ORDER NO. 06-609

ENTERED 10/26/06

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 174/UM 1275

In the Matters of NORTHWEST NATURAL GAS, dba NW NATURAL Request to: (a) revise rates for the effects of changes in purchased gas costs; (b) revise rates for the further effect of removing temporary rate adjustments incorporated into rates effective October 1, 2005; and (c) apply new temporary rate adjustments for inclusion in rates effective November 1, 2006. **(UG 174)** Application for Reauthorization of Deferred Accounting for the Purchased Gas Adjustment Mechanism. **(UM 1275)**	)	ORDER

DISPOSITION: APPLICATIONS APPROVED

On August 15, 2006, the Public Utility Commission of Oregon (Commission) received two applications from Northwest Natural Gas Company (NW Natural or company). 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 25, 2006, the Commission adopted Staff's recommendation to approve the applications.

ORDER

IT IS ORDERED that:

1. Waiver of statutory notice to allow the associated tariff sheets of Advice Nos. 06-13A and 06-13B to go into effect November 1, 2006, is approved.

2. Amortization of deferred accounts, base gas cost changes, and other rate changes as requested in Docket UG 174, is approved.

3. Reauthorization to use deferred accounting pursuant to Schedule P, as requested in UM 1275 for one year beginning November 1, 2006, is approved.

Made, entered and effective OCT 26 2006.

BY THE COMMISSION:

Becky L Beier

BECKY L. BEIER
Commission Secretary

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 25, 2006

REGULAR X **CONSENT** ____ **EFFECTIVE DATE** **November 1, 2006**

DATE: October 16, 2006

TO: Public Utility Commission

FROM: Ken Zimmerman, Lynn Kittilson and Ed Durrenberger

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

SUBJECT: NORTHWEST NATURAL: (Docket No. UG 174/Advice No. 06-13) Reflects changes in the cost of purchased gas and technical adjustments and makes adjustments to base rates for various programs. (Docket No. UM 1275) Requests reauthorization of the PGA deferral mechanism.

STAFF RECOMMENDATION:

We recommend the Commission approve Northwest Natural's (NW Natural, company or NWN) request to waive statutory notice (L.S.N.) and allow the company's proposed tariff sheets in Advice Nos. 06-13A and 06-13B to become effective with service on and after November 1, 2006. This filing increases the company's annual revenues for its Oregon operations by approximately $32.9 million, or 3.9%.

We also recommend the Commission approve the company's request for reauthorization to use deferred accounting pursuant to its Schedule P, Purchased Gas Cost Adjustments.

DISCUSSION:

On August 15, 2006, NW Natural submitted its annual gas cost tracking and technical adjustment filing, commonly known as its PGA filing. 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 adjustments and other deferred accounts. The filing has a requested effective date of November 1, 2006, and represents a permanent one month shift, from October 1 to November 1 in the PGA effective date. The filing is docketed UG 174/ Advice No. 06-13. It proposed an increase of $42.6 million, or about 5.1% in annual revenues for its Oregon operations for changes in purchased gas costs and certain temporary and permanent adjustments.

On October 5, 2006, the company made a substitute filing, Advice No. 06-13A, along with an L.S.N. application, to make updates to the company's initial calculations for the effects of changes in purchased gas costs. The net effect is a smaller proposed increase in the revenues for Oregon operations, now $32.9 million or about 3.9%. Consistent with Commission Order No. 06-570, entered October 2, 2006, the company proposes an effective date of November 1, 2006—a permanent one-month shift, from October 1 to November 1, in the effective dates of the annual PGA filing and deferral request.

On October 17, 2006, NW Natural filed replacement sheets for its Schedule P in Advice No. 06-13B.

UG 174

This application requests authority to increase rates to: (1) track increases in purchased gas costs, (2) adjust permanent base rates for certain approved programs, and (3) make technical adjustments to amortize NWN's deferred revenue and gas cost accounts. The change in annual revenue is summarized in the table below. Details on each line item are included in this Staff Report and in Attachment A.

PGA Base Gas Cost Increase	$39,119,998
Removal of Prior Year Temporary Debit Increment	(11,832,359)
Addition of New Temporary Debit Increment	3,064,959
Permanent Base Rate Adjustments	2,558,041
Total Proposed Increase	$32,910,639

With these changes, the monthly bill of a typical residential customer on Schedule No. 2 using 57 therms per month will increase by $2.78, or 3.5%, from $79.63 to $82.41. In January, a typical residential customer's consumption of 109 therms would result in a billing increase from $146.79 to $152.12.

A summary that compares the impact of this year's proposed PGA rate changes, on both an annual and January basis, for NW Natural, Avista and Cascade 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 60 therms plus the monthly customer charge, divided by 60 therms. The graph shows that NW Natural's residential customers have an effective rate of $1.44052 per therm, while Avista's and Cascade's effective rates are $1.53264 and $1.26082 respectively. The following table shows the rates the Commission has approved for NW Natural's residential customers on Rate Schedule No. 2 between 2002 and 2005, and the current proposal.

Date	Customer Charge	Rate per Therm	Percentage Change [1]
October 2002	$5.00	$0.87016	
September 2003 (UG 152)	$6.00	$0.87870	1.0%
October 2003	$6.00	$0.92213	4.9%
October 2004	$6.00	$1.10784	20.1%
October 2005	$6.00	$1.29167	16.6%
November 2006 [2] (Proposed)	$6.00	$1.34052	3.8%

NW Natural offers customer assistance programs. NW Natural also offers energy efficiency programs through Energy Trust of Oregon (ETO). 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, as well as on ETO's web site.

Staff Review of Gas Costs

National and Regional Natural Gas Markets

2005 was a very eventful year for natural gas in the US. Prices rose to unprecedented levels and price volatility was rampant. Soon after the turn of the year, however, many factors combined to tame this very dangerous market and thus reduce natural gas prices:

- The winter of 2005-2006 was generally mild; no great demand was placed on existing natural gas supply;
- The summer of 2006 was, apart from a few occasions on both coasts and in the Midwest, a mild summer in terms of the use of natural gas to generate electricity to meet cooling demand;
- No major supply interruptions have occurred to date; the hurricane season has been mild and uneventful;
- The prices of natural gas and oil have generally de-linked—rising oil prices are no longer carrying natural gas price along;

[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. In 2006, when the rate per therm is combined with the monthly customer charge of $6.00, the average customer's bill is increased 3.5%, as shown on Attachment B.
[2] The annual PGA effective date is permanently changed from October 1 to November 1 effective this year.

- Gas storage injections and inventory levels are at historic highs;
- The futures markets, including speculators and hedge funds traders, have generally not been able to promote any sustained increase in natural gas prices; futures prices across the country have consistently and generally declined, with particularly sharp declines in the West (e.g., Rockies);
- Demand destruction resulting from the hurricanes and higher prices of 2005 exceeded the supply lost because of the 2005 hurricanes;
- Domestic supply has remained steady, with no substantial decline—there has been a 300% increase in the number of wells drilling for domestic natural gas, helping domestic supply remain steady or even increase slightly;
- LNG imports, while not growing, remain poised to increase over the next several years; and
- The development of unconventional natural gas sources (e.g., coalbed methane, tight sands, deep-water) has expanded with significant events on both the technical and financial fronts.

Of course other potential factors may lead to increases in the price of natural gas. LNG imports into the US, while expanding, are not increasing at nearly the rate expected a few years ago. Plus, many other countries in the world are bidding for LNG supplies to help "fuel" their economic growth. Biggest among these are Japan, Korea, and several countries in Europe. 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. 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. Fourth, any large increase in either industrial production or the use of natural gas for electric generation could potentially lead to increases in the price of the resource. Fifth, any failure in the expected level or growth in the level of domestic natural gas production, either conventional or unconventional, could connect to an increase in price. Finally, the futures markets for natural gas, particularly the hedge funds involved in those markets, dominate both that market and the physical natural gas market in terms of money invested. With those futures markets not currently functioning in accordance with even the most expansive understanding of "market theory," the impacts of these markets on future natural gas prices cannot be understood and thus are impossible to forecast. Both market theory and government enforcement of market fundamentals will need to evolve to address this issue appropriately.

The US Department of Energy's Energy Information Agency (EIA) forecast of natural gas price at the Henry Hub has been declining since January. The next 12-months EIA forecast began the year at $9.81/MMBtu and steadily declined from that point. In its August 8, 2006 forecast, the EIA projected an average price for the next 12-months at the Henry Hub of $8.06/MMBtu and projected an average Henry Hub price for the winter season at the Henry Hub of $9.05/MMBtu. These forecasts translate to natural gas prices, for the hubs from which Oregon LDCs purchase, of less than $7.00/MMBtu for the PGA year and less than $8.00/MMBtu for the winter season. Of course, all Oregon LDCs lock-in the price of a portion of their natural gas supply portfolio well in advance of the 2006-2007 winter season, including multi-year fixed price financial contracts, and place natural gas into storage during the off-peak season 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.

Currently it seems the factors holding natural gas prices somewhat in check will control the futures and physical markets at least through the end of 2007. This should mean only slight increases over the next year from present prices and may even lead to some small price decreases in some parts of the US, including the Northwest.

The Appendix at the end of this document provides significant detail on the cash (spot) and futures prices of natural gas both nationally and regionally, as well as some discussion of futures pricing and gas supply, production and demand.

Natural Gas Purchasing Strategies

As Staff emphasized strongly in its PGA public meeting memos last year, and continues to emphasize strongly for its 2006 PGA memos,

> "[p]ortfolio theory 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. . . .The theory proposes 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. And the greater the risks of price change or supply availability, the greater the need to follow the diversity requirements of portfolio theory. . . .All portfolios should include each of the options in the table below, if available, to the extent possible

based on the set of physical, operational, and economic circumstances of the particular LDC."

No.	Portfolio Components
1	Base gas contracts
2	Seasonal contracts
3	Pricing in contracts – mix of fixed prices and index prices
4	Contract take provisions – flexible to allow daily nominations of less than 100% of MDDV[3] without penalty
5	Storage
6	Multiple suppliers for all contract types (more than six for each type if possible)
7	No single supplier with sufficient share to dominate gas supply
8	All gas contracts staggered in term
9	Load management, e.g., interruptible sales contracts, real time pricing sales contracts
10	Buy back contracts
11	Energy conservation, e.g., weatherization
12	Financial hedges, e.g., options, swaps, staggered in timing

The current decline in natural gas prices does not lessen but rather increases the importance of adhering strictly to portfolio purchasing. With prices declining there may be a temptation to deviate from such purchasing in favor of purchasing as much as possible at current low prices. Deviating from portfolio purchasing places the LDC into the position of speculating—guessing the direction of prices for natural gas in the future. Since it is impossible to consistently forecast accurately future natural gas prices, portfolio purchasing is the most effective means currently available to mitigate the impacts on both customers and the LDC of price movement of whatever size and whatever direction. For just as surely as natural gas prices can decline sharply, as they have in the past six months, they can also, and just as quickly, increase sharply. It is important that LDCs understand and apply portfolio practices in their gas purchasing. LDCs need to commit to expand these practices not only to include additional portfolio components but also to include more sophisticated means to evaluate portfolios.

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 year, and will be further discussed in a formal investigation (a request for a Commission investigation into the PGA Mechanism will be made before the end of the year) to be conducted in 2007.

[3] MDDV is Maximum Daily Delivery Volume and represents the company's maximum daily responsibility to a customer.

1. In specific practice, portfolio purchasing means the LDC <u>must</u> 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. Staff's public meeting memo last year and ensuing discussion with the three LDCs all indicated that a balanced approach was needed. For the 2006 PGA, NW Natural moderated its pre-PGA level of financial hedging to a more reasonable level. As prices declined, NW Natural was able to take advantage of these lower prices on behalf of its Oregon customers, precipitating a re-filing nearly two months after the company's original PGA filing (more detail on this filing later in this memo).

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 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.

NW Natural's Natural Gas Purchasing Strategies

In its 2006 PGA filing NW Natural proposes the following natural gas supply portfolio:

Firm natural gas contracts for the entire year, winter season, or some other portion of the PGA year financially hedged to fix the price (as of the time of the PGA filing)	46.68%
Storage	13.78%
Short-term and peaking natural gas purchased at index price (unhedged)	27.26%
Firm, not financially hedged	12.28%

NW Natural may during the remainder of the PGA year enter into additional financial hedges for a portion of its natural gas supply. However, it is Staff's recommendation that the final level of financial hedging for NW Natural should not exceed about 70%.

In Staff's view, NW Natural's portfolio for 2005-2006 was consistent with its portfolio for 2003-2004, in that a higher level of natural gas supply was financially hedged, but not with years prior to 2003-2004 in which a maximum of about 66% of gas supplies were hedged. This is demonstrated in the table at the top of the next page taken from the "**Public Utility Commission of Oregon Natural Gas Procurement Study**" published in 2005. During the period between 1999 and 2003, NW Natural generally hedged financially about 40%-50% of its supply requirement, with 2000-2001 being the exception at 66%. In 2003-2004 the percentage of natural gas supply financially hedged jumped to about 82% and remained near this level for 2005-2006. With its current PGA filing NW Natural has returned to the pre-2003 hedging pattern. At the same time the company appears to have reduced its use of fixed price contracts and, more importantly, substantially increased the level of natural gas it plans to purchase at index (unhedged short-term supply or firm supply at index prices) prices. These are appropriate developments for an LDC the size of NW Natural, operating in the context of the current Northwest and US natural gas markets. Between financially hedging and storage, NW Natural has, as of the time of the filing, fixed the price of about 60% of its gas supply.

Table E.3. NW Natural Natural Gas Purchases, PGA Years 1999/2000 through 2003/2004 (percent of total).

Strategy	99/00	00/01	01/02	02/03	03/04
Without Hedge	7.0	9.3	7.2	4.5	1.7
With Hedge[4]	41.9	66.1	49.5	54.7	82.2
Fixed Price[5]	31.1	8.2	30.2	27.0	3.3
Storage	20.0	16.4	13.1	13.9	12.8
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

The level of financial hedging by an LDC should reflect the levels of price and operational risk facing the LDC. As those levels increase then financial hedging should increase also to help mitigate these risks. Severe levels of risk for an LDC are the result of extreme limitations in purchasing, transportation, and/or pricing options. The extreme case is an LDC that can purchase from only one supply source, transport on only one pipeline (or even more limiting only one segment of one pipeline), has no or very limited access to storage, and has few or even no competitive options in the pricing for gas supply. Such an LDC should attempt to financially hedge all of its gas supply. LDCs facing fewer limitations should accordingly limit financial hedging to a level that directly reflects the level of limitations, and thus risk, they face. NW Natural's situation is clearly not the extreme. NW Natural has access to multiple supply and pricing points, including a large group of potential counter parties for financial hedging, is not limited severely in transportation options, and has access to a reasonable level of storage, considering the size of the company. While NW Natural's annual demand curve clearly indicates the largest peak is in winter, the company also has a reasonable year round (base load) demand. The result is an average level of limitations and thus risk, for an LDC the size of NW Natural. These circumstances, Staff believes, justifies financial hedging by NW Natural at a level of up to about 70% of the volumes required for the PGA year. Staff also expects that NW Natural will not enter into additional financial hedges if market intelligence and reliable fundamentals forecasts indicate purchasing gas at index price in either the day or month market is a lower-cost option.

According to NW Natural, however, there has been no change in its hedging pattern. NW Natural views financial and physical fixed price contracting as equivalent in terms of mitigating price risk and virtually identical in terms of operational risk. The company's overall strategy is to hedge (financially and physically) between 50% and 100% of

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[4] Price with a supplier is tied to an index, but a financial transaction (swap or option) with a separate counterparty fixes the price.
[5] Price was fixed with a supplier for some period of time.

required volumes, depending on market and operational circumstances. Storage is treated as an additional physical hedge. This pattern is seen over the entire period from 1999 to 2004, with NW Natural hedging financially and physically between about 70% and 85% of its gas supply needs. For the 2005 PGA this level was just over 90%.

Staff has concerns about and does not agree with NW Natural's hedging strategy, particularly the potential that 100% of required volumes might be hedged in a combination of financial and physical hedges. While there may be specific circumstances where financial hedging above 70% might be appropriate for a specific company, Staff does not believe that it is ever prudent to financially hedge at 100%. This topic will be discussed and examined more fully in upcoming workshops.

The prices contained within NW Natural's PGA filing are reasonable. NW Natural's overall hedge price is approximately $8.18/Dth, well within the range of futures pricing available during the first 8 months of 2006. Staff is concerned that NW Natural's forecast of spot prices for the coming PGA year is too high. That forecast could be applied to up to almost 28% of NW Natural's total gas requirements. The average spot price NW Natural initially forecasted over the PGA year is about $8.24/Dth. This is noticeably higher than the price being forecast by government and private fundamentals forecasters, primarily because it is based on a NYMEX strip of prices that include a risk premium currently estimated at approximately $2.00/Dth.[6] Spot price forecasts may certainly incorporate NYMEX pricing signals, but in addition should incorporate several reputable forecasts of spot prices, supply, and demand from government and private fundamentals natural gas forecasts. However, NW Natural explained, and provided data and calculations to support its explanation, that a 60-day NYMEX strip[7] of prices is a reasonable forecast of spot prices based on futures prices is preferable in its opinion and better fits the needs of its system and gas requirements. After meetings with Staff and a review of then current futures prices, however, NW Natural updated and thereby lowered the forecast to $7.23/Dth. This price is well within the forecast range of the best fundamentals forecasts. NW Natural has also agreed to integrate fundamentals forecasting into its forecasting of spot natural gas prices. Staff has scheduled this topic for consideration during the upcoming PGA workshops.

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[6] Mark Bolinger Ryan Wiser. *Comparison of AEO 2006 Natural Gas Price Forecast to NYMEX Futures Prices*, Lawrence Berkeley Laboratory, 2004 and 2005.
Paul M. Corby. "Why Hedging is Needed in the Current Natural Gas Market." 2006 Presentation to NARUC's Natural Gas Subcommittee.
Bagher Modjtahedi and Nahid Movassagh. "Natural Gas Futures: Bias Predictive Performance and the Theory of Storage." *Energy Economics*, 27 (2005) 617-637.
Mark N. Cooper. The Role Supply, Demand, and Financial Commodity Markets in the Natural Gas Price Spiral. Consumer Federation of America, 2006.
[7] Adjusted for the Northwest basis difference.

In its 2005 PGA memo for NW Natural, Staff recommended the company institute,

> . . . a fuller and more robust application of portfolio methods will be required to effectively address the trends in current natural gas markets toward higher and more volatile prices, and fewer options for LDCs to mitigate these trends.

Staff continues to support this recommendation.

Also in that 2005 memo, Staff recommended that NW Natural incorporate the following suggestions for future natural gas purchases:

1. NW Natural's use of pricing formulae in supply contracts is limited. If possible, NW Natural should look to add more and more flexible pricing options to its supply contracts (e.g., index changes, flexible MDDV, flexible nominations, weather derivatives).
2. Expand bidding (e.g., combination supply/transport, bid for hedges, direct comparison of bidding options).
3. Look into purchase partnerships with other LDCs or industrial customers.
4. NW Natural should analyze the following possible additional gas supply portfolio components:
   a. More volumes purchased through contracts of 5 years or longer (a workable option for an LDC the size of NW Natural)
   b. Direct LNG contracting
   c. Physical fixed price contracting
   d. Direct contracting for unconventional gas supplies
5. Improve coordination of energy efficiency programs, demand-response, buy-back contracts, and gas purchasing, to fine tune how the options might work together and get the maximum benefit in terms of customer cost.

Staff also recommends that NW Natural more rigorously apply portfolio methods through mathematical testing (statistical) of varied portfolios.

Staff continues to support these recommendations and urges NW Natural to pursue them diligently.

NW Natural's Natural Gas Costs

In its 2005 PGA public meeting memo for NW Natural, Staff noted that due to the uncertain future of natural gas prices and price volatility,

> . . . the changes proposed for NW Natural's purchasing process should help control its future cost of gas, thus limiting future increases and rate shock. NW Natural clearly understands the details of portfolio methods as applied to natural gas portfolio construction. NW Natural should perform more work on mathematical analysis of future portfolio, particularly in assessing the risk-cost trade-offs. As the largest of the LDCs, NW Natural should both lead in analysis and set an example for others to follow (within the limits of their particular load and circumstances).

Staff continues to support these recommendations.

For the time during which NW Natural purchased gas for the period November 2006 through October 2007, the average cash (spot) price in the Northwest was approximately $5.80/MMBtu, with prices declining through almost the entire period. The NYMEX price closed the period (September 2006) at about $8.80 ($8.00)/MMBtu for the PGA year,[8] with prices also declining over most of the period since January 2006. The 2006-2007 winter NYMEX strip ended the period at about $9.50 ($8.70), but ranged between $11.00 ($10.20) and $9.40 ($8.60) per MMBtu for the winter months of 2006-2007.

For the current PGA, NW Natural proposes to pass through to its sales customers a weighted average cost of gas (WACOG) of $0.73637/therm ($7.36/dekatherm (MMBtu)), based on normalized purchase volumes. NW Natural calculates a revenue-sensitive rate per therm of $0.75951 ($7.60/dekatherm (MMBtu)). When fixed delivery costs are added the WACOGs are $0.86373 ($8.64/Dth) and $0.89087 (8.91/Dth) revenue-sensitized. This pass through proposal is reasonable based upon the portfolio proposed by NW Natural, the market prices during the period in which NW Natural entered into financial hedges, and the spot price forecasted by NW Natural.

Three items about NW Natural's PGA filing require further explanation. First, as noted above in the discussion of NW Natural's natural gas purchasing strategies, it is Staff's recommendation that the total level of financial hedging by NW Natural should not exceed 60% of the volumes required for the current PGA year. For larger LDCs, such as NW Natural, with access to substantial storage and to multiple mainline transportation pipelines, with significant access to multiple gas markets, and with ongoing successful demand-side management programs, maintaining significant flexibility to purchase natural gas under several options is important. If NW Natural were to financially hedge 60% of its total volumes required for the 2006 PGA year and

[8] Prices in parentheses are estimated Northwest prices based on an average basis difference from national price of ($0.80). See additional discussion of basis pricing in the Appendix.

available storage volumes are added to this level, the total is about 74% of gas supply. In other words, these two options allow NW Natural to fix the price for up to 74% of its required gas supply for the PGA year. Leaving the remaining 26% open to short-term index pricing is appropriate for an LDC such as NW Natural.

Second, also as noted earlier, it is Staff's conclusion that the initial level of future spot natural prices forecasted by NW Natural, and especially the methodology upon which that level is based, is not appropriate. Even with the reduction in the spot price forecast made by NW Natural, the methodology remains a concern. If NW Natural financially hedges 60% of its PGA volume needs as suggested by Staff, leaving about 26% open to current index (spot) pricing, the reasonableness of the spot price forecast methodology and the results of its application are important. And to the extent NW Natural leaves a larger percentage of its gas supply open to index pricing, the creation of a reasonable spot price forecast becomes even more important. Spot price forecasts must integrate market intelligence with the results of reputable fundamentals forecasting that best fits the size and circumstances of the LDC. Generally this is done mathematically. NW Natural has rather chosen to use a 60-day NYMEX strip of prices as its spot price forecast. The company has not yet developed a process to integrate mathematically market intelligence and fundamentals forecasting results in forecasting spot natural gas prices. The Company needs to work toward this integration. However, NW Natural does seem to have given reasonable consideration to fundamentals forecasts of natural gas price, supply, and demand in its strategic planning and decisions regarding the design of its gas supply portfolio. These topics will be fully investigated in the upcoming PGA workshops, with the intent of developing criteria all LDCs can adhere to when forecasting spot natural gas prices for their PGA and IRP filings.

Finally, since 2001 NW Natural has been making what it calls a "storage inventory adjustment." This adjustment is intended to recover/return in the subsequent year all commodity costs for storage injections done after the PGA for the prior year has been approved by the Commission. For the 2006 PGA filing this adjustment added approximately $20 million to the total natural gas costs for NW Natural. Staff has removed this adjustment from the WACOG for 2006-07 because it is not part of NW Natural's cost of natural gas on a prospective basis. This amount has instead been correctly accounted for in this PGA filing as a commodity deferral to be amortized over one year, and is included in the company's temporary increments. Staff and the company have agreed to account for the storage cost difference in this manner through the 2006-07 PGA year, and will reassess the appropriateness of this accounting prior to the company's 2007 PGA filing. In addition, the company has agreed to an independent review of its storage operations by qualified storage experts to be completed prior to June 30, 2007.

At the end of June 2006 both interstate pipelines that NW Natural transports on filed general rate cases at the Federal Energy Regulatory Commission (FERC). Northwest Pipeline (NWPL) requests a rate increase of about $119 million, mostly related to rate base additions and an increase in its rate of return. Gas Transmission Northwest's (GTN) filing would nearly double its current rate for firm transportation. GTN also requests market-based rates for full haul interruptible transportation and a sharing of costs for turned back capacity. It has been over ten years since either company filed a general rate case at the FERC. The LDCs and Staff have agreed to place the full rate increase requested by both pipelines into the filed PGAs, subject to refund based on the actual rates finally approved by the FERC. For this reason, Staff has not analyzed the transportation portion of the increase in NW Natural's PGA filing except to ensure the increase fairly reflects the rates proposed by the two interstate pipelines.

The overall natural gas cost related increase in revenues proposed by NW Natural is $39,119,998. The overall increase in rates due to both natural gas commodity and transportation increases in cost is about 4.68%.

Technical Adjustments - Deferred Accounts

NW Natural'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 debit increments currently in place, decreasing revenues by $11,832,359.
- Addition of new temporary increments to the company's deferred revenue and gas cost accounts as detailed below. The Commission previously authorized all of the deferred amounts subject to amortization.

Temporary Debit (Credit) Increments	Amount
Commodity costs	($14,339,626)
Firm and Interruptible demand costs	($740,403)
Residential and Commercial Decoupling	($2,274,390)
Demand Side Management & Weatherization	($169,623)
Intervenor Funding	$46,394
Storage Inventory Adjustment	$20,525,025
Coos County Revenue Deferral	$17,582
Total	$3,064,959

Staff has reviewed the company's technical adjustments and determined that the proposed amortizations are appropriate. The revised amortization increments are incorporated in the energy charge component of the company's primary rate schedules. The net revenue effect of adding the new temporary increments and removing the current increments is a decrease of $8,767,400 on an annual basis.

Other Base Rate Adjustments

Bare Steel Replacement Program: Commencing in 2002 and continuing until 2021, NW Natural is removing bare steel pipe from its distribution system on an accelerated schedule. Bare steel pipe is leaky and requires higher levels of cathodic protection. The company has authorization to invest an incremental $3 million in accelerated bare steel replacement above a base level of investment of $3 million under this program. At the time of the annual PGA, the company is allowed to include in rates the cost of service associated with accelerated bare steel replacement for the preceding 12 months. This rate treatment for accelerated bare steel replacement costs is subject to an annual limit of $6 million beyond which the company must gain approval for treatment under the program. Staff last audited this program in April 2006. For the year starting November 1, 2006, $1,944,000 is proposed to be collected in rates for the accelerated Bare Steel Replacement project, a decrease of $242,000 over the previous year.

Geo-hazard Repair and Risk Mitigation: Commencing in 2002 and continuing until 2006, NW Natural is repairing and mitigating landslide hot spots, erosion and other geo-hazards. Staff last audited this program in April 2006. The costs in this filing are consistent with the findings of the audit. The rate impact of the revenue requirement for this program is an increase of $426,000 over the $360,000 currently in rates. From November 1, 2006 to October 31, 2007, a total of $786,000 will be collected. In addition, the company requested an extension of this program, until September 30, 2007, to complete a specific project, the Salmon River geo-hazard project. The Commission allowed the extension in Order No. 06-554, entered September 26, 2006.

Integrity Management Program: This new base rate increment applies adjustments to permanent rates related to investments in inspection and subsequent repair to transmission pipelines within the company's system as prescribed by the Office of Pipeline Safety in their "IMP Rule" and in Commission Order 04-390. Program costs were audited in April 2006; adjustments were recommended by Staff and verified to have been made by the company. For the period from November 1, 2006 to October 31, 2007, a base rate increment is requested to collect $1,861,000 for this program.

Coos County Distribution System: The Coos County Distribution system was placed in service at the end of October 2004. This project brought one of the nation's largest remaining population centers not previously served with natural gas into the NW Natural gas distribution system. A temporary increment of $17,582 is proposed to collect the unrecovered revenue requirement on the investment. In addition this filing includes a permanent base rate credit, funded by the company as authorized in Order 03-236, which will reduce rates by $123,563 from November 1, 2006 to October 31, 2007.

Price Elasticity Adjustment: This adjustment, included at the time of price changes in the company's PGA filings each year since 2002, accounts for the effect that rate changes have on customer usage. Permanent rates will be adjusted to collect $1,171,604 from November 1, 2006 through October 31, 2007.

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 requires an annual spring earnings review in lieu of an earnings review related to prospective purchased gas cost changes. In addition, Section (8) of the rule states that an earnings review is not applicable to amortization of deferred gas costs if the LDC assumes at least 33% of the responsibility for commodity cost differences in the risk sharing mechanism. NW Natural's mechanism includes a 33% sharing level, so amortization of deferred gas costs in this PGA filing are exempt from an earnings review.

ORS 757.259(6) and (7) states 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 proceeding calendar year, unless the Commission finds that allowing a higher amortization rate is reasonable under the circumstances. NW Natural's proposed amortizations are $3.06 million, well below the three percent threshold of $27.02 million and may be implemented as proposed.

UM 1275

In this filing, NW Natural requests reauthorization of deferrals pursuant to its automatic adjustment clause, the Purchased Gas Adjustment (PGA) mechanism. The information contained in the application is consistent with the requirements of ORS 757.259, 757.210 and OAR 860-027-0300. The 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. Consistent with Commission Order No. 06-570, entered October 2, 2006, the company will not compute interest on the deferrals accrued for the period November 1, 2006 through October 31, 2007, until amortization begins November 1, 2007.

PROPOSED COMMISSION MOTION:

NW Natural's request for: 1) a waiver of statutory notice to allow the associated tariff sheets of Advice Nos. 06-13A and 06-13B to go into effect November 1, 2006; 2) amortization of deferred accounts, base gas cost changes, and other rate changes as requested in Docket UG 174; and 3) reauthorization to use deferred accounting pursuant to Schedule P, as requested in UM 1275 for one year beginning November 1, 2006, be approved.

Attachments

NW Natural 2006 PGA

APPENDIX

This Appendix contains figures, charts and narrative referred to in the main text of the Staff Report. It is an integral part of Staff's report and is included here to provide detail not specific to NW Natural's filing, but rather details of national and regional natural gas prices and markets, and information and data that apply to all three Oregon LDCs.

Current Cash (Spot) Price of Natural Gas

National. Price at the Henry Hub has declined significantly since December 2005. Prices at the Henry Hub ranged from $13 to about $10 during the final quarter of 2005. Cash prices have declined since that point. The price hovered near and actually dropped below $6.00 during the spring and summer of 2006 and was approximately $7.00 for August, before dropping below $5.00 during September. The price is forecasted to increase as winter approaches but is not expected to exceed $9.00, on average, for the winter season. This history is depicted in Table 4 and Figure 2, found on pages 6 and 7 of this Appendix, respectively. A snapshot of the changes in price for cash (spot) natural gas is presented in Table 1.

Table 1 - Henry Hub Prices

Month	$/Dth (MMBtu)
October 2005	$13.71
November	$10.28
December	$12.99
January 2006	$8.76
February	$7.62
March	$6.88
April	$7.10
May	$6.23
June	$6.26
July	$6.05
August	$7.24
September	$4.95
October (as of October 9, 2006)	$4.19
AVERAGE (October 2005 – September 2006)	**$8.17**

Northwest Basis Difference. As it applies to the cash (spot) market for natural gas, basis is the difference between the national cash price (at the Henry Hub) and the cash price, for the time, place and quality where delivery actually occurs.

The cash price for natural gas in the Northwest US is directly influenced by the price at the Henry Hub, as this price reflects both domestic and world worldwide supply and demand factors. However, while Northwest US natural gas prices are heavily influenced by the Henry Hub prices, rising and falling generally in unison, they are seldom identical to the Henry Hub price. There is usually a difference in actual prices between the two market areas due to local variations in circumstances. This difference between the cash prices at the Henry Hub and the cash price at the Northwest hubs is called the basis. This basis reflects the supply and demand situation in the Northwest US market area and changes as local conditions change. Historically, the basis difference between the Henry Hub price and the price at the Northwest hubs has been negative, as the Northwest US does not utilize natural gas to the extent or frequency of much of the remainder of the country and has a large hydroelectric resource to rely on for a significant portion of its electric needs.

Average basis differential for 2006, through August, is negative $1.08/MMBtu. The differential in 2006 has varied, however between negative $0.75/MMBtu (February) and negative $1.39/MMBtu (April) through August. If, as Staff expects, natural gas prices across the country stabilize and perhaps even decline slightly from today's prices over the next year the Northwest differential is likely to decline, but remain negative.

Regional (various major trading hubs). As with the Henry Hub price, the prices at western and northwestern natural gas hubs have steadily declined since the beginning of the year, with only a modest up turn in August. The decline continues in September. This trend is clearly visible in Figure 2, with the actual average prices by month at most major western and northwestern hubs presented in Table 4. Most of the natural gas purchased by Oregon LDCs is purchased at the AECO, Sumas, and Rockies hubs. AECO's prices began the year at $7.48/MMBtu, declined to $5.10/MMBtu by July, before moving up slightly to $5.88/MMBtu in August. However, in September the price has declined to less than $4.50/MMBtu. The average price at AECO for the year through August is $5.85/MMBtu. Similar patterns are found at the Sumas and Rockies hubs. Sumas began the year at $7.71/MMBtu, moved up slightly in August to $6.13/MMBtu, before declining to less than $5.00/MMBtu in September. The average price at Sumas for the year through August is $5.61/MMBtu. The Rockies hub began in January at $7.30/MMBtu, turned up slightly in August to $6.02/MMBtu and declined in September to just over $3.50/MMBtu. The average price at the Rockies for the year through August is $4.99/MMBtu.

<u>Futures Price</u>

Like physical prices, the prices for natural gas futures on NYMEX have declined since last year's PGA filing, although not so much as the declines in physical prices. The history of these changes is depicted in Table 2 at the top of the next page.

Table 2 - Change in Futures Prices (NYMEX)

Month	October 2004	August 11, 2005	August 31, 2006
October 2005	$7.00	$11.00	
November	$7.00	$10.90	
December	$7.50	$11.70	
January 2006	$7.60	$10.90	
February	$7.60	$11.90	
March	$7.40	$10.60	
April	$6.25	$8.50	
May	$6.20	$8.20	
June	$6.10	$8.50	
July	$6.00	$8.60	
August	$6.10	$8.65	
September	$6.05	$8.60	
October			$6.05
November			$8.23
December			$9.98
January 2007			$10.63
February			$10.66
March			$10.48
April			$8.34
May			$8.19
June			$8.28
July			$8.39
August			$8.48
September			$8.57
October			$8.73
November			$9.70
AVERAGES	$6.73	$9.84	$8.91

The current basis difference between the futures at the Henry Hub and the futures prices in the Northwest is approximately $0.80 per Dth. When this difference is applied to the above NYMEX futures for the upcoming months the results are shown in Table 3.

Table 3 - Change in Futures Prices (Northwest)

Month	August 31, 2006
October	$5.25
November	$7.43
December	$9.18
January 2007	$9.83
February	$9.86
March	$9.68
April	$7.54
May	$7.39
June	$7.48
July	$7.59

Month	August 31, 2006
August	$7.68
September	$7.77
October	$7.93
November	$8.90
AVERAGES	$8.11

<u>Gas Supply, Production, and Demand</u>

In the early part of 2006, the EIA produced the data found in Figure 1 regarding expected US natural gas demand and supply. This data is still largely valid, as changes in expected demand have largely been offset by changes in domestic production, primarily in new onshore production in such places as Texas, the Rockies, and in deepwater offshore production. Imports from Canada are expected to decline, but it is expected that LNG imports will more than make-up for this loss. One of the main points of the Figure remains true—the US cannot now and is unlikely for the future to be able to meet its natural gas demand with domestic supplies alone. Conservation (designed or brought about by price) and weather (e.g., hurricanes, very cold winter) are primary factors in changing the supply-demand balance shown in Figure 1 below.

Figure 1 - EIA's Estimate of Expected US Natural Gas Demand and Supply

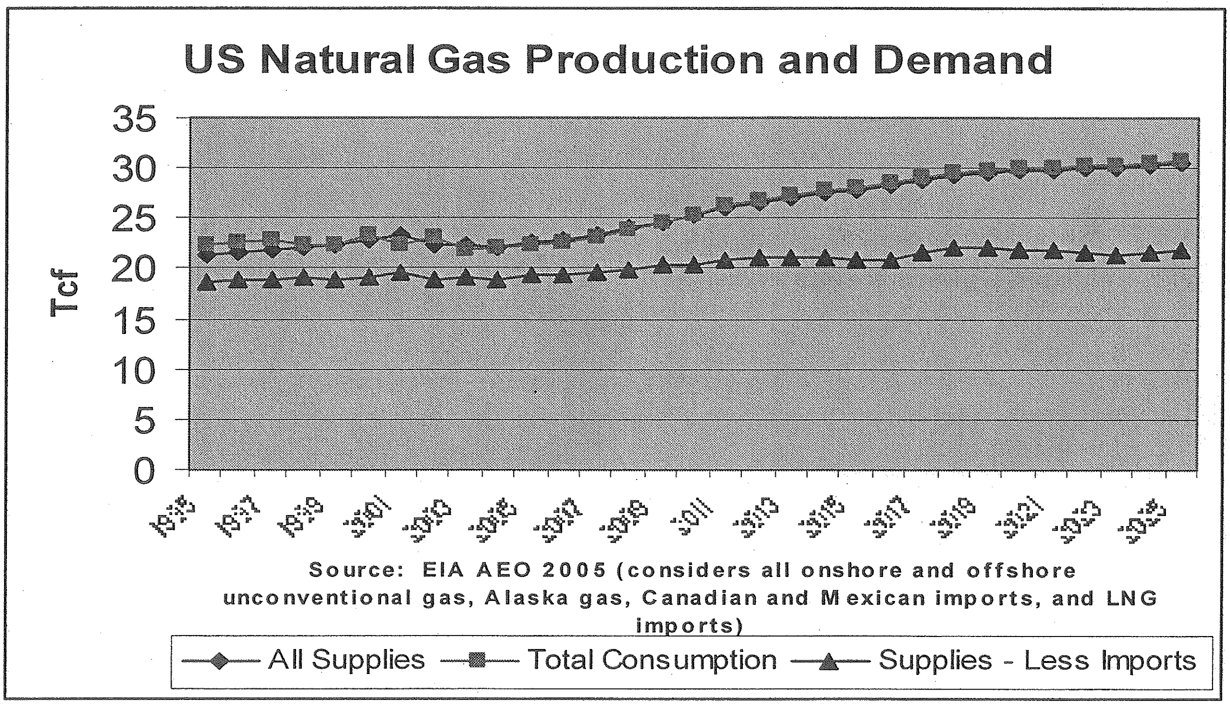
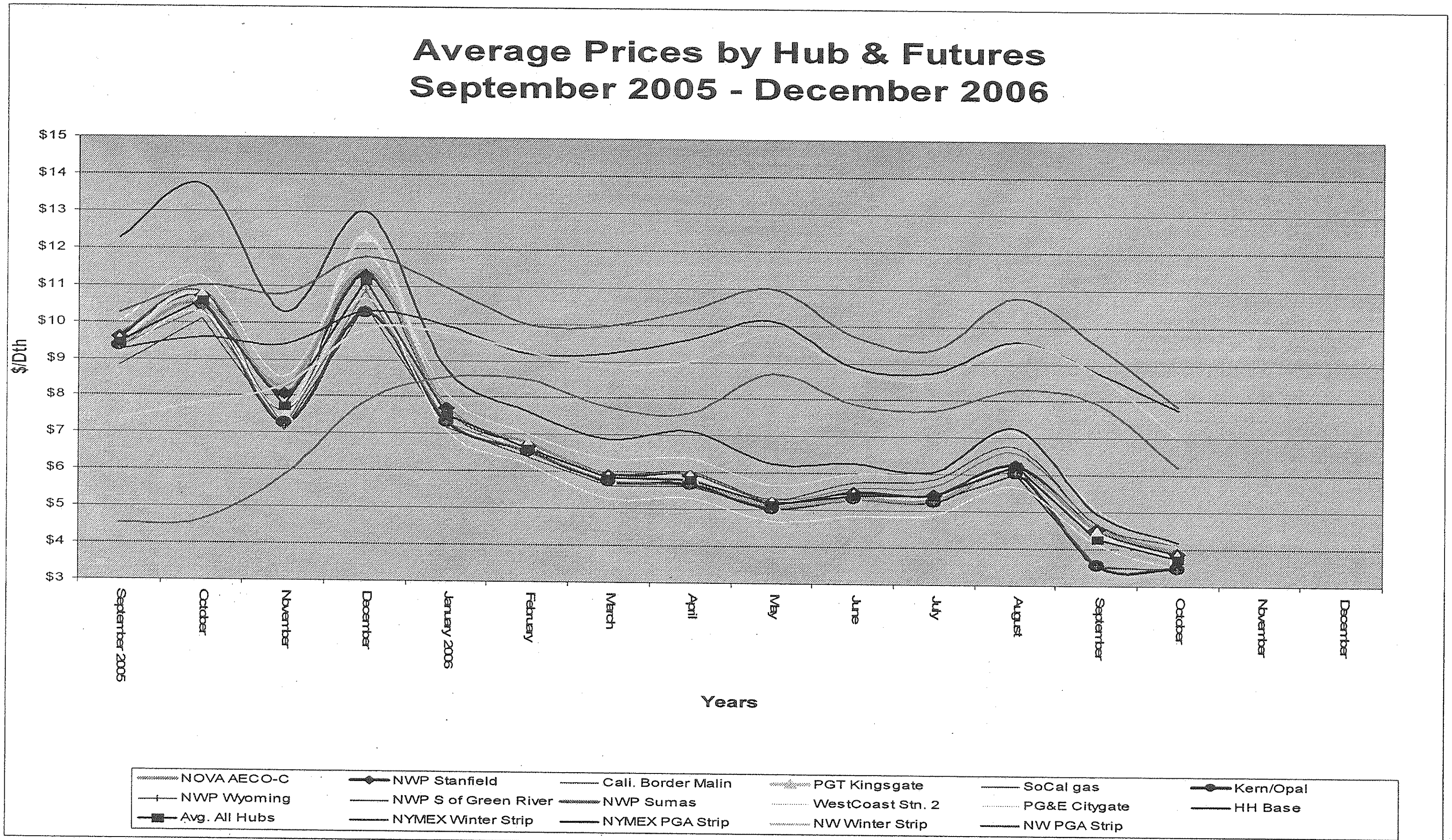


Table 4 – History of US Natural Gas Prices (Physical and Futures)

	Stanfield	Malin	Kingsgate	AECO	SoCal	Opal	Wyoming	S. of Green River	Sumas	Station 2	PG&E	Henry Hub	Avg. All NWP Hubs	NYMEX Winter Strip	NYMEX PGA Strip	NWP Winter Strip	NWP PGA Strip
September 2005	$9.61	$9.70	$9.50	$9.44	$9.65	$9.36	$9.33	$8.83	$9.38	$9.18	$10.02	$12.26	$9.45	$10.26	$9.25	$7.39	$4.52
October	$10.71	$10.83	$10.73	$10.54	$10.81	$10.46	$10.37	$10.09	$10.55	$10.26	$11.23	$13.71	$10.60	$11.03	$9.59	$7.83	$4.63
November	$8.06	$8.12	$7.49	$7.87	$7.58	$7.28	$7.15	$7.06	$8.27	$7.63	$8.54	$10.28	$7.73	$10.78	$9.42	$8.31	$5.84
December	$11.29	$11.37	$12.33	$10.79	$11.30	$10.29	$10.89	$10.47	$11.45	$10.67	$11.79	$12.99	$11.15	$11.79	$10.31	$9.82	$7.86
January 2006	$7.69	$7.76	$7.45	$7.48	$7.66	$7.34	$7.30	$7.17	$7.71	$7.08	$8.09	$8.76	$7.52	$10.96	$9.94	$9.75	$8.53
February	$6.69	$6.71	$6.72	$6.51	$6.79	$6.53	$6.52	$6.38	$6.78	$6.20	$7.00	$7.62	$6.62	$9.99	$9.19	$9.24	$8.49
March	$5.90	$5.94	$5.82	$5.73	$5.96	$5.75	$5.74	$5.61	$5.89	$5.26	$6.36	$6.88	$5.81	$9.97	$9.22	$8.86	$7.76
April	$5.91	$5.96	$5.88	$5.76	$6.00	$5.66	$5.65	$5.61	$5.77	$5.28	$6.37	$7.10	$5.80	$10.41	$9.63	$9.01	$7.62
May	$5.20	$5.28	$5.16	$5.07	$5.30	$5.04	$5.02	$5.02	$5.11	$4.67	$5.66	$6.23	$5.14	$10.99	$10.12	$9.84	$8.68
June	$5.47	$5.58	$5.41	$5.27	$5.75	$5.31	$5.28	$5.29	$5.33	$4.85	$5.97	$6.26	$5.41	$9.73	$8.89	$8.80	$7.88
July	$5.42	$5.67	$5.34	$5.10	$5.86	$5.24	$5.24	$5.24	$5.30	$4.90	$6.10	$6.05	$5.40	$9.39	$8.74	$8.55	$7.72
August	$6.25	$6.59	$6.14	$5.88	$6.76	$6.04	$6.02	$6.01	$6.13	$5.65	$7.16	$7.24	$6.24	$10.78	$9.60	$9.54	$8.30
September	$3.88	$3.90	$3.79	$3.57	$4.12	$3.48	$3.43	$3.47	$3.92	$3.48	$4.08	$4.19	$3.74	$7.84	$7.78	$7.03	$6.22
October																	
November																	
December																	
Average 2006	$5.91	$6.03	$5.83	$5.68	$6.10	$5.61	$5.60	$5.54	$5.85	$5.35	$6.43	$6.80	$5.81	$10.19	$9.35	$9.14	$8.[illegible]
Average 2005-2006	$7.14	$7.25	$7.12	$6.91	$7.25	$6.76	$6.78	$6.64	$7.10	$6.61	$7.65	$8.50	$7.02	$10.43	$9.44	$8.89	$7.[illegible]
Jan - Aug Strip Avgs.																$9.20	$8.[illegible]
Feb - Aug Strip Avgs.																$9.12	$8.[illegible]
Apr - Aug Strip Avgs.																$9.15	$8.[illegible]

ORDER NO. 06-609

Figure 2 – History of US Natural Gas Prices (Physical and Futures)



NW Natural
Rates & Regulatory Affairs
2006-2007 PGA Filing - Oregon
PGA Effects on Revenue - Detail for Memo Attachment

	Amount
Purchased Gas Cost Adjustment (PGA)	
Commodity Cost Change	$16,739,547
Demand Capacity Cost Change	22,380,451
Total Gas Cost Change	39,119,998
Temporary Increments	
Amortization of 191.xxx Account Gas Costs (Demand, Coos Bay Demand, Commodity & Storage Inventory)	5,444,996
Amortization DSM and Weatherization	(169,623)
Amortization of Intervenor Funding - CUB	46,394
Amortization of Decoupling (Residential & Commercial)	(2,274,390)
Amortization of remaining balance Coos Bay deferral	17,582
Total Proposed Temporary Increments	3,064,959
Removal of Current Temporary Increments	11,832,359
Total Net Temporary Rate Adjustment	(8,767,400)
Permanent Rate Adjustments	
Addition of Proposed Bare Steel Program Costs	1,944,000
Removal of Current Bare Steel Program Costs	(2,186,000)
Addition of Proposed Geo-Hazard Program Costs	786,000
Removal of Current Geo-Hazard Program Costs	(360,000)
Addition of Proposed Integrity Management Program Costs	1,861,000
Removal of Current Integrity Management Program Costs	(535,000)
Company Coos Bay Contribution	(123,563)
Price Elasticity Adjustment	1,171,604
Total Net Base Rate Adjustment	2,558,041
TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES	**$32,910,639**

Attachment B

Comparison of Proposed Rate and Bill Increases for Oregon Local Distribution Companies by Class of Service
(November 2006 PGAs)

Class of Service	Rate Schedule	RATE IMPACTS				BILL IMPACTS											
		Current Rate per Therm	Proposed Rate per Therm	Change Rate per Therm	%-Change Rate per Therm	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	$1.34729	$1.44931	0.10202	7.6%	98	$5.00	$137.03	$147.03	$10.00	7.3%	52	$5.00	$75.06	$80.36	$5.30	7.1%
Cascade	101	$1.11833	$1.21082	0.09249	8.3%	117	$3.00	$133.84	$144.67	$10.83	8.1%	62	$3.00	$72.34	$78.07	$5.73	7.9%
NW Natural	2	$1.29167	$1.34052	0.04885	3.8%	109	$6.00	$146.79	$152.12	$5.33	3.6%	57	$6.00	$79.63	$82.41	$2.78	3.5%
Commercial																	
Avista	420	$1.26353	$1.36555	0.10202	8.1%												
Cascade	104	$1.01813	$1.11062	0.09249	9.1%												
NW Natural	3	$1.19803	$1.24436	0.04633	3.9%												
Industrial																	
Avista	424	$1.20711	$1.30913	0.10202	8.5%												
Cascade	105	$0.97832	$1.03535	0.05703	5.8%												
NW Natural	31	$1.15524	$1.21826	0.06302	5.5%												
Interruptible																	
Avista	440	$1.01565	$1.02031	0.00466	0.5%												
Cascade	170	$0.91482	$1.00732	0.09250	10.1%												
NW Natural	32	$0.93900	$0.99873	0.05973	6.4%												

Attachment C