Avista Corp.
1411 East Mission P.O. Box 3727
Spokane. Washington 99220-0500
Telephone 509-489-0500
Toll Free 800-727-9170

September 10, 2015

UG-289/Advice No. 15-04-G Supplemental (Purchased Gas Cost Adjustment Filing)

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

Attention: Filing Center

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 an original and 10 copies of the following listed tariff sheets applicable to its Oregon natural gas operations along with three (3) copies of supporting workpapers (which are not a part of the official filing). The Company requests that the following tariff sheets become effective on November 1, 2015:

Oregon PUC Sheet No.	Title of Sheet	Canceling Oregon PUC Sheet No.
Supplemental Tenth Revision Tariff Sheet 461	Purchased Gas Cost Adjustment Provision	Supplemental Ninth Revision Tariff Sheet 461
Supplemental Eighth Revision Tariff Sheet 461A	Purchased Gas Cost Adjustment Provision	Supplemental Seventh Revision Tariff Sheet 461A
Supplemental Fifth Revision Tariff Sheet 462	Gas Cost Rate Adjustment	Supplemental Fourth Revision Tariff Sheet 462

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, 2015 through October 1, 2016). 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	$0.41155	$0.27342	**($0.13813)**
440	$0.41155	$0.27342	**($0.13813)**

Table No. 2 - Schedule 461 Demand

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	$0.20914	$0.19906	**($0.01008)**
440	$0.00000	$0.00000	**$0.00000**

Table No. 3 - Schedule 461 Commodity + Demand

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	$0.62069	$0.47248	**($0.14821)**
440	$0.41155	$0.27342	**($0.13813)**

Commodity Costs (Schedule 461)

As shown in the Table No. 1 above, the proposed weighted average cost of gas ("WACOG") is 27.3 cents per therm, a reduction of 13.8 cents per therm from the present WACOG of 41.1 cents per therm included in customer's rates. The reduction in the WACOG is generally the result of the continued increase in natural gas supply coupled with an overall reduction in customer demand. The winter of 2014-2015 was significantly warmer than normal, leading to lower customer demand which led to reduced wholesale natural gas prices in the winter and spring. The downward pressure on wholesale prices has continued even after the winter period due to the abundance of natural gas in storage and continued high natural gas production levels.

Avista has been hedging natural gas on both a periodic and discretionary basis throughout 2014-2015 for the forthcoming PGA year. Approximately 51% of estimated annual load requirements for the PGA year (November 2015 through October 2016) will be hedged at a fixed price, comprised of: 1) volumes hedged for a term of one year or less and 2) volumes from prior multi-year hedges. Through August 31, 2015, the planned hedge volumes for the PGA year have been executed at a weighted average price of $2.96 per dekatherm ($0.296 per therm).

As required by Commission Order 14-238, the Company used a 60-day (ending August 31, 2015) 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 $2.45 per dekatherm ($0.245 per therm). The remaining 3% of estimated load for the November 2015 to October 2016 load would be met with 3% storage withdrawals.

The Company has approximately 920,000 dekatherms of underground storage capacity at Jackson Prairie. As of June 30, 2015 approximately 258,000 dekatherms of this capacity is available to serve peak day needs with the remaining 662,000 dekatherms being utilized to capture financial benefits for customers associated with optimizing the use of Jackson Prairie by locking in price differentials between time periods.[1] Approximately $0.2 million in net storage optimization benefits have been included in this filing. The storage WACOG associated with withdrawal costs as of June 30, 2015 for all storage volumes is $2.33 per dekatherm ($0.233 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 the 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 a change in market dynamics etc., the Company documents and communicates any such changes with the 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 be a reduction of approximately 0.1 cents per therm. Included in the Company's filing are the new rates for TransCanada-Gas Transmission Northwest (GTN) which will go into effect January 1, 2016.

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	$0.05099	($0.04927)	**($0.10026)**
440	$0.05099	($0.04927)	**($0.10026)**

[1] Details regarding the storage optimization plan were provided to Staff in a previous communication on June 25, 2015 following with an in-depth discussion on August 17, 2015 during the quarterly Natural Gas Update meeting. The Company has included known optimization benefits in this filing, and will pass through to customers the net benefits of future storage optimization transactions in its next PGA.
[2] The Northwest Industrial Gas Users (NWIGU) and Citizens' Utility Board (CUB) are invited to, and attend, each Quarterly meeting.

Table No. 5 - Schedule 462 Demand Amortization

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	($0.05226)	$0.02078	**$0.07304**
440	$0.00000	$0.00000	**$0.00000**

Table No. 6 - Schedule 462 Commodity + Demand Amortizations

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	($0.00127)	($0.02849)	**($0.02722)**
440	$0.05099	($0.04927)	**($0.10026)**

For the commodity portion of the amortization rate, as noted earlier in this letter, actual wholesale natural gas prices were lower than the level approved in the Company's 2014 PGA. As a result, the amount of revenue collected from customers exceeded the Company's costs and created a rebate deferral balance of approximately $3.8 million (net of residual commodity amortization balance) or 4.9 cents per therm. With a present surcharge amortization rate of approximately 5.1 cents per therm, the proposed change in the commodity portion of the amortization rate is approximately 10.0 cents per therm.

For the demand portion of the amortization rate, the deferral balance as of June 30, 2015 is a surcharge of approximately $1.5 million (net of the residual deferral amortization balance) or 2.1 cents per therm. The present demand amortization rebate rate of 5.2 cents per therm was primarily related to the expiration of a contracted demand rate with Gas Transmission Northwest (GTN) for the Medford Lateral. The proposed surcharge rate is primarily the result of a reclassification of variable demand charges that had been inadvertently recorded in the Commodity Deferral account. In the absence of this reclassification, the demand deferral would have otherwise been relatively unchanged.

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.

3% Test

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 preceeding 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 gross revenues for calendar year 2014 was $201,089,425. The total amortization revenue requested for the "Prior Period Gas Cost Deferral" as shown in Attachment A is ($2,414,646). The total amortization revenue requested in Advice No. 15-06-G (DSM Cost Recovery) is $1,728,006. The net effect of combining the results of these two filings is an amortization balance of (686,641). The resulting annual average rate impact from the PGA amortization is (0.3%) and falls within the requirements of the statute.[3]

[3] Please see attachment C included in the Purchase Gas Adjustment work papers.

Other Information

This filing reflects an overall annual revenue decrease of $14.6 million, or 14.1% effective November 1, 2015. After combining the impact of this PGA filing with the two other tariff filings made on July 31, 2015 which also have a November 1, 2014 effective date[4], a residential customer using an average of 46 therms a month could expect their bill to *decrease* by $7.86, or 12.6 percent, for a revised monthly bill of $54.61 effective November 1, 2015.

Pursuant to OAR 860-022-0025 and OAR 860-022-0030, the total number of customers affected by the three filings, 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	87,066
Schedule 420	11,365
Schedule 424	81
Schedule 440	35
Schedule 444	4

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	$ 64,704,680	$ 56,356,347	$ (8,348,333)	-12.9%	46	$ 62.47	$ 54.61	$ (7.86)	-12.6%
420	General	$ 29,883,409	$ 25,323,888	$ (4,559,519)	-15.3%	191	$ 219.58	$ 184.07	$ (35.51)	-16.2%
424	Large General	$ 3,367,059	$ 2,617,042	$ (750,016)	-22.3%	4,394	$ 3,460.53	$ 2,689.70	$ (770.83)	-22.3%
				$ -						
440	Interruptible	$ 2,223,720	$ 1,310,378	$ (913,342)	-41.1%	9,460	$ 5,490.44	$ 3,235.37	$ (2,255.07)	-41.1%
				$ -						
444	Seasonal	$ 212,084	$ 166,086	$ (45,998)	-21.7%	5,959	$ 4,820.00	$ 3,774.61	$ (1,045.39)	-21.7%

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, 2015 effective date:

Rate Schedule	**Proposed Rate Change[5]**
Schedule 410	(12.6)%
Schedule 420	(14.9)%
Schedule 424	(20.8)%
Schedule 440	(41.3)%
Schedule 444	(21.2)%
Schedule 456	(1.8)%

[4] On July 31, 2015, Avista filed to update effective November 1, 2015 Schedule 476 (Intervenor Funding Schedule - Advice No. 15-05-G), and Schedule 478 (DSM Cost Recovery - Advice No. 15-06-G). The net effect of all filings is a revenue reduction of $14.3 million or 13.8%.

[5] Includes filed rate changes to Schedules 461, 462, 476, and 478.

Included with this 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 a newspaper advertisement with this updated PGA filing. A media release was released coincident with the Company's initial filing in July 2015.

Please direct any questions regarding this filing to Patrick Ehrbar at (509) 495-8620 or Annette Brandon at (509) 495-4324.

Sincerely,

Kelly Norwood

Kelly O. Norwood
Vice President, State and Federal Regulation

November 1, 2015
As of August 31, 2015
(As filed – these are not approved rate changes)

1	**Company**	**Avista**	
2	**Docket Numbers**	UG-289	
3	**Advice No.**	15-04-G	
4	**Principal Analysts**	Lisa Gorsuch	
5	**Current Customer Charge - Residential ($)**	$8.00	
6	**Average Monthly Therm Use (Residential)**	46	
7	**Current Energy Charge/Rate (dollars/therm)**	Billing - $1.18405 Base - $0.54073	
8	**PGA Base Gas Cost Change - Residential (dollars/therm)**	($0.13813)	Gas Cost Only – including revenue sensitive
9	**Other Temporary Rate Increments - Residential (dollars/therm)**	($0.01008) Demand ($0.02722) Amort	Demand, Amortization, including revenue sensitive
10	**Permanent Base Rate Adjustment – Residential (dollars/therm)**	$0.00	
11	**Overall Change - Residential Rate (dollars/therm)**	($0.17543)	Gas, Demand and Amortization
12	**Proposed Tariff Rate - Residential (dollars/therm)**	$1.01318	Including all filings (Gas and Non-gas) – See Attachment B in workpapers
13	**Average monthly bill change for typical residential customer ($/bill on an annual basis)**	($7.86)	Including all filings (Gas and Non-gas) – See Attachment D in workpapers
14	**Overall Change - Residential Revenue (%)**	(12.6%)	Including all filings (Gas and Non-gas) – See Attachment D in workpapers
15	**Overall Change – Commercial & Industrial firm (%)**	Commercial = (15.9%) Industrial = (21.1%)	Including all filings (Gas and Non-gas) – See Attachment D
16	**WACOG (dollars/therm) – not revenue-sensitized**	$0.2655	
	Comments – Other (continued)		

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served Avista Utilities', a division of Avista Corp, 2015 Purchased Gas Cost Adjustment upon the parties listed below by mailing a copy thereof, postage prepaid and by electronic mail or CD.

Bob Jenks
Nadine Hanhan
Citizens' Utilities Board
610 SW Broadway, Suite 400
Portland, OR 97205-3404
dockets@oregoncub.org
bob@OregonCUB.org
nadine@OregonCUB.org

Edward A. Finklea
Executive Director
Northwest Industrial Gas Users
326 Fifth Street
Lake Oswego, OR 97034
efinklea@nwigu.org

Chad Stokes
Tommy A. Brooks
Cable Huston Benedict
Haagensen & Lloyd, LLP
1001 SW 5th, Suite 2000
Portland, OR 97204-1136
cstokes@cablehuston.com
tbrooks@cablehuston.com

I declare under penalty of perjury that the foregoing is true and correct.

Dated at Spokane, Washington this 10th day of September, 2015.

Patrick Ehrbar
Manager, Rates & Tariffs

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

AVISTA UTILITIES

ADVICE NO. 15-04-G Supplemental

Tariff Sheets

September 10, 2015

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 $0.47248 per therm in all blocks of these rate schedules. (R)
(b) The rate of gas Schedule 440 is to be increased by $0.27342 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	$0.27342	(R)
Without Gross Revenue Factor	$0.26552	(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	$0.19906	(R)
Without Gross Revenue Factor	$0.19331	(R)

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

AVISTA CORPORATION
dba Avista Utilities

SCHEDULE 462

GAS COST RATE ADJUSTMENT – 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.

PURPOSE:
The purpose of this provision is to allow the Company to pass through the differences between the actual cost of gas purchased and transported for customer usage and the amount collected from customers. These differences are accumulated in a sub-account of Account 191 for later refund or surcharge to customers.

RATE:
(a) The rates of gas Schedules 410, 420, 424 and 444 are to be decreased by $0.02849 per therm. (R)
(b) The rate of gas Schedule 440 is to be decreased by $0.04927 per therm. (C) (R)

AMORTIZATION OF ACCOUNT 191 SUB-ACCOUNT DEFERRALS:
The Account 191 sub-account deferred balances approved for surcharge or refund to customers shall include interest calculated on a monthly basis using the interest rate(s) approved by the Commission.

The surcharge or refund rate shall be adjusted annually as part of the annual Purchased Gas Adjustment (PGA) filing.

AMOUNT OF ADJUSTMENT:
The amount of adjustment to be made to customers' rates shall consist of the sum of the changes in the Embedded Commodity Cost and Non-Commodity Cost deferral accounts and the change in amortization rates of the Account 191 sub-accounts, as well as other gas cost related deferral accounts as the Commission may approve.

GENERAL RULES AND REGULATIONS:
This schedule is subject to the General Rules and Regulations contained in this tariff and to those prescribed by regulatory authorities. This schedule is an automatic adjustment clause (PGA) as described in ORS 757.210(1) and is subject to the customer notification requirements as described in OAR 860-022-0017.

Advice No. 15-04-G Supplemental Effective For Service On & After
Issued September 10, 2015 November 1, 2015

Issued by Avista Utilities
By Kelly Norwood Kelly O. Norwood, V.P. State & Federal Regulation