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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA UTILITIES FOR AUTHORITY TO CHANGE ITS NATURAL GAS RATES AND CHARGES (2010 PURCHASED GAS COST ADJUSTMENT).	**CASE NO. AVU-G-10-03** **COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its Attorney of record, Kristine A. Sasser, Deputy Attorney General, and in response to the Notice of Application and Notice of Modified Procedure issued in Order No. 32081 on September 30, 2010, in Case No. AVU-G-10-03, submits the following comments.

BACKGROUND

On September 15, 2010, Avista Corporation dba Avista Utilities filed its annual Purchased Gas Cost Adjustment (PGA) Application requesting authority to increase its annualized revenues by approximately $3.1 million, or about 4.3%. Application at 1. The PGA mechanism is used to adjust rates to reflect annual changes in Avista's costs for the purchase of natural gas from suppliers – including transportation, storage, and other related costs. Avista's earnings will not be increased as a result of the proposed changes in prices and revenues. The Company requests that its Application be processed by Modified Procedure and that its rates become effective on November 1, 2010.

The Company states that if the proposed changes are approved its annual revenue will increase by approximately $3.1 million, or 4.3%. The average residential or small commercial customer using 63 therms per month will see an increase of $2.75 per month.

The Company states that it purchases natural gas for customer usage and transports this gas over various pipelines for delivery to customers. The Company defers the effect of timing differences due to implementation of rate changes and differences between the Company's actual weighted average cost of gas (WACOG) purchased and the WACOG embedded in rates. The Company states that it also defers various pipeline refunds or charges and miscellaneous revenue received from gas-related transactions, including pipeline capacity releases. Application at 2.

Avista's filing utilizes a WACOG of $0.458 per therm, or $0.461 per therm once the gross revenue factor (GRF) is included to reflect an allowance for uncollectibles and Commission fees. This is lower than the currently approved WACOG of $0.491 per therm. The Application asserts that daily wholesale natural gas prices have been higher this year than last year, thus impacting the cost of purchased natural gas for storage pricing. However, prices in the forward market have been lower this year than what is currently embedded in rates. The decrease in forward market prices offset the increase in storage prices, leading to a drop in the proposed WACOG.

The Company has been hedging gas on a periodic basis throughout 2010 for the coming PGA year. The Company states that approximately 60% of its estimated annual load requirements for the PGA year will be hedged at a fixed price comprised of: (1) 41% of volumes hedged for a term of one year or less; and (2) 19% of prior multi-year hedges. The Company states that an additional 10% of its annual volume comes from underground storage. The Company states that through August 2010, the planned hedge volumes for the PGA year have been executed at a weighted average price of $0.542 per therm. The storage gas has been purchased at an estimated weighted average price of $0.363 per therm.

The demand costs included in the Company's Application primarily represent the costs of pipeline transportation to the Company's system. Application at 3. Avista proposes a slight increase in demand charges due to a change in tariffs on the TransCanada (Alberta) and TransCanada (BC) pipelines. *Id.*

The Company is also proposing an amortization rate change of $0.035 per therm for interruptible service customers and an amortization rate change of $0.062 per therm for general and large general service customers. The expiration of the large 2009 amortization refund is the main change in the proposed amortization rate. Included in the proposed refund rate is a substantial deferral balance that the Company was refunding over the past year through Schedule 155 that was not fully refunded to customers as natural gas loads for the winter 2009/2010 were softer than projected. As a result, the proposed amortization rate still reflects some level of previous deferrals, allowing for a lower proposed rate for customers.

Avista asserts that it has notified customers of its proposed increase in rates by posting a notice at each of the Company's district offices in Idaho, by means of a press release distributed to various informational agencies, and by separate notice to each of its Idaho gas customers via a bill insert.

STAFF ANALYSIS

Staff has reviewed the Company's Application to determine whether its adjustments to Schedule 150 and 156 reasonably capture its fixed (demand) and variable (commodity) costs. More specifically, Staff has reviewed the Company's pipeline transportation and storage costs, fixed price hedges, estimates of future commodity prices, and its risk management policies. Staff has also reviewed the appropriateness of the Schedule 155 change in amortization rates that "true up" the expenses from the 2009 PGA. Each component of the rate changes will be discussed in greater detail below.

The Company filed the following rate changes that would result in an increase of approximately $3.1 million or about 4.3%:

Table 1:

Schedule	Description	Filed Schedule 156 Change per Therm	Filed Schedule 155 Amortization Change per Therm	Filed Total Rate Change per Therm	Overall Filed Percentage Change
101	General	($0.01842)	$0.06215	$0.04373	4.9%
111	Large General	($0.01842)	$0.06215	$0.04373	6.1%
131	Interruptible	($0.02992)	$0.03509	$0.00517	0.9%

Source: Application, Page 2.

Subsequent to the filing, the Company notified Staff that its filing contained a calculation error and omitted a deferred credit of approximately $2,000. To correct the calculation error, the gross revenue factor (GRF) for uncollectibles and Commission fees should be applied only to the rate change instead of to the entire rate. Staff comments reflect the corrections. The revised rates shown in Table 2 below result in a revenue increase of approximately $2.9 million, or about 3.9%, and support the proposed WACOG of $0.458 per therm.

Table 2:

Schedule	Description	REVISED Schedule 156 Change per Therm	Schedule 155 Amortization Change per Therm	REVISED Total Rate Change per Therm	Overall REVISED Percentage Change
101	General	($0.02204)	$0.06215	$0.04011	4.5%
111	Large General	($0.02204)	$0.06215	$0.04011	5.6%
131	Interruptible	($0.03296)	$0.03509	$0.00213	0.4%

Under the revised rates above, a residential or small business customer served under Schedule 101 using an average of 63 therms per month can expect to see an average increase of approximately $2.53 per month or about 4.5%. However, actual customer increases will vary based on therms consumed.

Schedules 150 and 156 – Purchased Gas Cost Adjustment

Schedules 150 and 156 are comprised of two parts: the commodity costs (WACOG) and the demand costs. Prior to the Company's PGA filing, Schedule 150 was suspended by Order No. 31038 in Case No. AVU-G-10-01.[1] In order to be able to update the forward-looking cost of natural gas purchased for customer usage during the suspension of Schedule 150 and because of the overlap between the Company's PGA filing and the general rate case final order, the Company created a new schedule, Schedule 156. The Company states that the current Schedule 150 and 156, when approved, will be consolidated into a single rate schedule.

The Company proposes a WACOG of $0.45817 per therm. The WACOG is the Company's forward-looking price of purchased gas and storage gas embedded in base rates. This also includes the benefit of some off system transactions, **[This section of Staff's comments contains confidential information]**. The demand costs represent the cost of pipeline transportation to the Company's distribution system. The Company's Application proposes a demand cost increase of $0.012 per therm. As previously discussed, due to the error in the Company's filing, this demand cost increase should be reduced to $0.011 per therm. This increase in demand cost is attributed to adjustments in tariffs by TransCanada (Alberta) and TransCanada (BC) pipelines.

The Company delivers transported natural gas to its Idaho and Washington city-gates via two interstate transportation natural gas pipeline providers, Northwest Pipeline and TransCanada – Gas Transmission Northwest (GTN). Each of these providers has transmission pipelines which run directly through the Company's service territory. The Company benefits from the geographic proximity of these pipelines because each transmits natural gas from separate and distinct supply basins which allows the Company to procure natural gas from the lowest cost supply basin to minimize commodity costs. Available capacity on these pipelines remains a key component in serving customers and maintaining supply diversity. The Company continuously determines when its contracted interstate transportation supply is under-utilized due to warmer weather or declines in industrial demand and will post for release to others with the release payments received benefiting the Company's customers.

As in prior years, the Company is bound, as are other natural gas entities that are served by Northwest Pipeline, to purchase gas **[This section of Staff's comments contains confidential information]**. The Company asserts that Sumas gas prices have typically been higher than both Rockies and AECO and, **[This section of Staff's comments contains confidential information]** the Company has utilized its proximity to GTN to acquire gas supply at lower commodity prices without incurring significant demand costs to acquire the gas supply.

Lower Rockies Basin prices have benefited natural gas utilities in the Northwest due to Rockies lack of pipeline infrastructure capable of moving Rockies gas east. However, Rockies Express pipeline, a 639 mile pipeline built to move gas east, was completed this past year. This pipeline will enable Rockies direct access to the eastern markets for the first time which is expected to increase price competition among suppliers in North America. To date, the completion of the Rockies Express pipeline has not significantly influenced natural gas prices.

The Company's diversity of supply basins has enabled it to exercise multiple hedging options and obtain expected winter flowing gas requirements at favorably contracted prices. This allows the Company to provide customers with low priced natural gas.

Weighted Average Cost of Gas (WACOG)

Throughout the last year, the wholesale cost of natural gas has been low, which has allowed the Company to purchase gas for the coming year at favorable rates. This request reflects the third WACOG decrease within the Company's past four PGA filings, and makes the Company's proposed WACOG the lowest since its 2003 filing. The table below illustrates the changes in the natural gas market over the past nine years and the volatility experienced over the same period:

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[1] As part of the AVU-G-10-01 case the parties agreed, and the Commission approved, to move all natural gas commodity and demand costs from base rates to Schedule 150 for purposes of clarity and transparency. The retail rate schedules now only reflect the non-commodity distribution rates. Order No. 32070.

Table 3:

Year	Approved Weighted Avg. Cost of Gas $/Therm	% Change From Previous Year	Resulting Total General Service Schedule 101 Tariff, $/Therm	% Change From Previous Year
2002	0.34572	Base Year	0.75722	Base Year
2003	0.44989	30.13%	0.77716	2.63%
2004	0.55739	23.89%	0.95315	22.64%
2005	0.76786	37.76%	1.18692	24.53%
2006	0.76085	-0.91%	1.16175	-2.12%
2007	0.75544	-0.71%	1.1056	-4.83%
2008	0.78646	4.11%	1.15103	4.11%
2009*	0.75984	-3.38%	1.07507	-6.60%
2009	0.49093	-35.39%	0.88199	-17.96%
2010	0.45817	-6.67%	0.79123	-10.29%

*The WACOG change was part of the AVU-G-09-01 general rate case settlement intended to offset the impact of the residential base rate increase approved in Order No. 30856.

The primary reason for the decline in the WACOG is the continuing decline in natural gas prices due to the weakness in our regional and national economy that has reduced the weather adjusted demand for natural gas during a period of time when natural gas supplies have been plentiful.

A national report issued by the Energy Information Administration (EIA) in August of this year, provides insight into the anticipated conditions of the natural gas industry through 2011 in the areas of natural gas consumption, production, inventory and pricing. Natural gas consumption is forecast to increase by 3.8% from the 2009 levels of 64.9 billion cubic feet per day (Bcf/d) in 2010 and remain flat in 2011. Natural gas consumption in the industrial sector is projected to increase by 7% through the remaining months of 2010 and expected to increase by only 1% through 2011. Residential and commercial consumption through 2011 is projected to remain at levels comparable to those of 2009. Production during 2010 is expected to be 1.1% above 2009 levels with a 1.4% reduction in drilling activity in 2011. The EIA Report (September 9, 2010) states that inventories held in underground storage in the lower 48 states is 5.5 percent above the five-year average of 2.998 trillion cubic feet, and 6.4 percent below last year's storage level of about 3.382 trillion cubic feet. Finally, natural gas spot prices averaged $0.463 per therm in July 2010 - $0.0017 per therm less than June 2010. EIA forecasts natural gas prices for the remainder of 2010 to average $0.447 per therm with an average price of $0.498 per therm in 2011.

Throughout the year, Staff reviews several publications relating to the natural gas industry. However, two primary sources are utilized to develop forecasts, specifically: (1) NYMEX Futures Index and (2) Energy Information Administration (EIA). For purposes of this Application, Staff has reviewed the Company's proposed WACOG of $0.458 per therm and its forecasted natural gas prices through October 2011. When comparing the data from the above informational sources, forecasts and the WACOG of other Pacific Northwest natural gas utilities, Staff believes the Company's forecasted natural gas prices are reasonable.

Schedule 155 – Deferred Expenses

The Schedule 155 portion of the PGA is the amortization component of the Company's deferral account. When the Company pays more for gas than what is estimated in the preceding WACOG, a surcharge is assessed to customers. However, if the Company pays less for gas than what is estimated in the preceding WACOG, a credit is issued to customers. Although gas prices have been lower than the WACOG anticipated in the Company's 2009 filing, the current refund rate required to amortize the current deferral is less than the refund rate approved in the 2009 PGA filing. The net effect of the adjustments is an increase of $4.5 million. Combining the two rate schedules (the reduction in Schedule 156 of $1.6 million and the increase in Schedule 155 of $4.5 million) the total revenue increase is $2.9 million.

Hedging Policies

As was the case in prior years, the Company's gas procurement plan generally incorporates a structured approach for the hedging portion of the portfolio, while maintaining flexibility such that discretionary adjustments can be made when the wholesale gas market presents opportunities to achieve cost reductions. Discretion is used in evaluating current volatility, forward curve shapes, and alternatives when considering price triggers. The Company continues to hedge utilizing a series of price targets. In the case of decreasing prices, target purchase volumes are increased.

Procedurally, the Company **[This section of Staff's comments contains confidential information]** develop an estimated cost for index/spot purchases. The estimated monthly volumes to be purchased **[This section of Staff's comments contains confidential information]** determine estimated spot purchase costs. These index/spot purchase volumes represent approximately **[This section of Staff's comments contains confidential information]** of the Company's estimated annual load for the coming year. At the time of this Application the price for this volume segment of the Company's annual gas required is $0.399 per therm.

The Company has been hedging gas on a periodic basis throughout 2010 for the coming PGA year. The Company states that approximately 60% of its estimated annual load requirements for the PGA year will be hedged at a fixed price comprised of: (1) 41% of volumes hedged for a term of one year or less; and (2) 19% of prior multi-year hedges. An additional 10% of the Company's annual volume comes from underground storage. The Company states that through August 2010, the planned hedge volumes for the PGA year have been executed at a weighted average price of $0.542 per therm. At the time of this Application, the Company's weighted average cost for the gas in storage is $0.363 per therm.

Following the filing of the Application, the Company provided additional information to Staff regarding the status of the Company's discretionary natural gas hedging program activities. The intent of the discretionary hedging program is to acquire low hedge prices in the event that natural gas market prices fall below Company established price targets. The discretionary hedging program is divided into short-term and long-term transactional components. **[This section of Staff's comments contains confidential information]**. As of October 2010, the Company has executed the last long-term hedge and previously executed all short term hedges for the 2010 gas year. The average executed price for the discretionary hedges was $0.505 per therm for the short-term and $0.530 per therm for the long-term components.

The Company typically develops, establishes and implements the annual procurement plan by November or December of each year. However, due to low current market prices and foreseeable low market prices in the coming months, the Company developed and implemented the annual procurement in October 2010 in order to a take advantage of favorable natural gas market prices.

The Company periodically meets with Staff to discuss the procurement plan given the wholesale natural gas environment. The Company has informed Staff that it plans to modify the hedging strategy developed last year and will soon meet with the Staff to discuss these options. The Company will continue to: (1) keep long-term hedges open for up to two or three years, depending on which strip triggers first; (2) decide price targets that will be "open" all year; and (3) maintain the current minimum portfolio hedge percentage **[This section of Staff's comments contains confidential information]**. Throughout the year the Company communicates with Staff when it believes a decision is being made outside the scope of the normal procurement plan. Over the course of the year, the Company has also continued to communicate with Staff regarding the Company's storage and procurement activities, **[This section of Staff's comments contains confidential information]**. The Company continues to purchase gas in an effort to provide price stability to customers within its service area.

CONSUMER ISSUES

Customer Notice and Press Release

The Press Release and Customer Notice were included in Avista's Application, which was filed with the Commission September 15, 2010. Staff reviewed the customer notice and press release and determined they were in compliance with the requirements of IPUC Rules of Procedure 125.04 and 125.05 (IDAPA 31.01.01.125). The customer notice was mailed with cyclical billings beginning September 22, 2010 and ending October 20, 2010.

Customer Comments

Customers were given until October 21, 2010, to file comments. As of October 20, 2010, only one comment had been filed by a customer. The customer opposed a rate increase during the current economic downturn.

STAFF RECOMMENDATION

After a complete examination of the Company's Application and gas purchases for the year, Staff has the following recommendations for the Commission:

1. Staff recommends that the Commission accept a WACOG of $0.45817 per therm.
2. Staff recommends the Commission accept the Schedule 155 (Gas Rate Adjustment) amortization for deferral balances. The combination of the first two recommendations results in an increase of $2.9 million or about 3.9%.
3. Staff also recommends that the Commission reserve the right to reopen this case and reevaluate any approved tariffs if the WACOG materially changes below that included in this Application.

Respectfully submitted this 21st day of October 2010.

Kristine A. Sasser

Kristine A. Sasser
Deputy Attorney General

Technical Staff: Doug Cox
Patricia Harms
Daniel Klein

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 21ST DAY OF OCTOBER 2010, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. AVU-G-10-03, BY E-MAILING AND MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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