NW Natural®

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August 1, 2024

NWN OPUC Advice No. 24-19
(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 November 1, 2024, as follows:

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

<u>Purpose</u>
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 November 1, 2024, and to show the removal of temporary rate adjustments incorporated into rates effective November 1, 2023.

[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.

2. Develop the commodity (Weighted Average Cost of Gas or WACOG) and non-commodity (demand or pipeline capacity) purchased gas costs to be effective November 1, 2024.

3. Highlight that NW Natural proposes to continue to exclude the costs associated with RNG from the PGA sharing mechanism.

The Company revises rates for these purposes annually; its last filing was effective November 1, 2023.

The number of customers affected by the changes proposed in this filing is 640,507 residential customers, 62,114 commercial customers, and 656 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 November 1. 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 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 $27,118,086, or about 2.78%; the effect of removing the Account 191 temporary adjustments placed into rates November 1, 2023, is a decrease of $409,308; 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 $26,708,778.

The proposed adjustments to customer rates are comprised of the following: (1) a rate of ($0.04129) per therm for all sales service customers related to the 191 commodity accounts, and (2) a rate of $0.00625 per therm for all firm sales service customers and a rate of $0.00581 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 ($0.03504) per therm for firm sales service customers and a rate of ($0.03548) 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. For more information, please refer to concurrently filed advice filings NWN OPUC Advice No. 24-14 and 24-17.

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 $8,804,770 or about 0.90%; the change in commodity cost is an increase of $7,473,545 and the change in demand cost is an increase of $1,331,225.

The change in gas costs results in a proposed Annual Sales WACOG of $0.44424 per therm, and a proposed Winter Sales WACOG of $0.46023. Revenue sensitive effects are applied for billing purposes, resulting in a proposed Annual Sales Billing WACOG of $0.45743 and a proposed Winter Sales Billing WACOG of $0.47389.

The change in demand costs results in a proposed firm service pipeline capacity charge of $0.09962 per therm, or $1.47 per therm of MDDV, and a proposed interruptible service pipeline capacity charge of $0.01185 per therm. Revenue sensitive effects are applied for billing purposes, resulting in a proposed firm service pipeline capacity charge of $0.10258 per therm or $1.51 per therm of MDDV, and a proposed interruptible service pipeline capacity charge of $0.01220 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 $18.2 million in costs for four offtake arrangements and related transaction costs in the commodity cost of this 2024-25 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 2024-25 PGA year, NW Natural proposes to maintain the language in Schedule P that excludes RNG costs from the PGA sharing mechanism.

4. Combined Effect on Customer Bills

The combined effect of this filing is to decrease the Company's annual revenues by about ($18,313,316), or about 1.88%; the change in purchased gas costs is an increase of $8,804,770 and the change in temporary adjustments to rates is a decrease of $27,118,086.

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

[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).

Class	Rate Schedule	Average Monthly Bill Change ($)	Average Monthly Bill Change (%)
Residential	Schedule 2	($1.26)	(1.6%)
Commercial	Schedule 3	($5.74)	(2.0%)
Commercial Firm Sales	Schedule 31	($71.27)	(2.9%)
Industrial Firm Sales	Schedule 32	($527.95)	(3.9%)
Industrial Interruptible Sales	Schedule 32	($1,234.80)	(4.7%)

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 November 1, 2024 would be a decrease of $479.16, or 3.5%.

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 workpapers, 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 November 1, 2024.

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 Lora Bourdo at lora.bourdo@nwnatural.com with copies to:

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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: November 1, 2024:		(C)
Estimated Annual Sales WACOG per therm (w/ revenue sensitive):	**$0.45743**	(I)
Estimated Annual Sales WACOG per therm (w/o revenue sensitive):	**$0.44424**	(I)

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

Effective: November 1, 2024:		(C)
Estimated Winter Sales WACOG per therm (w/ revenue sensitive):	**$0.47389**	(R)
Estimated Winter Sales WACOG per therm (w/o revenue sensitive):	**$0.46023**	(R)

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: November 1, 2024:		(C)
Estimated Non-Commodity Cost per therm-Firm Sales (w/revenue sensitive):	**$0.10258**	(I)
Estimated Non-Commodity Cost per therm-Firm Sales (w/o revenue sensitive):	**$0.09962**	(I)

(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: November 1, 2024:		(C)
Estimated Non-Commodity Cost per therm-Interruptible Sales (w/revenue sensitive):	**$0.01220**	(I)
Estimated Non-Commodity Cost per therm-Interruptible Sales (w/o revenue sensitive):	**$0.01185**	(I)

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: November 1, 2024:		(C)
Estimated Non-Commodity Cost per therm-MDDV Based Sales (w/revenue sensitive):	**$1.51**	(I)
Estimated Non-Commodity Cost per therm-MDDV Based Sales (w/o revenue sensitive):	**$1.47**	(I)

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, 2024 through October 31, 2025 are: (C)

November 2024	$7,844,377
December 2024	$10,867,700
January 2025	$11,009,949
February 2025	$9,648,778
March 2025	$8,344,759
April 2025	$6,264,792
May 2025	$3,860,196
June 2025	$2,736,552
July 2025	$2,211,518
August 2025	$1,907,063
September 2025	$2,202,332
October 2025	$4,393,257
ANNUAL TOTAL	$71,291,273

(C)

(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 November 1, 2024: $0.00000 per therm (C) (R)

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: November 1, 2024 (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		($0.04129)	$0.00625	**($0.03504)**	(R)
3 CSF		($0.04129)	$0.00625	**($0.03504)**	
3 ISF		($0.04129)	$0.00625	**($0.03504)**	
27		($0.04129)	$0.00625	**($0.03504)**	
31 CSF	Block 1	($0.04129)	$0.00625	**($0.03504)**	
	Block 2	($0.04129)	$0.00625	**($0.03504)**	(R)
31 CTF	Block 1	N/A	N/A	**$0.00000**	
	Block 2	N/A	N/A	**$0.00000**	
31 ISF	Block 1	($0.04129)	$0.00625	**($0.03504)**	(R)
	Block 2	($0.04129)	$0.00625	**($0.03504)**	(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: November 1, 2024 (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	($0.04129)	$0.00625	**($0.03504)**
	Block 2	($0.04129)	$0.00625	**($0.03504)**
	Block 3	($0.04129)	$0.00625	**($0.03504)**
	Block 4	($0.04129)	$0.00625	**($0.03504)**
	Block 5	($0.04129)	$0.00625	**($0.03504)**
	Block 6	($0.04129)	$0.00625	**($0.03504)**
32 ISF	Block 1	($0.04129)	$0.00625	**($0.03504)**
	Block 2	($0.04129)	$0.00625	**($0.03504)**
	Block 3	($0.04129)	$0.00625	**($0.03504)**
	Block 4	($0.04129)	$0.00625	**($0.03504)**
	Block 5	($0.04129)	$0.00625	**($0.03504)**
	Block 6	($0.04129)	$0.00625	**($0.03504)**
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	($0.04129)	$0.00581	**($0.03548)**
	Block 2	($0.04129)	$0.00581	**($0.03548)**
	Block 3	($0.04129)	$0.00581	**($0.03548)**
	Block 4	($0.04129)	$0.00581	**($0.03548)**
	Block 5	($0.04129)	$0.00581	**($0.03548)**
	Block 6	($0.04129)	$0.00581	**($0.03548)**
32 ISI	Block 1	($0.04129)	$0.00581	**($0.03548)**
	Block 2	($0.04129)	$0.00581	**($0.03548)**
	Block 3	($0.04129)	$0.00581	**($0.03548)**
	Block 4	($0.04129)	$0.00581	**($0.03548)**
	Block 5	($0.04129)	$0.00581	**($0.03548)**
	Block 6	($0.04129)	$0.00581	**($0.03548)**
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**

(R)
(R)
(R)
(R)

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: November 1, 2024 (C)

Annual Sales WACOG [1]	$0.45743	(I)
Winter Sales WACOG [2]	$0.47389	(R)
Firm Sales Service Pipeline Capacity Component [3]	$0.10258	(I)
Firm Sales Service Pipeline Capacity Component [4]	$1.51	
Interruptible Sales Service Pipeline Capacity Component [5]	$0.01220	(I)

[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.

CERTIFICATE OF SERVICE
UM 1286

I hereby certify that on August 1, 2024, I have served the unredacted Confidential and Highly Confidential portions of NW NATURAL'S EXHIBIT C AND EXHIBIT D in for NWN OPUC Advice 24-19, upon the Commission and Parties designated to receive confidential and/or highly confidential information subject to Modified Protective Order 10-337 in docket UM 1286, via electronic mail.

Filing Center (C)(HC)
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Kyle Walker (C)(HC)
NW Natural
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DATED August 1, 2024, Troutdale, Oregon.

/s/ Erica Lee-Pella
Erica Lee-Pella
Rates & Regulatory Affairs
NW NATURAL
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EXHIBIT A

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

Purchased Gas Cost Deferral Amortizations

UM 1496

NWN OPUC Advice No. 24-19

August 1, 2024

NW NATURAL

EXHIBIT A

Supporting Materials

Purchased Gas Cost Deferral Amortizations

NWN OPUC ADVICE NO. 24-19

NW Natural
Rates & Regulatory Affairs
2024-25 PGA - Oregon: August Filing
Summary of TEMPORARY Increments

Schedule	Block	Current Temporaries	WACOG Deferral	Demand Deferral - FIRM	Demand Deferral - INTERRUPTIBLE	Subtotal
		A	B	C	D	E
2R		$0.06135	($0.04129)	$0.00625	$0.00000	($0.03504)
3C Sales Firm		($0.01882)	($0.04129)	$0.00625	$0.00000	($0.03504)
3I Sales Firm		$0.06884	($0.04129)	$0.00625	$0.00000	($0.03504)
27 Dry Out		$0.03969	($0.04129)	$0.00625	$0.00000	($0.03504)
31C Sales Firm	Block 1	$0.00500	($0.04129)	$0.00625	$0.00000	($0.03504)
	Block 2	$0.00328	($0.04129)	$0.00625	$0.00000	($0.03504)
31C Trans Firm	Block 1	$0.01874	$0.00000	$0.00000	$0.00000	$0.00000
	Block 2	$0.01702	$0.00000	$0.00000	$0.00000	$0.00000
31I Sales Firm	Block 1	$0.06165	($0.04129)	$0.00625	$0.00000	($0.03504)
	Block 2	$0.06031	($0.04129)	$0.00625	$0.00000	($0.03504)
31I Trans Firm	Block 1	$0.01499	$0.00000	$0.00000	$0.00000	$0.00000
	Block 2	$0.01346	$0.00000	$0.00000	$0.00000	$0.00000
32C Sales Firm	Block 1	$0.06080	($0.04129)	$0.00625	$0.00000	($0.03504)
	Block 2	$0.05874	($0.04129)	$0.00625	$0.00000	($0.03504)
	Block 3	$0.05533	($0.04129)	$0.00625	$0.00000	($0.03504)
	Block 4	$0.05190	($0.04129)	$0.00625	$0.00000	($0.03504)
	Block 5	$0.04944	($0.04129)	$0.00625	$0.00000	($0.03504)
	Block 6	$0.04827	($0.04129)	$0.00625	$0.00000	($0.03504)
32I Sales Firm	Block 1	$0.05252	($0.04129)	$0.00625	$0.00000	($0.03504)
	Block 2	$0.05182	($0.04129)	$0.00625	$0.00000	($0.03504)
	Block 3	$0.05061	($0.04129)	$0.00625	$0.00000	($0.03504)
	Block 4	$0.04942	($0.04129)	$0.00625	$0.00000	($0.03504)
	Block 5	$0.04858	($0.04129)	$0.00625	$0.00000	($0.03504)
	Block 6	$0.04817	($0.04129)	$0.00625	$0.00000	($0.03504)
32C Trans Firm	Block 1	$0.00423	$0.00000	$0.00000	$0.00000	$0.00000
	Block 2	$0.00338	$0.00000	$0.00000	$0.00000	$0.00000
	Block 3	$0.00198	$0.00000	$0.00000	$0.00000	$0.00000
	Block 4	$0.00058	$0.00000	$0.00000	$0.00000	$0.00000
	Block 5	($0.00027)	$0.00000	$0.00000	$0.00000	$0.00000
	Block 6	($0.00084)	$0.00000	$0.00000	$0.00000	$0.00000
32I Trans Firm	Block 1	$0.00345	$0.00000	$0.00000	$0.00000	$0.00000
	Block 2	$0.00279	$0.00000	$0.00000	$0.00000	$0.00000
	Block 3	$0.00169	$0.00000	$0.00000	$0.00000	$0.00000
	Block 4	$0.00058	$0.00000	$0.00000	$0.00000	$0.00000
	Block 5	($0.00009)	$0.00000	$0.00000	$0.00000	$0.00000
	Block 6	($0.00052)	$0.00000	$0.00000	$0.00000	$0.00000
32C Sales Interr	Block 1	$0.05827	($0.04129)	$0.00000	$0.00581	($0.03548)
	Block 2	$0.05712	($0.04129)	$0.00000	$0.00581	($0.03548)
	Block 3	$0.05519	($0.04129)	$0.00000	$0.00581	($0.03548)
	Block 4	$0.05325	($0.04129)	$0.00000	$0.00581	($0.03548)
	Block 5	$0.05209	($0.04129)	$0.00000	$0.00581	($0.03548)
	Block 6	$0.05124	($0.04129)	$0.00000	$0.00581	($0.03548)
32I Sales Interr	Block 1	$0.05593	($0.04129)	$0.00000	$0.00581	($0.03548)
	Block 2	$0.05521	($0.04129)	$0.00000	$0.00581	($0.03548)
	Block 3	$0.05398	($0.04129)	$0.00000	$0.00581	($0.03548)
	Block 4	$0.05278	($0.04129)	$0.00000	$0.00581	($0.03548)
	Block 5	$0.05204	($0.04129)	$0.00000	$0.00581	($0.03548)
	Block 6	$0.05150	($0.04129)	$0.00000	$0.00581	($0.03548)
32C Trans Interr	Block 1	$0.00240	$0.00000	$0.00000	$0.00000	$0.00000
	Block 2	$0.00183	$0.00000	$0.00000	$0.00000	$0.00000
	Block 3	$0.00087	$0.00000	$0.00000	$0.00000	$0.00000
	Block 4	($0.00007)	$0.00000	$0.00000	$0.00000	$0.00000
	Block 5	($0.00065)	$0.00000	$0.00000	$0.00000	$0.00000
	Block 6	($0.00102)	$0.00000	$0.00000	$0.00000	$0.00000
32I Trans Interr	Block 1	$0.00307	$0.00000	$0.00000	$0.00000	$0.00000
	Block 2	$0.00247	$0.00000	$0.00000	$0.00000	$0.00000
	Block 3	$0.00145	$0.00000	$0.00000	$0.00000	$0.00000
	Block 4	$0.00045	$0.00000	$0.00000	$0.00000	$0.00000
	Block 5	($0.00016)	$0.00000	$0.00000	$0.00000	$0.00000
	Block 6	($0.00056)	$0.00000	$0.00000	$0.00000	$0.00000
33		($0.00147)	$0.00000	$0.00000	$0.00000	$0.00000
Special Contracts		$0.00191	$0.00000	$0.00000	$0.00000	$0.00000

Sources:

Direct Inputs	Current Tariff				
Equal ¢ per therm		Column B	Column E	Column H	
Equal % of margin					
Equal % of revenue					

Tariff Schedules

Rate Adjustment Schedule	Sched 162	Sched 162	Sched 162	

Filing:

Tariff Advice Notice #	24-19	24-19	24-19	

NW Natural
Rates & Regulatory Affairs
2024-25 PGA - Oregon: August Filing
Calculation of Increments Allocated on the EQUAL CENT PER THERM BASIS
ALL VOLUMES IN THERMS

1				**WACOG Deferral**			**Demand Deferral - FIRM**			**Demand Deferral - INTERRUPTIBLE**			**AWEC Deferral - Schedule 171 To Sales (WACOG)**		
2			**Oregon PGA** **Proposed Amount:**	(29,924,092) Temporary Increment			4,305,675 Temporary Increment			294,819 Temporary Increment			(615,086) Temporary Increment		
3			**Volumes page,** **Revenue Sensitive Multiplier:**	2.883% add revenue sensitive factor			2.883% add revenue sensitive factor			2.883% add revenue sensitive factor			2.883% add revenue sensitive factor		
4			**Column F** **Amount to Amortize:**	**(30,812,509)** to all sales			**4,433,507** to all firm sales			**303,571** to all interruptible sales			**(633,347)** 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		423,059,269	1.0	423,059,269	($0.04046)	1.0	423,059,269	$0.00625	0.0	0	$0.00000	1.0	423,059,269	($0.00083)
8	3C Firm Sales		178,618,735	1.0	178,618,735	($0.04046)	1.0	178,618,735	$0.00625	0.0	0	$0.00000	1.0	178,618,735	($0.00083)
9	3I Firm Sales		5,103,738	1.0	5,103,738	($0.04046)	1.0	5,103,738	$0.00625	0.0	0	$0.00000	1.0	5,103,738	($0.00083)
10	27 Dry Out		742,733	1.0	742,733	($0.04046)	1.0	742,733	$0.00625	0.0	0	$0.00000	1.0	742,733	($0.00083)
11	31C Firm Sales	Block 1	12,281,908	1.0	12,281,908	($0.04046)	1.0	12,281,908	$0.00625	0.0	0	$0.00000	1.0	12,281,908	($0.00083)
12		Block 2	10,043,265	1.0	10,043,265	($0.04046)	1.0	10,043,265	$0.00625	0.0	0	$0.00000	1.0	10,043,265	($0.00083)
13	31C Firm Trans	Block 1	1,267,742	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
14		Block 2	1,392,960	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	3,698,785	1.0	3,698,785	($0.04046)	1.0	3,698,785	$0.00625	0.0	0	$0.00000	1.0	3,698,785	($0.00083)
16		Block 2	7,639,515	1.0	7,639,515	($0.04046)	1.0	7,639,515	$0.00625	0.0	0	$0.00000	1.0	7,639,515	($0.00083)
17	31I Firm Trans	Block 1	144,356	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
18		Block 2	351,741	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	34,618,514	1.0	34,618,514	($0.04046)	1.0	34,618,514	$0.00625	0.0	0	$0.00000	1.0	34,618,514	($0.00083)
20		Block 2	9,360,621	1.0	9,360,621	($0.04046)	1.0	9,360,621	$0.00625	0.0	0	$0.00000	1.0	9,360,621	($0.00083)
21		Block 3	1,566,490	1.0	1,566,490	($0.04046)	1.0	1,566,490	$0.00625	0.0	0	$0.00000	1.0	1,566,490	($0.00083)
22		Block 4	544,281	1.0	544,281	($0.04046)	1.0	544,281	$0.00625	0.0	0	$0.00000	1.0	544,281	($0.00083)
23		Block 5	0	1.0	0	($0.04046)	1.0	0	$0.00625	0.0	0	$0.00000	1.0	0	($0.00083)
24		Block 6	0	1.0	0	($0.04046)	1.0	0	$0.00625	0.0	0	$0.00000	1.0	0	($0.00083)
25	32I Firm Sales	Block 1	8,547,588	1.0	8,547,588	($0.04046)	1.0	8,547,588	$0.00625	0.0	0	$0.00000	1.0	8,547,588	($0.00083)
26		Block 2	7,603,172	1.0	7,603,172	($0.04046)	1.0	7,603,172	$0.00625	0.0	0	$0.00000	1.0	7,603,172	($0.00083)
27		Block 3	2,763,251	1.0	2,763,251	($0.04046)	1.0	2,763,251	$0.00625	0.0	0	$0.00000	1.0	2,763,251	($0.00083)
28		Block 4	3,005,494	1.0	3,005,494	($0.04046)	1.0	3,005,494	$0.00625	0.0	0	$0.00000	1.0	3,005,494	($0.00083)
29		Block 5	195,767	1.0	195,767	($0.04046)	1.0	195,767	$0.00625	0.0	0	$0.00000	1.0	195,767	($0.00083)
30		Block 6	0	1.0	0	($0.04046)	1.0	0	$0.00625	0.0	0	$0.00000	1.0	0	($0.00083)
31	32C Firm Trans	Block 1	2,721,537	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
32		Block 2	2,020,003	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
33		Block 3	707,839	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
34		Block 4	869,038	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
35		Block 5	0	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	11,657,702	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
38		Block 2	17,056,306	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
39		Block 3	10,569,490	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
40		Block 4	22,324,991	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
41		Block 5	22,115,808	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
42		Block 6	7,865,614	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	4,649,733	1.0	4,649,733	($0.04046)	0.0	0	$0.00000	1.0	4,649,733	$0.00581	1.0	4,649,733	($0.00083)
44		Block 2	6,816,872	1.0	6,816,872	($0.04046)	0.0	0	$0.00000	1.0	6,816,872	$0.00581	1.0	6,816,872	($0.00083)
45		Block 3	3,782,502	1.0	3,782,502	($0.04046)	0.0	0	$0.00000	1.0	3,782,502	$0.00581	1.0	3,782,502	($0.00083)
46		Block 4	5,561,835	1.0	5,561,835	($0.04046)	0.0	0	$0.00000	1.0	5,561,835	$0.00581	1.0	5,561,835	($0.00083)
47		Block 5	3,284,822	1.0	3,284,822	($0.04046)	0.0	0	$0.00000	1.0	3,284,822	$0.00581	1.0	3,284,822	($0.00083)
48		Block 6	0	1.0	0	($0.04046)	0.0	0	$0.00000	1.0	0	$0.00581	1.0	0	($0.00083)
49	32I Interr Sales	Block 1	4,653,469	1.0	4,653,469	($0.04046)	0.0	0	$0.00000	1.0	4,653,469	$0.00581	1.0	4,653,469	($0.00083)
50		Block 2	6,055,122	1.0	6,055,122	($0.04046)	0.0	0	$0.00000	1.0	6,055,122	$0.00581	1.0	6,055,122	($0.00083)
51		Block 3	3,505,859	1.0	3,505,859	($0.04046)	0.0	0	$0.00000	1.0	3,505,859	$0.00581	1.0	3,505,859	($0.00083)
52		Block 4	9,726,364	1.0	9,726,364	($0.04046)	0.0	0	$0.00000	1.0	9,726,364	$0.00581	1.0	9,726,364	($0.00083)
53		Block 5	4,171,536	1.0	4,171,536	($0.04046)	0.0	0	$0.00000	1.0	4,171,536	$0.00581	1.0	4,171,536	($0.00083)
54		Block 6	0	1.0	0	($0.04046)	0.0	0	$0.00000	1.0	0	$0.00581	1.0	0	($0.00083)
55	32C Interr Trans	Block 1	822,778	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
56		Block 2	1,679,150	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
57		Block 3	978,518	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
58		Block 4	3,232,735	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
59		Block 5	472,307	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	6,144,023	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
62		Block 2	10,403,074	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
63		Block 3	6,958,044	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
64		Block 4	15,417,391	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
65		Block 5	35,960,832	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
66		Block 6	99,266,501	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		54,127,531	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
69															
70	TOTALS		1,098,129,249		761,601,240 $	(0.04046)		709,393,126 $	0.00625		52,208,114 $	0.00581		761,601,240 $	(0.00083)
71	**Sources for line 2 above:**														
72	**Inputs page**			Line 33			Line 35			Line 37			Line 55		
73	**Tariff Schedules**														
74	**Rate Adjustment Schedule**			Sched 162			Sched 162			Sched 162			Sched 162		

NW Natural
Rates and Regulatory Affairs
2024-2025 PGA Filing - OREGON
Basis for Revenue Related Costs

		Twelve Months		
1		Ended 06/30/24		
2				
3	Total Billed Gas Sales Revenues	$ 920,096,835		
4	Total Oregon Revenues	$ 925,565,009		
5				
6	Regulatory Commission Fees [1]	n/a	0.450%	Statutory rate
7	City License and Franchise Fees	$ 21,672,271	2.342%	Line 7 ÷ Line 4
8	Net Uncollectible Expense [2]	$ 845,048	0.091%	Line 8 ÷ Line 4
9				
10	Total		**2.883%**	Sum lines 8-9
11				
12				

13 **Note:**
14 [1] Dollar figure is set at statutory level of 0.275% times Total Oregon Revenues (line 4).
15 Because the fee changed since our last general rate case, the difference between the previous fee of 0.375%
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
2024-2025 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	$7,473,545
7	Demand Capacity Cost Change	1,331,225
9	**Total Gas Cost Change**	**8,804,770**
11	**Temporary Increments**	
13	Removal of Current Temporary Increments	
14	Amortization of 191.xxx Account Gas Costs	(409,308)
16	Addition of Proposed Temporary Increments	
17	Amortization of 191.xxx Account Gas Costs	(26,708,778)
19	**Net Temporary Rate Adjustment**	**(27,118,086)**
21	**TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES**	**($18,313,316)**
23	2023 Oregon Earnings Test Normalized Total Revenues	$975,829,919
25	Effect of this filing, as a percentage change (line 21 ÷ line 23)	-1.88%
27	Effect of this filing, as a percentage change (line 19 ÷ line 23)	-2.78%
29	Effect of this filing, as a percentage change (line 9 ÷ line 23)	0.90%

NW Natural
Rates & Regulatory Affairs
2024-2025 PGA Filing - June Filing
Summary of Deferred Accounts Included in the PGA

	Account	Balance 6/30/2024	Jul-Oct Estimated Activity	Jul-Oct Interest	Estimated Balance 10/31/2024	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	5.40%		G = E + F2
87	**Gas Cost Deferrals and Amortizations**							
88	151510 OREGON WACOG AMORTIZATION	337,508	(463,969)	2,436	(124,024)			
89	151505 OREGON WACOG DEFERRAL	(28,292,638)	0	(650,225)	(28,942,863)			
90	Total	(27,955,130)	(463,969)	(647,788)	(29,066,887)	5.40%	(857,205)	(29,924,092)
91								
92	151525 OREGON DEMAND AMORTIZATION	(600,619)	381,987	(7,606)	(226,239)			
93	151520 OREGON DEMAND DEFERRAL	(799,068)	0	(18,364)	(817,432)			
94	151535 COOS BAY DEMAND DEFERRAL	174,817	0	0	174,817			
95	151560 OREGON SEASONAL VOLUME DEMAND DEFERRAL	5,217,649	0	119,913	5,337,562			
96	Total	3,992,779	381,987	93,942	4,468,708	5.40%	131,786	4,600,494
97								
98	232092 AWEC Deferral - Schedule 171 CPP Deferrals - To Sales (SB98)	(584,044)	0	(13,423)	(597,466)	5.40%	(17,620)	(615,086)

Company: Northwest Natural Gas Company
State: Oregon
Description: Amortization of Oregon WACOG Deferral
Account Number: 151510
Docket: Dockets UM 1496, UG 486
Amortization of deferral approved in Order No. 23-387

Debit (Credit)

Month/Year	Note	Amortization	Transfers	Interest	Interest rate	Activity	Balance
(a)	(b)	(c)	(d)	(e1)	(e2)	(f)	(g)
Beginning Balance							
Jul-23		(1,293,339.76)		5,080.80	1.82%	(1,288,258.96)	2,708,387.67
Aug-23		(1,132,729.52)		3,248.73	1.82%	(1,129,480.79)	1,578,906.89
Sep-23		(1,203,367.69)		1,482.12	1.82%	(1,201,885.57)	377,021.31
Oct-23		(1,646,616.21)		(676.87)	1.82%	(1,647,293.08)	(1,270,271.77)
Nov-23	Old Rates	(1,683,679.94)		(3,203.37)	1.82%	(1,686,883.31)	(2,957,155.08)
Nov-23	New Rates (**1**)	(114,550.01)	5,575,578.37	23,590.75	5.13%	5,484,619.10	2,527,464.02
Dec-23		(389,364.43)		9,972.64	5.13%	(379,391.79)	2,148,072.23
Jan-24		(467,064.49)		8,184.66	5.13%	(458,879.83)	1,689,192.39
Feb-24		(404,766.92)		6,356.11	5.13%	(398,410.81)	1,290,781.58
Mar-24		(370,899.65)		4,725.29	5.13%	(366,174.36)	924,607.23
Apr-24		(255,702.61)		3,406.13	5.13%	(252,296.48)	672,310.75
May-24		(200,605.24)		2,445.33	5.13%	(198,159.91)	474,150.84
Jun-24		(138,373.66)		1,731.22	5.13%	(136,642.44)	337,508.40
Jul-24	*Forecasted*	*(94,173.88)*		1,241.55	5.13%	(92,932.33)	244,576.07
Aug-24	*Forecasted*	*(87,717.82)*		858.07	5.13%	(86,859.75)	157,716.32
Sep-24	*Forecasted*	*(96,073.42)*		468.88	5.13%	(95,604.54)	62,111.78
Oct-24	*Forecasted*	*(186,003.92)*		(132.06)	5.13%	(186,135.98)	(124,024.20)

History truncated for ease of viewing

NOTES:

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 22-430

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 Adiustment	Hedge Adjustment	RTC Retirement	Interest	Interest Rate	Transfer	Activity	Balance
(a)	(b)	(c)	(d)	(e)	(g)	(h1)	(h2)	(i)	(j)	(k)
Beginning Bal										
Jul-23		(2,377,806.77)	4,252.49	7,778.80	425,041.09	25,747.89	6.836%		(1,914,987)	3,575,197.64
Aug-23		(2,799,986.42)	4,206.63	8,851.50	211,939.52	13,032.28	6.836%		(2,561,956)	1,013,241.15
Sep-23		(2,148,690.29)	4,998.58	3,058.20	390,725.32	787.78	6.836%		(1,749,120)	(735,879.26)
Oct-23		(5,399,219.79)	9,636.95	5,054.80	(349,575.68)	(20,524.70)	6.836%		(5,754,628)	(6,490,507.68)
Nov-23	**1**	165,934.60	(7,821.36)	29,080.50	990,525.36	(65,381.93)	6.836%	(5,575,578.37)	(4,463,241)	(10,953,748.87)
Dec-23		1,334,365.84	(9,067.68)	(278,843.70)	(298,991.60)	(60,270.83)	6.836%		687,192	(10,266,556.85)
Jan-24		3,921,876.73	(11,451.06)	(316,776.60)	(644,988.67)	(50,086.38)	6.836%		2,898,574	(7,367,982.83)
Feb-24		557,476.74	(8,694.54)	(195,353.70)	(298,338.34)	(41,816.03)	6.836%		13,274	(7,354,708.70)
Mar-24		(2,994,117.51)	(7,848.18)	96,744.30	45,001.32	(50,044.18)	6.836%		(2,910,264)	(10,264,972.95)
Apr-24		(8,508,941.45)	(5,365.46)	(83,960.70)	(196,674.60)	(83,527.06)	6.836%		(8,878,469)	(19,143,442.22)
May-24		(5,874,902.70)	(3,916.42)	(24,477.80)	132,087.05	(125,492.14)	6.836%		(5,896,702)	(25,040,144.24)
Jun-24		(3,202,513.64)	(2,496.99)	(588.90)	104,583.43	(151,478.08)	6.836%		(3,252,494)	(28,292,638.41)
Jul-24						(161,173.73)	6.836%		(161,174)	(28,453,812.14)
Aug-24						(162,091.88)	6.836%		(162,092)	(28,615,904.02)
Sep-24						(163,015.27)	6.836%		(163,015)	(28,778,919.29)
Oct-24						(163,943.91)	6.836%		(163,944)	(28,942,863.20)

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 486
	Amortization of deferral approved in Order No. 23-387

1 Debit (Credit)

Line	Month/Year	Note	Amortization	Transfers	Interest Rate	Interest Interest	Activity	Balance
5	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
189	Jul-23		(49,604.27)		1.82%	180.72	(49,423.55)	94,533.38
190	Aug-23		(42,540.34)		1.82%	111.12	(42,429.22)	52,104.17
191	Sep-23		(45,611.61)		1.82%	44.44	(45,567.17)	6,536.99
192	Oct-23		(63,544.83)		1.82%	(38.27)	(63,583.10)	(57,046.11)
193	Nov-23	OLD	(75,009.30)		1.82%	(143.40)	(75,152.70)	(132,198.81)
194	Nov-23	NEW	89,638.77	(2,457,604.98)	5.13%	(10,314.66)	(2,378,280.87)	(2,510,479.68)
195	Dec-23		342,562.42		5.13%	(10,000.07)	332,562.35	(2,177,917.33)
196	Jan-24		416,886.35		5.13%	(8,419.50)	408,466.85	(1,769,450.48)
197	Feb-24		357,294.18		5.13%	(6,800.68)	350,493.50	(1,418,956.98)
198	Mar-24		326,247.68		5.13%	(5,368.69)	320,878.99	(1,098,077.98)
199	Apr-24		220,864.18		5.13%	(4,222.19)	216,641.99	(881,436.00)
200	May-24		171,256.56		5.13%	(3,402.08)	167,854.48	(713,581.51)
201	Jun-24		115,765.14		5.13%	(2,803.11)	112,962.03	(600,619.49)
202	Jul-24	*Forecasted*	*76,201.71*		5.13%	(2,404.77)	73,796.94	(526,822.55)
203	Aug-24	*Forecasted*	*69,773.46*		5.13%	(2,103.03)	67,670.43	(459,152.12)
204	Sep-24	*Forecasted*	*77,255.12*		5.13%	(1,797.74)	75,457.38	(383,694.74)
205	Oct-24	*Forecasted*	*158,756.52*		5.13%	(1,300.95)	157,455.57	(226,239.17)

208 **History truncated for ease of viewing**

210 **NOTES:**

211 **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 22-430
Narrative:	Deferral of 100% of the difference between actual demand cost incurred and the demand cost embedded in customer rates.

1 Debit (Credit)

Line	Month/Year	Note	Demand Deferral	Transfer	Interest	Interest Rate	Activity	Balance
4	(a)	(b)	(c)	(d)	(e1)	(e2)	(f)	(g)
5								
6	Beginning Bal							
210	Jul-23		47,548.30		3,697.64	6.836%	51,245.94	676,560.26
211	Aug-23		(25,973.94)		3,780.16	6.836%	(22,193.78)	654,366.49
212	Sep-23		2,523.91		3,734.90	6.836%	6,258.81	660,625.30
213	Oct-23		24,139.46		3,832.12	6.836%	27,971.58	688,596.88
214	Nov-23	**1**	(206,863.60)	(639,685.37)	(310.58)	6.836%	(846,859.55)	(158,262.67)
215	Dec-23		(165,656.54)		(1,373.41)	6.836%	(167,029.95)	(325,292.62)
216	Jan-24		(193,161.04)		(2,403.27)	6.836%	(195,564.31)	(520,856.93)
217	Feb-24		(94,275.74)		(3,235.68)	6.836%	(97,511.42)	(618,368.35)
218	Mar-24		(12,029.40)		(3,556.90)	6.836%	(15,586.30)	(633,954.66)
219	Apr-24		(54,759.75)		(3,767.40)	6.836%	(58,527.15)	(692,481.81)
220	May-24		(47,766.43)		(4,080.89)	6.836%	(51,847.32)	(744,329.13)
221	Jun-24		(50,354.99)		(4,383.62)	6.836%	(54,738.61)	(799,067.74)
222	Jul-24				(4,552.02)	6.836%	(4,552.02)	(803,619.76)
223	Aug-24				(4,577.95)	6.836%	(4,577.95)	(808,197.71)
224	Sep-24				(4,604.03)	6.836%	(4,604.03)	(812,801.74)
225	Oct-24				(4,630.26)	6.836%	(4,630.26)	(817,432.00)

227 **History truncated for ease of viewing**

229 **NOTES**

230 **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.

Debit (Credit)

Month/Year	Note	Deferral	Adjustment	Transfer	Activity	Balance
(a)	(b)	(c)	(d)	(e)	(f)	(g)
Beginning Bal						
Jul-23		23,971.00	(5,990.78)		17,980.22	206,559.99
Aug-23		23,971.00	(5,683.02)		18,287.98	224,847.97
Sep-23		23,971.00	(6,033.86)		17,937.14	242,785.11
Oct-23		23,971.00	(6,056.89)		17,914.11	260,699.22
Nov-23	**1**	23,971.00	(7,580.93)	(188,579.77)	(172,189.70)	88,509.52
Dec-23		23,971.00	(10,576.48)		13,394.52	101,904.04
Jan-24		22,321.00	(16,895.91)		5,425.09	107,329.13
Feb-24		22,321.00	(9,660.62)		12,660.38	119,989.51
Mar-24		22,321.00	(10,694.34)		11,626.66	131,616.17
Apr-24		22,321.00	(8,676.40)		13,644.60	145,260.77
May-24		22,321.00	(8,406.34)		13,914.66	159,175.43
Jun-24		22,321.13	(6,679.25)		15,641.88	174,817.31
Jul-24					0.00	174,817.31
Aug-24					0.00	174,817.31
Sep-24					0.00	174,817.31
Oct-24					0.00	174,817.31

History truncated for ease of viewing

NOTES

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 22-430
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)

2			Demand					
3	Month/Year	Note	Deferral	Interest	Interest Rate	Transfer	Activity	Balance
4	(a)	(b)	(d)	(e)	(f)	(g)	(i)	(j)
210	Jul-23		228,280.41	(17,647.76)	6.836%		210,632.65	(3,001,417.74)
211	Aug-23		72,395.26	(16,891.87)	6.836%		55,503.39	(2,945,914.35)
212	Sep-23		(73,008.43)	(16,989.84)	6.836%		(89,998.27)	(3,035,912.63)
213	Oct-23		(40,350.65)	(17,409.51)	6.836%		(57,760.16)	(3,093,672.78)
214	Nov-23	**1**	194,605.30	1,649.18	6.836%	3,285,870.12	3,482,124.60	388,451.82
215	Dec-23		1,867,731.24	7,532.80	6.836%		1,875,264.04	2,263,715.86
216	Jan-24		(480,571.84)	11,526.81	6.836%		(469,045.03)	1,794,670.83
217	Feb-24		1,298,433.49	13,922.01	6.836%		1,312,355.50	3,107,026.33
218	Mar-24		553,409.88	19,275.99	6.836%		572,685.87	3,679,712.21
219	Apr-24		965,800.74	23,713.02	6.836%		989,513.76	4,669,225.96
220	May-24		102,370.82	26,890.61	6.836%		129,261.43	4,798,487.39
221	Jun-24		390,713.42	28,448.27	6.836%		419,161.69	5,217,649.08
222	Jul-24			29,723.21	6.836%		29,723.21	5,247,372.29
223	Aug-24			29,892.53	6.836%		29,892.53	5,277,264.82
224	Sep-24			30,062.82	6.836%		30,062.82	5,307,327.64
225	Oct-24			30,234.08	6.836%		30,234.08	5,337,561.72

230 **History truncated for ease of viewing**

232 **NOTES**

233 **1** -Transferred June balance plus July-October interest on June balance to account 151525 for amortization.

EXHIBIT B

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

NW NATURAL SUPPORTING MATERIALS

Purchased Gas Cost

NWN OPUC Advice No. 24-19

August 1, 2024

NW NATURAL

EXHIBIT B

Supporting Materials

Purchased Gas Cost

NWN OPUC ADVICE NO. 24-19

Commodity and Non-Commodity Costs	Page

NW Natural
2024-2025 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**		$ 32,735,167	$51,836,840	$49,392,780	$34,539,879	$31,245,027	$17,566,528	$12,050,839	$9,490,782	$8,628,185	$7,701,125	$8,585,979	$14,673,590	$ 278,446,721
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**		$88,354	$105,528	$108,727	$82,908	$86,142	$71,824	$47,800	$34,466	$27,969	$24,783	$28,051	$53,529	$760,081
9	tab Commodity Cost from Vol Pipe, column F, line 78-89														
10	**Commodity Cost from Storage**		$1,913,187	$6,179,884	$6,989,315	$8,512,869	$4,798,577	$1,600,290	$0	$0	$0	$0	$0	$133,511	$30,127,633
11	tab Commodity Cost from Storage, column J, line 61-72														
12	**Commodity Cost from - Brown Gas**		$111,653	$115,373	$115,373	$104,209	$115,373	$111,653	$115,373	$111,653	$115,373	$115,373	$111,653	$115,373	$1,358,432
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**		$ 876,413	$ 876,413	$ 620,506	$ 620,506	$ 1,811,623	$ 1,734,578	$ 1,734,578	$ 1,734,578	$ 2,049,821	$ 2,049,821	$ 2,049,821	$ 2,049,821	$18,208,479
17	tab RNG RTC Costs, column L, line 1-12														
18	**Commodity Cost from Gas Reserves**		$788,617	$842,219	$837,909	$779,425	$779,700	$782,851	$795,384	$750,636	$765,479	$767,112	$769,701	$772,857	$9,431,891
19	tab Commodity Cost from Gas Reserve, column AF, line 59-70														
20	**Total Commodity Cost**		$ 36,513,391	$59,956,257	$58,064,610	$44,639,796	$38,836,443	$21,867,724	$14,743,973	$12,122,115	$11,586,827	$10,658,214	$11,545,204	$17,798,681	$ 338,333,237
21															
22	**VOLUMES**														
23	Commodity Volumes at Receipt Points		77,990,503	93,402,335	92,903,575	72,669,076	73,415,884	62,881,617	43,024,477	30,992,620	25,308,803	22,306,223	25,420,587	48,037,246	668,352,946
24	Pipeline Fuel Use		1,101,852	1,212,919	1,206,410	942,929	968,979	814,422	550,978	376,417	287,554	248,503	290,644	604,306	8,605,913
25	Gas Arriving at City Gate		76,888,651	92,189,416	91,697,165	71,726,147	72,446,905	62,067,195	42,473,498	30,616,203	25,021,249	22,057,720	25,129,943	47,432,940	659,747,033
26															
27	Brown Gas and Storage Gas Withdrawals		6,879,983.19	21,844,237	24,292,001	30,058,489	16,802,772	5,617,298	220,601	213,485	220,601	220,601	213,485	647,086	107,230,639
28	RNG Supply/Offtakes		-	-	-	-	-	-	-	-	-	-	-	-	0
29	Pipeline Fuel Use for Off-Site Storage		-	-	3,353	-	2,134	1,793	-	-	-	-	-	358	7,638
30	Storage Gas Deliveries at City Gate		6,879,983	21,844,237	24,288,647	30,058,489	16,800,638	5,615,504	220,601	213,485	220,601	220,601	213,485	646,728	107,223,000
31															
32	Total Gas At City Gate (Storage and Commodity)		83,768,635	114,033,653	115,985,812	101,784,635	89,247,543	67,682,700	42,694,100	30,829,688	25,241,850	22,278,321	25,343,428	48,079,668	766,970,033
33															
34	Unaccounted for Gas		625,693	750,205	746,199	583,682	589,548	505,081	345,635	249,144	203,614	179,498	204,499	385,992	5,368,790
35															
36	Load Served		83,142,942	113,283,448	115,239,613	101,200,953	88,657,995	67,177,619	42,348,465	30,580,544	25,038,236	22,098,823	25,138,929	47,693,676	761,601,243

WACOG Calculations

37	**Gas Reserves Supply:**													
38	Total cost (line 20 above)	$788,617	$842,219	$837,909	$779,425	$779,700	$782,851	$795,384	$750,636	$765,479	$767,112	$769,701	$772,857	$9,431,891
39	Load served by gas reserves	1,723,828	1,768,862	1,756,672	1,575,866	1,732,960	1,665,888	1,710,074	1,644,116	1,687,948	1,677,150	1,612,760	1,656,047	20,212,172
40														
41	**Total Load Served**													
42	Oregon	83,142,942	113,283,447	115,239,612	101,200,953	88,657,995	67,177,618	42,348,465	30,580,545	25,038,236	22,098,823	25,138,929	47,693,676	761,601,240
43	Total (same as line 36 +/- rounding)	83,142,942	113,283,447	115,239,612	101,200,953	88,657,995	67,177,618	42,348,465	30,580,545	25,038,236	22,098,823	25,138,929	47,693,676	761,601,240
44														
45	**Oregon WACOG Calculation**													
46														
47	Total Oregon commodity cost	$36,513,391	$59,956,257	$58,064,610	$44,639,796	$38,836,443	$21,867,724	$14,743,973	$12,122,115	$11,586,827	$10,658,214	$11,545,204	$17,798,681	$338,333,237
48	Total commodity cost for Oregon	$36,513,391	$59,956,257	$58,064,610	$44,639,796	$38,836,443	$21,867,724	$14,743,973	$12,122,115	$11,586,827	$10,658,214	$11,545,204	$17,798,681	$338,333,237
49														
50	**Oregon Sales WACOG (line 48 ÷ line 42)**	$0.43916	$0.52926	$0.50386	$0.44110	$0.43805	$0.32552	$0.34816	$0.39640	$0.46277	$0.48230	$0.45926	$0.37319	$0.44424
51														
52	**OREGON BILLING WACOG**	$0.45220	$0.54497	$0.51882	$0.45420	$0.45106	$0.33518	$0.35850	$0.40817	$0.47651	$0.49662	$0.47289	$0.38427	$0.45743

NW Natural
2024-2025 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	$4,441,496	$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	$48,534,402
Alberta: NOVA		760,706	760,706	760,706	760,706	760,706	760,706	760,706	760,706	760,706	760,706	760,706	760,706	9,128,475
Alberta: Foothills		547,179	547,179	547,179	547,179	547,179	488,403	488,403	488,403	488,403	488,403	488,403	547,179	6,213,486
Alberta: GTN		467,303	482,880	482,880	436,149	482,880	393,231	406,339	393,231	406,339	406,339	393,231	482,880	5,233,681
BC: Southern Crossing														0
BC: Spectra (Westcoast)		1,241,757	1,258,261	1,258,261	1,208,749	1,258,261	1,241,757	1,258,261	1,241,757	1,258,261	1,258,261	1,241,757	1,258,261	14,983,604
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		(404,266)	(404,266)	(404,266)	(404,266)	(404,266)	(404,266)	(404,266)	(404,266)	(404,266)	(404,266)	(404,266)	(404,266)	(4,851,189)
Total System Demand		**$6,649,911**	**$6,815,944**	**$7,104,944**	**$6,317,847**	**$6,815,944**	**$6,426,378**	**$6,586,919**	**$6,426,378**	**$6,586,919**	**$6,586,919**	**$6,426,378**	**$6,722,236**	**$79,466,717**

NW Natural

2024-2025 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		$79,466,717	
5	Oregon Allocation Factor 1/		88.63%	
6	Oregon Demand		$71,291,272	
7				
8	Oregon Firm Sales Forecasted Normal Volumes		709,393,126	
9	Oregon Interruptible Sales Forecasted Normal Volumes		52,208,113	
10				
11				
12	Proposed Firm Demand Per Therm 2/		$0.09962	$0.10258
13	Proposed Interruptible Demand 2/		$0.01185	$0.01220
14	Proposed MDDV Demand Charge		$1.47	$1.51
15				
16	Current Firm Demand Per Therm		$0.09742	$0.10025
17	Current Interruptible Demand		$0.01159	$0.01193
18	Current MDDV Demand Charge		$1.44	$1.48
19				
20	Percent Change in Firm Demand		2.26%	
21				
22				
23	1/Allocation Factor: 2024-25 PGA forecast firm sales volumes:			
24		Washington	Oregon	System
25	Firm Sales	90,969,890	709,393,126	800,363,017
26		11.37%	88.63%	100.00%
27				
28	2/Calculation of Proposed Demand Rates:			
29				
30	Demand change factor		1.023	
31				
32	Firm Demand (line 16 * line 30)		$0.09962	$70,672,491
33	Interruptible Demand (line 17 * line 30)		$0.01185	$618,781

NW Natural

2024-2025 PGA - SYSTEM: August Filing

Calculation of Winter WACOG

Prices are per therm

		AECO/NIT		
1	Forecast price for AECO gas:			
2				
3		AECO/NIT		
4				
5	November	$0.19410		
6	December	$0.22391		
7	January	$0.23566		
8	February	$0.23619		
9	March	$0.22261		
10	April	$0.20582		
11	May	$0.19828		
12	June	$0.19954		
13	July	$0.20860		
14	August	$0.21039		
15	September	$0.21271		
16	October	$0.22935		
17				
18				
19	Average price, November-March		$0.22249	average lines 5-9
20				
21	Annual average price, November-October		$0.21476	average lines 5-16
22				
23	Ratio of winter to annual		1.03599	line 19 ÷ line 21
24				
25			Without Rev	WITH Rev
26			Sensitive	Sensitive
OR	Oregon Annual WACOG		$0.44424	$0.45743
OR	Oregon Winter WACOG		$0.46023	$0.47389
			line 23 * $0.44424	

NW Natural
2023-2024 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. 11/01/24	Interr. Demand Increment Eff. 11/01/24	Seasonalized Fixed Charges
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
November	2024	48,753,791	26,288,033	3,103,538	4,997,580	83,142,942	$0.09962	$0.01185	$7,844,377
December	2024	68,443,075	35,940,899	4,136,644	4,762,829	113,283,447	$0.09962	$0.01185	$10,867,700
January	2025	68,724,545	37,221,614	3,930,991	5,362,462	115,239,612	$0.09962	$0.01185	$11,009,949
February	2025	59,383,996	32,986,900	3,893,874	4,936,184	101,200,953	$0.09962	$0.01185	$9,648,778
March	2025	50,053,421	29,256,554	3,791,610	5,556,409	88,657,995	$0.09962	$0.01185	$8,344,759
April	2025	36,697,773	22,203,545	3,403,408	4,872,892	67,177,618	$0.09962	$0.01185	$6,264,792
May	2025	21,033,862	14,336,478	2,891,160	4,086,966	42,348,465	$0.09962	$0.01185	$3,860,196
June	2025	14,006,313	10,447,157	2,595,213	3,531,863	30,580,545	$0.09962	$0.01185	$2,736,552
July	2025	10,718,684	8,557,761	2,538,823	3,222,968	25,038,236	$0.09962	$0.01185	$2,211,518
August	2025	8,950,396	7,295,307	2,497,779	3,355,341	22,098,823	$0.09962	$0.01185	$1,907,063
September	2025	10,833,809	8,045,568	2,817,639	3,441,913	25,138,929	$0.09962	$0.01185	$2,202,332
October	2025	25,459,605	15,196,730	2,956,634	4,080,707	47,693,676	$0.09962	$0.01185	$4,393,257
		423,059,269	247,776,546	38,557,311	52,208,113	761,601,240			$71,291,273

	Encana Gas Reserves Deal		Projected November 2024	Projected December 2024	Projected January 2025	Projected February 2025	Projected March 2025	Projected April 2025	Projected May 2025	Projected June 2025	Projected July 2025	Projected August 2025	Projected September 2025	Projected October 2025	Projected PGA Totals
1	**Therms Delivered (000s)**														
2	**Total Therms**		1,658.57	1,701.89	1,690.15	1,516.18	1,667.31	1,602.77	1,645.27	1,581.81	1,623.97	1,613.57	1,551.61	1,593.24	19,446.33
3	**Rate per Therm (Depletion Rate)**		0.13026	0.13026	0.13026	0.13026	0.13026	0.13026	0.13026	0.13026	0.13026	0.13026	0.13026	0.13026	0.13026
4	**Delivery Value**		216.04	221.69	220.16	197.50	217.18	208.78	214.31	206.04	211.54	210.18	202.11	207.53	2,533.06
5															0.1303
6	**Opex / Severance / Ad Valorem**														
7	**Operating Cost**		400.21	405.38	404.34	394.29	399.08	424.14	433.55	397.26	397.09	400.65	416.56	417.88	4,890.44
8	**Severance and Ad Valorem Taxes**		78.48	145.83	145.13	110.01	71.39	53.34	50.52	53.09	68.77	69.78	64.42	59.76	970.51
9	**Total**		478.69	551.21	549.47	504.30	470.47	477.48	484.07	450.35	465.86	470.43	480.98	477.64	5,860.95
10															0.3014
11	**Average Rate Base**		14,310.07	14,146.96	13,984.96	13,839.64	13,679.84	13,526.22	13,368.53	13,216.92	13,061.27	12,906.61	12,757.90	12,605.19	
12															
13	**Carrying Cost**														
14	**Equity**	**9.4000%**	56.05	55.41	54.77	54.21	53.58	52.98	52.36	51.77	51.16	50.55	49.97	49.37	
15	**Equity % of Cap Struct**	**50.0000%**													
16	**Equity Pretax**	**26.4193%**	48.29	23.49	22.88	34.59	47.46	53.05	53.21	51.49	45.09	43.91	45.02	45.87	
17	**Debt**	**4.2710%**	25.47	25.18	24.89	24.63	24.34	24.07	23.79	23.52	23.24	22.97	22.70	22.43	
18	**Total Carrying Cost**		73.76	48.67	47.77	59.21	71.80	77.12	77.00	75.01	68.34	66.88	67.73	68.30	801.58
19															0.0412
20	**Total Cost**		768.49	821.57	817.40	761.01	759.45	763.37	775.38	731.41	745.73	747.49	750.82	753.47	9,195.60
21	**Total Volume**		1,658.57	1,701.89	1,690.15	1,516.18	1,667.31	1,602.77	1,645.27	1,581.81	1,623.97	1,613.57	1,551.61	1,593.24	19,446.33
22	**Total Rate Per Therm**		0.463	0.483	0.484	0.502	0.455	0.476	0.471	0.462	0.459	0.463	0.484	0.473	0.473

Non-Carry Wells Gas Reserves Deal		Projected November 2024	Projected December 2024	Projected January 2025	Projected February 2025	Projected March 2025	Projected April 2025	Projected May 2025	Projected June 2025	Projected July 2025	Projected August 2025	Projected September 2025	Projected October 2025	Projected PGA Totals
Therms Delivered (000s)														
Total Therms		66.71	68.46	68.00	61.01	67.10	64.52	66.24	63.69	65.40	64.99	62.51	64.20	782.83
Rate per Therm (Depletion Rate)		0.2825	0.2825	0.2825	0.2825	0.2825	0.2825	0.2825	0.2825	0.2825	0.2825	0.2825	0.2825	0.2825
Delivery Value		18.84	19.34	19.21	17.23	18.95	18.22	18.71	17.99	18.47	18.36	17.66	18.13	221.13
														0.2825
Opex / Severance / Ad Valorem														
Operating Cost		13.95	14.10	14.09	13.76	13.89	14.42	14.69	13.79	13.79	13.84	14.30	14.37	168.99
Severance and Ad Valorem Taxes		3.37	5.01	5.26	4.53	3.29	2.50	2.48	2.52	2.89	2.94	2.71	2.71	40.19
Total		17.32	19.10	19.35	18.29	17.18	16.92	17.17	16.31	16.68	16.77	17.01	17.08	209.17
														0.2672
Average Rate Base		1,277.20	1,262.97	1,248.84	1,236.15	1,222.21	1,208.80	1,195.03	1,181.79	1,168.20	1,154.69	1,141.70	1,128.36	
Carrying Cost														
Equity	**9.4000%**	5.00	4.95	4.89	4.84	4.79	4.73	4.68	4.63	4.58	4.52	4.47	4.42	
Equity % of Cap Struct	**50.0000%**													
Equity Pretax	**26.4193%**	6.80	6.72	6.65	6.58	6.51	6.43	6.36	6.29	6.22	6.15	6.08	6.01	
Debt	**4.5290%**	2.41	2.38	2.36	2.33	2.31	2.28	2.26	2.23	2.20	2.18	2.15	2.13	
Total Carrying Cost		9.21	9.11	9.00	8.91	8.81	8.72	8.62	8.52	8.42	8.33	8.23	8.14	104.01
														0.1329
Total Cost		45.37	47.55	47.56	44.44	44.95	43.86	44.50	42.82	43.57	43.46	42.90	43.35	534.31
Total Volume		66.71	68.46	68.00	61.01	67.10	64.52	66.24	63.69	65.40	64.99	62.51	64.20	782.83
Total Rate Per Therm		0.680	0.694	0.699	0.728	0.670	0.680	0.672	0.672	0.666	0.669	0.686	0.675	0.683

NW Natural
Rates & Regulatory Affairs
2024-25 PGA - Oregon: August Filing
Attachment C: 3% Test

Non-Gas Cost Amortizations [1]	Surcharge	Credit
WARM	$ 2,835,014	
Oregon Regulatory Fee	$ 255,179	
CAT Incremental	$ 346,882	
Net Curtailment and Entitlment		$ (1,891,759)
RNG Transport Allocation	$ 415,598	
COVID	$ 1,314,604	
Rate Mitigation	$ 737,092	
TSA Cost of Service	$ 2,266,041	
TSA O&M	$ 220,566	
Residual Balances		(37,094)
Lincoln City Sale		$ (998,177)
Total	$ 8,390,976	$ (2,927,030)
Net Proposed Amortizations (subject to the 3% test)		$ 5,463,946
Utility Gross Revenues (2023) [2]		$975,829,919
3% of Utility Gross Revenues		$ 29,274,898
Allowed Amortization		$ 5,463,946
Allowed Amortization as % of Gross Revenues		0.6%

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
2024-25 PGA - Oregon: August Filing
Effects on Average Bill by Rate Schedule [1]
ALL VOLUMES IN THERMS

										Advice 24-19
										See note [15]
		Oregon PGA Normalized Volumes page, Column D	Therms in Block	Normal Therms Monthly Average use	Minimum Monthly Charge	11/1/2023 Billing Rates	11/1/2023 Current Average Bill	Proposed 11/1/2024 Schedule 164 PGA Rates	Proposed 11/1/2024 Schedule 164 PGA Average Bill	Proposed 11/1/2024 Schedule 164 PGA % Bill Change
							F=D+(C * E)		AO = D+(C*AN)	AP = (AO-F)/F
Schedule	Block	A	B	C	D	E	F	AN	AO	AP
2R		423,059,269	N/A	55	$8.00	$1.29519	$79.24	$1.27231	$77.98	-1.6%
3C Firm Sales		178,618,735	N/A	251	$15.00	$1.08753	$287.97	$1.06465	$282.23	-2.0%
3I Firm Sales		5,103,738	N/A	1,255	$15.00	$1.05830	$1,343.17	$1.03542	$1,314.45	-2.1%
27 Dry Out		742,733	N/A	37	$8.00	$1.08605	$48.18	$1.06317	$47.34	-1.7%
31C Firm Sales	Block 1	12,281,908	2,000	2,827	$325.00	$0.75920	**$2,447.92**	$0.73399	**$2,376.65**	-2.9%
	Block 2	10,043,265	all additional			$0.73098		$0.70577		
31C Firm Trans	Block 1	1,267,742	2,000	3,758	$575.00	$0.29503	**$1,639.68**	$0.29503	**$1,639.68**	0.0%
	Block 2	1,392,960	all additional			$0.26998		$0.26998		
31I Firm Sales	Block 1	3,698,785	2,000	5,430	$325.00	$0.74421	**$4,283.47**	$0.71900	**$4,146.58**	-3.2%
	Block 2	7,639,515	all additional			$0.72013		$0.69492		
31I Firm Trans	Block 1	144,356	2,000	6,890	$575.00	$0.25351	**$2,204.08**	$0.25351	**$2,204.08**	0.0%
	Block 2	351,741	all additional			$0.22946		$0.22946		
32C Firm Sales	Block 1	34,618,514	10,000	7,386	$675.00	$0.67131	**$5,633.30**	$0.64610	**$5,447.09**	-3.3%
	Block 2	9,360,621	20,000			$0.64449		$0.61928		
	Block 3	1,566,490	20,000			$0.59997		$0.57476		
	Block 4	544,281	100,000			$0.55528		$0.53007		
	Block 5	0	600,000			$0.52318		$0.49797		
	Block 6	0	all additional			$0.50796		$0.48275		
32I Firm Sales	Block 1	8,547,588	10,000	20,942	$675.00	$0.62727	**$13,593.87**	$0.60206	**$13,065.92**	-3.9%
	Block 2	7,603,172	20,000			$0.60740		$0.58219		
	Block 3	2,763,251	20,000			$0.57416		$0.54895		
	Block 4	3,005,494	100,000			$0.54104		$0.51583		
	Block 5	195,767	600,000			$0.51791		$0.49270		
	Block 6	0	all additional			$0.50628		$0.48107		
32C Firm Trans	Block 1	2,721,537	10,000	19,501	$925.00	$0.13325	**$3,337.38**	$0.13325	**$3,337.38**	0.0%
	Block 2	2,020,003	20,000			$0.11366		$0.11366		
	Block 3	707,839	20,000			$0.08114		$0.08114		
	Block 4	869,038	100,000			$0.04857		$0.04857		
	Block 5	0	600,000			$0.02899		$0.02899		
	Block 6	0	all additional			$0.01601		$0.01601		
32I Firm Trans	Block 1	11,657,702	10,000	75,569	$925.00	$0.13029	**$7,266.47**	$0.13029	**$7,266.47**	0.0%
	Block 2	17,056,306	20,000			$0.11125		$0.11125		
	Block 3	10,569,490	20,000			$0.07953		$0.07953		
	Block 4	22,324,991	100,000			$0.04783		$0.04783		
	Block 5	22,115,808	600,000			$0.02874		$0.02874		
	Block 6	7,865,614	all additional			$0.01613		$0.01613		
32C Interr Sales	Block 1	4,649,733	10,000	51,487	$675.00	$0.64462	**$32,098.38**	$0.61563	**$30,605.77**	-4.7%
	Block 2	6,816,872	20,000			$0.62250		$0.59351		
	Block 3	3,782,502	20,000			$0.58557		$0.55658		
	Block 4	5,561,835	100,000			$0.54861		$0.51962		
	Block 5	3,284,822	600,000			$0.52644		$0.49745		
	Block 6	0	all additional			$0.51023		$0.48124		
32I Interr Sales	Block 1	4,653,469	10,000	42,594	$675.00	$0.62793	**$26,377.14**	$0.59894	**$25,142.34**	-4.7%
	Block 2	6,055,122	20,000			$0.60846		$0.57947		
	Block 3	3,505,859	20,000			$0.57596		$0.54697		
	Block 4	9,726,364	100,000			$0.54347		$0.51448		
	Block 5	4,171,536	600,000			$0.52396		$0.49497		
	Block 6	0	all additional			$0.50968		$0.48069		
32C Interr Trans	Block 1	822,778	10,000	199,597	$925.00	$0.12471	**$11,732.30**	$0.12471	**$11,732.30**	0.0%
	Block 2	1,679,150	20,000			$0.10645		$0.10645		
	Block 3	978,518	20,000			$0.07601		$0.07601		
	Block 4	3,232,735	100,000			$0.04557		$0.04557		
	Block 5	472,307	600,000			$0.02730		$0.02730		
	Block 6	0	all additional			$0.01517		$0.01517		
32I Interr Trans	Block 1	6,144,023	10,000	198,801	$925.00	$0.12543	**$11,821.46**	$0.12543	**$11,821.46**	0.0%
	Block 2	10,403,074	20,000			$0.10713		$0.10713		
	Block 3	6,958,044	20,000			$0.07662		$0.07662		
	Block 4	15,417,391	100,000			$0.04610		$0.04610		
	Block 5	35,960,832	600,000			$0.02781		$0.02781		
	Block 6	99,266,501	all additional			$0.01563		$0.01563		
33		0	N/A	0.0	$38,000.00	$0.00862	$38,000.00	$0.00862	$38,000.00	
Special Contracts		54,127,531	N/A	0	$0	$0.00544	$0.00	$0.00544	$0.00	
Totals		**1,098,129,249**								

[1] For convenience of presentation, demand charges for Rate Schedules 31 and 32 have been removed.
[2] Tariff Advice Notice 24-04: Non-Gas Cost Deferral Amortizations - Intervenor Funding
[3] Tariff Advice Notice 24-05: Non-Gas Cost Deferral Amortizations - Oregon PUC Fee
[4] Tariff Advice Notice 24-06: Non-Gas Cost Deferral Amortizations - SRRM
[5] Tariff Advice Notice 24-07: Non-Gas Cost Deferral Amortizations - Industrial DSM
[6] Tariff Advice Notice 24-08: Non-Gas Cost Deferral Amortizations - Decoupling
[7] Tariff Advice Notice 24-09: Non-Gas Cost Deferral Amortizations - WARM
[8] Tariff Advice Notice 24-10: Non-Gas Cost Deferral Amortization - Corporate Activity Tax (CAT) Amortization
[9] Tariff Advice Notice 24-11: Non-Gas Cost Amortization - Net Curtaiment and Entitlement Revenues
[10] Tariff Advice Notice 24-12: Non-Gas Cost Amortization - Regulatory Rate Adjustment
[11] Tariff Advice Notice 24-13: Non-Gas Cost Amortization - Residenital Rate Mitigation
[12] Tariff Advice Notice 24-14: Non-Gas Cost Amortization - RNG Transport Allocation
[13] Tariff Advice Notice 24-15: COVID
[14] Tariff Advice Notice 24-16: Non-Gas Cost Amortization - TSA Security Directive
[15] Tariff Advice Notice 24-19: PGA
[16] Tariff Advice Notice 24-17: RNG Adj Mechanism
[17] Tariff Advice Notice 23-21: Mist Recall

NW Natural
Rates and Regulatory Affairs
2024-2025 PGA Filing - OREGON
Basis for Revenue Related Costs

Line		Twelve Months Ended 06/30/24		
1				
2				
3	Total Billed Gas Sales Revenues	$ 920,096,835		
4	Total Oregon Revenues	$ 925,565,009		
5				
6	Regulatory Commission Fees [1]	n/a	0.450%	Statutory rate
7	City License and Franchise Fees	$ 21,672,271	2.342%	Line 7 ÷ Line 4
8	Net Uncollectible Expense [2]	$ 845,048	0.091%	Line 8 ÷ Line 4
9				
10	Total		**2.883%**	Sum lines 8-9
11				
12				

13 **Note:**
14 [1] Dollar figure is set at statutory level of 0.275% times Total Oregon Revenues (line 4).
15 Because the fee changed since our last general rate case, the difference between the previous fee of 0.375%
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
2024-2025 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	$7,473,545
7	Demand Capacity Cost Change	1,331,225
9	**Total Gas Cost Change**	**8,804,770**
11	**Temporary Increments**	
13	Removal of Current Temporary Increments	
14	Amortization of 191.xxx Account Gas Costs	(409,308)
16	Addition of Proposed Temporary Increments	
17	Amortization of 191.xxx Account Gas Costs	(26,708,778)
19	**Net Temporary Rate Adjustment**	**(27,118,086)**
21	**TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES**	**($18,313,316)**
23	2023 Oregon Earnings Test Normalized Total Revenues	$975,829,919
25	Effect of this filing, as a percentage change (line 21 ÷ line 23)	-1.88%
27	Effect of this filing, as a percentage change (line 19 ÷ line 23)	-2.78%
29	Effect of this filing, as a percentage change (line 9 ÷ line 23)	0.90%

EXHIBIT C

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

Purchased Gas Cost

REDACTED

NWN OPUC Advice No. 24-19

August 1, 2024

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.	93	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.	110	CONFIDENTIAL
V.8	**Attestation as to Consistency**	114	

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 invalidation of the Climate Protection Program in December 2023 by the Oregon Court of Appeals.

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 490).

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

	Amount	Location in Company Filing (cite)
1) Change in Annual Revenues		
(Per OAR 860-022-0017(3)(a))		
A) Dollars *(To .1 million)*	($31,298,584)	Refer to workpaper "2024-25 PGA filing Summary Effects"
B) Percent *(To .1 percent)*	-3.21%	"
2) Annual Revenues Calculation *(Whole Dollars)*		
A) PGA Cost Change *(Commodity & Transportation*)	8,804,770	Refer to workpaper "2024-25 PGA filing Summary Effects"
B) Remove Last Year's Temporary Increment Total	(31,184,868)	"
C) Add New Temporary Increment	(9,862,036)	"
D) Remove Last Year's Permanent Increment Total	(4,839,313)	
E) Add New Permanent Increment Total	5,782,863	
E) Total Proposed Change	($31,298,584)	Refer to workpaper "2024-25 PGA filing Summary Effects"
3) Residential Bill Effects Summary		
A) Residential Schedule 2 Rate Impacts		
1) Current Billing Rate per Therm	$1.29519	Refer to workpaper '2024-2025 PGA Rate Development'
2) Proposed Billing Rate per Therm	$1.24573	"
3) Rate Change Per Therm	($0.04946)	"
4) Percent Change per Therm *(to .1%)*	-3.8%	"
B) Average Residential Bill Impact (forecasted weather-normalized annual)		
1) Average Residential Monthly Use	55.0	Refer to workpaper '2024-2025 PGA Rate Development'
2) Customer Charge	$8.00	"
3) Current Average Monthly Bill	$79.24	"
4) Proposed Average Monthly Bill	$76.52	"
5) Change in Average Monthly Bill	($2.72)	"
6) Percent change in Average Monthly Bill *(to .1%)*	-3.4%	"
C) Average January Residential Bill Impact		
1) Average January Residential Use *(forecasted weather-normalized)*	106.4	Refer to workpaper '2024-2025 PGA Rate Development'
2) Customer Charge	$8.00	"
3) Current Average January Bill	$145.87	"
4) Proposed Average January Bill	$140.61	"
5) Change in Average January Bill	($5.26)	"
6) Percent change in Average January Bill (*to .1%)*	-3.6%	"

4) Breakdown of Costs		
A) Embedded in Rates		
1) Total Commodity Cost	$335,201,283	NWN 2023-24 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)	$834,363	"
e) Total Storage Cost (assoc. w/ supply)	$43,283,502	"
f) Other	$291,083,418	"
2) Total Transportation Cost *(Pipeline related)*	$69,998,430	"
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	$405,199,713	"
B) Projected For New Rates (Oregon Costs)		
1) Total Commodity Cost	$338,333,237	NWN 2024-25 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 Vaporization Cost (assoc. w/ supply)		
e) Total Volumetric Cost (assoc. w/ supply)	$760,081	"
f) Total Storage Cost (assoc. w/ supply)	$39,559,524	"
g) Other	$298,013,632	"
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	$409,624,509	"

5) WACOG *(Weighted Average Cost of Gas)*		
A) Embedded in Rates		
1) WACOG *(Commodity Only)*		
a. With revenue sensitive	$0.44732	NWN 2024-25 PGA OR Gas Cost Development_September Filing
b. Without revenue sensitive	$0.43471	"
2) WACOG (Non-Commodity)		
a. With revenue sensitive	$0.10025	NWN 2024-25 PGA OR Gas Cost Development_September Filing
b. Without revenue sensitive	$0.09742	"
B) Proposed for New Rates		
1) WACOG *(Commodity Only)*		
a. With revenue sensitive	$0.45743	NWN 2024-25 PGA OR Gas Cost Development_September Filing
b. Without revenue sensitive	$0.44424	"
2) WACOG (Non-Commodity)		
a. With revenue sensitive	$0.10258	"
b. Without revenue sensitive	$0.09962	"
6) Therms Sold		"

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

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 IHS Markit 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 20,000 Dth/day to meet the 2024-25 design peak day of approximately 1 million Dth/day. The Company’s analysis led to a Mist recall of 20,000 Dth/d of deliverability.

(2) System modeling showed that adjusting system pressures increased Newport deliverability to the system on a peak day from 64,500 Dth/d to 78,000 Dth/d.

(3) An electrical upgrade is needed at Portland LNG, which will not be in place this 2024-25 winter. This limits Portland LNG deliverability for this upcoming winter to 99,630 Dth/day.

(4) We have executed a citygate call option with Powerex for 15,000 Dth/day for the 2024-25 winter. This option has no up-front cost associated with it but would be available if supplies were needed on a peak day, at the Sumas high daily price.

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

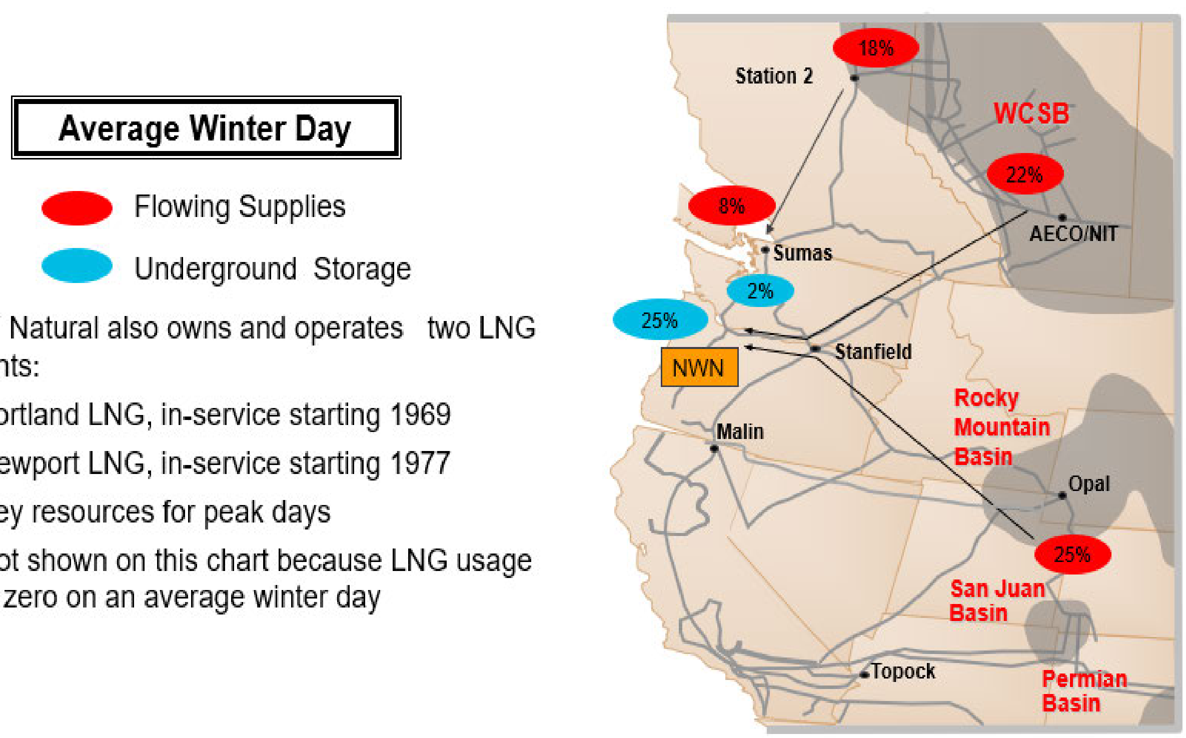
(i) A previously identified trend of higher heat content on the interstate pipeline system has not reversed, which means slightly higher deliverabilities from the Portland LNG and Newport LNG plants, along with slightly more working gas capacity for utility customers at Mist, continue to be maintained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

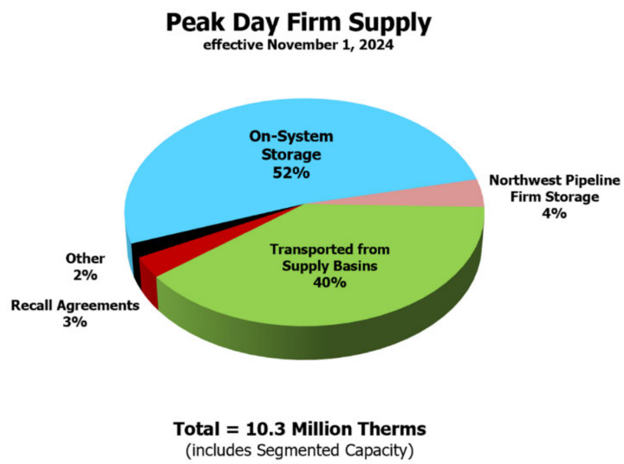
The Company's portfolio continues to reflect the gas reserves purchased under the agreement with Encana approved by the OPUC in 2011. That agreement was amended in March 2014 and seven new gas wells were drilled with the successor company Jonah Energy LLC. This PGA continues to reflect the approved regulatory 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.

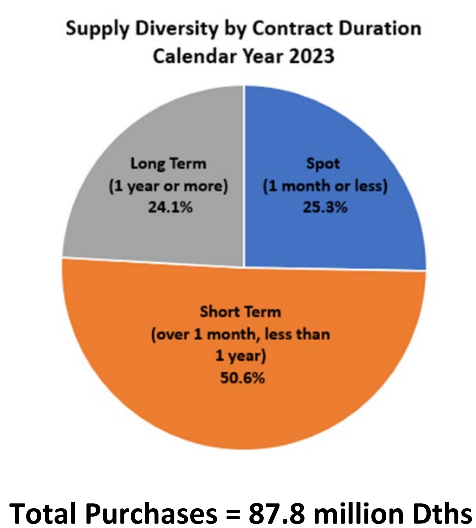
Should its "design" peak day occur during the upcoming heating season, all physical resources would be used in the following proportions (607,000 therms/day of segmented capacity is included):



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 2024 through October 2025 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 2.9 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 2023 calendar year, just over 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.



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 67% of the prices of its expected annual Oregon sales requirements for the upcoming PGA year commencing November 1, 2024. 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 14%. 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 29% 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

Table 1

NW Natural
Firm Off-System Gas Supply Contracts
for the 2024/2025 Tracker Year

Supply Location	Duration	Baseload Qty (Dth/day)	Contract Termination Date
British Columbia:			
Canadian Natural Resources	Nov-Oct	15,000	10/31/2025
ConocoPhillips Canada Marketing	Nov-Mar	10,000	3/31/2025
Direct Energy Marketing Limited	Nov-Mar	5,000	3/31/2025
J. Aron & Company	Nov-Mar	5,000	3/31/2025
MacQuarie Energy Canada Ltd.	Nov-Mar	5,000	3/31/2030
Powerex Corp	Nov-Mar	5,000	3/31/2030
Pacific Canbriam Energy Limited	Nov-Mar	5,000	3/31/2025
Uniper Trading Canada Ltd.	Nov-Mar	5,000	3/31/2025
MacQuarie Energy Canada Ltd.	Apr-May	5,000	5/31/2025
MacQuarie Energy Canada Ltd.	Apr-Jun	5,000	6/30/2025
MacQuarie Energy Canada Ltd.	Apr	5,000	4/30/2025
TD Energy Trading Inc	Oct	10,000	10/31/2025
Pending	Nov-Oct	5,000	10/31/2025
Pending	Nov-Mar	25,000	3/31/2025
Pending	Apr	10,000	5/31/2025
Pending	Oct	10,000	10/31/2025
Alberta:			
Suncor Energy Marketing Inc	Nov-Oct	5,000	10/31/2025
Castleton Commodities	Nov-Oct	5,000	10/31/2025
ConocoPhillips Canada Marketing	Nov-Mar	15,000	3/31/2025
MacQuarie Energy Canada Ltd.	Nov-Mar	5,000	3/31/2025
TD Energy Trading Inc	Nov-Mar	10,000	3/31/2025
J. Aron & Company	Nov-Mar	5,000	3/31/2025
Powerex Corp	Nov-Mar	5,000	3/31/2025
Suncor Energy Marketing Inc	Nov-Mar	5,000	3/31/2025
EDF Trading North America, LLC	Dec-Feb	5,000	2/28/2025
Suncor Energy Marketing Inc	Apr-Jun	5,000	6/30/2025
Suncor Energy Marketing Inc	Apr-May	5,000	5/31/2025
Suncor Energy Marketing Inc	Apr	10,000	4/30/2025
Suncor Energy Marketing Inc	Oct	10,000	10/31/2025
Pending	Nov-Oct	5,000	10/31/2025
Pending	Nov-Mar	10,000	3/31/2025
Pending	Nov-Feb	5,000	2/28/2025
Pending	Apr-May	10,000	5/31/2025
Pending	Apr	10,000	4/30/2025
Pending	Sep-Oct	5,000	10/31/2025
Pending	Oct	10,000	10/31/2025
Rockies:			
MacQuarie Energy, LLC	Nov-Oct	10,000	10/31/2025
ConocoPhillips Company	Nov-Oct	5,000	10/31/2025
CIMA Energy LTD	Nov-Oct	5,000	10/31/2025
Koch Energy Services, Inc	Nov-Oct	5,000	10/31/2025
CIMA Energy LTD	Nov-Mar	10,000	3/31/2025
MacQuarie Energy, LLC	Nov-Mar	5,000	3/31/2025
PureWest Resources, Inc.	Nov-Mar	5,000	3/31/2025
Concord Energy LLC	Dec-Mar	5,000	3/31/2025
Koch Energy Services, Inc	Dec-Mar	5,000	3/31/2025
MacQuarie Energy, LLC	Dec-Mar	15,000	3/31/2025
CIMA Energy LTD	Dec-Mar	10,000	3/31/2025
Citadel Energy Marketing, LLC	Dec-Mar	5,000	3/31/2025
Vitol Inc.	Dec-Feb	5,000	2/28/2025
CIMA Energy LTD	Apr	10,000	4/30/225
MacQuarie Energy, LLC	Oct	5,000	10/31/2025
Pending	Nov-Oct	20,000	10/31/2025
Pending	Nov-Mar	5,000	3/31/2025
Pending	Dec-Feb	10,000	2/28/2025
Pending	Apr	25,000	4/30/2025
Pending	Oct	5,000	10/31/2025

Month	Baseload Qty (Dth/day)
Nov-24	230,000
Dec-24	290,000
Jan-25	290,000
Feb-25	290,000
Mar-25	265,000
Apr-25	180,000
May-25	110,000
Jun-25	90,000
Jul-25	80,000
Aug-25	80,000
Sep-25	85,000
Oct-25	135,000

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 2024/2025 Tracker Year

Pipeline and Contract	Contract Demand (Dth/day)	Termination Date
Northwest Pipeline:		
Sales Conversion (#100005)	214,889	10/31/2031
1993 Expansion (#100058)	35,155	9/30/2044
1995 Expansion (#100138)	102,000	10/31/2030
Occidental cap. acq. (#139153)	1,046	10/31/2030
Occidental cap. acq. (#139154)	4,000	10/31/2030
International Paper cap. acq. (#138065)	4,147	10/31/2030
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	10/31/2025
1995 Rationalization	57,417	10/31/2025
Engage Capacity Acquisition	3,708	10/31/2025
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	10/31/2025
1995 Rationalization	57,909	10/31/2025
Engage Capacity Acquisition	3,739	10/31/2025
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	3/31/2026
Capacity (through FortisBC)	28,435	10/31/2025
2021 Expansion	25,511	10/31/2061
Total T-South Capacity	72,946	

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 contracts with Tenaska and Fortis, which have 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 2024/2025 Tracker Year

Facility	Max. Daily Rate (Dth/day)	Max. Seasonal Level (Dth)	Termination Date
Jackson Prairie:			
SGS-2F	46,030	1,120,288	10/31/2025
TF-2 (primary firm portion)	23,038	839,046	10/31/2025
TF-2 (primary firm portion)	9,467	281,242	10/31/2025
TF-1	13,525	n/a	10/31/2031
Firm On-System Storage Plants:			
Mist (reserved for core)	325,000	13,322,920	n/a
Portland LNG Plant	99,630	507,449	n/a
Newport LNG Plant	78,000	1,082,517	n/a
Total On-System Storage	502,630	14,912,886	
Total Firm Storage Resource	548,660	16,033,174	

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 1080 Btu/cf. The current heat content used for Newport LNG is 1095 Btu/cf and Portland LNG is 1107 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 2024-25 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 2024/2025 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		
Citygate Deliveries:			
Citygate Delivery	15,000	5	2/28/2025
On-System Supplies:			
Renewable Natural Gas	≈700	n/a	Varying Terms
Mist Production	≈500	n/a	Life of the wells
Total On System Supplies	1,200		

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. Citygate deal has been executed for 5 days peaking at 6,200 dth/day.
3. 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.
4. 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 2024/2025 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)	502,630
Recallable Capacity and Supply Agreements	31,000
Citygate Deliveries	15,000
On-System Supplies	1,200
Segmented Capacity (not primary firm)	60,700
Total Peak Day Resources	999,797

Notes:
1. Per the 2022 IRP, Segmented Capacity is included as a firm resource through the 2027-28 gas year. Reliance for a peak event reduces to zero dth/day beyond the 2027-28 gas year.

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.

	2024/2025
Forecast Annual Demand (therms)	853,772,745
Forecast Peak Demand (therms) - Normal	4,481,217
Forecast Peak Demand (therms) - Design	10,278,640
Forecast DSM Annual (therms)	9,679,948
Forecast DSM Peak (therms) - Normal	56,340
Forecast DSM Peak (therms) - Design Peak	129,227
Forecast Annual Demand with Forecast DSM	844,092,797
Forecast Peak Demand with Forecast DSM - Normal	4,424,877
Forecast Peak Demand with Forecast DSM - Design	10,149,413

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, 2024 - October 31, 2025
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	Swing Volume/Day in Dths	Swing Reservation Fee cents/Dth/day	Contractual Conditions	Default Receipt Pt. Purchase Location	Internal Reference No.
MacQuarie Energy, LLC (1)	12/1/2024	3/31/2025	[redacted]	IFGMR-NWP Rockies FOM	5,000				Opal	114834
Koch Energy Services, Inc (2)	12/1/2024	3/31/2025		IFGMR-NWP Rockies FOM	5,000				Wyoming Pool	114848
ConocoPhillips Company (3)	11/1/2024	10/31/2025		IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool	114876
MacQuarie Energy, LLC (4)	11/1/2024	10/31/2025		IFGMR-NWP Rockies FOM	5,000				Wyoming Pool	114977
CIMA Energy LTD (5)	12/1/2024	3/31/2025		IFGMR-NWP Rockies FOM	5,000				Opal	114998
MacQuarie Energy, LLC (6)	11/1/2024	10/31/2025		IFGMR-NWP Rockies FOM	5,000				Opal	115019
CIMA Energy LTD (7)	11/1/2024	3/31/2025		IFGMR-NWP Rockies FOM	5,000				Opal	115104
Vitol, Inc. (8)	12/1/2024	2/28/2025		IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool	115190
MacQuarie Energy, LLC (9)	12/1/2024	3/31/2025		IFGMR-NWP Rockies FOM	5,000				Wyoming Pool	115196
CIMA Energy LTD (10)	11/1/2024	3/31/2025		IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool	115213
Concord Energy LLC (11)	12/1/2024	3/31/2025		IFGMR-NWP Rockies FOM	5,000				Wyoming Pool	115260
MacQuarie Energy, LLC (12)	11/1/2024	3/31/2025		IFGMR-NWP Rockies FOM	5,000				Opal	115300
CIMA Energy LTD (13)	11/1/2024	10/31/2025		IFGMR-NWP Rockies FOM	5,000				Wyoming Pool	115314
CIMA Energy LTD (14)	12/1/2024	3/31/2025		IFGMR-NWP Rockies FOM	5,000				Opal	115350
Koch Energy Services, Inc (15)	11/1/2024	10/31/2025		IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool	115358
CIMA Energy LTD (16)	4/1/2025	4/30/2025		IFGMR-NWP Rockies FOM	10,000				Wyoming Pool	115388
MacQuarie Energy, LLC (17)	10/1/2025	10/31/2025		IFGMR-NWP Rockies FOM	5,000				Opal	115434
MacQuarie Energy, LLC (18)	12/1/2024	3/31/2025		IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool	115456
PureWest Resources, Inc. (19)	11/1/2024	3/31/2025		IFGMR-NWP Rockies FOM	5,000				Opal	115461
Citadel Energy Marketing, LLC (20)	12/1/2024	3/31/2025		IFGMR-NWP Rockies FOM	5,000				Wyoming Pool	115463

Transactions for new PGA year

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

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Table 2

Northwest Natural Gas Company
PGA Filing Guidelines

CONFIDENTIAL

November 1, 2024 - October 31, 2025
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	Swing Volume/Day in Dth's	Swing Reservation Fee cents/Dth/day	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	[redacted]	IFGMR-NWP Canadian Border FOM	5,000				Huntingdon	113597
Uniper Trading Canada Ltd. (3)	11/1/2024	3/31/2025	[redacted]	IFGMR-NWP Canadian Border FOM	5,000				Huntingdon	115004
Pacific Canbriam Energy Limited	11/1/2024	3/31/2025	[redacted]	IFGMR-NWP Canadian Border FOM	5,000				Huntingdon	115467

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids.	Winning Bid Criteria
(1) Huntingdon	3	[redacted]	Price
(2) Huntingdon	4	[redacted]	Price
(3) Huntingdon	10	[redacted]	Price
(4) Huntingdon	9	[redacted]	Price

Table 3

Northwest Natural Gas Company
PGA Filing Guidelines

CONFIDENTIAL

November 1, 2024 - October 31, 2025
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.
Canadian Natural Resources (1)	11/1/2024	10/31/2025	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	114863
ConocoPhillips Canada Marketing (2)	11/1/2024	3/31/2025	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	114972
Canadian Natural Resources (3)	11/1/2024	10/31/2025	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	115061
MacQuarie Energy Canada Ltd. (4)	4/1/2025	6/30/2025	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	115152
MacQuarie Energy Canada Ltd. (5)	4/1/2025	5/31/2025	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	115185
Direct Energy Marketing Limited (6)	11/1/2024	3/31/2025	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	115232
J. Aron & Company (7)	11/1/2024	3/31/2025	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	115279
ConocoPhillips Canada Marketing (8)	11/1/2024	3/31/2025	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	115343
Canadian Natural Resources (9)	11/1/2024	10/31/2025	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	115357
TD Energy Trading Inc (10)	10/1/2025	10/31/2025	[redacted]	CGPR AECO FOM (7A) $US/Dth	10,000	Station 2	115440
MacQuarie Energy Canada Ltd. (11)	4/1/2025	4/30/2025	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	115454

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	9	[redacted]	Price
(3) Station 2	6	[redacted]	Price
(4) Station 2	8	[redacted]	Price
(5) Station 2	7	[redacted]	Price
(6) Station 2	8	[redacted]	Price/Diversity
(7) Station 2	6	[redacted]	Price
(8) Station 2	7	[redacted]	Price
(9) Station 2	6	[redacted]	Price
(10) Station 2	8	[redacted]	Price
(11) Station 2	7	[redacted]	Price

[END HIGHLY CONFIDENTIAL]

[START HIGHLY CONFIDENTIAL]

Table 4

Northwest Natural Gas Company
PGA Filing Guidelines — CONFIDENTIAL

November 1, 2024 - October 31, 2025
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	Swing Volume/Day in Dth's	Contractual Conditions	Internal Reference No.
ConocoPhillips Canada Marketing (1)	11/1/2024	3/31/2025	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			114792
ConocoPhillips Canada Marketing (2)	11/1/2024	3/31/2025		CGPR AECO FOM (7A) $US/Dth	5,000			114961
Suncor Energy Marketing Inc (3)	4/1/2025	6/30/2025		CGPR AECO FOM (7A) $US/Dth	5,000			115005
Suncor Energy Marketing Inc (4)	4/1/2025	5/31/2025		CGPR AECO FOM (7A) $US/Dth	5,000			115032
Suncor Energy Marketing Inc (5)	11/1/2024	10/31/2025		CGPR AECO FOM (7A) $US/Dth	5,000			115085
Suncor Energy Marketing Inc (6)	4/1/2025	4/30/2025		CGPR AECO FOM (7A) $US/Dth	10,000			115120
EDF Trading North America, LLC (7)	12/1/2024	2/28/2025		CGPR AECO FOM (7A) $US/Dth	5,000			115170
MacQuarie Energy Canada Ltd. (8)	11/1/2024	3/31/2025		CGPR AECO FOM (7A) $US/Dth	5,000			115193
Suncor Energy Marketing Inc (9)	10/1/2025	10/31/2025		CGPR AECO FOM (7A) $US/Dth	10,000			115205
TD Energy Trading Inc (10)	11/1/2024	3/31/2025		CGPR AECO FOM (7A) $US/Dth	5,000			115248
TD Energy Trading Inc (11)	11/1/2024	3/31/2025		CGPR AECO FOM (7A) $US/Dth	5,000			115267
Suncor Energy Marketing Inc (12)	11/1/2024	3/31/2025		CGPR AECO FOM (7A) $US/Dth	5,000			115317
Castleton Commodities (13)	11/1/2024	10/31/2025		CGPR AECO FOM (7A) $US/Dth	5,000			115351
ConocoPhillips Canada Marketing (14)	11/1/2024	3/31/2025		CGPR AECO FOM (7A) $US/Dth	5,000			115411
J. Aron & Company (15)	11/1/2024	3/31/2025		CGPR AECO FOM (7A) $US/Dth	5,000			115442
Powerex Corp (16)	11/1/2024	3/31/2025		CGPR AECO FOM (7A) $US/Dth	5,000			115455

Transactions for new PGA year

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

[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 2024-2025 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 2024-2025, 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.

[START HIGHLY CONFIDENTIAL]

Trade type	Contract	Counterparty	Pricing Point	Trade quantity	Total quantity	Cost per Dth	Total Cost	State
Financial Swap	100102	[redacted]	AECO	2,500	1,140,000	[redacted]		Oregon
Financial Swap	100102		Rockies	2,500	302,500			Oregon
Financial Swap	100102		Station 2	2,500	377,500			Oregon
Financial Swap	100101		AECO	2,571	3,819,500			Oregon
Financial Swap	100101		Rockies	2,500	4,185,000			Oregon
Financial Swap	100101		Station 2	2,500	1,132,500			Oregon
Financial Swap	100101		Sumas	2,500	1,510,000			Oregon
Financial Swap	100100		Rockies	2,500	377,500			Oregon
Financial Swap	100100		Station 2	2,500	377,500			Oregon
Financial Swap	100104		Rockies	2,500	1,290,000			Oregon
Financial Swap	100104		Station 2	2,500	1,290,000			Oregon
Financial Swap	100104		Sumas	2,500	755,000			Oregon
Financial Swap	100106		Rockies	2,656	1,287,500			Oregon
Financial Swap	100107		AECO	2,500	377,500			Oregon
Financial Swap	100107		Rockies	2,500	377,500			Oregon
Financial Swap	100107		Station 2	7,500	232,500			Oregon
Financial Swap	100108		AECO	2,500	152,500			Oregon
Financial Swap	100108		Rockies	4,167	1,132,500			Oregon
Financial Swap	100109		AECO	2,500	2,422,500			Oregon
Financial Swap	100109		Rockies	2,500	1,667,500			Oregon
Financial Swap	100109		Station 2	2,500	3,115,000			Oregon
Financial Swap	100109		Sumas	2,500	377,500			Oregon
Financial Swap	100110		AECO	6,250	382,500			Oregon
Financial Swap	100110		Rockies	5,000	605,000			Oregon
Financial Swap	100110		Station 2	2,500	75,000			Oregon
Financial Swap	100111		AECO	2,500	3,555,000			Oregon
Financial Swap	100111		Rockies	2,500	2,957,500			Oregon
Financial Swap	100111		Station 2	2,500	2,580,000			Oregon
Financial Swap	100111		Sumas	2,500	377,500			Oregon
Financial Swap	100112		Rockies	2,500	912,500			Oregon
Financial Swap	100112		Station 2	2,500	377,500			Oregon

[END HIGHLY CONFIDENTIAL]

Section V.3 - Load Forecasting

a. Customer count and revenue by month and class.

NW Natural

UM 1286 PGA Portfolio Guidelines
2024-2025 Oregon PGA

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

	Customer Cnt Jul-23	Revenue Jul-23	Customer Cnt Aug-23	Revenue Aug-23	Customer Cnt Sep-23	Revenue Sep-23
Total	**796,054**	$ 39,549,513.53	**796,177**	$ 35,416,359.97	**795,753**	$ 37,146,200.10
Oregon	699,496	35,163,126.95	699,554	31,501,593.81	699,122	33,032,145.33
Washington	96,558	4,386,386.58	96,623	3,914,766.16	96,631	4,114,054.77
Total Residential	726,263	20,856,284.93	726,376	18,121,889.26	726,021	19,154,826.95
Total Commercial	68,728	11,884,722.03	68,741	10,497,041.12	68,669	11,013,843.31
Total Industrial	652	2,473,677.94	652	2,412,015.39	653	2,599,780.75
Total Interruptible	109	2,736,861.61	108	2,746,887.29	108	2,750,426.75
Total Transportation - Commercial Firm	95	147,869.66	95	147,561.20	95	158,811.46
Total Transportation - Industrial Firm	122	772,942.43	120	785,853.86	121	786,387.77
Total Transportation - Interruptible	85	677,154.93	85	705,111.85	86	682,123.11
Unbilled Revenue		(2,624,678.72)		1,304,646.77		4,267,391.29
Agency Fees						
Net Balancing/Overrun						
Total Gas Operating Revenue		**$ 36,924,834.81**		**$ 36,721,006.74**		**$ 41,413,591.39**

	Customer Cnt Oct-23	Revenue Oct-23	Customer Cnt Nov-23	Revenue Nov-23	Customer Cnt Dec-23	Revenue Dec-23
Total	**796,560**	$ 48,252,288.31	**797,528**	$ 88,139,168.99	**799,249**	$ 138,928,669.62
Oregon	748,905	44,483,949.98	749,846	81,900,624.47	751,444	129,510,933.98
Washington	47,655	3,768,338.33	47,682	6,238,544.52	47,805	9,417,735.64
Total Residential	726,643	26,477,374.77	727,475	55,740,211.74	728,915	91,264,012.70
Total Commercial	68,853	13,640,638.70	68,986	23,831,620.56	69,273	39,064,421.84
Total Industrial	654	3,018,668.37	658	3,651,940.12	653	3,458,862.34
Total Interruptible	108	3,341,500.88	102	3,090,701.46	101	3,319,696.59
Total Transportation - Commercial Firm	95	197,276.55	96	254,930.99	96	269,333.47
Total Transportation - Industrial Firm	122	842,491.99	122	897,646.39	123	900,135.22
Total Transportation - Interruptible	85	734,337.05	89	672,117.73	88	652,207.46
Unbilled Revenue		25,420,263.92		30,141,963.00		3,354,661.81
Agency Fees						-
Net Balancing/Overrun				-		
Total Gas Operating Revenue		**$ 73,672,552.23**		**$ 118,281,131.99**		**$ 142,283,331.43**

	Customer Cnt Jan-24	Revenue Jan-24	Customer Cnt Feb-24	Revenue Feb-24	Customer Cnt Mar-24	Revenue Mar-24
Total	**800,241**	$ 163,894,510.59	**800,766**	$ 122,984,043.24	**800,976**	$ 129,117,049.44
Oregon	752,357	153,923,896.21	752,846	115,091,920.39	752,986	120,375,732.76
Washington	47,884	9,970,614.38	47,920	7,892,122.85	47,990	8,741,316.68
Total Residential	729,854	109,151,400.83	730,398	81,611,710.84	730,555	83,057,245.66
Total Commercial	69,326	46,360,747.58	69,310	34,980,920.93	69,366	37,668,629.20
Total Industrial	654	3,429,876.98	655	2,551,752.85	653	3,238,288.72
Total Interruptible	100	3,034,190.73	99	1,952,305.51	98	3,230,864.20
Total Transportation - Commercial Firm	96	304,399.66	95	257,244.79	95	249,150.73
Total Transportation - Industrial Firm	123	945,036.44	122	923,751.79	122	1,007,089.86
Total Transportation - Interruptible	88	668,858.37	87	706,356.53	87	665,781.07
Unbilled Revenue		(934,886.17)		(11,890,021.20)		(12,452,249.57)
Agency Fees		-				
Net Balancing/Overrun				-		-
Total Gas Operating Revenue		**$ 162,959,624.42**		**$ 111,094,022.04**		**$ 116,664,799.87**

	Customer Cnt Apr-24	Revenue Apr-24	Customer Cnt May-24	Revenue May-24	Customer Cnt Jun-24	Revenue Jun-24
Total	**801,730**	$ 86,408,219.76	**801,906**	$ 71,733,991.05	**801,943**	$ 50,828,150.99
Oregon	753,748	80,359,005.47	753,951	66,389,118.68	753,984	47,025,891.23
Washington	47,982	6,049,214.29	47,955	5,344,872.37	47,959	3,802,259.76
Total Residential	731,203	55,438,307.89	731,441	43,891,976.99	731,497	29,323,259.75
Total Commercial	69,470	24,766,995.93	69,411	20,851,904.52	69,390	15,274,212.25
Total Industrial	653	2,381,030.88	652	2,672,346.74	654	2,385,765.14
Total Interruptible	98	2,129,682.94	97	2,578,382.91	97	2,196,649.76
Total Transportation - Commercial Firm	95	208,108.07	95	177,987.37	95	149,619.78
Total Transportation - Industrial Firm	124	814,760.57	123	861,982.42	123	829,230.09
Total Transportation - Interruptible	87	669,333.48	87	699,410.10	87	669,414.22
Unbilled Revenue		(12,180,028.08)		(12,563,978.16)		(10,605,884.21)
Agency Fees				-		-
Net Balancing/Overrun						
Total Gas Operating Revenue		**$ 74,228,191.68**		**$ 59,170,012.89**		**$ 40,222,266.78**

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

	2024/2025 Forecasted	2023/2024	2022/2023	2021/2022	2020/2021	2019/2020
System peak demand (therms)	10,278,640	10,181,910	10,297,610	10,206,740	10,121,250	10,038,360

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

Gas Year	2024/2025 Forecasted	2023/2024	2022/2023	2021/2022	2020/2021	2019/2020
Annual Demand (therms)	853,772,745	862,272,608	838,438,962	817,385,916	792,118,472	783,407,642

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	2024/2025 Forecasted	2023/2024	2022/2023	2021/2022	2020/2021	2019/2020
Residential (therms)	484,207,721	486,051,411	467,591,574	464,438,613	455,070,896	448,801,633
Commercial (therms)	274,360,540	274,918,917	262,438,496	261,935,975	263,351,922	253,064,895
Industrial Firm (therms)	41,794,756	40,455,746	42,053,861	34,202,800	37,165,044	35,036,394
Industrial Interruptible (therms)	53,409,728	60,846,533	66,355,031	61,567,111	54,137,070	46,504,720

2. Annual and monthly baseload.

Gas Year	2024/2025 Forecasted	2023/2024	2022/2023	2021/2022	2020/2021	2019/2020
November	24,616,239	21,521,199	32,008,982	30,709,933	29,969,601	23,387,175
December	28,903,191	24,388,941	36,240,142	33,590,735	31,307,203	23,921,400
January	33,358,807	27,694,685	42,189,006	36,168,000	34,107,108	23,078,200
February	30,978,735	26,267,236	38,815,909	33,929,102	32,215,083	22,084,555
March	31,479,838	26,937,910	39,913,157	36,509,535	33,569,472	26,260,801
April	27,507,205	24,771,735	35,710,634	33,156,039	30,395,597	27,513,875
May	23,914,784	22,974,153	32,711,512	30,364,879	28,937,453	28,662,936
June	22,113,670	20,932,483	29,402,280	28,541,575	28,169,111	26,209,423
July	18,968,054	18,792,979	26,827,120	25,960,692	25,359,279	23,215,822
August	16,878,121	16,536,474	24,490,204	24,016,589	23,386,015	23,182,155
September	19,206,265	18,238,335	25,090,116	23,815,161	23,625,511	22,840,123
October	22,202,856	20,486,173	30,016,148	28,784,191	28,841,952	27,565,149
Annual	**300,127,766**	**269,542,303**	**393,415,209**	**365,546,431**	**349,883,384**	**297,921,614**

3. Annual and month non-base load.

Gas Year	2024/2025 Forecasted	2023/2024	2022/2023	2021/2022	2020/2021	2019/2020
November	68,574,802	72,664,996	59,240,744	60,832,815	60,504,626	64,616,556
December	98,292,531	104,297,358	88,508,994	90,713,996	91,538,810	97,088,481
January	96,533,801	102,880,004	85,544,762	88,079,277	89,174,162	96,491,163
February	82,771,660	91,116,952	69,943,462	71,559,429	72,067,179	80,083,164
March	68,026,045	72,210,415	58,088,579	59,848,154	59,993,199	62,392,883
April	47,444,693	50,205,094	36,295,437	36,964,858	37,314,235	38,280,525
May	23,377,737	25,140,239	14,700,339	14,997,271	15,454,241	14,104,694
June	11,902,694	13,049,070	3,642,146	3,765,614	3,858,078	3,422,176
July	9,031,798	9,565,441	867,988	905,559	926,910	742,320
August	7,659,858	8,018,913	845,980	839,829	870,346	665,740
September	8,735,800	9,635,760	2,858,652	2,987,241	3,054,454	2,772,813
October	31,293,560	33,946,061	24,486,671	25,104,023	25,085,308	24,825,513
Annual	**553,644,979**	**592,730,305**	**445,023,753**	**456,598,067**	**459,841,547**	**485,486,028**

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

2024/2025	Albany	Astoria	Coos Bay	The Dalles (OR)	The Dalles (WA)	Eugene	Newport	Portland	Salem	Vancouver	Total
November	1,657,771	380,681	1,199,041	5,990,599	1,264,429	53,157,717	6,877,155	13,928,648	9,394,033	294,715	94,144,789
December	2,257,571	500,861	1,608,921	8,019,228	1,715,896	76,224,644	9,282,173	18,502,059	13,188,654	402,032	131,702,040
January	2,303,385	514,069	1,643,047	8,204,988	1,726,789	78,007,225	9,366,263	18,842,175	13,978,842	414,269	135,001,052
February	2,118,404	481,857	1,537,505	7,082,220	1,474,482	66,503,881	8,328,980	16,282,176	12,073,034	354,184	116,236,723
March	1,920,194	470,127	1,448,259	6,184,072	1,215,889	54,820,763	7,295,713	14,229,750	10,506,537	297,545	98,388,849
April	1,486,716	387,085	1,189,283	4,637,260	863,098	39,066,518	5,585,545	10,627,437	7,573,490	210,345	71,626,777
May	938,457	284,394	815,612	2,883,557	532,078	23,345,838	3,619,023	6,600,067	4,939,061	134,390	44,092,477
June	657,928	210,525	606,978	2,032,090	414,132	17,658,295	2,682,668	4,878,527	3,571,107	93,001	32,805,253
July	520,950	172,239	480,041	1,589,278	331,096	14,663,832	2,193,322	4,027,315	3,261,419	83,106	27,322,598
August	454,968	149,748	413,609	1,430,628	291,084	12,761,629	2,159,878	3,511,115	2,689,393	70,529	23,932,581
September	522,397	180,755	485,363	1,686,064	354,274	14,565,505	2,208,841	4,230,724	2,902,333	77,400	27,213,656
October	1,012,362	256,814	822,792	3,376,122	692,612	27,569,110	3,947,826	7,966,229	5,499,214	162,870	51,305,951
Annual	15,851,103	3,989,155	12,250,450	53,116,107	10,875,859	478,344,956	63,547,388	123,626,223	89,577,119	2,594,387	853,772,745

2023/2024	Albany	Astoria	Coos Bay	The Dalles (OR)	The Dalles (WA)	Eugene	Newport	Portland	Salem	Vancouver	Total
November	5,954,452	1,666,298	377,257	1,264,789	293,534	6,873,604	1,205,688	53,214,578	14,015,536	9,585,390	94,451,126
December	8,016,799	2,261,168	495,298	1,731,198	397,260	9,357,633	1,610,433	76,451,582	18,739,033	13,274,045	132,334,449
January	8,175,861	2,293,494	507,329	1,726,047	404,727	9,416,689	1,628,569	77,590,537	19,045,794	13,855,750	134,644,797
February	7,214,644	2,170,520	484,338	1,505,163	358,720	8,523,328	1,572,475	68,031,954	16,781,339	12,467,859	119,110,339
March	6,102,224	1,903,443	456,419	1,208,416	286,650	7,237,653	1,429,398	54,442,387	14,204,435	10,231,123	97,502,147
April	4,601,209	1,465,506	378,287	864,776	202,768	5,589,639	1,162,035	39,338,789	10,705,336	7,414,263	71,722,609
May	2,969,791	921,255	289,100	565,449	124,226	3,806,749	768,280	24,505,243	6,999,888	4,599,125	45,549,106
June	2,058,719	646,794	204,511	434,738	87,734	2,734,548	541,779	18,415,749	5,051,502	3,457,611	33,633,686
July	1,699,632	555,045	176,165	363,773	72,693	2,361,277	425,332	15,722,906	4,344,239	2,935,358	28,656,421
August	1,503,303	481,424	151,441	314,352	62,314	2,269,724	361,587	13,481,326	3,713,645	2,473,389	24,812,506
September	1,703,203	515,859	177,837	361,362	72,754	2,254,034	447,424	14,947,663	4,342,873	2,827,651	27,650,661
October	3,420,853	1,017,119	262,071	699,586	157,667	4,013,126	821,701	28,066,401	8,212,899	5,533,339	52,204,762
Annual	53,420,690	15,897,926	3,960,053	11,039,650	2,521,047	64,438,005	11,974,700	484,209,116	126,156,518	88,654,903	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	The Dalles (OR)	The Dalles (WA)	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
November	5,313,684	1,620,121	233,206	1,066,003	237,327	5,846,984	1,160,726	51,864,196	11,983,356	9,041,617	88,367,220
December	7,283,683	2,175,379	314,431	1,498,957	337,073	7,989,070	1,550,441	73,810,887	16,435,051	12,808,191	124,203,163
January	7,150,597	2,140,427	309,332	1,498,416	336,950	7,840,528	1,510,332	73,653,189	16,142,655	12,786,413	123,368,838
February	5,990,470	1,920,789	275,289	1,219,258	282,240	6,607,304	1,366,243	61,315,475	13,735,877	10,723,273	103,436,219
March	5,195,892	1,757,271	266,226	959,306	233,826	5,662,614	1,316,921	50,839,903	11,827,643	8,963,977	87,023,578
April	3,914,896	1,343,412	213,093	630,962	161,899	4,193,404	1,066,801	36,292,262	8,789,604	6,302,316	62,908,648
May	2,530,697	845,001	137,636	376,134	102,250	2,694,414	712,685	23,885,806	5,596,633	4,059,656	40,940,910
June	1,765,647	551,497	90,335	263,413	72,532	1,878,798	463,074	17,311,516	3,995,002	2,895,243	29,287,058
July	1,422,642	450,932	74,782	224,904	57,794	1,532,195	372,477	14,244,387	3,283,039	2,294,846	23,957,998
August	1,444,594	446,185	72,237	222,081	58,349	1,528,336	368,844	14,154,444	3,251,180	2,310,579	23,856,828
September	1,548,550	485,354	80,371	239,922	61,638	1,628,082	404,844	14,903,231	3,553,078	2,442,803	25,347,873
October	3,114,481	997,978	149,505	538,341	131,005	3,385,569	775,415	29,450,175	7,060,402	5,106,439	50,709,310
Annual	46,675,833	14,734,346	2,216,441	8,737,696	2,072,884	50,787,296	11,068,803	461,725,471	105,653,520	79,735,353	783,407,642

2018/2019	Albany	Astoria	Coos Bay	The Dalles (OR)	The Dalles (WA)	Eugene	Newport	Portland	Salem	Vancouver	Total

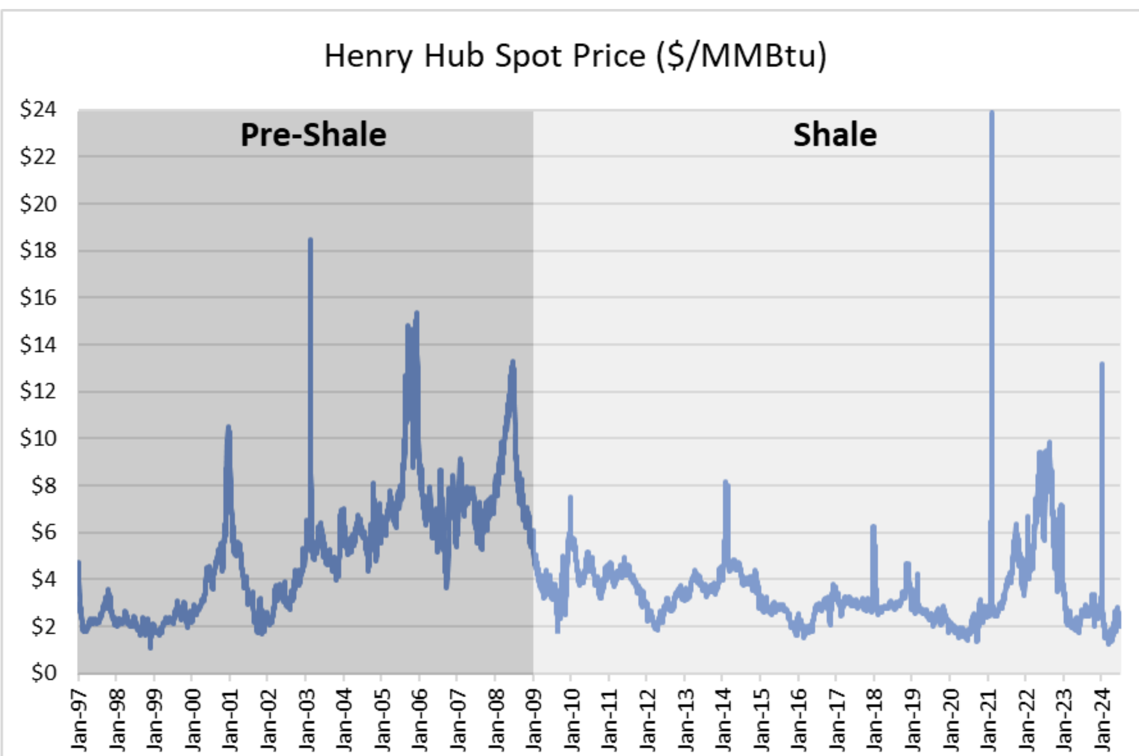
Section V.4 - Market Information

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.

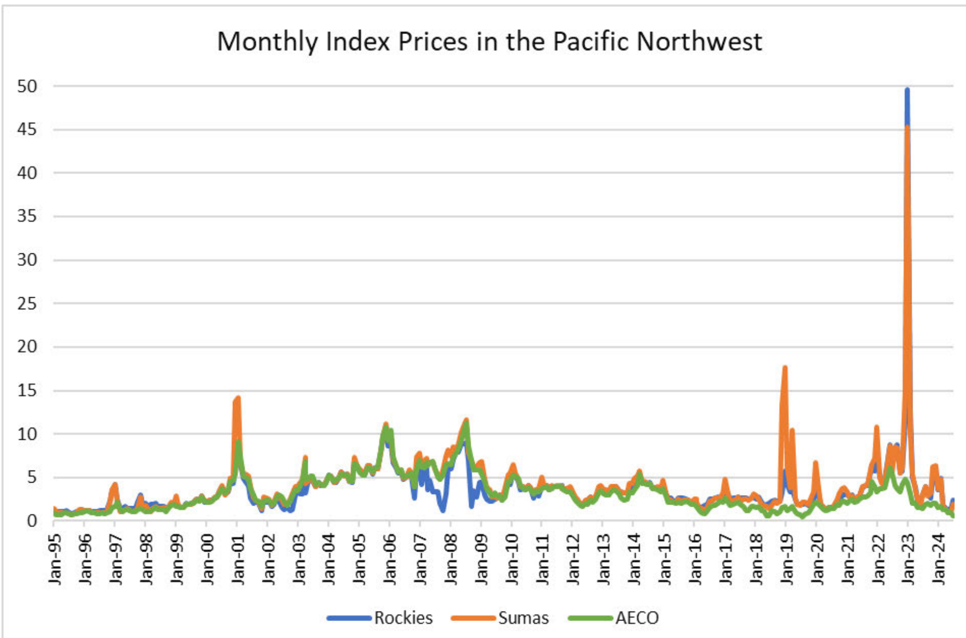
In the early 2000s, prices rose dramatically due to tightness in the supply/demand balance, a situation that Enron (and others) sought to exploit. This led to scandals, lawsuits, regulatory investigations, bankruptcies and other headline-making news that obscured the fact that gas supplies really were 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, have led to record volatility and an increase in prices, which has abated somewhat over the past year (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



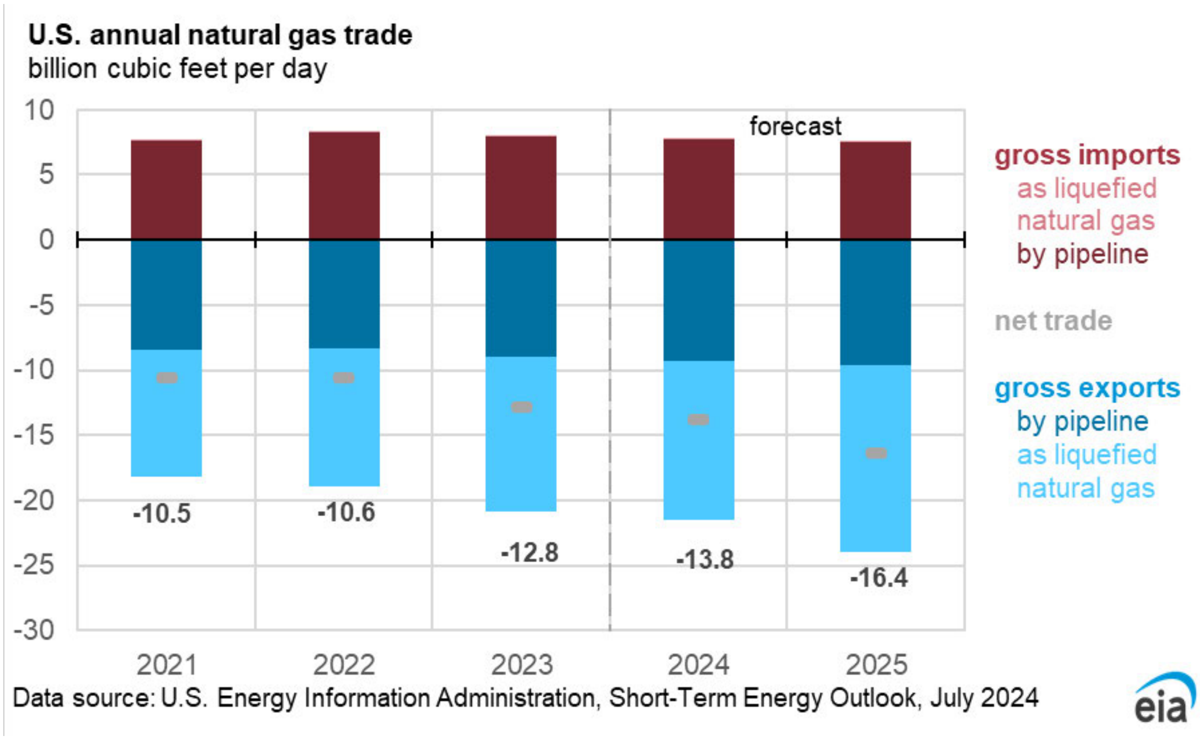
Prices fell in 2020 in the wake of the COVID-19 pandemic and its downward impact on energy demand. By April 20, 2020 the West Texas Intermediate crude oil price plunged into the negative for the first time in history. The drop in demand outpaced declines in production and led to a strong storage inventory. 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.

Figure 3



The US Energy Information Administration's (EIA) July 2024 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 increase through 2025 due to flat natural gas production as the storage surplus shrinks and additional LNG export capacity comes online (Figure 5). The EIA expects storage inventory to end the 2024 injection season 6% above the five-year average (Figure 6).

Figure 4

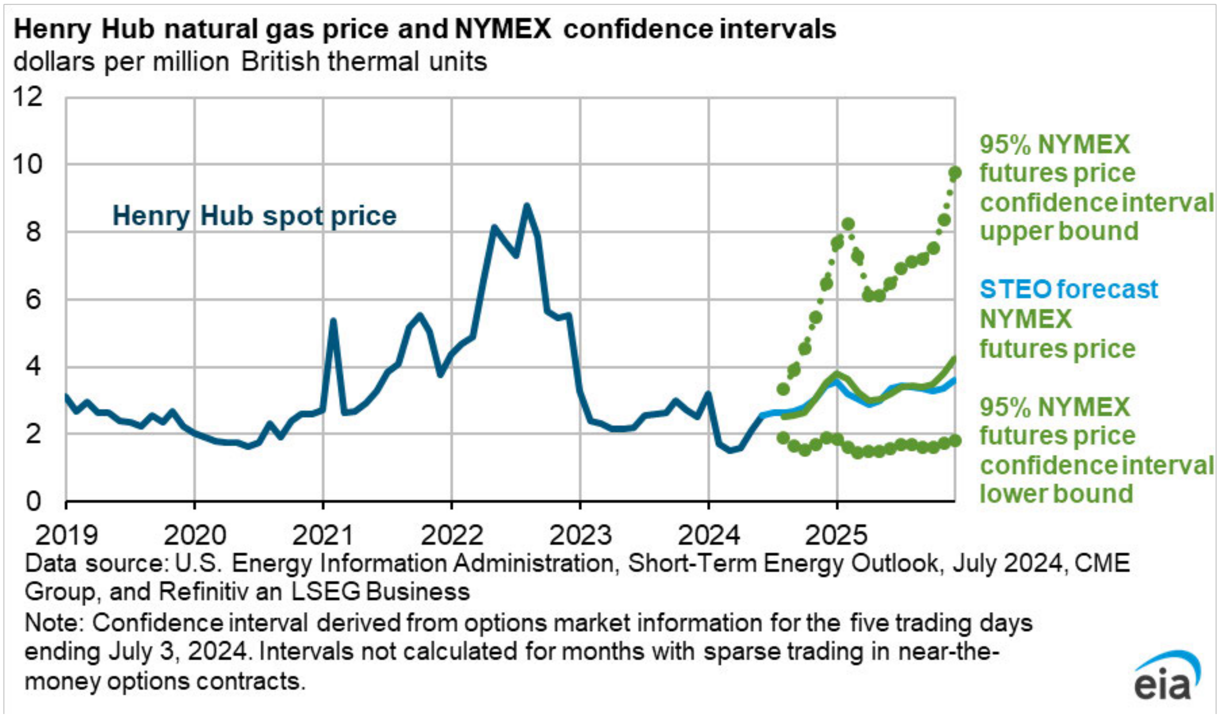
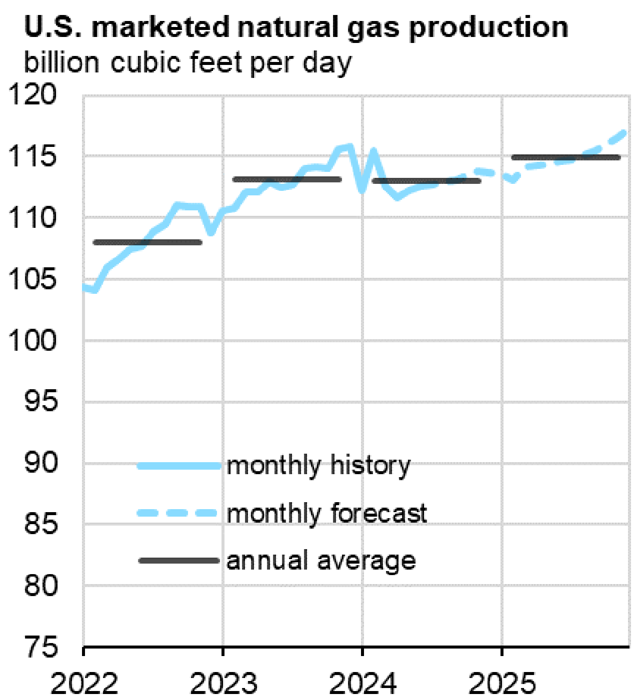
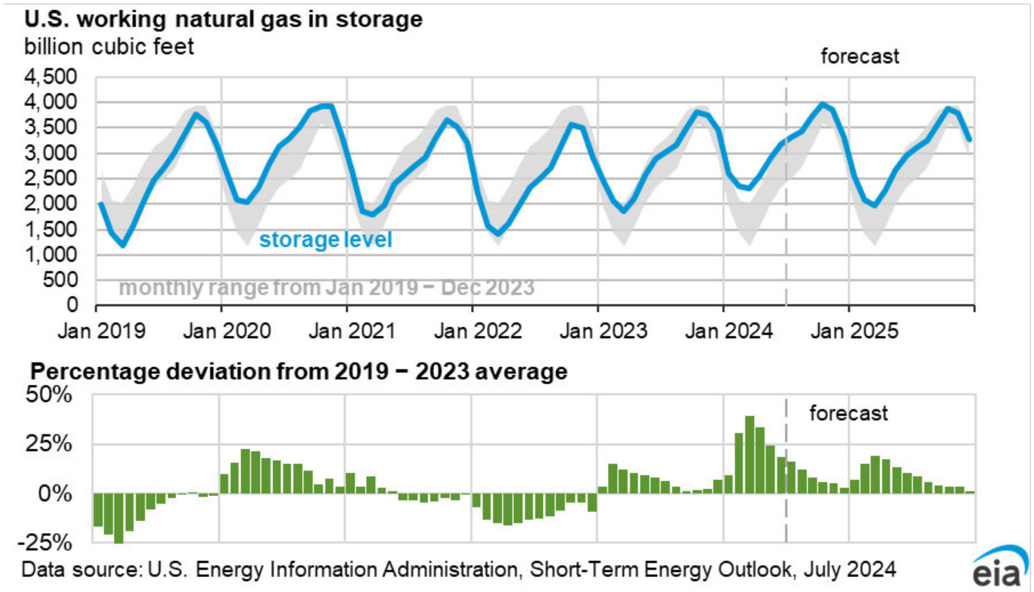


Figure 5



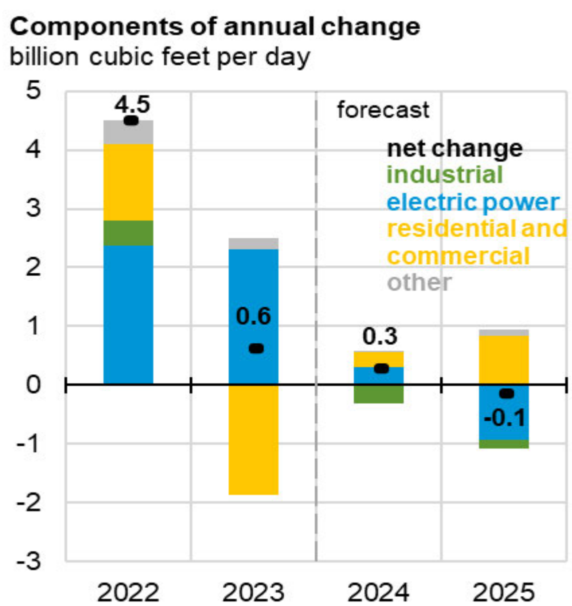
Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, July 2024

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 a decrease of natural gas for electric generation in 2025 compared to 2024 (Figure 7).

Figure 7



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, July 2024

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 summer of 2025, which will compete with California supply and could have an impact on regional prices. The LNG Canada export terminal located in British Columbia is also expected to begin commercial operations in mid-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.	Mid Office
5	Follows GSRMP for policy exceptions.	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.	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	Calculates and analyzes various credit risk metrics to better understand the current and potential risks in the portfolio.	Mid Office
12	Calculates and records appropriate credit reserves on a monthly basis.	Mid Office
13	Reviews credit limits at least twice a year, and additionally as needed, to assess whether changes should be made.	Mid Office
14	Monitors news articles, bankruptcy filings, legal actions, etc. on a daily basis for all counterparties with which the company has physical or financial gas commodity credit risk	Middle Office
15	Daily monitor markets impact (i.e. CDS spreads) on derivative counterparties credit risk.	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
2024-2025 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	325,000	13,322,920
Portland LNG - LNG Plant - Portland, OR	99,630	507,449
Newport LNG - LNG Plant - Newport, OR	78,000	1,082,517

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
2024-2025 Oregon PGA

NORTHWEST NATURAL GAS COMPANY
All Sites Therms Summary

	BEGINNING BALANCE			ISSUES (Withdrawals)		LIQUEFIED	INJECTIONS (Deliveries)		ENDING BALANCE		
MONTH	THERMS	AMOUNT	RATE	THERMS	AMOUNT	THERMS	AMOUNT	RATE	THERMS	AMOUNT	RATE
Jan-19	139,754,260	$ 38,119,630.22	0.27276	20,603,770	$ 5,537,137.86	-	$ -	-	119,150,490	$ 32,582,492.36	0.27346
Feb	119,150,490	$ 32,582,492.36	0.27346	38,853,330	$ 10,509,183.28	1,353,790	$ 554,885.49	0.40988	81,650,950	$ 22,628,194.57	0.27713
Mar	81,650,950	$ 22,628,194.57	0.27713	21,593,264	$ 5,986,536.34	2,771,390	$ 802,487.63	0.28956	62,829,076	$ 17,444,145.86	0.27764
Apr	62,829,076	$ 17,444,145.86	0.27764	664,960	$ 193,081.22	788,040	$ 164,679.38	0.20897	62,952,156	$ 17,415,744.02	0.27665
May	62,952,156	$ 17,415,744.02	0.27665	103,426	$ 29,533.72	2,287,569	$ 335,057.98	0.14647	65,136,299	$ 17,721,268.28	0.27206
Jun	65,136,299	$ 17,721,268.28	0.27206	229,439	$ 56,212.53	5,451,548	$ 569,577.39	0.10448	70,358,408	$ 18,234,633.14	0.25917
Jul	70,358,408	$ 18,234,633.14	0.25917	75,625	$ 16,530.98	28,240,482	$ 4,825,576.40	0.17087	98,523,265	$ 23,043,678.56	0.23389
Aug	98,523,265	$ 23,043,678.56	0.23389	80,760	$ 18,659.72	21,200,371	$ 3,015,922.95	0.14226	119,642,876	$ 26,040,941.79	0.21766
Sep	119,642,876	$ 26,040,941.79	0.21766	123,102	$ 24,684.03	6,014,325	$ 716,666.76	0.11916	125,534,099	$ 26,732,924.52	0.21295
Oct	125,534,099	$ 26,732,924.52	0.21295	2,957,866	$ 617,522.81	1,895,441	$ 502,051.32	0.26487	124,471,674	$ 26,617,453.03	0.21384
Nov	124,471,674	$ 26,617,453.03	0.21384	1,018,811	$ 207,686.37	11,104,295	$ 2,823,116.74	0.25424	134,557,158	$ 29,232,883.40	0.21725
Dec	134,557,158	$ 29,232,883.40	0.21725	1,933,604	$ 422,688.78	199,520	$ 54,222.00	0.27176	132,823,074	$ 28,864,416.62	0.21731
TOTAL 2019 ACTIVITY				88,237,957	23,619,458	81,306,771	$ 14,364,244.04				
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											
Aug											
Sep											
Oct											
Nov											
Dec											
TOTAL 2024 ACTIVITY				39,870,812	$ 13,118,087.86	33,408,010	$ 4,441,039.53				

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 2024-25 PGA period.

[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 September 26, 2017 and restates the Service Agreement made and entered into on January 21, 2008.

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. 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.

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): Restated Firm Service Agreement dated January 21, 2008, 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: RANDOLPH S. FRIEDMAN	Name: LYNN DAHLBERG
Title: SENIOR DIRECTOR, GAS SUPPLY	Title: DIRECTOR, MARKETING SERVICES

EXHIBIT A
Dated and Effective September 26, 2017
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, 2025
    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 Rat 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 Sheet No. 7 of 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 Sheet No. 7 of 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. 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 Sheet No. 7 of 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.

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, and PAL. Participating Shippers must notify Transporter's Marketing Services personnel of their intent to transfer such inventory, in writing, prior to the beginning of the gas day in which such transfer will occur. 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, 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)

5. 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 2024, 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 94-109) 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.

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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 2
- Section 2 – Attachments 1 to 6
- 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. 24-19

August 1, 2024

EXHIBIT D OVERVIEW – Renewable Natural Gas (RNG)

The following is included within this exhibit:

- Section 1 – New RNG Contracts or Updates
  - Attachment 1: Amerex Brokers Project Cost Model
  - Attachment 2: Terreva Renewables Project Cost Model
- Section 2 – Existing RNG Contracts by Feedstock
  - Attachment 1: Archaea Project Cost Model
  - Attachment 2: Archaea Environmental Attributes Monetization
  - Attachment 3: Archaea Environmental Attributes Purchase Agreement
  - Attachment 4: Archaea Environmental Attributes Letter Agreement
  - Attachment 5: BP Incremental Cost Model
  - Attachment 6: BP Environmental Attributes Purchase Agreement
- Section 3 – Historical Data
  - Attachment 1: 2024 NWN RFP
  - Attachment 2: 2024 Element Responses to RFP
  - Attachment 3: RNG Production through June 2024
- 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	Wasatch Resource Recovery
Product	Renewable Thermal Certificates (RTCs)
Contract Price	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Contract Quantity	72,996 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	Archaea Energy Marketing LLC
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	Environmental Attributes
Contract Price	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Contract Quantity	416,670 RTCs estimated annual generation
Delivery Deadline	Immediately following the production of the Biomethane
Start Date	11/10/2021
Delivery Term	Start Date through 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	Amerex Brokers LLC
Buyer	Northwest Natural Gas Company
Project	098 Amerex Landfill Gas
Product	Environmental Attributes
Contract Price	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Contract Quantity	712,000 RTCs estimated annual generation
Delivery Deadline	Immediately following the production of the Biomethane
Start Date	01/01/2025
Delivery Term	20 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. 4**
Seller	Terreva Renewables LLC
Buyer	Northwest Natural Gas Company
Project	O57 MEMS Terreva RFP
Product	Environmental Attributes and commodity gas
Contract Price	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Contract Quantity	382,000 RTCs estimated annual generation
Delivery Deadline	Immediately following the production of the Biomethane
Start Date	07/01/2025
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 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 be 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 the year. In 2024, NW Natural received a total of 53 proposals from 34 responders for its RFP. We use our same evaluation approach and incremental cost analysis to compare all available resources – both offtakes and developments – on the same incremental cost basis so that at any point, we have 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 came to our attention separately, around the same time as the RFP process (the company was not aware of the RFP process at the time). We evaluated it against other opportunities.

Section 1 lists the newly executed transactions since the last purchase gas adjustment. In Section 2, we present the incremental cost calculation of the historical offtake contracts compared, 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.

2024 RFP Evaluation process:

1. Each proposal was reviewed to verify it meets the general qualifications as stated in the RFP. If the proposal did not meet these qualifications, the evaluation did not continue to the next step.
2. A risk-adjusted incremental cost model was executed for each proposal. The model is based on information provided in the proposal such as volume, term and offtake price.
3. The proposals were ordered by the calculated incremental cost from smallest to largest. The proposals with the lowest 33% of incremental cost were placed on the short list and moved on to the next step in the evaluation process.
4. The calculated risk-adjusted incremental costs of the short-listed resources are compared to the incremental cost of other opportunities available outside of the RFP.
5. Short listed opportunities were interviewed, and a risk assessment was completed. Risk assessments were based on a pass-fail basis, and opportunities that failed were removed from the list.
6. Competitive proposals then follow the same process as opportunities that arose outside of the RFP, including risk assessment, negotiations and recommendations to management.

The new contracts noted in Section 1 were selected because they were determined to be the least cost/least risk opportunities that could be delivered in 2025.

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.

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REQUEST FOR PROPOSAL #2024-01
Renewable Natural Gas Resources

Table of Contents

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1 General Information

This Request for Proposal ("RFP") is part of a significant effort by Northwest Natural Gas Company ("NW Natural") to make a low-carbon, renewable energy future a reality. NW Natural is soliciting proposals from qualified firms to sell renewable natural gas (RNG) from existing or future projects. A definition of RNG is provided in Section 2.1.

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 describes the relevant **Background** 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 the Bidder and sets forth certain key defined terms.

Section 3 provides details on the **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 Requirements** including format and required information.

Appendix outlines the requirements for **renewable natural gas quality standards** for RNG resources that will interconnect with NW Natural's distribution system. Note that NW Natural does not require that acquired RNG resources be interconnected with our distribution system. Any RNG resource will need to satisfy the interconnection requirements and quality standards of whichever system the project is interconnected to.

1.2 About NW Natural

NW Natural is a wholly-owned subsidiary of Northwest Natural Holding Company ("NW Natural Holdings"), and has been serving residential, commercial, and industrial customers in the Pacific Northwest for over 160 years. NW Natural Holdings also has business interests in gas storage, water utilities, and other interests and activities. The company was founded in 1859 and is headquartered in Portland, Oregon. NW Natural Holdings has a market capitalization of approximately $1.4 billion and an enterprise value of approximately $5 billion. NW Natural has secured credit ratings of AA- and A2 by S&P and Moody's, respectively.

NW Natural's guiding principles embrace constructive relationships with stakeholders, superior customer service, and community involvement. We believe we are uniquely positioned to partner with RNG and hydrogen producers for the following reasons:

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- We are local operators and long-term stewards of our utilities. We have a long history in the utility business and are extremely proud of our track record and heritage. We invest in our systems and stakeholder relationships and have established a long history of trust and credibility with the regulating bodies.

- We are industry leaders in customer satisfaction. For the fourth consecutive year, NW Natural scored second-highest in customer satisfaction among large utilities in the Western United States, according to J.D. Power's Gas Utility Residential Customer Satisfaction Study. Per J.D. Power's annual independent study, this is the 20th time the company has scored in the top two in the West.

- We are actively engaged in the communities we serve. Our shareholders donate nearly $1 million annually through our corporate philanthropy programs. These funds support over 150 local community and nonprofit groups. Furthermore, our employees give nearly 5,000 hours of their own time annually for hands-on work with these organizations.

- NW Natural has a longstanding commitment to providing energy safely and securely to our customers. As one of the first natural gas utilities in the nation to establish voluntary carbon reduction goals and champion policies that encourage RNG development, NW Natural is committed to supporting the growing RNG market and bringing these important low-carbon resources to our customers.

1.3 Objectives

NW Natural seeks to provide RNG resources for the benefit of our customers, and to do so with the least negative impact on customer costs. To do this, NW Natural desires to partner with those who are interested in selling pipeline-quality RNG. This RFP seeks pipeline-quality RNG resources and/or associated environmental attributes. The resources may be sourced from around the country 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.

Oregon Senate Bill 98 enables gas utilities to invest in carbon reducing infrastructure and/ or to acquire RNG or hydrogen for delivery to their customers. The program sets voluntary targets for the percentage of RNG or hydrogen in the system that increases over time with a target of 5 percent by 2024, increasing to 10 percent in 2025-2029. NW Natural aims to meet or exceed these targets with a goal of carbon neutrality by 2050.

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

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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

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	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

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	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/Specification Overview

The Bidder may propose one of the following services in regard to 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 Renewable Thermal Certificates (RTCs) as well as the gas commodity. NW Natural would enter into a gas purchase agreement with the Bidder and receive the RNG at a specific location.
- The 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, the Bidder would separately sell or otherwise market the gas commodity.

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 December 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: https://www.nwnatural.com/about-us/environment/renewable-natural-gas. Materials provided include:

- 2024 RFP Response Template – Proposal
- 2024 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 Schedule

Date	Event
3/29/2024	Request for proposal issue date
4/12/2024	Questions due on RFP
4/19/2024	Question responses posted on website
5/10/2024 11:59PM	Proposal submissions due
6/06/2024	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 your 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 2024-01 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 proposal situation, 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 it its proposal is true and correct.
- Bidder shall under no circumstances use NW Natural's name or logos in advertising, marketing materials, printed matter, 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.

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.

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3.3.6 Request for Proposal Response Withdrawal
A Bidder that wishes to withdraw their 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 proposal and be available for questions either via email or phone after their detailed proposal is received by NW Natural.

Failure to meet the requirements of this RFP may result in the proposal being rejected. 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 our strategy.

3.4.2 Proposal Scoring
Proposals will be rated based on a range of criteria including, but not limited to, the following:

1. The overall cost of the product.
2. Resource availability date.
3. The experience and proven performance of the firm or team of firms making the proposal.
4. The volume of RNG or RTCs available for purchase.
5. Proposed terms of the purchase contract, including duration and renewal options.
6. Other claims of environmental benefits or emissions reductions on other products of the project (e.g., RIN or LCFS credits generated by other volumes of RNG produced by the project).
7. Overall ability of the project to successfully deliver qualifying RNG within the terms of the contract.
8. The Bidder's ability to help NW Natural increase its diverse business participation.
9. Contractual remedies for a resource's failure to deliver.
10. Location of the resource; resources located in Washington and Oregon are of particular interest.

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

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Bidders will be notified of proposal acceptance or rejection in accordance with the schedule outlined in section 3.2.

This is not a "low-bidder gets contract" bidding process. Rather, this is an RFP process in which 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 our 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 the 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 our 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;
- Method(s) used to produce the gas;
- Method of delivery to Oregon;
- 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. **2024 RFP Response Template – Proposal**
   Using the template provided by NW Natural, provide details about your 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. **2024 RFP Response Template – Certification**
   Using the template provided by NW Natural, certify and sign your 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. The Bidder may elect to submit draft agreements as part of their 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 you feel will aid NW Natural in making their selection.

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Appendix

The local natural gas utility to which this project might interconnect is NW Natural, which has the following specification for the injection of RNG into the distribution system:

Parameters	Value Min	Value Max	Action Level
Methane (%)	97.3		< 97.3
Heating Value (BTU[b]/SCF[c])	985	1155	< 985
Wobbe Number (BTU/SCF)	1290	1491	N/A
Temperature (°F)	35	120	> 120
Carbon Dioxide (%)		2.0	> 2.0
Nitrogen (%)		2.0	> 2.0
Total Inerts[d] + Oxygen (%)		3.0	> 3.0
Oxygen (%)		0.20	> 0.20
Hydrogen Sulfide (grain/CCF[e])		0.25	> 0.25
Total Sulfur (grain/CCF)		5.0	> 5.0
Moisture (lb/MMSCF[f])		7	> 7
Hydrocarbon Dew Point (°F)		15	> 15

Forward Pricing
Henry Hub

Year	Price
2024	$3.22
2025	$4.44
2026	$5.41
2027	$5.24
2028	$4.98
2029	$4.44
2030	$4.34
2031	$4.52
2032	$4.87
2033	$5.16
2034	$5.29
2035	$5.72
2036	$5.86
2037	$6.26
2038	$6.39
2039	$6.44
2040	$6.97
2041	$7.59
2042	$7.75
2043	$8.03
2044	$8.34
2045	$8.63
2046	$9.09
2047	$9.83
2048	$10.15