ORDER NO. 08-524

ENTERED 10/30/08

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 182 & UM 1390

In the Matters of AVISTA CORPORATION, dba AVISTA UTILITIES Changes in the cost of purchased gas and technical adjustments, (UG 182) and Application for Authorization to Defer Cost. (UM 1390).	))))))))))))	ORDER

DISPOSITION: APPLICATIONS APPROVED

On August 29, 2008, the Public Utility Commission of Oregon (Commission) received Avista Utilities' (Avista) annual gas cost tracking and technical adjustment application, commonly known as its PGA filing. On September 3, 2008, Avista filed its request for reauthorization for deferred accounting for the PGA deferral mechanism. A description of the filings and their procedural history is contained in the Staff Report, attached as Appendix A, and incorporated by reference.

Based on a review of the applications and the Commission's records, the Commission finds that the applications satisfy applicable statutes and administrative rules. At its Public Meeting on October 24, 2008, the Commission adopted Staff's recommendation to approve the applications as set forth in the Staff Report.

ORDER

IT IS ORDERED that:

1. The amortization of deferred accounts, base gas costs changes and other rate changes in docket UG 182 are approved.

2. The associated tariff sheets of Advice No. 08-07-G Supplemental are allowed to go into effect with less than statutory notice, beginning with service on or after November 1, 2008.

3. Reauthorization to use deferred accounting pursuant to Schedule 461, as filed in docket UM 1390, is approved.

Made, entered, and effective OCT 30 2008.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

ITEM NO. 1 & 2

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: October 24, 2008

REGULAR X **CONSENT** ____ **EFFECTIVE DATE** November 1, 2008

DATE: October 21, 2008

TO: Public Utility Commission

FROM: Ken Zimmerman, Lynn Kittilson and Deborah Garcia

THROUGH: Lee Sparling, Ed Busch, Bonnie Tatom and Judy Johnson

SUBJECT: AVISTA UTILITIES: (Docket No. UG 182/Advice No. 08-07-G) Reflects changes in the cost of purchased gas and technical adjustments.

AVISTA UTILITIES: (Docket No. UM 1390) Reauthorizes deferred accounting for the PGA deferral mechanism.

STAFF RECOMMENDATION:

Staff recommends the Commission approve Avista Utilities' (Avista or Company) application for less than statutory notice (LSN) and allow the Company's proposed tariff sheets in Advice No. 08-07-G Supplemental to go into effect for service on and after November 1, 2008. This filing decreases the Company's annual revenues by approximately $5.6 million, or 4.1%.

Staff also recommends Commission approval of Avista's request for reauthorization to use deferred accounting pursuant to Schedule 461, Purchased Gas Cost Adjustment Provision.

DISCUSSION:

On August 29, 2008, Avista filed its annual gas cost tracking and technical adjustment application, commonly known as its PGA filing. The PGA allows Avista to adjust tariffs annually for known and measurable changes in purchased base gas costs and for changes in amortization rates relating to the PGA account and other deferred accounts. The filing, docketed as UG 182, proposed a revenue increase of approximately $2.7 million or 2.0%, effective November 1, 2008. The filing reflected the changes in the cost of purchased gas and amortization of deferred revenue, gas cost and non-gas cost accounts through the temporary increment adjustment. In a concurrent filing docketed as UM 1390, Avista requested reauthorization of deferrals under the Company's PGA mechanism. On October 10, 2008, the Company withdrew Advice No. 08-07-G in its entirety and filed replacement Advice No. 08-07-G Supplemental, along with an LSN application, to lower its projected commodity cost. The re-filed PGA requests an overall revenue decrease of approximately $5.6 million annually, or 4.1%.

UG 182

In its amended filing, Avista seeks approval for an overall $4.2 million or 3.1% rate decrease to its Oregon customers. This rate change consists of an increase in the base cost of the Company's system gas supplies and a decrease from adjusting the amortization rates for deferred revenue and gas cost accounts, and an increase related to implementation of Phase II of the Company's most recent rate case[1]. The total change in annual revenues proposed in the PGA filing is summarized in Table 1 and additional detail is shown in Attachment A.

Table 1: Change in Annual Revenues

PGA Base Gas Cost Change	$7,073,391
Removal of Temporary Increment	($11,846,317)
Adding New Temporary Increment	($792,228)
Total Proposed PGA Decrease	($5,565,154)
Adding UG 181 Phase II	$1,355,930
Total Net Decrease	($4,209,244)

Considering only the change between the current billing rate and the one proposed in the company's PGA, the monthly bill of a typical residential customer using 53 therms per month would decrease by $3.28, or 4.1%, from $80.07 to $76.79. In January, a typical residential customer's consumption of 100 therms would result in a billing decrease from $146.19 to $140.01. However, the November 1, 2008, residential billing rate will be derived from the implementation of both the PGA and the UG 181 Phase II rate changes. Therefore, the monthly bill of a typical residential customer using 53 therms per month will only decrease by $2.32, or 2.9%, from $80.07 to $77.75. In January, a typical residential customer's consumption of 100 therms will result in a billing decrease from $146.19 to $141.38.

[1] Per the stipulation adopted by Order No. 08-185 in Avista's last general rate case (Docket No. UG 181), the rate increase was scheduled to take effect in two phases. Phase II rates are scheduled to go into effect on November 1, 2008, coincident with the change to rates in the PGA. Phase II rate changes include a $0.50 increase to the customer monthly charge as well as the revenue requirement associated with the addition of new plant, the East Medford reinforcement and a capacity increase to Jackson Prairie storage.

Avista Utilities 2008 PGA Filing
October 21, 2008
Page 3

A summary of the proposed tariff and revenue changes for Avista's major rate schedules is shown in Attachment A. A summary that compares the impact of this year's proposed rate changes, on both an annual and a January basis, for Avista, Cascade and NW Natural residential customers is shown in Attachment B. A graph illustrating each of the three local distribution companies' (LDCs') effective residential rates on a comparable basis is found in Attachment C. The effective residential rate is calculated as follows: the proposed residential rate multiplied by 56 therms plus the monthly customer charge, divided by 56 therms. The graph shows that Avista's residential customers have an effective rate of $1.46094[2] per therm, while Cascade's and NW Natural's effective rates are $1.33013 and $1.52216, respectively. Table 2 shows the rates the Commission has approved for Avista's residential customers on Rate Schedule 410 between 2004 and 2007, and the current proposal.

Table 2: Residential Rates 2004 – 2008 (Proposed)

Date	Customer Charge	Rate Per Therm	Percentage Change [3]	Net Percentage Change Eff. 11/01/08
April 2004	$5.00	$0.95764		
October 2004	$5.00	$1.08689	13.5%	
October 2005	$5.00	$1.34729	24.0%	
November 2006	$5.00	$1.44931	7.6%	
November 2007	$5.00	$1.42914	-1.4%	
April 2008 *UG 181 Phase I & UM 1351[4]*	$5.50	$1.42677	-0.2%	
June 2008 *SB 408*	$5.50	$1.40692	-2.0%	
November 2008 *Proposed PGA*	$5.50	$1.34512	-4.4%	
November 2008 *UG 181 Phase II*	$6.00	$1.35380	0.6%	-3.8%

[2] Avista's effective rate is calculated using the change proposed in the PGA as well as the UG 181 Phase II changes.
[3] The percentage change reflects only the change in the rate per therm, and does not include the effect of the monthly customer charge on the bill.
[4] Avista's most recent depreciation study. See Order No. 08-182.

Avista offers customer assistance programs. Avista also offers energy efficiency programs through the utility and through Energy Trust of Oregon. Specific information on these programs is readily available to customers on their monthly bills, by telephone, in person at the Company offices, and on the Company's web site.

National and Regional Natural Gas Markets

Natural gas prices increased steadily from November 2007; peaking at just over \$13/MMBtu at the Henry Hub spot market in June and on NYMEX in July. Since July, spot prices have declined about 45%, falling to between \$7.00 and \$7.50 per MMBtu in September. Likewise, NYMEX prices had declined to the \$8.00 to \$8.50 per MMBtu range by September. This is an approximate 40% decline in NYMEX prices since July. Pacific Northwest prices (both spot and futures) followed this trend, with a basis differential generally between (\$1.00) and (\$1.50) per MMBtu.

The conditions in the natural gas market over the last year include:

- The steady increase in natural gas price during November 2007 to July 2008, is generally attributed to two primary factors:
  - concerns about diminishing domestic reserves and production, and
  - the increase during that period in oil price. The oil price increase was attributed to continued growth in world and US demand, and financial speculation in oil markets.

- While total natural gas consumption is expected to increase by 2.7 percent in 2008 and by 2.2 percent in 2009, unlike past periods, domestic production is expected to increase by 7.8 percent in 2008 and by 3.8 percent in 2009.

- Concerns about declines in domestic natural gas reserves and production have been mitigated in the last few months by increases in unconventional domestic production and reserves from shale deposits. Currently, unconventional natural gas accounts for about one-half of annual US production, and is increasing. The fastest growing sector of unconventional production is gas from shale. Some estimates indicate at much as 118 years of reserves in shale gas alone. This is a dramatic departure from recent concerns about the continuous decline in domestic production and reserves.

- There are serious environmental concerns about unconventional production, particularly from shale deposits. These relate primarily to the use of and pollution of local water supplies. If validated, these environmental impacts may severely limit US unconventional natural gas production.

- Also, a supply based heavily on unconventional supplies will tend to keep pricing in the \$7.00 to \$10.00 range, as currently prices lower than \$7.00 will generally make unconventional production unprofitable. Depending on the production site, unconventional supply is more expensive to bring to market.

- Along with the increase in domestic supplies, Canadian imports, at least for the time being, have increased. For the period November 2007 to September 2008, Canadian pipeline imports to the US have increased 20% for California, 14% for the Midwest, and 6% for the Pacific Northwest. Canadian pipeline imports to the Northeast US declined by 7.4%, however.

- Liquefied natural gas (LNG) imports remain sluggish, however; severely hampered by global LNG demand growth and higher relative prices in the Asia/Pacific region and Europe. For 2008, LNG imports are expected to total about 350 billion cubic feet (Bcf), a decline of more than 50 percent, or 420 Bcf, from 2007, and then to total about 450 Bcf in 2009 as new global LNG supply is added to the market. However, a new possibility has entered the LNG arena. Several natural gas production companies, particularly those producing the new shale gas wells, have begun to propose that the US become a net LNG exporter rather than net importer. Whether these proposals will gain traction and actually translate to changes in the direction LNG flows at US terminals is impossible to say at this time.

- The Henry Hub natural gas spot price averaged \$7.17 per thousand cubic feet (Mcf) in 2007 and is expected to average about \$9.70 per Mcf in 2008 and about \$8.55 per Mcf in 2009. NYMEX futures (at the Henry Hub) averaged about \$8.05 over the 2006-2007 PGA year, and about \$9.50 for the 2007-2008 PGA year (through September 2008).

- Weather driven demand has not had a major impact over the last year. The winter of 2007-2008 was generally mild; placing little heating stress on supplies. Likewise, the summer of 2008 was mild in terms of the use of natural gas to generate electricity to meet cooling demand.

- Hurricane Gustav in August-September shut in about 6.1 Bcf/day (80%) of Gulf of Mexico (GOM) production. As of October 10, the Minerals Management Service (MMS) reported that 2.9 Bcf/day (39%) of GOM production remained shut in.

- While the prices of natural gas and oil are linked more closely today than at this same time last year, they remain partially delinked. If fully linked, the price of natural gas today would be about \$17-\$18 per MMBtu. The current natural gas price is less than half this.

- While not at record levels, as was the case last year, gas storage injections and inventory levels are high by historic standards. Natural gas in storage was 3,277 Bcf as of October 10, which is about 3% above the 5-year average, following an implied net injection of 79 Bcf.

- The futures markets, including speculators and hedge funds traders, have not sought a sustained increase in natural gas prices; futures prices across the country have consistently and generally declined since July, with particularly sharp declines in the West (e.g., Rockies).

- Amid signs of a softening economy, the spot price for natural gas at the Henry Hub remains relatively strong (just under \$7/MMBtu), especially when compared to the recent precipitous decline in crude oil prices (about \$75-\$78/barrel).

Of course, other factors could potentially destabilize US natural gas supply, demand, and/or price. Despite a current steady balance in supplies, a decrease in unconventional production, without offsetting increases in LNG and/or Canadian imports into the US, could once again unbalance the US supply sector. Second, imports of natural gas from Russia to Europe, China, etc., are not growing as quickly as expected, and it appears that Russia (the single largest holder of natural gas reserves in the world) is increasingly using natural gas and oil as foreign policy tools to seek control of the actions of other nations. Also, Russia is seeking control of natural gas delivery utilities in Europe, and perhaps the US. Any or all of this combination could upset world supplies/prices, which could easily affect US supply and/or prices. Third, weather can play a large part in increasing natural gas price. For example, an up tick in the severity or length of the US hurricane season or an exceptionally cold winter in either the US or Europe could lead to significant increases in prices and a reduction in supplies. Fourth, the continued over-reliance on gas-fired electric generation must eventually increase the price of natural gas across the US. Fifth, any failure in the expected level or growth in the level of domestic natural gas production, either conventional or unconventional, could lead to an increase in price. Sixth, despite the fact that Canadian imports to the US are currently increasing, a decision by Canada to use more of its vast gas supplies for domestic development or to export more as LNG would certainly affect US price. Seventh, as noted in recent testimony before Congress, financial commodities traders dominate the US natural gas market in terms of money invested. It's difficult to say what and how much impact this fact will have on natural gas prices over the remainder of 2008 and into 2009. The Federal Energy Regulatory Commission's (FERC) and the

Commodity Futures Trading Commission's (CFTC) "market manipulation" cases on oil and natural gas markets continue. Finally, and certainly not to be minimized, the current US financial crisis has already had some negative impacts on natural gas production, in terms of limitations on available credit and reductions in the overall market value of natural gas exploration and production companies. At the time of this writing, whether these negative impacts will continue or expand, or possibly decline, cannot reasonably be projected with any substantial degree of accuracy.

The US Department of Energy's (DOE) Energy Information Administration (EIA) weekly natural gas update shows the history of natural gas prices on NYMEX and physically at the Henry Hub, as well as the price of West Texas Intermediate (WTI) crude oil. Figures 1 and 2 are snapshots from this update for the period November 2007 to September 2008. As already noted, prices in both spot and futures markets have increased steadily since November 2007, reaching a peak in June and July. Figure 1 demonstrates clearly that oil and natural gas prices are only partially linked. In Figure 2 (see top of next page), estimated prices for the Pacific Northwest (PNW) winter and PGA year futures strips are also depicted. As this figure demonstrates, PNW prices have followed closely the national pattern over the last year.

Figure 1: Natural Gas and WTI Prices, Nov 2007 – Oct 2008

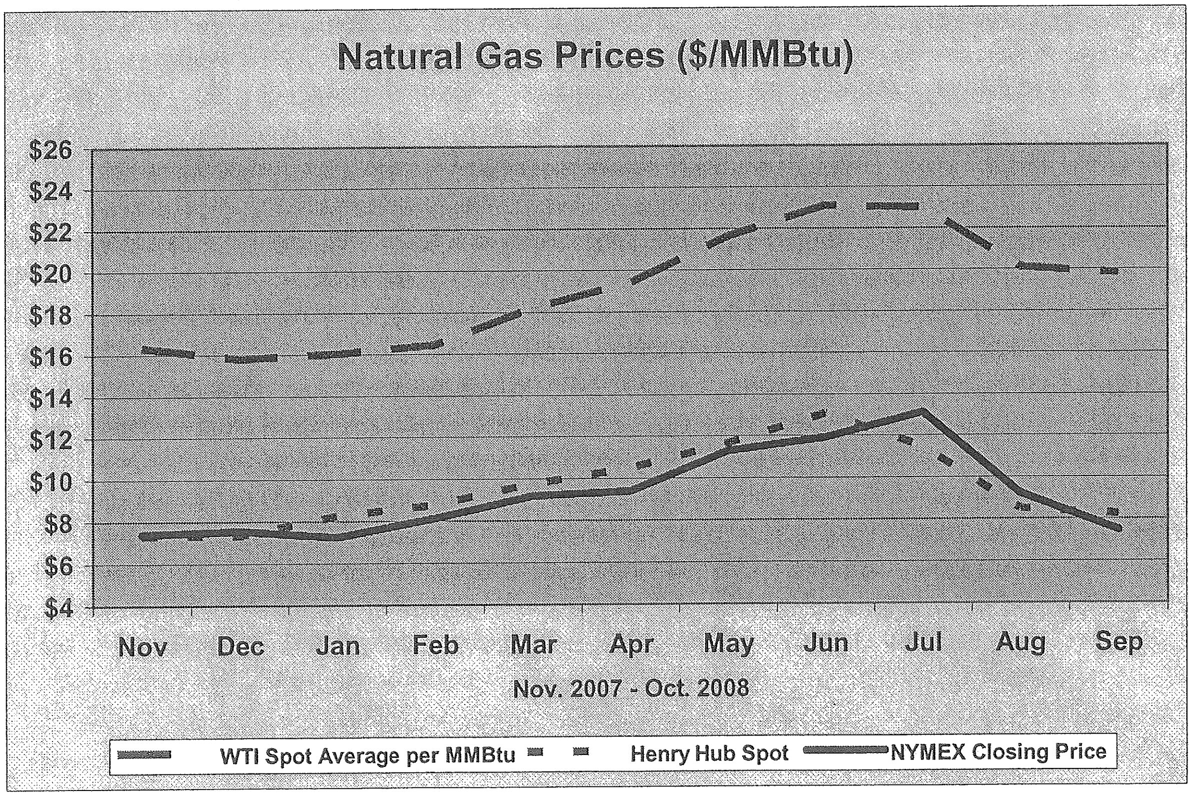
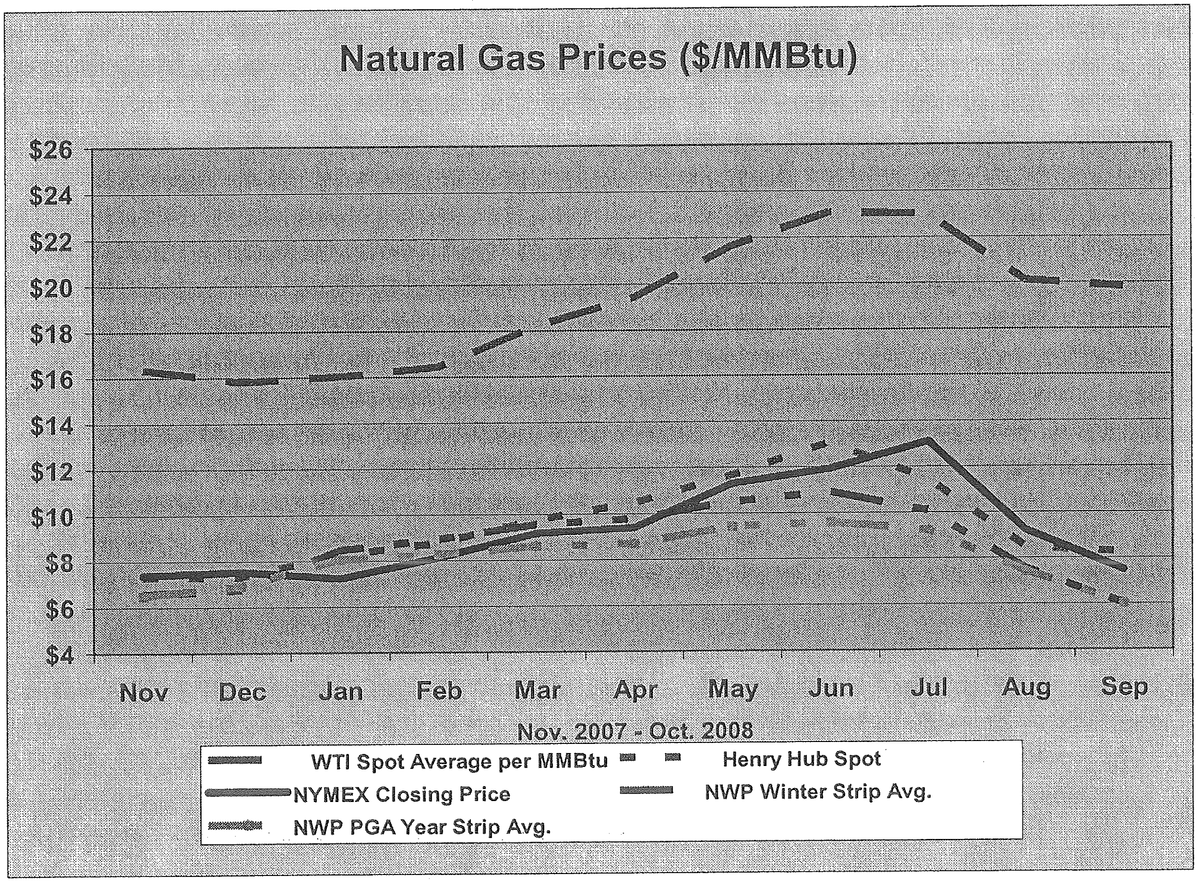


Figure 2: Natural Gas (National and PNW) and WTI Prices, Nov 2007 – Oct 2008



The EIA forecast of the natural gas price at the Henry Hub has fluctuated widely since January. The 12-month forecast began the year at just over $6.00, then moved to just over $8.00 in March, before reaching its peak of $12.01 in June. By August the 12-month forecast had fallen to $9.25 and in September the EIA's forecast for the next twelve months at the Henry Hub was just over $8.60. In October, the 12-month forecast from the EIA had declined to $8.40. Actual prices for spot gas at the Henry Hub began the year just under $8.00, jumped to nearly $13.00 by June, and currently stand between $6.50 and $7.00 depending on the day. These forecasts and actual prices translate to average natural gas prices, for the hubs from which Oregon LDCs purchase, of about $8.00/MMBtu for the PGA year and about $7.30/MMBtu for the winter season. Over this same period, NYMEX 12-month strips for the PGA year averaged about $9.50 while winter strips averaged about $10.00. PNW winter strips over the last year averaged $8.60, while strips for the PGA year average $8.00. Of course, all Oregon LDCs "lock-in" the price of a portion of their natural gas supply portfolio well in advance of the winter heating season for 2008-2009, including multiyear fixed price financial contracts, and place natural gas into storage during the off-peak season (spring and summer) for withdrawal during the winter season. This means the overall pricing for their portfolios cannot, and properly should not, reflect only current natural gas prices and price forecasts or simple averages of spot and futures prices over the twelve months from November 2007 through October 2008.

It appears the natural gas market has finally reached the price tipping point. From this time forward for the foreseeable future, prices at the Henry Hub will likely fall between \$8.00 and \$10.00 while PNW physical prices will likely fall in the range of \$7.00 to \$9.00. Futures prices are likely to be higher than these physical prices for both the nation and the PNW.

Natural Gas Purchasing Strategies

Staff continues to emphasize that "portfolio purchasing" has been accepted for the last two decades as the best means to deal with the risks involved in the purchasing of natural gas by LDCs. This purchasing approach requires that LDCs focus on selecting portfolios of gas supplies based on their overall risk-reward characteristics instead of merely compiling portfolios of purchases that each individually has attractive risk-reward characteristics. In a nutshell, LDCs in purchasing natural gas should select portfolios, not individual supply options. Such a portfolio should display the three characteristics of balance, flexibility, and diversity, and should be based on the particular circumstances in which the purchases are made. The greater the risks of price change or supply availability, the greater the need to follow the diversity requirements of portfolio theory.

Staff emphasizes the following points about portfolio purchasing that should be applied by all three LDCs. These points have been reviewed in meetings with the LDCs throughout the past four years and were included in the last three PGA Staff Reports.

1. In specific practice, portfolio purchasing means the LDC must purchase a combination of resources, including demand-side options, to meet the needs of its customers that are balanced, diverse, and flexible. Thus, it is not just the size of each resource making up the portfolio that must meet these objectives, but also such elements of the portfolio as timing, duration of supply contract, location of supply, contracting form/type, pricing, etc.

2. While the current natural gas market arrangements do limit the options of LDCs in controlling the level and volatility of the price paid for natural gas, portfolio purchasing provides an array of tools to retain at least some LDC control over these pricing concerns.

3. Overemphasizing any particular resource option(s) in a portfolio is contrary to the proper application of portfolio purchasing, no matter the precise form of that overemphasis or the resource(s) to which it is applied. In 2005, all the Oregon LDCs entered into financial hedging arrangements for too large a share of their natural gas supply. Some of, but not all, the LDCs also made this mistake in 2006 and 2007. We discuss Avista's current hedging strategy in the following section, and Cascade's and NW Natural's strategies in their respective Staff Reports.

4. Purchasing natural gas via the portfolio approach requires more attention and effort by the LDC to gather, review, interpret, and apply market intelligence in constructing the portfolio; in monitoring the actual functioning of the portfolio constructed; and in modifying the portfolio as market or operational changes require. This is hard work, especially when compared to purchasing natural gas from daily, weekly, or monthly cash markets.

5. There is no "one size fits all" in portfolio construction. Each portfolio must be designed, constructed, applied, and reviewed based on existing and expected market conditions and on the demand, supply, operational, and general economic circumstances of the LDC for whom the portfolio is being constructed.

6. Each and every portfolio decision and action must be as fully documented as possible. That is, the details behind every decision and action in making a portfolio choice must be available for review and analysis by the LDC and Staff without any extraordinary effort on the part of either the LDC or Staff.

Avista's Natural Gas Purchasing Strategies

In its review of Avista's 2006 PGA, Staff indicated it had multiple concerns regarding Avista's gas purchasing strategy, particularly the Company's decision to financially hedge over 90% of its volumes prior to the PGA year. That situation improved greatly in 2007 and has largely been resolved in the current PGA filing.

Table 3 at the top of the next page shows the portfolio upon which Avista's 2008 PGA filing is based.

Table 3: Avista Gas Supply Portfolio

Resource	Percentage in Portfolio
Pipeline deliveries of natural gas	91.23%
Storage deliveries of natural gas	8.77%
Percentage of firm natural gas deliveries fixed via financial hedges	59%

Avista may financially fix the price of additional volumes subsequent to the PGA filing, but its current target for financial hedging is approximately 59% of expected annual sales. With regard to storage, Avista indicates it is utilizing virtually all the new storage the company acquired over the last two years. This has raised the share of storage in its portfolio from the approximate 1% of two years ago to the current level of nearly 9%. This increase of storage use by Avista is a positive development. It not only allows the company greater resources and flexibility to meet winter peak demand, but also helps mitigate higher and more volatile gas prices for Avista's customers.

Avista's financial hedging program continues to improve. Avista's overall hedge price is approximately $8.87/Dth, which stands above the highest level of the range Staff calculated as reasonable for PNW futures pricing (see Table 4). Also, Avista's hedging price is higher than the hedge price for both NW Natural ($8.33/Dth) and Cascade[5] ($8.40/Dth). Avista continues to meet with Staff regularly, by phone, email, and face-to-face to discuss its financial hedging, storage, and other portfolio construction decisions. These meetings have improved both Avista's portfolio assembly work and Staff's oversight of that work. Avista and Staff will continue these frequent and regular meeting for the foreseeable future.

Table 4: Staff's Hedging Price Range for 2008 PGAs[6]

High	Low
$8.60	$8.00

Overall, the Company has secured a reasonable portfolio for an LDC of Avista's size, operational characteristics, and market options. In addition, Avista's entire gas procurement process and planning are advancing and both Staff and Avista expect that progress to continue. Avista's portfolio construction process is well organized, monitoring available market, demand, weather, and other information on a regular and

[5] For 2008 financial hedges only. Cascade includes rolling 3-year financial hedges as part of its portfolio. The overall price of all hedges in place for 2008 for Cascade is about $8.20/Dth.
[6] This range is based on a weighted average made up of high and low prices for the winter and PGA year Pacific Northwest winter strips combined with the averages for these strips over the period November 2007 to September 2008.

comprehensive basis, maintaining and providing to Staff and other parties reasonable documentation of its decision making processes, and working harder to understand which options at which times work best for Avista and its customers. Even what Staff has called Avista's "overly mechanical" approach to financial hedging is beginning to change with the company experimenting with inserting more flexibility and "real time" creativity into the process. Avista does not completely agree with Staff's assessment of its financial hedging strategies as "overly mechanical" but agrees with Staff that this is a topic for further discussion in the upcoming Phase II of Docket UM 1286 and in quarterly meetings with Staff and other interested stakeholders.

In summary, Avista is doing well in designing a portfolio that "works" in the current natural gas market, thus helping to mitigate the multiple risks inherent in today's natural gas market for both the company and its customers. Avista is making continual progress in implementing purchasing optionality (portfolio diversification, flexibility, and balance) through such tools as competitive bidding; mathematical testing of supply portfolios; and better coordination of supply-side and demand-side resources for meeting demand. Staff expects this progress to continue and considers the regular quarterly (and other more frequent) meetings with Avista a critical element in this continued progress.

Avista's Natural Gas Costs

During the period November 2007 to October 2008 when Avista purchased gas for the period November 2008 through October 2009, the average cash (spot) price in the PNW was approximately $8.03/MMBtu. PNW spot prices increased steadily through this period, reaching near $10.50 in June. Spot price dropped in July and reached a low point just below $6.00 in September. The NYMEX PGA strip price over the period November 2007 to September 2008 averaged about $9.50/MMBtu for the PGA year and about $10.00/MMBtu for the winter period, with a similar price pattern to the Henry Hub physical prices. Over that same period, the average forward prices for the hubs at which the Oregon LDCs purchase were about $8.10/MMBtu for the PGA year and about $8.60/MMBtu for the winter period, also with a similar price pattern.

The commodity price and transportation demand charge Avista proposes to pass through to its sales customers are shown in Table 5 (see top of next page), along with the range of prices for commodity Staff recommends as reasonable. Staff accepts the demand charge proposed by Avista, as it is established via FERC tariff. Staff has only verified that the transportation charge proposed by Avista is the actual charge approved by FERC and in place currently.

Table 5: Avista Commodity and Demand Costs for 2008 PGA[7]

Charge ($/therm)	Avista	Staff's Range
Commodity	$0.83040	$0.82500 - $0.87500
Commodity (revenue sensitized)	$0.85754	
Demand	$0.22376	$0.22376
Demand (revenue sensitized)	$0.23107	
Total	$1.05416	$1.04876 - $1.09876
Total (revenue sensitized)	$1.08861	

Avista's weighted average cost of gas (WACOG) is a 9% increase over its current WACOG. The total gas cost (including transportation charges) is a 9.1% increase over that currently in place.

Staff believes Avista's proposed WACOG is reasonable. Avista's gas purchasing and planning and portfolio design are improving and the company can reasonably be expected to continue that improvement. Staff particularly wants to note the pattern of Avista's financial hedging during the November 2007 to September 2008 time period. Despite some over emphasis during July, Avista's pattern of hedging shows the intent by the company to spread hedging across as large a portion of this time period as possible and prudent.

Staff recommends the PGA gas costs proposed by Avista be allowed to go into effect on November 1, 2008. The overall increase in gas cost revenues (including demand charges) proposed by Avista is $7,073,391. Given the upturn in prices during the middle of the last year, this is a reasonable gas cost increase request by Avista.

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[7] The low value in Staff's range is a ±1 SD/0.5 SD weighted average of the median and average values for the PNW futures strips for the winter and PGA year over the period November 2007 to September 2008 in combination with the average of two fundamentals forecasts. The high value in Staff's range is a ±1 SD/0.5 SD weighted average of the highest values for the PNW futures strips for the winter and PGA year over the period November 2007 to September 2008 in combination with the average of two fundamentals forecasts. Both values are rounded to the nearest cent.

Technical Adjustments - Deferred Accounts

Avista's application proposes to make technical adjustments in amortizing credit and debit balances in its deferred accounts. This activity consists of the following components:

- Removal of temporary increments currently in place, decreasing revenues by $11,846,317.
- Addition of a new temporary decrement of $792,228 to the Company's deferred accounts as detailed in Table 6 below. The Commission previously authorized all of the deferred amounts subject to amortization.

Table 6: Avista Temporary Revenue Increments for 2008 PGA

Temporary Debit (Credit) Revenues	Amount
Commodity and Demand costs	($4,491,151)
Demand Side Management & Weatherization	$3,140,959
Intervenor Funding	$65,321
Subtotal	($1,284,871)
Large Customer Margin Deferral Schedule 496	$492,643
Total	($792,228)

The net revenue effect of adding the new temporary decrements and removing the current increments is a decrease of $12,638,544 on an annual basis. Staff has reviewed the Company's technical adjustments and determined that the proposed amortizations are appropriate. The revised amortization increments in the amount of ($1,284,871) are incorporated in the Company's primary rate schedules. The revised amortization increment of $492,643 for the Large Customer Margin Deferral is incorporated in adder Schedule 496.

Earnings Review and Three Percent Test

Until 1999, as a matter of policy, the Commission conducted earnings reviews for both prospective purchased gas cost changes and PGA-related deferrals. The Commission then adopted OAR 860-022-0070, which requires an annual spring earnings review in lieu of an earnings review related to prospective purchased gas cost changes. In 2005, Staff and Avista agreed upon a sharing mechanism of 90/10. As the Company's level is less than the 33 percent sharing prescribed under OAR 860-022-0070(8), the Company is also subject to a fall earnings review, as well as the mandated spring earnings review. The purpose of the fall earnings review is to determine whether or not Avista should absorb any of its gas cost deferrals. In this filing, no determination is necessary as

Avista's gas cost deferrals have a credit balance of approximately $4.5 million that will be returned to customers in the current proposed rates.

ORS 757.259 (6) and (7) state that the overall annual average rate impact of the amortizations authorized under the statute may not exceed three percent of the natural gas utility's gross revenues for the preceding calendar year, unless the Commission finds that allowing a higher amortization rate is reasonable under the circumstances. As Avista's 2008 proposed net amortization authorized under the statute is a credit of $792,228 which clearly falls within the ORS requirement, the reduction to rates should be implemented as proposed.

UM 1390

In this filing, Avista requests reauthorization of deferrals pursuant to its automatic adjustment clause, the PGA mechanism. The PGA allows the Company to adjust tariffs annually for known and measurable changes in purchased base gas costs and for changes in amortization rates relating to the PGA balancing account.

Avista's application states that continued deferral of these cost and revenue differences minimizes the frequency of rate changes and appropriately matches costs borne and benefits received by ratepayers, consistent with ORS 757.259(2)(e). The reasons cited for reauthorization are still valid.

PROPOSED COMMISSION MOTION:

Avista Utilities' request for: (1) amortization of deferred accounts, base gas cost changes, and other rate changes as requested in Docket UG 182 be approved; (2) the application for LSN be approved and the associated tariff sheets of Advice No. 08-07-G Supplemental be allowed to go into effect with service on November 1, 2008; and, (3) reauthorization to use deferred accounting pursuant to Schedule 461 as requested in UM 1390 be approved.

ORDER NO. 08-524
Attachment A

Avista Utilities
Oregon Gas Operations
Summary of Present and Proposed Rates

Line No.	Description (A)	Rate Sch (B)	Adjusted Sales Therms (C)	Present Revenues (D)	Change in Gas Costs: Commodity Portion (E)	Change in Gas Costs: Demand Portion (F)	Change in Gas Costs: Total Change (G) (E) + (F)	Change in Amortization: Remove Old (H)	Change in Amortization: Add New (I)	Change in Amortization: Total Change (J) (H) + (I)	Total Change: In Rates (K) (G) + (J)	Total Change: In Revenue (L) (M) - (D)	Proposed Revenues (M)
1	Residential	410	54,433,987	$ 82,197,659	$ 0.07134	$ 0.00453	$ 0.07587	$ (0.13188)	$ (0.00579)	$ (0.13767)	$ (0.06180)	$ (3,364,021)	$ 78,833,638
2	General	420	30,504,470	$ 41,696,651	$ 0.07134	$ 0.00453	$ 0.07587	$ (0.13188)	$ (0.00699)	$ (0.13887)	$ (0.06300)	$ (1,921,782)	$ 39,774,869
3	Large General	424	4,599,613	$ 5,685,400	$ 0.07134	$ 0.00453	$ 0.07587	$ (0.09694)	$ (0.01279)	$ (0.10973)	$ (0.03386)	$ (155,743)	$ 5,529,657
4	Emergency Instit.	430	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Interruptible	440	3,737,523	$ 3,458,367	$ 0.07134	$ -	$ 0.07134	$ (0.04856)	$ (0.05424)	$ (0.10280)	$ (0.03146)	$ (117,582)	$ 3,340,785
6	Seasonal	444	177,970	$ 217,170	$ 0.07134	$ 0.00453	$ 0.07587	$ (0.09694)	$ (0.01279)	$ (0.10973)	$ (0.03386)	$ (6,026)	$ 211,144
7	Special Contract	447	3,220,068	$ 430,067	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 430,067.00
8	Firm Transportation	455	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Int. Transportation	456	30,322,840	$ 2,205,209	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,205,208.55
10	TOTAL		126,996,472	$ 135,890,521								$ (5,565,154)	$ 130,325,368
11	Residential	410	54,433,987	$ 82,197,659	$ 3,883,321	$ 246,586	$ 4,129,907	$ (7,178,754)	$ (315,173)	$ (7,493,927)		$ (3,364,021)	$ 78,833,638
12	General	420	30,504,470	$ 41,696,651	$ 2,176,189	$ 138,185	$ 2,314,374	$ (4,022,930)	$ (213,226)	$ (4,236,156)		$ (1,921,782)	$ 39,774,869
13	Large General	424	4,599,613	$ 5,685,400	$ 328,136	$ 20,836	$ 348,973	$ (445,887)	$ (58,829)	$ (504,716)		$ (155,743)	$ 5,529,657
14	Emergency Instit.	430	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
15	Interruptible	440	3,737,523	$ 3,458,367	$ 266,635	$ -	$ 266,635	$ (181,494)	$ (202,723)	$ (384,217)		$ (117,582)	$ 3,340,785
16	Seasonal	444	177,970	$ 217,170	$ 12,696	$ 806	$ 13,503	$ (17,252)	$ (2,276)	$ (19,529)		$ (6,026)	$ 211,144
17	Special Contract	447	3,220,068	$ 430,067	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ 430,067
18	Firm Transportation	455	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
19	Int. Transportation	456	30,322,840	$ 2,205,209	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ 2,205,209
20	TOTAL		126,996,472	$ 135,890,521	$ 6,666,977	$ 406,414	$ 7,073,391	$ (11,846,317)	$ (792,228)	$ (12,638,544)		$ (5,565,154)	$ 130,325,368

Note: These figures exclude the Phase II increase of $1,355,930

Attachment B

Comparison of Proposed Rate and Bill Increases for Oregon Local Distribution Companies by Class of Service
(November 2008 PGAs)

Class of Service	Rate Schedule	RATE IMPACTS: Current Rate per Therm	Proposed Rate per Therm	Change Rate per Therm	%-Change Rate per Therm	BILL IMPACTS: Average January Therms	Customer Charge	Current January Bill	Proposed January Bill	Change January Bill	%-Change January Bill	Annual Therms/ Month	Customer Charge	Current Monthly Bill	Proposed Monthly Bill	Change Monthly Bill	%-Change Monthly Bill
Residential																	
Avista	410*	$1.40692	$1.35380	-0.05312	-3.8%	100	$6.00	$146.19	$141.38	-$4.81	-3.3%	53	$6.00	$80.07	$77.75	-$2.32	-2.9%
Cascade	101	$1.20884	$1.27656	0.06772	5.6%	113	$3.00	$139.60	$147.25	$7.65	5.5%	59	$3.00	$74.32	$78.32	$4.00	5.4%
NW Natural	2	$1.22449	$1.41502	0.19053	15.6%	109	$6.00	$139.47	$160.24	$20.77	14.9%	56	$6.00	$74.57	$85.24	$10.67	14.3%
Commercial																	
Avista	420*	$1.33604	$1.27304	-0.06300	-4.7%												
Cascade	104	$1.10819	$1.17591	0.06772	6.1%												
NW Natural	3	$1.12149	$1.30440	0.18291	16.3%												
Industrial																	
Avista	424	$1.22216	$1.18830	-0.03386	-2.8%												
Cascade	105	$1.04579	$1.15085	0.10506	10.0%												
NW Natural	31ISF	$0.81672	$0.99780	0.18108	22.2%												
Interruptible																	
Avista	440	$0.92531	$0.89385	-0.03146	-3.4%												
Cascade	170	$0.99242	$1.09689	0.10447	10.5%												
NW Natural	32ISI	$0.74241	$0.93976	0.19735	26.6%												

* Rate Schedules 410 and 420 include the Margin Reduction Surcharge (in Rate Schedule 496) allowed under the approved Stipulation in Order No. 03-570.
Avista's proposed billing rates also include the effects of rate changes previously approved in Order No. 08-185, Docket UG 181.

Attachment C