ORDER NO. 08-522

ENTERED 10/30/08

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 183 & UM 1388

In the Matters of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL Changes in the cost of purchased gas and technical adjustments and adjustments to base rates for various programs (UG 183) and Application for reauthorization to defer PGA related expenses or revenues (UM 1388).	)	ORDER

DISPOSITION: APPLICATIONS APPROVED

On August 29, 2008, the Public Utility Commission of Oregon (Commission) received two applications from Northwest Natural Gas Company, dba Northwest Natural. A description of the filings and their procedural history is contained in the Staff Report, attached as Appendix A and incorporated by reference.

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

ORDER

IT IS ORDERED that:

1. The amortization of deferred accounts, base gas cost changes, and other rate changes as requested in docket UG 183 are approved.

2. Waiver of statutory notice to allow the associated tariff sheets of Advice No. 08-5C to go into effect November 1, 2008, is approved.

3. Reauthorization to use deferred accounting pursuant to Schedule P, as requested in docket UM 1388 for one year beginning November 1, 2008, is approved.

Made, entered, and effective OCT 3 0 2008.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

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

ITEM NO. 5 & 6

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

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

DATE: October 21, 2008

TO: Public Utility Commission

FROM: Ken Zimmerman, Lynn Kittilson and Carla Owings

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

SUBJECT: NORTHWEST NATURAL: (Docket No. UG 183/Advice No. 08-5) Reflects changes in the cost of purchased gas and technical adjustments and makes adjustments to base rates for various programs.

NORTHWEST NATURAL: (Docket No. UM 1388) Reauthorizes the PGA deferral mechanism.

STAFF RECOMMENDATION:

Staff recommends the Commission approve Northwest Natural's (NW Natural, Company or NWN) application for less than statutory notice (LSN) and allow the proposed tariff sheets in Advice No. 08-5C to become effective with service on and after November 1, 2008. This filing increases the Company's annual revenues for its Oregon operations by approximately $132.5 million, or 14.5%.

Staff also recommends Commission approval of NW Natural's request for reauthorization to use deferred accounting pursuant to its Schedule P, Purchased Gas Cost Adjustments.

DISCUSSION:

On August 29, 2008, 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 related to the PGA account and other deferred accounts. The filing docketed as UG 183, Advice No. 08-5, proposed an increase of approximately $235.7 million or 25.8%, effective November 1, 2008. In a concurrent filing docketed as UM 1388, NW Natural requested reauthorization of deferred accounting under the Company's PGA mechanism. On October 10, 2008, NW Natural replaced its filing in its entirety with a supplemental filing docketed as Advice 08-5A to become effective with service on and after November 1, 2008, along with an LSN application, to lower its projected commodity cost. On October 16, the Company filed one replacement tariff sheet in Advice No. 08-05B. On October 21, the Company replaced these filings in their entirety with Advice No. 08-5C. The re-filed PGA requests an overall revenue increase of approximately $132.5 million, or 14.5%.

UG 183

NW Natural requests approval to increase rates to: (1) track changes in purchased gas costs; (2) make a permanent adjustment to base rates for certain approved programs; and, (3) make technical adjustments to amortize NWN's deferred accounts. The total change in annual revenues proposed in the PGA filing 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	$100,304,799
Removal of Temporary Increment	$ 35,425,211
Adding New Temporary Decrement	$ (10,440,441)
Permanent Base Rate Adjustments	$ 7,259,466
Total Proposed Increase	$132,549,035

With these changes, the monthly bill of a typical residential customer on Schedule No. 2 using 56 therms per month will increase by $10.67, or 14.3%, from $74.57 to $85.24. In January, a typical residential customer's consumption of 109 therms will result in a billing increase from $139.47 to $160.24.

A summary that compares the impact of this year's proposed 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 56 therms plus the monthly customer charge, divided by 56 therms. The graph shows that NW Natural's residential customers have an effective rate of $1.52216 per therm, while Avista's and Cascade's effective rates are $1.46094 and $1.33013, respectively. Table 2 at the top of the next page shows the rates the Commission has approved for NW Natural's residential customers on Rate Schedule No. 2 between 2004 and 2007, and the current proposal.

Table 2: Residential Rates 2004 – 2008 (Proposed)

Date	Customer Charge	Rate per Therm	Percentage Change[1]
October 2004	$6.00	$1.10784	
October 2005	$6.00	$1.29167	16.6%
November 2006	$6.00	$1.34052	3.8%
November 2007	$6.00	$1.22449	-8.7%
November 2008	$6.00	$1.41502	15.6%

NW Natural offers customer assistance programs. NW Natural also offers energy efficiency programs through Energy Trust of Oregon (ETO). Low-income weatherization and bill payment assistance is provided by agreement with community service agencies. The Commission recently approved revisions to NW Natural's Schedules 301, 310 and 320 which, among other provisions, allows public purpose funding collected from residential customers for low-income programs to be used entirely for low-income bill payment assistance for residential customers through September 30, 2009. Specific information on these programs is readily available to customers on their monthly bills, by telephone, in person at the Company offices, on the Company's web site, and on the ETO's web site.

Staff Review of Gas Costs

National and Regional Natural Gas Markets

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

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

- The steady increase in natural gas price during November 2007 to July 2008, is generally attributed to two primary factors:
  - concerns about diminishing domestic reserves and production, and

[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 2008, when the rate per therm is combined with the monthly customer charge of $6.00, the average customer's bill is increased 14.3%, as shown on Attachment B.

  - o the increase during that period in oil price. The oil price increase was attributed to continued growth in world and US demand, and financial speculation in oil markets.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

NWN 2008 PGA Filing
October 21, 2008
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Figure 1: Natural Gas and WTI Prices, Nov 2007 – Oct 2008

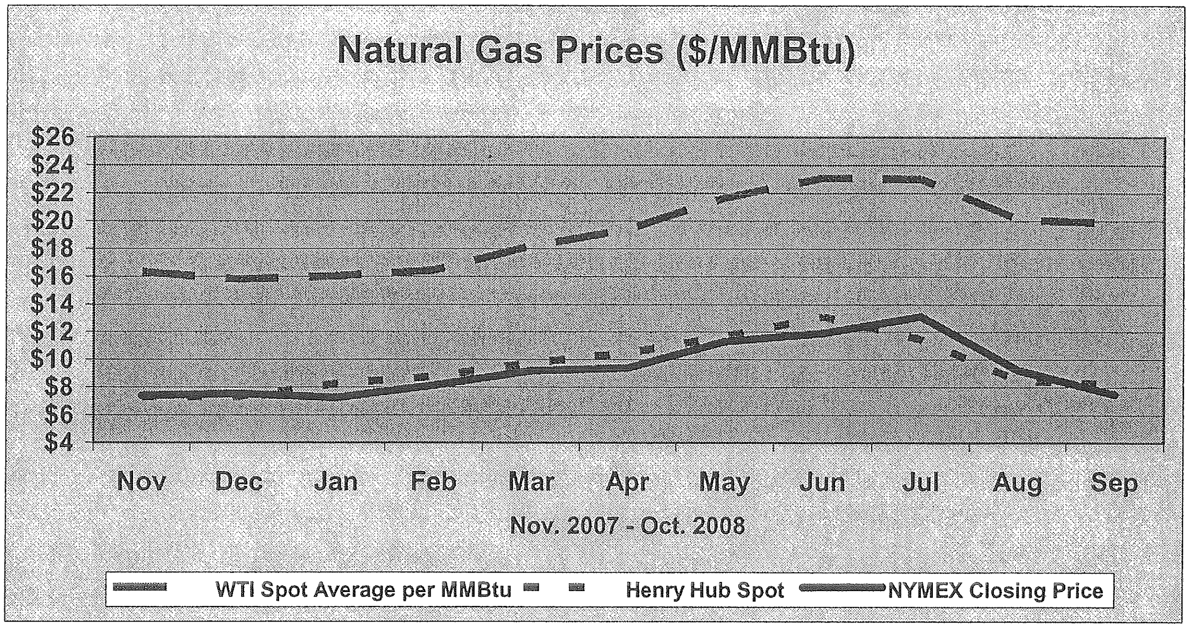
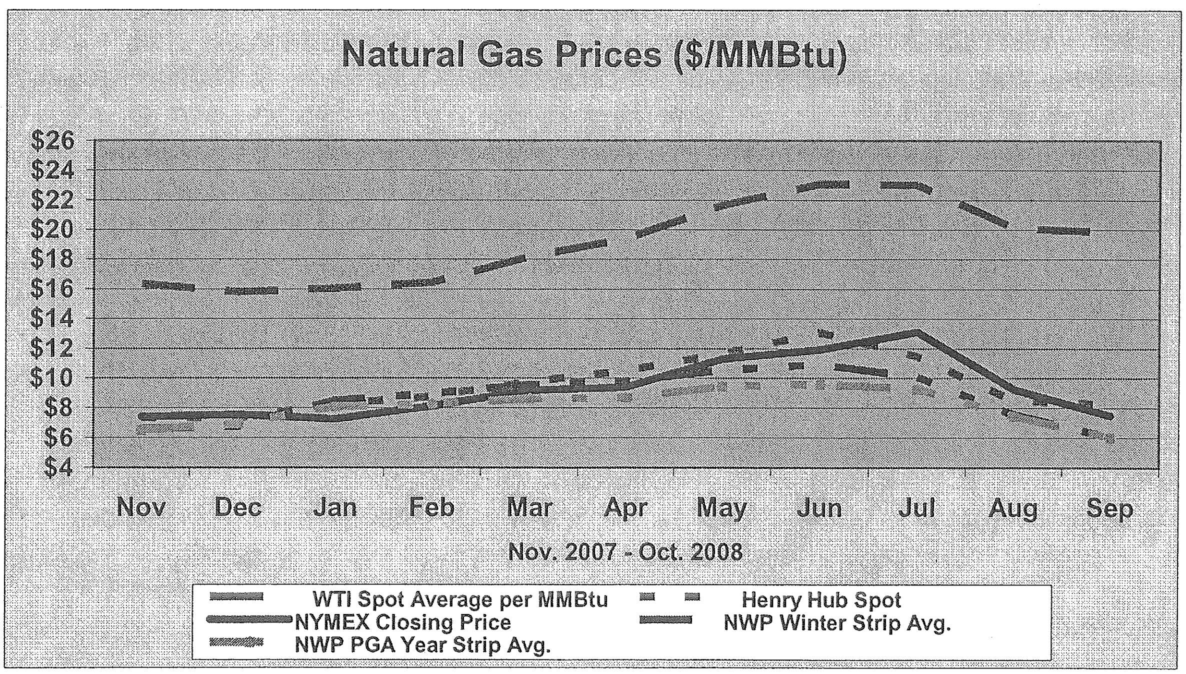


Figure 2: Natural Gas (National and PNW) and WTI Prices, Nov 2007 – Oct 2008



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

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

Natural Gas Purchasing Strategies

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

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

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

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

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

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

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

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

NW Natural's Natural Gas Purchasing Strategies

In its 2006 and 2007 PGA portfolios, NW Natural had financially fixed the price for about 60% of its projected annual sales and expected to provide from storage about 15% of the volumes its customers required. That picture has not changed very much for 2008, as shown in Table 3 below.

Table 3: NW Natural Gas Supply Portfolio

Resource	Percentage in Portfolio
Pipeline deliveries of natural gas	86.4%
Mist production	0.5%
Storage deliveries of natural gas	13.1%
Percentage of natural gas deliveries fixed via financial hedges	60%

As in the last two years, the company's target for financial hedging in 2007-2008 PGA year is approximately 60% of expected annual sales. NW Natural has indicated it may financially fix the price of additional volumes subsequent to the time the 2008 PGA goes into effect. Staff continues to recommend that the target for fixed-price financial hedging by NW Natural should not exceed 60% of expected annual sales volumes. As a matter of adherence to portfolio purchasing strategies, Staff would be more comfortable with a final level of fixed-price financial hedging toward the center or even at the lower end of the 50%-60% range. As noted, at the current time NW Natural has already financially hedged about 60% of expected annual volumes. This results in NW Natural hedging about 73% of expected annual sales volumes when storage is included. It is Staff's position that total hedged volumes by NW Natural should not exceed 75% of expected annual sales. And, as indicated above, a level of 65% to 70% for total hedging would be even more appropriate for an LDC of NW Natural's size, operational characteristics, and market options. However, Staff does not object to the 73% currently hedged financially and via storage, and suggests that this be the cap for NW Natural's total hedging for this PGA year. NW Natural does not agree with this position but agrees with Staff that this is a topic for further discussion in the upcoming Phase II of Docket UM 1286 and in quarterly meetings with Staff and other interested stakeholders.

The timing pattern of NW Natural's financial hedging indicates too large a focus on entering hedges during the months of April and July, and September and October. About 25% of the volumes hedged by the company were covered by hedging completed during April and July, while about 50% of the volumes hedged by NW Natural were covered by contracts entered into during September and October. Together these four months accounted for about 75% of the company's financial hedging (in terms of volumes). NW Natural explains that this pattern is the result of hedging only at the minimal level during the months (February – June) of the price "run-up." This does not explain the over hedging during April, however. In July, NW Natural states it was "catching up" for hedging not completed earlier in 2008, based on the fear that prices might not drop before the PGA filing was made. The September and October hedging levels are certainly, in part, the result of the significant declines in prices for hedges during those months. Staff has indicated on several occasions, however, that to the extent possible, hedging volumes should be spread as nearly as possible equally across each of the months of the February to September period of the PGA year. NW Natural has provided no data or information, or analysis, to show that following this timing schedule for financial hedging was impossible or imprudent for the period February 2008 to September 2008. NW Natural does not agree; Staff, NW Natural and stakeholders will discuss this further with NW Natural during our quarterly meetings.

NW Natural's overall hedge price is approximately $8.60/Dth, within the range of futures pricing Staff calculated as reasonable (see Table 4).

Table 4: Staff's Hedging Price Range for 2008 PGAs[2]

High	Low
$8.60	$8.00

In summary, Staff recommends the Commission accept NW Natural's hedging weighted average cost of gas (WACOG) as reasonable. However, as noted above, changes should be made in NW Natural's hedging process, most notably its timing. Staff and NW Natural will pursue these changes for the 2009 PGA filing.

<u>*NW Natural's Natural Gas Costs*</u>

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

[2] This range is based on a weighted average made up of high and low prices for the winter and PGA year Pacific Northwest winter strips combined with the averages for these strips over the period November 2007 to September 2008.

which the Oregon LDCs purchase were about $8.10/MMBtu for the PGA year and about $8.60/MMBtu for the winter period, also with a similar price pattern.

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

Table 5: NW Natural Commodity and Demand Costs for 2008 PGA[3]

Charge ($/therm)	NW Natural	Staff's Range
Commodity	$0.82668	$0.82500 - $0.87500
Commodity (revenue sensitized)	$0.85126	
Demand	$0.11765	$0.11765
Demand (revenue sensitized)	$0.12115	
Total	$0.94433	$0.94265 - $0.99265
Total (revenue sensitized)	$0.97241	

The proposed commodity WACOG is just over a 20% increase over the company's current commodity WACOG.

The overall increase in rates related to natural gas commodity and transportation costs proposed by NW Natural is $100,304,799. This increase in rates related to gas costs is reasonable, in light of the high market price of natural gas during 2008 up to June.

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

Technical Adjustments - Deferred Accounts

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 increments currently in place, increasing revenues by $35,425,211.

- Addition of new temporary increments totaling $(10,440,441) to the Company's deferred accounts as detailed in Table 6 below. The Commission previously authorized all of the deferred amounts subject to amortization.

Table 6: NW Natural Temporary Revenue Increments for 2008 PGA

Temporary Debit (Credit) Revenues	Amount
Commodity and demand costs	($7,890,666)
Residential and Commercial Decoupling	($2,511,507)
Demand Side Management & Weatherization	$14,555
Intervenor Funding	$82,429
Pipeline Integrity Refund	$47,970
Oregon Tax Kicker Refund	$78,681
Share of gain on Sale of Albany property	($261,903)
Total	($10,440,441)

A new decrement this year is the after-tax gain on the sale of the Company's Albany property (the subject of Commission Order No. 08-395 in Docket UP-245). Customers will be refunded $261,903 over the next year.

The net revenue effect of adding the new temporary increments and removing the current increments is an increase of $24,984,770 on an annual basis. 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.

Other Base Rate Adjustments

<u>Bare Steel Replacement Program</u>: 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 August 2008. For the year beginning November 1, 2008, $2,484,000 is proposed to be collected in rates for the accelerated Bare Steel Replacement project. This amount represents an increase from last year of $526,000.

<u>Geo-hazard Repair and Risk Mitigation</u>: Commencing in 2002 and originally scheduled to end in 2006, NW Natural is repairing and mitigating landslide hot spots, erosion and other geo-hazards. Staff last audited this program in August of 2008. 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 $194,000 from the amount currently collected in rates. From November 1, 2008 to October 31, 2009, a total of $961,000 will be collected.

<u>Integrity Management Program</u>: This 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 August of 2008. Staff verified that the costs in this filing are consistent with the audit findings. For the period from November 1, 2008 to October 31, 2009, $3,491,000 will be collected in rates, an increase of $1,390,000 from the amount currently collected from customers.

<u>Coos County Distribution System</u>: The Coos County Distribution system was placed in service in 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. This filing includes the removal of last year's credit increment of $134,214 and the addition of a new credit increment of $145,783 funded by the Company as authorized in Order 04-702.

<u>Storage Recall for Core:</u> The storage recall adjustment represents the permanent rate effects of the recall of 100,000 therms per day of Mist capacity from upstream market activities for use by core customers. The Company's core customers will use the capacity during winter time peaking periods to reduce commodity and demand costs. For this PGA, the Company has transferred a total of $523,287 investment for use by the utility. The Oregon portion of the revenue requirement associated with that investment is $73,835.

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 increased by $5,087,200 from November 1, 2008 through October 31, 2009, to account for price elasticity.

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 is 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 preceding calendar year, unless the Commission finds that allowing a higher amortization rate is reasonable under the circumstances. As NW Natural's proposed net amortization for 2008 is a credit of approximately $8.0 million, there is a negative rate impact related to the amortizations. As such, the reduction to rates should be implemented as proposed.

UM 1388

In this filing, NW Natural requests reauthorization of deferred accounting 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.

PROPOSED COMMISSION MOTION:

NW Natural's requests for: (1) amortization of deferred accounts, base gas cost changes, and other rate changes as requested in Docket UG 183 be approved; (2) the application for LSN be approved and the associated tariff sheets of Advice No. 08-5C be allowed to go into effect with service on or after November 1, 2008; and, (3) reauthorization to use deferred accounting pursuant to Schedule P as requested in UM 1388, be approved.

Attachments

NW Natural 2008 PGA

NW Natural
Rates & Regulatory Affairs
2008-2009 PGA Filing - Oregon: October refiling (revised)
PGA Effects on Revenue

	Amount
Purchased Gas Cost Adjustment (PGA)	
Commodity Cost Change	$100,775,234
Demand Capacity Cost Change	(470,435)
Total Gas Cost Change	100,304,799
Temporary Increments	
Amortization of 191.xxx Account Gas Costs (Demand, Coos Bay Demand, Commodity & Storage Inventory)	(7,890,666)
Amortization DSM and Weatherization	14,555
Amortization of Intervenor Funding - CUB & NWIGU	82,429
Amortization of Decoupling (Residential & Commercial)	(2,511,507)
Amortization of Pipeline Integrity Refund	47,970
Amortization of Oregon Tax Kicker Refund	78,681
Amortization of gain on sale of Albany property	(261,903)
Total Proposed Temporary Increments	(10,440,441)
Removal of Current Temporary Increments	(35,425,211)
Total Net Temporary Rate Adjustment	24,984,770
Permanent Rate Adjustments	
Addition of Proposed Bare Steel Program Costs	2,484,000
Removal of Current Bare Steel Program Costs	(1,958,000)
Addition of Proposed Geo-Hazard Program Costs	961,000
Removal of Current Geo-Hazard Program Costs	(767,000)
Addition of Proposed Integrity Management Program Costs	3,491,000
Removal of Current Integrity Management Program Costs	(2,101,000)
Addition of Proposed Company Coos Bay Contribution	(145,783)
Removal of Current Company Coos Bay Contribution	134,214
Storage Recall for Core	73,835
Price Elasticity Adjustment	5,087,200
Total Net Base Rate Adjustment	7,259,466
TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES	**$132,549,035**

Attachment B

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

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

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

Attachment C