NW Natural®

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September 14, 2026

NWN OPUC Advice No. 26-05A / UG 531

VIA ELECTRONIC FILING

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

Re: UG 531 - REQUEST FOR 2026–2027 PURCHASED GAS ADJUSTMENT (PGA) AND COINCIDENT RATE ADJUSTMENTS:

Northwest Natural Gas Company, dba NW Natural (NW Natural or Company), files herewith revisions and additions to its Tariff, P.U.C. Or. 25, stated to become effective with service on October 31, 2026, for applicable residential schedules, and November 1, 2026, for all other schedules, as follows:

Sixteenth Revision of Sheet P-2	Schedule P	Purchased Gas Cost Adjustments (continued)
Fourteenth Revision of Sheet P-3	Schedule P	Purchased Gas Cost Adjustments (continued)
Fifteenth Revision of Sheet P-5	Schedule P	Purchased Gas Cost Adjustments (continued)
Fourteenth Revision of Sheet 100-1	Schedule 100	Summary of Temporary Adjustments
Fourteenth Revision of Sheet 100-2	Schedule 100	Summary of Temporary Adjustments (continued)
Fourteenth Revision of Sheet 100-3	Schedule 100	Summary of Temporary Adjustments (continued)
Thirteenth Revision of Sheet 100-4	Schedule 100	Summary of Temporary Adjustments (continued)
Seventh Revision of Sheet 100-5	Schedule 100	Summary of Temporary Adjustments (continued)
Fifth Revision of Sheet 150-2	Schedule 150	Monthly Incremental Cost of Gas (continued)
Seventeenth Revision of Sheet 164-1	Schedule 164	Purchased Gas Cost Adjustments to Rates
Third Revision of Sheet 169-1	Schedule 169	Transportation Customer Energy Efficiency Program Cost Recovery

Sixth Revision of Sheet 171-1	Schedule 171	Transportation Customer Renewable Natural Gas Offtake Costs
Ninth Revision of Sheet 177-2	Schedule 177	Adjustment for Oregon Corporate Activity Tax (continued)
Thirteenth Revision of Sheet 195-1	Schedule 195	Weather Adjusted Rate Mechanism (WARM Program)

This filing replaces, in their entirety, the tariff sheets as indicated above and Exhibits A-D, J, K, M and T originally filed under NWN OPUC Advice No. 26-05 (UG 531), dated August 3, 2026. The purpose of this replacement filing is to revise the forecasted gas costs with updated inputs as well as include the related updates to Schedule 100 tariff sheets. This filing also includes revisions to Schedule 169 reflecting a refund applicable only to customers served during 2024, in addition to the current deferral applicable to all customers; Schedule 171 reflecting revised RNG offtake costs resulting from contract updates; Schedule 177 reflecting updated Corporate Activity Tax amounts based on the proposed revenue changes; and Schedule 195 correcting amounts related to interest recorded. **All other exhibits and tariff sheets filed on August 3, 2026, remain unchanged.**

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

Purpose

The purpose of this filing is to request approval of the Company's 2026–2027 Purchased Gas Adjustment (PGA), including revisions to purchased gas costs, amortizations of certain Commission-authorized deferred accounts, and updates to automatic adjustment mechanisms.

This filing is made pursuant to ORS 757.205 and ORS 757.259. The deferred balances included in this filing were authorized through Commission orders, approved tariffs, or deferred accounting authorizations and are eligible for amortization in rates.

The proposed tariff revisions result in increases to some adjustment schedules and decreases to others. The combined effect of all proposed adjustments in this filing is an overall annual revenue increase of approximately $66.6 million, with these tariff revisions effective October 31, 2026 for applicable residential schedules, and November 1, 2026, for all other schedules.

In compliance with OAR 860-022-0025 and OAR 860-022-0030, this filing includes a summary of the proposed revenue changes, representative customer bill impacts, the number and classes of customers affected by the proposed adjustments, and detailed supporting exhibits. The support for each adjustment schedule, including commodity gas cost calculations, rate increment calculations, and supporting workpapers, are provided in the corresponding exhibits and incorporated herein by reference.

Revised Adjustment Schedules Included in this Filing

The Company proposes revisions to purchased gas costs, Commission-authorized deferred account amortizations, and automatic adjustment mechanisms through the tariff schedules described below. NW Natural proposes to update rates for each of the rate adjustment schedules listed below to reflect the application of new base rate adjustments or temporary adjustments related to purchased gas costs or deferral balances, revised rates to reflect updated billing determinants where applicable, and the removal of current temporary adjustments where applicable. As mentioned above, the deferred balances included in this filing were authorized through Commission orders, approved tariffs, or deferred accounting authorizations and are eligible for amortization in rates. Supporting calculations for each rate adjustment schedule have been provided in the corresponding exhibit listed in Table 1.

Schedule P – Purchased Gas Cost Adjustments
Allows the Company to adjust applicable rate schedules for changes in the cost of purchased natural gas and demand in accordance with the provisions of Schedule P.

Schedule 100 – Summary of Temporary Adjustments
Summarizes the temporary adjustments included in customer billing rates under the Company's applicable adjustment schedules

Schedule 150 – Monthly Incremental Cost of Gas
Updates the incremental cost of gas for customers who switch from a transport schedule to sales schedule or another applicable way approved by the tariff.

Schedule 164 – Purchased Gas Cost Adjustments to Rates
Updates annual purchased gas costs to reflect projected commodity costs, transportation, or demand, costs, storage costs, and the amortization of Commission-authorized gas cost deferred balances used in determining rates.

Schedule 169 (UM 2323) – Transportation Customer Energy Efficiency Program Cost Recovery
Provides recovery of costs associated with the Transportation Customer Energy Efficiency Program offered under Schedule 361 of the Company's tariff.

Schedule 171 (UM 2252) – Transportation Customer Renewable Natural Gas Offtake Costs
Provides recovery of renewable natural gas offtake costs allocated to transportation and special contract customers in accordance with Oregon's Climate Protection Program.

Schedule 177 (UM 1984) – Adjustment for Oregon Corporate Activity Tax
Provides recovery or refund of costs associated with Oregon's Corporate Activity Tax adjustments in accordance with Commission Order No. 20-364.

Schedule 195 (UM 1798) – Weather Adjusted Rate Mechanism (WARM Program)
Provides recovery or refund of deferred balances resulting from weather conditions that cause the WARM adjustment to exceed the caps and floors.

<u>Summary of Proposed PGA Revenue</u>

The following table summarizes the annual revenue estimated to be derived from the proposed rate adjustment schedules included in this filing. The amounts in the table for each proposed Adjustment Schedule included in this filing are supported by an exhibit, referenced in the table below that details rate calculations, revenue impacts and bill impacts.

Table 1 – Proposed Revenue by Adjustment Schedule

Exhibit	Adjustment Schedule	Description	Revenue Change	Revenue %
A - D	164	Purchased Gas Cost Adjustment (UG 524)	$ 2,549,395	3.83%
E	120	Arrearage Management Program (UM 2372)	$ 958,559	1.44%
F	121	Demand Response (UM 2324)	$ 2,492,874	3.74%
G	151	Meter Modernization Program (UM 2311)	$ 2,038,194	3.06%
H	166	Rate Mitigation (UM2252)	$ (63,371)	0.00%
I	168	Curtailment and Entitlement Revenues (2123)	$ 323,440	0.49%
J	169	Transportation Customer Energy Efficiency Program (UM 2323)	$ (2,217,062)	-3.33%
K	171	Transportation Customer Renewable Natural Gas Offtake Costs (UM 2252)	$ 3,662,809	5.50%
L	172	Intervenor Funding (UM 1101)	$ (77,638)	-0.12%
M	177	Corporate Activity Tax (UM 1984)	$ (2,296)	0.00%
N	178	Regulatory Rate Adjustment / Residual Balances	$ 107,828	0.16%
O	181	Regulatory Fee (UM 1766)	$ (1,016,410)	-1.53%
P	183	Site Remediation Recovery Mechanism (UM 1078)	$ 2,143,321	3.22%
Q	188	Industrial Demand Side Management (UM 1420)	$ 2,782,390	4.17%
R	189	TSA Capital and Cost of Service Recovery (UM 2192)	$ (685,681)	-1.03%
S	190	Partial Decoupling Mechanism UM (1027)	$ 49,747,423	74.64%
T	195	Weather Adjusted Rate Mechanism (WARM) (UM1798)	$ 8,018,669	12.03%
U	198	Renewable Natural Gas Adjustment Mechanism (UM 2266)	$ (4,344,356)	-6.52%
V	122, 175, 196 & 197	Billing Determinants	$ -	0.00%
W	336	Bill Discount (UM 2233)	$ 227,446	0.34%
Total	—	**Combined Effect of All Proposed Adjustments**	**$ 66,645,534**	**100.00%**

Combined Customer Impacts

The following table summarizes the combined monthly bill impact for the average customer by rate schedule including all proposed adjustments included in this filing. The final column identifies the adjustment schedules that contribute to each representative bill impact. As mentioned above, impacts of individual Adjustment Schedules can be found in the corresponding exhibits as listed in Table 1.

Table 2 – Combined Customer Impacts by Customer Rate Schedule

Customer Schedule	Average Monthly Usage (Therms)	Combined Monthly Impact	Contributing Adjustment Schedules
Schedule 2 Residential	53	$5.08	121, 122, 151, 164, 166, 168, 172, 175, 177, 178, 181, 183, 189, 190, 195, 196, 197, 198, 336
Schedule 3 Commercial	250	$35.22	121, 122, 151, 164, 168, 175, 177, 178, 181, 183, 189, 190, 195, 196, 197, 198, 336
Schedule 3 Industrial	1,190	$11.98	122, 151, 164, 168, 172, 175, 177, 178, 181, 183, 188, 189, 196, 197, 198, 336
Schedule 27 Dry Out	35	$0.31	122, 151, 164, 168, 175, 177, 178, 181, 183, 189, 196, 197, 198, 336
Schedule 31 Firm Sales – Commercial	2,720	$72.18	122, 151, 164, 168, 175, 177, 178, 181, 183, 189, 190, 196, 197, 198, 336
Schedule 31 Firm Sales – Industrial	5,281	$42.46	122, 151, 164, 168, 172, 175, 177, 178, 181, 183, 188, 189, 196, 197, 198, 336
Schedule 31 Firm Transportation – Commercial	3,421	($60.60)	122, 151, 169, 171, 175, 177, 178, 181, 183, 189, 196, 197, 198, 336
Schedule 31 Firm Transportation – Industrial	6,893	($459.60)	122, 151, 169, 171, 172, 175, 177, 178, 181, 183, 189, 196, 197, 198, 336
Schedule 32 Firm Sales – Commercial	7,694	$58.63	122, 151, 164, 168, 175, 177, 178, 181, 183, 188, 189, 196, 197, 198, 336
Schedule 32 Firm Sales – Industrial	18,815	$133.36	122, 151, 164, 168, 169, 172, 175, 177, 178, 181, 183, 188, 189, 196, 197, 198, 336
Schedule 32 Firm Transportation – Commercial	18,166	($28.67)	122, 151, 169, 171, 175, 177, 178, 181, 183, 189, 196, 197, 198, 336
Schedule 32 Firm Transportation – Industrial	72,132	$257.88	122, 151, 169, 171, 172, 175, 177, 178, 181, 183, 189, 196, 197, 198, 336
Schedule 32 Interruptible Sales – Commercial	48,951	($437.28)	122, 151, 164, 175, 177, 178, 181, 183, 189, 196, 197, 198, 336
Schedule 32 Interruptible Transportation – Commercial	180,185	$1,097.60	122, 151, 169, 171, 175, 177, 178, 181, 183, 189, 196, 197, 198, 336
Schedule 32 Interruptible Transportation – Industrial	199,892	$1,241.02	122, 151, 169, 171, 172, 175, 177, 178, 181, 183, 189, 196, 197, 198, 336
Schedule 32 Interruptible Sales – Industrial	59,818	($533.11)	122, 151, 164, 172, 175, 177, 178, 181, 183, 188, 189, 196, 197, 198, 336

Proposed Changes

The following table compares the currently effective annual revenue amount for each adjustment schedule with the proposed 2026–2027 annual revenue amounts. The "Change" column reflects the net increase or decrease in revenue resulting from replacing the current temporary adjustments with the proposed temporary adjustments effective October 31, 2026, for residential schedules, and November 1, 2026, for all other schedules.

Table 3 – Proposed Change in Revenue by Adjustment Schedule

Schedule	2025-26 Current	2026-27 Proposed	Change
Schedule 164: PGA Gas Costs and Gas Cost Deferrals	$ (26,660,911)	$ (24,111,516)	$ 2,549,395
Schedule 120: Residential AMP	$ -	$ 958,559	$ 958,559
Schedule 121: Demand Response	$ -	$ 2,492,874	$ 2,492,874
Schedule 151: Meter Mod	$ 2,357,601	$ 4,395,795	$ 2,038,194
Schedule 166: Residential Rate Mitigation	$ 63,371	$ -	$ (63,371)
Schedule 168: Curtailment & Entitlement Revenues	$ (332,625)	$ (9,185)	$ 323,440
Schedule 169: Transport EE	$ 2,056,725	$ (160,337)	$ (2,217,062)
Schedule 171: RNG Transport Allocation	$ 5,213,841	$ 8,876,650	$ 3,662,809
Schedule 172: Intervenor Funding	$ 703,878	$ 626,240	$ (77,638)
Schedule 177: Corporate Activity Tax (CAT)	$ (50,105)	$ (52,401)	$ (2,296)
Schedule 178: Residual Balances	$ (112,141)	$ (4,313)	$ 107,828
Schedule 181: Oregon Regulatory Fee	$ 26,825	$ (989,585)	$ (1,016,410)
Schedule 183: SRRM	$ 11,944,966	$ 14,088,287	$ 2,143,321
Schedule 188: Industrial DSM	$ 10,858,714	$ 13,641,104	$ 2,782,390
Schedule 189: TSA Security Directive 2 Cost of Service	$ 1,095,891	$ 410,210	$ (685,681)
Schedule 190: Decoupling	$ 4,491,361	$ 54,238,784	$ 49,747,423
Schedule 195: WARM	$ 10,249,418	$ 18,268,087	$ 8,018,669
Schedule 198: Renewable Natural Gas Adjustment Mechanism	$ 5,074,267	$ 729,911	$ (4,344,356)
Billing Determinates	$ 10,266,786	$ 10,266,786	$ -
Schedule 336: Bill Discount Program	$ -	$ 227,446	$ 227,446
TOTAL	$ 37,247,862	$ 103,893,396	$ 66,645,534

Average Monthly Bill Impact

The following table shows the estimated monthly bill impact attributable to each adjustment schedule for representative customers in each rate class. The totals correspond to the combined monthly bill impacts summarized earlier in this filing. The average usage used to calculate these bill impacts for each adjustment schedule are detailed in the corresponding exhibit as listed in Table 1.

Table 4 – Average Monthly Bill Impact by Adjustment Schedule

Schedule	2	3 CSF	3 ISF	27	31CSF	31 ISF	31 CTF	31 ITF	32 CSF	32 ISF	32 CTF	32 ITF	32 CSI	32 CTI	32 ITI	32 IIS
Schedule 164	$0.34	$1.60	$7.64	$0.22	($22.12)	($42.94)			($62.55)	($152.96)			($1,149.86)			($1,405.13)
Schedule 120	$0.08	$0.30	$0.93	$0.05	$1.97	$2.58	$2.55	$3.68	$3.47	$5.11	$5.95	$12.41	$10.82	$19.91	$21.40	$10.58
Schedule 121	$0.24	$0.88														
Schedule 151	$0.18	$0.68	$2.03	$0.11	$4.38	$5.45	$5.87	$5.95	$6.54	$8.61	$13.27	$26.59	$19.18	$48.63	$52.69	$20.26
Schedule 166	$0.00															
Schedule 168	$0.02	$0.10	$0.32	$0.01	$0.66	$0.90			$1.23	$1.80			$0.00			
Schedule 169	($0.07)	($0.34)	($1.59)	($0.05)	($3.67)	($7.17)	($4.62)	($5.84)	($10.39)	($25.15)	($24.52)	($63.68)	($66.08)	($243.25)	($59.58)	($74.21)
Schedule 171							$78.89	$99.90			$418.91	$1,087.64		$4,155.06	$1,017.71	
Schedule 172	($0.02)		$0.25			$1.11		$1.44		$3.95		$15.15			$41.98	$12.56
Schedule 177	$0.00	($0.01)	($0.02)	$0.00	($0.02)	$0.00	($0.04)	$0.13	$0.00	$0.00	($0.10)	($0.42)	$0.00	($1.20)	($1.20)	$0.00
Schedule 178	$ -	$ 0.04	$ 0.13	$ -	$ 0.27	$0.39	$0.34	$ 1.48	$ 0.54	$ 0.86	$ 0.83	$ 2.24	$ 1.87	$ 3.90	$ 4.60	$ 1.99
Schedule 181	($0.09)	($0.32)	($1.29)	($0.05)	($2.37)	($4.13)	($1.89)	($3.32)	($5.77)	($12.15)	($5.12)	($12.05)	($29.79)	($22.32)	($24.09)	($34.31)
Schedule 183	$0.22	$0.81	$2.29	$0.16	$5.23	$6.17	$7.93	($83.30)	$8.47	$13.16	$21.28	$43.66	$26.48	$85.96	$88.36	$19.87
Schedule 188			$ 23.12			$102.61			$ 149.50	$365.58			$951.12			$ 1,162.26
Schedule 189	($0.06)	($0.21)	($0.63)	($0.04)	($1.17)	($1.93)	($1.61)	($42.89)	($2.31)	($0.75)	($1.01)	($1.82)	($6.88)	($2.30)	($4.70)	($2.60)
Schedule 190	$3.73	$27.92			$99.47											
Schedule 195	$0.67	$4.65														
Schedule 198	($0.22)	($1.00)	($4.76)	($0.14)	($10.88)	($21.13)	($41.77)	($52.89)	($30.77)	($75.26)	($221.81)	($575.90)	($195.80)	($2,200.06)	($538.86)	($239.28)
Bill Determinants	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Schedule 336	$0.02	$0.07	$0.22	$0.01	$0.47	$0.60	$0.60	$1,005.24	$0.85	$1.23	$1.37	$3,037.05	$2.66	$4.40	$17,007.82	$2.59
Total [1]	$5.08	$35.22	$11.98	$0.31	$72.18	$42.46	($60.60)	($459.60)	$58.63	$133.36	($28.67)	$257.88	($437.28)	$1,097.60	$1,241.02	($533.11)

Customers Affected by Rate Schedule

The following table identifies the approximate number of customers affected by each adjustment schedule by rate class. Shaded cells indicate customer classes that are not affected by the corresponding adjustment schedule.

Table 5 – Number of Customers Affected by Adjustment Schedule

Schedule	2	3 CSF	3 ISF	27	31CSF	31 ISF	31 CTF	31 ITF	32 CSF	32 ISF	32 CTF	32 ITF	32 CSI	32 CTI	32 ITI	32 IIS
Schedule 164	647,078	58,857	331	1,382	707	160			520	100			37			49
Schedule 120	647,078	58,857	331	1,382	707	160	55	5	520	100	31	101	37	3	66	49
Schedule 121	647,078	58,857														
Schedule 151	647,078	58,857	331	1,382	707	160	55	5	520	100	31	101	37	3	66	49
Schedule 166	647,078															
Schedule 168	647,078	58,857	331	1,382	707	160			520	100			37			
Schedule 169	647,078	58,857	331	1,382	707	160	55	5	520	100	31	101	37	3	66	49
Schedule 171							55	5			31	101		3	66	
Schedule 172	647,078		331			160		5		100		101			66	49
Schedule 177	647,078	58,857	331	1,382	707	160	55	5	520	100	31	101	37	3	66	49
Schedule 178	647,078	58,857	331	1,382	707	160	55	5	520	100	31	101	37	3	66	49
Schedule 181	647,078	58,857	331	1,382	707	160	55	5	520	100	31	101	37	3	66	49
Schedule 183	647,078	58,857	331	1,382	707	160	55	5	520	100	31	101	37	3	66	49
Schedule 188			331			160			520	100			37			49
Schedule 189	647,078	58,857	331	1,382	707	160	55	5	520	100	31	101	37	3	66	49
Schedule 190	647,078	58,857			707											
Schedule 195	647,078	58,857														
Schedule 198	647,078	58,855	328	1,382	706	158	55	4	519	95	31	93	37	3	52	45
Bill Determinants	647,078	58,855	328	1,382	706	158	55	4	519	95	31	93	37	3	52	45
Schedule 336	647,078	58,855	328	1,382	706	158	55	4	519	95	31	93	37	3	52	45

Renewable Natural Gas (RNG)

In compliance with OAR 860-150-0300, NW Natural has included about $42.8 million in costs for various offtake arrangements and related transaction costs in the commodity cost of this 2026-27 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.

Three new RNG offtake agreements reflected in the Company's RNG Portfolio have not yet been fully executed as of the date of this filing. Accordingly, placeholders have been included for the related highly confidential attachments, and the executed agreements will be provided to the Commission upon execution and prior to the proposed rate effective date.

UM 1286 Natural Gas Portfolio Development Guidelines

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

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

Conclusion

In support of this filing, the Company includes supporting materials as part of this filing and will separately submit work papers in electronic format, all of which are incorporated herein by reference.

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

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

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Rates & Regulatory Affairs
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Sincerely,

NW NATURAL

/s/ Kyle Walker, CPA

Kyle Walker, CPA
Rates/Regulatory Senior Manager

Attachments:
Exhibits A-D, J, M and T - Supporting Materials

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

DEFINITIONS (continued):

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

Effective: October 31, 2026: For Residential Schedule 2		(C)
Effective: November 1, 2026: For all other applicable rate schedules		(C)
Estimated Annual Sales WACOG per therm (w/ revenue sensitive):	**$0.36778**	(R)
Estimated Annual Sales WACOG per therm (w/o revenue sensitive):	**$0.35709**	(R)

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

Effective: October 31, 2026: For Residential Schedule 2		(C)
Effective: November 1, 2026: For all other applicable rate schedules		(C)
Estimated Winter Sales WACOG per therm (w/ revenue sensitive):	**$0.40635**	(R)
Estimated Winter Sales WACOG per therm (w/o revenue sensitive):	**$0.39454**	(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: October 31, 2026: For Residential Schedule 2		(C)
Effective: November 1, 2026: For all other applicable rate schedules		(C)
Estimated Non-Commodity Cost per therm-Firm Sales (w/revenue sensitive):	**$0.11482**	(I)
Estimated Non-Commodity Cost per therm-Firm Sales (w/o revenue sensitive):	**$0.11148**	(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, 2026: For all other applicable rate schedules		(C)
Estimated Non-Commodity Cost per therm-Interruptible Sales (w/revenue sensitive):	**$0.01366**	(I)
Estimated Non-Commodity Cost per therm-Interruptible Sales (w/o revenue sensitive):	**$0.01326**	(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, 2026: For all other applicable rate schedules		(C)
Estimated Non-Commodity Cost per therm-MDDV Based Sales (w/revenue sensitive):	**$1.69**	(I)
Estimated Non-Commodity Cost per therm-MDDV Based Sales (w/o revenue sensitive):	**$1.64**	(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, 2026 through October 31, 2027 are: (C)

November	2026	$8,882,961	(C)
December	2026	$12,141,068	
January	2027	$12,197,682	
February	2027	$10,472,315	
March	2027	$9,148,400	
April	2027	$6,554,619	
May	2027	$4,086,916	
June	2027	$2,899,030	
July	2027	$2,266,196	
August	2027	$2,249,971	
September	2027	$2,519,747	
October	2027	$5,003,558	
ANNUAL TOTAL		$78,422,463	(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 100
SUMMARY OF TEMPORARY ADJUSTMENTS

PURPOSE:
To list the temporary adjustments included in billing rates.

DESCRIPTION:
The temporary adjustments to rates reflected in this Schedule are the result of the Commission's approval of an application by NW Natural to defer certain revenues or expenses for later amortization in customer rates under the authority of ORS 757.259, OAR 860-022-0070, and OAR 860-027-0300. The details specific to each adjustment can be found in the respective Adjustment Schedules.

All adjustment amounts identified in this Schedule shall be in effect for a 12-month period commencing with the stated effective date, or for such other period approved by the Commission.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Rate Schedule 2	Rate Schedule 27	Rate Schedule 32
Rate Schedule 3	Rate Schedule 31	Rate Schedule 33

All temporary adjustments are stated on a cent per therm basis.

Schedule 2: Residential Sales Service
TABLE OF TEMPORARY ADJUSTMENTS: Effective: October 31, 2026 (C)

	Applicable	Firm Sales Residential	
Meter Modernization (Schedule 151)	All Therms	$0.00730	(I)
Deferred Gas Cost Amortization (Schedule 162)	All Therms	$0.02480	(I)
Rate Mitigation (Schedule 166)	All Therms	$0.00000	(R)
Net Curtailment and Entitlement Revenues (Schedule 168)	All Therms	($0.00002)	(I)
Intervenor Funding (Schedule 172)	All Therms	$0.00105	(R)
Covid-19 Deferral (Schedule 173)	All Therms	$0.00000	
Corporate Activity Tax (CAT) (Schedule 177)	All Therms	($0.00008)	
Regulatory Rate Adjustment (Schedule 178)	All Therms	$0.00000	(I)
TSA Security Directive 2 Compliance Costs (Schedule 180)	All Therms	$0.00000	
Regulatory Fee (Schedule 181)	All Therms	($0.00152)	(R)
Site Remediation Cost Recovery Mechanism (SRRM) (Schedule 183)	All Therms	$0.02339	(I)
TSA Capital and Cost of Service Recovery (Schedule 189)	All Therms	$0.00070	(R)
Decoupling Adjustment (Schedule 190)	All Therms	$0.09638	(I)
WARM True-up (Schedule 195)	All Therms	$0.02769	(I)
Thermostat Rewards Program Cost Recovery (Schedule 121)	All Therms	$0.00455	(I)
Transportation Customer Energy Efficiency Program Cost Recovery (Schedule 169)	All Therms	$0.00015	(R)
Residential AMP (Schedule 120)	All Therms	$0.00159	(N)
Bill Discount Administrative Cost Recovery (Schedule 336)	All Therms	$0.00038	(N)

Schedule 3: Basic Firm Sales - Non-Residential
TABLE OF TEMPORARY ADJUSTMENTS: Effective: November 1, 2026 (C)

	Applicable	Firm Sales Commercial	Firm Sales Industrial	
Meter Modernization (Schedule 151)	All Therms	$0.00563	$0.00360	(I)(I)
Deferred Gas Cost Amortization (Schedule 162)	All Therms	$0.02480	$0.02480	(I)((I)
Net Curtailment and Entitlement Revenues (Schedule 168)	All Therms	($0.00001)	($0.00001)	(I)(I)
Intervenor Funding (Schedule 172)	All Therms		$0.00061	(I)
Covid-19 Deferral (Schedule 173)	All Therms	$0.00000	$0.00000	
Corporate Activity Tax (CAT) (Schedule 177)	All Therms	($0.00007)	($0.00005)	(R)
Regulatory Rate Adjustment (Schedule 178)	All Therms	$0.00000	$0.00000	(I)(I)
TSA Security Directive 2 Compliance Costs (Schedule 180)	All Therms	$0.00000	$0.00000	
Regulatory Fee (Schedule 181)	All Therms	($0.00124)	($0.00105)	(R)(R)
Site Remediation Cost Recovery Mechanism (SRRM) (Schedule 183)	All Therms	$0.01806	$0.01154	(I)(I)
Industrial DSM (Schedule 188)	All Therms		$0.09582	(I)
TSA Capital and Cost of Service Recovery (Schedule 189)	All Therms	$0.00056	$0.00033	(R)(R)
Decoupling Adjustment (Schedule 190)	All Therms	$0.07626		(I)
WARM True-up (Schedule 195)	All Therms	$0.03901		(I)
Thermostat Rewards Program Cost Recovery (Schedule 121)	All Therms	$0.00352	$0.00000	(I)
Transportation Customer Energy Efficiency Program Cost Recovery (Schedule 169)	All Therms	$0.00015	$0.00015	(R)(R)
Residential AMP (Schedule 120)	All Therms	$0.00123	$0.00078	(N)(N)
Bill Discount Administrative Cost Recovery (Schedule 336)	All Therms	$0.00029	$0.00019	(N)(N)

(continue to Sheet 100-2)

SCHEDULE 100
SUMMARY OF TEMPORARY ADJUSTMENTS
(continued)

TABLE OF TEMPORARY ADJUSTMENTS (continued): Effective: November 1, 2026 (C)

Rate Schedule 27: Residential Heating Dry Out Service

	Applicable	FIRM SALES Commercial	
Meter Modernization (Schedule 151)	All Therms	$0.00678	(I)
Deferred Gas Cost Amortization (Schedule 162)	All Therms	$0.02480	
Net Curtailment and Entitlement Revenues (Schedule 168)	All Therms	($0.00002)	(I)
Covid-19 Deferral (Schedule 173)	All Therms	$0.00000	
Corporate Activity Tax (CAT) (Schedule 177)	All Therms	($0.00007)	
Regulatory Rate Adjustment (Schedule 178)	All Therms	$0.00000	(I)
TSA Security Directive 2 Compliance Costs (Schedule 180)	All Therms	$0.00000	
Regulatory Fee (Schedule 181)	All Therms	($0.00141)	(R)
Site Remediation Recovery Mechanism (Schedule 183)	All Therms	$0.02173	(I)
TSA Capital and Cost of Service Recovery (Schedule 189)	All Therms	$0.00088	(R)
Thermostat Rewards Program Cost Recovery (Schedule 121)	All Therms	$0.00000	
Intervenor Funding (Schedule 172)	All Therms	$0.00000	
Transportation Customer Energy Efficiency Program Cost Recovery (Schedule 169)	All Therms	$0.00015	(R)
Residential AMP (Schedule 120)		$0.00148	(N)
Bill Discount Administrative Cost Recovery (Schedule 336)		$0.00035	(N)

Schedule 31: Non-Residential Firm Sales and Firm Transportation

		FIRM SALES		FIRM TRANSPORTATION		
	Applicable	Commercial	Industrial	Commercial	Industrial	
Meter Modernization (Schedule 151)	Block 1	$0.00340	$0.00238	$0.00355	$0.00263	(I)(I)(I)(I)
	Block 2	$0.00310	$0.00215	$0.00325	$0.00238	(I)(I)
Deferred Gas Cost Amortization (Schedule 162)	All Blocks	$0.02480	$0.02480			
Net Curtailment and Entitlement Revenues (Schedule 168)	Block 1	($0.00001)	($0.00001)			
	Block 2	($0.00001)	$0.00000			(I)(I)
Transportation Customer Renewable Natural Gas Offtake Costs (Schedule 171)	All Blocks			$0.07910	$0.07910	(I)(I)
Intervenor Funding (Schedule 172)	All Blocks		$0.00061		$0.00061	
Covid-19 Deferral (Schedule 173)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	
Corporate Activity Tax (CAT) (Schedule 177)	Block 1	($0.00005)	($0.00004)	($0.00003)	($0.00003)	(R) (R)(I)
	Block 2	($0.00004)	($0.00004)	($0.00003)	($0.00002)	(R)(I)
Regulatory Rate Adjustment (Schedule 178)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	(I)(I)(I)(I)
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	(I)(I)(I)(I)
TSA Security Directive 2 Compliance Costs (Schedule 180)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	
Regulatory Fee (Schedule 181)	Block 1	($0.00086)	($0.00078)	($0.00056)	($0.00049)	(R)(R)(R)(R)
	Block 2	($0.00083)	($0.00075)	($0.00052)	($0.00045)	(R)(R)(R)(R)
Site Remediation Recovery Mechanism (SRRM) (Schedule 183)	Block 1	$0.01088	$0.00764	$0.01138	$0.00843	(I)(I)(I)(R)
	Block 2	$0.00995	$0.00690	$0.01043	$0.00764	(I)(I)(I)(R)
Industrial DSM (Schedule 188)	All Blocks		$0.09582			(I)
TSA Capital and Cost of Service Recovery ((Schedule 189)	Block 1	$0.00027	$0.00025	$0.00033	$0.00027	(R)(R)(R)(R)
	Block 2	$0.00025	$0.00023	$0.00031	$0.00025	(R)(R)(R)(R)
Decoupling Adjustment (Schedule 190)	All Blocks	$0.05033				(I)
Thermostat Rewards Program Cost Recovery (Schedule 121)	All Blocks	$0.00000	$0.00000			
Transportation Customer Energy Efficiency Program Cost Recovery (Schedule 169)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	(R)(R)(R)(R)
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	(R)(R)(R)(R)
Residential AMP (Schedule 120)	Block 1	$0.00074	$0.00052	$0.00077	$0.00057	(N)(N)(N)(N)
	Block 2	$0.00068	$0.00047	$0.00071	$0.00052	
Bill Discount Administrative Cost Recovery (Schedule 336)	Block 1	$0.00018	$0.00012	$0.00018	$0.00014	
	Block 2	$0.00016	$0.00011	$0.00017	$0.00012	(N)(N)(N)(N)

(continue to Sheet 100-3)

SCHEDULE 100
SUMMARY OF TEMPORARY ADJUSTMENTS
(continued)

TABLE OF TEMPORARY ADJUSTMENTS (continued): Effective: November 1, 2026 (C)

Schedule 32: Large Volume Non-Residential Sales and Transportation

		FIRM SALES		FIRM TRANSPORTATION		
	Applicable	Commercial	Industrial	Commercial	Industrial	
Meter Modernization (Schedule 151)	Block 1	$0.00205	$0.00135	$0.00159	$0.00120	(I)(I)(I)(I)
	Block 2	$0.00174	$0.00115	$0.00136	$0.00103	
	Block 3	$0.00123	$0.00081	$0.00098	$0.00075	
	Block 4	$0.00071	$0.00047	$0.00061	$0.00046	
	Block 5	$0.00034	$0.00024	$0.00038	$0.00029	
	Block 6	$0.00016	$0.00012	$0.00023	$0.00018	(I)(I)
Deferred Gas Cost Amortization (Schedule 162)	All Blocks	$0.02480	$0.02480			
Net Curtailment and Entitlement Revenues (Schedule 168)	Block 1	$0.00000	$0.00000			(I)(I)
	Block 2	$0.00000	$0.00000			
	Block 3	$0.00000	$0.00000			
	Block 4	$0.00000	$0.00000			
	Block 5	$0.00000	$0.00000			
	Block 6	$0.00000	$0.00000			(I)(I)
Transportation Customer Renewable Natural Gas Offtake Costs (Schedule 171)	All Blocks			$0.07910	$0.07910	(I)(I)
Intervenor Funding (Schedule 172)	Block 1	$0.00000	$0.00061		$0.00061	(I) (I)
	Block 2	$0.00000	$0.00061		$0.00061	
	Block 3	$0.00000	$0.00061		$0.00061	
	Block 4	$0.00000	$0.00061		$0.00061	
	Block 5	$0.00000	$0.00061		$0.00061	
	Block 6	$0.00000	$0.00061		$0.00061	(I) (I)
Covid-19 Deferral (Schedule 173)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 3	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 4	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 5	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 6	$0.00000	$0.00000	$0.00000	$0.00000	
Corporate Activity Tax (CAT) (Schedule 177)	Block 1	($0.00004)	($0.00003)	($0.00002)	($0.00001)	(R)
	Block 2	($0.00004)	($0.00003)	($0.00001)	($0.00001)	
	Block 3	($0.00003)	($0.00003)	($0.00001)	($0.00001)	(R)
	Block 4	($0.00003)	($0.00003)	($0.00001)	($0.00001)	(R)(R)
	Block 5	($0.00003)	($0.00003)	($0.00001)	($0.00001)	(R)(R)
	Block 6	($0.00003)	($0.00003)	($0.00001)	$0.00000	(R)
Regulatory Rate Adjustment (Schedule 178)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	(I)(I)(I)(I)
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	(I)(I)(I)(I)
	Block 3	$0.00000	$0.00000	$0.00000	$0.00000	(I)(I)(I)(I)
	Block 4	$0.00000	$0.00000	$0.00000	$0.00000	(I)
	Block 5	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 6	$0.00000	$0.00000	$0.00000	$0.00000	(R)(R)(R)
TSA Security Directive 2 Compliance Costs (Schedule 180)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 3	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 4	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 5	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 6	$0.00000	$0.00000	$0.00000	$0.00000	
Regulatory Fee (Schedule 181)	Block 1	($0.00073)	($0.00064)	($0.00029)	($0.00022)	(R)(R)(R)(R)
	Block 2	($0.00070)	($0.00061)	($0.00026)	($0.00020)	
	Block 3	($0.00065)	($0.00058)	($0.00021)	($0.00016)	
	Block 4	($0.00059)	($0.00054)	($0.00016)	($0.00012)	
	Block 5	($0.00055)	($0.00051)	($0.00013)	($0.00010)	
	Block 6	($0.00053)	($0.00050)	($0.00011)	($0.00008)	(R)(R)(R)(R)
Site Remediation Recovery Mechanism (Schedule 183)	Block 1	$0.00658	$0.00433	$0.00508	$0.00385	(I)(I)(I)(I)
	Block 2	$0.00558	$0.00368	$0.00436	$0.00330	
	Block 3	$0.00393	$0.00260	$0.00316	$0.00239	
	Block 4	$0.00227	$0.00152	$0.00195	$0.00149	
	Block 5	$0.00108	$0.00077	$0.00123	$0.00094	(I)(I)
	Block 6	$0.00051	$0.00039	$0.00075	$0.00058	
Industrial DSM (Schedule 188)	All Blocks	$0.09582	$0.09582			(I)(I)
TSA Capital and Cost of Service Recovery (Schedule 189)	Block 1	$0.00019	$0.00002	$0.00003	$0.00003	(R)(R)(R)(R)
	Block 2	$0.00016	$0.00002	$0.00003	$0.00002	
	Block 3	$0.00012	$0.00001	$0.00002	$0.00002	
	Block 4	$0.00007	$0.00001	$0.00001	$0.00001	(R)
	Block 5	$0.00003	$0.00000	$0.00001	$0.00001	
	Block 6	$0.00002	$0.00000	$0.00000	$0.00000	(R)(R)(R)(R)
Thermostat Rewards Program Cost Recovery (Schedule 121)	All Blocks	$0.00000	$0.00000			
Transportation Customer Energy Efficiency Program Cost Recovery (Schedule 169)	Block 1	$0.00015	$0.00015	($0.00350)	($0.00262)	(R)(R)(R)(R)
	Block 2	$0.00015	$0.00015	($0.00298)	($0.00222)	
	Block 3	$0.00015	$0.00015	($0.00212)	($0.00157)	
	Block 4	$0.00015	$0.00015	($0.00126)	($0.00092)	
	Block 5	$0.00015	$0.00015	($0.00074)	($0.00053)	
	Block 6	$0.00015	$0.00015	($0.00039)	($0.00027)	(R)(R)(R)(R)
Residential AMP (Schedule 120)	Block 1	$0.00045	$0.00029	$0.00035	$0.00026	(N)(N)(N)(N)
	Block 2	$0.00038	$0.00025	$0.00030	$0.00022	
	Block 3	$0.00027	$0.00018	$0.00021	$0.00016	
	Block 4	$0.00015	$0.00010	$0.00013	$0.00010	
	Block 5	$0.00007	$0.00005	$0.00008	$0.00006	
	Block 6	$0.00003	$0.00003	$0.00005	$0.00004	
Bill Discount Administrative Cost Recovery (Schedule 336)	Block 1	$0.00011	$0.00007	$0.00008	$0.00006	
	Block 2	$0.00009	$0.00006	$0.00007	$0.00005	
	Block 3	$0.00006	$0.00004	$0.00005	$0.00004	
	Block 4	$0.00004	$0.00002	$0.00003	$0.00002	
	Block 5	$0.00002	$0.00001	$0.00002	$0.00002	
	Block 6	$0.00001	$0.00001	$0.00001	$0.00001	(N)(N)(N)(N)

(continue to Sheet 100-4)

SCHEDULE 100
SUMMARY OF TEMPORARY ADJUSTMENTS
(continued)

TABLE OF TEMPORARY ADJUSTMENTS (continued): Effective: November 1, 2026 (C)

Schedule 32: Large Volume Non-Residential Sales and Transportation

		INTERRUPTIBLE SALES		INTERRUPTIBLE TRANSPORT		
	Applicable	Commercial	Industrial	Commercial	Industrial	
Meter Modernization (Schedule 151)	Block 1	$0.00128	$0.00113	$0.00104	$0.00108	(I)(I)(I)(I)
	Block 2	$0.00109	$0.00096	$0.00090	$0.00093	
	Block 3	$0.00077	$0.00068	$0.00065	$0.00068	
	Block 4	$0.00045	$0.00040	$0.00040	$0.00042	
	Block 5	$0.00025	$0.00023	$0.00026	$0.00027	
	Block 6	$0.00011	$0.00010	$0.00016	$0.00017	(I)(I)(I)(I)
Deferred Gas Cost Amortization (Schedule 162)	All Blocks	$0.00377	$0.00377			(I)(I)
Intervenor Funding (Schedule 172)	All Blocks		$0.00061		$0.00061	(I) (I)
Transportation Customer Renewable Natural Gas Offtake Costs (Schedule 171)	All Blocks			$0.07910	$0.07910	(I)(I)
Covid-19 Deferral (Schedule 173)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 3	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 4	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 5	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 6	$0.00000	$0.00000	$0.00000	$0.00000	
Corporate Activity Tax (CAT) (Schedule 177)	Block 1	($0.00003)	($0.00003)	($0.00001)	($0.00001)	
	Block 2	($0.00003)	($0.00003)	($0.00001)	($0.00001)	
	Block 3	($0.00003)	($0.00003)	($0.00001)	($0.00001)	(R)(R)
	Block 4	($0.00003)	($0.00003)	($0.00001)	($0.00001)	(R)(R)
	Block 5	($0.00003)	($0.00003)	$0.00000	$0.00000	
	Block 6	($0.00002)	($0.00002)	$0.00000	$0.00000	
Regulatory Rate Adjustment (Schedule 178)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	(I)(I)(I)(I)
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	(I)(I)(I)(I)
	Block 3	$0.00000	$0.00000	$0.00000	$0.00000	(I)(I)(I)(I)
	Block 4	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 5	$0.00000	$0.00000	$0.00000	$0.00000	(R)
	Block 6	$0.00000	$0.00000	$0.00000	$0.00000	(R)(R)(R)(R)
TSA Security Directive 2 Compliance Costs (Schedule 180)	Block 1	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 2	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 3	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 4	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 5	$0.00000	$0.00000	$0.00000	$0.00000	
	Block 6	$0.00000	$0.00000	$0.00000	$0.00000	
Regulatory Fee (Schedule 181)	Block 1	($0.00062)	($0.00060)	($0.00020)	($0.00020)	(R)(R)(R)(R)
	Block 2	($0.00060)	($0.00058)	($0.00018)	($0.00018)	
	Block 3	($0.00056)	($0.00054)	($0.00015)	($0.00015)	
	Block 4	($0.00052)	($0.00051)	($0.00011)	($0.00011)	
	Block 5	($0.00049)	($0.00049)	($0.00009)	($0.00009)	
	Block 6	($0.00048)	($0.00047)	($0.00008)	($0.00008)	(R)(R)(R)(R)
Site Remediation Recovery Mechanism (Schedule 183)	Block 1	$0.00412	$0.00361	$0.00334	$0.00347	(I)(I)(I)(I)
	Block 2	$0.00350	$0.00307	$0.00287	$0.00298	
	Block 3	$0.00247	$0.00217	$0.00208	$0.00217	
	Block 4	$0.00143	$0.00127	$0.00130	$0.00135	
	Block 5	$0.00081	$0.00073	$0.00083	$0.00086	(I)
	Block 6	$0.00036	$0.00033	$0.00051	$0.00053	(I) (I)(I)
Industrial DSM (Schedule 188)	All Blocks	$0.09582	$0.09582			(I)(I)
TSA Capital and Cost of Service Recovery (Schedule 189)	Block 1	$0.00012	$0.00003	$0.00003	$0.00002	(R)(R)(R)(R)
	Block 2	$0.00010	$0.00003	$0.00002	$0.00002	(R)
	Block 3	$0.00007	$0.00002	$0.00002	$0.00002	(R)
	Block 4	$0.00004	$0.00001	$0.00001	$0.00001	(R)
	Block 5	$0.00002	$0.00001	$0.00001	$0.00001	
	Block 6	$0.00001	$0.00000	$0.00000	$0.00000	(R)(R)(R)(R)
Thermostat Rewards Program Cost Recovery (Schedule 121)	All Blocks	$0.00000	$0.00000			
Transportation Customer Energy Efficiency Program Cost Recovery (Schedule 169)	Block 1	$0.00015	$0.00015	($0.00225)	($0.00235)	(R)(R)(R)(R)
	Block 2	$0.00015	$0.00015	($0.00191)	($0.00199)	
	Block 3	$0.00015	$0.00015	($0.00135)	($0.00141)	
	Block 4	$0.00015	$0.00015	($0.00078)	($0.00082)	
	Block 5	$0.00015	$0.00015	($0.00044)	($0.00047)	
	Block 6	$0.00015	$0.00015	($0.00022)	($0.00023)	(R)(R)(R)(R)
Residential AMP (Schedule 120)	Block 1	$0.00028	$0.00025	$0.00023	$0.00024	(N)(N)(N)(N)
	Block 2	$0.00024	$0.00021	$0.00020	$0.00020	
	Block 3	$0.00017	$0.00015	$0.00014	$0.00015	
	Block 4	$0.00010	$0.00009	$0.00009	$0.00009	
	Block 5	$0.00006	$0.00005	$0.00006	$0.00006	
	Block 6	$0.00002	$0.00002	$0.00003	$0.00004	
Bill Discount Administrative Cost Recovery (Schedule 336)	Block 1	$0.00007	$0.00006	$0.00005	$0.00006	
	Block 2	$0.00006	$0.00005	$0.00005	$0.00005	
	Block 3	$0.00004	$0.00004	$0.00003	$0.00003	
	Block 4	$0.00002	$0.00002	$0.00002	$0.00002	
	Block 5	$0.00001	$0.00001	$0.00001	$0.00001	
	Block 6	$0.00001	$0.00001	$0.00001	$0.00001	(N)(N)(N)(N)

(continue to Sheet 100-5)

SCHEDULE 100
SUMMARY OF TEMPORARY ADJUSTMENTS
(continued)

TABLE OF TEMPORARY ADJUSTMENTS (continued): Effective: November 1, 2026

Rate Schedule 33: High Large Volume Non-Residential Firm Transportation and Interruptible Service

		FIRM TRANSPORTATION		
	Applicable	**Commercial**	**Industrial**	
Meter Modernization (Schedule 151)	All Therms	$0.00000	$0.00000	
Transportation Customer Renewable Natural Gas Offtake Costs (Schedule 171)	All Therms	$0.07910	$0.07910	(I)(I)
Site Remediation Recovery Mechanism (Schedule 183)	All Therms	$0.00000	$0.00000	
Transportation Customer Energy Efficiency Program Cost Recovery (Schedule 169)	All Therms	$0.00015	$0.00015	(R)(R)
Oregon PUC Fee (Schedule 181)	All Therms	($0.00007)	($0.00007)	(N)(N)

		INTERRUPTIBLE TRANSPORTATION	
	Applicable	**All**	
Transportation Customer Renewable Natural Gas Offtake Costs (Schedule 171)	All Therms	$0.07910	(I)
Site Remediation Recovery Mechanism (Schedule 183)	All Therms	$0.00000	
Transportation Customer Energy Efficiency Program Cost Recovery (Schedule 169)	All Therm	$0.00015	(R)
Oregon PUC Fee (Schedule 181)	All Therms	($0.00007)	(N)

Rate Schedule 60: Special Contracts

	Applicable	**All**	
Transportation Customer Renewable Natural Gas Offtake Costs (Schedule 171)	All Therms	$0.07335	(I)

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, 2026: $0.05853 per therm (C) (I)

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

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

SCHEDULE 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 Schedule of this Tariff: (T)

Rate Schedule 2 (T)

APPLICATION TO RATE SCHEDULES: Effective: October 31, 2026 (C)

Annual Sales WACOG [1]	$0.36778	(R)
Winter Sales WACOG [2]	$0.40635	(R)
Firm Sales Service Pipeline Capacity Component [3]	$0.11482	(I)

APPLICABLE:
To the following Rate Schedules of this Tariff:

Rate Schedule 3 Rate Schedule 27 (T)
Rate Schedule 31 Rate Schedule 32

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2026 (C)

Annual Sales WACOG [1]	$0.36778	(R)
Winter Sales WACOG [2]	$0.40635	(R)
Firm Sales Service Pipeline Capacity Component [3]	$0.11482	(I)
Firm Sales Service Pipeline Capacity Component [4]	$1.69	(I)
Interruptible Sales Service Pipeline Capacity Component [5]	$0.01366	(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.

SCHEDULE 169
TRANSPORTATION CUSTOMER ENERGY EFFICIENCY PROGRAM COST RECOVERY

PURPOSE:
This Schedule recovers the costs of the program offered under Schedule 361 “Transportation Customer Energy Efficiency Program.”

APPLICABLE:
For costs of the 2024 program, applicable to all Transportation service Customers on Rate Schedule 31, Rate Schedule 32, and Rate Schedule 33. Costs will be allocated on an equal percentage of margin basis.

For costs of the 2025 program, applicable to all Customers on the Rate Schedules below that are not Emissions-Intensive and Trade-Exposed under the Oregon Climate Protection Program. Costs will be allocated on an equal cent per therm basis.

Rate Schedule 2	Rate Schedule 3	Rate Schedule 27	Rate Schedule 31
Rate Schedule 32	Rate Schedule 33		

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2026 (C)
The Temporary Adjustments in the applicable above-listed Rate Schedules include the adjustment shown below. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

For costs of the 2024 program:

Schedule	Block	Total Adjustment
31 CTF	Block 1	($0.00818)
	Block 2	($0.00750)
31 ITF	Block 1	($0.00606)
	Block 2	($0.00550)
32 CTF	Block 1	($0.00365)
	Block 2	($0.00313)
	Block 3	($0.00227)
	Block 4	($0.00141)
	Block 5	($0.00089)
	Block 6	($0.00054)
32 ITF	Block 1	($0.00277)
	Block 2	($0.00237)
	Block 3	($0.00172)
	Block 4	($0.00107)
	Block 5	($0.00068)
	Block 6	($0.00042)

Schedule	Block	Total Adjustment
32 CTI	Block 1	($0.00240)
	Block 2	($0.00206)
	Block 3	($0.00150)
	Block 4	($0.00093)
	Block 5	($0.00059)
	Block 6	($0.00037)
32 ITI	Block 1	($0.00250)
	Block 2	($0.00214)
	Block 3	($0.00156)
	Block 4	($0.00097)
	Block 5	($0.00062)
	Block 6	($0.00038)
33 (all)		$0.00000

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

For costs of the 2025 program: Effective: October 31, 2026 (C)

Residential Schedule 2: $0.00015 per therm (R)

Effective: November 1, 2026 (C)

All Non-Residential Schedules: $0.00015 per therm (R)

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

Issued September 14, 2026 Effective with service on
NWN OPUC Advice No. 26-05A and after October 31, 2026

SCHEDULE 171
TRANSPORTATION CUSTOMER RENEWABLE NATURAL GAS OFFTAKE COSTS

PURPOSE:
To recover costs associated with RNG offtakes from customers taking service under a Transportation Schedule per compliance with the Oregon's Climate Protection Program.

APPLICABLE:
To all Transportation Service Customers on the Rate Schedules of this Tariff listed below that are not Emissions-Intensive and Trade-Exposed under the Oregon Climate Protection Program:

Rate Schedule 31	Rate Schedule 32
Rate Schedule 60	Rate Schedule 33
Rate Schedule 60A	

Costs of RNG offtakes are included in the Company's Annual Sales Weighted Average Cost of Gas ("WACOG") in Schedule 164. Thus, these costs are recovered from customers taking service under a Sales Service rate schedule and subject to WACOG through Schedule 164.

This Schedule 171 will recover costs of RNG offtakes from customers taking service under a Transportation Service or Special Contract rate schedule.

GENERAL:
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.

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2026 (C)

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

Schedule	Block	Total Adjustment
31 CTF	Block 1	$0.07910
	Block 2	$0.07910
31 ITF	Block 1	$0.07910
	Block 2	$0.07910
32 CTF	Block 1	$0.07910
	Block 2	$0.07910
	Block 3	$0.07910
	Block 4	$0.07910
	Block 5	$0.07910
	Block 6	$0.07910
32 ITF	Block 1	$0.07910
	Block 2	$0.07910
	Block 3	$0.07910
	Block 4	$0.07910
	Block 5	$0.07910
	Block 6	$0.07910

Schedule	Block	Total Adjustment
32 CTI	Block 1	$0.07910
	Block 2	$0.07910
	Block 3	$0.07910
	Block 4	$0.07910
	Block 5	$0.07910
	Block 6	$0.07910
32 ITI	Block 1	$0.07910
	Block 2	$0.07910
	Block 3	$0.07910
	Block 4	$0.07910
	Block 5	$0.07910
	Block 6	$0.07910
33 (all)		$0.07910
60		$0.07910
60A		$0.07910

(I) (I)

(I)
(I)

SCHEDULE 177
ADJUSTMENT FOR OREGON CORPORATE ACTIVITY TAX
(continued)

APPLICATION TO RATE SCHEDULES (continued):

The adjustments applicable to each Rate Schedule is shown in the table below:

Effective: October 31, 2026 (C)

Schedule	CAT
2	($0.00008)

Effective: November 1, 2026 (C)

Schedule	Block	CAT		Schedule	Block	CAT	
				32 ITF	Block 1	($0.00001)	
3 CSF		($0.00007)			Block 2	($0.00001)	(R)
3 ISF		($0.00006)			Block 3	($0.00001)	(R)
27		($0.00008)			Block 4	($0.00001)	
31 CSF	Block 1	($0.00005)			Block 5	($0.00001)	(R) (R)
	Block 2	($0.00004)			Block 6	$0.00000	
31 CTF	Block 1	($0.00003)		32 CSI	Block 1	($0.00003)	(R)
	Block 2	($0.00003)			Block 2	($0.00003)	(R)
31 ISF	Block 1	($0.00004)			Block 3	($0.00003)	
	Block 2	($0.00004)			Block 4	($0.00003)	
31 ITF	Block 1	($0.00003)			Block 5	($0.00003)	(I)
	Block 2	($0.00002)			Block 6	($0.00003)	(I) (R)
32 CSF	Block 1	($0.00004)		32 ISI	Block 1	($0.00003)	
	Block 2	($0.00004)			Block 2	($0.00003)	
	Block 3	($0.00003)			Block 3	($0.00003)	
	Block 4	($0.00003)			Block 4	($0.00003)	
	Block 5	($0.00003)			Block 5	($0.00003)	
	Block 6	($0.00003)			Block 6	($0.00003)	(R)
32 ISF	Block 1	($0.00003)		32 CTI	Block 1	($0.00001)	
	Block 2	($0.00003)			Block 2	($0.00001)	
	Block 3	($0.00003)			Block 3	($0.00001)	(R)
	Block 4	($0.00003)			Block 4	($0.00001)	(R)
	Block 5	($0.00003)			Block 5	$0.00000	
	Block 6	($0.00003)			Block 6	$0.00000	
32 CTF	Block 1	($0.00002)		32 ITI	Block 1	($0.00001)	(R)
	Block 2	($0.00001)			Block 2	($0.00001)	
	Block 3	($0.00001)			Block 3	($0.00001)	(R)
	Block 4	($0.00001)			Block 4	($0.00001)	(R) (R)
	Block 5	($0.00001)			Block 5	$0.00000	(R)
	Block 6	($0.00001)			Block 6	$0.00000	(R)
				33 (all)		$0.00000	

SCHEDULE 195
WEATHER ADJUSTED RATE MECHANISM
(WARM Program)

PURPOSE:
To describe the Weather Adjusted Rate Mechanism (WARM) adopted by the Public Utility Commission of Oregon in Docket UG 221, Order No. 12-408 entered October 26, 2012, as modified in Docket UM 1750 by Commission Order No. 16-223 entered June 20, 2016.

APPLICABLE:
To Residential and Commercial Customers served on the following Rate Schedules of this Tariff:

Rate Schedule 2	Rate Schedule 3

APPLICATION TO RATE SCHEDULES:
The WARM Adjustment will be applied as an adjustment to the per-therm Billing Rate on applicable Residential and Commercial Customer bills issued during the WARM Period. The WARM Period covers bills that are generated based on meters read on or after December 1st and on or before May 15th.

SPECIAL CONDITIONS:

1. The WARM Adjustment will apply to Customer bills that are based on applicable Residential Rate Schedule 2 or Commercial Rate Schedule 3 meters read on or after December 1st and on or before May 15th.

2. Residential bills --The maximum WARM Adjustment (increase or decrease) that will be made to any regular monthly bill during the WARM Period will be twelve dollars ($12.00), or twenty-five percent (25%) of the usage portion of that bill, whichever is less. For any billing period in which the total monthly WARM adjustment exceeds either $12.00 or 25% of the usage, the balance of the WARM adjustment will be deferred in accordance with Special Condition 4.

3. Commercial bills--The maximum WARM Adjustment (increase or decrease) that will be added to any regular monthly bill during the WARM Period will be thirty-five dollars ($35.00), or twenty-five percent (25%) of the usage portion of that bill, whichever is less. For any billing period in which the total monthly WARM adjustment exceeds either thirty-five dollars or 25% of the usage, the balance of the WARM adjustment will be deferred in accordance with Special Condition 4.

4. Any amounts not applied to a Residential or Commercial Customer's bill during the WARM Period due to the caps and floor described in Special Conditions 2 and 3 will be set aside in a respective Residential or Commercial WARM deferral account. Each year, concurrent with the Company's annual Purchased Gas Adjustment (PGA) filing, the balance in the Residential and Commercial WARM deferral accounts will be collected from or credited to all Rate Schedule 2 and Rate Schedule 3 customers, respectively, on an equal cent-per-therm basis. The adjustment included in the Temporary Adjustments reflected in the above-listed Rate Schedules effective October 31, 2026 are: (C)

Rate Schedule 2:	$0.02769

(I)

Adjustments reflected in the above-listed Rate Schedules effective November 1, 2026 are (C)

Rate Schedule 3:	$0.03901

(I)

(continue to Sheet 195-2)

EXHIBIT A

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

Purchased Gas Cost Deferral Amortizations

UM 1496

NWN OPUC Advice No. 26-05A / UG 531

September 14, 2026

NW NATURAL

EXHIBIT A

Supporting Materials

Purchased Gas Cost Deferral Amortizations

NWN OPUC ADVICE NO. 26-05A / UG 531

NW Natural
Rates & Regulatory Affairs
2026-27 PGA - Oregon: September Filing
Summary of TEMPORARY Increments

			Current Temporaries	WACOG Deferral (Schedule 164)	Demand Deferral - FIRM (Schedule 164)	Demand Deferral - INTERRUPTIBLE (Schedule 164)	Subtotal
1							
2							
3	Schedule	Block	A	B	C	D	E
4	2R		$0.03419	$0.00320	$0.02387	$0.00000	$0.02707
5	3C Sales Firm		($0.02887)	$0.00320	$0.02387	$0.00000	$0.02707
6	3I Sales Firm		$0.05646	$0.00320	$0.02387	$0.00000	$0.02707
7	27 Dry Out		($0.01049)	$0.00320	$0.02387	$0.00000	$0.02707
8	31C Sales Firm	Block 1	($0.00753)	$0.00320	$0.02387	$0.00000	$0.02707
9		Block 2	($0.00847)	$0.00320	$0.02387	$0.00000	$0.02707
10	31C Trans Firm	Block 1	$0.09322	$0.00000	$0.00000	$0.00000	$0.00000
11		Block 2	$0.09013	$0.00000	$0.00000	$0.00000	$0.00000
12	31I Sales Firm	Block 1	$0.05254	$0.00320	$0.02387	$0.00000	$0.02707
13		Block 2	$0.05177	$0.00320	$0.02387	$0.00000	$0.02707
14	31I Trans Firm	Block 1	$0.14545	$0.00000	$0.00000	$0.00000	$0.00000
15		Block 2	$0.13695	$0.00000	$0.00000	$0.00000	$0.00000
16	32C Sales Firm	Block 1	$0.05103	$0.00320	$0.02387	$0.00000	$0.02707
17		Block 2	$0.04999	$0.00320	$0.02387	$0.00000	$0.02707
18		Block 3	$0.04826	$0.00320	$0.02387	$0.00000	$0.02707
19		Block 4	$0.04652	$0.00320	$0.02387	$0.00000	$0.02707
20		Block 5	$0.04526	$0.00320	$0.02387	$0.00000	$0.02707
21		Block 6	$0.04467	$0.00320	$0.02387	$0.00000	$0.02707
22	32I Sales Firm	Block 1	$0.04884	$0.00320	$0.02387	$0.00000	$0.02707
23		Block 2	$0.04821	$0.00320	$0.02387	$0.00000	$0.02707
24		Block 3	$0.04712	$0.00320	$0.02387	$0.00000	$0.02707
25		Block 4	$0.04603	$0.00320	$0.02387	$0.00000	$0.02707
26		Block 5	$0.04527	$0.00320	$0.02387	$0.00000	$0.02707
27		Block 6	$0.04491	$0.00320	$0.02387	$0.00000	$0.02707
28	32C Trans Firm	Block 1	$0.07262	$0.00000	$0.00000	$0.00000	$0.00000
29		Block 2	$0.07032	$0.00000	$0.00000	$0.00000	$0.00000
30		Block 3	$0.06650	$0.00000	$0.00000	$0.00000	$0.00000
31		Block 4	$0.06267	$0.00000	$0.00000	$0.00000	$0.00000
32		Block 5	$0.06037	$0.00000	$0.00000	$0.00000	$0.00000
33		Block 6	$0.05885	$0.00000	$0.00000	$0.00000	$0.00000
34	32I Trans Firm	Block 1	$0.06995	$0.00000	$0.00000	$0.00000	$0.00000
35		Block 2	$0.06811	$0.00000	$0.00000	$0.00000	$0.00000
36		Block 3	$0.06506	$0.00000	$0.00000	$0.00000	$0.00000
37		Block 4	$0.06202	$0.00000	$0.00000	$0.00000	$0.00000
38		Block 5	$0.06018	$0.00000	$0.00000	$0.00000	$0.00000
39		Block 6	$0.05898	$0.00000	$0.00000	$0.00000	$0.00000
40	32C Sales Interr	Block 1	$0.04288	$0.00320	$0.00000	$0.00284	$0.00604
41		Block 2	$0.04222	$0.00320	$0.00000	$0.00284	$0.00604
42		Block 3	$0.04111	$0.00320	$0.00000	$0.00284	$0.00604
43		Block 4	$0.04000	$0.00320	$0.00000	$0.00284	$0.00604
44		Block 5	$0.03931	$0.00320	$0.00000	$0.00284	$0.00604
45		Block 6	$0.03884	$0.00320	$0.00000	$0.00284	$0.00604
46	32I Sales Interr	Block 1	$0.04265	$0.00320	$0.00000	$0.00284	$0.00604
47		Block 2	$0.04209	$0.00320	$0.00000	$0.00284	$0.00604
48		Block 3	$0.04114	$0.00320	$0.00000	$0.00284	$0.00604
49		Block 4	$0.04019	$0.00320	$0.00000	$0.00284	$0.00604
50		Block 5	$0.03961	$0.00320	$0.00000	$0.00284	$0.00604
51		Block 6	$0.03921	$0.00320	$0.00000	$0.00284	$0.00604
52	32C Trans Interr	Block 1	$0.06758	$0.00000	$0.00000	$0.00000	$0.00000
53		Block 2	$0.06605	$0.00000	$0.00000	$0.00000	$0.00000
54		Block 3	$0.06351	$0.00000	$0.00000	$0.00000	$0.00000
55		Block 4	$0.06095	$0.00000	$0.00000	$0.00000	$0.00000
56		Block 5	$0.05942	$0.00000	$0.00000	$0.00000	$0.00000
57		Block 6	$0.05840	$0.00000	$0.00000	$0.00000	$0.00000
58	32I Trans Interr	Block 1	$0.06879	$0.00000	$0.00000	$0.00000	$0.00000
59		Block 2	$0.06713	$0.00000	$0.00000	$0.00000	$0.00000
60		Block 3	$0.06439	$0.00000	$0.00000	$0.00000	$0.00000
61		Block 4	$0.06162	$0.00000	$0.00000	$0.00000	$0.00000
62		Block 5	$0.05996	$0.00000	$0.00000	$0.00000	$0.00000
63		Block 6	$0.05886	$0.00000	$0.00000	$0.00000	$0.00000
64	33		$0.05754	$0.00000	$0.00000	$0.00000	$0.00000
65	Special Contracts		$0.05279	$0.00000	$0.00000	$0.00000	$0.00000

NW Natural
Rates & Regulatory Affairs
2026-27 PGA - Oregon: September Filing
Calculation of Increments Allocated on the EQUAL CENT PER THERM BASIS
ALL VOLUMES IN THERMS

1				**WACOG Deferral (Schedule 164)**			**Demand Deferral - FIRM (Schedule 164)**			**Demand Deferral - INTERRUPTIBLE (Schedule 164)**			**AWEC Deferral - Schedule 171 To Sales (WACOG)**		
2			**Oregon PGA** **Proposed Amount:**	2,344,970 Temporary Increment			16,145,579 Temporary Increment			156,938 Temporary Increment			(1,661,355) Temporary Increment		
3			**Volumes page,** **Revenue Sensitive Multiplier:**	2.907% add revenue sensitive factor			2.907% add revenue sensitive factor			2.907% add revenue sensitive factor			2.907% add revenue sensitive factor		
4			**Column F** **Amount to Amortize:**	**2,415,169** to all sales			**16,628,910** to all firm sales			**161,636** to all interruptible sales			**(1,711,089)** 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		411,057,580	1.0	411,057,580	$0.00320	1.0	411,057,580	$0.02387	0.0	0	$0.00000	1.0	411,057,580	($0.00227)
8	3C Firm Sales		176,503,361	1.0	176,503,361	$0.00320	1.0	176,503,361	$0.02387	0.0	0	$0.00000	1.0	176,503,361	($0.00227)
9	3I Firm Sales		4,727,872	1.0	4,727,872	$0.00320	1.0	4,727,872	$0.02387	0.0	0	$0.00000	1.0	4,727,872	($0.00227)
10	27 Dry Out		584,677	1.0	584,677	$0.00320	1.0	584,677	$0.02387	0.0	0	$0.00000	1.0	584,677	($0.00227)
11	31C Firm Sales	Block 1	13,656,203	1.0	13,656,203	$0.00320	1.0	13,656,203	$0.02387	0.0	0	$0.00000	1.0	13,656,203	($0.00227)
12		Block 2	9,421,084	1.0	9,421,084	$0.00320	1.0	9,421,084	$0.02387	0.0	0	$0.00000	1.0	9,421,084	($0.00227)
13	31C Firm Trans	Block 1	1,155,877	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
14		Block 2	1,101,903	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	3,368,480	1.0	3,368,480	$0.00320	1.0	3,368,480	$0.02387	0.0	0	$0.00000	1.0	3,368,480	($0.00227)
16		Block 2	6,770,266	1.0	6,770,266	$0.00320	1.0	6,770,266	$0.02387	0.0	0	$0.00000	1.0	6,770,266	($0.00227)
17	31I Firm Trans	Block 1	129,581	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
18		Block 2	284,018	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	35,905,676	1.0	35,905,676	$0.00320	1.0	35,905,676	$0.02387	0.0	0	$0.00000	1.0	35,905,676	($0.00227)
20		Block 2	9,554,234	1.0	9,554,234	$0.00320	1.0	9,554,234	$0.02387	0.0	0	$0.00000	1.0	9,554,234	($0.00227)
21		Block 3	1,745,309	1.0	1,745,309	$0.00320	1.0	1,745,309	$0.02387	0.0	0	$0.00000	1.0	1,745,309	($0.00227)
22		Block 4	802,581	1.0	802,581	$0.00320	1.0	802,581	$0.02387	0.0	0	$0.00000	1.0	802,581	($0.00227)
23		Block 5	0	1.0	0	$0.00320	1.0	0	$0.02387	0.0	0	$0.00000	1.0	0	($0.00227)
24		Block 6	0	1.0	0	$0.00320	1.0	0	$0.02387	0.0	0	$0.00000	1.0	0	($0.00227)
25	32I Firm Sales	Block 1	9,268,308	1.0	9,268,308	$0.00320	1.0	9,268,308	$0.02387	0.0	0	$0.00000	1.0	9,268,308	($0.00227)
26		Block 2	8,227,501	1.0	8,227,501	$0.00320	1.0	8,227,501	$0.02387	0.0	0	$0.00000	1.0	8,227,501	($0.00227)
27		Block 3	2,696,668	1.0	2,696,668	$0.00320	1.0	2,696,668	$0.02387	0.0	0	$0.00000	1.0	2,696,668	($0.00227)
28		Block 4	2,255,924	1.0	2,255,924	$0.00320	1.0	2,255,924	$0.02387	0.0	0	$0.00000	1.0	2,255,924	($0.00227)
29		Block 5	130,032	1.0	130,032	$0.00320	1.0	130,032	$0.02387	0.0	0	$0.00000	1.0	130,032	($0.00227)
30		Block 6	0	1.0	0	$0.00320	1.0	0	$0.02387	0.0	0	$0.00000	1.0	0	($0.00227)
31	32C Firm Trans	Block 1	3,057,342	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
32		Block 2	2,128,039	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
33		Block 3	644,113	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
34		Block 4	866,120	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
35		Block 5	62,190	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	11,016,531	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
38		Block 2	15,602,797	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
39		Block 3	9,458,456	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
40		Block 4	22,451,387	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
41		Block 5	21,475,941	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
42		Block 6	7,418,474	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	4,132,294	1.0	4,132,294	$0.00320	0.0	0	$0.00000	1.0	4,132,294	$0.00284	1.0	4,132,294	($0.00227)
44		Block 2	6,058,058	1.0	6,058,058	$0.00320	0.0	0	$0.00000	1.0	6,058,058	$0.00284	1.0	6,058,058	($0.00227)
45		Block 3	3,271,549	1.0	3,271,549	$0.00320	0.0	0	$0.00000	1.0	3,271,549	$0.00284	1.0	3,271,549	($0.00227)
46		Block 4	4,837,562	1.0	4,837,562	$0.00320	0.0	0	$0.00000	1.0	4,837,562	$0.00284	1.0	4,837,562	($0.00227)
47		Block 5	3,434,773	1.0	3,434,773	$0.00320	0.0	0	$0.00000	1.0	3,434,773	$0.00284	1.0	3,434,773	($0.00227)
48		Block 6	0	1.0	0	$0.00320	0.0	0	$0.00000	1.0	0	$0.00284	1.0	0	($0.00227)
49	32I Interr Sales	Block 1	5,733,047	1.0	5,733,047	$0.00320	0.0	0	$0.00000	1.0	5,733,047	$0.00284	1.0	5,733,047	($0.00227)
50		Block 2	7,298,404	1.0	7,298,404	$0.00320	0.0	0	$0.00000	1.0	7,298,404	$0.00284	1.0	7,298,404	($0.00227)
51		Block 3	4,456,416	1.0	4,456,416	$0.00320	0.0	0	$0.00000	1.0	4,456,416	$0.00284	1.0	4,456,416	($0.00227)
52		Block 4	12,581,349	1.0	12,581,349	$0.00320	0.0	0	$0.00000	1.0	12,581,349	$0.00284	1.0	12,581,349	($0.00227)
53		Block 5	5,103,939	1.0	5,103,939	$0.00320	0.0	0	$0.00000	1.0	5,103,939	$0.00284	1.0	5,103,939	($0.00227)
54		Block 6	0	1.0	0	$0.00320	0.0	0	$0.00000	1.0	0	$0.00284	1.0	0	($0.00227)
55	32C Interr Trans	Block 1	667,319	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
56		Block 2	1,394,375	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
57		Block 3	939,924	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
58		Block 4	3,098,587	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
59		Block 5	386,468	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
60		Block 6	0	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
61	32I Interr Trans	Block 1	5,864,800	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
62		Block 2	9,761,912	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
63		Block 3	5,807,692	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
64		Block 4	12,637,820	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
65		Block 5	28,598,086	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
66		Block 6	95,643,968	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		75,345,634	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
69															
70	TOTALS		1,090,582,502		753,583,147	$ 0.00320		696,675,755	$ 0.02387		56,907,391	$ 0.00284		753,583,147	$ (0.00227)
71	**Sources for line 2 above:**														
72	**Inputs page**			Line 33			Line 35			Line 37			Line 61		
73	**Tariff Schedules**														
74	**Rate Adjustment Schedule**			Sched 164			Sched 164			Sched 164			Sched 171		

NW Natural
Rates and Regulatory Affairs
2026-2027 PGA Filing - OREGON
Basis for Revenue Related Costs

		Twelve Months		
1		Ended 06/30/26		
2				
3	Total Billed Gas Sales Revenues	$ 914,402,342		
4	Total Oregon Revenues	$ 918,820,399		
5				
6	Regulatory Commission Fees [1]	n/a	0.360%	Statutory rate
7	City License and Franchise Fees	$ 21,576,831	2.348%	Line 7 ÷ Line 4
8	Net Uncollectible Expense [2]	$ 1,824,506	0.199%	Line 8 ÷ Line 4
9				
10	Total		**2.907%**	Sum lines 8-9
11				
12				

13 **Note:**
14 [1] Dollar figure is set at statutory level of Total Oregon Revenues (line 4).
15 [2] Represents the normalized net write-offs based on a three-year average.

NW Natural
Rates & Regulatory Affairs
2026-2027 PGA Filing - Oregon: September Filing
PGA Effects on Revenue
Schedule 164: PGA Gas Costs and Gas Cost Deferrals

Line		Including Revenue Sensitive Amount
1		
2		
3	**Purchased Gas Cost Adjustment (PGA)**	
4		
5	Commodity Cost Change	($49,913,709)
6		
7	Demand Capacity Cost Change	8,307,567
8		
9	**Total Gas Cost Change**	**(41,606,142)**
10		
11	**Temporary Increments**	
12		
13	Removal of Current Temporary Increments	
14	Amortization of 191.xxx Account Gas Costs	26,660,911
15		
16	Addition of Proposed Temporary Increments	
17	Amortization of 191.xxx Account Gas Costs	17,494,626
18		
19	**Net Temporary Rate Adjustment**	**44,155,537**
20		
21	**TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES**	**$2,549,395**
22		
23	2025 Oregon Earnings Test Normalized Total Revenues	$1,005,966,120
24		
25	Effect of this filing, as a percentage change (line 21 ÷ line 23)	0.25%
26		
27	Effect of this filing, as a percentage change (line 19 ÷ line 23)	4.39%
28		
29	Effect of this filing, as a percentage change (line 9 ÷ line 23)	-4.14%

NW Natural
Rates & Regulatory Affairs
2026-27 PGA Filing - July Filing
Summary of Deferred Accounts Included in the PGA

Account	Balance 6/30/2026	Jul-Oct Estimated Activity	Jul-Oct Interest	Estimated Balance 10/31/2026	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	4.61%		G = E + F2
Gas Cost Deferrals and Amortizations							
151510 OREGON WACOG AMORTIZATION	**(8,335,657)**	3,538,832	(110,868)	(4,907,693)			
151505 OREGON WACOG DEFERRAL	**7,026,880**	-	168,261	7,195,142			
Total	(1,308,777)	3,538,832	57,394	2,287,449	4.61%	57,521	2,344,970
151525 OREGON DEMAND AMORTIZATION	1,243,814	(506,187)	16,773	754,400			
151520 OREGON DEMAND DEFERRAL	1,754,677	-	42,016	1,796,693			
151535 COOS BAY DEMAND DEFERRAL	128,018	-	-	128,018			
151560 OREGON SEASONAL VOLUME DEMAND DEFERRAL	12,914,274	-	309,237	13,223,512			
Total	16,040,783	(506,187)	368,027	15,902,624	4.61%	399,893	16,302,517
232092 - Sales Offset -RTC	(1,582,704)	0	(37,898)	(1,620,603)	4.61%	(40,752)	(1,661,355)

Company: Northwest Natural Gas Company
State: Oregon
Description: Amortization of Oregon WACOG Deferral
Account Number: 151510
Docket: Dockets UM 1496, UG 524
Amortization of deferral approved in Order No. 24-086

1 Debit (Credit)

2

3						Interest		
4	Month/Year	Note	Amortization	Transfers	Interest	rate	Activity	Balance
5	(a)	(b)	(c)	(d)	(e1)	(e2)	(f)	(g)
6								
7	Beginning Balance							
253	Jul-25		941,789.84		(26,565.02)	5.40%	915,224.82	(5,459,007.55)
254	Aug-25		823,647.36		(22,712.33)	5.40%	800,935.03	(4,658,072.53)
255	Sep-25		852,901.37		(19,042.30)	5.40%	833,859.07	(3,824,213.46)
256	Oct-25		1,228,126.22		(14,445.68)	5.40%	1,213,680.54	(2,610,532.92)
257	Nov-25	OLD	1,175,020.52		(9,103.60)	5.40%	1,165,916.92	(1,444,616.00)
258	Nov-25	NEW	1,065,886.42	(26,596,476.68)	(112,073.19)	5.16%	(25,642,663.45)	(27,087,279.44)
259	Dec-25		3,206,328.49		(109,581.70)	5.16%	3,096,746.79	(23,990,532.65)
260	Jan-26		4,038,542.14		(94,476.42)	5.16%	3,944,065.72	(20,046,466.93)
261	Feb-26		3,877,119.38		(77,864.00)	5.16%	3,799,255.38	(16,247,211.55)
262	Mar-26		3,171,371.40		(63,044.56)	5.16%	3,108,326.84	(13,138,884.71)
263	Apr-26		2,292,644.41		(51,568.02)	5.16%	2,241,076.39	(10,897,808.32)
264	May-26		1,529,460.60		(43,572.24)	5.16%	1,485,888.36	(9,411,919.96)
265	Jun-26		1,114,338.51		(38,075.43)	5.16%	1,076,263.08	(8,335,656.87)
266	Jul-26	forecasted	992,425.72		(33,709.61)	5.16%	958,716.11	(7,376,940.76)
267	Aug-26	forecasted	969,771.54		(29,635.84)	5.16%	940,135.70	(6,436,805.06)
268	Sep-26	forecasted	1,059,010.77		(25,401.39)	5.16%	1,033,609.38	(5,403,195.68)
269	Oct-26	forecasted	517,623.61		(22,120.85)	5.16%	495,502.76	(4,907,692.92)
270								

271 **History truncated for ease of viewing**

Company:	Northwest Natural Gas Company
State:	Oregon
Description:	Core Market Commodity gas cost deferral
Account Number:	151505
Docket:	Docket UM 1496
	Last deferral reauthorization was approved in Order 25-523
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%.

1	Debit (Credit)										
2			Commodity	Storage	Hedge	RTC					
3	Month/Year	Note	Deferral	Adjustment	Adjustment	Retirement	Interest	Interest Rate	Transfer	Activity	Balance
4	(a)	(b)	(c)	(d)	(e)	(g)	(h1)	(h2)	(i)	(j)	(k)
5											
6	Beginning Bal										
234	Jul-25		(787,289.69)	(3,659.05)	(1,833.00)	725,921.74	(146,893.55)	7.056%		(213,754)	(25,162,220.37)
235	Aug-25		(230,263.45)	(3,596.94)	(2,576.40)	2,896,008.96	(140,134.71)	7.056%		2,519,437	(22,642,782.91)
236	Sep-25		(921,637.32)	(3,985.44)	(1,372.50)	3,928,105.55	(124,316.30)	7.056%		2,876,794	(19,765,988.92)
237	Oct-25		(6,198,977.65)	(8,903.68)	(22,140.90)	603,256.50	(132,766.71)	7.056%		(5,759,532)	(25,525,521.35)
238	Nov-25		3,333,900.06	(6,277.95)	17,053.90	(1,974,163.39)	4,154.43	7.120%	25,540,450.55	26,915,118	1,389,596.25
239	Dec-25		3,819,078.22	(7,918.64)	(102,057.50)	(108,344.29)	18,927.19	7.120%		3,619,685	5,009,281.23
240	Jan-26		882,153.73	(9,942.14)	(143,144.00)	(2,663,257.35)	23,983.64	7.120%		(1,910,206)	3,099,075.11
241	Feb-26		1,723,981.92	(7,877.72)	(100,268.30)	2,697,114.68	31,182.93	7.120%		4,344,134	7,443,208.62
242	Mar-26		4,663,575.76	(6,522.91)	52,274.30	(455,793.35)	56,781.85	7.120%		4,310,316	11,753,524.26
243	Apr-26		(4,335,468.02)	(4,454.90)	(8,167.40)	200,573.86	57,433.28	7.120%		(4,090,083)	7,663,441.08
244	May-26		(1,094,901.05)	(2,663.35)	7,244.60	327,711.91	43,207.35	7.120%		(719,401)	6,944,040.55
245	Jun-26		(678,961.73)	(2,259.08)	(2.20)	722,738.31	41,324.47	7.120%		82,840	7,026,880.32
246	Jul-26						41,692.82	7.120%		41,693	7,068,573.14
247	Aug-26						41,940.20	7.120%		41,940	7,110,513.34
248	Sep-26						42,189.05	7.120%		42,189	7,152,702.39
249	Oct-26						42,439.37	7.120%		42,439	7,195,141.76
250											
251	**History truncated for ease of viewing**										

Company:	Northwest Natural Gas Company
State:	Oregon
Description:	Amortization of Oregon Demand Deferral
Account Number:	151525
Docket:	Dockets UM 1496, UG 524
	Amortization of deferral approved in Order No. 25-426

1 Debit (Credit)

Line	Month/Year	Note	Amortization	Transfers	Interest Rate	Interest	Activity	Balance
5	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
7	Beginning Balance							
215	Jul-25		(141,215.37)		5.40%	4,414.87	(136,800.50)	914,889.46
216	Aug-25		(123,309.65)		5.40%	3,839.56	(119,470.09)	795,419.37
217	Sep-25		(127,777.80)		5.40%	3,291.89	(124,485.91)	670,933.46
218	Oct-25		(184,519.97)		5.40%	2,604.03	(181,915.94)	489,017.52
219	Nov-25	OLD	(177,908.17)		5.40%	1,800.29	(176,107.88)	312,909.64
220	Nov-25	NEW	(148,494.82)	3,899,018.96	5.16%	16,446.52	3,766,970.66	4,079,880.30
221	Dec-25		(488,652.68)		5.16%	16,492.88	(472,159.80)	3,607,720.51
222	Jan-26		(618,833.02)		5.16%	14,182.71	(604,650.31)	3,003,070.20
223	Feb-26		(594,480.45)		5.16%	11,635.07	(582,845.38)	2,420,224.82
224	Mar-26		(480,372.32)		5.16%	9,374.17	(470,998.15)	1,949,226.67
225	Apr-26		(341,463.88)		5.16%	7,647.53	(333,816.35)	1,615,410.32
226	May-26		(222,963.60)		5.16%	6,466.89	(216,496.71)	1,398,913.61
227	Jun-26		(160,769.33)		5.16%	5,669.67	(155,099.66)	1,243,813.95
228	Jul-26	forecasted	(140,982.41)		5.16%	5,045.29	(135,937.12)	1,107,876.83
229	Aug-26	forecasted	(137,668.88)		5.16%	4,467.88	(133,201.00)	974,675.83
230	Sep-26	forecasted	(151,101.92)		5.16%	3,866.24	(147,235.68)	827,440.15
231	Oct-26	forecasted	(76,433.48)		5.16%	3,393.66	(73,039.82)	754,400.33

233 **History truncated for ease of viewing**

Company:	Northwest Natural Gas Company
State:	Oregon
Description:	Core Market Demand cost deferral
Account Number:	151520
Docket:	Docket UM 1496
	Last deferral reauthorization was approved in Order 25-523
Narrative:	Deferral of 100% of the difference between actual demand cost incurred and the demand cost embedded in customer rates.

1 Debit (Credit)

	Month/Year	Note	Demand Deferral	Transfer	Interest	Interest Rate	Activity	Balance
4	(a)	(b)	(c)	(d)	(e1)	(e2)	(f)	(g)
5								
6	Beginning Bal							
234	Jul-25		91,611.33		(9,541.78)	7.056%	82,069.55	(1,586,488.15)
235	Aug-25		81,901.03		(9,087.76)	7.056%	72,813.27	(1,513,674.88)
236	Sep-25		6,842.03		(8,880.29)	7.056%	(2,038.26)	(1,515,713.14)
237	Oct-25		74,066.14		(8,694.64)	7.056%	65,371.50	(1,450,341.64)
238	Nov-25		(19,934.90)	1,708,149.68	1,470.52	7.120%	1,689,685.30	239,343.66
239	Dec-25		63,413.21		1,608.23	7.120%	65,021.44	304,365.11
240	Jan-26		76,898.98		2,034.03	7.120%	78,933.01	383,298.11
241	Feb-26		56,687.66		2,442.41	7.120%	59,130.07	442,428.19
242	Mar-26		82,031.80		2,868.43	7.120%	84,900.23	527,328.41
243	Apr-26		167,030.41		3,624.34	7.120%	170,654.75	697,983.16
244	May-26		675,651.54		6,145.80	7.120%	681,797.34	1,379,780.50
245	Jun-26		365,624.77		9,271.38	7.120%	374,896.15	1,754,676.64
246	Jul-26				10,411.08	7.120%	10,411.08	1,765,087.72
247	Aug-26				10,472.85	7.120%	10,472.85	1,775,560.57
248	Sep-26				10,534.99	7.120%	10,534.99	1,786,095.56
249	Oct-26				10,597.50	7.120%	10,597.50	1,796,693.06

251 **History truncated for ease of viewing**

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

1 Debit (Credit)

2

3

Line	Month/Year	Note	Deferral	Adjustment	Transfer	Activity	Balance
5	(a)	(b)	(c)	(d)	(e)	(f)	(g)
6	Beginning Bal						
234	Jul-25		23,574.00	(10,295.33)		13,278.67	67,516.72
235	Aug-25		23,574.00	(8,748.34)		14,825.66	82,342.38
236	Sep-25		23,574.00	(8,216.79)		15,357.21	97,699.59
237	Oct-25		23,574.00	(8,938.34)		14,635.66	112,335.25
238	Nov-25		23,574.00	(10,956.43)	(54,238.05)	(41,620.48)	70,714.77
239	Dec-25		23,574.00	(14,503.15)		9,070.85	79,785.62
240	Jan-26		22,544.00	(13,653.35)		8,890.65	88,676.27
241	Feb-26		22,544.00	(18,777.87)		3,766.13	92,442.40
242	Mar-26		22,544.00	(14,231.49)		8,312.51	100,754.91
243	Apr-26		22,544.00	(16,774.11)		5,769.89	106,524.80
244	May-26		22,544.00	(12,956.22)		9,587.78	116,112.58
245	Jun-26		22,544.00	(10,638.34)		11,905.66	128,018.24
246	Jul-26					0.00	128,018.24
247	Aug-26					0.00	128,018.24
248	Sep-26					0.00	128,018.24
249	Oct-26					0.00	128,018.24
250							

251 **History truncated for ease of viewing**

Company:	Northwest Natural Gas Company
State:	Oregon
Description:	Seasonalized Demand Collection Deferral
Account Number:	151560
Docket:	Docket UM 1496
	Last deferral reauthorization was approved in Order 25-523
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)
234	Jul-25		361,204.57	32,956.37	7.056%		394,160.94	5,818,384.16
235	Aug-25		70,441.66	34,419.20	7.056%		104,860.86	5,923,245.02
236	Sep-25		155,210.76	35,285.00	7.056%		190,495.76	6,113,740.78
237	Oct-25		(244,888.78)	35,228.82	7.056%		(209,659.96)	5,904,080.82
238	Nov-25		1,546,302.33	6,670.85	7.120%	(5,552,930.59)	(3,999,957.41)	1,904,123.41
239	Dec-25		2,861,315.65	19,786.37	7.120%		2,881,102.02	4,785,225.43
240	Jan-26		697,538.20	30,461.70	7.120%		727,999.90	5,513,225.33
241	Feb-26		1,419,260.20	36,922.28	7.120%		1,456,182.48	6,969,407.81
242	Mar-26		1,960,493.91	47,167.95	7.120%		2,007,661.86	8,977,069.68
243	Apr-26		1,716,809.18	58,357.15	7.120%		1,775,166.33	10,752,236.01
244	May-26		1,470,766.17	68,159.87	7.120%		1,538,926.04	12,291,162.05
245	Jun-26		548,557.48	74,554.95	7.120%		623,112.43	12,914,274.48
246	Jul-26			76,624.70	7.120%		76,624.70	12,990,899.18
247	Aug-26			77,079.34	7.120%		77,079.34	13,067,978.52
248	Sep-26			77,536.67	7.120%		77,536.67	13,145,515.19
249	Oct-26			77,996.72	7.120%		77,996.72	13,223,511.91
250								

251 **History truncated for ease of viewing**

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

	Month/Year	Rates	Deferral	Transfers	Interest Rate	Interest	Activity	Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Beginning Balance							
1	Nov-23				6.836%	-	0.00	0.00
2	Dec-23		(3,769.57)		6.836%	(10.74)	(3,780.31)	(3,780.31)
3	Jan-24		(166,949.39)		6.836%	(497.06)	(167,446.45)	(171,226.76)
4	Feb-24		(166,563.27)		6.836%	(1,449.85)	(168,013.12)	(339,239.88)
5	Mar-24		36,970.03		6.836%	(1,827.23)	35,142.80	(304,097.07)
6	Apr-24		(145,336.46)		6.836%	(2,146.31)	(147,482.77)	(451,579.84)
7	May-24		(40,386.59)		6.836%	(2,687.53)	(43,074.12)	(494,653.96)
8	Jun-24		(86,326.07)		6.836%	(3,063.76)	(89,389.83)	(584,043.79)
9	Jul-24		(192,023.34)		6.836%	(3,874.05)	(195,897.39)	(779,941.18)
10	Aug-24		(186,380.13)		6.836%	(4,973.94)	(191,354.07)	(971,295.24)
11	Sep-24		14,335.22		6.836%	(5,492.31)	8,842.91	(962,452.33)
12	Oct-24		(68,414.71)		6.836%	(5,677.64)	(74,092.35)	(1,036,544.68)
13	Nov-24			1,036,545	7.056%	-	1,036,544.68	0.00
14	Dec-24				7.056%	-	0.00	0.00
15	Jan-25		(104,978.87)		7.056%	(308.64)	(105,287.51)	(105,287.51)
16	Feb-25		(24,046.63)		7.056%	(689.79)	(24,736.42)	(130,023.94)
17	Mar-25		(488,469.23)		7.056%	(2,200.64)	(490,669.87)	(620,693.81)
18	Apr-25		(118,131.77)		7.056%	(3,996.99)	(122,128.76)	(742,822.57)
19	May-25		(134,811.21)		7.056%	(4,764.14)	(139,575.35)	(882,397.92)
20	Jun-25		(123,777.61)		7.056%	(5,552.41)	(129,330.02)	(1,011,727.95)
21	Jul-25		(175,749.00)		7.056%	(6,465.66)	(182,214.66)	(1,193,942.60)
22	Aug-25		(496,427.77)		7.056%	(8,479.88)	(504,907.65)	(1,698,850.25)
23	Sep-25		(650,498.16)		7.056%	(11,901.70)	(662,399.86)	(2,361,250.11)
24	Oct-25		(189,878.83)		7.056%	(14,442.39)	(204,321.22)	(2,565,571.33)
25	Nov-25		0.00	1,056,026	7.120%	(8,956.63)	1,047,069.50	(1,518,501.83)
26	Dec-25		0.00		7.120%	(9,009.78)	(9,009.78)	(1,527,511.61)
27	Jan-26		0.00		7.120%	(9,063.24)	(9,063.24)	(1,536,574.85)
28	Feb-26		0.00		7.120%	(9,117.01)	(9,117.01)	(1,545,691.86)
29	Mar-26		0.00		7.120%	(9,171.11)	(9,171.11)	(1,554,862.97)
30	Apr-26		0.00		7.120%	(9,225.52)	(9,225.52)	(1,564,088.49)
31	May-26		0.00		7.120%	(9,280.26)	(9,280.26)	(1,573,368.75)
32	Jun-26		0.00		7.120%	(9,335.32)	(9,335.32)	(1,582,704.07)
33	Jul-26		0.00		7.120%	(9,390.71)	(9,390.71)	(1,592,094.78)
34	Aug-26		0.00		7.120%	(9,446.43)	(9,446.43)	(1,601,541.21)
35	Sep-26		0.00		7.120%	(9,502.48)	(9,502.48)	(1,611,043.69)
36	Oct-26		0.00		7.120%	(9,558.86)	(9,558.86)	(1,620,602.55)

EXHIBIT B

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

Purchased Gas Cost

NWN OPUC Advice No. 26-05A / UG 531

September 14, 2026

NW NATURAL

EXHIBIT B

Supporting Materials

Purchased Gas Cost

NWN OPUC ADVICE NO. 26-05A / UG 531

NW Natural
2026-2027 PGA - SYSTEM: September 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**		$ 24,222,598	$32,001,440	$31,200,935	$25,376,759	$22,769,862	$13,354,683	$8,979,602	$7,262,529	$6,587,837	$6,595,220	$7,075,720	$11,903,279	$ 197,330,463
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**		$98,716	$108,568	$105,631	$85,645	$87,412	$72,073	$47,743	$34,567	$27,025	$26,878	$30,156	$57,831	$782,245
9	tab Commodity Cost from Vol Pipe, column F, line 78-89														
10	**Commodity Cost from Storage**		$269,603	$4,232,451	$5,384,315	$5,178,944	$3,010,018	$311,502	$0	$0	$0	$0	$0	$142,764	$18,529,597
11	tab Commodity Cost from Storage, column J, line 61-72														
12	**Commodity Cost from - Brown Gas**		$92,135	$95,206	$95,206	$85,992	$95,206	$92,135	$95,206	$92,135	$95,206	$95,206	$92,135	$95,206	$1,120,974
13	tab Commodity Cost from RNG, column M, line 61-72														
14	**Commodity Cost from RNG Supply/Offtakes**		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	tab Commodity Cost from RNG, column N, line 61-72														
16	**Commodity Cost from RNG RTCs**		$ 3,006,081	$ 2,942,244	$ 3,625,073	$ 3,625,073	$ 3,625,073	$ 3,625,083	$ 3,625,073	$ 3,625,073	$ 3,625,083	$ 3,625,073	$ 3,956,798	$ 3,956,808	$42,862,536
17	tab RNG RTC Costs, column L, line 1-12														
18	**Commodity Cost from Gas Reserves**		$708,674	$727,812	$729,122	$689,934	$700,872	$713,283	$727,580	$681,856	$694,471	$715,095	$700,144	$681,291	$8,470,136
19	tab Commodity Cost from Gas Reserve, column AF, line 59-70														
20	**Total Commodity Cost**		$ 28,397,807	$40,107,721	$41,140,282	$35,042,347	$30,288,443	$18,168,759	$13,475,204	$11,696,160	$11,029,622	$11,057,472	$11,854,953	$16,837,179	$ 269,095,951
21															
22	**VOLUMES**														
23	Commodity Volumes at Receipt Points		84,383,593	93,759,681	88,306,552	73,501,371	72,336,193	62,525,194	41,303,015	29,980,140	23,856,656	23,717,342	26,344,050	49,213,863	669,227,652
24	Pipeline Fuel Use		1,184,581	1,141,301	1,071,066	873,503	874,135	722,738	519,426	342,666	229,531	227,736	283,943	613,680	8,084,305
25	Gas Arriving at City Gate		83,199,012	92,618,380	87,235,486	72,627,868	71,462,058	61,802,456	40,783,590	29,637,474	23,627,126	23,489,606	26,060,107	48,600,183	661,143,347
26															
27	Brown Gas and Storage Gas Withdrawals		1,673,175.74	21,882,617	28,139,228	26,725,300	16,028,126	1,921,573	234,254	226,698	234,254	234,254	226,698	1,027,007	98,553,186
28	RNG Supply/Offtakes		2,229.45	2,304	2,304	2,081	2,304	2,229	2,304	2,229	2,304	2,304	2,229	2,304	27,125
29	Pipeline Fuel Use for Off-Site Storage		1,226	-	3,113	-	3,795	944	-	-	-	-	-	542	9,621
30	Storage Gas Deliveries at City Gate		1,674,179	21,884,921	28,138,419	26,727,381	16,026,635	1,922,859	236,558	228,927	236,558	236,558	228,927	1,028,769	98,570,691
31															
32	Total Gas At City Gate (Storage and Commodity)		84,873,191	114,503,300	115,373,905	99,355,249	87,488,694	63,725,315	41,020,148	29,866,402	23,863,684	23,726,164	26,289,034	49,628,952	759,714,038
33															
34	Unaccounted for Gas		771,518	858,865	808,949	673,491	662,680	573,104	378,193	274,833	219,098	217,823	241,660	450,678	6,130,892
35															
36	Load Served		84,101,673	113,644,435	114,564,956	98,681,758	86,826,014	63,152,211	40,641,955	29,591,569	23,644,586	23,508,341	26,047,374	49,178,274	753,583,146

WACOG Calculations

37	**Gas Reserves Supply:**													
38	Total cost (line 20 above)	$708,674	$727,812	$729,122	$689,934	$700,872	$713,283	$727,580	$681,856	$694,471	$715,095	$700,144	$681,291	$8,470,136
39	Load served by gas reserves	1,240,581	1,273,793	1,265,774	1,136,141	1,250,079	1,202,318	1,234,815	1,187,743	1,219,950	1,212,657	1,166,568	1,198,336	14,588,756
40														
41	**Total Load Served**													
42	Oregon	84,101,672	113,644,434	114,564,957	98,681,759	86,826,015	63,152,210	40,641,954	29,591,568	23,644,585	23,508,342	26,047,375	49,178,274	753,583,147
43	Total (same as line 36 +/- rounding)	84,101,672	113,644,434	114,564,957	98,681,759	86,826,015	63,152,210	40,641,954	29,591,568	23,644,585	23,508,342	26,047,375	49,178,274	753,583,147
44														
45	**Oregon WACOG Calculation**					86,826,014.86								
46														
47	Total Oregon commodity cost	$28,397,945	$40,107,859	$41,140,420	$35,042,486	$30,288,581	$18,168,897	$13,475,343	$11,696,298	$11,029,760	$11,057,610	$11,855,091	$16,837,318	$269,097,609
48	Total commodity cost for Oregon	$28,397,945	$40,107,859	$41,140,420	$35,042,486	$30,288,581	$18,168,897	$13,475,343	$11,696,298	$11,029,760	$11,057,610	$11,855,091	$16,837,318	$269,097,609
49														
50	**Oregon Sales WACOG (line 48 ÷ line 42)**	$0.33766	$0.35292	$0.35910	$0.35511	$0.34884	$0.28770	$0.33156	$0.39526	$0.46648	$0.47037	$0.45514	$0.34237	$0.35709
51														
52	**OREGON BILLING WACOG**	$0.34777	$0.36348	$0.36985	$0.36574	$0.35928	$0.29631	$0.34149	$0.40709	$0.48044	$0.48445	$0.46876	$0.35262	$0.36778

NW Natural
2026-2027 PGA - SYSTEM: August Filing
Summary of Total Demand Charges

SYSTEM 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			30	31	31	28	31	30	31	30	31	31	30	31	365
4	**Transport charges by transporter:**														
5															
6	Northwest Pipeline		$4,397,957	$4,544,554	$4,544,554	$4,104,758	$4,544,554	$4,299,021	$4,442,320	$4,299,021	$4,442,320	$4,442,320	$4,299,021	$4,442,320	$52,802,718
7															
8	Alberta: NOVA		803,120	803,120	803,120	803,120	803,120	803,120	803,120	803,120	803,120	803,120	803,120	803,120	9,637,440
9															
10	Alberta: Foothills		577,616	577,616	577,616	577,616	577,616	515,570	515,570	515,570	515,570	515,570	515,570	577,616	6,559,116
11															
12	Alberta: GTN		359,658	371,647	371,647	335,681	371,647	302,674	312,763	302,674	312,763	312,763	302,674	371,647	4,028,238
13															
14	BC: Southern Crossing														0
15															
16	BC: Spectra (Westcoast)		4,107,420	1,635,626	1,635,626	1,551,009	1,635,626	1,607,420	1,635,626	1,607,420	1,635,626	1,635,626	1,607,420	1,635,626	21,930,068
17															
18	KB Pipeline														0
19															
20	Shell Capacity Release Premium		(638,944)	(638,944)	(638,944)	(638,944)	(638,944)	(638,944)	(638,944)	(638,944)	(638,944)	(638,944)	(638,944)	(638,944)	(7,667,328)
21															
22	**Total System Demand**		**$9,606,827**	**$7,293,618**	**$7,293,618**	**$6,733,240**	**$7,293,618**	**$6,888,861**	**$7,070,455**	**$6,888,861**	**$7,070,455**	**$7,070,455**	**$6,888,861**	**$7,191,385**	**$87,290,252**

NW Natural

2026-2027 PGA - SYSTEM: September 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		$87,290,252	
5	Oregon Allocation Factor 1/		88.29%	
6	Oregon Demand		$78,422,463	
7				
8	Oregon Firm Sales Forecasted Normal Volumes		696,675,755	
9	Oregon Interruptible Sales Forecasted Normal Volumes		56,907,391	
10				
11				
12	Proposed Firm Demand Per Therm 2/		$0.11148	$0.11482
13	Proposed Interruptible Demand 2/		$0.01326	$0.01366
14	Proposed MDDV Demand Charge		$1.64	$1.69
15				
16	Current Firm Demand Per Therm		$0.09724	$0.10027
17	Current Interruptible Demand		$0.01157	$0.01193
18	Current MDDV Demand Charge		$1.43	$1.47
19				
20	Percent Change in Firm Demand		14.64%	
21				
22				
23	1/Allocation Factor: 2026-27 PGA forecast firm sales volumes:			
24		Washington	Oregon	System
25	Firm Sales	92,426,585	696,675,755	789,102,341
26		11.71%	88.29%	100.00%
27				
28	2/Calculation of Proposed Demand Rates:			
29				
30	Demand change factor		1.146	
31				
32	Firm Demand (line 16 * line 30)		$0.11148	$77,667,603
33	Interruptible Demand (line 17 * line 30)		$0.01326	$754,860
34				$78,422,463
35				$0.00

NW Natural

2026-2027 PGA - SYSTEM: September Filing

Calculation of Winter WACOG

Prices are per therm

1	Forecast price for AECO gas:			
2				
3		AECO/NIT		
4				
5	November	$0.15345		
6	December	$0.18359		
7	January	$0.19348		
8	February	$0.19509		
9	March	$0.16677		
10	April	$0.15165		
11	May	$0.14383		
12	June	$0.14498		
13	July	$0.14524		
14	August	$0.14748		
15	September	$0.14877		
16	October	$0.16416		
17				
18				
19	Average price, November-March		$0.17848	average lines 5-9
20				
21	Annual average price, November-October		$0.16154	average lines 5-16
22				
23	Ratio of winter to annual		1.10487	line 19 ÷ line 21
24				
25			Without Rev	WITH Rev
26			Sensitive	Sensitive
OR	Oregon Annual WACOG		$0.35709	$0.36778
OR	Oregon Winter WACOG		$0.39454	$0.40635
			line 23 * $0.35709	

NW Natural
2026-2027 PGA - OREGON: September Filing
Derivation of Oregon Seasonalized Fixed Charges

OREGON:

Line			Normalized Residential Volumes	Normalized Commercial Volumes	Firm Industrial Volumes	Interruptible Volumes	Total	Firm Demand Increment Eff. 11/01/26	Interr. Demand Increment Eff. 11/01/26	Seasonalized Fixed Charges
4	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
5										
6	November	2026	49,209,118	26,693,604	3,179,894	5,019,057	84,101,672	$0.11148	$0.01326	$8,882,961
7	December	2026	67,680,739	36,915,206	3,668,793	5,379,695	113,644,434	$0.11148	$0.01326	$12,141,068
8	January	2027	67,689,139	37,043,013	3,984,696	5,848,108	114,564,957	$0.11148	$0.01326	$12,197,682
9	February	2027	56,488,207	32,763,437	4,043,677	5,386,439	98,681,759	$0.11148	$0.01326	$10,472,315
10	March	2027	48,342,924	29,620,601	3,453,702	5,408,789	86,826,015	$0.11148	$0.01326	$9,148,400
11	April	2027	33,590,363	21,539,402	3,076,454	4,945,991	63,152,210	$0.11148	$0.01326	$6,554,619
12	May	2027	19,612,747	13,772,130	2,736,845	4,520,233	40,641,954	$0.11148	$0.01326	$4,086,916
13	June	2027	12,827,917	10,123,920	2,567,963	4,071,768	29,591,568	$0.11148	$0.01326	$2,899,030
14	July	2027	9,481,309	7,930,806	2,467,723	3,764,747	23,644,585	$0.11148	$0.01326	$2,266,196
15	August	2027	9,487,934	7,868,421	2,376,695	3,775,292	23,508,342	$0.11148	$0.01326	$2,249,971
16	September	2027	10,863,870	8,496,110	2,776,851	3,910,544	26,047,375	$0.11148	$0.01326	$2,519,747
17	October	2027	25,783,314	15,406,475	3,111,757	4,876,729	49,178,274	$0.11148	$0.01326	$5,003,558
21			411,057,580	248,173,125	37,445,051	56,907,391	753,583,147			$78,422,463

	Encana Gas Reserves Deal		Projected November 2026	Projected December 2026	Projected January 2027	Projected February 2027	Projected March 2027	Projected April 2027	Projected May 2027	Projected June 2027	Projected July 2027	Projected August 2027	Projected September 2027	Projected October 2027	Projected PGA Totals
1	**Therms Delivered (000s)**														
2	**Total Therms**		1,195.35	1,227.35	1,219.64	1,094.74	1,204.53	1,158.52	1,189.84	1,144.49	1,175.53	1,168.51	1,124.10	1,154.72	14,057.30
3	**Rate per Therm (Depletion Rate)**		0.17270	0.17270	0.17270	0.17270	0.17270	0.17270	0.17270	0.17270	0.17270	0.17270	0.17270	0.17270	0.17270
4	**Delivery Value**		206.43	211.96	210.63	189.06	208.02	200.07	205.48	197.65	203.01	201.80	194.13	199.42	2,427.63
5															0.1727
6	**Opex / Severance / Ad Valorem**														
7	**Operating Cost**		383.33	384.26	383.89	377.64	381.65	409.16	419.62	382.03	382.91	405.65	401.44	378.52	4,690.10
8	**Severance and Ad Valorem Taxes**		43.60	64.32	70.87	57.36	38.10	29.60	28.15	30.23	41.13	41.50	39.23	38.31	522.41
9	**Total**		426.92	448.58	454.76	435.00	419.75	438.75	447.77	412.26	424.04	447.15	440.67	416.83	5,212.51
10															0.3708
11	**Average Rate Base**		10,560.11	10,404.14	10,249.16	10,110.06	9,957.00	9,809.78	9,658.59	9,513.16	9,363.78	9,215.30	9,072.46	8,925.73	
12															
13	**Carrying Cost**														
14	**Equity**	**9.4000%**	41.36	40.75	40.14	39.60	39.00	38.42	37.83	37.26	36.67	36.09	35.53	34.96	
15	**Equity % of Cap Struct**	**50.0000%**													
16	**Equity Pretax**	**26.4193%**	40.72	32.53	29.38	33.44	39.46	41.70	41.41	39.90	35.23	34.31	34.35	33.90	
17	**Debt**	**4.2710%**	18.79	18.52	18.24	17.99	17.72	17.46	17.19	16.93	16.66	16.40	16.15	15.88	
18	**Total Carrying Cost**		59.51	51.04	47.62	51.43	57.18	59.16	58.60	56.83	51.89	50.71	50.50	49.78	644.26
19															0.0458
20	**Total Cost**		692.87	711.59	713.00	675.49	684.95	697.98	711.85	666.74	678.94	699.66	685.30	666.03	8,284.40
21	**Total Volume**		1,195.35	1,227.35	1,219.64	1,094.74	1,204.53	1,158.52	1,189.84	1,144.49	1,175.53	1,168.51	1,124.10	1,154.72	14,057.30
22	**Total Rate Per Therm**		0.580	0.580	0.585	0.617	0.569	0.602	0.598	0.583	0.578	0.599	0.610	0.577	0.589

Non-Carry Wells Gas Reserves Deal		Projected November 2026	Projected December 2026	Projected January 2027	Projected February 2027	Projected March 2027	Projected April 2027	Projected May 2027	Projected June 2027	Projected July 2027	Projected August 2027	Projected September 2027	Projected October 2027	Projected PGA Totals
Therms Delivered (000s)														
Total Therms		46.53	47.76	47.46	42.59	46.85	45.05	46.26	44.49	45.69	45.41	43.68	44.86	546.64
Rate per Therm (Depletion Rate)		0.5449	0.5449	0.5449	0.5449	0.5449	0.5449	0.5449	0.5449	0.5449	0.5449	0.5449	0.5449	0.5449
Delivery Value		25.35	26.03	25.86	23.21	25.53	24.55	25.21	24.24	24.90	24.74	23.80	24.45	297.87
														0.5449
Opex / Severance / Ad Valorem														
Operating Cost		14.03	14.08	14.08	13.85	13.95	14.55	14.90	13.93	13.97	14.53	14.46	13.87	170.21
Severance and Ad Valorem Taxes		1.70	2.50	2.76	2.23	1.48	1.15	1.09	1.18	1.60	1.61	1.52	1.49	20.32
Total		15.72	16.58	16.84	16.08	15.43	15.70	15.99	15.11	15.57	16.15	15.98	15.36	190.52
														0.3485
Average Rate Base		988.82	969.67	950.64	933.56	914.78	896.71	878.17	860.33	842.01	823.80	806.29	788.30	
Carrying Cost														
Equity	**9.4000%**	3.87	3.80	3.72	3.66	3.58	3.51	3.44	3.37	3.30	3.23	3.16	3.09	
Equity % of Cap Struct	**50.0000%**													
Equity Pretax	**26.4193%**	5.26	5.16	5.06	4.97	4.87	4.77	4.67	4.58	4.48	4.39	4.29	4.20	
Debt	**4.5290%**	1.87	1.83	1.79	1.76	1.73	1.69	1.66	1.62	1.59	1.55	1.52	1.49	
Total Carrying Cost		7.13	6.99	6.85	6.73	6.60	6.47	6.33	6.20	6.07	5.94	5.81	5.68	76.81
														0.1405
Total Cost		48.20	49.60	49.55	46.01	47.56	46.72	47.53	45.55	46.54	46.83	45.60	45.49	565.20
Total Volume		46.53	47.76	47.46	42.59	46.85	45.05	46.26	44.49	45.69	45.41	43.68	44.86	546.64
Total Rate Per Therm		1.036	1.038	1.044	1.080	1.015	1.037	1.027	1.024	1.019	1.031	1.044	1.014	1.034

NW Natural
Rates & Regulatory Affairs
2026-27 PGA - Oregon: September Filing
Attachment C: 3% Test

Non-Gas Cost Amortizations [1]		**Surcharge**		**Credit**
WARM	$	18,268,087		
Meter Mod (Schedule 151)		$4,395,795		
Demand Response (Schedule 121)		$2,492,874		
Oregon Regulatory Fee			$	(989,585)
CAT Incremental			$	(51,985)
Net Curtailment and Entitlment			$	(9,185)
RNG Transport Allocation	$	2,227,937		
Residential AMP (Schedule 120)	$	958,559		
TSA Cost of Service	$	410,210		
Residual Balances				(4,313)
Bill Discount Program (Schedule 336)		227,446	$	-
Transportation EE	$	353,533		
Total	$	29,334,441	$	(1,055,068)
Net Proposed Amortizations (subject to the 3% test)			$	28,279,373
Utility Gross Revenues (2025) [2]				$963,177,046
3% of Utility Gross Revenues			$	28,895,311
Allowed Amortization			$	28,279,373
Allowed Amortization as % of Gross Revenues				2.9%

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
2026-27 PGA - Oregon: September Filing
Effects on Average Bill by Rate Schedule [1]
ALL VOLUMES IN THERMS

								11/1/2025	11/1/2025			Advice See note [15]
1			Oregon PGA		Normal				Proposed	Proposed	Proposed
2			Normalized		Therms	Minimum		Normal	10/31/2026	10/31/2026	10/31/2026
3			Volumes page,	Therms in	Monthly	Monthly	Billing	Current	Schedule 164 PGA	Schedule 164 PGA	Schedule 164 PGA
4			Column D	Block	Average use	Charge	Rates	Average Bill	Rates	Average Bill	% Bill Change
5								F=D+(C * E)		AO = D+(C*AN)	AP = (AO-F)/F
6	Schedule	Block	A	B	C	D	E	F	AN	AO	AP
7	2SF		364,525,125	N/A	53	$10.00	$1.41220	$84.85	$1.41862	$85.19	0.4%
	2MF		46,532,455	N/A	53	$8.00	$1.41220	$82.85	$1.41862	$83.19	0.4%
8	3C Firm Sales		176,503,361	N/A	250	$15.00	$1.23970	$324.93	$1.24612	$326.53	0.5%
9	3I Firm Sales		4,727,872	N/A	1,190	$15.00	$1.08572	$1,307.01	$1.09214	$1,314.65	0.6%
10	27 Dry Out		584,677	N/A	35	$8.00	$1.25251	$51.84	$1.25893	$52.06	0.4%
11	31C Firm Sales	Block 1	13,656,203	2,000	2,720	$325.00	$0.78159	**$2,428.24**	$0.77346	**$2,406.12**	-0.9%
12		Block 2	9,421,084	all additional			$0.75008		$0.74195		
13	31C Firm Trans	Block 1	1,155,877	2,000	3,421	$575.00	$0.41819	**$1,962.63**	$0.41819	**$1,962.63**	0.0%
14		Block 2	1,101,903	all additional			$0.38793		$0.38793		
15	31I Firm Sales	Block 1	3,368,480	2,000	5,281	$325.00	$0.75710	**$4,235.25**	$0.74897	**$4,192.31**	-1.0%
16		Block 2	6,770,266	all additional			$0.73028		$0.72215		
17	31I Firm Trans	Block 1	129,581	2,000	6,893	$575.00	$0.42698	**$3,347.90**	$0.42698	**$3,347.90**	0.0%
18		Block 2	284,018	all additional			$0.39218		$0.39218		
19	32C Firm Sales	Block 1	35,905,676	10,000	7,694	$675.00	$0.67950	**$5,903.07**	$0.67137	**$5,840.52**	-1.1%
20		Block 2	9,554,234	20,000			$0.64912		$0.64099		
21		Block 3	1,745,309	20,000			$0.59863		$0.59050		
22		Block 4	802,581	100,000			$0.54796		$0.53983		
23		Block 5	0	600,000			$0.51155		$0.50342		
24		Block 6	0	all additional			$0.49429		$0.48616		
25	32I Firm Sales	Block 1	9,268,308	10,000	18,815	$675.00	$0.62799	**$12,294.23**	$0.61986	**$12,141.27**	-1.2%
26		Block 2	8,227,501	20,000			$0.60571		$0.59758		
27		Block 3	2,696,668	20,000			$0.56843		$0.56030		
28		Block 4	2,255,924	100,000			$0.53127		$0.52314		
29		Block 5	130,032	600,000			$0.50532		$0.49719		
30		Block 6	0	all additional			$0.49228		$0.48415		
31	32C Firm Trans	Block 1	3,057,342	10,000	18,166	$925.00	$0.22444	**$4,807.01**	$0.22444	**$4,807.01**	0.0%
32		Block 2	2,128,039	20,000			$0.20054		$0.20054		
33		Block 3	644,113	20,000			$0.16081		$0.16081		
34		Block 4	866,120	100,000			$0.12106		$0.12106		
35		Block 5	62,190	600,000			$0.09716		$0.09716		
36		Block 6	0	all additional			$0.08133		$0.08133		
37	32I Firm Trans	Block 1	11,016,531	10,000	72,132	$925.00	$0.21299	**$12,552.91**	$0.21299	**$12,552.91**	0.0%
38		Block 2	15,602,797	20,000			$0.19090		$0.19090		
39		Block 3	9,458,456	20,000			$0.15413		$0.15413		
40		Block 4	22,451,387	100,000			$0.11736		$0.11736		
41		Block 5	21,475,941	600,000			$0.09523		$0.09523		
42		Block 6	7,418,474	all additional			$0.08060		$0.08060		
43	32C Interr Sales	Block 1	4,132,294	10,000	48,951	$675.00	$0.63625	**$30,088.95**	$0.61276	**$28,939.09**	-3.8%
44		Block 2	6,058,058	20,000			$0.61173		$0.58824		
45		Block 3	3,271,549	20,000			$0.57078		$0.54729		
46		Block 4	4,837,562	100,000			$0.52983		$0.50634		
47		Block 5	3,434,773	600,000			$0.50524		$0.48175		
48		Block 6	0	all additional			$0.48727		$0.46378		
49	32I Interr Sales	Block 1	5,733,047	10,000	59,818	$675.00	$0.61610	**$35,054.32**	$0.59261	**$33,649.19**	-4.0%
50		Block 2	7,298,404	20,000			$0.59475		$0.57126		
51		Block 3	4,456,416	20,000			$0.55916		$0.53567		
52		Block 4	12,581,349	100,000			$0.52354		$0.50005		
53		Block 5	5,103,939	600,000			$0.50215		$0.47866		
54		Block 6	0	all additional			$0.48653		$0.46304		
55	32C Interr Trans	Block 1	667,319	10,000	180,185	$925.00	$0.20565	**$23,940.40**	$0.20565	**$23,940.40**	0.0%
56		Block 2	1,394,375	20,000			$0.18462		$0.18462		
57		Block 3	939,924	20,000			$0.14961		$0.14961		
58		Block 4	3,098,587	100,000			$0.11452		$0.11452		
59		Block 5	386,468	600,000			$0.09350		$0.09350		
60		Block 6	0	all additional			$0.07952		$0.07952		
61	32I Interr Trans	Block 1	5,864,800	10,000	199,892	$925.00	$0.20496	**$25,770.28**	$0.20496	**$25,770.28**	0.0%
62		Block 2	9,761,912	20,000			$0.18409		$0.18409		
63		Block 3	5,807,692	20,000			$0.14935		$0.14935		
64		Block 4	12,637,820	100,000			$0.11453		$0.11453		
65		Block 5	28,598,086	600,000			$0.09368		$0.09368		
66		Block 6	95,643,968	all additional			$0.07979		$0.07979		
67	33		0	N/A	0.0	$38,000.00	$0.06550	$38,000.00	$0.06550	$38,000.00	
68	Special Contracts		75,345,634	N/A	0	$0	$0.00000	$0.00	$0.00000	$0.00	
69											
70	**Totals**		**1,090,582,502**								

NW Natural
Rates and Regulatory Affairs
2026-2027 PGA Filing - OREGON
Basis for Revenue Related Costs

Line		Twelve Months		
1		Ended 06/30/26		
2				
3	Total Billed Gas Sales Revenues	$ 914,402,342		
4	Total Oregon Revenues	$ 918,820,399		
5				
6	Regulatory Commission Fees [1]	n/a	0.360%	Statutory rate
7	City License and Franchise Fees	$ 21,576,831	2.348%	Line 7 ÷ Line 4
8	Net Uncollectible Expense [2]	$ 1,824,506	0.199%	Line 8 ÷ Line 4
9				
10	Total		**2.907%**	Sum lines 8-9
11				
12				

13 **Note:**
14 [1] Dollar figure is set at statutory level of Total Oregon Revenues (line 4).
15 [2] Represents the normalized net write-offs based on a three-year average.

NW Natural
Rates & Regulatory Affairs
2026-2027 PGA Filing - Oregon: September Filing
PGA Effects on Revenue
Schedule 164: PGA Gas Costs and Gas Cost Deferrals

		Including Revenue Sensitive Amount
1		
2		
3	**Purchased Gas Cost Adjustment (PGA)**	
4		
5	Commodity Cost Change	($49,913,709)
6		
7	Demand Capacity Cost Change	8,307,567
8		
9	**Total Gas Cost Change**	**(41,606,142)**
10		
11	**Temporary Increments**	
12		
13	Removal of Current Temporary Increments	
14	Amortization of 191.xxx Account Gas Costs	26,660,911
15		
16	Addition of Proposed Temporary Increments	
17	Amortization of 191.xxx Account Gas Costs	17,494,626
18		
19	**Net Temporary Rate Adjustment**	**44,155,537**
20		
21	**TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES**	**$2,549,395**
22		
23	2025 Oregon Earnings Test Normalized Total Revenues	$1,005,966,120
24		
25	Effect of this filing, as a percentage change (line 21 ÷ line 23)	0.25%
26		
27	Effect of this filing, as a percentage change (line 19 ÷ line 23)	4.39%
28		
29	Effect of this filing, as a percentage change (line 9 ÷ line 23)	-4.14%

EXHIBIT C

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

Purchased Gas Cost

REDACTED

NWN OPUC Advice No. 26-05A / UG 531

September 14, 2026

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	15-18	
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.	18	
8	Forecasted annual and peak demand used in the current PGA portfolio, with and without effects from gas supply incentive mechanisms, with explanation.	18	
9	Summary of portfolio documentation provided	18	
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.	19	
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.	19	

GUIDELINE REFERENCE	DATA REQUIREMENT	Page No.	STATUS
3	Brief explanation of each contract's role within the portfolio.	19	
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:	22	
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.	22	
2	Any contract provisions that materially deviate from the standard NAESB contract.	22	
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.	24	**HIGHLY CONFIDENTIAL**
V.3	**Load Forecasting**		
a)	Customer count and revenue by month and class.	26	
b)	Historical (five years) and forecasted (one year ahead) sales system physical peak demand.	27	
c)	Historical (five years), and forecasted (one year ahead) sales system physical annual demand.	27	
d)	Historical (five years), and forecasted (one year ahead) sales system physical demand for each of following,	27	
1	Annual for each customer class	27	
2	Annual and monthly baseload.	27	
3	Annual and monthly non-baseload.	27	
4	Annual and monthly for the geographic regions utilized by each LDC in its most recent IRP or IRP update.	28	
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.	29	
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.	34	

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.	35	
	NW Natural Gas Supply Risk Management Policies	36	CONFIDENTIAL
V.7	**Storage**		
	Workpapers should include the following information about natural gas storage included in the portfolio upon which that PGA is based.	62	
a)	Type of storage (e.g., depleted field, salt dome).	62	
b)	Location of each storage facility.	62	
c)	Total level of storage in terms of deliverability and capacity held during the gas year.	62	
d)	Historical (five years) gas supply delivered to storage, both annual total and by month.	62	
e)	Historical (five years) gas supply withdrawn from storage, both annual total and by month.	62	
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.	64	
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.	64	
h)	For LDCs that own and operate storage:		
a.	The date and results of the last engineering study for that storage.	79	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.	96	CONFIDENTIAL
V.8	**Attestation as to Consistency**	98	

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) HB 3179 the FAIR Energy Act went into effect July of 2025.

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 2025 IRP as well as its most recent Oregon rate case (UG 520).

Note, also that the supply portfolio for this PGA is based on a demand side management (DSM) savings forecast that is consistent with the forecast used in the 2025 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)*	$66,645,534	Refer to workpaper "2026-27 PGA filing Summary Effects"
B) Percent *(To .1 percent)*	6.63%	"
2) Annual Revenues Calculation *(Whole Dollars)*		
A) PGA Cost Change *(Commodity & Transportation)*	(41,606,142)	Refer to workpaper "2026-27 PGA filing Summary Effects"
B) Remove Last Year's Temporary Increment Total	(32,173,595)	"
C) Add New Temporary Increment	144,769,627	"
D) Remove Last Year's Permanent Increment Total	(5,074,267)	
E) Add New Permanent Increment Total	729,911	
E) Total Proposed Change	66,645,534	Refer to workpaper "2026-27 PGA filing Summary Effects"
3) Residential Bill Effects Summary		
A) Residential Schedule Rate Impacts		
1) Current Billing Rate per Therm	$1.41220	Refer to workpaper "2026-2027 PGA Rate Development"
2) Proposed Billing Rate per Therm	$1.50819	"
3) Rate Change Per Therm	$0.09599	"
4) Percent Change per Therm *(to .1%)*	6.8%	"
B) Average Residential Bill Impact (forecasted weather-normalized annual)		
1) Average Residential Monthly Use	53.0	Refer to workpaper "2026-2027 PGA Rate Development"
2) Customer Charge	$10.00	"
3) Current Average Monthly Bill	$84.85	"
4) Proposed Average Monthly Bill	$89.93	"
5) Change in Average Monthly Bill	$5.08	"
6) Percent change in Average Monthly Bill *(to .1%)*	6.0%	"
C) Average January Residential Bill Impact		
1) Average January Residential Use *(forecasted weather-normalized)*	104.2	Refer to workpaper "2026-2027 PGA Rate Development"
2) Customer Charge	$10.00	"
3) Current Average January Bill	157.20	"
4) Proposed Average January Bill	167.20	"
5) Change in Average January Bill	$10.01	"
6) Percent change in Average January Bill *(to .1%)*	6.4%	"

	Amount	Location in Company Filing (cite)
4) Breakdown of Costs		
A) Embedded in Rates (System Costs)		
1) Total Commodity Cost	$328,619,739	NWN 2026-27 PGA OR Gas Cost Development
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)	$1,454,928	"
e) Total Storage Cost (assoc. w/ supply)	$21,174,762	"
f) Other - Volumetric Pipeline Charges	$305,990,049	"
2) Total Transportation Cost *(Pipeline related)*	$71,260,897	"
a) Total Upstream Canadian Toll	$0	
i.Total Demand, Capacity, or Reservation Cost	$0	
ii. Total Volumetric Cost	$0	
b) Total Domestic Cost	$0	
i. Total Demand, Capacity, or Reservation Cost	$0	
ii. Total Volumetric Cost	$0	
3) Total Storage Costs	$0	
4) Capacity Release Credits	$0	
5) Total Gas Costs	$399,880,636	"
B) Projected For New Rates (Oregon Costs)		
1) Total Commodity Cost	$269,095,951	Refer to workpaper" 2026-27 PGA Gas Cost Development"
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)	$782,245	"
f) Total Storage Cost (assoc. w/ supply)	$18,529,597	"
g) Other (A&G Benchmark Savings)	$249,784,109	"
2) Total Transportation Cost *(Pipeline related)*	$78,422,463	"
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	$347,518,414	"

	Amount	Location in Company Filing (cite)
5) WACOG *(Weighted Average Cost of Gas)*		
A) Embedded in Rates		
1) WACOG *(Commodity Only)*		
a. With revenue sensitive	$0.43451	NWN 2026-27 PGA OR Gas Cost Development
b. Without revenue sensitive	$0.42140	"
2) FIRM Demand (Non-Commodity)		
a. With revenue sensitive	$0.10027	"
b. Without revenue sensitive	$0.09724	"
B) Proposed for New Rates		**Exhibit B, Page 1**
1) WACOG *(Commodity Only)*		
a. With revenue sensitive	$0.36778	NWN 2026-27 PGA OR Gas Cost Development
b. Without revenue sensitive	$0.35709	"
2) FIRM Demand (Non-Commodity)		
a. With revenue sensitive	$0.11482	"
b. Without revenue sensitive	$0.11148	"
6) Therms Sold (OR only)		

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

b) Gas Supply Portfolio and Related Transportation

1. Summary of Portfolio Planning Process

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

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

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

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

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

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

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

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

(2) Try to match our year-round customer requirements to baseload (take-or-pay) year-round supply contracts to obtain the most favorable pricing and simplify administration;

(3) Use multiple month and bullet (single month) term contracts to match our rise in requirements during the heating season and shoulder months;

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

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

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

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

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

2. LDC sales system demand forecasting

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

3. Natural gas price forecasts

NW Natural relies on forecasts prepared by the US Energy Information Administration (EIA), S&P Global Commodity Insights, and 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) A project is ongoing for Portland LNG that should have it back to full deliverability for the 2026-2027 PGA year.

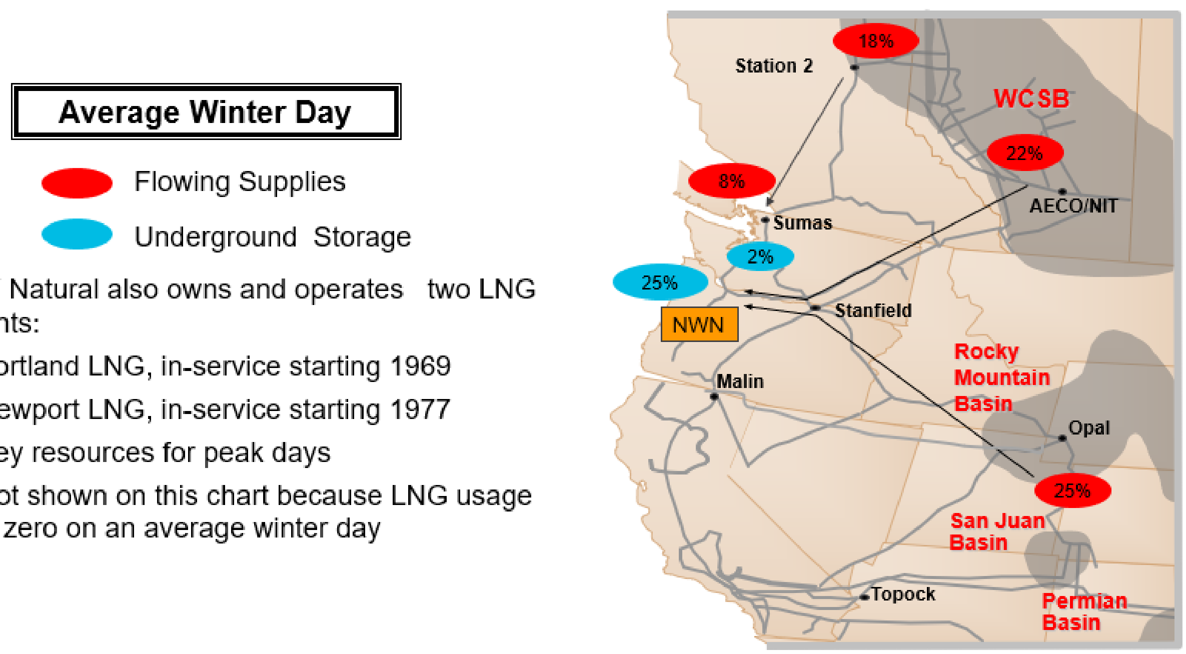
Other physical resource items that do not represent changes, but merit mention are:

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

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

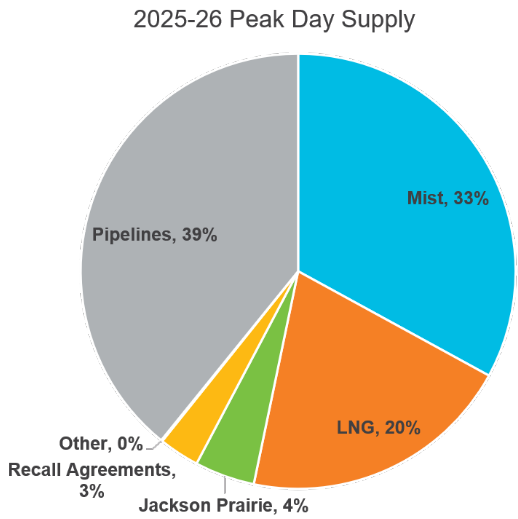
The Company's portfolio continues to reflect the gas reserves purchased under the agreement with Encana approved by the OPUC in 2011. That agreement was amended in March 2014 and seven new gas wells were drilled with the successor company Jonah Energy LLC. This PGA continues to reflect the approved regulatory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

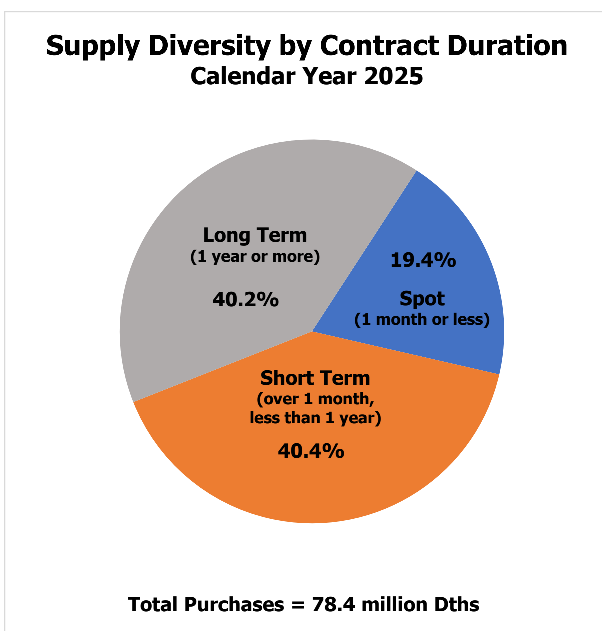
Should its "design" peak day occur during the upcoming heating season, all physical resources would be used in the following proportions (607,000 therms/day of segmented capacity is included):



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 2026 through October 2027 period. This reflects the relatively stable daily component of NWN's demand, i.e., water heater and other non-space heating loads that are not seasonal in nature.

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

With slightly over 3.4 million therms per day of firm upstream pipeline capacity to its service territory, and potentially over 4.0 million therms per day if segmented capacity is included, this means substantial capacity is available for spot purchases (one month and shorter duration) as, and when, needed. During the 2025 calendar year, approximately twenty percent 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 70% of the prices of its expected annual Oregon sales requirements for the upcoming PGA year commencing November 1, 2026. Gas reserves are expected to hedge about 2% of projected sales volumes. Storage gas, which again is gas purchased on the spot market, will account for approximately another 13%. On-system resources including Mist gas production and renewable natural gas production continue to add roughly 1% to the total requirements. Assuming normal weather, the remaining annual purchase volumes, when combined with our purchases for storage, means roughly 28% 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 2026/2027 Tracker Year

Supply Location	Duration	Baseload Qty (Dth/day)	Contract Termination Date
British Columbia:			
Canadian Natural Resources	Nov-Oct	10,000	10/31/2027
ConocoPhillips Canada Marketing	Nov-Oct	5,000	10/31/2027
IGI Resources	Nov-Oct	5,000	10/31/2027
Canadian Natural Resources	Nov-Mar	15,000	3/31/2027
ConocoPhillips Canada Marketing	Nov-Mar	10,000	3/31/2027
J. Aron & Company	Nov-Mar	5,000	3/31/2027
MacQuarie Energy Canada Ltd.	Nov-Mar	5,000	3/31/2027
MacQuarie Energy Canada Ltd.	Nov-Mar	10,000	3/31/2030
Powerex Corp	Nov-Mar	15,000	3/31/2030
IGI Resources	Nov-Mar	8,500	3/31/2030
Shell North America (Canada) Inc	Apr-Jun	5,000	6/30/2027
Canadian Natural Resources	Apr-May	5,000	5/31/2027
Shell North America (Canada) Inc	Apr-May	10,000	5/31/2027
MacQuarie Energy Canada Ltd.	Sep-Oct	5,000	10/31/2027
Shell North America (Canada) Inc	Oct	5,000	10/31/2027
Alberta:			
BP Canada Energy Group	Nov-Oct	5,000	10/31/2027
Castleton Commodities	Nov-Oct	5,000	10/31/2027
Suncor Energy Marketing Inc	Nov-Oct	5,000	10/31/2027
BP Canada Energy Group	Nov-Mar	5,000	3/31/2027
Castleton Commodities	Nov-Mar	5,000	3/31/2027
ConocoPhillips Canada Marketing	Nov-Mar	15,000	3/31/2027
MacQuarie Energy Canada Ltd.	Nov-Mar	5,000	3/31/2027
Powerex Corp	Nov-Mar	5,000	3/31/2027
Suncor Energy Marketing Inc	Nov-Mar	20,000	3/31/2027
BP Canada Energy Group	Nov-Feb	5,000	2/28/2027
BP Canada Energy Group	Dec-Feb	5,000	2/28/2027
BP Canada Energy Group	Apr-Jun	5,000	6/30/2027
Suncor Energy Marketing Inc	Apr-Jun	5,000	6/30/2027
Castleton Commodities	Apr-May	5,000	5/31/2027
Shell North America (Canada) Inc	Apr-May	5,000	5/31/2027
BP Canada Energy Group	Apr	5,000	4/30/2027
Shell North America (Canada) Inc	Apr	5,000	4/30/2027
Suncor Energy Marketing Inc	Sep-Oct	5,000	10/31/2027
BP Canada Energy Group	Oct	5,000	10/31/2027
Castleton Commodities	Oct	5,000	10/31/2027
J Aron & Company LLC	Oct	5,000	10/31/2027
Suncor Energy Marketing Inc	Oct	10,000	10/31/2027
Rockies:			
MacQuarie Energy, LLC	Nov-Oct	5,000	10/31/2031
MIECO LLC	Nov-Oct	5,000	10/31/2031
Cima	Nov-Oct	5,000	10/31/2027
ConocoPhillips Company	Nov-Oct	5,000	10/31/2027
Koch	Nov-Oct	5,000	10/31/2027
MacQuarie Energy, LLC	Nov-Oct	10,000	10/31/2027
Sequent Energy Management, LP	Nov-Oct	5,000	10/31/2027
Vitol Inc.	Nov-Oct	5,000	10/31/2027
MacQuarie Energy, LLC	Nov-Mar	5,000	3/31/2027
MIECO LLC	Nov-Mar	5,000	3/31/2027
CIMA Energy LTD	Nov-Mar	10,000	3/31/2027
MIECO LLC	Nov-Mar	5,000	3/31/2027
CIMA Energy LTD	Dec-Mar	10,000	3/31/2027
Citadel Energy Marketing, LLC	Dec-Mar	5,000	3/31/2027
MacQuarie Energy, LLC	Dec-Mar	5,000	3/31/2027
MIECO LLC	Dec-Mar	10,000	3/31/2027
PureWest Resources, Inc	Dec-Mar	5,000	3/31/2027
WWM Logistics, LLC	Dec-Mar	5,000	3/31/2027
CIMA Energy LTD	Dec-Feb	10,000	2/28/2027
Citadel Energy Marketing, LLC	Dec-Feb	5,000	2/28/2027
WWM Logistics, LLC	Apr-May	5,000	5/31/2027
CIMA Energy LTD	Apr	10,000	4/30/2027
ConocoPhillips Company	Apr	5,000	4/30/2027
Koch Energy Services, Inc	Apr	5,000	4/30/2027
Sequent Energy Management, LP	Apr	5,000	4/30/2027
WWM Logistics, LLC	Apr	5,000	4/30/2027
CIMA Energy LTD	Oct	5,000	10/31/2027
ConocoPhillips Company	Oct	5,000	10/31/2027

Month	Baseload Qty (Dth/day)
Nov-26	233,500
Dec-26	293,500
Jan-27	293,500
Feb-27	293,500
Mar-27	268,500
Apr-27	165,000
May-27	125,000
Jun-27	95,000
Jul-27	80,000
Aug-27	80,000
Sep-27	90,000
Oct-27	130,000

Notes:

1. Contract quantities represent deliveries into upstream pipelines. Accordingly, quantities delivered into NW

Supporting information to IV.2.b.4

Table 2

NW Natural
Firm Transportation Capacity
for the 2026/2027 Tracker Year

Pipeline and Contract	Contract Demand (Dth/day)	Termination Date
Northwest Pipeline:		
Sales Conversion (#100005)	214,889	10/31/2033
1993 Expansion (#100058)	35,155	9/30/2044
1995 Expansion (#100138)	102,000	10/31/2033
Occidental cap. acq. (#139153)	1,046	10/31/2033
Occidental cap. acq. (#139154)	4,000	10/31/2033
International Paper cap. acq. (#138065)	4,147	10/31/2033
March Point cap. acq. (#136455)	12,000	12/31/2046
Total NWP Capacity	373,237	
less recallable release to -		
Portland General Electric	(30,000)	10/31/2028
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	10/31/2027
1995 Rationalization	57,417	10/31/2027
Engage Capacity Acquisition	3,708	10/31/2027
2004 Capacity Acquisition	48,669	10/31/2030
Total Foothills Capacity	157,521	
less release to -		
Shell Energy North America (Canada) Inc	(48,669)	10/31/2030
Net Foothills Capacity	108,852	
TransCanada - NOVA:		
1993 Expansion	48,135	10/31/2030
1995 Rationalization	57,909	10/31/2030
Engage Capacity Acquisition	3,739	10/31/2030
2004 Capacity Acquisition	49,138	10/31/2030
Total NOVA Capacity	158,921	
less release to -		
Shell Energy North America (Canada) Inc	(49,138)	10/31/2030
Net NOVA Capacity	109,783	
T-South		
Capacity (through Tenaska)	19,000	3/31/2029
2021 Expansion	25,515	10/31/2061
Capacity FI-3931	25,022	4/30/2028
Total T-South Capacity	69,538	

Notes:

1. All of the above agreements continue year-to-year after termination at NW Natural's sole option except for PGE, which requires mutual agreement to continue, and the T-South contract with Tenaska for 19,000 Dth/day, which has no renewal rights.
2. The numbers shown for the 1993 Expansion contracts on GTN and Foothills are for the winter season (Oct-Mar) only. Both contracts decline during the summer season (Apr-Sep) to approximately 30,000 Dth/day.
3. Segmented capacity has not been included in this table.
4. The 2004 Capacity Acquisition on NOVA and Foothills totaling about 49,000 Dth/day has been released to a third party through 10/31/2030. The revenues related to this arrangement are being credited back to customers as outlined in Schedule P.
5. T-South Capacity of 25,022 Dth/day on contract FI-3931 commenced on 04/01/2026. This capacity has renewal rights after the termination date.

Supporting information to IV.2.b.4

Table 3

NW Natural
Firm Storage Resources
for the 2026/2027 Tracker Year

Facility	Max. Daily Rate (Dth/day)	Max. Seasonal Level (Dth)	Termination Date
Jackson Prairie:			
SGS-2F	46,030	1,120,288	10/31/2033
TF-2 (primary firm portion)	23,038	839,046	10/31/2033
TF-2 (primary firm portion)	9,467	281,242	10/31/2033
TF-1	13,525	n/a	10/31/2033
Firm On-System Storage Plants:			
Mist (reserved for core)	340,000	13,386,040	n/a
Portland LNG Plant	131,520	502,406	n/a
Newport LNG Plant	78,000	1,122,061	n/a
Total On-System Storage	549,520	15,010,507	
Total Firm Storage Resource	595,550	16,130,795	

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 1094 Btu/cf. The current heat content used for Newport LNG is 1135 Btu/cf and Portland LNG is 1096 Btu/cf. An engineering study was conducted for Newport LNG peak deliverability supporting 78,000 Dth/d as the maximum daily rate.
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 2026/2027 Tracker Year

Type	Max. Daily Rate (Dth/day)	Max. Availability (days)	Termination Date
Recall Agreements:			
PGE	30,000	30	10/31/2028
Georgia Pacific-Halsey mill	1,000	15	Upon 1-year notice
Total Recall Resource	31,000		
On-System Supplies:			
Renewable Natural Gas	≈600	n/a	Varying Terms
Mist Production	≈400	n/a	Life of the wells
Total On System Supplies	1,000		

Notes:
1. There are a variety of terms and conditions surrounding the recall rights under each of the above agreements, but they all include delivery of the gas to NW Natural's system.
2. Mist production is expected to flow at roughly the figure shown above. Flows vary as new wells are added and older wells deplete. NW Natural's obligation is to buy gas from existing wells through the life of those wells.
3. Assumes four 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 2026/2027 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)	549,520
Recallable Capacity and Supply Agreements	31,000
On-System Supplies	1,000
Segmented Capacity (not primary firm)	60,700
Total Peak Day Resources	1,031,487

Notes:

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

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

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

	2025/2026
Forecast Annual Demand (therms)	847,099,393
Forecast Peak Demand (therms) - Normal	4,410,998
Forecast Peak Demand (therms) - Design	10,297,486
Forecast DSM Annual (therms)	6,625,277
Forecast DSM Peak (therms) - Normal	42,583
Forecast DSM Peak (therms) - Design Peak	99,410
Forecast Annual Demand with Forecast DSM	840,474,116
Forecast Peak Demand with Forecast DSM - Normal	4,368,415
Forecast Peak Demand with Forecast DSM - Design	10,198,075

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, 2026 - October 31, 2027
Physical Natural Gas term contracts

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

Rocky Mountain Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dths	Contractual Conditions	Default Receipt Pt. Purchase Location	Internal Reference No.
WWM Logistics, LLC (1)	12/1/2026	3/31/2027	[redacted]	IFGMR-NWP Rockies FOM	5,000		Opal	118514
CIMA Energy LTD (2)	12/1/2026	2/28/2027		IFGMR-NWP Rockies FOM	5,000		Opal	118516
CIMA Energy LTD (3)	11/1/2026	3/31/2027		IFGMR-NWP Rockies FOM	5,000		Rocky Mountain Pool	118548
MacQuarie Energy, LLC (4)	11/1/2026	10/31/2027		IFGMR-NWP Rockies FOM	5,000		Wyoming Pool	118555
Koch Energy Services, Inc (5)	4/1/2027	4/30/2027		IFGMR-NWP Rockies FOM	5,000		Opal	118557
Vitol Inc. (6)	11/1/2026	10/31/2027		IFGMR-NWP Rockies FOM	5,000		Opal	118591
ConocoPhillips Company (7)	4/1/2027	4/30/2027		IFGMR-NWP Rockies FOM	5,000		Wyoming Pool	118598
CIMA Energy LTD (8)	12/1/2026	2/28/2027		IFGMR-NWP Rockies FOM	5,000		Rocky Mountain Pool	118601
MIECO LLC (9)	11/1/2026	3/31/2027		IFGMR-NWP Rockies FOM	5,000		Opal	118607
CIMA Energy LTD (10)	12/1/2026	3/31/2027		IFGMR-NWP Rockies FOM	5,000		Opal	118623
MIECO LLC (11)	12/1/2026	3/31/2027		IFGMR-NWP Rockies FOM	5,000		Opal	118624
CIMA Energy LTD (12)	12/1/2026	3/31/2027		IFGMR-NWP Rockies FOM	5,000		Wyoming Pool	118650
ConocoPhillips Company (13)	11/1/2026	10/31/2027		IFGMR-NWP Rockies FOM	5,000		Rocky Mountain Pool	118665
Sequent Energy Management, LP (14)	4/1/2027	4/30/2027		IFGMR-NWP Rockies FOM	5,000		Opal	118668
MacQuarie Energy, LLC (15)	12/1/2026	3/31/2027		IFGMR-NWP Rockies FOM	5,000		Rocky Mountain Pool	118674
Citadel Energy Marketing, LLC (16)	12/1/2026	2/28/2027		IFGMR-NWP Rockies FOM	5,000		Rocky Mountain Pool	118685
MIECO LLC (17)	12/1/2026	3/31/2027		IFGMR-NWP Rockies FOM	5,000		Opal	118707
ConocoPhillips Company (18)	10/1/2027	10/31/2027		IFGMR-NWP Rockies FOM	5,000		Rocky Mountain Pool	118711
Citadel Energy Marketing, LLC (19)	12/1/2026	3/31/2027		IFGMR-NWP Rockies FOM	5,000		Opal	118713
CIMA Energy LTD (20)	11/1/2026	3/31/2027		IFGMR-NWP Rockies FOM	5,000		Rocky Mountain Pool	118758
WWM Logistics, LLC (21)	4/1/2027	4/30/2027		IFGMR-NWP Rockies FOM	5,000		Opal	118765
Sequent Energy Management, LP (22)	11/1/2026	10/31/2027		IFGMR-NWP Rockies FOM	5,000		Rocky Mountain Pool	118804
CIMA Energy LTD (23)	4/1/2027	4/30/2027		IFGMR-NWP Rockies FOM	5,000		Wyoming Pool	118807
WWM Logistics, LLC (24)	4/1/2027	5/31/2027		IFGMR-NWP Rockies FOM	5,000		Opal	118812
MacQuarie Energy, LLC (25)	11/1/2026	3/31/2031		IFGMR-NWP Rockies FOM	5,000		Opal	118815
MIECO LLC (26)	11/1/2026	3/31/2031		IFGMR-NWP Rockies FOM	5,000		Opal	118817
MacQuarie Energy, LLC (27)	11/1/2026	10/31/2031		IFGMR-NWP Rockies FOM	5,000		Opal	118814
MIECO LLC (28)	11/1/2026	10/31/2031		IFGMR-NWP Rockies FOM	5,000		Opal	118816
MacQuarie Energy, LLC (29)	11/1/2026	10/31/2027		IFGMR-NWP Rockies FOM	5,000		RMP	118842
CIMA Energy LTD (30)	10/1/2027	10/31/2027		IFGMR-NWP Rockies FOM	5,000		WYO	118851
PureWest Resources, Inc (31)	12/1/2026	3/31/2027		IFGMR-NWP Rockies FOM	5,000		Opal	118863
Koch Energy Services, Inc (32)	11/1/2026	10/31/2027		IFGMR-NWP Rockies FOM	5,000		Opal	118876
CIMA Energy LTD (33)	4/1/2027	4/30/2027		IFGMR-NWP Rockies FOM	5,000		Opal	118894
CIMA Energy LTD (34)	11/1/2026	10/31/2027		IFGMR-NWP Rockies FOM	5,000		Opal	118911

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids	Winning Bid Criteria
(1) Opal	7	[redacted]	Price
(2) Opal	6		Price
(3) Rocky Mountain Pool	6		Price
(4) Wyoming Pool	5		Price
(5) Opal	6		Price
(6) Opal	5		Price
(7) Wyoming Pool	4		Price/Diversity
(8) Rocky Mountain Pool	6		Price
(9) Opal	8		Price
(10) Opal	3		Price
(11) Opal	4		Price
(12) Wyoming Pool	4		Price
(13) Rocky Mountain Pool	8		Price
(14) Opal	6		Price
(15) Rocky Mountain Pool	5		Price
(16) Rocky Mountain Pool	4		Price
(17) Opal	5		Price
(18) Rocky Mountain Pool	4		Price/Diversity
(19) Opal	4		Price
(20) Rocky Mountain Pool	5		Price
(21) Opal	5		Price
(22) Rocky Mountain Pool	5		Price
(23) Wyoming Pool	3		Price
(24) Opal	5		Price
(25) Opal	6		Price
(26) Opal	6		Price
(27) Opal	6		Price
(28) Opal	6		Price
(29) RMP	5		Price
(30) WYO	3		Price
(31) Opal	5		Price/Diversity
(32) Opal	6		Price
(33) Opal	5		Price
(34) Opal	5		Price

[END HIGHLY CONFIDENTIAL]

[START HIGHLY CONFIDENTIAL]

Table 2

Northwest Natural Gas Company
PGA Filing Guidelines

CONFIDENTIAL

November 1, 2026 - October 31, 2027
Physical Natural Gas term contracts

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

Huntingdon, BC Supply contracts

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

Transactions for new PGA year

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

Table 3

Northwest Natural Gas Company
PGA Filing Guidelines

CONFIDENTIAL

November 1, 2026 - October 31, 2027
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)	11/1/2026	10/31/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	118515
Shell North America (Canada) Inc (2)	4/1/2027	5/31/2027		CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	118517
Canadian Natural Resources (3)	11/1/2026	3/31/2027		CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	118532
Canadian Natural Resources (4)	4/1/2027	5/31/2027		CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	118599
J. Aron & Company LLC (5)	11/1/2026	3/31/2027		CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	118614
Canadian Natural Resources (6)	11/1/2026	3/31/2027		CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	118655
ConocoPhillips Canada Marketing (7)	11/1/2026	10/31/2027		CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	118669
MacQuarie Energy Canada Ltd. (8)	9/1/2027	10/31/2027		CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	118684
Shell North America (Canada) Inc (9)	4/1/2027	6/30/2027		CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	118714
Canadian Natural Resources (10)	11/1/2026	3/31/2027		CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	118743
Shell North America (Canada) Inc (11)	10/1/2027	10/31/2027		CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	118805
IGI Resources Inc (12)	11/1/2026	10/31/2027		CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	118808
Shell North America (Canada) Inc (13)	4/1/2027	5/31/2027		CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	118811
ConocoPhillips Canada Marketing (14)	11/1/2026	3/31/2027		CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	118848
MacQuarie Energy Canada Ltd. (15)	11/1/2026	3/31/2027		CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	118869
Canadian Natural Resources (16)	11/1/2026	10/31/2027		CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	118905
ConocoPhillips Canada Marketing (17)	11/1/2026	3/31/2027		CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	118929

Transactions for new PGA year

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

[END HIGHLY CONFIDENTIAL]

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Table 4

Northwest Natural Gas Company
PGA Filing Guidelines

CONFIDENTIAL

November 1, 2026 - October 31, 2027
Physical Natural Gas term contracts

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

Aeco-NIT Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dth's	Contractual Conditions	Internal Reference No.
Suncor Energy Marketing Inc (1)	11/1/2026	3/31/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118512
BP Canada Energy Group (2)	12/1/2026	2/28/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118518
Castleton Commodities (3)	11/1/2026	10/31/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118547
Castleton Commodities (4)	10/1/2027	10/31/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118554
BP Canada Energy Group (5)	11/1/2026	3/31/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118581
Suncor Energy Marketing Inc (6)	4/1/2027	6/30/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118600
Suncor Energy Marketing Inc (7)	9/1/2027	10/31/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118603
BP Canada Energy Group (8)	11/1/2026	2/28/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118645
MacQuarie Energy Canada Ltd. (9)	11/1/2026	3/31/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118654
BP Canada Energy Group (10)	4/1/2027	4/30/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118661
Shell North America (Canada) Inc (11)	4/1/2027	4/30/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118662
BP Canada Energy Group (12)	4/1/2027	6/30/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118672
BP Canada Energy Group (13)	11/1/2026	10/31/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118701
ConocoPhillips Canada Marketing (14)	11/1/2026	3/31/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118710
Suncor Energy Marketing Inc (15)	10/1/2027	10/31/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118712
Suncor Energy Marketing Inc (16)	11/1/2026	3/31/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118751
Suncor Energy Marketing Inc (17)	10/1/2027	10/31/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118760
Suncor Energy Marketing Inc (18)	11/1/2026	3/31/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118806
Castleton Commodities (19)	4/1/2027	5/31/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118810
ConocoPhillips Canada Marketing (20)	11/1/2026	3/31/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118838
Suncor Energy Marketing Inc (21)	11/1/2026	10/31/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118843
Shell North America (Canada) Inc (22)	4/1/2027	5/31/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118858
BP Canada Energy Group (23)	10/1/2027	10/31/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118864
J Aron & Company LLC (24)	10/1/2027	10/31/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118865
ConocoPhillips Canada Marketing (25)	11/1/2026	3/31/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118887
Castleton Commodities (26)	11/1/2026	3/31/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118893
Suncor Energy Marketing Inc (27)	11/1/2026	3/31/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118921
Powerex Corp (28)	11/1/2026	3/31/2027	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		118934

Transactions for new PGA year

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

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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 2026-2027 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 2026-2027, 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 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	912,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100102	[redacted]	AECO	2,500	227,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100102	[redacted]	AECO	2,500	75,000	$ [redacted]	[redacted]	Oregon
Financial Swap	100102	[redacted]	AECO	2,500	77,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100102	[redacted]	AECO	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100102	[redacted]	Rockies	2,500	225,000	$ [redacted]	[redacted]	Oregon
Financial Swap	100102	[redacted]	Rockies	5,000	605,000	$ [redacted]	[redacted]	Oregon
Financial Swap	100102	[redacted]	Rockies	2,500	535,000	$ [redacted]	[redacted]	Oregon
Financial Swap	100102	[redacted]	Rockies	2,500	77,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100102	[redacted]	Rockies	2,500	535,000	$ [redacted]	[redacted]	Oregon
Financial Swap	100102	[redacted]	Rockies	2,500	77,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100102	[redacted]	Station 2	2,500	152,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100102	[redacted]	Station 2	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100101	[redacted]	AECO	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100101	[redacted]	AECO	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100101	[redacted]	Rockies	2,500	535,000	$ [redacted]	[redacted]	Oregon
Financial Swap	100101	[redacted]	Rockies	2,500	535,000	$ [redacted]	[redacted]	Oregon
Financial Swap	100101	[redacted]	Rockies	2,500	912,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100101	[redacted]	Rockies	2,500	912,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100101	[redacted]	Rockies	2,500	912,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100101	[redacted]	Station 2	2,500	912,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100101	[redacted]	Station 2	2,500	912,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100101	[redacted]	Sumas	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	201022	[redacted]	AECO	2,500	152,500	$ [redacted]	[redacted]	Oregon
Financial Swap	201022	[redacted]	AECO	5,000	155,000	$ [redacted]	[redacted]	Oregon
Financial Swap	100104	[redacted]	AECO	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100104	[redacted]	AECO	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100104	[redacted]	AECO	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100104	[redacted]	Rockies	2,500	912,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100104	[redacted]	Rockies	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100104	[redacted]	Rockies	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100104	[redacted]	Rockies	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100104	[redacted]	Rockies	2,500	912,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100104	[redacted]	Rockies	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100104	[redacted]	Station 2	2,500	912,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100104	[redacted]	Station 2	2,500	77,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100104	[redacted]	Sumas	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100104	[redacted]	Sumas	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100104	[redacted]	Sumas	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100106	[redacted]	AECO	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100106	[redacted]	AECO	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100106	[redacted]	AECO	5,000	305,000	$ [redacted]	[redacted]	Oregon
Financial Swap	100106	[redacted]	Rockies	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100106	[redacted]	Rockies	5,000	150,000	$ [redacted]	[redacted]	Oregon
Financial Swap	100106	[redacted]	Station 2	2,500	152,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100106	[redacted]	Station 2	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100106	[redacted]	Station 2	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100170	[redacted]	AECO	2,500	227,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100170	[redacted]	Rockies	5,000	605,000	$ [redacted]	[redacted]	Oregon
Financial Swap	100170	[redacted]	Rockies	5,000	605,000	$ [redacted]	[redacted]	Oregon
Financial Swap	100170	[redacted]	Station 2	2,500	152,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100170	[redacted]	Station 2	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100108	[redacted]	AECO	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100108	[redacted]	AECO	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100108	[redacted]	AECO	2,500	77,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100108	[redacted]	AECO	2,500	152,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100108	[redacted]	Rockies	2,500	912,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100108	[redacted]	Rockies	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100108	[redacted]	Rockies	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100108	[redacted]	Rockies	2,500	912,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100108	[redacted]	Rockies	5,000	150,000	$ [redacted]	[redacted]	Oregon
Financial Swap	100108	[redacted]	Rockies	5,000	450,000	$ [redacted]	[redacted]	Oregon
Financial Swap	100108	[redacted]	Station 2	2,500	152,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100108	[redacted]	Station 2	2,500	377,500	$ [redacted]	[redacted]	Oregon
Financial Swap	100108	[redacted]	Station 2	2,500	377,500	$ [redacted]	[redacted]	Oregon

Financial Swap	100108	[redacted]	Station 2	2,500	377,500	$	[redacted]	regon
Financial Swap	100108	[redacted]	Station 2	2,500	377,500	$	[redacted]	regon
Financial Swap	100108	[redacted]	Station 2	5,000	150,000	$	[redacted]	regon
Financial Swap	100108	[redacted]	Sumas	2,500	377,500	$	[redacted]	regon
Financial Swap	100108	[redacted]	Sumas	2,000	302,000	$	[redacted]	regon
Financial Swap	201023	[redacted]	AECO	2,500	77,500	$	[redacted]	regon
Financial Swap	201023	[redacted]	AECO	2,500	377,500	$	[redacted]	regon
Financial Swap	201023	[redacted]	Rockies	5,000	150,000	$	[redacted]	regon
Financial Swap	201023	[redacted]	Rockies	2,500	225,000	$	[redacted]	regon
Financial Swap	201023	[redacted]	Rockies	5,000	605,000	$	[redacted]	regon
Financial Swap	201023	[redacted]	Rockies	5,000	605,000	$	[redacted]	regon
Financial Swap	201023	[redacted]	Rockies	5,000	150,000	$	[redacted]	regon
Financial Swap	201023	[redacted]	Station 2	2,500	377,500	$	[redacted]	regon
Financial Swap	201023	[redacted]	Station 2	2,500	377,500	$	[redacted]	regon
Financial Swap	201023	[redacted]	Sumas	2,500	377,500	$	[redacted]	regon
Financial Swap	100109	[redacted]	AECO	2,500	912,500	$	[redacted]	regon
Financial Swap	100109	[redacted]	AECO	2,500	377,500	$	[redacted]	regon
Financial Swap	100109	[redacted]	AECO	2,500	225,000	$	[redacted]	regon
Financial Swap	100109	[redacted]	AECO	2,500	225,000	$	[redacted]	regon
Financial Swap	100109	[redacted]	AECO	2,500	227,500	$	[redacted]	regon
Financial Swap	100109	[redacted]	AECO	2,500	75,000	$	[redacted]	regon
Financial Swap	100109	[redacted]	AECO	2,500	77,500	$	[redacted]	regon
Financial Swap	100109	[redacted]	Rockies	2,500	912,500	$	[redacted]	regon
Financial Swap	100109	[redacted]	Rockies	2,500	535,000	$	[redacted]	regon
Financial Swap	100109	[redacted]	Rockies	2,500	377,500	$	[redacted]	regon
Financial Swap	100109	[redacted]	Rockies	5,000	150,000	$	[redacted]	regon
Financial Swap	100109	[redacted]	Rockies	2,500	377,500	$	[redacted]	regon
Financial Swap	100109	[redacted]	Rockies	2,500	377,500	$	[redacted]	regon
Financial Swap	100109	[redacted]	Rockies	2,500	377,500	$	[redacted]	regon
Financial Swap	100109	[redacted]	Station 2	2,500	912,500	$	[redacted]	regon
Financial Swap	100109	[redacted]	Sumas	2,500	377,500	$	[redacted]	regon
Financial Swap	100109	[redacted]	Sumas	2,500	377,500	$	[redacted]	regon
Financial Swap	100111	[redacted]	AECO	2,500	377,500	$	[redacted]	regon
Financial Swap	100111	[redacted]	AECO	2,500	377,500	$	[redacted]	regon
Financial Swap	100111	[redacted]	AECO	2,500	377,500	$	[redacted]	regon
Financial Swap	100111	[redacted]	AECO	2,500	912,500	$	[redacted]	regon
Financial Swap	100111	[redacted]	AECO	2,500	912,500	$	[redacted]	regon
Financial Swap	100111	[redacted]	AECO	2,500	912,500	$	[redacted]	regon
Financial Swap	100111	[redacted]	AECO	2,500	377,500	$	[redacted]	regon
Financial Swap	100111	[redacted]	Rockies	2,500	912,500	$	[redacted]	regon
Financial Swap	100111	[redacted]	Station 2	2,500	377,500	$	[redacted]	regon
Financial Swap	100111	[redacted]	Station 2	2,500	535,000	$	[redacted]	regon
Financial Swap	100111	[redacted]	Station 2	2,500	77,500	$	[redacted]	regon
Financial Swap	100111	[redacted]	Sumas	2,500	377,500	$	[redacted]	regon
Financial Swap	100112	[redacted]	AECO	2,500	377,500	$	[redacted]	regon

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Section V.3 - Load Forecasting

a. Customer count and revenue by month and class.

NW Natural

UM 1286 PGA Portfolio Guidelines
2026-2027 Oregon PGA

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

	Customer Cnt Jul-25	Revenue Jul-25	Customer Cnt Aug-25	Revenue Aug-25	Customer Cnt Sep-25	Revenue Sep-25
Total	806,720	$ 38,209,175.72	806,240	$ 33,780,730.79	806,016	$ 34,703,059.95
Oregon	708,136	34,529,977.59	707,584	30,522,961.17	707,381	31,325,573.84
Washington	98,584	3,679,198.13	98,656	3,257,769.62	98,635	3,377,486.11
Total Residential	736,452	21,098,885.00	736,114	18,179,475.84	736,002	18,629,146.41
Total Commercial	69,227	11,600,110.40	69,088	10,296,478.61	68,975	10,449,410.05
Total Industrial	651	2,171,542.27	653	2,122,687.43	652	2,334,354.41
Total Interruptible	90	1,788,152.47	89	1,765,002.00	90	1,800,533.89
Total Transportation - Commercial Firm	92	138,308.34	92	139,008.43	92	149,151.34
Total Transportation - Industrial Firm	125	851,715.19	121	725,657.41	123	771,443.72
Total Transportation - Interruptible	83	560,462.05	83	552,421.07	82	569,020.13
Unbilled Revenue		(3,187,566.80)		1,109,974.71		2,830,280.05
Agency Fees						
Net Balancing/Overrun						
Total Gas Operating Revenue		$ 35,021,608.92		$ 34,890,705.50		$ 37,533,340.00

	Customer Cnt Oct-25	Revenue Oct-25	Customer Cnt Nov-25	Revenue Nov-25	Customer Cnt Dec-25	Revenue Dec-25
Total	806,587	$ 46,639,735.95	808,332	$ 84,673,070.58	809,597	$ 129,426,836.60
Oregon	707,837	42,278,369.03	709,430	77,240,754.97	710,498	119,190,365.32
Washington	98,750	4,361,366.92	98,902	7,432,315.61	99,099	10,236,471.28
Total Residential	736,644	26,559,192.64	738,216	53,306,124.34	739,337	85,157,269.48
Total Commercial	68,910	13,481,704.49	69,080	23,734,797.01	69,214	36,260,958.99
Total Industrial	647	2,858,102.66	646	2,956,746.09	649	3,168,057.29
Total Interruptible	88	2,134,129.50	89	2,431,984.36	89	2,647,202.69
Total Transportation - Commercial Firm	92	194,625.83	95	299,772.95	101	343,936.85
Total Transportation - Industrial Firm	123	825,114.07	126	1,197,727.26	127	1,139,758.17
Total Transportation - Interruptible	83	586,866.76	80	745,918.57	80	709,653.13
Unbilled Revenue		28,714,431.84		24,882,785.57		10,669,421.38
Agency Fees						
Net Balancing/Overrun				-		
Total Gas Operating Revenue		$ 75,354,167.79		$ 109,555,856.15		$ 140,096,257.98

	Customer Cnt Jan-26	Revenue Jan-26	Customer Cnt Feb-26	Revenue Feb-26	Customer Cnt Mar-26	Revenue Mar-26
Total	810,211	$ 158,164,984.84	810,167	$ 124,774,165.76	810,984	$ 93,224,205.69
Oregon	710,984	145,437,886.33	710,896	112,182,493.82	711,588	85,685,112.13
Washington	99,227	12,727,098.51	99,271	12,591,671.94	99,396	7,539,093.56
Total Residential	739,875	104,470,737.62	739,903	82,669,560.75	740,752	58,704,010.76
Total Commercial	69,296	44,757,569.14	69,225	35,735,506.93	69,201	27,026,382.81
Total Industrial	649	3,337,160.77	653	2,577,751.85	647	2,731,544.56
Total Interruptible	90	2,937,865.92	89	1,636,139.71	87	2,518,741.74
Total Transportation - Commercial Firm	95	389,659.24	95	352,756.26	96	263,025.57
Total Transportation - Industrial Firm	127	1,525,512.00	123	1,080,320.12	123	1,200,165.06
Total Transportation - Interruptible	79	746,480.15	79	722,130.14	78	780,335.19
Unbilled Revenue		(2,980,080.55)		(16,928,247.90)		(14,507,913.04)
Agency Fees						
Net Balancing/Overrun						
Total Gas Operating Revenue		$ 155,184,904.29		$ 107,845,917.86		$ 78,716,292.65

	Customer Cnt Apr-26	Revenue Apr-26	Customer Cnt May-26	Revenue May-26	Customer Cnt Jun-26	Revenue Jun-26
Total	807,816	$ 95,463,013.71	810,537	$ 63,446,752.56	809,917	$ 46,630,477.28
Oregon	709,333	87,219,430.30	711,158	58,227,724.40	710,534	42,512,674.37
Washington	98,483	8,243,583.41	99,379	5,219,028.16	99,383	4,117,802.91
Total Residential	737,260	60,603,776.84	740,450	38,103,900.78	740,064	26,372,622.09
Total Commercial	69,512	28,137,711.16	69,056	18,570,599.49	68,824	14,083,190.79
Total Industrial	652	2,675,466.91	646	2,485,949.75	644	2,319,181.96
Total Interruptible	91	2,423,356.86	89	2,138,123.66	89	1,809,420.59
Total Transportation - Commercial Firm	92	196,218.65	96	211,365.68	96	186,392.60
Total Transportation - Industrial Firm	126	834,970.53	123	1,177,299.77	123	1,107,662.12
Total Transportation - Interruptible	83	591,512.76	77	759,513.43	77	752,007.13
Unbilled Revenue		(18,455,546.87)		(14,965,070.47)		(4,768,379.54)
Agency Fees						
Net Balancing/Overrun						
Total Gas Operating Revenue		$ 77,007,466.84		$ 48,481,682.09		$ 41,862,097.74

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

	Forecasted 2026/2027	2025/2026	2024/2025	2023/2024	2022/2023	2021/2022
System peak demand (therms)	10,297,486	10,385,450	10,278,640	10,181,910	10,297,610	10,206,740

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

Gas Year	Forecasted 2026/2027	2025/2026	2024/2025	2023/2024	2022/2023	2021/2022
Annual Demand (therms)	847,099,393	871,891,040	853,772,745	862,272,608	838,438,962	822,144,498

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	Forecasted 2026/2027	2025/2026	2024/2025	2023/2024	2022/2023	2021/2022
Residential (therms)	471,736,109	481,610,965	484,207,721	486,051,411	467,591,574	464,438,613
Commercial (therms)	276,277,801	294,593,318	274,360,540	274,918,917	262,438,496	261,935,975
Industrial Firm (therms)	41,088,431	41,196,130	41,794,756	40,455,746	42,053,861	34,202,800
Industrial Interruptible (therms)	57,997,052	54,490,627	53,409,728	60,846,533	66,355,031	61,567,111
TOTAL	**847,099,393**	**871,891,040**	**853,772,745**	**862,272,608**	**838,438,962**	**822,144,498**

2. Annual and monthly baseload.

Gas Year	Forecasted 2026/2027	2025/2026	2024/2025	2023/2024	2022/2023	2021/2022
November	32,443,615	31,492,592	31,229,979	31,311,525	32,008,982	30,709,933
December	36,363,018	35,312,131	35,108,897	35,249,858	36,240,142	33,590,735
January	40,555,694	39,531,899	40,277,469	40,615,585	42,189,006	36,168,000
February	38,038,190	37,915,213	37,590,441	38,511,215	38,815,909	33,929,102
March	39,006,964	39,345,425	39,398,342	39,194,949	39,913,157	36,509,535
April	34,624,631	35,105,033	34,988,564	35,084,626	35,710,634	33,156,039
May	31,466,997	32,488,564	32,213,795	33,054,213	32,711,512	30,364,879
June	29,241,816	29,338,484	29,395,632	29,484,398	29,402,280	28,541,575
July	25,583,112	25,622,804	26,003,123	26,281,243	26,827,120	25,960,692
August	23,778,534	23,738,677	23,329,915	23,415,851	24,490,204	24,016,589
September	24,442,753	24,133,603	24,213,170	24,452,531	25,090,116	23,815,161
October	29,807,800	29,086,319	28,627,171	29,369,636	30,016,148	28,784,191
Annual	**385,353,124**	**383,110,745**	**382,376,499**	**386,025,629**	**393,415,209**	**365,546,431**

3. Annual and month non-base load.

Gas Year	Forecasted 2026/2027	2025/2026	2024/2025	2023/2024	2022/2023	2021/2022
November	61,862,776	63,934,748	61,961,062	62,874,670	59,240,744	60,832,815
December	91,955,151	95,752,173	92,086,825	93,436,441	88,508,994	90,713,996
January	89,044,541	91,092,860	89,615,139	89,959,105	85,544,762	88,079,277
February	73,330,049	75,621,015	76,159,954	78,872,973	69,943,462	71,559,429
March	58,740,787	63,281,315	60,107,540	59,953,377	58,088,579	59,848,154
April	36,058,614	39,658,399	39,963,335	39,892,203	36,295,437	36,964,858
May	14,002,080	17,787,135	15,078,726	15,060,180	14,700,339	14,997,271
June	3,760,843	5,366,733	4,620,732	4,497,156	3,642,146	3,765,614
July	848,001	1,853,923	1,996,729	2,077,177	867,988	905,559
August	2,444,175	3,298,002	1,208,063	1,139,536	845,980	839,829
September	4,556,462	5,471,046	3,728,894	3,421,564	2,858,652	2,987,241
October	25,142,790	25,662,945	24,869,246	25,062,598	24,486,671	25,104,023
Annual	**461,746,269**	**488,780,295**	**471,396,246**	**476,246,979**	**445,023,753**	**456,598,067**

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

NW Natural
UM1286 PGA Portfolio Guidelines
2026-2027 Oregon PGA

V.3.d. Historical (five years), and forecasted (one year ahead) sales system physical demand for each of the following:
4. Annual and monthly for the geographic regions utilized by each LDC in its most recent IRP or IRP update

2026/2027	ASTORIA	COOS BAY	NEWPORT	ALBANY	DALLES	PORTLAND	EUGENE	SALEM	WA VANCOUVER	WA DALLES WA	Total
November	2,946,272	405,809	2,586,913	6,037,925	1,197,086	52,163,159	6,340,847	12,713,948	9,648,238	275,581	94,315,778
December	3,679,571	527,474	3,062,416	8,081,731	1,630,748	73,861,538	8,567,128	17,225,735	13,981,540	393,667	131,011,548
January	3,715,718	503,217	3,056,038	8,175,435	1,644,082	75,017,471	8,599,434	17,324,935	14,507,370	404,223	132,947,922
February	3,406,973	471,809	2,852,312	6,942,722	1,366,494	62,641,490	7,403,843	14,786,108	12,330,184	331,761	112,533,697
March	3,216,651	452,740	2,414,634	6,121,085	1,151,024	52,578,451	6,460,688	12,887,196	10,647,253	279,130	96,208,852
April	2,656,012	354,983	2,199,696	4,442,698	803,040	36,156,199	4,656,708	9,193,758	7,365,022	189,245	68,017,362
May	1,844,261	250,791	1,955,899	2,870,372	514,164	22,743,350	2,993,001	5,768,420	4,816,620	121,105	43,877,984
June	1,584,056	196,358	1,596,712	2,091,045	394,905	17,030,125	2,198,604	4,285,737	3,493,937	87,229	32,958,707
July	1,428,675	165,393	1,461,211	1,724,657	325,925	13,502,979	1,739,714	3,415,770	2,868,779	71,390	26,704,492
August	1,405,021	160,510	1,452,027	1,729,471	326,843	13,301,083	1,725,232	3,419,433	2,792,982	66,806	26,379,408
September	1,551,805	176,851	1,565,270	1,890,956	355,700	14,494,338	1,881,385	3,816,792	3,018,532	74,123	28,825,752
October	2,226,471	277,499	2,087,545	3,523,097	670,194	27,877,332	3,628,594	7,275,631	5,599,784	151,746	53,317,893
Annual	29,661,485	3,943,436	26,290,672	53,631,194	10,380,204	461,367,516	56,195,177	112,113,463	91,070,242	2,446,005	847,099,393

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

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

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

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

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

2020/2021	ALBANY	ASTORIA	COOS BAY	DALLES (OR)	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

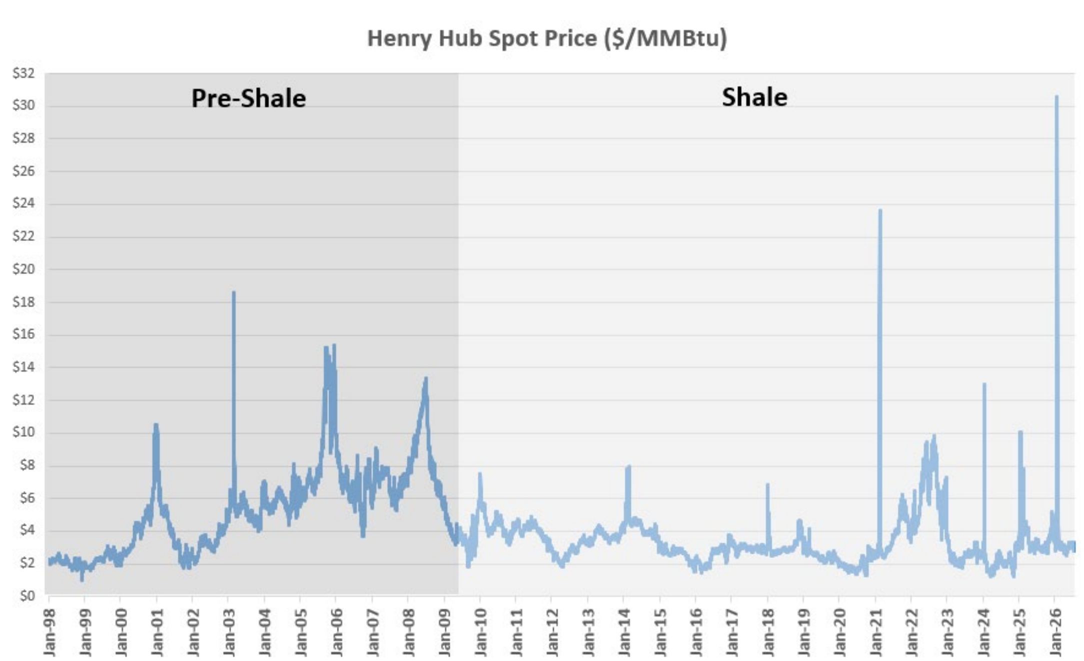
Section V.4 - Market Information

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

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

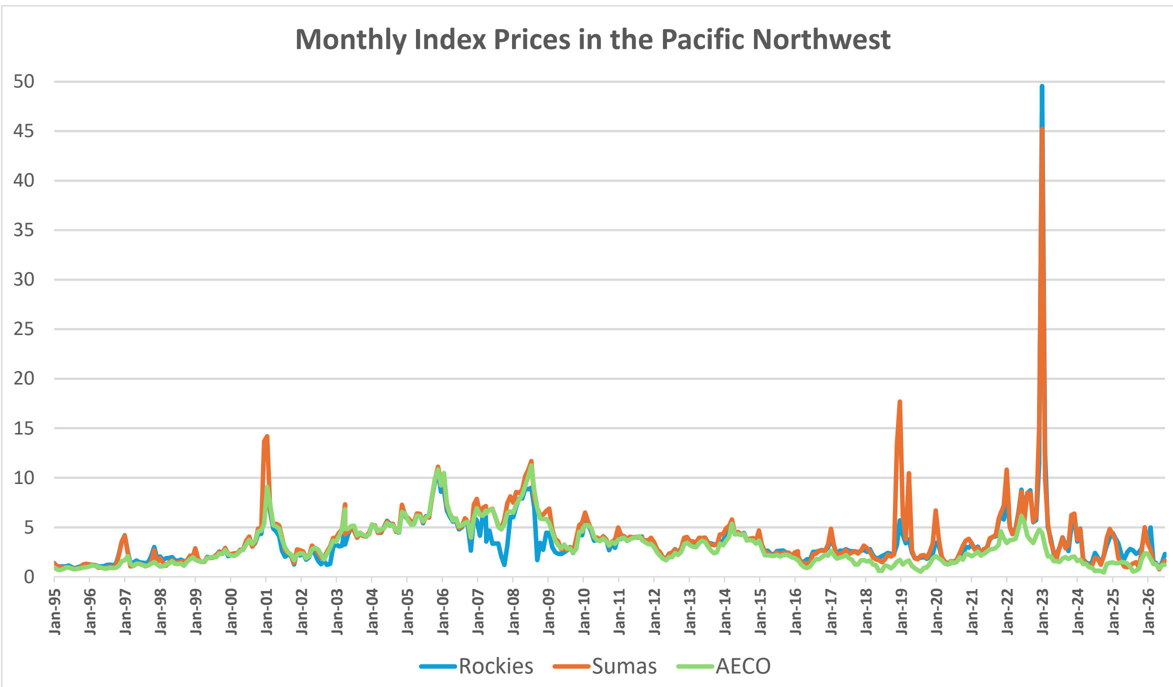
In the early 2000s, prices rose dramatically due to tightness in the supply/demand balance, a situation that Enron (and others) sought to exploit. This led to scandals, lawsuits, regulatory investigations, bankruptcies and other headline-making news that obscured the fact that gas supplies really were tightening and that demand growth would be dependent on bringing additional supplies to North America in the form of LNG imports. Catastrophic hurricanes (Katrina, Rita, et al) in 2005 interrupted natural gas supplies from the Gulf of Mexico and prices spiked again. Gas prices soared in the spring and summer of 2008 on the tail of predicted supply shortfalls. At that time, Henry Hub prices peaked at $13.31/Dth. Within months, the onset of a global economic recession reduced demand while the advent of horizontal drilling into shale formations unleashed a surge of production. Prices soon tumbled and remained quite low for over 10-years. More recently, extreme weather, LNG export growth, and infrastructure constraints, along with a variety of other factors, led to record volatility and a sharp rise in prices in 2022. While prices abated throughout 2023 and early 2024, they have since rebounded in 2025 amid tightening balances, with volatility returning as market fundamentals shift again. In 2026, natural gas prices are expected to remain above 2024 levels as growing LNG export demand supports market fundamentals. However, record U.S. natural gas production and above-average storage inventories are expected to moderate upward price pressure and help limit the magnitude of price increases. (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.

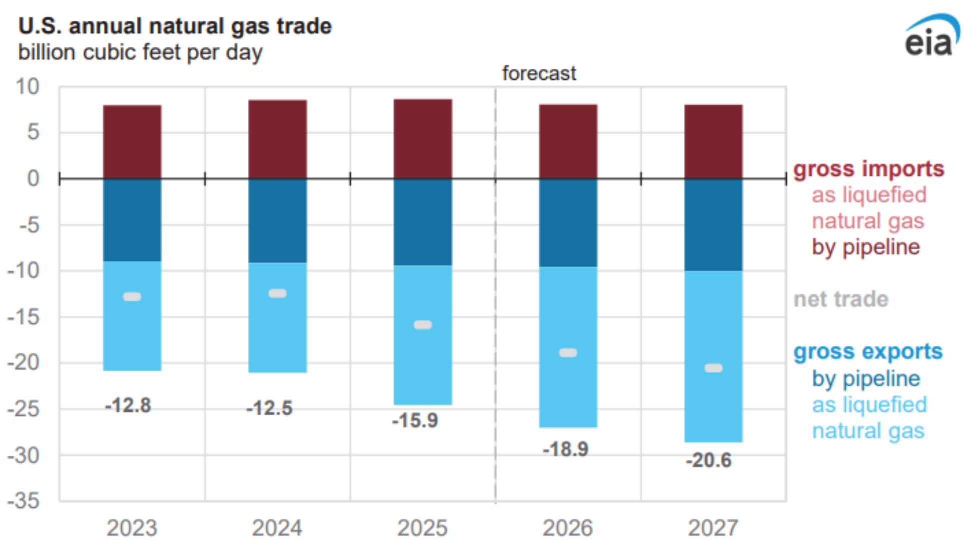
Sluggish production growth combined with strong demand for natural gas generation and LNG and Mexico pipeline exports added to a tight market and created upward pressure on prices during the second half of 2021. LNG exports continued to grow in 2022 as two new facilities came online and there was additional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

Production began to increase in late 2022 and hit a new average monthly record of 107 Bcf/d in December 2023. With supply finally outpacing demand, the U.S. storage inventory recovered to above the five-year average. Additionally, the consecutive mild winters of 2022/23 and 2023/24 in Europe provided relief to global LNG demand and prices. The additional supply led to lower prices in 2023 and resulted in a drop in both oil and gas rig counts. The outcome was seen in early 2024 as production began to decline and supply and demand came closer into balance.

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

By 2026, market fundamentals remained well supplied as record production and above-average storage inventories continued to moderate prices and limit volatility. However, demand trends shifted. Growing LNG exports and rising electricity consumption increased overall gas demand, while relatively low natural gas prices supported greater utilization of gas-fired generation. As a result, gas-fired power demand strengthened even as renewable generation continued to expand, marking a reversal from the softer power-sector demand observed in 2025.

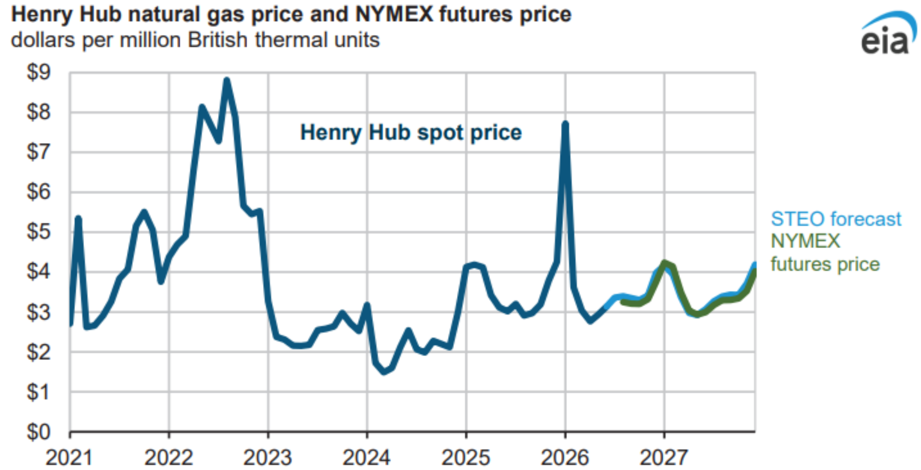
Figure 3



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, July 2026

The U.S. Energy Information Administration's (EIA) July 2026 Short-Term Energy Outlook has a baseline price forecast, 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. The EIA as well as the futures market represented by the NYMEX curve, indicate an expectation of relatively stable prices through 2026 and 2027, supported by record domestic production, above-average storage inventories , and continued growth in LNG exports (Figure 5). The EIA expects storage inventories to end the 2026 injection season 5% above the five-year average (Figure 6).

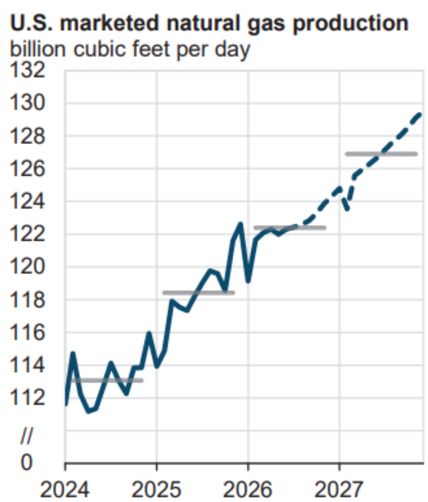
Figure 4



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, July 2026, Bloomberg L.P., and LSEG Data

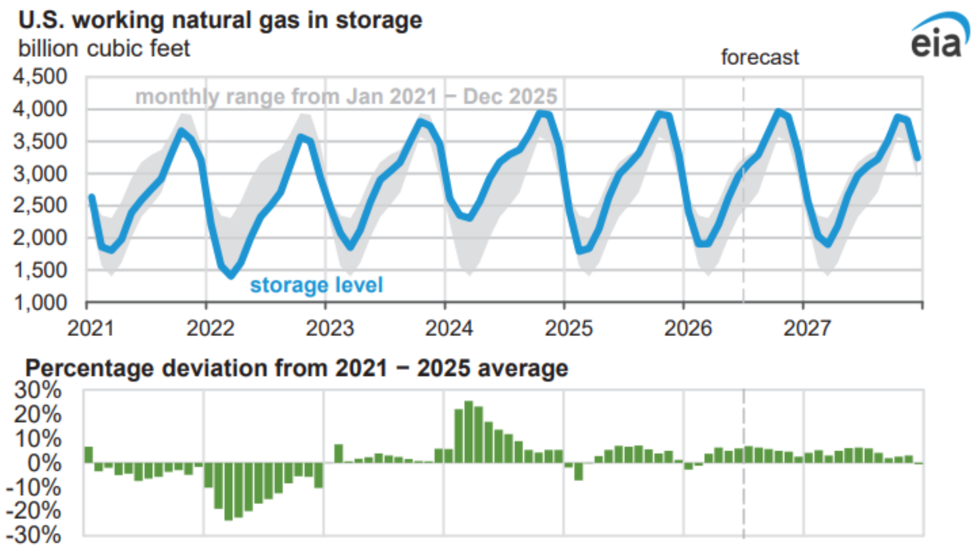
Note: Futures curve is the average settlement price for five trading days ending July 1, 2026.

Figure 5



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, July 2026

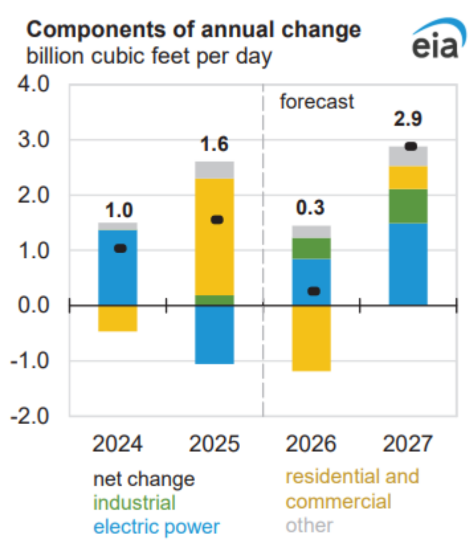
Figure 6



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, July 2026

Gas-fired electric generation can be another big driver of natural gas consumption and pricing. Due to growing electricity demand, additions to gas-fired generating capacity, and relatively low natural gas prices, demand for natural gas generation has increased in recent years. Although continued growth in renewable energy is expected to contribute a larger share of electricity generation, natural gas-fired generation is expected to remain an important complement to renewable resources by helping maintain system reliability and balancing intermittent generation sources such as wind and solar. Overall, the EIA expects an increase in natural gas consumption for electric generation in 2026 and 2027 compared to 2025 (Figure 7).

Figure 7



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, July 2026

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 began LNG production from phase 1 in 2026 and is expected to increase demand for gas supplies serving the California and Southwest markets, which could have an impact on regional prices. The LNG Canada export terminal located in British Columbia began commercial operations in 2025 and the Woodfibre LNG export terminal is expected to be online in 2027. Woodfibre LNG will utilize approximately 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 could be increased constraints and reduced liquidity at Sumas between the time Woodfibre LNG comes online in 2027 and the planned 2028 in-service date of the T-South expansion. The magnitude of the price response will also depend on the ability of gas producers to tap more supplies from western Canada (primarily BC shales) and the Rockies. These factors are not expected to have a major impact on the upcoming PGA year, whereas storage positions, the weather, and pipeline operations (maintenance activities, etc.) will continue, as they have in the past, to be the dominant factors influencing near-term prices.

Section V.5 - Data Interpretation

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

See Exhibit C, IV.2.b

Section V.6 - Credit Worthiness Standards

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

IV. Credit Risk Management

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

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

Source: NW Natural General Procedure G-72; Physical and financial Commodity Transaction Procedures
Effective March 28, 2005; Last updated January 5, 2015

The entire text of NW Natural Gas Supply Risk Management Policies
(pages 36-61) 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
2026-2027 Oregon PGA

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

Facility	Max. Daily Rate (Dth/day)	Max. Seasonal Level (Dth)
Jackson Prairie - aquifer - Chehalis, WA	46,030	1,120,288
Mist (share allocated to Utility) - depleted field - Mist, OR	340,000	13,386,040
Portland LNG - LNG Plant - Portland, OR	131,520	502,406
Newport LNG - LNG Plant - Newport, OR	78,000	1,122,061

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
2026-2027 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-22	119,491,279	$ 39,803,952.82	0.33311	30,332,306	$ 9,764,472.15	495,770	$ 181,363.05	0.36582	89,654,743	$ 30,220,843.72	0.33708
Feb	89,654,743	$ 30,220,843.72	0.33708	21,782,705	$ 7,566,832.47	-	$ -	-	67,872,038	$ 22,654,011.25	0.33378
Mar	67,872,038	$ 22,654,011.25	0.33378	5,809,463	$ 1,870,379.81	-	$ -	-	62,062,575	$ 20,783,631.44	0.33488
Apr	62,062,575	$ 20,783,631.44	0.33488	13,717,798	$ 5,181,177.62	470,660	$ 296,905.84	0.63083	48,815,437	$ 15,899,359.66	0.32570
May	48,815,437	$ 15,899,359.66	0.32570	1,189,464	$ 404,147.40	17,594,964	$ 12,988,824.99	0.73821	65,220,937	$ 28,484,037.25	0.43673
Jun	65,220,937	$ 28,484,037.25	0.43673	104,489	$ 35,940.04	22,093,556	$ 15,626,716.14	0.70730	87,210,004	$ 44,074,813.35	0.50539
Jul	87,210,004	$ 44,074,813.35	0.50539	71,804	$ 31,570.78	16,766,575	$ 8,899,782.01	0.53081	103,904,775	$ 52,943,024.58	0.50953
Aug	103,904,775	$ 52,943,024.58	0.50953	43,995	$ 19,515.40	23,156,431	$ 15,118,342.40	0.65288	127,017,211	$ 68,041,851.58	0.53569
Sep	127,017,211	$ 68,041,851.58	0.53569	99,721	$ 40,802.29	15,810,366	$ 8,502,694.85	0.53779	142,727,856	$ 76,503,744.13	0.53601
Oct	142,727,856	$ 76,503,744.13	0.53601	1,045,005	$ 598,517.41	16,911,241	$ 7,980,458.99	0.47190	158,594,092	$ 83,885,685.72	0.52893
Nov	158,594,092	$ 83,885,685.72	0.52893	7,637,659	$ 4,087,081.91	3,223	$ 2,459.65	0.76316	150,959,656	$ 79,801,063.46	0.52863
Dec	150,959,656	$ 79,801,063.46	0.52863	26,378,774	$ 14,000,235.69	202,826	$ 295,977.33	1.45927	124,783,708	$ 66,096,805.10	0.52969
TOTAL 2022 ACTIVITY				108,213,183	$ 43,600,672.97	113,505,612	$ 69,893,525.25				
Jan-23	124,783,708	$ 66,096,805.10	0.52969	28,212,941	$ 14,979,987.33	249,200	$ 75,627.50	0.30348	96,819,967	$ 51,192,445.27	0.52874
Feb	96,819,967	$ 51,192,445.27	0.52874	31,775,058	$ 16,896,399.03	-	$ -	-	65,044,909	$ 34,296,046.24	0.52727
Mar	65,044,909	$ 34,296,046.24	0.52727	16,466,254	$ 8,881,623.71	897,780	$ 283,663.50	0.31596	49,476,435	$ 25,698,086.03	0.51940
Apr	49,476,435	$ 25,698,086.03	0.51940	6,788,869	$ 3,334,552.47	13,152,839	$ 4,245,399.24	0.32277	55,840,405	$ 26,608,932.80	0.47652
May	55,840,405	$ 26,608,932.80	0.47652	85,460	$ 33,176.43	19,426,664	$ 3,967,966.47	0.20425	75,181,609	$ 30,543,722.85	0.40627
Jun	75,181,609	$ 30,543,722.85	0.40627	19,150	$ 7,434.22	22,766,674	$ 4,844,647.54	0.21280	97,929,133	$ 35,380,936.17	0.36129
Jul	97,929,133	$ 35,380,936.17	0.36129	11,790	$ 4,341.90	21,024,456	$ 6,019,331.56	0.28630	118,941,799	$ 41,395,925.83	0.34804
Aug	118,941,799	$ 41,395,925.83	0.34804	131,230	$ 49,767.75	18,674,385	$ 5,722,370.74	0.30643	137,484,954	$ 47,068,528.82	0.34235
Sep	137,484,954	$ 47,068,528.82	0.34235	240,710	$ 90,343.78	13,699,121	$ 3,496,004.74	0.25520	150,943,365	$ 50,474,189.77	0.33439
Oct	150,943,365	$ 50,474,189.77	0.33439	4,249,460	$ 1,192,092.17	6,576,373	$ 2,038,775.80	0.31002	153,270,278	$ 51,320,873.40	0.33484
Nov	153,270,278	$ 51,320,873.40	0.33484	6,302,866	$ 2,091,031.97	3,233,700	$ 1,005,742.59	0.31102	150,201,112	$ 50,235,584.02	0.33446
Dec	150,201,112	$ 50,235,584.02	0.33446	3,625,981	$ 1,220,551.01	1,244,340	$ 226,008.97	0.18163	147,819,471	$ 49,241,041.98	0.33312
TOTAL 2023 ACTIVITY				97,909,769	$ 48,781,301.77	120,945,532	$ 31,925,538.65				
Jan-24	147,819,471	$ 49,241,041.98	0.33312	33,240,052	$ 10,878,497.62	1,169,510	$ 678,435.10	0.58010	115,748,929	$ 39,040,979.46	0.33729
Feb	115,748,929	$ 39,040,979.46	0.33729	5,512,390	$ 1,850,511.49	-	$ -	-	110,236,539	$ 37,190,467.97	0.33737
Mar	110,236,539	$ 37,190,467.97	0.33737	313,180	$ 116,315.06	9,580,965	$ 1,318,504.79	0.13762	119,504,324	$ 38,392,657.70	0.32127
Apr	119,504,324	$ 38,392,657.70	0.32127	288,400	$ 95,003.15	6,367,964	$ 770,870.59	0.12105	125,583,888	$ 39,068,525.14	0.31110
May	125,583,888	$ 39,068,525.14	0.31110	305,180	$ 105,188.88	11,682,281	$ 1,271,103.38	0.10881	136,960,989	$ 40,234,439.64	0.29377
Jun	136,960,989	$ 40,234,439.64	0.29377	211,610	$ 72,571.66	4,607,290	$ 402,125.68	0.08728	141,356,669	$ 40,563,993.65	0.28696
Jul	141,356,669	$ 40,563,993.65	0.28696	243,390	$ 82,419.24	3,228,149	$ 188,029.09	0.05825	144,341,428	$ 40,669,603.50	0.28176
Aug	144,341,428	$ 40,669,603.50	0.28176	292,630	$ 96,675.72	9,509,232	$ 785,537.93	0.08261	153,558,030	$ 41,358,465.71	0.26933
Sep	153,558,030	$ 41,358,465.71	0.26933	257,020	$ 83,827.02	8,902,958	$ 877,990.20	0.09862	162,203,968	$ 42,152,628.89	0.25987
Oct	162,203,968	$ 42,152,628.89	0.25987	1,887,390	$ 477,814.16	3,363,780	$ 468,217.98	0.13919	163,680,358	$ 42,143,032.72	0.25747
Nov	163,680,358	$ 42,143,032.72	0.25747	3,818,247	$ 928,734.05	1,857,700	$ 357,174.70	0.19227	161,719,811	$ 41,571,473.37	0.25706
Dec	161,719,811	$ 41,571,473.37	0.25706	9,291,133	$ 2,362,965.39	1,277,080	$ 182,760.33	0.14311	153,705,758	$ 39,391,268.31	0.25628
TOTAL 2024 ACTIVITY				55,660,622	$ 17,150,523.44	61,546,909	$ 7,300,749.77				
Jan-25	153,705,758	$ 39,391,268.31	0.25628	33,236,284	$ 8,410,355.56	-	$ -	-	120,469,474	$ 30,980,912.75	0.25717
Feb	120,469,474	$ 30,980,912.75	0.25717	24,861,330	$ 6,396,693.57	772,950	$ 138,003.45	0.17854	96,381,094	$ 24,722,222.63	0.25650
Mar	96,381,094	$ 24,722,222.63	0.25650	1,614,180	$ 370,989.80	4,830,630	$ 587,888.63	0.12170	99,597,544	$ 24,939,121.46	0.25040
Apr	99,597,544	$ 24,939,121.46	0.25040	1,001,600	$ 208,650.07	10,955,754	$ 1,574,141.05	0.14368	109,551,698	$ 26,304,612.44	0.24011
May	109,551,698	$ 26,304,612.44	0.24011	157,000	$ 46,241.33	9,904,570	$ 1,441,859.83	0.14558	119,299,268	$ 27,700,230.94	0.23219
Jun	119,299,268	$ 27,700,230.94	0.23219	414,530	$ 98,660.11	10,860,534	$ 1,070,252.06	0.09855	129,745,272	$ 28,671,822.89	0.22099
Jul	129,745,272	$ 28,671,822.89	0.22099	258,110	$ 72,583.74	12,781,271	$ 2,202,153.88	0.17230	142,268,433	30,801,393	0.21650
Aug	142,268,433	$ 30,801,393.03	0.21650	260,230	$ 73,222.33	11,836,832	$ 1,607,660.39	0.13582	153,845,035	32,335,831	0.21018
Sep	153,845,035	$ 32,335,831.09	0.21018	185,000	$ 49,172.44	11,454,608	$ 1,332,413.66	0.11632	165,114,643	33,619,072	0.20361
Oct	165,114,643	$ 33,619,072.32	0.20361	1,759,470	$ 339,324.40	1,745,413	$ 274,370.54	0.15720	165,100,586	33,554,118	0.20323
Nov	165,100,586	$ 33,554,118.45	0.20323	1,650,080	$ 312,561.57	3,986,426	$ 1,449,507.62	0.36361	167,436,932	34,691,064	0.20719
Dec	167,436,932	$ 34,691,064.50	0.20719	3,345,473	$ 695,346.98	500,000	$ 103,272.84	0.20655	164,591,459	34,098,990	0.20717
TOTAL 2025 ACTIVITY				68,743,287	$ 17,073,801.90	79,628,988	$ 11,781,523.95				
Jan-26	164,591,459	$ 34,098,990.36	0.20717	19,490,750	$ 3,947,157.16	-	$ -	-	145,100,709	$ 30,151,833.20	0.20780
Feb	145,100,709	$ 30,151,833.20	0.20780	9,768,959	$ 1,976,341.38	-	$ -	-	135,331,750	$ 28,175,491.82	0.20820
Mar	135,331,750	$ 28,175,491.82	0.20820	252,680	$ 66,493.88	1,966,587	$ 350,503.16	0.17823	137,045,657	$ 28,459,501.10	0.20766
Apr	137,045,657	$ 28,459,501.10	0.20766	3,498,274	$ 744,321.74	2,096,610	$ 189,056.03	0.09017	135,643,993	$ 27,904,235.38	0.20572
May	135,643,993	$ 27,904,235.38	0.20572	216,770	$ 56,329.25	5,958,391	$ 608,931.10	0.10220	141,385,614	$ 28,456,837.23	0.20127
Jun	141,385,614	$ 28,456,837.23	0.20127	233,620	$ 58,997.22	4,477,567	$ 633,624.78	0.14151	145,629,561	$ 29,031,464.79	0.19935
Jul											
Aug											
Sep											
Oct											
Nov											
Dec											
TOTAL 2026 ACTIVITY				33,461,053	$ 6,849,640.63	14,499,155	$ 1,782,115.06				

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]

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

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 2026-27 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 October 24, 2024 and restates the Service Agreement made and entered into on September 26, 2017.

WHEREAS:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Title: DIRECTOR, GAS SUPPLY

Title: Director Commercial Services

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

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

   Exhibit B No

   Exhibit D No

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm

1. AVAILABILITY

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

2. APPLICABILITY AND CHARACTER OF SERVICE

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

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

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

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

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

3. MONTHLY RATE

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

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

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

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

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

3.2 Discounted Recourse Rates.

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

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

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

3. MONTHLY RATE (Continued)

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

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

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

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

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

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

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

3. MONTHLY RATE (Continued)

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

4. MINIMUM MONTHLY BILL

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

5. FUEL GAS REIMBURSEMENT

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

6. STORAGE DEMAND

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

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

7. STORAGE CAPACITY

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

8. DEFINITIONS

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

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

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

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

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

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

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

8. DEFINITIONS (Continued)

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

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

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

9. WITHDRAWALS OF STORAGE GAS

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

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

9. WITHDRAWALS OF STORAGE GAS (Continued)

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

10. INJECTIONS OF WORKING GAS FOR SHIPPER'S ACCOUNT

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

11. RESERVED FOR FUTURE USE

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

12. LIMITATIONS ON INJECTIONS AND WITHDRAWALS FROM STORAGE

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

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

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

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

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

14. TRANSFER OF WORKING GAS INVENTORY

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

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

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

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

15. EVERGREEN PROVISION

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

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

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

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

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

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

15. EVERGREEN PROVISION (Continued)

(a) The established rollover period will be:

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

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

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

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

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

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

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

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

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

15. EVERGREEN PROVISION (Continued)

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

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

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

16. GENERAL TERMS AND CONDITIONS

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

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

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

See attachment to V.7.h to this Exhibit C dated July 2026, 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 Field (pages 80-95) is confidential subject to Modified Protective Order No. 10-337 and has been redacted.

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

[BEGIN CONFIDENTIAL]

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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 8
- Section 2 – Attachments 1 to 15
- Section 3 – Attachments 2 and 3
- Section 4 – Attachment 1

NWN OPUC Advice No. 26-05A / UG 531

September 14, 2026

EXHIBIT D OVERVIEW – Renewable Natural Gas (RNG)

The following is included within this exhibit:

- Section 1 – New RNG Contracts or Updates
  - Attachment 1: **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** Environmental Attributes Purchase Agreement
  - Attachment 2: **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** Project Cost Model
  - Attachment 3: **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** Renewable Thermal Certificates Purchase and Sale Agreement
  - Attachment 4: **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** Project Cost Model
  - Attachment 5: **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** Environmental Attributes Purchase Agreement
  - Attachment 6: **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** Project Cost Model
  - Attachment 7: **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** Environmental Attributes Purchase Agreement
  - Attachment 8: **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** Project Cost Model
- Section 2 – Existing RNG Contracts by Feedstock
  - Attachment 1: BP Products North America Portfolio Environmental Attributes Monetization
  - Attachment 2: BP Products North America Portfolio Environmental Attributes Purchase Agreement
  - Attachment 3: BP Products North America Portfolio Project Cost Model
  - Attachment 4: BP Products North America Wasatch Resource Recovery Environmental Attributes Purchase Agreement
  - Attachment 5: BP Products North America Wasatch Resource Recovery Project Cost Model
  - Attachment 6: Terreva RNG Holdings LLC Brown Gas Purchase Agreement
  - Attachment 7: Terreva RNG Holdings LLC Bundled Resource Transaction Confirmation
  - Attachment 8: Terreva RNG Holdings LLC Bundled Resource Base Contract
  - Attachment 9: Terreva RNG Holdings LLC Project Cost Model
  - Attachment 10: Anew RNG LLC City of Topeka Wastewater Treatment Plant Attributes Purchase Agreement
  - Attachment 11: RNG LLC City of Topeka Wastewater Treatment Plant Project Cost Model
  - Attachment 12: Trident Group LLC Landfill Portfolio Environmental Attributes Purchase Agreement
  - Attachment 13: Trident Group LLC Landfill Portfolio Project Cost Model
  - Attachment 14: Junction City Clean Fuels LLC Environmental Attributes Purchase Agreement
  - Attachment 15: City Clean Fuels LLC Project Cost Model

- Section 3 – Historical Data
  - Attachment 1: 2026 NWN RFP
  - Attachment 2: 2026 Element Responses to RFP
  - Attachment 3: RNG Production through August 2026
- 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	Sources utilized to date are noted below, however, the seller may, from time-to-time during the Delivery Term, and upon ten (10) days' advanced written notice to buyer, add sources to the list: **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Product	Renewable Thermal Certificates (RTCs)
Contract Price	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Contract Quantity	250,000 RTCs per quarter
Delivery Deadline	Immediately following the production of the Biomethane
Start Date	1/01/2022
Delivery Term	Start Date thru 12/31/42
Certification Standard	Public Utility Commission of Oregon, Order No. 20-227
Tracking System	Midwest Renewable Energy Tracking System, Inc (M-RETS)

RNG Deal	Transaction No. 2
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	73,000 RTCs estimated annual generation
Delivery Deadline	Monthly following generation of RTC
Start Date	12/1/2021
Delivery Term	5 years from start date
Certification Standard	Oregon Administrative Rules, ch. 860, div. 150
Tracking System	Midwest Renewable Energy Tracking System, Inc (M-RETS)

RNG Deal	Transaction No. 3
Seller	Terreva Renewables LLC
Buyer	Northwest Natural Gas Company
Project	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Product	Renewable Thermal Certificates (RTCs) and commodity gas
Contract Price	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Contract Quantity	371,109 estimated annual generation (88.29% allocated to Oregon)
Delivery Deadline	Immediately following the production of the Biomethane
Start Date	09/01/2025
Delivery Term	15 years
Certification Standard	Public Utility Commission of Oregon, Order No. 20-227
Tracking System	Midwest Renewable Energy Tracking System, Inc (M-RETS)

RNG Deal	Transaction No. 4
Seller	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Buyer	Northwest Natural Gas Company
Project	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Product	Renewable Thermal Certificates (RTCs)
Contract Price	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Contract Quantity	7,300 estimated annual generation
Delivery Deadline	Monthly following generation of RTC
Start Date	1/1/2027
Delivery Term	Start date and continuing until Seller gives Buy 60 days' notice, not to exceed 2 years
Certification Standard	Oregon Administrative Rules, ch. 860, div. 150
Tracking System	Midwest Renewable Energy Tracking System, Inc (M-RETS)

RNG Deal	Transaction No. 5
Seller	Anew RNG LLC
Buyer	Northwest Natural Gas Company
Project	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Product	Renewable Thermal Certificates (RTCs)
Contract Price	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Contract Quantity	24,000 estimated annual generation
Delivery Deadline	Monthly following generation of RTC
Start Date	11/01/2025
Delivery Term	Start date thru 12/31/2027
Certification Standard	Oregon Administrative Rules, ch. 860, div. 150
Tracking System	Midwest Renewable Energy Tracking System, Inc (M-RETS)

RNG Deal	Transaction No. 6
Seller	Trident Group LLC
Buyer	Northwest Natural Gas Company
Project	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Product	Renewable Thermal Certificates (RTCs)
Contract Price	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Contract Quantity	1,365,000 estimated annual generation
Delivery Deadline	Monthly following generation of RTC
Start Date	11/01/2025
Delivery Term	Start date thru 09/01/2028
Certification Standard	Oregon Administrative Rules, ch. 860, div. 150
Tracking System	Midwest Renewable Energy Tracking System, Inc (M-RETS)

RNG Deal	Transaction No. 7
Seller	Junction City Clean Fuels LLC
Buyer	Northwest Natural Gas Company
Project	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Product	Renewable Thermal Certificates (RTCs)
Contract Price	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Contract Quantity	60,000 estimated annual generation
Delivery Deadline	Monthly following generation of RTC
Start Date	11/01/2025
Delivery Term	2 years, with annual renewals continuing until either party gives 60 days' prior written notice of non-renewal
Certification Standard	Oregon Administrative Rules, ch. 860, div. 150
Tracking System	Midwest Renewable Energy Tracking System, Inc (M-RETS)

RNG Deal	Transaction No. 8
Seller	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Buyer	Northwest Natural Gas Company
Project	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Product	Renewable Thermal Certificates (RTCs)
Contract Price	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Contract Quantity	720,000 estimated annual generation
Delivery Deadline	Monthly following generation of RTC
Start Date	1/01/2027
Delivery Term	1 year
Certification Standard	Oregon Administrative Rules, ch. 860, div. 150
Tracking System	Midwest Renewable Energy Tracking System, Inc (M-RETS)

RNG Deal	Transaction No. 9
Seller	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Buyer	Northwest Natural Gas Company
Project	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Product	Renewable Thermal Certificates (RTCs)
Contract Price	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Contract Quantity	109,500 estimated annual generation
Delivery Deadline	Monthly following generation of RTC
Start Date	1/01/2027
Delivery Term	5 years
Certification Standard	Oregon Administrative Rules, ch. 860, div. 150
Tracking System	Midwest Renewable Energy Tracking System, Inc (M-RETS)

RNG Deal	Transaction No. 10
Seller	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Buyer	Northwest Natural Gas Company
Project	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Product	Renewable Thermal Certificates (RTCs)
Contract Price	**[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**
Contract Quantity	100,000 estimated annual generation in 2027
Delivery Deadline	Monthly following generation of RTC
Start Date	9/01/2027
Delivery Term	5 years
Certification Standard	Oregon Administrative Rules, ch. 860, div. 150
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 are RNG purchases or projects developed by NW Natural.

NW Natural applies its risk adjusted incremental cost methodology to all potential utility RNG investments and RNG purchase opportunities. The Company develops its portfolio of RNG purchase opportunities by conducting an annual Request for Proposals (RFP) as well as evaluating other opportunities that arise outside of the RFP process throughout the year. In 2026, NW Natural received a total of 54 proposals from 24 responders in response to its RFP. NW Natural uses the same evaluation approach and incremental cost analysis to compare all available resources – both offtakes and development projects – on the same incremental cost basis so that at any point, there is visibility into whether a certain resource appears to be a better choice for customers than another. Section 1 lists the newly executed transactions since the last purchase gas adjustment. Section 2 provides the incremental cost calculation of the historical offtake contracts, as well as the contract term and other pertinent details. Among the opportunities that were available at the time, these offtake contracts had the lowest risk adjusted incremental cost.

2026 RFP Evaluation process:

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

RNG INCLUSION CONSISTENT WITH SB 98

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

RNG ALLOCATION

In the 2026-27 PGA, NW Natural allocated 88.29% of the total RNG volume (and associated costs) of Transaction 3 to Oregon customers and 11.71% to Washington customers, based on forecasted load volume. The remaining contracts are allocated 100% to Oregon.

EXHIBIT D

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

RENEWABLE NATURAL GAS

Section 1 Attachment 3 Placeholder

This highly confidential attachment will be filed with the Commission once the contract is fully executed, prior to the rate effective date.

NWN OPUC Advice No. 26-05A / UG 531

September 14, 2026

EXHIBIT D

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

RENEWABLE NATURAL GAS

Section 1 Attachment 5 Placeholder

This highly confidential attachment will be filed with the Commission once the contract is fully executed, prior to the rate effective date.

NWN OPUC Advice No. 26-05A / UG 531

September 14, 2026

EXHIBIT D

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

RENEWABLE NATURAL GAS

Section 1 Attachment 7 Placeholder

This highly confidential attachment will be filed with the Commission once the contract is fully executed, prior to the rate effective date.

NWN OPUC Advice No. 26-05A / UG 531

September 14, 2026

NW Natural®

REQUEST FOR PROPOSAL #2026-01
Renewable Natural Resources
250 SW Taylor St.
Portland, OR 97204
www.nwnatural.com

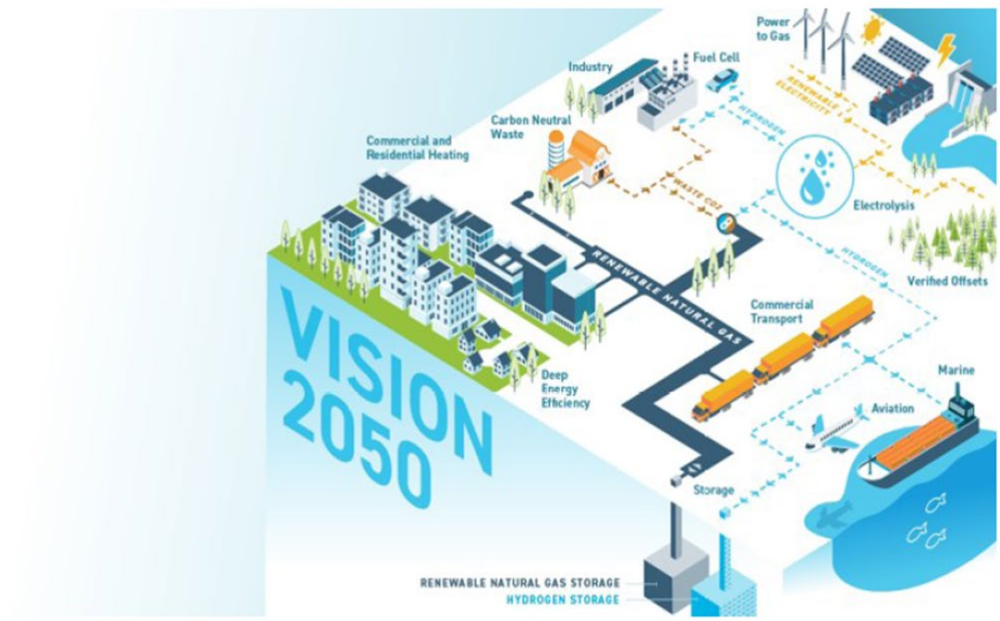

Table of Contents

1 General Information

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

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

1.1 Document Components

This document is organized in the following manner:

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

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

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

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

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

1.2 About NW Natural

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

1.3 Regulatory Summary

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

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

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

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

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

1.4 Objectives

NW Natural is a 167-year-old company that has evolved many times since 1859 to meet the essential energy needs of the region. NW Natural is committed to implementing climate solutions that work for the environment, our customers and the community. In 2016 NW Natural established a Low Carbon Pathway as a cornerstone of the company's strategic plan, setting a voluntary goal of 30% carbon savings by 2035 (using a 2015 customer and company operations baseline) and a goal of reaching carbon neutrality by 2050. With a long history of operating as a forward-looking and progressive utility company, NW Natural looks forward to the next chapter, bringing decarbonized resources to customers throughout its service territory.

NW Natural's objective for the 2026 RFP is to secure agreements to purchase Environmental Attributes associated with the production of RNG under our regulatory frameworks for the benefit of customers, and to do so with the least impact on customer costs. The resources may be sourced from around the country as well as Canada, and from a wide variety of feedstocks and sources including green hydrogen and synthetic methane produced from green or biogenic hydrogen and biogenic carbon sources. A portfolio approach, where RNG volumes are sourced from more than one resource, is acceptable.

NW Natural seeks to procure a total of 720,000 additional Dth of RNG in the 2026-2027 Price Gas Adjustment (PGA) year, which spans the period November 2026-October 2027. Agreements may be of any term length.

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

2 Project Overview and Scope of Services

2.1 Definitions

Environmental Attributes	"Environmental Attributes" means any and all environmental claims, credits, benefits, emissions reductions, offsets, and allowances attributable to the production of a renewable fuel and its avoided emission of pollutants. The environmental attributes of renewable fuel 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 fuel 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 fuel production facility for compliance with local, state, provincial, or federal operating and/or air quality permits.

Renewable Natural Gas or RNG	"Renewable Natural Gas" or "RNG" is gas that satisfies the definition of "renewable natural gas" or "renewable hydrogen" in either Oregon or Washington. The definitions have been set forth below for your convenience. Oregon definition per ORS 757.392(7): "Renewable natural gas" means any of the following products processed to meet pipeline quality standards or transportation fuel grade requirements: (a) Biogas that is upgraded to meet natural gas pipeline quality standards such that it may blend with, or substitute for, geologic natural gas; (b) Hydrogen gas derived from renewable energy sources; or (c) Methane gas derived from any combination of: a. Biogas; b. Hydrogen gas or carbon oxides derived from renewable energy sources; or c. Waste carbon dioxide. Washington definitions per RCW 54.04.190(6): "Renewable natural gas" means a gas consisting largely of methane and other hydrocarbons derived from the decomposition of organic material in landfills, wastewater treatment facilities, and anaerobic digesters. "Renewable hydrogen" means hydrogen produced using renewable resources both as the source for the hydrogen and the source for the energy input into the production process.
Renewable Thermal Certificate (RTC)	"Renewable Thermal Certificate" means a unique representation of the Environmental Attributes associated with the production, transport, and use of one dekatherm of renewable natural gas delivered to an injection point on a common carrier pipeline.
Clean Counts previously - Midwest Renewable Energy Tracking System (M-RETS)	The energy certificate system for tracking the purchase and sale of RTCs.

2.2 Scope of Services

NW Natural is seeking to procure the Environmental Attributes associated with RNG and will require the transfer of those attributes as RTCs. Bidder would sell and deliver to NW Natural, and NW Natural would purchase and receive from Bidder, all or a negotiated portion of the

RTCs from an RNG product. In this situation, 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 October 31, 2027.

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.

3.2 Materials

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

- 2026 Request for Proposal
- 2026 RFP Response Template – Proposal
- 2026 RFP Response Template – Certification
- Exhibit A: Non-disclosure Agreement
- Exhibit B: Renewable Natural Gas Attributes Purchase and Sale Agreement
- Exhibit C: Hydrogen Attributes Purchase and Sale Agreement

3.3 Request for Proposal Timeline

Date	Event
5/15/2026	Request for proposal issue date
5/29/2026	Questions due on RFP
6/5/2026	Question responses posted on website
6/26/2026 23:59 (PST)	Proposal submissions due
7/10/2026	Initial notification to responders

3.4 Request for Proposal and Bid Procedures

3.4.1 Questions and Communications

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

3.4.2 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 2026-01 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.

3.4.3 Terms and Conditions of Submission

- Bidder shall comply with all state and federal laws in regard to formulation and submittal of proposals. Bidder should note that this is a competitive process, and that conferring with other Bidders about pricing or other specific details of a proposal may violate antitrust law and is prohibited.
- Bidder represents that to the Bidder's knowledge it has satisfied all the requirements and that everything in its proposal is true and correct.
- Bidder shall under no circumstances use NW Natural's name or logos in advertising, marketing materials, printed materials, reference lists, or in any other way that could be construed as advertising (e.g., memo pads, tee shirts, binders, reference lists, etc.) without NW Natural's prior written consent.
- Any non-public information provided by NW Natural in connection with this RFP is confidential and proprietary to NW Natural. Such materials are to be used solely for the purpose of responding to this RFP. By requesting further information or submitting a proposal, Bidder agrees not to disclose any such information to any third party without the prior written consent of NW Natural (which consent shall be conditioned upon the written agreement of the intended recipient to treat the same as confidential), except as may be required by law. NW Natural may request at any time that any or all NW Natural material be returned or destroyed.
- Notwithstanding any non-disclosure or confidentiality agreement by and between NW Natural (or any affiliates) and Bidder (or any affiliates), Bidder acknowledges and agrees that any information set forth in a proposal submitted by Bidder may be subject to review and approval 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 a Non-Disclosure Agreement with NW Natural that will not expire in the next two years.
- NW Natural requires that the effectiveness of any proposed project or contract be conditioned on acknowledgement of such project or contract from the Oregon Public Utility Commission, pursuant to NW Natural's annual Purchase Gas Adjustment process, by November 1, 2026.

3.4.4 Renewable Thermal Certificates Requirements

- 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 Environmental Attributes that satisfy all requirements for listing on the Clean Counts system, and NW Natural may request further documentation in support of these 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 Clean Counts.

3.4.5 Errors or Omissions

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

3.4.6 Request for Proposal Response Withdrawal

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

3.5 Proposal Selection and Award Process

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

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

3.5.2 Proposal Scoring

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

1. The overall cost of the product.
2. Proposed terms of the purchase contract, including duration and renewal options.
3. Commercial terms including contractual remedies for failure to deliver.
4. The quantity of RTCs available for purchase.
5. The RNG site information/history.
6. The experience and proven performance of the firm making the proposal.

7. Overall ability of the project to successfully deliver qualifying RTCs within the terms of the contract.
8. Certification as a minority owned, women-owned, disadvantaged or emerging small business.
9. The existence of a demonstrated sustainability plan.
10. Resources in Oregon and Washington are particularly welcome.

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

3.5.3 Right to Reject Proposals and Negotiate Contract Terms

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

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

3.5.4 Awards and Final Offers

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

The terms of an unbundled purchase of RTCs would be set forth in an agreement (Exhibit B or C), containing legal terms that are standard for the purchase of RTCs or similar products, to be negotiated between the parties.

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

- Description of the fuel pathway from feedstock to end use;
- The type and quality of the gas, including the high heating value of the gas;

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

3.5.5 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. **2026 RFP Response Template – Proposal**
   Using the template provided by NW Natural, provide details about the proposed opportunity. See the instructions provided on the first tab. Please provide the file in Excel format.

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

   This requirement does not apply to those Bidders who have previously executed a Non-disclosure Agreement with NW Natural that will not expire in the next two years.

3. **2026 RFP Response Template – Certification**
   Using the template provided by NW Natural, certify and sign the proposal. The file may be provided in Word or .PDF format.

Optional

4. **Purchase Agreements**
   Section 3.4.4 outlines the agreements that are expected by NW Natural for finalization of a purchase transaction. Utilizing the templates, Bidder may elect to submit draft agreements as part of its RFP response to expedite the evaluation of their proposal. Files may be provided in Word or .PDF format.

5. **Additional Information**
   Provide any information, outside of the required data, which may aid NW Natural in making its selection.

EXHIBIT J

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

Non-Gas Cost Inclusions Associated With

Transportation Customer Energy Efficiency Program

UM 2323

NWN OPUC Advice No. 26-05A / UG 531

September 14, 2026

NW NATURAL

EXHIBIT J

Supporting Materials

Non-Gas Cost Associated With

Transportation Customer Energy Efficiency Program

NWN OPUC ADVICE NO. 26-05A / UG 531

NW Natural
Rates & Regulatory Affairs
2026-27 PGA - Oregon: September Filing
Calculation of Increments Allocated on the EQUAL PERCENTAGE OF MARGIN BASIS
ALL VOLUMES IN THERMS

1					Billing	WACOG &	Temps from							**Transportation EE Deferral 2024**		
2			Oregon PGA	Oregon PGA	Rate from	Demand from	Temporary						**Proposed Amount:**	(278,099)	Temporary Increment	
3			Volumes page,	Volume- EITEs	Rates page,	Rates page,	Increment page,	**MARGIN**	Volumetric	**Customer**		**Total**	**Revenue Sensitive Multiplier:**	2.907%	add revenue sensitive factor	
4			Column F		Column A	Column B+C+D*	Column A	**Rate**	Margin	**Charge**	**Customers**	**Margin**	**Amount to Amortize:**	**(286,424)**	to all classes and schedules	
5								**F=C-D-E**				**K=(I*J*12)+G**		**Multiplier**	Allocation to RS	**Increment**
6	Schedule	Block	**A**	**B**	**C**	**D**	**E**	**F**	**G = I * A**	**I**	**J**	**K**				
7	2R		411,057,580	411,057,580	$1.41220	$0.53478	$0.03419	$0.84323	$346,616,083	$9.78	647,078	$422,566,578		0.0	$0	$0.00000
8	3C Firm Sales		176,503,361	176,503,361	$1.23970	$0.53478	($0.02887)	$0.73379	$129,516,401	$15.00	58,857	$140,110,661		0.0	$0	$0.00000
9	3I Firm Sales		4,727,872	4,727,872	$1.08572	$0.53478	$0.05646	$0.49448	$2,337,838	$15.00	331	$2,397,418		0.0	$0	$0.00000
10	27 Dry Out		584,677	584,677	$1.25251	$0.53478	($0.01049)	$0.72822	$425,773	$8.00	1,382	$558,445		0.0	$0	$0.00000
11	31C Firm Sales	Block 1	13,656,203	13,656,203	$0.78159	$0.43451	($0.00753)	$0.35461	$7,895,434	$325.00	707	$10,652,734		0.0	$0	$0.00000
12		Block 2	9,421,084	9,421,084	$0.75008	$0.43451	($0.00847)	$0.32404						0.0		$0.00000
13	31C Firm Trans	Block 1	1,155,877	1,155,877	$0.41819	$0.00000	$0.09322	$0.32497	$703,772	$575.00	55	$1,083,272		1.0	($17,724)	($0.00818)
14		Block 2	1,101,903	1,101,903	$0.38793	$0.00000	$0.09013	$0.29780						1.0		($0.00750)
15	31I Firm Sales	Block 1	3,368,480	3,368,480	$0.75710	$0.43451	$0.05254	$0.27005	$2,561,603	$325.00	160	$3,185,603		0.0	$0	$0.00000
16		Block 2	6,770,266	6,770,266	$0.73028	$0.43451	$0.05177	$0.24400						0.0		$0.00000
17	31I Firm Trans	Block 1	129,581	110,831	$0.42698	$0.00000	$0.14545	$0.28153	$108,971	$575.00	5	$143,471		1.0	($2,347)	($0.00606)
18		Block 2	284,018	242,920	$0.39218	$0.00000	$0.13695	$0.25523						1.0		($0.00550)
19	32C Firm Sales[1]	Block 1	35,905,676	35,905,676	$0.67950	$0.43451	$0.05103	$0.19396	$8,793,011	$675.00	520	$13,109,315		0.0	$0	$0.00000
20		Block 2	9,554,234	9,554,234	$0.64912	$0.43451	$0.04999	$0.16462						0.0		$0.00000
21		Block 3	1,745,309	1,745,309	$0.59863	$0.43451	$0.04826	$0.11586						0.0		$0.00000
22		Block 4	802,581	802,581	$0.54796	$0.43451	$0.04652	$0.06693						0.0		$0.00000
23		Block 5	0	0	$0.51155	$0.43451	$0.04526	$0.03178						0.0		$0.00000
24		Block 6	0	0	$0.49429	$0.43451	$0.04467	$0.01511						0.0		$0.00000
25	32I Firm Sales[1]	Block 1	9,268,308	9,268,308	$0.62799	$0.43451	$0.04884	$0.14464	$2,704,303	$675.00	100	$3,561,032		0.0	$0	$0.00000
26		Block 2	8,227,501	8,227,501	$0.60571	$0.43451	$0.04821	$0.12299						0.0		$0.00000
27		Block 3	2,696,668	2,696,668	$0.56843	$0.43451	$0.04712	$0.08680						0.0		$0.00000
28		Block 4	2,255,924	2,255,924	$0.53127	$0.43451	$0.04603	$0.05073						0.0		$0.00000
29		Block 5	130,032	130,032	$0.50532	$0.43451	$0.04527	$0.02554						0.0		$0.00000
30		Block 6	0	0	$0.49228	$0.43451	$0.04491	$0.01286						0.0		$0.00000
31	32C Firm Trans	Block 1	3,057,342	3,057,342	$0.22444	$0.00000	$0.07262	$0.15182	$854,886	$925.00	31	$1,257,816		1.0	($20,579)	($0.00365)
32		Block 2	2,128,039	2,128,039	$0.20054	$0.00000	$0.07032	$0.13022						1.0		($0.00313)
33		Block 3	644,113	644,113	$0.16081	$0.00000	$0.06650	$0.09431						1.0		($0.00227)
34		Block 4	866,120	866,120	$0.12106	$0.00000	$0.06267	$0.05839						1.0		($0.00141)
35		Block 5	62,190	62,190	$0.09716	$0.00000	$0.06037	$0.03679						1.0		($0.00089)
36		Block 6	0	0	$0.08133	$0.00000	$0.05885	$0.02248						1.0		($0.00054)
37	32I Firm Trans	Block 1	11,016,531	10,457,112	$0.21299	$0.00000	$0.06995	$0.14304	$6,489,716	$925.00	101	$7,669,646		1.0	($125,485)	($0.00277)
38		Block 2	15,602,797	14,810,488	$0.19090	$0.00000	$0.06811	$0.12279						1.0		($0.00237)
39		Block 3	9,458,456	8,978,156	$0.15413	$0.00000	$0.06506	$0.08907						1.0		($0.00172)
40		Block 4	22,451,387	21,311,308	$0.11736	$0.00000	$0.06202	$0.05534						1.0		($0.00107)
41		Block 5	21,475,941	20,385,395	$0.09523	$0.00000	$0.06018	$0.03505						1.0		($0.00068)
42		Block 6	7,418,474	7,041,764	$0.08060	$0.00000	$0.05898	$0.02162						1.0		($0.00042)
43	32C Interr Sales	Block 1	4,132,294	4,132,294	$0.63625	$0.43451	$0.04288	$0.15886	$2,161,149	$675.00	37	$2,460,849		0.0	$0	$0.00000
44		Block 2	6,058,058	6,058,058	$0.61173	$0.43451	$0.04222	$0.13500						0.0		$0.00000
45		Block 3	3,271,549	3,271,549	$0.57078	$0.43451	$0.04111	$0.09516						0.0		$0.00000
46		Block 4	4,837,562	4,837,562	$0.52983	$0.43451	$0.04000	$0.05532						0.0		$0.00000
47		Block 5	3,434,773	3,434,773	$0.50524	$0.43451	$0.03931	$0.03142						0.0		$0.00000
48		Block 6	0	0	$0.48727	$0.43451	$0.03884	$0.01392						0.0		$0.00000
49	32I Interr Sales	Block 1	5,733,047	5,733,047	$0.61610	$0.43451	$0.04265	$0.13894	$2,788,548	$675.00	49	$3,185,448		0.0	$0	$0.00000
50		Block 2	7,298,404	7,298,404	$0.59475	$0.43451	$0.04209	$0.11815						0.0		$0.00000
51		Block 3	4,456,416	4,456,416	$0.55916	$0.43451	$0.04114	$0.08351						0.0		$0.00000
52		Block 4	12,581,349	12,581,349	$0.52354	$0.43451	$0.04019	$0.04884						0.0		$0.00000
53		Block 5	5,103,939	5,103,939	$0.50215	$0.43451	$0.03961	$0.02803						0.0		$0.00000
54		Block 6	0	0	$0.48653	$0.43451	$0.03921	$0.01281						0.0		$0.00000
55	32C Interr Trans	Block 1	667,319	667,319	$0.20565	$0.00000	$0.06758	$0.13807	$517,557	$925.00	3	$550,857		1.0	($9,013)	($0.00240)
56		Block 2	1,394,375	1,394,375	$0.18462	$0.00000	$0.06605	$0.11857						1.0		($0.00206)
57		Block 3	939,924	939,924	$0.14961	$0.00000	$0.06351	$0.08610						1.0		($0.00150)
58		Block 4	3,098,587	3,098,587	$0.11452	$0.00000	$0.06095	$0.05357						1.0		($0.00093)
59		Block 5	386,468	386,468	$0.09350	$0.00000	$0.05942	$0.03408						1.0		($0.00059)
60		Block 6	0	0	$0.07952	$0.00000	$0.05840	$0.02112						1.0		($0.00037)
61	32I Interr Trans	Block 1	5,864,800	5,690,968	$0.20496	$0.00000	$0.06879	$0.13617	$6,068,607	$925.00	66	$6,801,207		1.0	($111,276)	($0.00250)
62		Block 2	9,761,912	9,472,569	$0.18409	$0.00000	$0.06713	$0.11696						1.0		($0.00214)
63		Block 3	5,807,692	5,635,552	$0.14935	$0.00000	$0.06439	$0.08496						1.0		($0.00156)
64		Block 4	12,637,820	12,263,236	$0.11453	$0.00000	$0.06162	$0.05291						1.0		($0.00097)
65		Block 5	28,598,086	27,750,439	$0.09368	$0.00000	$0.05996	$0.03372						1.0		($0.00062)
66		Block 6	95,643,968	92,809,083	$0.07979	$0.00000	$0.05886	$0.02093						1.0		($0.00038)
67	33		0	0	$0.06550	$0.00000	$0.05754	$0.00796	$0	$38,000.00	0	$0		1.0	0	$0.00000
68	Special Contracts		75,345,634	17,609,566	$0.00000	$0.00000	$0.05279	($0.05279)	($3,977,496)	$0.00	7	($3,977,496)		0.0	$0	$0.00000
69																
70	TOTALS		1,090,582,502						$ 516,566,156			$ 615,316,856		$ 17,506,269	$ (286,424)	

NW Natural
Rates & Regulatory Affairs
2026-27 PGA - Oregon: September Filing
Calculation of Increments Allocated on the EQUAL CENT PER THERM BASIS
ALL VOLUMES IN THERMS

1					**Transportation EE Deferral 2025**		
2			**Oregon PGA**	**Proposed Amount:**	122,422	Temporary Increment	
3			**Volumes page,**	**Revenue Sensitive Multiplier:**	2.907%	add revenue sensitive factor	
4			**Column F**	**Amount to Amortize:**	**126,087**	to all customers	
5					**Multiplier**	**Volumes**	**Increment**
6	Schedule	Block	**A**		**BM**	**BN**	**BO**
7	2R		411,057,580		1.0	411,057,580	$0.00015
8	3C Firm Sales		176,503,361		1.0	176,471,328	$0.00015
9	3I Firm Sales		4,727,872		1.0	4,625,789	$0.00015
10	27 Dry Out		584,677		1.0	584,677	$0.00015
11	31C Firm Sales	Block 1	13,656,203		1.0	13,638,642	$0.00015
12		Block 2	9,421,084		1.0	9,405,566	$0.00015
13	31C Firm Trans	Block 1	1,155,877		1.0	1,155,877	$0.00015
14		Block 2	1,101,903		1.0	1,101,903	$0.00015
15	31I Firm Sales	Block 1	3,368,480		1.0	3,342,841	$0.00015
16		Block 2	6,770,266		1.0	6,716,234	$0.00015
17	31I Firm Trans	Block 1	129,581		1.0	69,732	$0.00015
18		Block 2	284,018		1.0	138,218	$0.00015
19	32C Firm Sales	Block 1	35,905,676		1.0	35,866,199	$0.00015
20		Block 2	9,554,234		1.0	9,542,095	$0.00015
21		Block 3	1,745,309		1.0	1,743,173	$0.00015
22		Block 4	802,581		1.0	801,617	$0.00015
23		Block 5	0		1.0	(18)	$0.00015
24		Block 6	0		1.0	0	$0.00015
25	32I Firm Sales	Block 1	9,268,308		1.0	8,760,924	$0.00015
26		Block 2	8,227,501		1.0	7,758,694	$0.00015
27		Block 3	2,696,668		1.0	2,525,194	$0.00015
28		Block 4	2,255,924		1.0	2,086,713	$0.00015
29		Block 5	130,032		1.0	103,982	$0.00015
30		Block 6	0		1.0	0	$0.00015
31	32C Firm Trans	Block 1	3,057,342		1.0	3,057,342	$0.00015
32		Block 2	2,128,039		1.0	2,128,039	$0.00015
33		Block 3	644,113		1.0	644,113	$0.00015
34		Block 4	866,120		1.0	866,120	$0.00015
35		Block 5	62,190		1.0	62,190	$0.00015
36		Block 6	0		1.0	0	$0.00015
37	32I Firm Trans	Block 1	11,016,531		1.0	6,577,168	$0.00015
38		Block 2	15,602,797		1.0	9,278,472	$0.00015
39		Block 3	9,458,456		1.0	5,593,328	$0.00015
40		Block 4	22,451,387		1.0	13,953,246	$0.00015
41		Block 5	21,475,941		1.0	12,751,811	$0.00015
42		Block 6	7,418,474		1.0	4,483,162	$0.00015
43	32C Interr Sales	Block 1	4,132,294		1.0	4,132,294	$0.00015
44		Block 2	6,058,058		1.0	6,058,058	$0.00015
45		Block 3	3,271,549		1.0	3,271,549	$0.00015
46		Block 4	4,837,562		1.0	4,837,562	$0.00015
47		Block 5	3,434,773		1.0	3,434,773	$0.00015
48		Block 6	0		1.0	0	$0.00015
49	32I Interr Sales	Block 1	5,733,047		1.0	4,860,358	$0.00015
50		Block 2	7,298,404		1.0	6,133,529	$0.00015
51		Block 3	4,456,416		1.0	3,795,628	$0.00015
52		Block 4	12,581,349		1.0	10,690,075	$0.00015
53		Block 5	5,103,939		1.0	4,204,805	$0.00015
54		Block 6	0		1.0	0	$0.00015
55	32C Interr Trans	Block 1	667,319		1.0	667,319	$0.00015
56		Block 2	1,394,375		1.0	1,394,375	$0.00015
57		Block 3	939,924		1.0	939,924	$0.00015
58		Block 4	3,098,587		1.0	3,098,587	$0.00015
59		Block 5	386,468		1.0	386,468	$0.00015
60		Block 6	0		1.0	0	$0.00015
61	32I Interr Trans	Block 1	5,864,800		1.0	1,172,368	$0.00015
62		Block 2	9,761,912		1.0	1,966,046	$0.00015
63		Block 3	5,807,692		1.0	875,397	$0.00015
64		Block 4	12,637,820		1.0	1,156,592	$0.00015
65		Block 5	28,598,086		1.0	4,831,452	$0.00015
66		Block 6	95,643,968		1.0	17,537,234	$0.00015
67	33		0		1.0	0	$0.00015
68	Special Contracts		75,345,634		0.0	0	$0.00000
69							
70	TOTALS		1,090,582,502			842,336,346	$ 0.00015

NW Natural
Rates & Regulatory Affairs
2026-27 PGA - Oregon: September Filing
Effects on Average Bill by Rate Schedule [1]
ALL VOLUMES IN THERMS

						Sch 169 ALL (Sales+Transport) Removed		11/1/2025	11/1/2025	**Sch 169 ALL (Sales+Transport) Removed** 11/1/2025						**Advice** See note [18]
1			Oregon PGA		Normal	Normal					Proposed	Proposed	Proposed	Proposed	Proposed	Proposed
2			Normalized		Therms	Therms	Minimum		Normal	Normal	10/31/2026	10/31/2026	10/31/2026	10/31/2026	10/31/2026	10/31/2026
											Schedule 169	Schedule 169	**Schedule 169**	Schedule 169		**Schedule 169**
											Transport EE	Transport EE	**Transport EE**	Transport EE	Schedule 169	**Transport EE**
3			Volumes page,	Therms in	Monthly	Monthly	Monthly	Billing	Current	Current	2024	2024	**2024**	**2025**	Transport EE 2025	**2025**
4			Column D	Block	Average use	Average use	Charge	Rates	Average Bill	Average Bill	Rates	Average Bill	**% Bill Change**	Rates	Average Bill	**% Bill Change**
5									**F=D+(C * E)**			**AI = D+(C * AH)**	**AJ = (AI- F)/F**		**AO = D+(C*AN)**	**AP = (AO-F)/F**
6	Schedule	Block	**A**	**B**	**C**		**D**	**E**	**F**		**AH**	**AI**	**AJ**	**AN**	**AO**	**AP**
7	2SF		364,525,125	N/A	53	53	$10.00	$1.41220	$84.85	$84.85	$1.41220	$84.85	0.0%	$1.41085	$84.78	-0.1%
	2MF		46,532,455	N/A	53	53	$8.00	$1.41220	$82.85	$82.85	$1.41220	$82.85		$1.41085	$82.78	-0.1%
8	3C Firm Sales		176,503,361	N/A	250	250	$15.00	$1.23970	$324.93	$324.93	$1.23970	$324.93	0.0%	$1.23835	$324.59	-0.1%
9	3I Firm Sales		4,727,872	N/A	1,190	1,175	$15.00	$1.08572	$1,307.01	$1,290.72	$1.08572	$1,307.01	0.0%	$1.08437	$1,289.13	-0.1%
10	27 Dry Out		584,677	N/A	35	35	$8.00	$1.25251	$51.84	$51.84	$1.25251	$51.84	0.0%	$1.25116	$51.79	-0.1%
11	31C Firm Sales	Block 1	13,656,203	2,000	2,720	2,720	$325.00	$0.78159	**$2,428.24**	**$2,428.24**	$0.78159	**$2,428.24**	0.0%	$0.78024	**$2,424.57**	-0.2%
12		Block 2	9,421,084	all additional				$0.75008			$0.75008			$0.74873		
13	31C Firm Trans	Block 1	1,155,877	2,000	3,421	3,421	$575.00	$0.41819	**$1,962.63**	**$1,962.63**	$0.38582	**$1,855.83**	-5.4%	$0.41684	**$1,958.01**	-0.2%
14		Block 2	1,101,903	all additional				$0.38793			$0.35833			$0.38658		
15	31I Firm Sales	Block 1	3,368,480	2,000	5,281	5,305	$325.00	$0.75710	**$4,235.25**	**$4,252.78**	$0.75710	**$4,235.25**	0.0%	$0.75575	**$4,245.61**	-0.2%
16		Block 2	6,770,266	all additional				$0.73028			$0.73028			$0.72893		
17	31I Firm Trans	Block 1	129,581	2,000	6,893	4,332	$575.00	$0.42698	**$3,347.90**	**$2,343.52**	$0.36327	**$2,938.88**	-12.2%	$0.42563	**$2,337.68**	-0.2%
18		Block 2	284,018	all additional				$0.39218			$0.33463			$0.39083		
19	32C Firm Sales	Block 1	35,905,676	10,000	7,694	7,700	$675.00	$0.67950	**$5,903.07**	**$5,907.15**	$0.67950	**$5,903.07**	0.0%	$0.67815	**$5,896.76**	-0.2%
20		Block 2	9,554,234	20,000				$0.64912			$0.64912			$0.64777		
21		Block 3	1,745,309	20,000				$0.59863			$0.59863			$0.59728		
22		Block 4	802,581	100,000				$0.54796			$0.54796			$0.54661		
23		Block 5	0	600,000				$0.51155			$0.51155			$0.51020		
24		Block 6	0	all additional				$0.49429			$0.49429			$0.49294		
25	32I Firm Sales	Block 1	9,268,308	10,000	18,815	18,628	$675.00	$0.62799	**$12,294.23**	**$12,180.97**	$0.62799	**$12,294.23**	0.0%	$0.62664	**$12,155.82**	-0.2%
26		Block 2	8,227,501	20,000				$0.60571			$0.60571			$0.60436		
27		Block 3	2,696,668	20,000				$0.56843			$0.56843			$0.56708		
28		Block 4	2,255,924	100,000				$0.53127			$0.53127			$0.52992		
29		Block 5	130,032	600,000				$0.50532			$0.50532			$0.50397		
30		Block 6	0	all additional				$0.49228			$0.49228			$0.49093		
31	32C Firm Trans	Block 1	3,057,342	10,000	18,166	18,166	$925.00	$0.22444	**$4,807.01**	**$4,807.01**	$0.21043	**$4,569.65**	-4.9%	$0.22309	**$4,782.49**	-0.5%
32		Block 2	2,128,039	20,000				$0.20054			$0.18863			$0.19919		
33		Block 3	644,113	20,000				$0.16081			$0.15239			$0.15946		
34		Block 4	866,120	100,000				$0.12106			$0.11614			$0.11971		
35		Block 5	62,190	600,000				$0.09716			$0.09434			$0.09581		
36		Block 6	0	all additional				$0.08133			$0.07991			$0.07998		
37	32I Firm Trans	Block 1	11,016,531	10,000	72,132	47,166	$925.00	$0.21299	**$12,552.91**	**$9,518.70**	$0.20198	**$12,038.38**	-4.1%	$0.21164	**$9,455.02**	-0.7%
38		Block 2	15,602,797	20,000				$0.19090			$0.18155			$0.18955		
39		Block 3	9,458,456	20,000				$0.15413			$0.14753			$0.15278		
40		Block 4	22,451,387	100,000				$0.11736			$0.11350			$0.11601		
41		Block 5	21,475,941	600,000				$0.09523			$0.09302			$0.09388		
42		Block 6	7,418,474	all additional				$0.08060			$0.07949			$0.07925		
43	32C Interr Sales	Block 1	4,132,294	10,000	48,951	48,951	$675.00	$0.63625	**$30,088.95**	**$30,088.95**	$0.63625	**$30,088.95**	0.0%	$0.63490	**$30,022.87**	-0.2%
44		Block 2	6,058,058	20,000				$0.61173			$0.61173			$0.61038		
45		Block 3	3,271,549	20,000				$0.57078			$0.57078			$0.56943		
46		Block 4	4,837,562	100,000				$0.52983			$0.52983			$0.52848		
47		Block 5	3,434,773	600,000				$0.50524			$0.50524			$0.50389		
48		Block 6	0	all additional				$0.48727			$0.48727			$0.48592		
49	32I Interr Sales	Block 1	5,733,047	10,000	59,818	54,971	$675.00	$0.61610	**$35,054.32**	**$32,516.72**	$0.61610	**$35,054.32**	0.0%	$0.61475	**$32,442.51**	-0.2%
50		Block 2	7,298,404	20,000				$0.59475			$0.59475			$0.59340		
51		Block 3	4,456,416	20,000				$0.55916			$0.55916			$0.55781		
52		Block 4	12,581,349	100,000				$0.52354			$0.52354			$0.52219		
53		Block 5	5,103,939	600,000				$0.50215			$0.50215			$0.50080		
54		Block 6	0	all additional				$0.48653			$0.48653			$0.48518		
55	32C Interr Trans	Block 1	667,319	10,000	180,185	180,185	$925.00	$0.20565	**$23,940.40**	**$23,940.40**	$0.19632	**$23,192.85**	-3.1%	$0.20430	**$23,697.15**	-1.0%
56		Block 2	1,394,375	20,000				$0.18462			$0.17669			$0.18327		
57		Block 3	939,924	20,000				$0.14961			$0.14400			$0.14826		
58		Block 4	3,098,587	100,000				$0.11452			$0.11125			$0.11317		
59		Block 5	386,468	600,000				$0.09350			$0.09163			$0.09215		
60		Block 6	0	all additional				$0.07952			$0.07857			$0.07817		
61	32I Interr Trans	Block 1	5,864,800	10,000	199,892	44,133	$925.00	$0.20496	**$25,770.28**	**$8,767.16**	$0.19499	**$24,932.60**	-3.3%	$0.20361	**$8,707.58**	-0.7%
62		Block 2	9,761,912	20,000				$0.18409			$0.17562			$0.18274		
63		Block 3	5,807,692	20,000				$0.14935			$0.14336			$0.14800		
64		Block 4	12,637,820	100,000				$0.11453			$0.11104			$0.11318		
65		Block 5	28,598,086	600,000				$0.09368			$0.09168			$0.09233		
66		Block 6	95,643,968	all additional				$0.07979			$0.07879			$0.07844		
67	33		0	N/A	0.0	0.0	$38,000.00	$0.06550	$38,000.00	$38,000.00	$0.06550	$38,000.00		$0.06415	$38,000.00	
68	Special Contracts		75,345,634	N/A	0	0	$0	$0.00000	$0.00	$0.00	$0.00000	$0.00		$0.00000	$0.00	

NW Natural
Rates and Regulatory Affairs
2026-2027 PGA Filing - OREGON
Basis for Revenue Related Costs

		Twelve Months		
1		Ended 06/30/26		
2				
3	Total Billed Gas Sales Revenues	$ 914,402,342		
4	Total Oregon Revenues	$ 918,820,399		
5				
6	Regulatory Commission Fees [1]	n/a	0.360%	Statutory rate
7	City License and Franchise Fees	$ 21,576,831	2.348%	Line 7 ÷ Line 4
8	Net Uncollectible Expense [2]	$ 1,824,506	0.199%	Line 8 ÷ Line 4
9				
10	Total		**2.907%**	Sum lines 8-9
11				
12				
13	**Note:**			
14	[1] Dollar figure is set at statutory level of Total Oregon Revenues (line 4).			
15	[2] Represents the normalized net write-offs based on a three-year average.			

NW Natural
Rates & Regulatory Affairs
2026-2027 PGA Filing - Oregon: September Filing
PGA Effects on Revenue
Schedule 169: Transport EE

		Including Revenue Sensitive Amount
1		
2	**Temporary Increments**	
3		
4	Removal of Current Temporary Increments	
5	Amortization of Transport EE	(2,056,725)
6		
7	Addition of Proposed Temporary Increments	
8	Amortization of Transport EE	(160,337)
9		(160,337)
10		
11	**TOTAL OF ALL COMPONENTS OF RATE CHANGES**	**($2,217,062)**
12		
13		
14		
15	2025 Oregon Earnings Test Normalized Total Revenues	$1,005,966,120
16		
17	Effect of this filing, as a percentage change (line 11 ÷ line 15)	-0.22%

NW Natural
Rates & Regulatory Affairs
2026-27 PGA Filing - September Filing
Summary of Deferred Accounts Included in the PGA

Account		Balance 6/30/2026	Jul-Oct Estimated Activity	Jul-Oct Interest	Estimated Balance 10/31/2026	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	**4.61%**		G = E + F2
151831 TRANSPORTATION EE DEFERRAL		**(328,749)**	-	(7,872)	(336,621)			
151833 TRANSPORTATION EE AMORTIZATION		**650,058**	(472,515)	7,220.92	184,764			
Total		321,309	(472,514.88)	(651)	(151,857)	4.61%	(3,819)	(155,676)
	Amortization Split							
Transport EE 2024 Deferral		(328,749)	0	(7,872)	(336,621)			
Transport EE 2024 Amortization	35.37%	229,903	(167,112)	2,554	65,345			
					(271,277)	4.61%	(6,822)	**(278,099)**
Transport EE 2025 Deferral		0	-	0	0			
Transport EE 2025 Amortization	64.63%	420,154	(305,402)	4,667	119,419	4.61%	3,003	**122,422**

Company: Northwest Natural Gas Company
State: Oregon
Description: OR Transportation Energy Efficiency
Account Number: **151831**
Info: UM 2323, Order 25-425

Debit (Credit)

	Month/Year	Note	Deferrals	Transfers	Interest Rate	Interest	Activity	Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Beginning Balance							
61	Jul-25		-		7.06%	11,142.82	11,142.82	1,906,180.27
62	Aug-25		-		7.06%	11,208.34	11,208.34	1,917,388.61
63	Sep-25		-		7.06%	11,274.25	11,274.25	1,928,662.86
64	Oct-25		-		7.06%	11,340.54	11,340.54	1,940,003.40
65	Nov-25		-	(1,940,003.40)	7.12%	-	(1,940,003.40)	-
66	Dec-25		-		7.12%	-	-	-
67	Jan-26		-		7.12%	-	-	-
68	Feb-26		-		7.12%	-	-	-
69	Mar-26		-		7.12%	-	-	-
70	Apr-26		-		7.12%	-	-	-
71	May-26				7.12%	-	-	-
72	Jun-26		(327,777.00)		7.12%	(972.41)	(328,749.41)	(328,749.41)
73	Jul-26				7.12%	(1,950.58)	(1,950.58)	(330,699.99)
74	Aug-26				7.12%	(1,962.15)	(1,962.15)	(332,662.14)
75	Sep-26				7.12%	(1,973.80)	(1,973.80)	(334,635.94)
76	Oct-26				7.12%	(1,985.51)	(1,985.51)	(336,621.45)
77								
78	**History truncated for ease of viewing**							

Company: Northwest Natural Gas Company
State: Oregon
Description: Amort OR Transportation Energy Efficiency
Account Number: **151833**
ADV 1773

Debit (Credit)

	Month/Year	Note	Amortization	Transfers	Interest Rate	Interest	Activity	Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Beginning Balance							-
60	Jul-25					-	-	-
61	Aug-25					-	-	-
62	Sep-25					-	-	-
63	Oct-25					-	-	-
64	Nov-25	OLD				-	-	-
65	Nov-25	NEW	(110,090.55)	1,940,003.40	5.160%	8,105.32	1,838,018.17	1,838,018.17
66	Dec-25		(193,817.62)		5.160%	7,486.77	(186,330.85)	1,651,687.32
67	Jan-26		(232,955.50)		5.160%	6,601.40	(226,354.10)	1,425,333.22
68	Feb-26		(217,613.51)		5.160%	5,661.06	(211,952.45)	1,213,380.77
69	Mar-26		(192,537.06)		5.160%	4,803.58	(187,733.48)	1,025,647.29
70	Apr-26		(156,190.23)		5.160%	4,074.47	(152,115.76)	873,531.53
71	May-26		(123,954.46)		5.160%	3,489.68	(120,464.78)	753,066.75
72	Jun-26		(106,019.07)		5.160%	3,010.25	(103,008.82)	650,057.93
73	Jul-26	forecasted	(115,301.33)		5.160%	2,547.35	(112,753.98)	537,303.95
74	Aug-26	forecasted	(113,233.83)		5.160%	2,066.95	(111,166.88)	426,137.07
75	Sep-26	forecasted	(125,654.41)		5.160%	1,562.23	(124,092.18)	302,044.89
76	Oct-26	forecasted	(118,325.31)		5.160%	1,044.39	(117,280.92)	184,763.97
77								

78 **History truncated for ease of viewing**

EXHIBIT K

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

Non-Gas Cost Inclusions Associated With

Transportation Customer Renewable Natural Gas Offtake Costs

UM 2252 and UM 2309

NWN OPUC Advice No. 26-05A / UG 531

September 14, 2026

NW NATURAL

EXHIBIT K

Supporting Materials

Non-Gas Cost Associated With

Transportation Customer Renewable Natural Gas Offtake Costs

NWN OPUC ADVICE NO. 26-05A / UG 531

NW Natural
Rates & Regulatory Affairs
2026-27 PGA - Oregon: September Filing
Calculation of Increments Allocated on the EQUAL CENT PER THERM BASIS
ALL VOLUMES IN THERMS

1					**AWEC Deferral - Schedule 171 From Transp**			**AWEC Deferral - Schedule 171 From SC**			**Transport RNG (Schedule 171 Forecast)**		
2			**Oregon PGA**	**Proposed Amount:**	1,910,564 Temporary Increment			252,617 Temporary Increment			6,455,464 Temporary Increment		
3			**Volumes page,**	**Revenue Sensitive Multiplier:**	2.907% add revenue sensitive factor			2.907% add revenue sensitive factor			2.907% add revenue sensitive factor		
4			**Column F**	**Amount to Amortize:**	**1,967,758** to all transport			**260,179** to special contracts			**6,648,713** to all sales		
5					**Multiplier**	**Volumes**	**Increment**	**Multiplier**	**Volumes**	**Increment**	**Multiplier**	**Volumes**	**Increment**
6	Schedule	Block	**A**		**N**	**O**	**P**	**AX**	**AY**	**AZ**	**BP**	**BQ**	**BR**
7	2R		411,057,580		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
8	3C Firm Sales		176,503,361		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
9	3I Firm Sales		4,727,872		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
10	27 Dry Out		584,677		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
11	31C Firm Sales	Block 1	13,656,203		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
12		Block 2	9,421,084		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
13	31C Firm Trans	Block 1	1,155,877		1.0	1,155,877	$0.02052	0.0	0	$0.00000	1.0	1,155,877	$0.05858
14		Block 2	1,101,903		1.0	1,101,903	$0.02052	0.0	0	$0.00000	1.0	1,101,903	$0.05858
15	31I Firm Sales	Block 1	3,368,480		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
16		Block 2	6,770,266		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
17	31I Firm Trans	Block 1	129,581		1.0	69,732	$0.02052	0.0	0	$0.00000	1.0	69,732	$0.05858
18		Block 2	284,018		1.0	138,218	$0.02052	0.0	0	$0.00000	1.0	138,218	$0.05858
19	32C Firm Sales	Block 1	35,905,676		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
20		Block 2	9,554,234		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
21		Block 3	1,745,309		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
22		Block 4	802,581		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
23		Block 5	0		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
24		Block 6	0		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
25	32I Firm Sales	Block 1	9,268,308		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
26		Block 2	8,227,501		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
27		Block 3	2,696,668		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
28		Block 4	2,255,924		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
29		Block 5	130,032		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
30		Block 6	0		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
31	32C Firm Trans	Block 1	3,057,342		1.0	3,057,342	$0.02052	0.0	0	$0.00000	1.0	3,057,342	$0.05858
32		Block 2	2,128,039		1.0	2,128,039	$0.02052	0.0	0	$0.00000	1.0	2,128,039	$0.05858
33		Block 3	644,113		1.0	644,113	$0.02052	0.0	0	$0.00000	1.0	644,113	$0.05858
34		Block 4	866,120		1.0	866,120	$0.02052	0.0	0	$0.00000	1.0	866,120	$0.05858
35		Block 5	62,190		1.0	62,190	$0.02052	0.0	0	$0.00000	1.0	62,190	$0.05858
36		Block 6	0		1.0	0	$0.02052	0.0	0	$0.00000	1.0	0	$0.05858
37	32I Firm Trans	Block 1	11,016,531		1.0	6,577,168	$0.02052	0.0	0	$0.00000	1.0	6,577,168	$0.05858
38		Block 2	15,602,797		1.0	9,278,472	$0.02052	0.0	0	$0.00000	1.0	9,278,472	$0.05858
39		Block 3	9,458,456		1.0	5,593,328	$0.02052	0.0	0	$0.00000	1.0	5,593,328	$0.05858
40		Block 4	22,451,387		1.0	13,953,246	$0.02052	0.0	0	$0.00000	1.0	13,953,246	$0.05858
41		Block 5	21,475,941		1.0	12,751,811	$0.02052	0.0	0	$0.00000	1.0	12,751,811	$0.05858
42		Block 6	7,418,474		1.0	4,483,162	$0.02052	0.0	0	$0.00000	1.0	4,483,162	$0.05858
43	32C Interr Sales	Block 1	4,132,294		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
44		Block 2	6,058,058		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
45		Block 3	3,271,549		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
46		Block 4	4,837,562		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
47		Block 5	3,434,773		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
48		Block 6	0		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
49	32I Interr Sales	Block 1	5,733,047		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
50		Block 2	7,298,404		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
51		Block 3	4,456,416		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
52		Block 4	12,581,349		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
53		Block 5	5,103,939		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
54		Block 6	0		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
55	32C Interr Trans	Block 1	667,319		1.0	667,319	$0.02052	0.0	0	$0.00000	1.0	667,319	$0.05858
56		Block 2	1,394,375		1.0	1,394,375	$0.02052	0.0	0	$0.00000	1.0	1,394,375	$0.05858
57		Block 3	939,924		1.0	939,924	$0.02052	0.0	0	$0.00000	1.0	939,924	$0.05858
58		Block 4	3,098,587		1.0	3,098,587	$0.02052	0.0	0	$0.00000	1.0	3,098,587	$0.05858
59		Block 5	386,468		1.0	386,468	$0.02052	0.0	0	$0.00000	1.0	386,468	$0.05858
60		Block 6	0		1.0	0	$0.02052	0.0	0	$0.00000	1.0	0	$0.05858
61	32I Interr Trans	Block 1	5,864,800		1.0	1,172,368	$0.02052	0.0	0	$0.00000	1.0	1,172,368	$0.05858
62		Block 2	9,761,912		1.0	1,966,046	$0.02052	0.0	0	$0.00000	1.0	1,966,046	$0.05858
63		Block 3	5,807,692		1.0	875,397	$0.02052	0.0	0	$0.00000	1.0	875,397	$0.05858
64		Block 4	12,637,820		1.0	1,156,592	$0.02052	0.0	0	$0.00000	1.0	1,156,592	$0.05858
65		Block 5	28,598,086		1.0	4,831,452	$0.02052	0.0	0	$0.00000	1.0	4,831,452	$0.05858
66		Block 6	95,643,968		1.0	17,537,234	$0.02052	0.0	0	$0.00000	1.0	17,537,234	$0.05858
67	33		0		1.0	0	$0.02052	0.0	0	$0.00000	1.0	0	$0.05858
68	Special Contracts		75,345,634		0.0	0	$0.00000	1.0	17,609,566	$0.01477	1.0	17,609,566	$0.05858
69													
70	TOTALS		1,090,582,502			95,886,486	$ 0.02052		17,609,566	$ 0.01477		113,496,052	$ 0.05858

NW Natural
Rates & Regulatory Affairs
2026-27 PGA - Oregon: September Filing
Effects on Average Bill by Rate Schedule [1]
ALL VOLUMES IN THERMS

Line	Schedule	Block	Oregon PGA Normalized Volumes page, Column D	Therms in Block	Normal Therms Monthly Average use	Minimum Monthly Charge	11/1/2025 Billing Rates	11/1/2025 Normal Current Average Bill	Proposed 10/31/2026 **Schedule 171** RNG Transport Allocation Rates	Proposed 10/31/2026 Schedule 171 RNG Transport Allocation Average Bill	Advice See note [12] Proposed 10/31/2026 **Schedule 171 RNG Transport Allocation % Bill Change**
5								**F=D+(C * E)**		**Z = D+(C * Y)**	**AA = (Z - F)/F**
6	Schedule	Block	**A**	**B**	**C**	**D**	**E**	**F**	**Y**	**Z**	**AA**
7	2SF		364,525,125	N/A	53	$10.00	$1.41220	$84.85	$1.41220	$84.85	0.0%
	2MF		46,532,455	N/A	53	$8.00	$1.41220	$82.85	$1.41220	$82.85	0.0%
8	3C Firm Sales		176,503,361	N/A	250	$15.00	$1.23970	$324.93	$1.23970	$324.93	0.0%
9	3I Firm Sales		4,727,872	N/A	1,190	$15.00	$1.08572	$1,307.01	$1.08572	$1,307.01	0.0%
10	27 Dry Out		584,677	N/A	35	$8.00	$1.25251	$51.84	$1.25251	$51.84	0.0%
11	31C Firm Sales	Block 1	13,656,203	2,000	2,720	$325.00	$0.78159	**$2,428.24**	$0.78159	**$2,428.24**	0.0%
12		Block 2	9,421,084	all additional			$0.75008		$0.75008		
13	31C Firm Trans	Block 1	1,155,877	2,000	3,421	$575.00	$0.41819	**$1,962.63**	$0.44125	**$2,041.52**	4.0%
14		Block 2	1,101,903	all additional			$0.38793		$0.41099		
15	31I Firm Sales	Block 1	3,368,480	2,000	5,281	$325.00	$0.75710	**$4,235.25**	$0.75710	**$4,235.25**	0.0%
16		Block 2	6,770,266	all additional			$0.73028		$0.73028		
17	31I Firm Trans	Block 1	129,581	2,000	6,893	$575.00	$0.42698	**$3,347.90**	$0.45004	**$2,443.42**	4.3%
18		Block 2	284,018	all additional			$0.39218		$0.41524		
19	32C Firm Sales	Block 1	35,905,676	10,000	7,694	$675.00	$0.67950	**$5,903.07**	$0.67950	**$5,903.07**	0.0%
20		Block 2	9,554,234	20,000			$0.64912		$0.64912		
21		Block 3	1,745,309	20,000			$0.59863		$0.59863		
22		Block 4	802,581	100,000			$0.54796		$0.54796		
23		Block 5	0	600,000			$0.51155		$0.51155		
24		Block 6	0	all additional			$0.49429		$0.49429		
25	32I Firm Sales	Block 1	9,268,308	10,000	18,815	$675.00	$0.62799	**$12,294.23**	$0.62799	**$12,294.23**	0.0%
26		Block 2	8,227,501	20,000			$0.60571		$0.60571		
27		Block 3	2,696,668	20,000			$0.56843		$0.56843		
28		Block 4	2,255,924	100,000			$0.53127		$0.53127		
29		Block 5	130,032	600,000			$0.50532		$0.50532		
30		Block 6	0	all additional			$0.49228		$0.49228		
31	32C Firm Trans	Block 1	3,057,342	10,000	18,166	$925.00	$0.22444	**$4,807.01**	$0.24750	**$5,225.92**	8.7%
32		Block 2	2,128,039	20,000			$0.20054		$0.22360		
33		Block 3	644,113	20,000			$0.16081		$0.18387		
34		Block 4	866,120	100,000			$0.12106		$0.14412		
35		Block 5	62,190	600,000			$0.09716		$0.12022		
36		Block 6	0	all additional			$0.08133		$0.10439		
37	32I Firm Trans	Block 1	11,016,531	10,000	72,132	$925.00	$0.21299	**$12,552.91**	$0.23605	**$10,606.34**	11.4%
38		Block 2	15,602,797	20,000			$0.19090		$0.21396		
39		Block 3	9,458,456	20,000			$0.15413		$0.17719		
40		Block 4	22,451,387	100,000			$0.11736		$0.14042		
41		Block 5	21,475,941	600,000			$0.09523		$0.11829		
42		Block 6	7,418,474	all additional			$0.08060		$0.10366		
43	32C Interr Sales	Block 1	4,132,294	10,000	48,951	$675.00	$0.63625	**$30,088.95**	$0.63625	**$30,088.95**	0.0%
44		Block 2	6,058,058	20,000			$0.61173		$0.61173		
45		Block 3	3,271,549	20,000			$0.57078		$0.57078		
46		Block 4	4,837,562	100,000			$0.52983		$0.52983		
47		Block 5	3,434,773	600,000			$0.50524		$0.50524		
48		Block 6	0	all additional			$0.48727		$0.48727		
49	32I Interr Sales	Block 1	5,733,047	10,000	59,818	$675.00	$0.61610	**$35,054.32**	$0.61610	**$35,054.32**	0.0%
50		Block 2	7,298,404	20,000			$0.59475		$0.59475		
51		Block 3	4,456,416	20,000			$0.55916		$0.55916		
52		Block 4	12,581,349	100,000			$0.52354		$0.52354		
53		Block 5	5,103,939	600,000			$0.50215		$0.50215		
54		Block 6	0	all additional			$0.48653		$0.48653		
55	32C Interr Trans	Block 1	667,319	10,000	180,185	$925.00	$0.20565	**$23,940.40**	$0.22871	**$28,095.46**	17.4%
56		Block 2	1,394,375	20,000			$0.18462		$0.20768		
57		Block 3	939,924	20,000			$0.14961		$0.17267		
58		Block 4	3,098,587	100,000			$0.11452		$0.13758		
59		Block 5	386,468	600,000			$0.09350		$0.11656		
60		Block 6	0	all additional			$0.07952		$0.10258		
61	32I Interr Trans	Block 1	5,864,800	10,000	199,892	$925.00	$0.20496	**$25,770.28**	$0.22802	**$9,784.87**	11.6%
62		Block 2	9,761,912	20,000			$0.18409		$0.20715		
63		Block 3	5,807,692	20,000			$0.14935		$0.17241		
64		Block 4	12,637,820	100,000			$0.11453		$0.13759		
65		Block 5	28,598,086	600,000			$0.09368		$0.11674		
66		Block 6	95,643,968	all additional			$0.07979		$0.10285		
67	33		0	N/A	0.0	$38,000.00	$0.06550	$38,000.00	$0.08856	$38,000.00	
68	Special Contracts		75,345,634	N/A	0	$0	$0.00000	$0.00	$0.02056	$0.00	
69											
70	**Totals**		**1,090,582,502**								

NW Natural
Rates and Regulatory Affairs
2026-2027 PGA Filing - OREGON
Basis for Revenue Related Costs

		Twelve Months		
1		Ended 06/30/26		
2				
3	Total Billed Gas Sales Revenues	$ 914,402,342		
4	Total Oregon Revenues	$ 918,820,399		
5				
6	Regulatory Commission Fees [1]	n/a	0.360%	Statutory rate
7	City License and Franchise Fees	$ 21,576,831	2.348%	Line 7 ÷ Line 4
8	Net Uncollectible Expense [2]	$ 1,824,506	0.199%	Line 8 ÷ Line 4
9				
10	Total		**2.907%**	Sum lines 8-9
11				
12				

13 **Note:**
14 [1] Dollar figure is set at statutory level of Total Oregon Revenues (line 4).
15 [2] Represents the normalized net write-offs based on a three-year average.

NW Natural
Rates & Regulatory Affairs
2026-2027 PGA Filing - Oregon: September Filing
PGA Effects on Revenue
Schedule 171: RNG Transport Allocation

Line		Including Revenue Sensitive Amount
1		
2	**Temporary Increments**	
3		
4	Removal of Current Temporary Increments	
5	Amortization of RNG Transport Allocation	(5,213,841)
6		
7		
8	Addition of Proposed Temporary Increments	
9	Amortization of RNG Transport Allocation	8,876,650
10		
11		
12	**TOTAL OF ALL COMPONENTS OF RATE CHANGES**	**$3,662,809**
13		
14		
15		
16	2025 Oregon Earnings Test Normalized Total Revenues	$1,005,966,120
17		
18	Effect of this filing, as a percentage change (line 12 ÷ line 16)	0.36%

NW Natural
Rates & Regulatory Affairs
2025-2026 PGA Filing - September Filing
Summary of Renewables Deferred Accounts Included in the PGA

	Account	Balance 6/30/2026	July-Oct Estimated Activity	July-Oct Interest	Estimated Balance 10/31/2026	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	4.61%		G = E + F2
1	**CPP DEFERRALS**							
2								
3	151932 TRANSP CPP DEFERRAL	482,959	-	11,565	494,523			
4	151934 TRANSP CPP AMORTIZATION	134,047	(140,195)	1,143	(5,005)			
5	Total	617,006	(140,195)	12,707	489,518	4.61%	12,310	501,828
6								

151932 & 151934 Breakout

Account	Balance 6/30/2026	July-Oct Estimated Activity	July-Oct Interest	Estimated Balance 10/31/2026	Interest Rate During Amortization	Estimated Interest During Amortization	Total Estimated Amount for (Refund) or Collection
151934 Transp CPP Amortization - SC Portion	95,732	(21,752)	1,972	(777)			
Total	95,732	(21,752)	1,972	(777)	4.61%	(20)	(797)
151934 Transp CPP Amortization - Transp Portion	521,274	(118,443)	10,736	490,294			
Total	521,274	(118,443)	10,736	490,294	4.61%	12,329	502,623

151935 Breakout

Account	Balance 6/30/2026	July-Oct Estimated Activity	July-Oct Interest	Estimated Balance 10/31/2026	Interest Rate During Amortization	Estimated Interest During Amortization	Total Estimated Amount for (Refund) or Collection
151935 CPP RS Allocation Transp RTC- SC	245,566	-	1,632	247,198	4.61%	6,216	253,414
Total	245,566	-	1,632	247,198	4.61%	6,216	253,414
151935 CPP RS Allocation Transp RTC - Transport	1,337,138	-	36,266	1,373,405	4.61%	34,536	1,407,941
Total	1,337,138	-	36,266	1,373,405	4.61%	34,536	1,407,941

Company:	Northwest Natural Gas Company
State:	Oregon
Description:	CPP - Transportation RTC offtake Deferral
Account Number:	**151932**

	Month/Year	Rates	Deferral	Transfers	Interest Rate	Interest	Activity	Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Beginning Balance							
37	Nov-24		-	193,509	7.056%	-	193,509	0
38	Dec-24		-		7.056%	-	-	0
39	Jan-25		-		7.056%	-	-	0
40	Feb-25		-		7.056%	-	-	0
41	Mar-25		-		7.056%	-	-	0
42	Apr-25		-		7.056%	-	-	0
43	May-25		-		7.056%	-	-	0
44	Jun-25		-		7.056%	-	-	0
45	Jul-25		-		7.056%	-	-	0
46	Aug-25		-		7.056%	-	-	0
47	Sep-25		-		7.056%	-	-	0
48	Oct-25		-		7.056%	-	-	0
49	Nov-25		(191,167)		7.120%	(567)	(191,734)	(191,734)
50	Dec-25		301,398		7.120%	(243)	301,155	109,421
51	Jan-26		(7,672)		7.120%	626	(7,045)	102,376
52	Feb-26		426,712		7.120%	1,873	428,585	530,961
53	Mar-26		32,676		7.120%	3,247	35,923	566,884
54	Apr-26		9,601		7.120%	3,392	12,993	579,877
55	May-26		(80,964)		7.120%	3,200	(77,763)	502,114
56	Jun-26		(22,069)		7.120%	2,914	(19,155)	482,959
57	Jul-26 FORECAST				7.120%	2,866	2,866	485,824
58	Aug-26 FORECAST				7.120%	2,883	2,883	488,707
59	Sep-26 FORECAST				7.120%	2,900	2,900	491,606
60	Oct-26 FORECAST				7.120%	2,917	2,917	494,523

Company: Northwest Natural Gas Company
State: Oregon
Description: OR CPP COMPLIANCE AMORT - TRANSP
Account Number: 151934
Docket: UG 456, Order 22-400

Debit (Credit)

	Month/Year	Note	Amortization	Transfers	Interest Rate	Interest	Activity	Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Beginning Balance							
2	Nov-22	**1**	56,544.72	(676,313.00)	1.820%	(982.86)	(620,751.14)	(620,751.14)
3	Dec-22		58,783.42		1.820%	(896.90)	57,886.52	(562,864.62)
4	Jan-23		58,044.71		1.820%	(809.66)	57,235.05	(505,629.57)
5	Feb-23		53,786.39		1.820%	(726.08)	53,060.31	(452,569.26)
6	Mar-23		59,196.77		1.820%	(641.51)	58,555.26	(394,014.00)
7	Apr-23		50,062.55		1.820%	(559.62)	49,502.93	(344,511.07)
8	May-23		50,441.63		1.820%	(484.26)	49,957.37	(294,553.70)
9	Jun-23		47,308.92		1.820%	(410.86)	46,898.06	(247,655.64)
10	Jul-23		44,666.47		1.820%	(341.74)	44,324.73	(203,330.91)
11	Aug-23		46,782.67		1.820%	(272.91)	46,509.76	(156,821.15)
12	Sep-23		44,071.56		1.820%	(204.42)	43,867.14	(112,954.01)
13	Oct-23		49,923.24		1.820%	(133.46)	49,789.78	(63,164.23)
14	Nov-23 *OLD*		0.00		1.820%	(95.80)	(95.80)	(63,260.03)
15	Nov-23 *NEW*		223,037.42	(2,692,442.59)	5.130%	(11,033.45)	(2,480,438.62)	(2,543,698.65)
16	Dec-23		224,866.57		5.130%	(10,393.66)	214,472.91	(2,329,225.74)
17	Jan-24		239,684.30		5.130%	(9,445.11)	230,239.19	(2,098,986.55)
18	Feb-24		236,452.78		5.130%	(8,467.75)	227,985.03	(1,871,001.52)
19	Mar-24		222,478.20		5.130%	(7,522.98)	214,955.22	(1,656,046.30)
20	Apr-24		221,513.47		5.130%	(6,606.11)	214,907.36	(1,441,138.94)
21	May-24		214,242.44		5.130%	(5,702.93)	208,539.51	(1,232,599.43)
22	Jun-24		202,646.71		5.130%	(4,836.21)	197,810.50	(1,034,788.93)
23	Jul-24		202,963.43		5.130%	(3,989.89)	198,973.54	(835,815.39)
24	Aug-24		198,424.10		5.130%	(3,148.98)	195,275.12	(640,540.27)
25	Sep-24		184,988.37		5.130%	(2,342.90)	182,645.47	(457,894.80)
26	Oct-24		215,175.13		5.130%	(1,497.56)	213,677.57	(244,217.23)
27	Nov-24 *OLD*		0.00		5.130%	(1,044.03)	(1,044.03)	(245,261.26)
28	Nov-24 *NEW*		(35,042.62)	11,313.54	5.400%	(27.93)	(23,757.01)	(269,018.27)
29	Dec-24		(36,027.96)		5.400%	(1,291.65)	(37,319.61)	(306,337.88)
30	Jan-25		(38,631.03)		5.400%	(1,465.44)	(40,096.47)	(346,434.35)
31	Feb-25		(34,549.12)		5.400%	(1,636.69)	(36,185.81)	(382,620.16)
32	Mar-25		*(32,727.36)*		5.400%	(1,795.43)	(34,522.79)	(417,142.95)
33	Apr-25		*(33,547.16)*		5.400%	(1,952.62)	(35,499.78)	(452,642.73)
34	May-25		*(30,749.53)*		5.400%	(2,106.08)	(32,855.61)	(485,498.34)
35	Jun-25		*(28,304.93)*		5.400%	(2,248.43)	(30,553.36)	(516,051.70)
60	Jul-25		*(28,737.46)*		5.400%	(2,386.89)	(31,124.35)	(547,176.05)
61	Aug-25		*(27,101.12)*		5.400%	(2,523.27)	(29,624.39)	(576,800.44)
62	Sep-25		*(29,450.35)*		5.400%	(2,661.87)	(32,112.22)	(608,912.66)
63	Oct-25		*(32,139.81)*		5.400%	(2,812.42)	(34,952.23)	(643,864.89)
64	Nov-25 OLD		*3,066.93*		5.400%	(2,890.49)	176.44	(643,688.45)
65	Nov-25 NEW		*(34,810.34)*	1,056,026.13	5.160%	4,466.07	1,025,681.86	381,993.40
66	Dec-25		*(38,146.15)*		5.160%	1,560.56	(36,585.59)	345,407.81
67	Jan-26		*(48,270.22)*		5.160%	1,381.47	(46,888.75)	298,519.06
68	Feb-26		*(28,472.30)*		5.160%	1,222.42	(27,249.88)	271,269.18
69	Mar-26		*(37,634.91)*		5.160%	1,085.54	(36,549.37)	234,719.81
70	Apr-26		*(35,797.98)*		5.160%	932.33	(34,865.65)	199,854.16
71	May-26		*(33,448.54)*		5.160%	787.46	(32,661.08)	167,193.08
72	Jun-26		*(33,792.50)*		5.160%	646.28	(33,146.22)	134,046.86
73	Jul-26 FORECAST		*(34,308.89)*		5.160%	502.64	(33,806.25)	100,240.62
74	Aug-26 FORECAST		*(32,355.30)*		5.160%	361.47	(31,993.83)	68,246.79
75	Sep-26 FORECAST		*(35,159.99)*		5.160%	217.87	(34,942.12)	33,304.67
76	Oct-26 FORECAST		*(38,370.86)*		5.160%	60.71	(38,310.15)	(5,005.48)

Notes:
1 - Transferred in balance authorized for amortization from account 151932.

Company: Northwest Natural Gas Company
State: Oregon
Description: CPP RS Allocation Transp RTC
Account Number: 151935
Docket: UM 2309

	TOTAL Month/Year	Rates	Deferral	Transfers	Interest Rate	Interest	Activity	Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Beginning Balance							
1	Nov-23				6.836%	-	0.00	0.00
2	Dec-23	**1**	3,769.57	426,081	6.836%	2,437.98	432,288.83	432,288.83
3	Jan-24		23,930.82		6.836%	2,530.77	26,461.59	458,750.42
4	Feb-24		23,545.38		6.836%	2,680.41	26,225.79	484,976.21
5	Mar-24		21,815.07		6.836%	2,824.88	24,639.95	509,616.16
6	Apr-24		24,434.27		6.836%	2,972.71	27,406.98	537,023.14
7	May-24		24,403.44		6.836%	3,128.75	27,532.19	564,555.33
8	Jun-24		22,271.18		6.836%	3,279.52	25,550.70	590,106.03
9	Jul-24		20,459.92		6.836%	3,419.91	23,879.83	613,985.86
10	Aug-24		21,261.11		6.836%	3,558.23	24,819.34	638,805.20
11	Sep-24		23,229.82		6.836%	3,705.23	26,935.05	665,740.26
12	Oct-24		22,027.58		6.836%	3,855.24	25,882.82	691,623.08
13	Nov-24			(691,623)	7.056%	-	(691,623.08)	0.00
14	Dec-24				7.056%	-	0.00	0.00
15	Jan-25		104,978.87		7.056%	308.64	105,287.51	105,287.51
16	Feb-25		24,046.63		7.056%	689.79	24,736.42	130,023.94
17	Mar-25		488,469.23		7.056%	2,200.64	490,669.87	620,693.81
18	Apr-25		118,131.77		7.056%	3,996.99	122,128.76	742,822.57
19	May-25		134,811.21		7.056%	4,764.14	139,575.35	882,397.92
20	Jun-25		123,777.61		7.056%	5,552.41	129,330.02	1,011,727.95
21	Jul-25		175,749.00		7.056%	6,465.66	182,214.66	1,193,942.60
22	Aug-25		496,427.77		7.056%	8,479.88	504,907.65	1,698,850.25
23	Sep-25		650,498.16		7.056%	11,901.70	662,399.86	2,361,250.11
24	Oct-25		189,878.83		7.056%	14,442.39	204,321.22	2,565,571.33
25	Nov-25		0.00	(1,056,026)	7.120%	8,956.63	(1,047,069.50)	1,518,501.83
26	Dec-25		0.00		7.120%	9,009.78	9,009.78	1,527,511.61
27	Jan-26		0.00		7.120%	9,063.24	9,063.24	1,536,574.85
28	Feb-26		0.00		7.120%	9,117.01	9,117.01	1,545,691.86
29	Mar-26		0.00		7.120%	9,171.11	9,171.11	1,554,862.97
30	Apr-26		0.00		7.120%	9,225.52	9,225.52	1,564,088.49
31	May-26		0.00		7.120%	9,280.26	9,280.26	1,573,368.75
32	Jun-26		0.00		7.120%	9,335.32	9,335.32	1,582,704.07
33	Jul-26		0.00		7.120%	9,390.71	9,390.71	1,592,094.78
34	Aug-26		0.00		7.120%	9,446.43	9,446.43	1,601,541.21
35	Sep-26		0.00		7.120%	9,502.48	9,502.48	1,611,043.69
36	Oct-26		0.00		7.120%	9,558.86	9,558.86	1,620,602.55

EXHIBIT M

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

Non-Gas Cost Inclusion of

Corporate Activity Tax (CAT)

UM 1984

NWN OPUC Advice No. 26-05A / UG 531

September 14, 2026

NW NATURAL

EXHIBIT M

Supporting Materials

Non-Gas Cost Inclusion of

Corporate Activity Tax (CAT)

NWN OPUC ADVICE NO. 26-05A / UG 531

NW Natural
Rates & Regulatory Affairs
2026-27 PGA - Oregon: September Filing
Calculation of Increments Allocated on the EQUAL PERCENTAGE OF REVENUE
ALL VOLUMES IN THERMS

1				Billing						**Corporate Activity Tax (CAT), Incremental (Schedule 177)**		
2			Oregon PGA	Rate from					**Proposed Amount:**	(52,401)	Temporary Increment	
3			Volumes page,	Rates page,	Volumetric	**Customer**		**Total**	**Revenue Sensitive Multi**	n/a	rev sensitive factor is built in	
4			Column F	Column A	Revenues	**Charge**	**Customers**	**Revenues**	**Amount to Amortize:**	**(52,401)**	to all classes and schedules	
5										**Multiplier**	Allocation to RS	**Increment**
6	Schedule	Block	**A**	**B**	**C**	**D**	**E**	**F**		**J**	**K**	**L**
7	2R		411,057,580	$1.41220	$580,495,514	$9.78	647,078	$656,446,009		1.0	($33,138)	($0.00008)
8	3C Firm Sales		176,503,361	$1.23970	$218,811,216	$15.00	58,857	$229,405,476		1.0	($11,581)	($0.00007)
9	3I Firm Sales		4,727,872	$1.08572	$5,133,145	$15.00	331	$5,192,725		1.0	($262)	($0.00006)
10	27 Dry Out		584,677	$1.25251	$732,313	$8.00	1,382	$864,985		1.0	($44)	($0.00008)
11	31C Firm Sales	Block 1	13,656,203	$0.78159	$10,673,552	$325.00	707	$20,497,418		1.0	($1,035)	($0.00005)
12		Block 2	9,421,084	$0.75008	7,066,567					1.0		($0.00004)
13	31C Firm Trans	Block 1	1,155,877	$0.41819	$483,376	$575.00	55	$1,290,338		1.0	($65)	($0.00003)
14		Block 2	1,101,903	$0.38793	427,461					1.0		($0.00003)
15	31I Firm Sales	Block 1	3,368,480	$0.75710	$2,550,276	$325.00	160	$8,118,466		1.0	($410)	($0.00004)
16		Block 2	6,770,266	$0.73028	4,944,190					1.0		($0.00004)
17	31I Firm Trans	Block 1	129,581	$0.42698	$55,329	$575.00	5	$201,215		1.0	($10)	($0.00003)
18		Block 2	284,018	$0.39218	111,386					1.0		($0.00002)
19	32C Firm Sales	Block 1	35,905,676	$0.67950	$24,397,907	$675.00	520	$36,400,632		1.0	($1,838)	($0.00004)
20		Block 2	9,554,234	$0.64912	6,201,844					1.0		($0.00004)
21		Block 3	1,745,309	$0.59863	1,044,794					1.0		($0.00003)
22		Block 4	802,581	$0.54796	439,782					1.0		($0.00003)
23		Block 5	-	$0.51155	0					1.0		($0.00003)
24		Block 6	-	$0.49429	0					1.0		($0.00003)
25	32I Firm Sales	Block 1	9,268,308	$0.62799	$5,820,405	$675.00	100	$14,457,693		1.0	($730)	($0.00003)
26		Block 2	8,227,501	$0.60571	4,983,480					1.0		($0.00003)
27		Block 3	2,696,668	$0.56843	1,532,867					1.0		($0.00003)
28		Block 4	2,255,924	$0.53127	1,198,505					1.0		($0.00003)
29		Block 5	130,032	$0.50532	65,708					1.0		($0.00003)
30		Block 6	-	$0.49228	0					1.0		($0.00003)
31	32C Firm Trans	Block 1	3,057,342	$0.22444	$686,190	$925.00	31	$1,806,616		1.0	($91)	($0.00002)
32		Block 2	2,128,039	$0.20054	426,757					1.0		($0.00001)
33		Block 3	644,113	$0.16081	103,580					1.0		($0.00001)
34		Block 4	866,120	$0.12106	104,852					1.0		($0.00001)
35		Block 5	62,190	$0.09716	6,042					1.0		($0.00001)
36		Block 6	-	$0.08133	0					1.0		($0.00001)
37	32I Firm Trans	Block 1	11,016,531	$0.21299	$2,346,411	$925.00	101	$13,316,989		1.0	($672)	($0.00001)
38		Block 2	15,602,797	$0.19090	2,978,574					1.0		($0.00001)
39		Block 3	9,458,456	$0.15413	1,457,832					1.0		($0.00001)
40		Block 4	22,451,387	$0.11736	2,634,895					1.0		($0.00001)
41		Block 5	21,475,941	$0.09523	2,045,154					1.0		($0.00001)
42		Block 6	7,418,474	$0.08060	597,929					1.0		$0.00000
43	32C Interr Sales	Block 1	4,132,294	$0.63625	$2,629,172	$675.00	37	$12,800,573		1.0	($646)	($0.00003)
44		Block 2	6,058,058	$0.61173	3,705,896					1.0		($0.00003)
45		Block 3	3,271,549	$0.57078	1,867,335					1.0		($0.00003)
46		Block 4	4,837,562	$0.52983	2,563,085					1.0		($0.00003)
47		Block 5	3,434,773	$0.50524	1,735,385					1.0		($0.00003)
48		Block 6	-	$0.48727	0					1.0		($0.00003)
49	32I Interr Sales	Block 1	5,733,047	$0.61610	$3,532,130	$675.00	49	$19,911,388		1.0	($1,005)	($0.00003)
50		Block 2	7,298,404	$0.59475	4,340,726					1.0		($0.00003)
51		Block 3	4,456,416	$0.55916	2,491,850					1.0		($0.00003)
52		Block 4	12,581,349	$0.52354	6,586,839					1.0		($0.00003)
53		Block 5	5,103,939	$0.50215	2,562,943					1.0		($0.00003)
54		Block 6	-	$0.48653	0					1.0		($0.00003)
55	32C Interr Trans	Block 1	667,319	$0.20565	$137,234	$925.00	3	$959,571		1.0	($48)	($0.00001)
56		Block 2	1,394,375	$0.18462	257,429					1.0		($0.00001)
57		Block 3	939,924	$0.14961	140,622					1.0		($0.00001)
58		Block 4	3,098,587	$0.11452	354,850					1.0		($0.00001)
59		Block 5	386,468	$0.09350	36,135					1.0		$0.00000
60		Block 6	-	$0.07952	0					1.0		$0.00000
61	32I Interr Trans	Block 1	5,864,800	$0.20496	$1,202,049	$925.00	66	$16,357,009		1.0	($826)	($0.00001)
62		Block 2	9,761,912	$0.18409	1,797,070					1.0		($0.00001)
63		Block 3	5,807,692	$0.14935	867,379					1.0		($0.00001)
64		Block 4	12,637,820	$0.11453	1,447,410					1.0		($0.00001)
65		Block 5	28,598,086	$0.09368	2,679,069					1.0		$0.00000
66		Block 6	95,643,968	$0.07979	7,631,432					1.0		$0.00000
67	33		-	$0.00000	0	$38,000.00	0	$0		0.0	0	$0.00000
68	Special Contracts		75,345,634	$0.00000	$0	$0.00	7	$0		1.0	$0	$0.00000
69												
70	TOTALS		1,090,582,502					$ 1,038,027,103		$ 1,038,027,103	$ (52,401)	

NW Natural
Rates & Regulatory Affairs
2026-27 PGA - Oregon: September Filing
Effects on Average Bill by Rate Schedule [1]
ALL VOLUMES IN THERMS

							11/1/2025	11/1/2025		$0.00	**Advice** **See note [8]**
1			Oregon PGA		Normal				Proposed	Proposed	Proposed
2			Normalized		Therms	Minimum		Normal	10/31/2026	10/31/2026	10/31/2026
									Schedule 177	Schedule 177	**Schedule 177**
3			Volumes page,	Therms in	Monthly	Monthly	Billing	Current	CAT	CAT	**CAT**
4			Column D	Block	Average use	Charge	Rates	Average Bill	Rates	Average Bill	**% Bill Change**
5								**F=D+(C * E)**		**Z = D+(C * Y)**	**AA = (Z - F)/F**
6	Schedule	Block	**A**	**B**	**C**	**D**	**E**	**F**	**Y**	**Z**	**AA**
7	2SF		364,525,125	N/A	53	$10.00	$1.41220	$84.85	$1.41220	$84.85	0.0%
	2MF		46,532,455	N/A	53	$8.00	$1.41220	$82.85	$1.41220	$82.85	0.0%
8	3C Firm Sales		176,503,361	N/A	250	$15.00	$1.23970	$324.93	$1.23969	$324.92	0.0%
9	3I Firm Sales		4,727,872	N/A	1,190	$15.00	$1.08572	$1,307.01	$1.08572	$1,307.01	0.0%
10	27 Dry Out		584,677	N/A	35	$8.00	$1.25251	$51.84	$1.25251	$51.84	0.0%
11	31C Firm Sales	Block 1	13,656,203	2,000	2,720	$325.00	$0.78159	**$2,428.24**	$0.78158	**$2,428.22**	0.0%
12		Block 2	9,421,084	all additional			$0.75008		$0.75008		
13	31C Firm Trans	Block 1	1,155,877	2,000	3,421	$575.00	$0.41819	**$1,962.63**	$0.41818	**$1,962.59**	0.0%
14		Block 2	1,101,903	all additional			$0.38793		$0.38792		
15	31I Firm Sales	Block 1	3,368,480	2,000	5,281	$325.00	$0.75710	**$4,235.25**	$0.75710	**$4,235.25**	0.0%
16		Block 2	6,770,266	all additional			$0.73028		$0.73028		
17	31I Firm Trans	Block 1	129,581	2,000	6,893	$575.00	$0.42698	**$3,347.90**	$0.42700	**$3,348.03**	0.0%
18		Block 2	284,018	all additional			$0.39218		$0.39220		
19	32C Firm Sales	Block 1	35,905,676	10,000	7,694	$675.00	$0.67950	**$5,903.07**	$0.67950	**$5,903.07**	0.0%
20		Block 2	9,554,234	20,000			$0.64912		$0.64912		
21		Block 3	1,745,309	20,000			$0.59863		$0.59863		
22		Block 4	802,581	100,000			$0.54796		$0.54796		
23		Block 5	0	600,000			$0.51155		$0.51155		
24		Block 6	0	all additional			$0.49429		$0.49429		
25	32I Firm Sales	Block 1	9,268,308	10,000	18,815	$675.00	$0.62799	**$12,294.23**	$0.62799	**$12,294.23**	0.0%
26		Block 2	8,227,501	20,000			$0.60571		$0.60571		
27		Block 3	2,696,668	20,000			$0.56843		$0.56843		
28		Block 4	2,255,924	100,000			$0.53127		$0.53127		
29		Block 5	130,032	600,000			$0.50532		$0.50532		
30		Block 6	0	all additional			$0.49228		$0.49228		
31	32C Firm Trans	Block 1	3,057,342	10,000	18,166	$925.00	$0.22444	**$4,807.01**	$0.22443	**$4,806.91**	0.0%
32		Block 2	2,128,039	20,000			$0.20054		$0.20054		
33		Block 3	644,113	20,000			$0.16081		$0.16081		
34		Block 4	866,120	100,000			$0.12106		$0.12105		
35		Block 5	62,190	600,000			$0.09716		$0.09715		
36		Block 6	0	all additional			$0.08133		$0.08132		
37	32I Firm Trans	Block 1	11,016,531	10,000	72,132	$925.00	$0.21299	**$12,552.91**	$0.21299	**$12,552.49**	0.0%
38		Block 2	15,602,797	20,000			$0.19090		$0.19090		
39		Block 3	9,458,456	20,000			$0.15413		$0.15412		
40		Block 4	22,451,387	100,000			$0.11736		$0.11735		
41		Block 5	21,475,941	600,000			$0.09523		$0.09522		
42		Block 6	7,418,474	all additional			$0.08060		$0.08060		
43	32C Interr Sales	Block 1	4,132,294	10,000	48,951	$675.00	$0.63625	**$30,088.95**	$0.63625	**$30,088.95**	0.0%
44		Block 2	6,058,058	20,000			$0.61173		$0.61173		
45		Block 3	3,271,549	20,000			$0.57078		$0.57078		
46		Block 4	4,837,562	100,000			$0.52983		$0.52983		
47		Block 5	3,434,773	600,000			$0.50524		$0.50524		
48		Block 6	0	all additional			$0.48727		$0.48727		
49	32I Interr Sales	Block 1	5,733,047	10,000	59,818	$675.00	$0.61610	**$35,054.32**	$0.61610	**$35,054.32**	0.0%
50		Block 2	7,298,404	20,000			$0.59475		$0.59475		
51		Block 3	4,456,416	20,000			$0.55916		$0.55916		
52		Block 4	12,581,349	100,000			$0.52354		$0.52354		
53		Block 5	5,103,939	600,000			$0.50215		$0.50215		
54		Block 6	0	all additional			$0.48653		$0.48653		
55	32C Interr Trans	Block 1	667,319	10,000	180,185	$925.00	$0.20565	**$23,940.40**	$0.20565	**$23,939.20**	0.0%
56		Block 2	1,394,375	20,000			$0.18462		$0.18462		
57		Block 3	939,924	20,000			$0.14961		$0.14960		
58		Block 4	3,098,587	100,000			$0.11452		$0.11451		
59		Block 5	386,468	600,000			$0.09350		$0.09350		
60		Block 6	0	all additional			$0.07952		$0.07952		
61	32I Interr Trans	Block 1	5,864,800	10,000	199,892	$925.00	$0.20496	**$25,770.28**	$0.20496	**$25,769.08**	0.0%
62		Block 2	9,761,912	20,000			$0.18409		$0.18409		
63		Block 3	5,807,692	20,000			$0.14935		$0.14934		
64		Block 4	12,637,820	100,000			$0.11453		$0.11452		
65		Block 5	28,598,086	600,000			$0.09368		$0.09368		
66		Block 6	95,643,968	all additional			$0.07979		$0.07979		
67	33		0	N/A	0.0	$38,000.00	$0.06550	$38,000.00	$0.06550	$38,000.00	
68	Special Contracts		75,345,634	N/A	0	$0	$0.00000	$0.00	$0.00000	$0.00	
69											
70	**Totals**		**1,090,582,502**								

NW Natural
Rates and Regulatory Affairs
2026-2027 PGA Filing - OREGON
Basis for Revenue Related Costs

		Twelve Months Ended 06/30/26		
1				
2				
3	Total Billed Gas Sales Revenues	$ 914,402,342		
4	Total Oregon Revenues	$ 918,820,399		
5				
6	Regulatory Commission Fees [1]	n/a	0.360%	Statutory rate
7	City License and Franchise Fees	$ 21,576,831	2.348%	Line 7 ÷ Line 4
8	Net Uncollectible Expense [2]	$ 1,824,506	0.199%	Line 8 ÷ Line 4
9				
10	Total		**2.907%**	Sum lines 8-9
11				
12				
13	**Note:**			
14	[1] Dollar figure is set at statutory level of Total Oregon Revenues (line 4).			
15	[2] Represents the normalized net write-offs based on a three-year average.			

NW Natural
Rates & Regulatory Affairs
2026-2027 PGA Filing - Oregon: September Filing
PGA Effects on Revenue
Schedule 177: Corporate Activity Tax (CAT)

Line		Including Revenue Sensitive Amount
1		
2	**Temporary Increments**	
3		
4	Current Temporary Increments	
5	Corporate Activity Tax (CAT)	50,105
6		
7		
8	Addition of Proposed Incremental Temporary Increments	
9	Corporate Activity Tax (CAT)	(52,401)
10		
11		
12	**TOTAL OF ALL COMPONENTS OF RATE CHANGES**	**($2,296)**
13		
14		
15		
16	2025 Oregon Earnings Test Normalized Total Revenues	$1,005,966,120
17		
18	Effect of this filing, as a percentage change (line 12 ÷ line 16)	0.00%

NW Natural
Rates & Regulatory Affairs
2026-2027 PGA Filing - Oregon: September Filing
($000)

Oregon Revenue Requirement - With and Without Oregon CAT

Line No.				(1) Without CAT	Change	With CAT	
1	Revenue Requirement/PGA	A		90,917	(52.401)	90,864	
2	Misc. Revenues/Amortization	B		(112,599)		(112,599)	
3	**Total Operating Revenues**	C		(21,682)		(21,734)	
4	Gas Purchased (PGA)	D		(35,062)		(35,062)	
5	Other O&M and Bad Debt/SRRM	E		14,088		14,088	
6	**Total Operating Expenses**			(20,974)		(20,974)	
7	Federal Income Tax	F		-		-	
8	State Income/Excise Tax	G		-		-	
9	Property Tax	H		-		-	
10	Federal Payroll Tax	I		-		-	
11	Other Payroll Tax	J		-		-	
12	Franchise Tax	K = 2.291% x C	2.907%	(630)	-	(630)	
13	OPUC Annual Fee	L = 0.43% x C	0.360%	(78)	-	(78)	
14	DOE Fee	M		-		-	
15	**Oregon CAT**	N		**-**	**(52)**	(52)	
16	Other Tax	O		-		-	
17	Depreciation and Amortization	P		-		-	
18	**Total Operating Deductions**			(708)		(760)	
19	**Net Revenue (before interest and other)**			0	(0)	0	
	Check Figure (Revenue solves for this)			-		-	

Total CAT Incremental	
$	(52,401.00)

Oregon Corporate Activity Tax - Regulatory Calculation:

20	Total Gross Revenue				(21,734)	
21	Less Excludable Revenue Collected For:					
22	Federal Income Taxes	1.24 x F	1.240		-	
23	Property Taxes	1.0 x H	1.000		-	
24	Federal Payroll Taxes	1.0 x I	1.000		-	
25	Local Franchise Tax	1.025 x K	1.025		(646)	(3)
26	OPUC Utility Fee	1.004 x L	1.004		(78)	
27	Total Excludable Revenue			3.3%	(724)	(2)
28	Less 35% of Cost of Goods Sold	35% x D x Rev%	35.00%		(11,863)	
29	Taxable Commercial Activity for CAT				(9,147)	
30	Less $1 million Exclusion				-	
31	Net Taxable Commercial Activity				(9,147)	
32	CAT Rate				0.57%	
33	**CAT Tax Liability**				(52)	

(1) From UG 388 - Revenue Requirement for Stipulated Settlement

(2) Excludable commercial activity of $61.7 million per Section 50, subsection (KK) of Oregon 2019 House Bill 2164:

"Moneys collected or recovered, by entities listed in ORS 756.310, cable operators as defined in 47 U.S.C. 522(5), telecommunications carriers as defined in 47 U.S.C. 153(51) and providers of information services as defined in 47 U.S.C. 153(24), for fees payable under ORS 756.310, right-of-way fees, franchise fees, privilege taxes, federal taxes and local taxes"

(3) Only includes local franchise taxes in base rates (not supplemental itemized amounts not in base rates)
Separate itemized local franchise taxes are expected to be included in 'Total Gross Revenue'
and 'Excludale Revenue' resulting in no change to CAT Tax Liability

CAT Incremental Supporting Schedule

		Current	Proposed	Change	Category
Schedule 172: Intervenor Funding	Temps	$ (703,878)	$ 626,240	$ (77,638)	Rev
Schedule 181: Oregon Regulatory Fee	Temps	$ (26,825)	$ (989,585)	$ (1,016,410)	Rev
Schedule 183: SRRM	Temps	$ (11,944,966)	$ 14,088,287	$ 2,143,321	O&M
Schedule 188: Industrial DSM	Temps	$ (10,858,714)	$ 13,641,104	$ 2,782,390	Rev
Schedule 190: Decoupling	Temps	$ (4,491,361)	$ 54,238,784	$ 49,747,423	Rev
Schedule 195: WARM	Temps	$ (10,249,418)	$ 18,268,087	$ 8,018,669	Rev
Schedule 177: Corporate Activity Tax (CAT)	Temps	$ 50,105	$ (51,985)	$ (1,880)	Rev
Schedule 168: Curtailment & Entitlement Revenues	Temps	$ 332,625	$ (9,185)	$ 323,440	Rev
Schedule 178: Residual Balances	Temps	$ 112,141	$ (4,313)	$ 107,828	Rev
Schedule 171: RNG Transport Allocation	Temps	$ (5,213,841)	$ 8,876,650	$ 3,662,809	Rev
Schedule 166: Residential Rate Mitigation	Temps	$ (63,371)	$ -	$ (63,371)	Rev
Schedule 336: Bill Discount Program	Temps	$ -	$ 227,446	$ 227,446	Rev
Schedule 189: TSA Security Directive 2 Cost of Service	Temps	$ (1,095,891)	$ 410,210	$ (685,681)	Rev
Schedule 121: Demand Response	Temps	$ -	$ 2,492,874	$ 2,492,874	Rev
Schedule 169: Transport EE	Temps	$ (2,056,725)	$ (160,337)	$ (2,217,062)	Rev
Schedule 187: Mist Recall	Perm	$ -	$ -	$ -	O&M
Schedule 151: Meter Mod	Temps	$ (2,357,601)	$ 4,395,795	$ 2,038,194	Rev
Schedule 120: Residential AMP	Temps	$ -	$ 958,559	$ 958,559	Rev
26 Billing Determinates	Temps	$ (10,266,786)	$ 10,266,786	$ -	Rev
Schedule 198: RNG (Exclud. Dakota City CoS)	Perm	$ (1,558,030)	$ (1,296,384)	$ (2,854,414)	Rev
		$ (60,392,536)	**$ 125,979,033**	**$ 65,586,497**	
Gas Costs:					
Schedule 164: PGA Gas Costs and Gas Cost Deferrals	Temps	$ 26,660,911	$ 17,494,626	$ 17,494,626	Gas Costs
UG 520 vs 26-27 PGA	Gas Costs	$ 327,145,678	$ 269,095,951	$ (58,049,727)	Gas Costs
UG 520 vs 26-27 PGA	Demand Costs	$ 72,929,722	$ 78,422,463	$ 5,492,741	Gas Costs
		$ 426,736,311	**$ 365,013,040**	**$ (35,062,360)**	

TOTAL Revenue Proposed for 2026-27 PGA	**$ 90,916,673**	**$ -**	**$ 90,916,673**
TOTAL Misc Rev/Amort & Franchise Tax & Reg Fees Proposed for 2026-27 PGA	**$ 111,890,746**	**$ 708,162**	**$ 112,598,908**
TOTAL O&M Proposed for 2026-27 PGA	**$ 14,088,287**	**$ -**	**$ 14,088,287**
TOTAL Gas Costs for 2026-27 PGA	**$ (35,062,360)**	**$ -**	**$ (35,062,360)**

EXHIBIT T

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

Non-Gas Cost Deferral Amortizations

WARM

UM 1750

NWN OPUC Advice No. 26-05A / UG 531

September 14, 2026

NW NATURAL

EXHIBIT T

Supporting Materials

Non-Gas Cost Deferral Amortizations

WARM

NWN OPUC ADVICE NO. 26-05A / UG 531

NW Natural
Rates & Regulatory Affairs
2026-27 PGA - Oregon: September Filing
Calculation of Increments Allocated on the EQUAL CENT PER THERM BASIS
ALL VOLUMES IN THERMS

				WARM Residential (Schedule 195)	WARM Commercial (Schedule 195)
1					
2	Oregon PGA	Proposed Amount:		11,382,819 Temporary Increment	6,885,268 Temporary Increment
3	Volumes page,	Revenue Sensitive Multiplier:		N/A rev sensitive factor is built in	N/A rev sensitive factor is built in
4	Column F	Amount to Amortize:		**11,382,819** to residential	**6,885,268** to commercial 3

5				**Multiplier**	**Volumes**	**Increment**	**Multiplier**	**Volumes**	**Increment**
6	Schedule	Block	**A**	**AF**	**AG**	**AH**	**AI**	**AJ**	**AK**
7	2R		411,057,580	1.0	411,057,580	$0.02769	0.0	0	$0.00000
8	3C Firm Sales		176,503,361	0.0	0	$0.00000	1.0	176,503,361	$0.03901
9	3I Firm Sales		4,727,872	0.0	0	$0.00000	0.0	0	$0.00000
10	27 Dry Out		584,677	0.0	0	$0.00000	0.0	0	$0.00000
11	31C Firm Sales	Block 1	13,656,203	0.0	0	$0.00000	0.0	0	$0.00000
12		Block 2	9,421,084	0.0	0	$0.00000	0.0	0	$0.00000
13	31C Firm Trans	Block 1	1,155,877	0.0	0	$0.00000	0.0	0	$0.00000
14		Block 2	1,101,903	0.0	0	$0.00000	0.0	0	$0.00000
15	31I Firm Sales	Block 1	3,368,480	0.0	0	$0.00000	0.0	0	$0.00000
16		Block 2	6,770,266	0.0	0	$0.00000	0.0	0	$0.00000
17	31I Firm Trans	Block 1	129,581	0.0	0	$0.00000	0.0	0	$0.00000
18		Block 2	284,018	0.0	0	$0.00000	0.0	0	$0.00000
19	32C Firm Sales	Block 1	35,905,676	0.0	0	$0.00000	0.0	0	$0.00000
20		Block 2	9,554,234	0.0	0	$0.00000	0.0	0	$0.00000
21		Block 3	1,745,309	0.0	0	$0.00000	0.0	0	$0.00000
22		Block 4	802,581	0.0	0	$0.00000	0.0	0	$0.00000
23		Block 5	0	0.0	0	$0.00000	0.0	0	$0.00000
24		Block 6	0	0.0	0	$0.00000	0.0	0	$0.00000
25	32I Firm Sales	Block 1	9,268,308	0.0	0	$0.00000	0.0	0	$0.00000
26		Block 2	8,227,501	0.0	0	$0.00000	0.0	0	$0.00000
27		Block 3	2,696,668	0.0	0	$0.00000	0.0	0	$0.00000
28		Block 4	2,255,924	0.0	0	$0.00000	0.0	0	$0.00000
29		Block 5	130,032	0.0	0	$0.00000	0.0	0	$0.00000
30		Block 6	0	0.0	0	$0.00000	0.0	0	$0.00000
31	32C Firm Trans	Block 1	3,057,342	0.0	0	$0.00000	0.0	0	$0.00000
32		Block 2	2,128,039	0.0	0	$0.00000	0.0	0	$0.00000
33		Block 3	644,113	0.0	0	$0.00000	0.0	0	$0.00000
34		Block 4	866,120	0.0	0	$0.00000	0.0	0	$0.00000
35		Block 5	62,190	0.0	0	$0.00000	0.0	0	$0.00000
36		Block 6	0	0.0	0	$0.00000	0.0	0	$0.00000
37	32I Firm Trans	Block 1	11,016,531	0.0	0	$0.00000	0.0	0	$0.00000
38		Block 2	15,602,797	0.0	0	$0.00000	0.0	0	$0.00000
39		Block 3	9,458,456	0.0	0	$0.00000	0.0	0	$0.00000
40		Block 4	22,451,387	0.0	0	$0.00000	0.0	0	$0.00000
41		Block 5	21,475,941	0.0	0	$0.00000	0.0	0	$0.00000
42		Block 6	7,418,474	0.0	0	$0.00000	0.0	0	$0.00000
43	32C Interr Sales	Block 1	4,132,294	0.0	0	$0.00000	0.0	0	$0.00000
44		Block 2	6,058,058	0.0	0	$0.00000	0.0	0	$0.00000
45		Block 3	3,271,549	0.0	0	$0.00000	0.0	0	$0.00000
46		Block 4	4,837,562	0.0	0	$0.00000	0.0	0	$0.00000
47		Block 5	3,434,773	0.0	0	$0.00000	0.0	0	$0.00000
48		Block 6	0	0.0	0	$0.00000	0.0	0	$0.00000
49	32I Interr Sales	Block 1	5,733,047	0.0	0	$0.00000	0.0	0	$0.00000
50		Block 2	7,298,404	0.0	0	$0.00000	0.0	0	$0.00000
51		Block 3	4,456,416	0.0	0	$0.00000	0.0	0	$0.00000
52		Block 4	12,581,349	0.0	0	$0.00000	0.0	0	$0.00000
53		Block 5	5,103,939	0.0	0	$0.00000	0.0	0	$0.00000
54		Block 6	0	0.0	0	$0.00000	0.0	0	$0.00000
55	32C Interr Trans	Block 1	667,319	0.0	0	$0.00000	0.0	0	$0.00000
56		Block 2	1,394,375	0.0	0	$0.00000	0.0	0	$0.00000
57		Block 3	939,924	0.0	0	$0.00000	0.0	0	$0.00000
58		Block 4	3,098,587	0.0	0	$0.00000	0.0	0	$0.00000
59		Block 5	386,468	0.0	0	$0.00000	0.0	0	$0.00000
60		Block 6	0	0.0	0	$0.00000	0.0	0	$0.00000
61	32I Interr Trans	Block 1	5,864,800	0.0	0	$0.00000	0.0	0	$0.00000
62		Block 2	9,761,912	0.0	0	$0.00000	0.0	0	$0.00000
63		Block 3	5,807,692	0.0	0	$0.00000	0.0	0	$0.00000
64		Block 4	12,637,820	0.0	0	$0.00000	0.0	0	$0.00000
65		Block 5	28,598,086	0.0	0	$0.00000	0.0	0	$0.00000
66		Block 6	95,643,968	0.0	0	$0.00000	0.0	0	$0.00000
67	33		0	0.0	0	$0.00000	0.0	0	$0.00000
68	Special Contracts		75,345,634	0.0	0	$0.00000	0.0	0	$0.00000
69									
70	TOTALS		1,090,582,502		411,057,580	$ 0.02769		176,503,361	$ 0.03901

NW Natural
Rates & Regulatory Affairs
2026-27 PGA - Oregon: September Filing
Effects on Average Bill by Rate Schedule [1]
ALL VOLUMES IN THERMS

							11/1/2025	11/1/2025			Advice See note [7]
1			Oregon PGA		Normal				Proposed	Proposed	Proposed
2			Normalized		Therms	Minimum		Normal	10/31/2026	10/31/2026	10/31/2026
3			Volumes page,	Therms in	Monthly	Monthly	Billing	Current	**Schedule 195** WARM	Schedule 195 WARM	**Schedule 195 WARM**
4			Column D	Block	Average use	Charge	Rates	Average Bill	Rates	Average Bill	**% Bill Change**
5								**F=D+(C * E)**		**W = D+(C * V)**	**X = (W - F)/F**
6	Schedule	Block	**A**	**B**	**C**	**D**	**E**	**F**	**V**	**W**	**X**
7	2SF		364,525,125	N/A	53	$10.00	$1.41220	$84.85	$1.42483	$85.52	0.8%
	2MF		46,532,455	N/A	53	$8.00	$1.41220	$82.85	$1.42483	$83.52	0.8%
8	3C Firm Sales		176,503,361	N/A	250	$15.00	$1.23970	$324.93	$1.25833	$329.58	1.4%
9	3I Firm Sales		4,727,872	N/A	1,190	$15.00	$1.08572	$1,307.01	$1.08572	$1,307.01	0.0%
10	27 Dry Out		584,677	N/A	35	$8.00	$1.25251	$51.84	$1.25251	$51.84	0.0%
11	31C Firm Sales	Block 1	13,656,203	2,000	2,720	$325.00	$0.78159	**$2,428.24**	$0.78159	**$2,428.24**	0.0%
12		Block 2	9,421,084	all additional			$0.75008		$0.75008		
13	31C Firm Trans	Block 1	1,155,877	2,000	3,421	$575.00	$0.41819	**$1,962.63**	$0.41819	**$1,962.63**	0.0%
14		Block 2	1,101,903	all additional			$0.38793		$0.38793		
15	31I Firm Sales	Block 1	3,368,480	2,000	5,281	$325.00	$0.75710	**$4,235.25**	$0.75710	**$4,235.25**	0.0%
16		Block 2	6,770,266	all additional			$0.73028		$0.73028		
17	31I Firm Trans	Block 1	129,581	2,000	6,893	$575.00	$0.42698	**$3,347.90**	$0.42698	**$3,347.90**	0.0%
18		Block 2	284,018	all additional			$0.39218		$0.39218		
19	32C Firm Sales	Block 1	35,905,676	10,000	7,694	$675.00	$0.67950	**$5,903.07**	$0.67950	**$5,903.07**	0.0%
20		Block 2	9,554,234	20,000			$0.64912		$0.64912		
21		Block 3	1,745,309	20,000			$0.59863		$0.59863		
22		Block 4	802,581	100,000			$0.54796		$0.54796		
23		Block 5	0	600,000			$0.51155		$0.51155		
24		Block 6	0	all additional			$0.49429		$0.49429		
25	32I Firm Sales	Block 1	9,268,308	10,000	18,815	$675.00	$0.62799	**$12,294.23**	$0.62799	**$12,294.23**	0.0%
26		Block 2	8,227,501	20,000			$0.60571		$0.60571		
27		Block 3	2,696,668	20,000			$0.56843		$0.56843		
28		Block 4	2,255,924	100,000			$0.53127		$0.53127		
29		Block 5	130,032	600,000			$0.50532		$0.50532		
30		Block 6	0	all additional			$0.49228		$0.49228		
31	32C Firm Trans	Block 1	3,057,342	10,000	18,166	$925.00	$0.22444	**$4,807.01**	$0.22444	**$4,807.01**	0.0%
32		Block 2	2,128,039	20,000			$0.20054		$0.20054		
33		Block 3	644,113	20,000			$0.16081		$0.16081		
34		Block 4	866,120	100,000			$0.12106		$0.12106		
35		Block 5	62,190	600,000			$0.09716		$0.09716		
36		Block 6	0	all additional			$0.08133		$0.08133		
37	32I Firm Trans	Block 1	11,016,531	10,000	72,132	$925.00	$0.21299	**$12,552.91**	$0.21299	**$12,552.91**	0.0%
38		Block 2	15,602,797	20,000			$0.19090		$0.19090		
39		Block 3	9,458,456	20,000			$0.15413		$0.15413		
40		Block 4	22,451,387	100,000			$0.11736		$0.11736		
41		Block 5	21,475,941	600,000			$0.09523		$0.09523		
42		Block 6	7,418,474	all additional			$0.08060		$0.08060		
43	32C Interr Sales	Block 1	4,132,294	10,000	48,951	$675.00	$0.63625	**$30,088.95**	$0.63625	**$30,088.95**	0.0%
44		Block 2	6,058,058	20,000			$0.61173		$0.61173		
45		Block 3	3,271,549	20,000			$0.57078		$0.57078		
46		Block 4	4,837,562	100,000			$0.52983		$0.52983		
47		Block 5	3,434,773	600,000			$0.50524		$0.50524		
48		Block 6	0	all additional			$0.48727		$0.48727		
49	32I Interr Sales	Block 1	5,733,047	10,000	59,818	$675.00	$0.61610	**$35,054.32**	$0.61610	**$35,054.32**	0.0%
50		Block 2	7,298,404	20,000			$0.59475		$0.59475		
51		Block 3	4,456,416	20,000			$0.55916		$0.55916		
52		Block 4	12,581,349	100,000			$0.52354		$0.52354		
53		Block 5	5,103,939	600,000			$0.50215		$0.50215		
54		Block 6	0	all additional			$0.48653		$0.48653		
55	32C Interr Trans	Block 1	667,319	10,000	180,185	$925.00	$0.20565	**$23,940.40**	$0.20565	**$23,940.40**	0.0%
56		Block 2	1,394,375	20,000			$0.18462		$0.18462		
57		Block 3	939,924	20,000			$0.14961		$0.14961		
58		Block 4	3,098,587	100,000			$0.11452		$0.11452		
59		Block 5	386,468	600,000			$0.09350		$0.09350		
60		Block 6	0	all additional			$0.07952		$0.07952		
61	32I Interr Trans	Block 1	5,864,800	10,000	199,892	$925.00	$0.20496	**$25,770.28**	$0.20496	**$25,770.28**	0.0%
62		Block 2	9,761,912	20,000			$0.18409		$0.18409		
63		Block 3	5,807,692	20,000			$0.14935		$0.14935		
64		Block 4	12,637,820	100,000			$0.11453		$0.11453		
65		Block 5	28,598,086	600,000			$0.09368		$0.09368		
66		Block 6	95,643,968	all additional			$0.07979		$0.07979		
67	33		0	N/A	0.0	$38,000.00	$0.06550	$38,000.00	$0.06550	$38,000.00	
68	Special Contracts		75,345,634	N/A	0	$0	$0.00000	$0.00	$0.00000	$0.00	
69											
70	**Totals**		**1,090,582,502**								

NW Natural
Rates and Regulatory Affairs
2026-2027 PGA Filing - OREGON
Basis for Revenue Related Costs

		Twelve Months		
1		Ended 06/30/26		
2				
3	Total Billed Gas Sales Revenues	$ 914,402,342		
4	Total Oregon Revenues	$ 918,820,399		
5				
6	Regulatory Commission Fees [1]	n/a	0.360%	Statutory rate
7	City License and Franchise Fees	$ 21,576,831	2.348%	Line 7 ÷ Line 4
8	Net Uncollectible Expense [2]	$ 1,824,506	0.199%	Line 8 ÷ Line 4
9				
10	Total		**2.907%**	Sum lines 8-9
11				
12				
13	**Note:**			
14	[1] Dollar figure is set at statutory level of Total Oregon Revenues (line 4).			
15	[2] Represents the normalized net write-offs based on a three-year average.			

NW Natural
Rates & Regulatory Affairs
2026-2027 PGA Filing - Oregon: September Filing
PGA Effects on Revenue
Schedule 195: WARM

Line	Description	Not Including Revenue Sensitive Amount
1		
2	**Temporary Increments**	
3		
4	Removal of Current Temporary Increments	
5	Amortization of WARM (Residential & Commercial)	(10,249,418)
6		
7		
8	Addition of Proposed Temporary Increments	
9	Amortization of WARM (Residential & Commercial)	18,268,087
10		
11		
12	**TOTAL OF ALL COMPONENTS OF RATE CHANGES**	**$8,018,669**
13		
14		
15		
16	2025 Oregon Earnings Test Normalized Total Revenues	$1,005,966,120
17		
18	Effect of this filing, as a percentage change (line 12 ÷ line 16)	0.80%

NW Natural
Rates & Regulatory Affairs
2026-27 PGA Filing - July Filing
Summary of Deferred Accounts Included in the PGA

	Account	Balance 6/30/2026	Jul-Oct Estimated Activity	Jul-Oct Interest	Estimated Balance 10/31/2026	Interest Rate During Amortization	Estimated Interest During Amortization	Total Estimated Amount for (Refund) or Collection
	A	B	C	D	E	F1	F2	G
27	**WARM Deferral and Amortizations**							
28	151832 RESIDENTIAL WARM AMORTIZATION	**1,962,471**	(583,326)	28,642	1,407,787			
29	151830 RESIDENTIAL WARM DEFERRAL	**9,516,605**	-	179,212	9,695,817			
30	Total	11,479,076	(583,326)	207,854	11,103,604	4.61%	279,215	11,382,819
31								
32	151836 COMMERCIAL WARM AMORTIZATION	**1,218,597**	(453,390)	16,738	781,945			
33	151834 COMMERCIAL WARM DEFERRAL	**5,824,741**	-	109,689	5,934,430			
34	Total	7,043,339	(453,390)	126,427	6,716,376	4.61%	168,892	6,885,268

Company: Northwest Natural Gas Company
State: Oregon
Description: OR Deferred WARM-Residential
Account Number: 151830
Docket: Docket UM 1798
Last authorization to defer granted in Order 26-012

1 Debit (Credit)

Line	Month/Year	Note	Deferral	Transfers	Interest Rate	Interest	Activity	Balance
5	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
6								
7	Beginning Balance							
116	Jul-25		(604.56)		6.16%	29,999.22	29,394.66	5,873,700.88
117	Aug-25		(393.52)		6.16%	30,150.65	29,757.13	5,903,458.01
118	Sep-25		(487.02)		6.16%	30,303.17	29,816.15	5,933,274.16
119	Oct-25		(291.83)		6.16%	30,456.72	30,164.89	5,963,439.05
120	Nov-25		(56.99)	(5,965,236.50)	6.16%	(9.37)	(5,965,302.86)	(1,863.81)
121	Dec-25		4,886,760.66		6.16%	12,533.12	4,899,293.78	4,897,429.97
122	Jan-26		3,216,082.90		5.61%	30,413.08	3,246,495.98	8,143,925.95
123	Feb-26		50,170.70		5.61%	38,190.13	88,360.83	8,232,286.78
124	Mar-26		229,608.55		5.61%	39,022.65	268,631.20	8,500,917.98
125	Apr-26		490,454.18		5.61%	40,888.23	531,342.41	9,032,260.39
126	May-26		396,908.35		5.61%	43,153.59	440,061.94	9,472,322.33
127	Jun-26		(0.43)		5.61%	44,283.11	44,282.68	9,516,605.01
128	Jul-26				5.61%	44,490.13	44,490.13	9,561,095.14
129	Aug-26				5.61%	44,698.12	44,698.12	9,605,793.26
130	Sep-26				5.61%	44,907.08	44,907.08	9,650,700.34
131	Oct-26				5.61%	45,117.02	45,117.02	9,695,817.36

Company: Northwest Natural Gas Company
State: Oregon
Description: Amort WARM Residential
Account Number: 151832
Docket: Dockets UM 1798 and UG 510
Amortization of WARM adjustment approved in Order 25-10

	Month/Year	Note	Amortization	Transfers	Interest Rate	Interest	Activity	Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Beginning Balance							
105	Jul-25		(31,021.07)		5.40%	1,413.51	(29,607.56)	300,017.16
106	Aug-25		(25,118.91)		5.40%	1,293.56	(23,825.35)	276,191.81
107	Sep-25		(26,085.49)		5.40%	1,184.17	(24,901.32)	251,290.49
108	Oct-25		(44,365.14)		5.40%	1,030.99	(43,334.15)	207,956.34
109	Nov-25	OLD	(57,161.91)		5.40%	807.19	(56,354.72)	151,601.62
110	Nov-25	NEW	(206,433.10)	5,965,236.50	5.16%	25,206.69	5,784,010.09	5,935,611.71
111	Dec-25		(702,880.98)		5.16%	24,011.94	(678,869.04)	5,256,742.67
112	Jan-26		(907,362.14)		5.16%	20,653.16	(886,708.98)	4,370,033.69
113	Feb-26		(857,373.16)		5.16%	16,947.79	(840,425.37)	3,529,608.32
114	Mar-26		(677,742.74)		5.16%	13,720.17	(664,022.57)	2,865,585.75
115	Apr-26		(463,570.04)		5.16%	11,325.34	(452,244.70)	2,413,341.05
116	May-26		(282,203.68)		5.16%	9,770.63	(272,433.05)	2,140,908.00
117	Jun-26		(187,240.33)		5.16%	8,803.34	(178,436.99)	1,962,471.01
118	Jul-26	forecasted	(155,890.97)		5.16%	8,103.46	(147,787.51)	1,814,683.50
119	Aug-26	forecasted	(151,645.73)		5.16%	7,477.10	(144,168.63)	1,670,514.87
120	Sep-26	forecasted	(172,411.00)		5.16%	6,812.53	(165,598.47)	1,504,916.40
121	Oct-26	forecasted	(103,378.57)		5.16%	6,248.88	(97,129.69)	1,407,786.71

Company:	Northwest Natural Gas Company
State:	Oregon
Description:	OR Deferred WARM-Commercial
Account Number:	151834
Docket:	Docket UM 1798
	Last authorization to defer granted in Order 26-012

1 Debit (Credit)
2
3

Line	Month/Year	Note	Deferral	Transfers	Interest Rate	Interest	Activity	Balance
5	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
6								
7	Beginning Balance							
116	Jul-25		(474.24)		6.16%	18,341.99	17,867.75	3,591,219.29
117	Aug-25		(2,130.95)		6.16%	18,429.46	16,298.51	3,607,517.80
118	Sep-25		(241.46)		6.16%	18,517.97	18,276.51	3,625,794.31
119	Oct-25		(461.57)		6.16%	18,611.23	18,149.66	3,643,943.97
120	Nov-25		1,329.52	(3,647,291.26)	6.16%	(13.77)	(3,645,975.51)	(2,031.54)
121	Dec-25		2,616,126.98		6.16%	6,704.30	2,622,831.28	2,620,799.74
122	Jan-26		1,668,804.05		5.61%	16,153.07	1,684,957.12	4,305,756.86
123	Feb-26		50,723.05		5.61%	20,247.98	70,971.03	4,376,727.89
124	Mar-26		368,909.47		5.61%	21,323.53	390,233.00	4,766,960.89
125	Apr-26		606,994.67		5.61%	23,704.39	630,699.06	5,397,659.95
126	May-26		375,080.15		5.61%	26,110.81	401,190.96	5,798,850.91
127	Jun-26		(1,216.22)		5.61%	27,106.79	25,890.57	5,824,741.48
128	Jul-26				5.61%	27,230.67	27,230.67	5,851,972.15
129	Aug-26				5.61%	27,357.97	27,357.97	5,879,330.12
130	Sep-26				5.61%	27,485.87	27,485.87	5,906,815.99
131	Oct-26				5.61%	27,614.36	27,614.36	5,934,430.35

Company:	Northwest Natural Gas Company
State:	Oregon
Description:	Amort WARM Commercial
Account Number:	151836
Docket:	Dockets UM 1798 and UG 510
	Amortization of WARM adjustment approved in Order 25-10

	Month/Year	Note	Amortization	Transfers	Interest Rate	Interest	Activity	Balance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Beginning Balance							
105	Jul-25		(45,465.89)		5.40%	1,215.48	(44,250.41)	248,588.56
106	Aug-25		(40,006.07)		5.40%	1,028.63	(38,977.44)	209,611.12
107	Sep-25		(40,613.94)		5.40%	851.87	(39,762.07)	169,849.05
108	Oct-25		(54,103.83)		5.40%	642.59	(53,461.24)	116,387.81
109	Nov-25	OLD	(59,229.39)		5.40%	390.48	(58,838.91)	57,548.90
110	Nov-25	NEW	(112,619.64)	3,647,291.26	5.16%	15,441.22	3,550,112.84	3,607,661.74
111	Dec-25		(403,074.24)		5.16%	14,646.34	(388,427.90)	3,219,233.84
112	Jan-26		(516,666.58)		5.16%	12,731.87	(503,934.71)	2,715,299.13
113	Feb-26		(508,094.12)		5.16%	10,583.38	(497,510.74)	2,217,788.39
114	Mar-26		(408,887.35)		5.16%	8,657.38	(400,229.97)	1,817,558.42
115	Apr-26		(286,844.57)		5.16%	7,198.79	(279,645.78)	1,537,912.64
116	May-26		(188,600.48)		5.16%	6,207.53	(182,392.95)	1,355,519.69
117	Jun-26		(142,444.90)		5.16%	5,522.48	(136,922.42)	1,218,597.27
118	Jul-26	forecasted	(131,554.50)		5.16%	4,957.13	(126,597.37)	1,091,999.90
119	Aug-26	forecasted	(128,289.91)		5.16%	4,419.78	(123,870.13)	968,129.77
120	Sep-26	forecasted	(131,477.74)		5.16%	3,880.28	(127,597.46)	840,532.31
121	Oct-26	forecasted	(62,067.84)		5.16%	3,480.84	(58,587.00)	781,945.31
122								
123	**History truncated for ease of viewing**							

CERTIFICATE OF SERVICE
UM 1286

I hereby certify that on September 14, 2026, I have served the unredacted, Confidential and Highly Confidential portions of NW NATURAL'S EXHIBIT C AND EXHIBIT D in docket UG 531 (NWN OPUC Advice No. 26-05A), upon the Public Utility Commission of Oregon and Parties designated to receive confidential and/or highly confidential information, subject to Modified Protective Order 10-337 (docket UM 1286), via electronic transmission.

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DATED September 14, 2026, Troutdale, Oregon.

/s/ Erica Lee-Pella
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