525.14	0.31110	305,180	$ 105,188.88	11,682,281	$ 1,271,103.38	0.10881	136,960,989	$ 40,234,439.64	0.29377
Jun	136,960,989	$ 40,234,439.64	0.29377	211,610	$ 72,571.66	4,607,290	$ 402,125.68	0.08728	141,356,669	$ 40,563,993.65	0.28696
Jul	141,356,669	$ 40,563,993.65	0.28696	243,390	$ 82,419.24	3,228,149	$ 188,029.09	0.05825	144,341,428	$ 40,669,603.50	0.28176
Aug	144,341,428	$ 40,669,603.50	0.28176	292,630	$ 96,675.72	9,509,232	$ 785,537.93	0.08261	153,558,030	$ 41,358,465.71	0.26933
Sep	153,558,030	$ 41,358,465.71	0.26933	257,020	$ 83,827.02	8,902,958	$ 877,990.20	0.09862	162,203,968	$ 42,152,628.89	0.25987
Oct	162,203,968	$ 42,152,628.89	0.25987	1,887,390	$ 477,814.16	3,363,780	$ 468,217.98	0.13919	163,680,358	$ 42,143,032.72	0.25747
Nov	163,680,358	$ 42,143,032.72	0.25747	3,818,247	$ 928,734.05	1,857,700	$ 357,174.70	0.19227	161,719,811	$ 41,571,473.37	0.25706
Dec	161,719,811	$ 41,571,473.37	0.25706	9,291,133	$ 2,362,965.39	1,277,080	$ 182,760.33	0.14311	153,705,758	$ 39,391,268.31	0.25628
TOTAL 2024 ACTIVITY				55,660,622	$ 17,150,523.44	61,546,909	$ 7,300,749.77				
Jan-25	153,705,758	$ 39,391,268.31	0.25628	33,236,284	$ 8,410,355.56	-	$ -	-	120,469,474	$ 30,980,912.75	0.25717
Feb	120,469,474	$ 30,980,912.75	0.25717	24,861,330	$ 6,396,693.57	772,950	$ 138,003.45	0.17854	96,381,094	$ 24,722,222.63	0.25650
Mar	96,381,094	$ 24,722,222.63	0.25650	1,614,180	$ 370,989.80	4,830,630	$ 587,888.63	0.12170	99,597,544	$ 24,939,121.46	0.25040
Apr	99,597,544	$ 24,939,121.46	0.25040	1,001,600	$ 208,650.07	10,955,754	$ 1,574,141.05	0.14368	109,551,698	$ 26,304,612.44	0.24011
May	109,551,698	$ 26,304,612.44	0.24011	157,000	$ 46,241.33	9,904,570	$ 1,441,859.83	0.14558	119,299,268	$ 27,700,230.94	0.23219
Jun	119,299,268	$ 27,700,230.94	0.23219	414,530	$ 98,660.11	10,860,534	$ 1,070,252.06	0.09855	129,745,272	$ 28,671,822.89	0.22099
Jul											
Aug											
Sep											
Oct											
Nov											
Dec											
TOTAL 2025 ACTIVITY				61,284,924	$ 15,531,590.44	37,324,438	$ 4,812,145.02				

f) An explanation of the methodology utilized by the LDC to price storage injections and withdrawals, as well as the total and average (per unit) cost of storage gas.

The price of gas placed into storage, classed as working inventory, will be the average cost of gas defined as the average commodity cost of gas delivered to the city gate (utilizing unhedged discretionary sources first: i.e., spot gas first, then swing, and base load term supplies last. If storage injections exceed unhedged gas purchases, then average cost of hedged gas would be used to value the remainder of the storage injections). This price would represent commodity cost, transportation cost, and fuel-in-kind (FIK) at either the NWN city gas (internal storage) or at the external storage site.

This pricing policy will apply to all storage locations owned or under contract to the NWN, with exceptions as noted.

* When the contract for a storage site includes a provision for the price of the gas placed into storage, the price shall be the price as defined by the agreement.

* Direct associated costs, such as liquefaction fees, fuel-in-kind and actual material costs incurred can be added to the base cost when determined significant.

* Injections into virtual storage sites are valued using specific commodity deals plus added costs for fuel and to maintain specific contract terms for each site. In addition, the price will include the virtual storage reservation fees.

Withdrawals at each facility are priced at the average inventory price as established at the beginning of each month. The beginning of the month cost at each facility is adjusted for any withdrawals and any injections to create the end of the month cost, which then becomes the beginning of the month cost for the next month.

g) Copies of all contracts or other agreements and tariffs that control the LDC's use of the storage facilities included in the current portfolio.

See below for the Rate Schedule SGS-2F Service Agreement.[1]

The FERC tariffs that apply to Jackson Prairie storage have not changed from last year.
The Company has no other off-system storage agreements in effect for the 2025-26 PGA period.

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[1] The use of the storage facilities also requires the use of transportation service agreements controlled by the tariffs of the applicable upstream pipelines as and when needed to inject gas into and withdraw gas from each of these facilities.

Rate Schedule SGS-2F Service Agreement

Contract No. 100502

THIS SERVICE AGREEMENT (Agreement) by and between Northwest Pipeline LLC (Transporter) and Northwest Natural Gas Company (Shipper) is made and entered into on October 24, 2024 and restates the Service Agreement made and entered into on September 26, 2017.

WHEREAS:

A. Shipper originally acquired capacity by entering into a binding precedent agreement through the open season for incremental firm storage service at Jackson Prairie, as authorized by FERC in Docket No. CP06-416.

B. Significant events and previous amendments of this Agreement include:

1. By a Restatement dated September 26, 2017, Transporter and Shipper agree to amend the Primary Term End Date on Exhibit A from October 31, 2004, to October 31, 2025. This amendment is being executed in conjunction with 1) contract extensions and pressure increases on Agreement Nos. 100005, 139153 and 139154, 2) contract extensions on Agreement Nos. 100138, 100308, 100310, 138065 and 140964 and 3) realignment of MDDOs on Agreement No. 136455.

2. Transporter and Shipper further agree to restate the Agreement in the current form of service and extend Primary Term End Date on Exhibit A from October 31, 2025, to October 31, 2033. This amendment is being executed in conjunction with 1) contract extensions on Agreement Nos. 100005, 100138, 100308, 100310, 138587, 139153, 139154, and 140964 and 2) contract extension and realignment of MDDOs on Agreement No. 138065.

THEREFORE, in consideration of the premises and mutual covenants set forth herein, Transporter and Shipper agree as follows:

1. Tariff Incorporation. Rate Schedule SGS-2F and the General Terms and Conditions (GT&C) that apply to Rate Schedule SGS-2F, as such may be revised from time to time in Transporter's FERC Gas Tariff (Tariff), are incorporated by reference as part of this Agreement, except to the extent that any provisions thereof may be modified by non-conforming provisions herein.

2. Storage Service. Subject to the terms and conditions that apply to service under this Agreement, Transporter agrees to inject, store and withdraw natural gas for Shipper, on a firm basis. Shipper may request Transporter to withdraw volumes in excess of Shipper's Storage Demand on a best-efforts basis as provided in Rate Schedule SGS-2F. The Storage Demand and Storage Capacity are set forth on Exhibit A.

3. Storage Rates. Shipper agrees to pay Transporter for all services rendered under this Agreement at the rates set forth or referenced herein. The Maximum Base Tariff Rates (Recourse Rates) set forth in the Statement of Rates in the Tariff, as revised from time to time, that apply to the Rate Schedule SGS-2F customer category identified on Exhibit A will apply to service hereunder unless and to the extent that discounted Recourse Rates or awarded capacity release rates apply as set forth on Exhibit A or negotiated rates apply as set forth on Exhibit D.

4. Service Term. This Agreement becomes effective on the effective date set forth on Exhibit A. The primary term begin date for the storage service hereunder is set forth on Exhibit A. This Agreement will remain in full force and effect through the primary term end date set forth on Exhibit A and, if Exhibit A indicates that an evergreen provision applies, through the established evergreen rollover periods thereafter until terminated in accordance with the notice requirements under the applicable evergreen provision.

5. Non-Conforming Provisions. All aspects in which this Agreement deviates from the Tariff, if any, are set forth as non-conforming provisions on Exhibit B. If Exhibit B includes any material non-conforming provisions, Transporter will file the Agreement with the Federal Energy Regulatory Commission (Commission) and the effectiveness of such non-conforming provisions will be subject to the Commission acceptance of Transporter's filing of the non-conforming Agreement.

6. Capacity Release. If Shipper is a temporary capacity release Replacement Shipper, any capacity release conditions, including recall rights and the amount of the Releasing Shipper's Working Gas Quantity released to Shipper for the initial Storage Cycle, are set forth on Exhibit A.

7. Exhibit / Addendum to Service Agreement Incorporation. Exhibit A is attached hereto and incorporated as part of this Agreement. If any other Exhibits apply, as noted on Exhibit A to this Agreement, then such Exhibits also are attached hereto and incorporated as part of this Agreement. If an Addendum to Service Agreement has been generated pursuant to Sections 11.5 or 22.12 of the GT&C of the Tariff, it also is attached hereto and incorporated as part of this Agreement.

8. Regulatory Authorization. Storage service under this Agreement is authorized pursuant to the Commission regulations set forth on Exhibit A.

9. Superseded Agreements. When this Agreement takes effect, it supersedes, cancels and terminates the following agreement(s): Service Agreement dated September 26, 2017, but the following Amendments and/or Addendum to Service Agreement which have been executed but are not yet effective are not superseded and are added to and become an Amendment and/or Addendum to this agreement: None

IN WITNESS WHEREOF, Transporter and Shipper have executed this Agreement as of the date first set forth above.

Northwest Natural Gas Company	Northwest Pipeline LLC
By: /S/	By: /S/
Name: SCOTT JOHNSON	Name: GARY VENZ

Title: DIRECTOR, GAS SUPPLY

Title: Director Commercial Services

EXHIBIT A
Dated and Effective October 24, 2024
to the
Rate Schedule SGS-2F Service Agreement
(Contract No. 100502)
between Northwest Pipeline LLC
and Northwest Natural Gas Company
SERVICE DETAILS

1. Customer Category: Pre-Expansion Shipper
2. Storage Demand: 46,030 Dth per day
3. Storage Capacity: 1,120,288 Dth
4. Recourse or Discounted Recourse Storage Rates:
    a. Demand Charge (per Dth of Storage Demand):
       Maximum Base Tariff Rate
    b. Capacity Demand Charge (per Dth of Storage Capacity):
       Maximum Base Tariff Rate
    c. Rate Discount Conditions Consistent with Section 3.2 of Rate Schedule SGS-2F:
       Not Applicable
5. Service Term:
    a. Primary Term Begin Date: November 01, 1998
    b. Primary Term End Date: October 31, 2033
    c. Evergreen Provisions: Yes, grandfathered unilateral evergreen under Section 15.3 of Rate Schedule SGS-2F
6. Regulatory Authorization: 18 CFR 284.223
7. Additional Exhibits:

   Exhibit B No

   Exhibit D No

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm

1. AVAILABILITY

This Rate Schedule is available to any Shipper for the purchase of natural gas storage service from Transporter when Shipper and Transporter have executed a Service Agreement for the storage of gas under this Rate Schedule and have arranged for the related transportation of gas to and from the Jackson Prairie Storage Project under one of Transporter's transportation rate schedules.

2. APPLICABILITY AND CHARACTER OF SERVICE

2.1 Applicability. This Rate Schedule shall apply to firm storage gas service at the Jackson Prairie Storage Project. The executed Service Agreement for service under this Rate Schedule will specify the Shipper category, i.e., whether the Shipper is a Pre-Expansion Shipper or an Expansion Shipper. The Jackson Prairie Storage Project capacity available for this Rate Schedule will be Transporter's undivided interest as an owner in the Project, excluding any portion of such interest which may be authorized for use by Transporter for transportation balancing. Delivery of natural gas by Shipper to Transporter for injection and by Transporter to Shipper upon withdrawal shall be at the point of interconnection between the Jackson Prairie Storage Project and Transporter's main transmission line.

2.2 Storage Components. Firm storage service consists of Transporter’s injection storage and withdrawal of Shipper’s gas.

2.3 Character of Service. Storage gas service rendered to Shipper under this Rate Schedule, up to Shipper's Storage Demand and Storage Capacity and subject to the limitations of this Rate Schedule and the executed Service Agreement, shall be firm and shall not be subject to curtailment or interruption except as expressly provided in this Rate Schedule and in the General Terms and Conditions. Storage gas service rendered to Shipper under this Rate Schedule in excess of Shipper’s Storage Demand and Storage Capacity is not firm.

2.4 Capacity Release. Shippers releasing firm storage rights shall do so in accordance with the capacity release provisions outlined in Section 22 of the General Terms and Conditions. Any such release is subject to the terms and conditions of this Rate Schedule.

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

3. MONTHLY RATE

Each month, Shipper will pay Transporter for service rendered under this Rate Schedule the amounts specified in this Section 3, as applicable.

3.1 Storage Service. The sum of (a) and (b) below:

(a) The demand charge will be the sum of the daily product of Shipper's Storage Demand and the Demand Charge rate stated on the Statement of Rates in this Tariff that applies to the customer category identified in the Service Agreement.

(b) The capacity demand charge is the sum of the daily product of Shipper's Storage Capacity and the Capacity Demand Charge rate stated on the Statement of Rates in this Tariff that applies to the customer category identified in the Service Agreement.

The related transportation of gas to and from the Jackson Prairie storage facility shall be subject to separate transportation charges under applicable open-access Rate Schedules. The rates set forth in the sub-paragraphs above are exclusive of the aforementioned transportation charges.

3.2 Discounted Recourse Rates.

(a) Transporter reserves the right to discount at any time the Recourse Rates for any individual Shipper under any service agreement without discounting any other Recourse Rates for that or another Shipper; provided, however, that such discounted Recourse Rates shall not be less than the minimum base rates set forth on the Statement of Rates in this Tariff, or any superseding tariff. Such discounted Recourse Rates may apply to specific volumes of gas such as volumes injected, withdrawn or stored above or below a certain level or all volumes if volumes exceed a certain level, and volumes of gas injected, withdrawn or stored during specific time periods. If Transporter discounts any Recourse Rates to any Shipper, Transporter will file with the Commission any required reports reflecting such discounts.

(b) Discounted Recourse Rates also may be calculated using a formula based on index prices for specific receipt and/or delivery points or other agreed-upon published pricing reference points. Index-based, discounted rates will be no lower than the minimum and no higher than the Maximum Base Tariff Rate.

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

3. MONTHLY RATE (Continued)

3.3 Charges for Capacity Release Service: The rates for capacity release service are set forth in Sheet No. 7. See Section 22 of the General Terms and Conditions for information about rates for capacity release service, including information about acceptable bids. In the event of a base tariff maximum and/or minimum rate change, the Replacement Shipper will be obligated to pay:

(a) the lesser of the awarded bid rate and the new Maximum Base Tariff Rate, or the greater of the awarded bid rate and the new minimum base tariff rate, as applicable, for the remaining term of the release for capacity release transactions with a term of more than one year and where the awarded bid rate was not tied to the Maximum Base Tariff Rate as it may change from time to time;

(b) the greater of the minimum base tariff rate and the awarded bid rate for the remaining term of the release for capacity release transactions with a term of one year or less that take effect on or before one year from the date on which Transporter is notified of the release and where the award bid rate was not tied to the Maximum Base Tariff Rate; or

(c) the new Maximum Base Tariff Rate or, if applicable, the percentage of the new Maximum Base Tariff Rate for capacity release transactions where the awarded bid rate was tied to the Maximum Base Tariff Rate as it may change from time to time.

For capacity release service subject to demand charges, the payments by the Replacement Shipper shall be equal to the sum of the daily product of the accepted Demand Charge bid rate and the Storage Demand, plus the sum of the daily product of the accepted Capacity Demand Charge bid rate and the Storage Capacity.

For capacity release service subject to volumetric bid rates, the payments by the Replacement Shipper shall be equal to the accepted volumetric bid rate for withdrawals multiplied by the actual volumes withdrawn each day plus the accepted volumetric bid rate for storage multiplied by the actual volumes in storage each day.

RATE SCHEDULE SGS-2F
Storage Gas Service – Firm (Continued)

3. MONTHLY RATE (Continued)

3.4 Negotiated Rates. Notwithstanding the general provisions of this Section 3, if Transporter and Shipper mutually agree to Negotiated Rates for service hereunder, such Negotiated Rates will apply in lieu of the otherwise applicable rates identified in this Section 3.

4. MINIMUM MONTHLY BILL

Unless Transporter and Shipper mutually agree otherwise, the Minimum Monthly Bill will consist of the sum of the demand and capacity demand charges specified in Section 3 of this Rate Schedule, as applicable.

5. FUEL GAS REIMBURSEMENT

Shipper shall reimburse Transporter for fuel use in-kind, as detailed in Section 14 of the General Terms and Conditions.

6. STORAGE DEMAND

The Storage Demand shall be the largest number of Dth Transporter is obligated to withdraw and deliver to Shipper, and Shipper is entitled to receive from Transporter, at Jackson Prairie on any one day, to the limitations set forth in Section 9 below, and shall be specified in the executed Service Agreement between Transporter and Shipper. Transporter’s service obligation is limited to Shipper’s Storage Demand, as adjusted for any released capacity pursuant to Section 22 of the General Terms and Conditions.

RATE SCHEDULE SGS-2F
Storage Gas Service – Firm (Continued)

7. STORAGE CAPACITY

Shipper's Storage Capacity shall be the maximum quantity of gas in Dth which Transporter is obligated to store for Shipper's account and shall be specified in the executed Service Agreement between Transporter and Shipper. Transporter’s service obligation is limited to Shipper’s Storage Capacity, as adjusted for any released capacity pursuant to Section 22 of the General Terms and Conditions.

8. DEFINITIONS

8.1 A Storage Cycle is the twelve-month period beginning October 1 of any calendar year and ending September 30 of the following calendar year.

8.2 Shipper's Working Gas Inventory shall be the actual quantity of working gas in storage for Shipper's account at the beginning of any given day.

8.3 Shipper's Working Gas Quantity for a Storage Cycle shall be determined as of October 1 and shall be the lesser of:

(a) Shipper's Working Gas Inventory as of October 1, the beginning of the Storage Cycle; or

(b) The minimum quantity of Shipper's Working Gas Inventory at any time between August 31 and September 30 of the preceding Storage Cycle divided by 0.80; or

(c) The minimum quantity of Shipper's Working Gas Inventory at any time between June 30 and September 30 of the preceding Storage Cycle divided by 0.35.

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm
(Continued)

8. DEFINITIONS (Continued)

The above method of determining Shipper's Working Gas Quantity may be modified consistent with any comparable modification under the January 15, 1998 Gas Storage Project Agreement, or superseding agreement, permitted by the Jackson Prairie Storage Project Management Committee. A Shipper’s Working Gas Quantity will be adjusted for any Working Gas Quantity released as indicated on Exhibit A to a Replacement Shipper’s Service Agreement.

8.4 Shipper's Available Working Gas on any day during the Storage Cycle shall be equal to Shippers' Working Gas Inventory less Shipper's Unavailable Working Gas.

8.5 Shipper's Unavailable Working Gas on any day during the Storage Cycle shall be equal to the highest level of Shipper's Working Gas Inventory during the preceding days of the current Storage Cycle less Shipper's Working Gas Quantity.

9. WITHDRAWALS OF STORAGE GAS

9.1 General Procedure. Shipper may nominate to withdraw gas on any day, specifying the quantity of gas within Shipper's Available Working Gas which it desires withdrawn under this Rate Schedule during such day. Transporter will schedule the withdrawal of the quantity of gas so nominated, subject to the limitations set forth in this Rate Schedule and subject as necessary to confirmation of the nomination changes for the related transportation service agreement.

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm
(Continued)

9. WITHDRAWALS OF STORAGE GAS (Continued)

9.2 Withdrawal Obligation. Transporter's daily withdrawal obligation shall be at 100 percent of the Shipper's Storage Demand as long as Shipper's Available Working Gas is greater than or equal to 60 percent of Shipper's Storage Capacity. On any day when Shipper's Available Working gas is less than 60 percent of Shipper's Storage Capacity, Transporter's daily withdrawal obligation shall be reduced by two percent of Shipper's Storage Demand for each one percent that Shipper's Available Working Gas is less than 60 percent of Shipper's Storage Capacity, until a minimum daily withdrawal rate equal to 10 percent of Shipper’s Storage Demand is reached.

10. INJECTIONS OF WORKING GAS FOR SHIPPER'S ACCOUNT

Upon Transporter’s request, Shipper shall provide written notice to Transporter prior to May 1 of each year, of the quantities of gas to be injected for the account of Shipper during the period of May 1 through September 30 of such year. Shipper may nominate to inject gas on any day, specifying the quantity of gas it desires injected under this Rate Schedule during such day, including the applicable fuel reimbursement requirements. Transporter will schedule the injection of the quantity of gas so nominated, subject to the limitations set forth in this Rate Schedule and subject to delivery of such quantity, and shall retain any fuel use reimbursement furnished in-kind in accordance with Section 14 of the General Terms and Conditions in addition to any fuel reimbursement required from the party under whose Service Agreement the gas is to be transported to Jackson Prairie.

11. RESERVED FOR FUTURE USE

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

12. LIMITATIONS ON INJECTIONS AND WITHDRAWALS FROM STORAGE

Shipper may Nominate gas to be injected into or withdrawn from storage for Shipper's account at any time during the year. In no event shall the balance of gas stored in Shipper's account exceed Shipper's Storage Capacity as defined under Section 6 of this Rate Schedule. Transporter will schedule available injection capacity consistent with the priority of service provisions and curtailment policy in Section 12 of the General Terms and Conditions.

After the commencement of an annual Storage Cycle, withdrawals from Shipper's Available Working Gas may be replaced both to maintain deliverability and to restore the quantity available for withdrawals. Additional working gas may also be injected during the Storage Cycle; provided, however, that Shipper's Unavailable Working Gas as defined in Section 8 above shall not be available for withdrawal during the current Storage Cycle.

13. WITHDRAWALS IN EXCESS OF FIRM ENTITLEMENT (BEST-EFFORTS WITHDRAWALS)

Shipper may nominate to withdraw quantities in excess of Shipper's Storage Demand on a best-efforts basis; provided, however, that the total quantity withdrawn may not exceed the level of Shipper's Available Working Gas. Transporter may make such excess withdrawal, consistent with the priority of service provisions contained in Section 12 of the General Terms and Conditions.

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

14. TRANSFER OF WORKING GAS INVENTORY

Shippers that are subject to this Rate Schedule may agree to transfer their respective Jackson Prairie Working Gas Inventories to any capacity holder in the Jackson Prairie Storage facility under Rate Schedules SGS-2F, SGS-2I, TPAL, and PAL. Participating Shippers must notify Transporter's Marketing Services personnel of their intent to transfer such inventory, in writing. Transfers of Working Gas Inventory may not result in any Shipper taking title to quantities that exceed such Shipper's contractual rights.

Pursuant to the January 15, 1998 Gas Storage Project Agreement, owners of the Jackson Prairie Storage Project may transfer portions of their respective available working gas inventories, as defined in the Project Agreement, to each other. Upon agreement of the parties, and subject to the terms of the Project Agreement, Transporter may utilize its ownership account on behalf of a Rate Schedule SGS-2F Shipper to transfer such Shipper’s Working Gas Inventory to an owner’s available working gas inventory account. Conversely, an owner may transfer its available working gas inventory to a Rate Schedule SGS-2F Shipper’s Working Gas Inventory account.

Transfers from a SGS-2F to SGS-2I, TPAL, and PAL contracts will be scheduled pursuant to the priority of service provisions and curtailment policy in Section 12 of the General Terms and Conditions.

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

15. EVERGREEN PROVISION

15.1 Standard Unilateral Evergreen Provision. If Transporter and Shipper agree to include a standard unilateral evergreen provision as indicated on Exhibit A of the Service Agreement, the following conditions will apply:

(a) The established rollover period will be one year.

(b) Shipper may terminate the Service Agreement in its entirety upon the primary term end date or upon the conclusion of any evergreen rollover period thereafter by giving written notice to Transporter so stating at least five years before the termination date.

(c) The termination notice required under Section 15.1(b) will be deemed given when posted on Transporter's Designated Site.

15.2 Standard Bi-Lateral Evergreen Provision. If Transporter and Shipper agree to include a standard bi-lateral evergreen provision as indicated on Exhibit A of the Service Agreement, the following conditions will apply:

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

15. EVERGREEN PROVISION (Continued)

(a) The established rollover period will be:

(i) one month for a Service Agreement with a primary term of less than one year; or

(ii) one year for a Service Agreement with a primary term of one year or more.

(b) Either Transporter or Shipper may terminate the Service Agreement in its entirety upon the primary term end date or upon the conclusion of any evergreen rollover period thereafter by giving the other party termination notice at least:

(i) ten Business Days before the termination date if Section 15.2(a)(i) applies; or

(ii) one year before the termination date if Section 15.2(a)(ii) applies.

(c) The termination notice required under Section 15.2(b) will be deemed given when posted on Transporter's Designated Site. If Transporter gives termination notice, such termination notice also will be given via Internet E-mail or fax if specified by Shipper on the Business Associate Information form.

15.3 Grandfathered Unilateral Evergreen Provision. If Shipper's Service Agreement contains a grandfathered unilateral evergreen provision as indicated on Exhibit A of the Service Agreement, the following conditions will apply:

(a) The established rollover period will be one year, at Shipper's sole option.

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

15. EVERGREEN PROVISION (Continued)

(b) Shipper may terminate all or any portion of service under its Service Agreement either at the expiration of the primary term, or upon any anniversary thereafter, by giving written notice to Transporter so stating at least twelve months in advance.

(c) Shipper also will have the sole option to enter into a new Service Agreement for all or any portion of the service under its Service Agreement at or after the end of the primary term of its Service Agreement. It is Transporter's and Shipper's intent that this provision provide Shipper with a "contractual right to continue such service" and to provide Transporter with concurrent pregranted abandonment of any volume that Shipper terminates within the meaning of 18 CFR 284.221(d)(2)(i) as promulgated by Order No. 636 on May 8, 1992.

(d) The termination notice required under Section 15.3(b) will be deemed given when posted on Transporter's Designated Site.

16. GENERAL TERMS AND CONDITIONS

The General Terms and Conditions contained in this Tariff, are applicable to this Rate Schedule and are hereby made a part hereof.

h) For LDC's that own and operate storage:

a. The date and results of the last engineering study for that storage.

See attachment to V.7.h to this Exhibit C dated July 2025, identified as Confidential and subject to Modified Protective Order No. 10-337.

The entire text of NW Natural's Capacity Performance Study of the Mist Underground Natural Gas Storage (pages 92-107) is confidential subject to Modified Protective Order No. 10-337 and has been redacted.

b. A description of any significant changes in physical or operational parameters of the storage facility (including LNG) since the current engineering study was completed.

[BEGIN CONFIDENTIAL] [redacted]

[redacted]

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[END CONFIDENTIAL]

Section V.8 - Attestation as to Consistency

See IV.1.c

EXHIBIT D

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

RENEWABLE NATURAL GAS

The following documents for this exhibit are highly confidential in their entirety under Modified Protective Order No. 10-337 and no redacted version exists:

- Section 1 – Attachments 1 to 7
- Section 2 – Attachments 1 to 11
- Section 3 – Attachment 3

The following document for this exhibit is confidential in its entirety under Modified Protective Order No. 10-337 and no redacted version exists:

- Section 3 – Attachment 2

NWN OPUC Advice No. 25-21 / UG 524

July 31, 2025

EXHIBIT D OVERVIEW – Renewable Natural Gas (RNG)

The following is included within this exhibit:

- Section 1 – New RNG Contracts or Updates
  - Attachment 1: Anew RNG LLC Newtown Creek Environmental Attributes Purchase Agreement
  - Attachment 2: Anew RNG LLC Newtown Creek Environmental Attributes Purchase Agreement Renewal
  - Attachment 3: Anew RNG LLC Project Cost Model
  - Attachment 4: Clinton P2G Environmental Attributes Purchase Agreement
  - Attachment 5: Clinton P2G Project Cost Model
  - Attachment 6: WM Columbia Ridge Project Cost Model
  - Attachment 7: Anew Topeka Project Cost Model
- Section 2 – Existing RNG Contracts by Feedstock
  - Attachment 1: BP Products Norther America Portfolio Environmental Attributes Monetization
  - Attachment 2: BP Products Norther America Portfolio Environmental Attributes Purchase Agreement
  - Attachment 3: BP Products Norther America Portfolio Project Cost Model
  - Attachment 4: BP Products Norther America Wasatch Resource Recovery Environmental Attributes Purchase Agreement
  - Attachment 5: BP Products Norther America Wasatch Resource Recovery Project Cost Model
  - Attachment 6: Anew RNG LLC McCommas Bluff Environmental Attributes Purchase Agreement
  - Attachment 7: Anew RNG LLC McCommas Bluff Project Cost Model
  - Attachment 8: Terrava RNG Holdings LLC Brown Gas Purchase Agreement
  - Attachment 9: Terrava RNG Holdings LLC Bundled Resource Transaction Confirmation
  - Attachment 10: Terrava RNG Holdings LLC Bundled Resource Base Contract
  - Attachment 11: Terrava RNG Holdings LLC Project Cost Model
- Section 3 – Historical Data
  - Attachment 1: 2025 NWN RFP
  - Attachment 2: 2025 Element Responses to RFP
  - Attachment 3: RNG Production through June 2025
- Section 4 – Forward Gas Curves
  - Attachment 1: Henry Hub gas curves

RNG FACT SHEET INCLUDED IN PGA FILING

RNG Deal	Transaction No. 1
Seller	BP Products North America, Inc.
Buyer	Northwest Natural Gas Company
Project	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Product	Renewable Thermal Certificates (RTCs)
Contract Price	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Contract Quantity	73,000 RTCs estimated annual generation
Delivery Deadline	Monthly following generation of RTC
Start Date	12/1/2021
Delivery Term	5 years from start date
Certification Standard	Oregon Administrative Rules, ch. 860, div. 150
Tracking System	Midwest Renewable Energy Tracking System, Inc (M-RETS)

RNG Deal	Transaction No. 2
Seller	BP Products North America, Inc.
Buyer	Northwest Natural Gas Company
Project	Sources utilized to date are noted below, however, the seller may, from time-to-time during the Delivery Term, and upon ten (10) days' advanced written notice to buyer, add sources to the list: **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Product	Renewable Thermal Certificates (RTCs)
Contract Price	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Contract Quantity	250,000 RTCs per quarter
Delivery Deadline	Immediately following the production of the Biomethane
Start Date	1/01/2022
Delivery Term	Start Date thru 12/31/42
Certification Standard	Public Utility Commission of Oregon, Order No. 20-227
Tracking System	Midwest Renewable Energy Tracking System, Inc (M-RETS)

RNG Deal	Transaction No. 3
Seller	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Buyer	Northwest Natural Gas Company
Project	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Product	Renewable Thermal Certificates (RTCs)
Contract Price	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Contract Quantity	660,000 RTCs estimated annual generation
Delivery Deadline	Immediately following the production of the Biomethane
Start Date	01/01/2025
Delivery Term	1 year
Certification Standard	Public Utility Commission of Oregon, Order No. 20-227
Tracking System	Midwest Renewable Energy Tracking System, Inc (M-RETS)

RNG Deal	Transaction No. 4
Seller	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Buyer	Northwest Natural Gas Company
Project	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Product	Renewable Thermal Certificates (RTCs) and commodity gas
Contract Price	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Contract Quantity	526,985 estimated annual generation
Delivery Deadline	Immediately following the production of the Biomethane
Start Date	06/01/2025
Delivery Term	15 years
Certification Standard	Public Utility Commission of Oregon, Order No. 20-227
Tracking System	Midwest Renewable Energy Tracking System, Inc (M-RETS)

RNG Deal	Transaction No. 5
Seller	Anew RNG LLC
Buyer	Northwest Natural Gas Company
Project	Newtown Creek Wastewater Treatment Plant
Product	Renewable Thermal Certificates (RTCs)
Contract Price	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Contract Quantity	162,806 RTCs estimated annual generation
Delivery Deadline	Monthly following generation of RTC
Start Date	04/01/2025
Delivery Term	1 year
Certification Standard	Oregon Administrative Rules, ch. 860, div. 150
Tracking System	Midwest Renewable Energy Tracking System, Inc (M-RETS)

RNG Deal	Transaction No. 6
Seller	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Buyer	Northwest Natural Gas Company
Project	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Product	Renewable Thermal Certificates (RTCs)
Contract Price	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Contract Quantity	7,300 estimated annual generation
Delivery Deadline	Monthly following generation of RTC
Start Date	Commercial Operation Date, estimated to be 07/01/2026
Delivery Term	Continuing until Seller gives Buyer 60 days' prior written notice of the end date, not to exceed 24 months
Certification Standard	Oregon Administrative Rules, ch. 860, div. 150
Tracking System	Midwest Renewable Energy Tracking System, Inc (M-RETS)

RNG Deal	Transaction No. 7
Seller	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Buyer	Northwest Natural Gas Company
Project	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Product	Renewable Thermal Certificates (RTCs)
Contract Price	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Contract Quantity	24,000 estimated annual generation
Delivery Deadline	Monthly following generation of RTC
Start Date	11/01/2025
Delivery Term	Start date thru 12/31/2027
Certification Standard	Oregon Administrative Rules, ch. 860, div. 150
Tracking System	Midwest Renewable Energy Tracking System, Inc (M-RETS)

RNG Deal	Transaction No. 8
Seller	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Buyer	Northwest Natural Gas Company
Project	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Product	Renewable Thermal Certificates (RTCs)
Contract Price	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Contract Quantity	1,310,000 estimated annual generation
Delivery Deadline	Monthly following generation of RTC
Start Date	The month following the commercial Operation Date, estimated to be 12/12/2025
Delivery Term	10 years
Certification Standard	Oregon Administrative Rules, ch. 860, div. 150
Tracking System	Midwest Renewable Energy Tracking System, Inc (M-RETS)

New 2025 RFP Contracts

In this July 31st preliminary PGA filing, NW Natural identified two new RNG offtake contracts to pursue in the 2025 RFP. These proposals have been evaluated through the Company's incremental cost model. Throughout August 2025, due diligence and contract negotiations will be conducted for these opportunities. These opportunities are included in this July 31st preliminary PGA, with one contract expected to begin delivery in November 2025 and the other in January 2026. See Section 1 Attachments 6 and 7 for incremental cost models for the prospective contracts. The pricing for the larger volume proposal has been used as a placeholder[1] for both resources. Final contracted volumes and pricing will be included in the final September PGA filing.

RNG SOLICITATION/SELECTION PROCESS

To determine which RNG projects to pursue, NW Natural uses its risk adjusted incremental cost methodology established in UM 2030. This methodology is used to assess the ratepayer costs and benefits of NW Natural-owned RNG projects and third-party RNG contracts. In other words, the methodology assists in determining the least cost/least risk RNG projects, whether they are RNG purchases or projects developed by NW Natural.

NW Natural applies its risk adjusted incremental cost methodology to all potential utility RNG investments and RNG purchase opportunities. The Company develops its portfolio of RNG purchase opportunities by conducting an annual Request for Proposals (RFP) as well as evaluating other opportunities that arise outside of the RFP process throughout

[1] The placeholder represents the average price over the prospective 10-year contract.

the year. In 2025, NW Natural received a total of 82 proposals from 49 responders in response to its RFP. NW Natural uses the same evaluation approach and incremental cost analysis to compare all available resources – both offtakes and development projects – on the same incremental cost basis so that at any point, there is visibility into whether a certain resource appears to be a better choice for customers than another. For instance, the BP Products North America, Inc. resource was not procured through the RFP process, but was presented separately, around the same time as the RFP process (the company was not aware of the RFP process at the time). It was evaluated against other opportunities.

Section 1 lists the newly executed transactions since the last purchase gas adjustment. Section 2 provides the incremental cost calculation of the historical offtake contracts, as well as the contract term and other pertinent details. Among the opportunities that were available at the time, these offtake contracts had the lowest risk adjusted incremental cost.

2025 RFP Evaluation process:

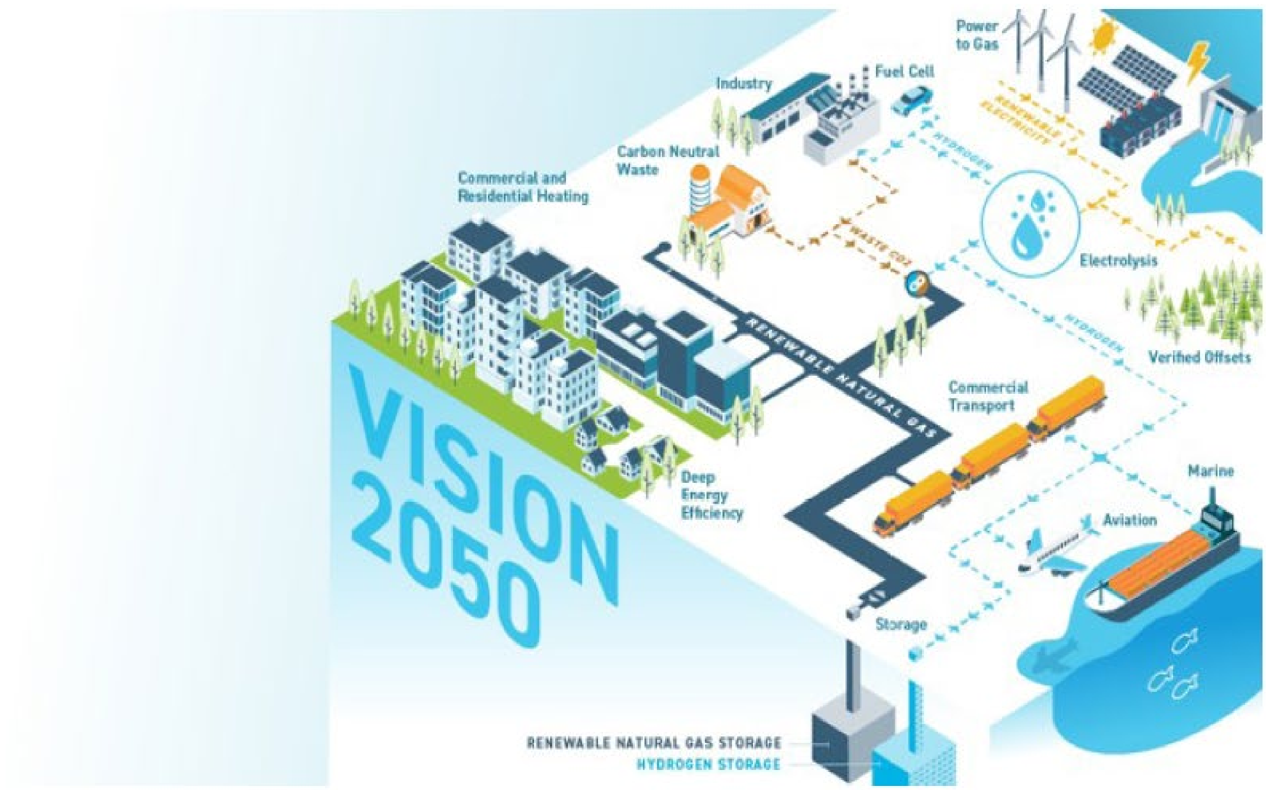
1. Each proposal is reviewed to verify it meets the general qualifications as stated in the RFP. If the proposal does not meet these qualifications, the evaluation may not continue to the next step.
2. A risk-adjusted incremental cost model is completed for each accepted proposal. For bundled products, an assumption is made for the commodity price if the proposal does not indicate a fixed commodity price. The model will be based on information provided in the proposal such as volume, term, price, and assessed risk.
3. The proposals are ordered by the calculated incremental cost from lowest to highest. The proposals with the lowest 33% of incremental cost are placed on the short list and advanced to the next step in the evaluation process.
4. The short-listed proposals are assigned a score for risk-adjusted incremental cost (90%), local economic benefit (5%), and contract equity (5%).
5. The risk-adjusted incremental cost of the short-listed resources are compared to the risk-adjusted incremental cost of other opportunities available outside of the RFP. Those proposals that compare favorably to these other opportunities are pursued further, while those that do not are rejected. The RFP scoring categories of local economic benefit and contract equity are considered when comparing proposals that are comparable in cost.
6. Competitive proposals then follow the same process as opportunities that arose outside of the RFP, including due diligence, contract negotiations, and recommendations to management.

RNG INCLUSION CONSISTENT WITH SB 98

Senate Bill 98 (ORS 757.390 – ORS 757.398) allows NW Natural to acquire RNG, even if the cost of that gas exceeds the cost of conventional natural gas. For RNG that is purchased from a third party, OAR 860-150-0300(1) allows NW Natural to “pass through prudently incurred costs associated with the purchase of RNG” in its purchased gas adjustment (PGA). Accordingly, NW Natural included the above RNG purchases in its PGA and is seeking to pass through the associated costs.

NW Natural®

PREQUEST FOR PROPOSAL #2025-01
Renewable Natural Gas Resources
250 SW Taylor St.
Portland, OR 97204
www.nwnatural.com



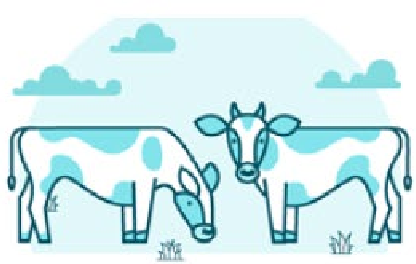


Table of Contents

1 General Information

Northwest Natural Gas Company ("NW Natural") is soliciting proposals from qualified firms to sell renewable natural gas (as defined in section 2.1). This Request for Proposal ("RFP") aligns with the company's broader initiative to comply with Oregon's Climate Protection Program and Washington's Climate Commitment Act's carbon reduction requirements, in addition to supporting the goal of reaching carbon neutrality by 2050.

For the latest information on the RFP and other procurement activities related to renewable resources, please check the RNG page on NW Natural's website.

1.1 Document Components

This document is organized in the following manner:

Section 1 provides **General Information** and outlines NW Natural's objectives in partnering with other organizations to purchase RNG.

Section 2 outlines the **Project Overview and Scope of Services** expected of Bidder and sets forth certain key defined terms.

Section 3 provides details on **Bidder Instructions** regarding submitting a response to the RFP including key dates, questions and communications, submission of the proposal as well as a description of the proposal selection process.

Section 4 provides information on the **Proposal Response Package Components** including format and required information.

Refer to NW Natural RNG Interconnect to review the requirements for **renewable natural gas quality standards** required for resources connecting to NW Natural's distribution system. Note that NW Natural does not require that acquired RNG resources be interconnected with its distribution system. All RNG resources must meet the interconnection requirements and quality standards of the specific system to which the project connected.

1.2 About NW Natural

NW Natural, a part of Northwest Natural Holding Company, (NYSE: NWN), is headquartered in Portland, Oregon, and has been doing business since 1859. Northwest Natural Holding Company owns NW Natural, NW Natural Water Company, NW Natural Renewables Holdings and other business interests. NW Natural is a local distribution company that currently provides natural gas service to approximately two million people in more than 140 communities through 800,000 meters in Oregon and Southwest Washington with one of the most modern pipeline systems in the nation.

1.3 Regulatory Summary

Recent state-level policies and regulatory rules give natural gas utilities in the Pacific Northwest the ability and incentive to procure low-carbon gas resources for their customers. Applicable state-level programs include:

The final rules for Oregon Senate Bill 98 (SB98), adopted in 2020, enable gas utilities to invest in carbon reducing infrastructure and/or to acquire RNG or hydrogen for delivery to its customers. The rules implementing this program are established and overseen by the Public Utility Commission of Oregon, including limits on total expenditures for RNG and hydrogen. The program sets voluntary targets for the percentage of RNG or hydrogen in the system that increases over time with targets of 5% by 2024 and 10% by 2029.

The 2025 Climate Protection Program (CPP), administered by the Oregon Department of Environmental Quality, sets a declining limit, or cap, on greenhouse gas emissions from fossil fuels used throughout Oregon, including diesel, gasoline, natural gas, and propane, used in transportation, residential, commercial, and industrial settings. Emissions covered by the CPP's caps will be cut 50% by 2035 and 90% by 2050 from 2017-2019 average baseline emissions.

In 2019, the Washington State legislature passed a bill supporting RNG procurement. House Bill 1257 established the legal framework for natural gas utilities to support a smooth transition to a low carbon energy economy in Washington state. The bill went into effect on July 28, 2019.

In 2021, the Washington Legislature passed the Climate Commitment Act (CCA) which established a comprehensive program to reduce carbon pollution and achieve the greenhouse gas limits set in state law. The CCA caps and reduces greenhouse gas emissions from the state's largest emitting sources and industries, allowing businesses to find the most efficient paths to lower carbon emissions. The program went into effect January 1, 2023.

1.4 Objectives

NW Natural is a 166-year-old company that has evolved many times since 1859 to meet the essential energy needs of the region. NW Natural is committed to implementing climate solutions that work for the environment, the customers and the community. In 2016 NW Natural established a Low Carbon Pathway as a cornerstone of the company's strategic plan, setting a voluntary goal of 30% carbon savings by 2035 (using a 2015 customer and company operations baseline) and a goal of reaching carbon neutrality by 2050. With a long history of operating as a forward-looking and progressive utility company, NW Natural looks forward to the next chapter, bringing decarbonized resources to customers throughout its service territory.

NW Natural's objective for the 2025 RFP is to secure agreements to purchase RNG for the benefit of its customers, and to do so with the least impact on customer costs, while meeting the CPP and CCA carbon reduction requirements. This RFP seeks pipeline-quality RNG resources and/or associated environmental attributes. The resources may be sourced from around the country as well as Canada, and from a wide variety of feedstocks and sources including green hydrogen and synthetic methane produced from green or biogenic hydrogen and biogenic carbon sources. A portfolio approach, where RNG volumes are sourced from more than one resource, is acceptable.

NW Natural seeks to procure a total of 1,350,000 additional Dth of RNG in the 2025-2026 Price Gas Adjustment (PGA) year, which spans the period November 2025-October 2026. Agreements may be of any term length.

Awards may be made to multiple Bidders offering proposals in accordance with the terms and conditions of this solicitation.

2 Project Overview and Scope of Services

2.1 Definitions

Environmental Attributes	"Environmental Attributes" means any and all environmental claims, credits, benefits, emissions reductions, offsets, and allowances attributable to the production of renewable natural gas and its avoided emission of pollutants. The environmental attributes of renewable natural gas include, but are not limited to, the avoided greenhouse gas emissions associated with the production, transport, and combustion of a quantity of renewable natural gas compared with the same quantity of geologic natural gas. "Environmental Attributes" do not include: (a) The renewable natural gas itself (molecules) or the energy content of that gas; (b) Any tax credits associated with the construction or operation of the renewable natural gas production facility, and any other financial incentives in the form of credits, reductions, or allowances associated with the production of renewable natural gas that are applicable to a state, provincial, or federal income taxation obligation; (c) Fuel- or feedstock-related subsidies or "tipping fees" that may be paid to the seller to accept certain fuels, or local subsidies received by the renewable natural gas production facility for the destruction of particular pre-existing pollutants or the promotion of local environmental benefits; or (d) Emission reduction credits encumbered or used by the renewable natural gas production facility for compliance with local, state, provincial, or federal operating and/or air quality permits.

NAESB Base Contract for Sale and Purchase of Natural Gas ("NAESB Base Contract")	According to its website, "The North American Energy Standards Board (NAESB) serves as an industry forum for the development and promotion of standards which will lead to a seamless marketplace for wholesale and retail natural gas and electricity, as recognized by its customers, business community, participants, and regulatory entities." NAESB published the NAESB Base Contract for Sale and Purchase of Natural Gas in 2002, and then published an updated version in 2006, which are widely used in the gas industry for physical gas purchase and sale transactions. The NAESB Base Contract consists of the published General Terms and Conditions, published elections pages on which the executing parties make certain elections, and, usually, bespoke amendments to the published form called the "Special Provisions." The NAESB Base Contract sets forth the legal terms that will govern future physical gas purchase and sale transactions between the executing parties (until the NAESB Base Contract is terminated) and eliminates the need for the negotiation of new legal terms for each new transaction. After execution of a Base Contract, the parties can transact by entering into transaction confirmations specifying the economic terms of each transaction. The Base Contract together with each transaction confirmation entered thereunder form one integrated agreement.
Renewable Natural Gas or RNG	"Renewable Natural Gas" or "RNG" is gas that satisfies the definition of "renewable natural gas" or "renewable hydrogen" in either Oregon or Washington. The definitions have been set forth below for your convenience. Oregon definition per ORS 757.392(7): "Renewable natural gas" means any of the following products processed to meet pipeline quality standards or transportation fuel grade requirements: (a) Biogas that is upgraded to meet natural gas pipeline quality standards such that it may blend with, or substitute for, geologic natural gas; (b) Hydrogen gas derived from renewable energy sources; or (c) Methane gas derived from any combination of: a. Biogas; b. Hydrogen gas or carbon oxides derived from renewable energy sources; or

	c. Waste carbon dioxide. Washington definitions per RCW 54.04.190(6): "Renewable natural gas" means a gas consisting largely of methane and other hydrocarbons derived from the decomposition of organic material in landfills, wastewater treatment facilities, and anaerobic digesters. "Renewable hydrogen" means hydrogen produced using renewable resources both as the source for the hydrogen and the source for the energy input into the production process.
Renewable Thermal Certificate (RTC)	"Renewable Thermal Certificate" means a unique representation of the Environmental Attributes associated with the production, transport, and use of one dekatherm of renewable natural gas.
Midwest Renewable Energy Tracking System (M-RETS)	The energy certificate system for tracking the purchase and sale of RTCs.

2.2 Scope of Services

NW Natural will consider the purchase of bundled or unbundled RNG and will require the transfer of RNG attributes as RTCs. Bidder may propose one of the following services regarding RNG as defined in Section 2.1:

- Bidder would sell and deliver to NW Natural, and NW Natural would purchase and receive from Bidder, RNG, as a bundled product consisting of *both* the RTCs as well as the gas commodity. NW Natural would enter into a gas purchase agreement with Bidder and receive the RNG at a specific location.
- Bidder would sell and deliver to NW Natural, and NW Natural would purchase and receive from Bidder, all the RTCs from an RNG product. In this situation, Bidder would separately sell or otherwise market the gas commodity.

The second scenario, an unbundled product, is preferred. In either of the above scenarios, the RTCs that are purchased by NW Natural must satisfy the requirements of the definition of Environmental Attributes as noted in section 2.1. Commercial terms considered will vary, ranging from spot transfers to agreements lasting up to 20 years.

2.3 Delivery Date

Delivery of the resource to NW Natural may be initiated immediately upon the execution of definitive agreements and must commence no later than October 31, 2026.

3 Bidder Instructions

3.1 Point of Contact

All correspondence, including but not limited to, questions and submissions shall be directed to: renewables@nwnatural.com.

Please visit the RNG page on our website for RFP materials: Materials provided include:

- 2025 Request for Proposal
- 2025 RFP Response Template – Proposal
- 2025 RFP Response Template – Certification
- Exhibit A: Non-disclosure Agreement
- Exhibit B: Transaction Confirmation for a Fixed Quantity
- Exhibit C: Transaction Confirmation for a Variable Quantity
- Exhibit D: Renewable Natural Gas Attributes Purchase and Sale Agreement
- Exhibit E: Hydrogen Attributes Purchase and Sale Agreement

3.2 Request for Proposal Timeline

Date	Event
5/15/2025	Request for proposal issue date
5/29/2025	Questions due on RFP
6/5/2025	Question responses posted on website
6/26/2025 23:59 (PST)	Proposal submissions due
7/25/2025	Initial notification to responders

3.3 Request for Proposal and Bid Procedures

3.3.1 Questions and Communications

For RFP issues and information requests, please direct question(s) to the email address noted above in Section 3.1.

3.3.2 Submission of Proposal

- Each Bidder shall submit its proposal adhering to the requirements outlined in this Section and in Section 4.
- Proposals shall be submitted via email to the above address with the subject line “RFP 2025-01 Submission”.
- Multiple proposals from a vendor will be permissible, however, each proposal must conform fully to the requirements for proposal submission. Each such proposal must be separately submitted and labeled as Proposal #1, Proposal #2, etc.
- Proposed projects with alternatives, such as contract length, pricing, and volume combinations, should be treated as separate proposals.

3.3.3 Terms and Conditions of Submission

- Bidder shall comply with all state and federal laws in regard to formulation and submittal of proposals. Bidder should note that this is a competitive process, and that conferring with other Bidders about pricing or other specific details of a proposal may violate antitrust law and is prohibited.
- Bidder represents that to the Bidder's knowledge it has satisfied all the requirements and that everything in its proposal is true and correct.
- Bidder shall under no circumstances use NW Natural's name or logos in advertising, marketing materials, printed materials, reference lists, or in any other way that could be construed as advertising (e.g., memo pads, tee shirts, binders, reference lists, etc.) without NW Natural's prior written consent.
- Any non-public information provided by NW Natural in connection with this RFP is confidential and proprietary to NW Natural. Such materials are to be used solely for the purpose of responding to this RFP. By requesting further information or submitting a proposal, Bidder agrees not to disclose any such information to any third party without the prior written consent of NW Natural (which consent shall be conditioned upon the written agreement of the intended recipient to treat the same as confidential), except as may be required by law. NW Natural may request at any time that any or all NW Natural material be returned or destroyed.
- Notwithstanding any non-disclosure or confidentiality agreement by and between NW Natural (or any affiliates) and Bidder (or any affiliates), Bidder acknowledges and agrees that any information set forth in a proposal submitted by Bidder may be subject to review by regulating bodies, including the Oregon Public Utility Commission and/or the Washington Utilities and Transportation Commission, and Bidder hereby waives any objection it may have to NW Natural sharing such information and hereby waives any objection to such review.
- Each Bidder is required to enter into a Non-disclosure Agreement with submittal of its proposal. NW Natural will countersign and return the fully executed Non-disclosure Agreement to Bidder. Given the timeframe of this RFP process, NW Natural is unable to entertain modifications to the language contained in the Non-disclosure Confidentiality Agreement. This requirement does not apply to those Bidders who have an unexpired Non-disclosure Agreement with NW Natural.
- NW Natural requires that the effectiveness of any proposed project or contract be conditioned on acknowledgement of such project or contract from the Oregon Public Utility Commission, pursuant to NW Natural's annual Purchase Gas Adjustment process, by November 1, 2025.

3.3.4 Renewable Thermal Certificates Requirements

- If the proposed project entails the sale or transfer of RTCs, the RTCs that would be purchased by NW Natural must satisfy the requirements of the definition of Environmental Attributes per Section 2.1 above.
- By definition, RTCs may not also be claimed by any other party, such as anyone selling the attributes into programs such as the California Low-Carbon Fuel Standard or the Oregon Clean Fuels Program. Additionally, the environmental attributes cannot be claimed by any party also generating Renewable Identification Numbers (RINs) from the same gas for satisfaction of obligations within the Renewable Fuel Standard.

- NW Natural will only purchase RNG if the Environmental Attributes would satisfy all requirements for listing on the M-RETS system, and NW Natural may request further documentation in support of this criteria if a Bidder is invited to move on to the next stage of NW Natural's selection process. Winning Bidders will be responsible for ensuring that RTCs are established in M-RETS.

3.3.5 Errors or Omissions

A Bidder that discovers an error and/or omission in its proposal response package may withdraw that package and resubmit, provided it does so before the deadline for submission of proposal responses.

3.3.6 Request for Proposal Response Withdrawal

A Bidder that wishes to withdraw its proposal response package may do so at any time by submitting notice to the email address noted in Section 3.1.

3.4 Proposal Selection and Award Process

3.4.1 Proposal Evaluation

NW Natural will evaluate and rank the proposal submitted by each Bidder against the proposals submitted by other Bidders in response to this RFP. The evaluation and ranking of the provided information will focus on conformance of each Bidder's submittal with the requirements of this RFP as well as the proposed pricing and other factors of each proposed opportunity. Such evaluation and ranking shall be performed in a fair and consistent manner. All Bidders should be prepared to discuss their proposals and be available for questions either via email or phone after each detailed proposal is received by NW Natural.

Failure to meet the requirements of this RFP may result in the rejection of the proposal. In the event that a Bidder's proposal does not meet all of the RFP requirements, NW Natural reserves the right to continue the evaluation of the non-conforming proposal and to select the proposals that provide the best opportunities for NW Natural to secure RNG resources in accordance with its strategy.

3.4.2 Proposal Scoring

Proposals will be scored based on a range of criteria including, but not limited to, the following:

1. The overall cost of the product.
2. Proposed terms of the purchase contract, including duration and renewal options.
3. Commercial terms including contractual remedies for a resource's failure to deliver.
4. The volume of RNG or RTCs available for purchase.
5. The RNG site information/history.
6. The experience and proven performance of the firm making the proposal.
7. Overall ability of the project to successfully deliver qualifying RNG within the terms of the contract.
8. Certification as a minority owned, women-owned, disadvantaged or emerging small business.
9. The existence of a demonstrated Environmental, Social, and Governance (ESG) plan.

10. Resources in Oregon and Washington are particularly welcome.

Note that NW Natural does not consider the carbon intensity score as part of its evaluation; however, it is required for regulatory reporting purposes.

3.4.3 Right to Reject Proposals and Negotiate Contract Terms

NW Natural has no obligation to reveal the basis for contract award or to provide any information to Bidders relative to the evaluation or decision-making process. All participating Bidders will be notified of proposal acceptance or rejection in accordance with the schedule outlined in section 3.2.

This is a best-value bidding process. NW Natural reserves all rights regarding the review and evaluation of proposals, selection of a firm, and award of a contract. NW Natural expressly reserves the rights to (a) select a firm and award a contract to that firm, with or without prior negotiations, (b) select one or more firms and then negotiate with them jointly or collectively before making an award decision, (c) select no firm and award no contract, with or without prior negotiations, (d) proceed with another RFP or other selection process, after selecting no firm or awarding no contract, and (e) waive and disregard any defects, irregularities, omissions, discrepancies, inconsistencies, lack of "responsiveness," absence of "responsibility" and any other shortcomings in or of any proposal. In exercising these rights, NW Natural also reserves the right to make selection and award decisions based, in whole or in part, on any factors and considerations that it chooses in its discretion. This RFP gives rise to no contractual obligations, implied or otherwise. Bidder waives any right to claim damages of any nature whatsoever based on the selection process, final selection, and any communications associated with the selection.

3.4.4 Awards and Final Offers

Awards may be granted to multiple Bidders. Should Bidder and NW Natural jointly decide to move into the negotiation phase, NW Natural may request additional documentation to support Bidder's ability to satisfy the terms of its bid and NW Natural's requirements.

NW Natural expects that the legal terms of a bundled RNG purchase transaction would be documented in a NAESB Base Contract, and that transaction-specific details, such as volume, price, delivery location, quality specifications, and regulatory requirements related to Environmental Attributes, would be set forth in a Transaction Confirmation (Exhibits B or C) entered into pursuant to the NAESB Base Contract. The terms of an unbundled purchase of RTCs would be set forth in an agreement (Exhibit D or E), containing legal terms that are standard for the purchase of RTCs or similar products, to be negotiated between the parties.

State regulatory programs require the disclosure of information related to NW Natural's renewable resources. Successful Bidders will be expected to provide the following information about their contracted resources:

- The type and quality of the gas, including the high heating value of the gas;
- Name and address of all intermediary and direct vendor(s) from which the fuel is purchased;

- Name, address, and facility type from which the fuel was produced;
- Fuel feedstock;
- Method(s) used to produce the gas;
- Method of delivery (Interstate or Intrastate);
- The lifecycle carbon intensity, as defined in OAR chapter 340, division 253 of the pathway for the contractually delivered biomethane or hydrogen. Lifecycle carbon intensity values must be estimated using the methodology and tools described in OAR chapter 340, division 253;
- Name and air permit source identification number for the final end user of the gas in Oregon, if applicable.

3.4.5 Notification of Intent to Award

As a courtesy, NW Natural will send a notification of award to responding Bidders upon the conclusion of the RFP process and will inform all Bidders of their status.

4 Proposal Response Package Components

The proposal response package should be composed of the documents outlined below.

Please do not utilize zip files.

Required

1. **2025 RFP Response Template – Proposal**
   Using the template provided by NW Natural, provide details about the proposed opportunity. See the instructions provided on the first tab. Please provide the file in Excel format.

2. **Non-disclosure Agreement**
   As noted in Section 3.3.3, submittal of a Non-disclosure Agreement is required. The template is available as Exhibit A. The file may be provided in Word or .PDF format. NW Natural is unable to entertain modifications to the language contained in the Non-disclosure Confidentiality Agreement.

   This requirement does not apply to those Bidders who have previously executed a Non-disclosure Agreement with NW Natural.

3. **2025 RFP Response Template – Certification**
   Using the template provided by NW Natural, certify and sign the proposal. The file may be provided in Word or .PDF format.

Optional

4. **Purchase Agreements**
   Section 3.4.4 outlines the agreements that are expected by NW Natural for finalization of a purchase transaction. Utilizing the templates, Bidder may elect to submit draft

agreements as part of its RFP response to expedite the evaluation of their proposal. Files may be provided in Word or .PDF format.

5. Additional Information

Provide any information, outside of the required data, that may aid NW Natural in making its selection.

CERTIFICATE OF SERVICE
UM 1286

I hereby certify that on July 31, 2025, I have served the unredacted, Confidential and Highly Confidential portions of NW NATURAL'S EXHIBIT C AND EXHIBIT D in docket UG 524 (NWN OPUC Advice 25-21), upon the Public Utility Commission of Oregon and Parties designated to receive confidential and/or highly confidential information, subject to Modified Protective Order 10-337 (docket UM 1286), via electronic transmission.

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