ORDER NO. 09-447
ENTERED 11/09/09

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 188 & UM 1447

In the Matters of AVISTA CORPORATION dba AVISTA UTILITIES Changes in the Cost of Purchased Gas and Technical Rate Adjustments (UG 188) and Application for Authorization to Defer PGA Related Expenses or Revenues. (UM 1447).	ORDER

DISPOSITION: APPLICATIONS APPROVED

On August 31, 2009, and September 1, 2009, the Public Utility Commission of Oregon (Commission) received two applications from Avista Corporation dba Avista Utilities related to changes in the costs of purchased gas and technical adjustments. 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 27, 2009, the Commission adopted Staff's recommendation to approve the applications.

ORDER

IT IS ORDERED that:

1. The amortization of deferred accounts, base gas cost changes and rate changes as requested in docket UG 188 are approved.

2. The associated tariff sheets of Advice No. 09-06-G Supplemental are allowed to go into effect with less than statutory notice, beginning with service on or after November 1, 2009.

3. Reauthorization to use deferred accounting pursuant to Schedule 461, as requested in docket UM 1447, for one year beginning November 1, 2009, is approved.

Made, entered, and effective NOV 0 9 2009.

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 27, 2009

REGULAR X **CONSENT** ____ **EFFECTIVE DATE** **November 1, 2009**

DATE: October 21, 2009

TO: Public Utility Commission

FROM: Ken Zimmerman, Moshrek Sobhy, Deborah Garcia and Lisa Gorsuch

THROUGH: Lee Sparling, Ed Busch, Lori Koho and Judy Johnson

SUBJECT: AVISTA UTILITIES: (Docket No. UG 188/Advice No. 09-06-G) Reflects changes in the cost of purchased gas and technical adjustments.

AVISTA UTILITIES: (Docket No. UM 1447) 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. 09-06-G Supplemental to go into effect for service on and after November 1, 2009. This filing decreases the Company's annual revenues by approximately $27.9 million, or 21.8%.

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 31, 2009, 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 188, proposed a revenue decrease of approximately $28.5 million or 22.1%, effective November 1, 2009. 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. Avista also proposed that its gas cost related amortization be spread over two years rather than the customary one year period. In a concurrent filing docketed as UM 1447, Avista requested reauthorization of deferrals under the Company's PGA mechanism.

On October 13, 2009, the Company filed replacement Advice No. 09-06-G Supplemental, along with an LSN application, to lower its projected commodity cost and to change the gas cost related amortization period to a one year period. The re-filed PGA requests an overall revenue decrease of approximately $27.9 million annually, or 21.8%.

UG 188

In its amended filing, Avista seeks approval to (1) track changes in purchased gas costs; (2) make technical adjustments to amortize Avista's deferred accounts including gas costs, demand side management and weatherization, Large Customer Margin Deferral Schedule 496, and intervenor funding. The change in annual revenues is summarized in Table 1 below, and additional detail is shown in Attachment A.

Table 1: Change in Annual Revenues

PGA Base Gas Cost Change	($26,901,901)
Remove 2008 Temporary Increment	$839,813
Add 2009 Temporary Increment	($1,845,048)
Total Proposed PGA Decrease	($27,907,136)

With these changes, the monthly bill of a typical residential customer using 52 therms per month will decrease by $15.99, or 20.7 percent, from $77.43 to $61.44. In January, a typical residential customer's consumption of 104 therms will result in a billing decrease of $32.12 or 21.5%, from $149.48 to $117.36.

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 $1.17328 per therm, while Cascade's and NW Natural's effective rates are $1.15524 and $1.22901, respectively. Table 2 shows the rates the Commission has approved for Avista's residential customers on Rate Schedule 410 between 2004 and 2008, and the current proposal.

Table 2: Residential Rates 2004 – 2009 (Proposed)

Date	Customer Charge	Rate Per Therm	Percentage Change [1]
October 2004	$5.00	$1.08689	
October 2005	$5.00	$1.34729	24.0%
November 2006	$5.00	$1.44931	7.6%
November 2007	$5.00	$1.42914	-1.4%
November 2008	$6.00	$1.37365	-3.9%
November 2009	$6.00	$1.06614	-22.4%

Avista offers both customer assistance and energy efficiency programs. 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.

ANALYSIS:

Before presenting the results of its review of Avista's 2009 PGA filing and the gas supply portfolio upon which that filing is based, Staff wants to compliment and thank Avista for the thoroughness of its response to the recently adopted Commission PGA Filing and Portfolio Guidelines.[2] Properly addressing each area in these detailed guidelines is a difficult and time consuming endeavor. Avista has taken quite seriously the task of demonstrating and documenting its compliance with the guidelines.

Natural Gas Portfolio Development Guidelines

Accepted "best practices" for purchasing of natural gas supply by local distribution companies is a portfolio construction that balances the objectives of reliability, cost, and price volatility using the tools of diversity, flexibility, and balance. The "Natural Gas Portfolio Development" (Portfolio Guidelines) guidelines acknowledged by the Commission in Order No. 09-248, (corrected by Commission Order No. 09-263) implement these "best practices" for Oregon LDCs. The following review of and conclusions regarding Avista's natural gas supply portfolio and related purchasing strategies and actions is based on these guidelines.

[1] 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.
[2] The "Natural Gas Portfolio Development" and "PGA Filing Guidelines" were acknowledged by the Commission in Order No. 09-248 and corrected in Order No. 09-263.

Section III – Portfolio Planning Guidelines

III. A. Portfolio Planning and the IRP
The IRP provides the framework for the portfolio planning process, and the portfolio planning process should build upon the IRP; this nexus includes both forecasting methodology and supply options. The gas supply process should begin with a strategic planning effort to provide a reliable supply and consider how best to balance the issues of price, flexibility, and diversity in the context of the utility's system and its customers' needs. The portfolio planning process should be regularly updated to capture changes in forecast load, available resources, and market conditions.

III.C. Portfolio Planning Process: General
The portfolio planning process should consider the following:

1. *Expected monthly average core and peak load based on normal weather conditions. Development of the utility's load forecast should be based on the same methodology that was utilized in the utility's most recently acknowledged IRP or IRP update, while considering any changes to conditions since that time. Any differences in the methodology used to forecast load for gas portfolio development from that used in the IRP process should be identified and explained.*
2. *All reasonable supply-side and demand-side resources (physical and financial) available to meet each segment of a utility's forecast load.*
3. *Fundamental analysis.*

Avista's portfolio preparation and planning process meets these requirements.

III. D.	***Portfolio Planning: Physical Natural Gas*** *A physical natural gas portfolio should meet the following objective:* 1. *The portfolio should include a sufficient number of nonaffiliated suppliers to ensure diversity of supply sources.* 2. *The utility's portfolio should include contracts of varying duration.* 3. *The utility's portfolio should include contracts entered into at various times throughout the gas year.* 4. *To the extent reasonable and feasible, the utility's portfolio should include contracts that allow the utility to vary its gas take and pricing requirements on a seasonal or monthly basis. Physical arrangements may also cover annual and multi-year periods.* 5. *The utility should be able to demonstrate that its gas supply portfolio is sufficiently flexible to meet reasonably expected weather, pipeline operations, gas supply shortage, system load reduction events, and market scenarios.* 6. *A utility should comply with its own minimum standards for creditworthiness and financial stability when evaluating counterparties in order to minimize the risk of counterparty failure or diminished performance.*

Avista satisfies all the above guidelines except III.D.4. Guideline 4 cannot be satisfied at this time because such provisions are not offered in current non-spot (non-daily and non-monthly) contracts.

III.E.	***Portfolio Planning: Financial Natural Gas*** *If the utility maintains a financial natural gas portfolio, that portfolio should meet the following objectives:* 1. *The portfolio should include a sufficient number of nonaffiliated counterparties to ensure diversity of counterparties.* 2. *The portfolio should include financial contracts covering both annual and seasonal periods. Financial arrangements may also cover multi-year periods. A utility should thoroughly evaluate qualitatively and, if possible, quantitatively, the use of multi-year financial arrangements in preparing its portfolio.* 3. *The portfolio should include financial arrangements for natural gas entered into at various times throughout the gas year.* 4. *When it is reasonable and feasible, no single financial transaction should cover more than 25% of the total annual volumes for the portfolio. Also, to the extent reasonable and feasible, multiple types of financial arrangements should be considered.* 5. *A utility's gas supply financial arrangements should be sufficiently flexible to meet reasonably expected weather, pipeline operations, gas supply shortage, system load reduction events, and market scenarios.* 6. *A utility should comply with its own minimum standards for creditworthiness and financial stability when evaluating counterparties in order to minimize the risk of counterparty failure or diminished performance.*

Avista's 2009-2010 portfolio satisfies each of these guidelines.

> ***III. F. Portfolio Planning: Contractual Arrangements***
> *In developing its natural gas supply portfolio, a utility should consider at least the following:*
> a. *A wide range of physical and financial contracts and hedges based on market conditions, the utility's annual, seasonal, and peak demands; varying weather conditions; and other utility-specific conditions;*
> b. *Storage;*
> c. *Demand response programs;*
> d. *Coordinated purchasing with other companies;*
> e. *Natural gas exchange opportunities;*
> f. *Arrangements with third parties already on the utility system that have their own gas supply;*
> g. *Direct purchases from a non-utility LNG facility; and*
> h. *Direct purchases from producers of natural gas.*

Avista provides information in its 2009 PGA filing that clearly shows it considers on a regular basis each of these options.

AVISTA PORTFOLIO FOR 2009 PGA

Avista's actual supply portfolio, both physical and financial is presented in Table 3 below.

Table 3: Avista Gas Supply Portfolio for 2009-2010 PGA Year

Resource	Percentage in Portfolio
Pipeline deliveries of natural gas	90.55%
Storage deliveries of natural gas	9.45%
Percentage of firm natural gas deliveries fixed via financial hedges	57.52 %

In light of current market conditions, the shape and level of load expected on Avista's system for the upcoming PGA year, and the purchasing opportunities available to Avista this portfolio is reasonable. Avista has slightly reduced (59% to 51%) its financial hedging this year compared to last. This is a response to the contango[3] status of the natural gas futures market now and over the last several months.

[3] When the market is "in contango," the price for deliveries in out months is higher than the "prompt month" price, which shows up as an upward, sloping, forward curve.

PGA Filing Guidelines

Order No. 09-248 also acknowledges "PGA Filing" guidelines that identify the information that should be included in the PGA filing and its format. The review of Avista's PGA filing that follows is based on these guidelines.

Section IV – General Information and Forecasting

As part of its annual PGA filing the utility should include the following general information and data regarding its natural gas supply portfolio, including related transportation, upon which its PGA filing is based.

> ***IV. 1. General Information***
>
> *a) Definitions of all major terms and acronyms in the data and information provided.*
>
> *b) Any significant new regulatory requirements identified by the utility that in the utility's judgment directly impacts the Oregon portfolio design, implementation, or assessment.*
>
> *c) All forecasts of demand, weather, etc. upon which the gas supply portfolio for the current PGA filing is based should be based on a methodology and data sources that are consistent with the most recently acknowledged IRP or IRP update for the utility. If the methodology and/or data sources are not consistent each difference should be identified, explained, and documented as part of the PGA filing workpapers.*

Avista provides comprehensive definitions. Also, Avista used the expected case demand forecast, adjusted for normal weather, from the 2009 draft IRP in preparing the Company's 2009 PGA filing. As to guidelines IV.1.b), Avista finds there are "... no new regulatory requirements that impacted portfolio design implementation or assessment." Avista bases this conclusion on an interpretation of this guideline that limits it to requirements of other states (WA/ID) that could impact its overall portfolio approach. Avista indicates that it monitors pending and proposed regulatory changes like those identified below through its IRP process and otherwise. Avista notes, however, that no major legislation has been enacted that would directly impact the 2009-2010 gas supply portfolio. Pending regulatory changes that Avista is monitoring that could impact its gas buying and portfolio development even for the 2009 PGA include pending changes to natural gas commodity market position limits for non-commercial traders (often referred to as speculators); proposed changes to environmental regulations covering hydraulic fracturing used for shale natural gas drilling; and proposed CO_2 emission regulations that could easily shift more overall energy demand to natural gas. Multi-year physical and financial contracting, as is done by Avista, makes such potential changes important to recognize and monitor.

IV. 2.	***Workpapers*** *Workpapers to the PGA should include:* *a) PGA Summary Sheet: Utilities should provide a PGA Summary Sheet. See Appendix A.* *b) Gas Supply Portfolio and Related Transportation: Utilities should provide the following information related to the gas supply portfolio and related transmission:* *1. General Information.* *2. Overview of portfolio planning process.* *3. LDC sales system demand forecasting.* *4. Natural gas price forecasts.* *5. Physical resources for the portfolio.* *6. Financial resources for the portfolio (derivatives instruments and other financial arrangements).* *7. Storage resources.* *8. Forecasted annual and peak demand used in the current PGA portfolio, with and without programmatic and non-programmatic demand response, with explanation.* *9. Forecasted annual and peak demand used in the current PGA portfolio, with and without effects from gas supply incentive mechanisms, with explanation.* *10. Overview of portfolio documentation provided.*

Avista includes a fully completed PGA Summary Sheet in its filing. Avista also provides and/or provides references to all items in IV.2. b) in its PGA fling.

Section V – Data and Analysis

As part of its annual PGA filing the LDC should include the following information and data regarding the PGA gas supply portfolio, including related transportation. Historical data requirements will go into effect over a three year period, beginning with the 2009 PGA filing. During the first year the guidelines are in effect, historical data for three years should be provided, adding one additional historical data year for each of the subsequent two years, for a total of five years.

V.1. *Physical Gas Supply*

a) For each physical natural gas supply resource that is included in a utility's portfolio (except spot purchases) upon which the current PGA is based, the utility should provide the following:

1. *Pricing for the resource, including the commodity price and, if relevant, reservation charges.*
2. *For new transactions and contracts with pricing provisions entered into since the last PGA: competitive bidding process for the resource. This should include number of bidders, bid prices, utility decision criteria in selecting a "winning" bid, and any special pricing or delivery provisions negotiated as part of the bidding process.*
3. *Brief explanation of each contract's role within the portfolio.*

b) For purchases of physical natural gas supply resource from the spot natural gas market included in the portfolio at the time of the filing of the current PGA or after that filing, the utility should provide the following:

1. *An explanation of the utility's spot purchasing guidelines, the data/information generally reviewed and analyzed in making spot purchases, and the general process through which such purchases are completed by the utility.*
2. *Any contract provisions that materially deviate from the standard NAESB contract.*

Avista has satisfied the V.1.a) 1., 2., guidelines. Avista has also satisfied guideline a) 3. However, Avista's actions in meeting guideline a) 3., require a bit of explanation since Avista's approach is somewhat different from the other LDCs. Avista uses the linear programming model SENDOUT® to model its expected monthly demand for each month of the PGA year. Avista calls this forecast "baseload" demand. Avista purchases "baseload" gas supply based on this modeling for each month of the PGA year. If there is more demand than expected during a month, additional gas is either purchased on the short-term market or withdrawn from storage, depending on the time of the year. Alternatively, if demand is less than expected during a month, unneeded gas is either injected into storage or sold on short-term markets, depending on the time of the year. As with the other LDCs, Avista has financially hedged a portion of the "baseload" gas supply (see Table 1 above). This is certainly an acceptable approach to gas supply contracting. Obviously the quality of the SENDOUT® modeling is an important factor in how well this strategy performs. That question is one Staff will address in its review of Avista's current draft IRP.

Avista has satisfied the V. b) 1. guideline. Avista also satisfies guideline b) 2., noting that it would not enter into a contract with "material" deviations from the standard North American Energy Standards Board (NAESB) contract. Avista indicates it has "over 75 NAESB" agreements with various counterparties and no two are exactly the same. However, the differences between these contracts are not material deviations from the standard NAESB contract. For example, such differences include credit terms/provisions and form of confirmation.

V.2.	***Hedging*** *The utility should clearly identify by type, contract, counterparty, and pricing point both the total cost and the cost per volume unit of each financial hedge included in its portfolio.*

Avista's PGA filing and associated workpapers provide all the information required by guideline V.2.

V.3.	***Load Forecasting:*** *a) Customer count and revenue by month and class.* *b) Historical (five years) and forecasted (one year ahead) sales system physical peak demand.* *c) Historical (five years), and forecasted (one year ahead) sales system physical annual demand.* *1. Annual for each customer class.* *2. Annual and monthly baseload.* *3. Annual and monthly non-baseload.* *4. Annual and monthly for the geographic regions utilized by each LDC in its most recent IRP or IRP update.*

Avista has provided full information in its PGA filing in response to all areas covered in guideline V.3.

V.4.	***Market information:*** *General historical and forecasted (one year ahead) conditions in the national and regional physical and financial natural gas purchase markets. This should include descriptions of each major supply point from which the LDC physically purchases and the major factors affecting supply, prices, and liquidity at those points.*

Avista includes a quite detailed and helpful overview of its views about the current state of the US and PNW natural gas market (and related markets) as well as the potential future for those markets. These descriptions are helpful for Staff.

V.5.	***Data Interpretation:*** *If not included in the PGA filing please explain the major aspects of the LDC's analysis and interpretation of the data and information described in (1) and (2) above, the most important conclusions resulting from that analysis and interpretation, and the application of these conclusions in the development of the current PGA portfolio.*

Avista satisfies this guideline. Avista's interpretive process is quite standard, considering all the major factors that impact natural gas supply, price, and demand. While not particularly creative the process is useful and necessary.

V.6. Credit worthiness standards:
A copy of the Board or officer approved credit worthiness standards in place for the period in which the current gas supply portfolio was developed, along with full documentation for these standards. Also, a copy of the credit worthiness standards actually applied in the purchase of physical gas and entering into financial hedges. If the two are one and the same, please indicate so.

As part of the PGA filing and/or associated workpapers, Avista provides a copy of the Board or officer approved credit worthiness standards in place for the period in which the current gas supply portfolio was developed, along with full documentation for these standards.

V.7. Storage:
Workpapers should include the following information about natural gas storage included in the portfolio upon which that PGA is based.

- *a) Type of storage (e.g., depleted field, salt dome).*
- *b) Location of each storage facility.*
- *c) Total level of storage in terms of deliverability and capacity held during the gas year.*
- *d) Historical (five years) gas supply delivered to storage, both annual total and by month.*
- *e) Historical (five years) gas supply withdrawn from storage, both annual total and by month.*
- *f) An explanation of the methodology utilized by the LDC to price storage injections and withdrawals, as well as the total and average (per unit) cost of storage gas.*
- *g) Copies of all contracts or other agreements and tariffs that control the LDC's use of the storage facilities included in the current portfolio.*
- *h) For LDCs that own and operate storage:*
  - *a. The date and results of the last engineering study for that storage.*
  - *b. A description of any significant changes in physical or operational parameters of the storage facility (including LNG) since the current engineering study was completed.*

Avista satisfied guideline V.7. Avista includes copies of all contracts and agreements as part of the support for its PGA filing. Guideline V.7.h) is not applicable to Avista, since it does not operate natural gas storage facilities.

National and Regional Natural Gas Markets – Summary

National and regional natural gas markets look very different today than they looked this time last year. Natural gas physical and futures prices in the Pacific Northwest (PNW) have fallen from approximately $12.00 per MMBtu[4] to approximately $5.00. Physical prices in the PNW may drop as low as $3.00 per MMBTU by this winter while the trajectory of futures prices beyond the next few months is difficult to predict. PNW LDCs are currently facing the challenges associated with a natural gas futures market that is "in contango."

Multiple factors contribute to the current state of the natural gas market, physical and futures. Natural gas supply across the nation has increased significantly over the past year both in terms of production and known/proven natural gas reserves. At the same time production and reserves were increasing, demand for natural gas was greatly decreasing, both as a result of the current economic downturn and improving efficiency. This has caused a glut of gas to be placed into storage, which is fast approaching capacity. Weather has been a "non-factor" for natural gas markets, so far, and early in 2009 it appears natural gas and crude oil prices delinked. Aside from fundamentals, financial speculation in natural gas remains high. For example U.S. Natural Gas Fund (UNG) has taken a financial position equivalent to about 9% of total US winter natural gas demand.

Looking ahead, assorted legislative proposals, if enacted, could impact natural gas demand, supply and price on both a national and a regional level. The potential legislation under consideration is the result of many issues ranging from environmental concerns, commodity speculation, and price volatility. On the environmental front federal regulation of "hydraulic fracturing" used in unconventional shale gas production is proposed, which could slowdown drilling and increase associated costs. Placing gas-fired power plants ahead of coal-fired plants in the dispatch order is also proposed, which would considerably increase the demand for natural gas and thus impact supply and cost. Another noteworthy proposal provides for additional oversight and position limits on natural gas financial traders (at both exchanges and in over-the-counter (OTC) transactions), which may reduce price volatility in both physical and financial markets. The extreme volatility in the natural gas markets over the last few years is thought to be the result of speculation.

Items of special interest to the PNW include the potential loss of Huntington-Sumas as a viable trading hub, additional pipelines from gas supplies in the Rockies and British Columbia, the potential for LNG imports through Oregon, the chance that Canadian natural gas exports may decline, and the dispute over the impacts of the Western

[4] Million British Thermal Unit (BTU)

Climate Initiative (WCI) and what role, if any, natural gas may eventually play in the WCI.

Comprehensive details surrounding national and regional gas markets can be found in Attachment D.

AVISTA GAS SUPPLY COSTS

All Oregon LDCs purchase a portion on their gas supply during the PGA year on a short-term or spot basis. This is often referred to as the cash market and covers periods from a single day up to a month. Table 4 presents the price range expected for such purchased made during the 2009-2010 PGA year. Table 4 represents the price change in dekatherms (Dth)[5].

Table 4: Physical Cost of Gas Range for 2009 PGAs ($/Dth)[6]

High	Low
$5.14	$4.75

Avista's forecasted average for physical purchases for the 2009-2010 PGA year is within this range and thus is reasonable.

All Oregon LDCs utilize financial hedging in preparing their gas supply portfolios. Table 5 presents the expected range for the average cost of financial hedged gas supply for the 2009 PGA.

Table 5: Financial Hedging Price Range for 2009 PGAs ($/Dth)[7]

High	Low
$5.80	$5.12

Avista's average price for 2009 financial hedging per Dth is within this range. Staff therefore believes Avista's cost for hedging natural gas costs in the 2009 PGA are appropriate.

[5] Decatherm (Dth) is ten therms or 1 million BTU. One dekatherm is equal to approximately 1,000 cubic feet of natural gas.
[6] This range is based on ±1 Standard Deviation (SD) from the average of four forecasts of physical prices (adjusted to the PNW) over the period November 2009 through October 2010. The two public forecasts are from the EIA and IEA. Two private forecasts are also included.
[7] This range is based on a weighted average made up of high and low prices for the winter and PGA year PNW futures strips combined with the averages for these strips over the period November 2008 to September 2009. This range also includes hedges carried over from past years.

Each Oregon LDC includes storage as one of the elements of its gas supply portfolio. Table 6 presents the expected range for storage injections during the 2009 injection season (roughly March – September).

Table 6: Storage Injections Cost Range for 2009 PGAs ($/Dth)[8]

High	Low
$3.84	$3.45

The average price for 2009 natural gas storage injections reported by Avista is well below the lower end of the range. Therefore, Avista's storage injection cost for the 2009 PGA is reasonable.

Table 7 presents the weighted average cost of gas (WACOG) proposed by Avista in its 2009 PGA filing, as compared to the expected range for this WACOG prepared by Staff.

Table 7: Avista Commodity and Demand Costs for 2009 PGA ($/therm)[9]

Charge ($/therm)	Avista	Staff's Range
Commodity	$0.52997	$0.55600 - $0.58800
Commodity (revenue sensitized)	$0.54634	
Demand	$0.23937	$0.23937
Demand (revenue sensitized)	$0.24676	
Total	$0.76934	$0.79537 – $0.82737
Total (revenue sensitized)	$0.79310	

The WACOG proposed by Avista for the 2009-2010 PGA year is clearly below the lower end of the WACOG range proposed by Staff. Consequently, Staff believes Avista's proposed WACOG is reasonable and should be approved for inclusion in rates.

[8] These values represent ± 1 SD below and above the average of the PNW physical price of gas over the period March to June 2009. The PNW purchasing points included are AECO, Rockies, and Kingsgate.
[9] 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 2008 to September 2009 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 2008 to September 2009 in combination with the average of two fundamentals forecasts. Both values are rounded to the nearest cent per dekatherm.

The overall decrease in rates related to gas cost proposed by Avista is $28,245,561. This decrease in rates related to gas costs is reasonable, in light of the dramatic drop in natural gas price over the period August 2008 through July 2009. This represents a 22.36% reduction in total cost of gas commodity from 2008.

Technical Adjustments - Deferred Accounts

Included in the Filing Guidelines are the assumptions[10] the utility must use in its general rate development as follows: forecasted therms must be used to develop rate increments associated with deferrals and amortizations; the manner in which revenue sensitive costs should be calculated and applied to deferral balances in rate development; and a requirement that revenue totals used in a summary tie directly to account balances. Staff agrees that Avista followed the Filing Guidelines in the development of rate increments associated with its deferral 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 the temporary increment currently in place, increasing revenues by $839,813.
- Addition of a new temporary increment of ($1,845,048) to the Company's deferred accounts as detailed in Table 8 below. The Commission previously authorized all of the deferred amounts subject to amortization.

Table 8: Avista Temporary Revenue Increments for 2009

Temporary Debit (Credit) Revenues	Amount
Commodity and Demand costs	($3,420,421)
Demand Side Management & Weatherization	$1,753,865
Intervenor Funding	$42,466
Subtotal	($1,624,090)
Large Customer Margin Deferral Schedule 496	($220,957)
Total	($1,845,048)

The net revenue effect of removing the current increment and adding the new temporary increment is a decrease of $1,005,234 on an annual basis. Staff has reviewed the Company's technical adjustments and determined that the proposed

[10] See PGA Filing Guidelines, Section III. 1.

amortizations are appropriate. The revised amortization increments in the amount of ($1,624,090) are incorporated into the Company's primary rate schedules. The revised amortization increment of $220,957 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 costs changes and PGA-related deferrals. The Commission then adopted OAR 860-022-0070, which formalized earnings review procedures.

By Order No. 08-504 (UM 1286), the Commission adopted new requirements related to purchased gas cost changes. The Order specifies, among other things, that:

1. An earnings review will be conducted each spring.
2. The fall earnings review is eliminated.
3. The 2009 earnings review will use the 2008 fiscal year results of operations (ROO) and the earnings thresholds in effect for that period, as allowed by the Commission for each LDC.
4. For subsequent years, the earnings threshold applied to each ROO will correspond to the sharing election made by the LDC the previous August, for The following PGA Year, as described in the Order.

The results of the 2009 spring earnings review were that Avista was not over-earning and no sharing should be included in the current PGA filing.

On October 23, 2008, Avista elected a sharing ratio of 90/10 for the 2008-2009 PGA period. This means that in the spring of 2010, an earnings review will be conducted of Avista's 2009 fiscal year results of operations. If the outcome of the review reveals that Avista is over-earning by more than 100 basis points return on equity, Avista must share 33 percent of the over-earnings with customers.

On July 20, 2009, Avista elected a 90/10 sharing for the 2009-2010 PGA period.

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.

Included in the PGA Filing Guidelines are definitions[11] to amplify the origin of the factors used to calculate the Three Percent Test. After review, Staff agrees that the factors used by Avista meet the definitions.

As Avista's 2009 proposed net amortization authorized under the statute is a credit of $1,845,048 which clearly falls within the ORS requirement, the reduction to rates should be implemented as proposed.

UM 1447

Included in the PGA Filing Guidelines are conditions[12] that essentially restate the requirements found in ORS 757.259 and OAR 860-027-0300 that specify what information must be included in an application to defer costs, or a request for reauthorization of an existing deferral. Avista met the requirements in its filing.

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 188 be approved; (2) the application for LSN be approved and the associated tariff sheets of Advice No. 09-06-G Supplemental be allowed to go into effect with service on November 1, 2009; and, (3) reauthorization to use deferred accounting pursuant to Schedule 461 as requested in UM 1447 be approved.

[11] See PGA Filing Guidelines, Section III. 3.
[12] See PGA Filing Guidelines, Section III. 4.

Attachment A

Avista Utilities
2009-2010 PGA Filing - Oregon: October Revised Filing
PGA Effects on Revenue

1	**Purchased Gas Cost Adjustment (PGA)**	**Amount**
2		
3	Commodity Cost Change	($28,245,561)
4		
5	Demand Capacity Cost Change	$1,343,659
6		
7	**Total Gas Cost Change**	($26,901,901)
8		
9	**Temporary Increments**	
10		
11	Amortization of Commodity and Demand Cost Differences *	($3,641,378)
12		
13	Amortization of Intervenor Funding - CUB & NWIGU	$42,466
14		
15	Amortization of DSM Accounts	$1,753,865
20		
21	Total Proposed Temporary Increments	($1,845,048)
22		
23	Removal of Current Temporary Increments	$839,813
24		
25	**Total Net Temporary Rate Adjustment**	($1,005,234)
26		
33		
34	**TOTAL OF ALL RATE CHANGE COMPONENTS**	**($27,907,136)**

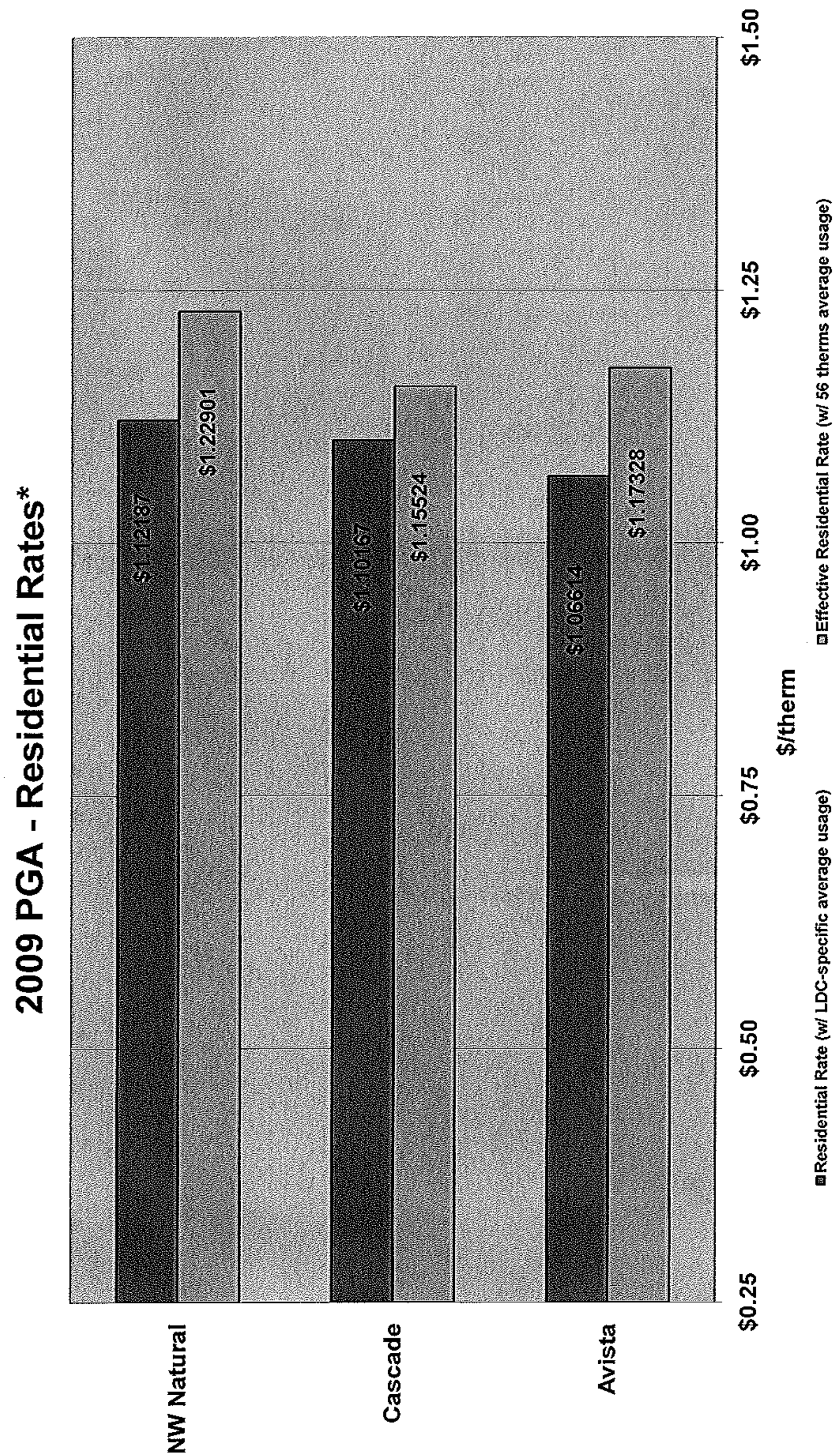
* Includes Large Customer Margin Deferral Amortization $220,957

Attachment B

Comparison of Proposed Rate and Bill Increases for Oregon Local Distribution Companies by Class of Service
(November 2009 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	$1.37365	$1.06614	-0.30751	-22.4%	104	$6.00	$148.86	$116.88	-$31.98	-21.5%	52	$6.00	$77.43	$61.44	-$15.99	-20.7%
Cascade	101	$1.27656	$1.10167	-0.17489	-13.7%	121	$3.00	$157.46	$136.30	-$21.16	-13.4%	56	$3.00	$74.49	$64.69	-$9.80	-13.2%
NW Natural	2	$1.39384	$1.12187	-0.27197	-19.5%	108	$6.00	$156.53	$127.16	-$29.37	-18.8%	55	$6.00	$82.66	$67.70	-$14.96	-18.1%
Commercial																	
Avista	420	$1.29272	$0.98875	-0.30397	-23.5%												
Cascade	104	$1.17591	$0.99653	-0.17938	-15.3%												
NW Natural	3	$1.28982	$1.00987	-0.27995	-21.7%												
Industrial																	
Avista	424	$1.18131	$0.87734	-0.30397	-25.7%												
Cascade	105	$1.15085	$0.93320	-0.21765	-18.9%												
NW Natural	31ISF	$1.00149	$0.70330	-0.29819	-29.8%												
Interruptible																	
Avista	440	$0.89041	$0.57713	-0.31328	-35.2%												
Cascade	170	$1.09689	$0.87753	-0.21936	-20.0%												
NW Natural	32ISI	$1.02147	$0.91948	-0.10199	-10.0%												

* The residential rates illustrated above do not include pass-through charges included on customer bills that utilities are required to collect and distribute to the appropriate third parties, such as for franchise fees or the Public Purposes Charge.



* The residential rates illustrated above do not include pass-through charges included on customer bills that utilities are required to collect and distribute to the appropriate third parties, such as for franchise fees or the Public Purposes Charge.

Attachment D

National and Regional Natural Gas Markets

At this time last year the headline was;

> Natural gas prices increased steadily from November 2007; peaking at just over $13/MMBtu at the Henry Hub spot market in June and on MYMEX 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 (PNW) prices (both spot and futures) followed this trend, with a basis differential generally between ($1.00) and ($1.50) per MMBtu; meaning prices in the PNW peaked at around $12/MMBtu, and fell quickly to near $7.00/MMBtu by September.

As they say, a single year can make a great deal of difference. During July and August the prices on the Henry Hub dropped to a 7-year low, at just under $3.00 for physical gas and well under $3.00 for futures gas for September delivery. Since July prices at the regional and national level have trended up, but only about $0.50. Compared to the prices this same time last year this represents a decrease of over 75%. There is no indication the price decline is finished. Many experienced producers and marketers expect national prices to be near or below $5.00 at least until the arrival of winter. In the PNW prices have fallen from near $12 to $5.00 or slightly higher. Prices in this range, and perhaps even near $3.00 in some instances are expected to continue in the PNW until winter.

The hedging the price range for the nation is presented in Table 1.

Table 1: 2009 PGA Year Hedging Range for US

High	Low
$5.60	$5.25

The hedging range for the PNW is presented in Table 2.

Table 2: 2009 PGA Year Hedging Range for PNW[1]

High	Low
$5.20	$4.85

[1] This does not include the impact of financial hedges and fixed price physical contracts from prior years. To the extent these exist, they will likely increase the level of the PGA WACOG. Also, the actual cost of an LDC's gas supply portfolio will depend on the size of the LDC, its overall retail and wholesale demand, and the particular mix of physical and financial deals made by the LDC in constructing its portfolio. Prudence is always an issue in this construction work.

Tables and 1 and 2 present the range of prices, on average, a commercial hedging party would be expected to incur over the period November 2008 through July 2009, for the PGA year November 1, 2009 through October 31, 2010.

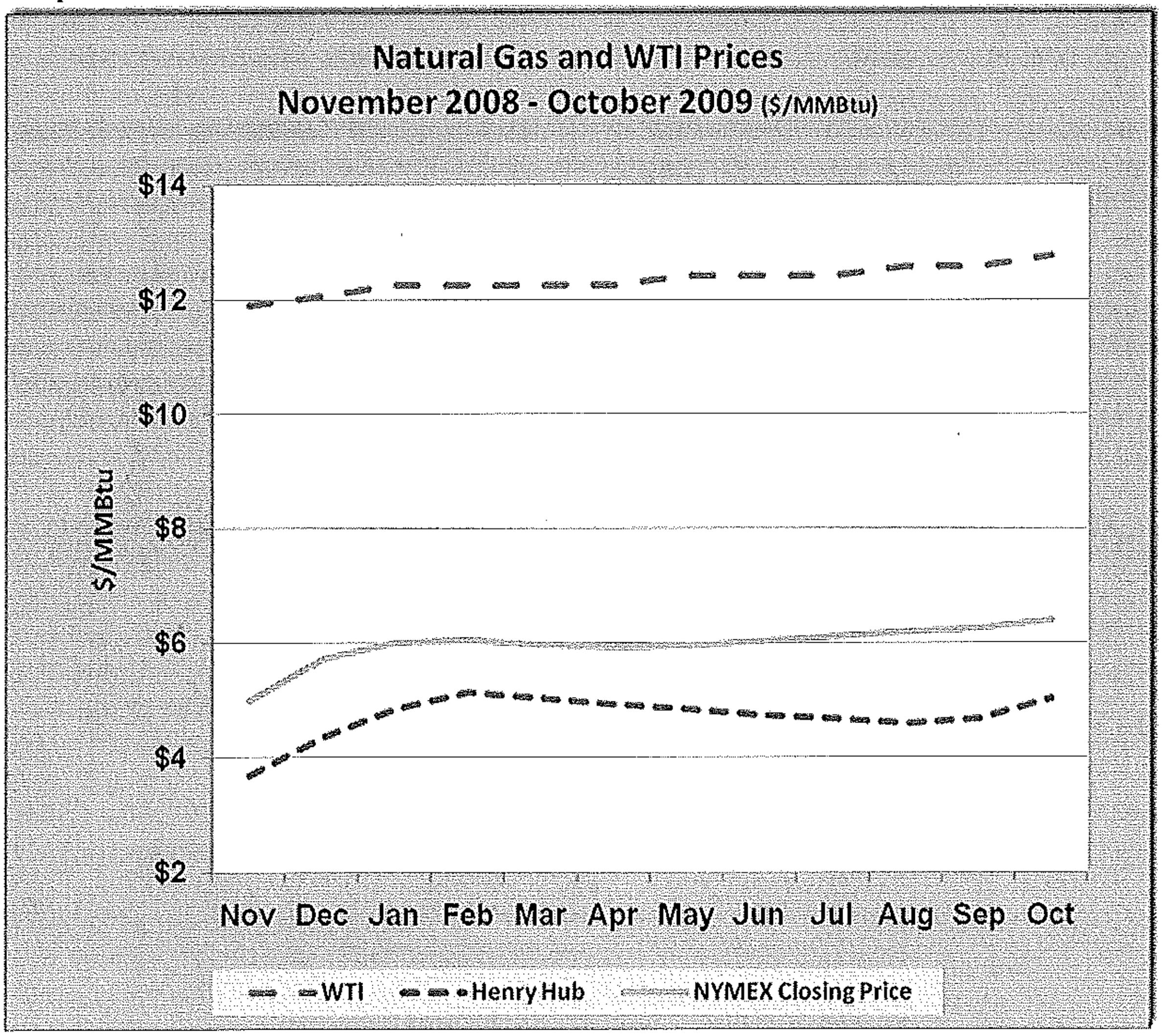
On the physical side the price paid for natural gas depends on when purchases were made and at what purchasing hub they were made. Table 3 presents a sample of physical natural gas prices during the period November 2008 through September 2009.

Table 3: Physical Natural Gas Prices

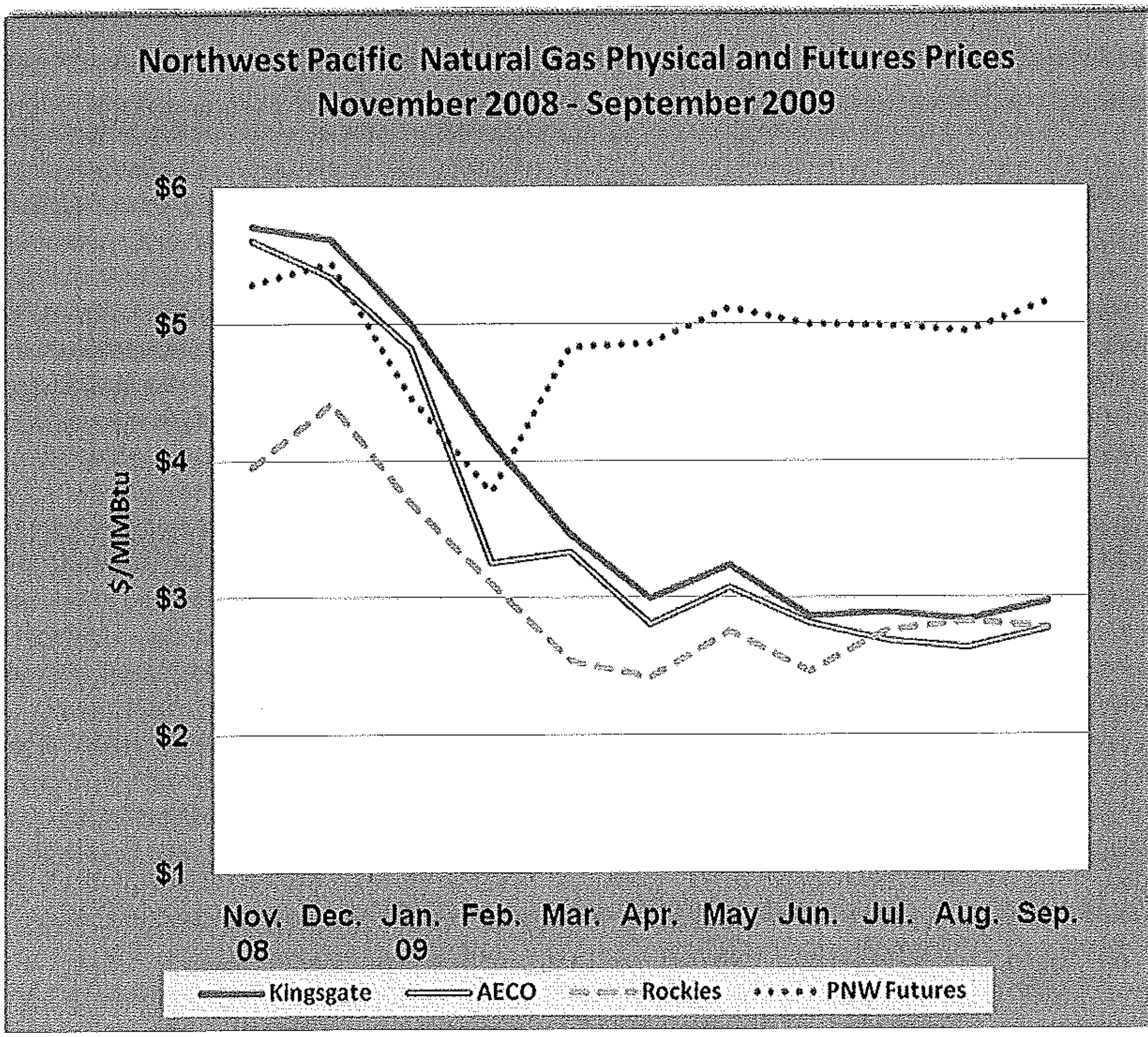
Physical Natural Gas Prices at Selected Hubs (Monthly Averages November 2008 – September 2009) $/Dth					
	Kingsgate	AECO	Sumas	Rockies	Henry Hub
Nov.	$5.71	$5.61	$5.79	$3.95	$6.62
Dec.	$5.61	$5.34	$6.91	$4.42	$5.79
Jan.	$5.00	$4.82	$5.24	$3.69	$5.27
Feb.	$4.14	$3.26	$4.39	$3.10	$4.62
Mar.	$3.46	$3.33	$3.55	$2.54	$3.96
Apr.	$2.99	$2.81	$2.98	$2.41	$3.51
May	$3.23	$3.07	$3.11	$2.75	$3.75
Jun.	$2.87	$2.82	$2.70	$2.47	$3.79
Jul.	$2.89	$2.69	$2.77	$2.76	$3.40
Aug.	$2.84	$2.63	$2.85	$2.82	$3.15
Sep.	$2.97	$2.77	$3.04	$2.78	$2.90

National and PNW prices for the November 2008 through October 2009 period are also shown in the graphs below.

Graph 1: Natural Gas and WTI Prices November 2008 – October 2009



Graph 2: PNW Natural Gas Physical and Futures Prices November 2008 – October 2009[2]



These prices are the result of several factors.

- Natural gas supply across the nation has increased significantly over the last year, both in terms of actual production and proved natural gas reserves. Production increased nearly 8% in 2008 over 2007 and is expected to remain flat for 2009. This is the case despite the fact that wells producing natural gas declined by nearly 50% from this time last year. The "culprits" in this situation are the number and productivity of shale gas wells and the inability (or

[2] PNW futures prices in this graph are not comparable to the NYMEX closing prices in Graph 1. PNW futures prices are the PGA-year strip price average for each month listed. I do not have access to monthly futures trading daily closing prices for the various PNW hubs and thus cannot compare these to daily closing NYMEX prices.

unwillingness) of many producers to shut-in production even in the face of the rapidly falling prices. This is certainly the case for gas production from the Rockies region, from which Oregon LDCs purchase supply. Prices for Canadian natural gas have fallen as well. The majority of gas purchased by Oregon LDCs is from Canada. Canada's National Energy Board (NEB) is now discussing how to respond to these dramatic declines in price. At the same time that production remained robust, the proved and estimated domestic natural gas reserves rose greatly. The Potential Gas Committee (PGC) estimates that the "... United States (US) possesses a total resource base of 1,836 trillion cubic feet (Tcf). This is the highest resource evaluation in the Committee's 44-year history. Most of the increase from the previous assessment arose from reevaluation of shale-gas plays in the Appalachian basin and in the Mid-Continent, Gulf Coast and Rocky Mountain areas." When the PGC's results are combined with the US Department of Energy's latest available determination of proved gas reserves, 238 Tcf as of year-end 2007, the United States has a total available *future supply* of 2,074 Tcf. This is an increase of 542 Tcf (35%) over the previous evaluation.

- At the same time that production and future available supply have increased, or at least not declined, demand for natural gas has dropped noticeably. The Energy Information Agency (EIA) projects total US natural gas consumption will decline by 2% in 2009 and by 0.2% in 2010. The 2010 projection by EIA may be optimistic. Despite some recent signs of economic stability, the severe contraction during the first half of the year contributed to an estimated 12.4% decline in daily average natural gas consumption compared with consumption during the first half of 2008. The decline in natural gas use during this period was driven principally by a drop in industrial activity, reflected in the 17-percent year-over-year decline in the natural-gas-weighted industrial production index during the first half of the year. A bright spot, of sorts, natural gas prices have declined to the point where they now compete against coal for a share of the baseload generation in the electric power sector. Consequently, natural gas consumption in the electric power sector has not declined and is expected to increase by 0.4% in 2009. Assuming improved economic conditions in 2010, demand in the residential, commercial, and industrial sectors may increase, if only slightly, next year. However, the expectation of higher natural gas prices and lower coal prices in 2010 likely will lead to a slight reduction in natural gas consumption in the electric power sector.

- The above two factors have lead to a glut of gas in storage. As of September 25, gas in storage was 3,589 Bcf (3.589 Tcf). This is 16% higher than the amount of gas in storage at this time last year, 3.098 Bcf. This amount is also 12% above the 5-year average for gas in storage at this time of the year of 3,108 Bcf. The total capacity of US storage in not accurately known but the current 3,589 Bcf is thought to be within 200 Bcf of that total capacity. This means that by the time, or even before winter arrives there may be no place to put gas that cannot be immediately sold and used.

- Weather often has an impact on natural gas supply, demand, and price. Over the last year, however, weather has been a non-factor. Winter 2008-2009 was overall mild, although slightly colder than normal at times in the PNW. Likewise, the summer of 2009 was mild overall but with distinct and isolated episodes of high temperatures, even in the PNW. Similarly, weather has had little impact on natural gas production. The Hurricane Season has thus far been uneventful, as have the Midwest and Southeast storm seasons. The Hurricane Season does not end until November 30, so there is still time for hurricanes to disrupt supply. However, with the huge reserves now in storage, it appears only a massive hurricane destroying most of the Gulf of Mexico (GOM) production infrastructure could have a noticeable impact on natural gas prices. Also, based on current forecasts, the likelihood is low of a major hurricane hitting the GOM, or anywhere else that might damage significant natural gas production areas or infrastructure.

- The claim is often made that the prices of natural gas and crude oil are linked at some ratio[3]. For the November 2008 through current period however, Graph 1 above clearly indicates that link was broken early in 2009. Perhaps the link will reestablish itself, but until that is actually the case, natural gas prices cannot depend on surging crude oil prices to bring them higher. Right now natural gas prices appear to have reached a bottom, if perhaps temporarily, at around $3.00 and are moving up.

- Also directly impacting natural gas prices are the actions of participants in the natural gas futures market at NYMEX and the Intercontinental Exchange (ICE). Currently the natural gas futures market is in contango. Contango is a term used in the futures market to describe an *upward* sloping forward curve. Or, in simpler terms, the future price of a commodity, e.g., natural gas is higher in out years than in the current year(s). Futures players, particularly arbitrageurs, are betting that short positions held today will pay off in the future so are willing to purchase large amounts of "futures" natural gas in anticipation of that future profit. This has a tendency to raise futures prices in the longer-term but not in the near term. This places an additional burden on commercial market participants (e.g., producers and gas utilities) since it increases the price risk of purchasing multi-year hedges to lock-in next year's of the year after that's natural gas price through the futures market. After all, if the future higher prices do not materialize, those trading ownership of futures contracts for natural gas only stand to lose money. The producer and

[3] Historically said to be 6:1 $/barrel compared to $/MMBtu.

gas utility may find itself in bankruptcy while also facing economic penalties from regulators.

- Another category of market and market participant is also impacting natural gas prices. This is pure market speculation.[4] Such speculators bounce back and forth among stocks, commodities, money markets, etc., all with the intent of finding the greatest return-on-investment. The maxim underlying the actions of speculators is leverage. With respect to natural gas, for example, a speculator could commit $6,000,000 to leverage as much as a $500 million payday. Admittedly such large returns are infrequent but smaller profits from this level of investment are quite common. For example, a $10,000,000 bet could generate $100 million in profit if the call at the basis of the bet was actually fulfilled. But the extreme price volatility of the natural gas market makes it more likely that only a $5 - $7 million profit will be realized. But to place this in perspective, the same market actor that made the $6 million bet has also often made other bets of varying sizes that are fluctuating both ways in terms of price. Speculators also take positions on price in certain deals as a way to seek influence over prices that benefit their positions in other deals. For example, U.S. Natural Gas Fund, an exchange-traded hedge fund listed as UNG on the NYSE, holds (between its futures contracts at NYMEX and over-the-counter (OTC) swaps) the equivalent of more than 50% of the October open interests. UNG's strategy has been thus far to roll over this position as the current prompt month ends. This means UNG could own or control more than 50% of open interests for the upcoming winter months. UNG's strategy leads to massive losses for the fund and continues to push down the price of natural gas. UNG's long-term goals are unknown but clearly at this juncture, its month-to-month strategy is controlling the market. In terms of volumes, UNG's position amounts to over a Tcf, about 5% of total annual US usage, or nearly 9% of US winter usage.

- Many new and alternative approaches for the use of natural gas have been proposed, including using compressed natural gas (CNG) as a transportation fuel for automobiles, buses, etc. It has also been proposed that the dispatch order of electric power plants be reversed so that gas-fired plants are dispatched ahead of coal. This would increase consumer prices slightly, but has the added advantage of reducing the carbon footprint of electric generation. On average, generating with natural gas produces about half the CO_2 emissions of generating with coal. It has also been proposed that if the US began exporting a large share of its huge natural gas surplus in the form of liquefied natural gas (LNG) this would have several substantial and world-wide impacts. These impacts include: stabilizing the US balance of

[4] LDCs participate in the natural gas futures market, for hedging purposes. However, no Oregon LDC participates in speculation in any market.

payments with China, reversing the US economic downturn, blunting the efforts of Russia to use its currently largest in the world natural gas production/reserves as a political weapon and aiding in the reduction of CO_2 emissions in developing countries. Exporting a portion of the US gas surplus would also raise domestic and world-wide prices for natural gas, thus stabilizing an industry now experiencing some significant cash-flow problems. This, in turn, would assist the many states and workers that depend heavily on natural gas production for their economic welfare. At a macroeconomic level, such exports could help stabilize US energy prices, thus providing a foundation for the control of both the "financialization"[5] of the US economy and the rebirth of US manufacturing and high technology. Internationally these exports could also afford the US time to stave off the hegemony of the "Beijing Consensus,"[6] or at least allow the US input into that new international economic consensus.

- Several factors are now beginning to have significant impact on the natural gas sector and may have even greater impact over the next several years.

  - Most of the large increase in natural gas production and estimates of proved reserves are the result of unconventional production. Unconventional production is coal bed methane (CBM), tight (tar) sands, and shale gas. Just over half of US production in total is now from unconventional plays. Shale gas is the leader in such production, with estimates of reserves as high as 600-700 Tcf[7] and production sites scattered across two thirds of the US and Canada. To produce shale natural gas, a technique call hydraulic fracturing ("fracing") is used. This requires large amounts of water and includes proprietary mixtures of chemicals. The technique itself has been around since World War II but has never been applied at the level and across this much of the continent. As a result, environmental concerns have arisen regarding both threats to the adequacy of exiting water supplies and the pollution of drinking water.

[5] Financialization refers to the increasing role of financial motives, financial markets, financial actors and financial institutions in the operation of the domestic and international economies. Also, financialization is the "...ascendancy of 'shareholder value' as a mode of corporate governance; ... the growing dominance of capital market financial systems over bank-based financial systems; ... the increasing political and economic power of a particular class grouping: the rentier class; ... the explosion of financial trading with a myriad of new financial instruments; and ... pattern of accumulation in which profit making occurs increasingly through financial channels rather than through trade and commodity production."

[6] China's emerging approach to international relations, trade, and economics. It emphasizes high speed and comprehensive innovation, constant improvements in sustainability and quality-of-life to allow control of the chaos created by constant innovation, and contains a theory of self-determination that stresses using leverage to move big, hegemonic powers (read: US, Russia) that may be tempted to tread on your toes. It has been gradually displacing the "Washington Consensus" that originated with the US in the early 1990s.

[7] Annual US natural gas usage is currently around 22-24 Tcf.

Fracing is regulated currently by the states and is explicitly exempted from regulation under the Safe Drinking Water Act (SDWA) by the Energy Policy Act of 2005. However, legislation has been introduced in the US Congress to have the EPA regulate fracing along with the states and to require that the chemicals mixes used be revealed to state and federal regulators. This proposal is opposed by natural gas producers as well by state regulators[8]. If enacted, EPA regulation of fracing will undoubtedly slow shale drilling and reduce shale production levels. No reliable estimate of the level of the slowdown or reduced production currently exists. But for the current dismal supply/demand/price balance for natural gas generally, this issue would have already impacted shale gas exploration and production, and perhaps even price. This is important for the PNW because much of the future gas production from the Rockies and Canada, on which the PNW depends for supplies, is likely to be from shale.

- The other issue now under consideration in the natural sector is proposals by the Commodity Futures Trading Commission CFTC) and Federal Energy Regulatory Commission (FERC) to tighten position limits on non-commercial energy commodity traders on NYMEX and the ICE, including natural gas traders.[9] This proposal also includes extending such limits to the OTC market by requiring these trades be cleared via a public exchange (NYMEX, ICE, and the Chicago Mercantile Exchange (CME)). This proposal is generating massive opposition, particularly from large investment banks. If enacted it would likely reduce price volatility in the futures markets. This would be beneficial for commercial participants in these markets such as producers and gas utilities. However, it would also reduce the potential for high profits by large traders such as investment banks.
- Finally, with market prices so far below production costs over an extended period of time, concerns about the current and future viability of many small and mid-size gas exploration and production (E&P) companies are not displaced. With cash reserves low and credit problems, many of these companies may not be able to survive until prices rise above production costs. A particular concern is that if these companies fail, only two market players have the financial strength to purchase them – speculators (e.g., investment banks and hedge funds) and large multi-national energy companies, including national energy companies from China, Russia, and the Middle East. Either such trajectory not only raises concerns about

[8] At it's just concluded summer meeting the National Association of Regulatory Utility Commissioners (NARUC) approved a resolution opposing federal regulation of fracing and supporting continued state regulation.

[9] NYMEX and ICE already instituted position and trading limits in early July. However, it is unlikely these will be sufficient in the eyes of the CFTC and FERC.

energy security but also about some level of monopoly control of natural gas and other energy prices.

- Aside from the factors described above some factors more directly impact PNW natural gas demand, supply, and price.
  - First, the number of trades and thus trading liquidity at the Sumas hub decreased significantly over the last year. Many marketers and purchasers have ceased doing business at Sumas. Soon Oregon LDCs may be forced to move their purchasing of physical gas and hedges away from the Sumas hub.
  - Northwest Natural Gas Co. CEO Gregg Kantor gave LNG only a 50-50 chance of LNG coming to Oregon. But he also reported that the company's joint venture (with PG&E) 20 Bcf underground gas storage project in Northern California, Gill Ranch, is progressing on schedule and should be operational by August next year. And at its existing Mist storage facility in Oregon, preliminary studies and plans continue for a 3 Bcf capacity addition. This is good news considering the need for additional storage in the west and storage that can be accessed by the PNW.
  - FERC staff issued the draft environmental impact statement (DEIS) for El Paso Corp.'s proposed Ruby Pipeline Project, which would be capable of transporting up to 1.5 million Dth/d of natural gas about 675 miles from the Rocky Mountains to the west coast. This puts Ruby well ahead of the other major pipeline proposed to move Rockies gas to the west coast, Sunstone. It's unlikely both will be built since there is not sufficient need for capacity at this time. Sunstone would bring the greatest direct benefit to Oregon natural gas users, but with the right arrangements, Ruby could also help Oregon gas users.
  - Canadian pipeline exports to the US dropped to all but one significant US destination during the first two months of the 2008-2009 contract year from the same period of 2007-2008. The slippage was 9% to 81 Bcf in shipments to California, 11.6% to 264 Bcf to the U.S. Midwest and 12% to 180 Bcf to the U.S. Northeast. The exception was the US Pacific Northwest, where Canadian shipments rose 5% to 91 Bcf. The big question is will this trend continue?
  - The NEB blamed the dramatic fall of Canadian natural gas and oil prices in the latter half of 2008 on the development of US unconventional resource plays. This created a supply glut, which added to the economic slowdown and reduced demand, according to the NEB.
  - A study funded by the Western Business Roundtable (WBR) raises the possibility that the Western Climate Initiative (WCI) outline for limiting greenhouse gas (GHG) emissions and implementing a cap-and-trade system could turn out to be counterproductive and actually harm -- not stimulate -- the economy. The WBR stressed as unrealistic three major

conclusions of the work by Management Information Services: (1) WCI's assumption of no new traditional baseload power generation in the next decade; (2) WCI's recommendation that almost all future electric demand growth be met by intermittent renewable power sources, and (3) the fact that internationally accepted measures indicate the WCI plan would result in "a virtually immeasurable reduction of future global temperatures" during the next century. The report was also extremely critical of the cap-and-trade mechanism the WCI proposes to use to control emissions. This approach would, says the report, "disadvantage" the West by limiting energy resources and "discouraging employment of new technologies" that are needed to grow a more low-carbon economy. The report does not mention expanded use of natural gas as a means to control emissions that is not considered by the WCI. But this is a role that has been proposed for natural gas.