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September 12, 2025

Advice No. 25-02-G/UG-523 (Purchased Gas Cost Adjustment Filing) - Supplemental

Public Utility Commission of Oregon
201 High St SE, Suite 100
Salem, OR 97301

Attn: Filing Center

Pursuant to Order Nos. 08-504, 11-196 and 14-238 in Docket No. UM 1286, Avista Corporation, doing business as, "Avista Utilities" hereby electronically submits its 2025 Purchased Gas Cost Adjustment (cover letter, as filed summary, tariff sheets, and newspaper advertisement draft).[1]

In accordance with guidance provided in Docket No. UM 1286, the Company has updated commodity costs to reflect index purchases based on 60-day basin-weighted average prices and executed hedges as of August 31, 2025. Supplemental Tariff Sheets 461 and 461A reflect these updates. Tariff Sheet 462 (amortization) remains unchanged from the original filing dated July 31, 2025, and has not been included in this Supplemental filing.

The Company requests that the following tariff sheets become effective on October 31, 2025[2]:

Oregon PUC Sheet No.	Title of Sheet	Canceling Oregon PUC Sheet No.
Supplemental Twenty-First Revision Tariff Sheet 461	Purchased Gas Cost Adjustment Provision	Supplemental Twentieth Revision Tariff Sheet 461
Supplemental Nineteenth Revision Tariff Sheet 461A	Purchased Gas Cost Adjustment Provision	Supplemental Eighteenth Revision Tariff Sheet 461A

[1] The Company has also emailed confidential workpapers and non-confidential workpapers to "puc.workpapers@state.or.us".
[2] Concurrent with this filing, the Company filed a motion in UM 1286 to waive the November 1 effective date in the PGA guidelines and allow an effective date of October 31, 2025 in the current year.

This filing is a Purchased Gas Cost Adjustment (PGA) to change rates within Avista Utilities' natural gas service schedules to reflect the projected cost of natural gas pursuant to tariff Schedule 461, "Purchased Gas Cost Adjustment Provision". Schedule 461 sets forth the estimated purchased natural gas costs for the forthcoming year (November 1, 2025 through October 31, 2026). The difference between the actual cost of natural gas purchased and the amount collected from customers (i.e., the amortization rate pertaining to the PGA balancing account) are passed through to customers through Schedule 462, "Gas Cost Rate Adjustment".

Table Nos. 1 through 3 below summarize the changes in the 1) forward looking commodity costs included in Schedule 461, 2) the demand costs included in Schedule 461, and 3) the combined changes to Schedule 461 (both commodity and demand):

Table No. 1 - Schedule 461 Commodity

Rate Schedule	Present	Proposed	Change
410, 411, 420, 424, 444	$ 0.27787	$ 0.26490	**$ (0.01297)**
440	$ 0.27787	$ 0.26490	**$ (0.01297)**

Table No. 2 - Schedule 461 Demand

Rate Schedule	Present	Proposed	Change
410, 411, 420, 424, 444	$ 0.15493	$ 0.18101	**$ 0.02608**
440	$ -	$ -	**$ -**

Table No. 3 - Schedule 461 Commodity + Demand

Rate Schedule	Present	Proposed	Change
410, 411, 420, 424, 444	$ 0.43280	$ 0.44591	**$ 0.01311**
440	$ 0.27787	$ 0.26490	**$ (0.01297)**

Commodity Costs (Schedule 461)

As shown in the Table No. 1 above, the proposed weighted average cost of gas ("WACOG") is $0.26490 per therm, a decrease of $0.01297 per therm from the present WACOG of $0.27787 per therm included in customer's rates.

The past year has been relatively uneventful for the natural gas market in the Pacific Northwest. While the Central and Eastern United States had seen a couple of large demand events in January and February, those events did not extend to our region. The region's largest supply points, Sumas and AECO, have traded at a discount to Henry Hub, the national natural gas benchmark, since the end of this last winter as supply has been plentiful to meet demand for the region aside from some interstate pipeline maintenance. Before the winter season had ended, Sumas was trading much more closely to Henry Hub; AECO however maintained its consistent, historical discount throughout the past year.

As we look toward the upcoming winter, the national market fundamentals show strong production that is matched by growth in demand for LNG feed-gas that is exported abroad. Currently, the national gas storage volume has exceeded the five-year average for this time of year and some bearish price signals have appeared as supply confidence grows in strength. That bearishness has been even stronger for the Pacific Northwest as storage balances are near the top of the 5-year range and Canadian production remains strong (which provides most of the supply to the Pacific Northwest region). One new source of demand in Western Canada is LNG Canada, located in British Columbia. LNG Canada, when fully operational (projected by end of 2025), will provide the region with additional demand of nearly 2 Bcf/day. Despite this incremental demand, recent pricing for the upcoming winter has fallen, displaying the market's perception of supply strength for the region and its ability to serve demand.

Approximately 46% of estimated annual load requirements for the PGA year (November 2025 through October 2026) have been hedged at a fixed price in accordance with the Company's Procurement Plan as further discussed in the Company's Natural Gas Portfolio Development Guidelines. Through August 31, 2025, the Company's average executed hedge costs is \$2.75 per dekatherm (\$0.27500 per therm).

The Company has approximately 920,000 dekatherms of underground storage capacity at Jackson Prairie available for its Oregon customers. Total underground storage capacity represents approximately 8% of annual load requirements (12.7% of load requirements during the Nov.-Mar. withdrawal period). As of August 31, 2025, the current storage balance is approximately 907,779 dekatherms and costs for all storage volumes is \$1.06 per dekatherm (\$0.10573 per therm). The Company will inject additional volumes into storage throughout the Summer which will be included in the Company's PGA update filing in September.

As required by Commission Order No. 14-238, the Company used a 60-day (ending August 31, 2025) historical average of forward prices weighted by supply basin to determine the estimated cost associated with index/spot volumes. These index/spot volumes represent approximately 46% of estimated annual volumes and the annual weighted average price for these volumes is \$2.53 per dekatherm (\$0.25295 per therm).

The information contained in the Company's responses to "Natural Gas Portfolio Development Guidelines" describes the Company's Natural Gas Procurement Plan ("Procurement Plan"). The Company's Procurement Plan uses a diversified approach to procure natural gas for the upcoming year. While the Procurement Plan generally incorporates a structured approach for the hedging portion of the portfolio, the Company exercises flexibility and discretion in all areas of the plan based on changes in the wholesale market. The Company meets with Commission Staff quarterly[3] to discuss the state of the wholesale market and the status of the Company's Procurement Plan, among other things. Should there be a deviation from the Procurement Plan due to material changes in market dynamics etc., the Company documents and communicates any such changes with the Company's Risk Management Committee and provides updates to Commission Staff.

[3] Alliance of Western Energy Consumers (AWEC) and Citizens' Utility Board (CUB) are invited too, and generally attend, each quarterly meeting.

<u>Demand Costs (Schedule 461)</u>

Demand costs reflect the cost of pipeline transportation to the Company's system, as well as fixed costs associated with natural gas storage. As shown in the Table No. 2 above, demand costs are expected to increase slightly from $0.15493 per therm to $0.18101 per therm, for a proposed increase of approximately $0.02608 per therm. This change is related to a variety of factors including Canadian exchange rate, updated demand forecast, and pipeline rates in effective for the PGA year.

<u>Amortization of Deferral Accounts (Schedule 462)</u>

Table Nos. 4 through 6 summarize the changes in the commodity and demand amortization rates included in Schedule 462, and the combined change to Schedule 462 (both commodity <u>and</u> demand):

Table No. 4 - Schedule 462 Commodity Amortization

Rate Schedule	Present	Proposed	Change
410, 411, 420, 424, 444	$(0.12110)	$(0.16741)	**$(0.04631)**
440	$(0.12110)	$(0.16741)	**$(0.04631)**

Table No. 5 - Schedule 462 Demand Amortization

Rate Schedule	Present	Proposed	Change
410, 411, 420, 424, 444	$ 0.01709	$ 0.02792	**$ 0.01083**
440	$ -	$ -	**$ -**

Table No. 6 - Schedule 462 Commodity + Demand Amortizations

Rate Schedule	Present	Proposed	Change
410, 411, 420, 424, 444	$(0.10401)	$(0.13949)	**$(0.03548)**
440	$(0.12110)	$(0.16741)	**$(0.04631)**

Related to the commodity portion of the amortization rate, net commodity costs for the current PGA year to date were less than the commodity WACOG included in Schedule 461 resulting in a net rebate amortization rate of $0.16741 per therm, a decrease of $0.04631 compared to the present rate in effect. As previously discussed in the Demand Costs (Schedule 461) section above, demand costs are impacted by a variety of factors including the Canadian exchange rate, demand volumes, and changes in pipeline contracts and rates. A combination of these factors has resulted in a surcharge amortization rate of $0.02792 per therm. Combining the commodity and demand amortization balances results in an overall decrease in the amortization rates included in Schedule 462 as shown in Table No. 6.

<u>3% Test</u>

Pursuant to ORS 757.259 and OAR 860-027-0300, the overall annual average rate impact of the amortizations authorized under the statutes may not exceed three percent of the natural gas utility's gross revenues for the proceeding calendar year, unless the Commission finds that allowing a higher amortization rate is reasonable under the circumstances. Total <u>gross</u> revenue for calendar year 2024 was $144,378,437 and total Prior Period Gas Cost Deferral True-up amortizations is a <u>rebate</u> of $16,129,403. The resulting annual average rate impact from the PGA amortization is

(11.2)%.[4] Including the effect of the Company's other amortization rates filed coincident with the initial July PGA filing, the resulting annual average rate impact from the Company's qualifying amortization is (7.8)%. Please see Attachment C of the Company's PGA workpapers for a detailed calculation, and applicable amortization schedules, for the 3% test.

Other Information

The PGA filing reflects an overall annual revenue decrease of approximately $3.3 million, or 2.6% effective October 31, 2025. Pursuant to OAR 860-022-0025 and OAR 860-022-0030, the total number of customers affected by this filing, the annual revenue before and after the impact of the proposed rate changes, and the average monthly use and resulting bills under existing and proposed rates are as follows:

Rate Schedule	Average Number of Customers
Schedule 410	95,714
Schedule 420	11,975
Schedule 424	100
Schedule 440	48
Schedule 444	2

Sch No	Description	Present Revenues	Proposed Revenues	Revenue Incr (Decr)	Percent Incr (Decr)	Use (Therms)	Present Monthly Cost	Proposed Monthly Cost	Change to Monthly Cost	% Change Monthly Cost
410/411	Residential	$ 78,957,314	$ 77,768,841	$ (1,188,473)	-1.5%	46	$ 68.43	$ 67.40	$ (1.03)	-1.5%
420	General	$ 37,691,615	$ 37,020,290	$ (671,325)	-1.8%	209	$ 262.48	$ 257.80	$ (4.68)	-1.8%
424	Large General	$ 2,597,250	$ 2,477,631	$ (119,619)	-4.6%	4,456	$ 2,164.33	$ 2,064.65	$ (99.68)	-4.6%
440	Interruptible	$ 6,636,641	$ 5,303,701	$ (1,332,940)	-20.1%	39,037	$ 11,396.85	$ 9,207.74	$ (2,189.11)	-19.2%
444	Seasonal	$ 86,947	$ 83,097	$ (3,850)	-4.4%	8,194	$ 4,140.10	$ 3,956.80	$ (183.30)	-4.4%

After combining the impact of this filing with the Company's other regulatory filings with an October 31, 2025 effective date,[5] a residential customer using an average of 46 therms a month could expect their bill to increase by $1.75, or 2.6%, for a revised monthly bill of $70.18 effective October 31, 2025.

The following table shows the net impact to the Company's customers, by rate schedule, inclusive of all of the filings made by the Company that have an October 31, 2025 effective date:

Rate Schedule	Proposed Rate Change[6]
Schedule 410/411	2.6%
Schedule 420	3.4%
Schedule 424	11.3%

[4] Please see Attachment C included in the Purchase Gas Adjustment workpapers.

[5] On July 31, 2025, Avista filed to update effective October 31, 2025 Schedules 461 Purchased Gas Cost Adjustment and 462 Gas Cost Rate Adjustment (Advice No. 25-02-G), Schedule 463 CPP (Advice No. 25-07-G), Schedule 467 COVID Deferred Costs (Advice No. 25-08-G), Schedule 475 Decoupling (Advice No. 25-03-G), Schedule 476 Intervenor Funding (Advice No. 25-04-G), Schedule 482 Regulatory Fee Amortization (Advice No. 25-05-G), and Schedule 493 LIRAP (Advice No. 25-06-G). The net effect of all filings is a revenue increase of approximately $4.1 million or 3.2%.

[6] Includes filed rate changes to Schedules 461, 462, 463, 467, 475, 476, 482, and 493.

Schedule 440	6.4%
Schedule 444	10.9%
Schedule 456	4.9%
Total	3.2%

Included with the original filing is the information in response to the Natural Gas Portfolio Development Guidelines and the PGA Filing Guidelines, as approved by the Commission in Order No. 09-248 and as amended in Order No. 10-197, Order No. 11-196 and Order No. 14-238. The Company will provide notice to customers via newspaper advertisement with this updated PGA filing. In compliance with OAR 860-022-0017(4), Avista attests that notice to customers via newspaper advertisement occurred after the Company's initial filing in July 2025, which also included the language included in the advertisements. All were run on August 13th. Below is a listing of publications the advertisements ran in:

Rogue Valley Times
Klamath Falls Herald and News
Roseburg News Review
Grants Pass Daily Courier
East Oregonian

Please direct any questions regarding this filing to Derek Isaak at (509) 495-7326 or derek.isaak@avistacorp.com.

Sincerely,

/s/ Joe Miller

Joe Miller
Senior Manager of Rates and Tariffs, Regulatory Affairs
Enclosures

October 31, 2025
As of August 31, 2025
(As filed – these are not approved rate changes)

1	**Company**	**Avista**	
2	**Docket Numbers**	UG-523	
3	**Advice No.**	25-02-G	
4	**Principal Analysts**	Anna Kim	
5	**Current Customer Charge - Residential ($)**	$11.25	
6	**Average Monthly Therm Use (Residential)**	46	
7	**Current Energy Charge/Rate (dollars/therm)**	Billing - $1.24296 Base - $0.81650	
8	**PGA Base Gas Cost Change - Residential (dollars/therm)**	($0.01297)	Commodity Only – including revenue sensitive
9	**Other Temporary Rate Increments - Residential (dollars/therm)**	$0.02608 Demand $(0.03548) Amort	Demand, Amortization, including revenue sensitive
10	**Permanent Base Rate Adjustment – Residential (dollars/therm)**	$0.00	
11	**Overall Change - Residential Rate (dollars/therm)**	($0.02237)	Gas, Demand and Amortization
12	**Proposed Tariff Rate - Residential (dollars/therm)**	$1.28106	Including all filings (Gas and Non-gas) – See Attachment B in workpapers
13	**Average monthly bill change for typical residential customer ($/bill on an annual basis)**	$1.75	Including all filings (Gas and Non-gas) – See Attachment D in workpapers
14	**Overall Change - Residential Revenue (%)**	2.6%	Including all filings (Gas and Non-gas) – See ”Change in Annual Revenues” workpapers
15	**Overall Change – Commercial & Industrial firm (%)**	Commercial = 3.4% Industrial = 11.3%	Including all filings (Gas and Non-gas) – See ”Change in Annual Revenues” workpapers
16	**WACOG (dollars/therm) – not revenue-sensitized**	$0.25638 Commodity $0.17519 Demand	
	Comments – Other (continued)		

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

AVISTA UTILITIES
ADVICE NO. 25-02-G
Supplemental

Tariff Sheets

September 12, 2025

SCHEDULE 461

PURCHASED GAS COST ADJUSTMENT PROVISION – OREGON

APPLICABILITY:

This schedule applies to all schedules for natural gas sales service within the entire territory served by the Company in the State of Oregon. The definitions and provisions described herein shall establish the natural gas costs for Purchased Gas Adjustment (PGA) deferral purposes on a monthly basis.

PURPOSE:

The purpose of this provision is to allow the Company, on established Adjustment Dates, to adjust rate schedules for changes in the cost of gas purchased in accordance with the rate adjustment provisions described herein.

RATE:

(a) The rates of gas Schedules 410, 411, 420, 424 and 444 are to be increased by $0.44591 per therm in all blocks of these rate schedules. (I)
(b) The rate of gas Schedule 440 is to be increased by $0.26490 per therm in all blocks of these rate schedules. (R)
(c) The rates of transportation Schedule 456 are to be increased by $0.0000 per therm in all blocks.

A. DEFINITIONS:

1. Actual Commodity Cost: The natural gas supply costs for commodity actually paid for the month, including Financial Transactions, fuel use, and distribution system lost and unaccounted for natural gas (LUFG) plus Gas Storage Facilities withdrawals, plus or minus the cost of gas associated with pipeline imbalances, plus propane costs, plus odorization charges, less Commodity Off-System Sales Revenues received during the month, plus actual Variable Transportation Costs, plus commodity-related reservation charges, less all transportation demand charges embedded in commodity costs.

2. Commodity Off-System Sales Revenues: Revenues received from the sale of natural gas to a party other than the Company's Oregon sales customers less costs associated with the sales transactions.

3. Variable Transportation Costs: Variable transportation costs, including pipeline volumetric charges and other variable costs related to volumes of commodity delivered to sales customers.

4. Actual Non-Commodity Cost: Actual Non-Commodity gas costs shall be equal to actual Demand Costs, less actual Capacity Release Benefits, plus or minus actual pipeline refunds or surcharges.

5. Demand Costs: Fixed monthly pipeline costs and other demand-related natural gas costs such as capacity reservation charges, plus any transportation demand charges embedded in commodity cost.

SCHEDULE 461 (continued)

PURCHASED GAS COST ADJUSTMENT PROVISION – OREGON

6. Capacity Release Benefits: This component includes revenues associated with pipeline capacity releases. The benefits to Customers, through the monthly PGA deferrals, shall be 100% of the capacity release revenues up to the full pipeline rate, and 80% of the capacity release revenues in excess of full pipeline rates. Capacity release revenues shall be quantified on a transaction-by-transaction basis.

7. Estimated Weighted Average Cost Of Gas (WACOG): The estimated WACOG is calculated by the following formula: (Forecasted Purchases at Adjusted Contract Prices) divided by forecasted sales.

a. "Forecasted Purchases" means November 1 – October 31 forecasted sales, plus a percentage for "Distribution System Unaccounted for Gas."
b. "Distribution System Unaccounted for Gas" means the 5-year average of actual unaccounted for gas, not to exceed 2%.
c. "Adjusted Contract Prices" means contract prices that are adjusted by each associated Canadian pipeline's published (closest to August 1) fuel-in-kind and line loss amount provided for by tariff, and by each associated U.S. pipeline's tariffed rate.

The Estimated WACOG per therm is as follows:

With Gross Revenue Factor	$0.26490	(R)
Without Gross Revenue Factor	$0.25638	(R)

8. Estimated Non-Commodity Cost per Therm: The estimated Non-Commodity Cost per therm shall be equal to estimated Demand Costs, less estimated Capacity Release Benefits, plus or minus estimated pipeline refunds or surcharges, divided by November 1 – October 31 forecasted sales

The Estimated Non-Commodity Cost per therm is as follows:

With Gross Revenue Factor	$0.18101	(I)
Without Gross Revenue Factor	$0.17519	(I)

9. Forecasted Monthly Calendar Sales Volumes: Forecasted billed sales therms, adjusted for estimated unbilled therms, for Schedules 410, 411, 420, 424, 440, and 444.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

AVISTA UTILITIES

ADVICE NO. 25-02-G
Supplemental

**NEWSPAPER AD
(DRAFT)**

September 12, 2025

DRAFT

Recently, Avista requested a change in natural gas rates for our Oregon customers. We know you care about your energy costs, so we think it's important to share this news with you.

On Sept. 12, 2025, Avista filed a request with the Public Utility Commission of Oregon (PUC) to update the Purchased Gas Cost Adjustment (PGA) originally filed with the PUC on July 31, 2025, asking for an overall decrease in natural gas revenues of approximately $3.3 million, or 2.6%.

On July 31, 2025, Avista also proposed six other rate adjustments related to intervenor funding, COVID deferred costs, decoupling, Low Income Rate Assistance Program, Climate Protection Program, and recovering costs associated with regulatory fees. All seven requests, inclusive of the updated PGA filing, if approved, are designed to increase overall natural gas revenue by approximately $4.1 million or 3.2% effective Oct. 31, 2025. These filings have no impact on Avista's earnings.

PGAs are filed each year to balance the actual cost of wholesale natural gas purchased by Avista to serve customers with the amount included in rates. This includes the natural gas commodity cost as well as the cost to transport natural gas on interstate pipelines to Avista's local distribution system. This rate adjustment is driven primarily by wholesale natural gas prices being lower than the level included in rates over the past year. Avista does not profit on the actual natural gas commodity or the costs to transport natural gas to Avista's service territory. Avista's request, if approved by the PUC, would go into effect on Oct. 31, 2025.

The bottom line
If all seven requests are approved, and you are an Avista natural gas customer using an average of 46 therms per month, you could expect your bill to increase by $1.75, or 2.6% for a revised monthly bill of $70.18 beginning Oct. 31, 2025. All other customer groups receiving firm natural gas service from Avista would also see increases.

For more information
Copies of our filings are available at www.myavista.com/rates or you can call us at 1-800-227-9187.

This announcement is to provide you with general information about Avista's rate request and its effect on customers. The calculations and statements in this announcement are not binding on the PUC. For more information about the filing or for information about the time and place of any hearing, contact the PUC at:

Public Utility Commission of Oregon
201 High Street SE, Ste. 100
Salem, OR 97301
(800) 522-2404, www.puc.state.or.us

This notice contains forward-looking statements regarding the Company's current expectations. Forward-looking statements are all statements other than historical facts. Such statements speak only as of the date of the notice and are subject to a variety of risks and uncertainties, many of which are beyond the Company's control, which could cause actual results to differ materially from the expectations. These risks and uncertainties include, in addition to those discussed herein, all the factors discussed in the Company's Annual Report on Form 10-K for the year ended Dec. 31, 2024 and the Quarterly Report on Form 10-Q for the quarter ended June 30, 2025.