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September 14, 2020

Advice No. 20-06-G Supplemental /UG-392 (Purchased Gas Cost Adjustment Filing)

Public Utility Commission of Oregon
Attn: Filing Center
201 High St SE, Suite 100
Salem, OR 97301

Pursuant to OAR 860-022-0070, ORS 757.210 and Order Nos. 08-504, 11-196 and 14-238 in Docket No. UM 1286, Avista Utilities hereby submits electronically the following listed tariff sheets applicable to its Oregon natural gas operations.[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 as of August 31, 2020. No additional hedges have been executed since our original filing dated July 31, 2020. Supplemental Tariff Sheets 461 and 461A reflect these updates. Tariff Sheet 462 (amortization) remains unchanged from the original filing dated July 31, 2020 and has not been included in this Supplemental filing.

The Company requests that the following tariff sheets become effective on November 1, 2020:

Oregon PUC Sheet No.	**Title of Sheet**	**Canceling Oregon PUC Sheet No.**
Supplemental Sixteenth Revision Tariff Sheet 461	Purchased Gas Cost Adjustment Provision	Supplemental Fifteenth Revision Tariff Sheet 461
Supplemental Fourteenth Revision Tariff Sheet 461A	Purchased Gas Cost Adjustment Provision	Supplemental Thirteenth Revision Tariff Sheet 461A

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

[1] The Company has also emailed confidential workpapers to "puc.workpapers@state.or.us".

purchased natural gas costs for the forthcoming year (November 1, 2020 through October 1, 2021). 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, 420, 424, 444	$0.16806	$0.20655	**$0.03849**
440	$0.16806	$0.20655	**$0.03849**

Table No. 2 - Schedule 461 Demand

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	$0.16237	$0.15787	**($0.00450)**
440	$0.00000	$0.00000	**$0.00000**

Table No. 3 - Schedule 461 Commodity + Demand

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	$0.33043	$0.36442	**$0.03399**
440	$0.16806	$0.15787	**($0.00450)**

Commodity Costs (Schedule 461)

As shown in the Table No. 1 above, the proposed weighted average cost of gas (“WACOG”) is $0.20655 per therm, an increase of $0.03849 per therm from the present WACOG of $0.16806 per therm included in customer’s rates. The increase in commodity WACOG is primarily attributed to the market’s response to the continued ambiguity around the COVID-19 pandemic and supply uncertainty for the upcoming winter. The pandemic has caused a dramatic reduction in oil drilling activity in North America, the extent and duration of which will impact the volume of associated gas produced from oil wells in the coming months and years. Strong seasonal summer natural gas demand, especially in August 2020, coupled with continued production uncertainty has driven forward natural gas prices up in the interim.

Approximately 39% of estimated annual load requirements for the PGA year (November 2020 through October 2021) has been hedged at a fixed price in accordance with the Company’s procurement plan. Through June 30, 2020, the Company’s average executed hedge costs is $1.716 per dekatherm ($0.1716 per therm).

As required by Commission Order 14-238, the Company used a 60-day (ending August 31, 2020) 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 61%

of estimated annual volumes and the annual weighted average price for these volumes is $2.111 per dekatherm ($0.2111 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[2] 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.

Demand Costs (Schedule 461)

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 decrease slightly from $0.16237 per therm to $0.15787 per therm, for a proposed reduction of approximately $0.00450 per therm. This reduction is primarily due to rate changes. TC Energy – NOVA had an interim rate set in late 2019 that was substantially higher than the final 2020 rates recently established through the conclusion of a multi-year revenue requirement negotiation settlement.

Amortization of Deferral Accounts (Schedule 462)

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

Table No. 4 - Schedule 462 Commodity Amortization

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	($0.01004)	($0.02026)	**($0.01022)**
440	($0.01004)	($0.02026)	**($0.01022)**

Table No. 5 - Schedule 462 Demand Amortization

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	$0.00009	$0.00477	**$0.00468**
440	$0.00000	$0.00000	**$0.00000**

[2] Alliance of Western Energy Consumers (AWEC) and Citizens' Utility Board (CUB) are invited to, and attend, each Quarterly meeting.

Table No. 6 - Schedule 462 Commodity + Demand Amortizations

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	($0.00995)	($0.01549)	**($0.00554)**
440	($0.01004)	($0.02026)	**($0.01022)**

Related to the Commodity portion of the amortization rate, for the winter of 2019-2020, after the early part of December, temperatures across the country for the balance of winter were warmer than average leading to below average natural gas demand for both heating and power generation. This mild weather contributed to weaker than average demand. Combined with growing production and very high storage levels, resulted in much lower prices versus the previous winter's unusual events[3]. The end of winter coincided with the onset of the COVID-19 pandemic in the U.S. The price response to the pandemic has been mixed. So far, the impact to demand has been greater than that of supply, which has been reflected in the cash market (day ahead Henry Hub index) by falling prices. Lower prices reflective of a combination of these factors has resulted in a rebate amortization rate of $0.02026 per therm.

As previously discussed in the Demand Costs (Schedule 461) section above, TC Energy – NOVA had a higher interim rate greater than what was embedded in customer rates. This was the primary factor that resulted in a surcharge amortization rate of $0.00477 per therm.

Combining the commodity and demand amortization balances results in an overall reduction in the amortization rates included in Schedule 462 as shown in Table No. 6 above.

<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. As shown on Attachment C of the Company's PGA workpapers, total <u>gross</u> revenue for calendar year 2019 was $144,734,103 and Total Prior Period Gas Cost Deferral True-up is a <u>rebate</u> of $1,548,086. The resulting annual average rate impact from the PGA amortization is (1.07%).[4]

Including the effect of the Company's other four amortization rates filed coincident with the initial July PGA filing (Intervenor Funding Advice No. 20-05-G, Natural Gas Decoupling Amortization Advice No. 20-06-G, Demand Side Management Amortization Advice No.20-08-G, and Regulatory Fees Amortization Advice No. 20-09-G) the resulting annual average rate impact from the Company's qualifying amortization is (3.3%).

[3] For the winter of 2018-2019, due in part to the catastrophic pipeline rupture on Enbridge prices were higher than normal.
[4] Please see attachment C included in the Purchase Gas Adjustment workpapers.

Other Information

The PGA filing reflects an overall annual revenue increase of approximately $2.7 million, or 2.8% effective November 1, 2020. Pursuant to OAR 860-022-0025 and OAR 860-022-0030, the total number of customers affected by the four filings with an effective date of November 1, 2020, and the annual revenue before and after the impact of the proposed rate changes, are as follows:

Rate Schedule	Average Number of Customers
Schedule 410	1,105,825
Schedule 420	142,784
Schedule 424	986
Schedule 440	405
Schedule 444	37
Schedule 456	372

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	Residential	$62,215,973	$63,690,222	$1,474,249	2.4%	47	$ 56.40	$ 57.74	$ 1.34	2.4%
420	General	$28,087,483	$28,896,974	$ 809,491	2.9%	199	$ 196.47	$ 202.13	$ 5.66	2.9%
424	Large General	$ 1,890,356	$ 2,002,712	$ 112,356	5.9%	4,005	$ 1,917.05	$ 2,030.99	$ 113.94	5.9%
				$ -						
440	Interruptible	$ 3,181,026	$ 3,515,691	$ 334,665	10.5%	29,230	$ 7,854.39	$ 8,680.73	$ 826.34	10.5%
				$ -						
444	Seasonal	$ 97,963	$ 103,555	$ 5,592	5.7%	5,312	$ 2,647.87	$ 2,799.00	$ 151.13	5.7%

After combining the impact of this PGA filing with the four other regulatory filings, which also have a November 1, 2020 effective date[5], a residential customer using an average of 47 therms a month could expect their bill to *decrease* by $0.19, or 0.3 percent, for a revised monthly bill of $56.21 effective November 1, 2020.

Below is a table showing the net impact to the Company's customers, by rate schedule, inclusive of all of the filings made by the Company that have a November 1, 2020 effective date:

[5] On July 31, 2020, Avista filed to update effective November 1, 2020 Schedule 476 Intervenor Funding (Advice No. 20-05-G), Schedule 475 Decoupling (Advice No. 20-06-G), Schedule 478 Demand Side Management (Advice No. 20-08-G), and Schedule 489 Regulatory Fees (Advice No. 20-09-G). The net effect of all filings (including PGA) is a revenue decrease of approximately $500 thousand or 0.5%.

Rate Schedule	Proposed Rate Change[6]
Schedule 410	(0.3)%
Schedule 420	(0.6)%
Schedule 424	(1.1)%
Schedule 440	(2.1)%
Schedule 444	(1.1)%
Schedule 456	(0.5)%
Total	(0.5)%

Included with the original filing (July 31, 2020) 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. A newspaper advertisement was released coincident with the Company's initial filing in July 2020.

Please direct any questions regarding this filing to Kaylene Schultz at (509) 495-2482.

Sincerely,

/S/Patrick D. Ehrbar

Patrick D. Ehrbar
Director of Regulatory Affairs

Enc.

[6] Includes filed rate changes to Schedules 461, 462, 475, 476, 478, and 484.

November 1, 2020
As of September 14, 2020
(As filed – these are not approved rate changes)

1	**Company**	**Avista**	
2	**Docket Numbers**	UG-392	
3	**Advice No.**	20-06-G	
4	**Principal Analysts**	Brian Fjeldheim	
5	**Current Customer Charge - Residential ($)**	$10.00	
6	**Average Monthly Therm Use (Residential)**	47	
7	**Current Energy Charge/Rate (dollars/therm)**	Billing - $0.98724 Base - $0.63943	
8	**PGA Base Gas Cost Change - Residential (dollars/therm)**	$0.03849	Commodity Only – including revenue sensitive
9	**Other Temporary Rate Increments - Residential (dollars/therm)**	($0.00450) Demand ($0.00554) Amort	Demand, Amortization, including revenue sensitive
10	**Permanent Base Rate Adjustment – Residential (dollars/therm)**	$0.00	
11	**Overall Change - Residential Rate (dollars/therm)**	$0.02845	Gas, Demand and Amortization
12	**Proposed Tariff Rate - Residential (dollars/therm)**	$0.98324	Including all filings (Gas and Non-gas) – See Attachment B in workpapers
13	**Average monthly bill change for typical residential customer ($/bill on an annual basis)**	($0.19)	Including all filings (Gas and Non-gas) – See Attachment D in workpapers
14	**Overall Change - Residential Revenue (%)**	(0.3%)	Including all filings (Gas and Non-gas) – See ”Change in Annual Revenues” workpapers
15	**Overall Change – Commercial & Industrial firm (%)**	Commercial = (0.6%) Industrial = (1.2%)	Including all filings (Gas and Non-gas) – See ”Change in Annual Revenues” workpapers
16	**WACOG (dollars/therm) – not revenue-sensitized**	$0.19991	
	Comments – Other (continued)		

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

AVISTA UTILITIES

ADVICE NO. 20-06-G Supplemental

Tariff Sheets

September 14, 2020

AVISTA CORPORATION
dba Avista Utilities

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, 420, 424 and 444 are to be increased by $0.36442 per therm in all blocks of these rate schedules. (I)
(b) The rate of gas Schedule 440 is to be increased by $0.20655 per therm in all blocks of these rate schedules. (I)
(c) The rates of transportation Schedule 456 are to be increased by $0.0000 per therm in all blocks.

A. DEFINITIONS:

1. <u>Actual Commodity Cost:</u> 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. <u>Commodity Off-System Sales Revenues</u>: 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. <u>Variable Transportation Costs</u>: Variable transportation costs, including pipeline volumetric charges and other variable costs related to volumes of commodity delivered to sales customers.

4. <u>Actual Non-Commodity Cost</u>: 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. <u>Demand Costs:</u> 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.

Patrick D. Ehrbar

AVISTA CORPORATION
dba Avista Utilities

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	$0.20655	(I)
Without Gross Revenue Factor	$0.19991	(I)

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	$0.15787	(R)
Without Gross Revenue Factor	$0.15279	(R)

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