ORDER NO. 06-608

ENTERED 10/30/06

# BEFORE THE PUBLIC UTILITY COMMISSION

# OF OREGON

UG 175/UM 1278

| | | |
|---|---|---|
| In the Matters of | ) | |
| | ) | |
| CASCADE NATURAL GAS | ) | ORDER |
| | ) | |
| Change in purchased gas cost resulting from changes in the cost of commodity gas supply and transportation capacity, and realignment of existing firm transportation capacity. | ) | |
| **(UG 175)** | ) | |
| | ) | |
| Application for Reauthorization of deferral accounts associated with the PGA's Gas Cost Balancing Account and wholesale gas cost. | ) | |
| **(UM 1278)** | ) | |

DISPOSITION: APPLICATIONS APPROVED

On August 31, 2006, the Public Utility Commission of Oregon (Commission) received two applications from the Cascade Natural Gas Corporation. 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. Amortization of deferred accounts, base gas cost changes, and rate changes, as requested in docket UG 175, are approved.

2. The associated tariff sheets of Advice No. CNG/O06-08-06A are allowed to go into effect with service on or after November 1, 2006, with less than statutory notice.

3. Reauthorization to use deferred accounting pursuant to Schedule 177, as requested in UM 1278, for one year beginning November 1, 2006, is approved.

Made, entered and effective OCT 30 2006.

BY THE COMMISSION:

Becky L Beier

**BECKY L. BEIER**
Commission Secretary

PUBLIC UTILITY COMMISSION OF OREGON

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. 3 & 4**

**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, Judy Johnson and Bonnie Tatom

**SUBJECT:** CASCADE NATURAL GAS: (Docket No. UG 175/Advice No. O06-08-06) Reflects changes in the cost of purchased gas and technical adjustments. (Docket No. UM 1278) Requests reauthorization of the PGA deferral mechanism.

**STAFF RECOMMENDATION:**

We recommend the Commission approve Cascade Natural Gas Corporation's (Cascade or company) request to waive statutory notice (L.S.N.) and allow the company's proposed tariff sheets in Advice No. O06-08-06A to become effective with service on and after November 1, 2006. This filing increases the company's annual revenues by $6.2 million, or 7.0%.

We also recommend the Commission approve the company's request for authorization to use deferred accounting pursuant to its tariff Schedule 177, Purchased Gas Cost Adjustment Provision.

**DISCUSSION:**

On August 31, 2006, Cascade submitted its annual gas cost tracking and technical adjustment filing, commonly known as its PGA filing. The PGA allows Cascade to adjust tariffs annually for known and measurable changes in purchased base gas costs and for changes in amortization rates relating to the PGA account and other deferred accounts. This filing consisted of a proposed increase in annual revenues docketed as UG 175, Advice No. CNG/O06-08-06 and a concurrent filing docketed as UM 1278, requesting reauthorization of deferrals under the company's PGA mechanism. The filing increased the company's annual revenues by $4.8 million, or 5.5%.

On October 11, 2006, the company made a substitute filing, Advice No. O06-08-06A, along with an L.S.N., to make corrections to the company's initial calculations for the effects of changes in purchased gas costs. The net effect is a larger proposed increase in the revenues for Oregon operations, now $6.2 million or about 7.0%. Consistent with Commission Order No. 06-569, 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.

## UG 175

In its amended filing, Cascade seeks approval to increase rates to: (1) track increases in purchased gas costs and (2) make technical adjustments to amortize Cascade's deferred revenue and gas cost accounts. The change in annual revenues is summarized in the table below and shown in Attachment A.

| | |
|---|---|
| PGA Base Gas Cost Change | $6,584,967 |
| Removal of Prior Year Temporary Credit Increment | 835,183 |
| Addition of New Temporary Credit Increment | (1,214,592) |
| Total Proposed Increase | $6,205,558 |

With these changes, the monthly bill of a typical residential customer using 62 therms per month will increase by $5.73, or 7.9 percent, from $72.34 to $78.07. In January, a typical residential customer's consumption of 117 therms would result in a billing increase from $133.84 to $144.67.

A summary of the proposed tariff and revenue changes for Cascade's major rate schedules is shown in Attachment A. A summary that compares the impact of this year's proposed PGA rate changes, on both an annual and January basis, for Cascade, Avista and NW Natural residential customers is shown in Attachment B. A graph illustrating each of the three local distribution companies' (LDCs') effective residential rates on a comparable basis is found in Attachment C. The effective residential rate is calculated as follows: The proposed residential rate multiplied by 60 therms plus the monthly customer charge, divided by 60 therms. The graph shows that Cascade's residential customers have an effective rate of $1.26082 per therm, while Avista's and NW Natural's effective rates are $1.53264 and $1.44052, respectively.

The table on the top of the next page shows the rates the Commission has approved for Cascade's residential customers on Rate Schedule 101 between 2002 and 2005, and the current proposal.

| Date | Customer Charge | Rate Per Therm | Percentage Change [1] |
|---|---|---|---|
| October 2002 | $3.00 | $0.88603 | |
| October 2003 | $3.00 | $0.90402 | 2.0% |
| October 2004 | $3.00 | $0.97948 | 8.3% |
| October 2005 | $3.00 | $1.11833 | 14.2% |
| November 2006 [2] (Proposed) | $3.00 | $1.21082 | 8.3% |

Cascade implemented its Conservation Alliance Plan (CAP or Plan) this year which was approved in Commission Order No. 06-191, entered April 19, 2006. The Plan includes a decoupling mechanism consisting of two deferral accounts, one to track changes in margin due to variations in weather-normalized usage and another to track changes in margin due to weather that varies from normal. These variances are calculated monthly and recorded in deferred accounts for amortization each year at the time of the PGA. This program began with service beginning May 1, 2006. The deferred amounts are relatively small to date and the company and Staff have agreed not to begin amortizing the accounts until the 2007 PGA. An important element of the CAP is that Cascade's conservation programs will be provided by agreement with Energy Trust of Oregon (ETO) and low-income weatherization and bill payment assistance provided by agreement with community service agencies. 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 the ETO 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;

[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 $3.00, the average customer's bill is increased about 7.9%, as shown on Attachment B.
[2] The annual PGA effective date is permanently changed from October 1 to November 1 effective this year.

- 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;
- 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

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

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.

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. 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, Cascade moderated its pre-PGA level of financial hedging to a more reasonable level. As prices declined, Cascade 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.

*Cascade's Natural Gas Purchasing Strategies*

In its 2006 PGA filing Cascade 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) | 68.15% |
| Storage | 6.09% |
| Short-term and peaking natural gas purchased at index price (unhedged at the time of the PGA filing) | 25.76% |

Cascade's portfolio for 2005-2006 and now 2006-2007 are both improvements over its historical portfolio as demonstrated in the table on the next page taken from the **"Public Utility Commission of Oregon Natural Gas Procurement Study"** published in 2005. During each year of the period between 1999 and 2004, Cascade fixed the price of at least 95% of the gas it purchased. It did this through fixed price physical contracts with suppliers. Since the availability of such contracts has declined substantially in the last few years, particularly for small LDCs, Cascade has switched to financial hedging for fixing the price of a portion of its gas supply portfolio. As of the time of the PGA filing Cascade had financially hedged about 68% of its required volumes. Staff assumes Cascade will continue to financially hedge through the PGA year, but recommends and expects those additional hedges will not raise the overall level of financial hedging above 90% of required volumes.

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. Cascade's situation is not the extreme. Cascade has access to multiple supply and pricing points, but is also limited in transportation options and severely limited in storage access. Add to this Cascade's relatively small and clearly winter peaking demand. The result is a higher than average level of limitations and thus risk. Staff believes that Cascade's circumstances justify a higher level of financial hedging. Financially hedging up to about 90% of the volumes required for the PGA year is appropriate for Cascade. Staff also expects that Cascade 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.

**Table E.2. Cascade Natural Gas Purchases, PGA Years 1999/2000 through 2003/2004 (percent of total).**

| **Strategy** | **99/00** | **00/01** | **01/02** | **02/03** | **03/04** |
|---|---|---|---|---|---|
| Physical with Fixed Price from Supplier | 96.1 | 95.6 | 97.7 | 98.7 | 99.1 |
| Storage | 3.9 | 4.4 | 2.3 | 1.3 | 0.9 |
| **Total** | **100.0** | **100.0** | **100.0** | **100.0** | **100.0** |

The prices contained within Cascade's PGA filing are reasonable. Cascade's overall hedge price is approximately $8.11/Dekatherm (Dth), well within the range of futures pricing available during the first 8 months of 2006. Staff is concerned that Cascade's forecast of spot prices for the coming PGA year is too high. That forecast is applied to up to almost 26% of Cascade's total gas requirements. The average spot price forecasted by Cascade over the PGA year is just over $8.70/Dth. This is significantly higher than the price being forecasted 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. 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, Cascade explained, and provided data and calculations to support its explanation, that a conservative (higher) forecast of spot prices based on futures prices is preferable in its opinion and better fits the needs of Cascade's system and gas requirements. Cascade has also agreed to integrate fundamentals forecasting into its forecasting of spot natural gas prices. Staff accepts but does not entirely agree with this explanation and has scheduled this topic for consideration during the upcoming PGA workshops.

In its 2005 PGA public meeting memo for Cascade, Staff recommended,

> Staff's analysis does not indicate that Cascade's current purchasing strategy is imprudent. However, Staff recommends that Cascade analyze and assess the impacts on its gas supply portfolio options, such as the following, for future natural gas purchases:

1. Use of larger variety of contracting formulae (e.g., index changes, flexible MDDV, flexible nominations, weather derivatives).
2. Expand bidding (e.g., combination supply/transport, bid for hedges).
3. Look into purchase partnerships with other LDCs or industrial customers.
4. Portfolio mix changes for study:
   a. More volumes purchased through contracts of 5 years or longer
   b. Direct LNG contracting
   c. Build/Purchase strategic storage (storage that allows the LDC to fine tune its purchases, thus reducing the total volumes of NG purchased and the purchase of high priced volumes during times of high need)
   d. Physical fixed price contracting
   e. Direct contracting for unconventional gas supplies
5. All this closely coordinated, of course, with demand-response and energy efficiency programs.

Staff continues to support these recommendations and urges Cascade to pursue them diligently. The situation for Cascade remains as indicated in Staff's 2005 memo, however:

> "Unfortunately, due to its relatively small load and level of natural gas purchases, Cascade's opportunities to actually implement many of these options to reduce purchase price may be limited. In addition, Cascade's size also mitigates against adding significant new personnel or resources for Cascade to more rigorously apply portfolio methods. Neither of these factors, however, relieves Cascade of its responsibility to more rigorously apply portfolio methods within the limits of its load and general financial circumstances."

Still, Cascade should continue to explore and seriously consider these recommendations, implementing, if only partially, as many as feasible. Cascade should fully and accurately document its consideration of Staff's recommendations and be prepared to justify and support its decisions about and application of these recommendations. As indicated in Staff's 2005 memo, Cascade must focus on not just "controlling" the price it pays for natural gas through financial or some other form of hedging, but also on reducing the price it pays for that natural gas through alternative contracting, more formal bidding, purchasing partnerships, more physical hedging, etc.

*Cascade's Natural Gas Costs*

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

> ". . . the changes proposed for Cascade's purchasing process should help control its future cost of gas, thus limiting future increases and rate shock. Cascade appears to have intuitively applied portfolio purchasing practices in its purchase of physical gas and financial hedges. Such intuitive application may not work effectively to provide the greatest balance, diversity, and flexibility in Cascade's future gas supply portfolio. Consequently, it is important that Cascade improve its data gathering and analysis related to portfolio construction, to add both more rigor and more accountability to the process."

Staff continues to support these recommendations.

For the time during which Cascade 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,[4] 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 ($10.20) and $9.40 ($8.60) per MMBtu for the winter months of 2006-2007.

For the current PGA, Cascade proposes to pass through to its sales customers a weighted average cost of gas (WACOG) of $0.75111/therm ($7.51/dekatherm (MMBtu)), based on normalized purchase volumes. Cascade calculates a revenue-sensitive rate per therm of $0.76935 ($7.69/dekatherm (MMBtu)). When fixed delivery costs are added the WACOGs are $0.88094 ($8.81/Dth) and $0.90233 (9.02/Dth) revenue-sensitized. This pass through proposal is reasonable based upon the portfolio proposed by Cascade, the market prices during the period in which Cascade entered into financial hedges, and the spot price forecasted by Cascade.

[4] 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.

Two items about Cascade's PGA filing require further explanation. First, as noted above in the discussion of Cascade's natural gas purchasing strategies, it is Staff's recommendation that the total level of financial hedging by Cascade should not exceed 90% of the volumes required for the PGA year. LDCs with smaller demand requirements (particularly in the winter), limited market purchasing power, limited storage, and scattered demand centers, in general, may legitimately choose to financially hedge a higher percentage of their gas supply. Cascade has exercised this option. But even such LDCs should retain some flexibility in their portfolios to purchase at current index prices. Cascade currently has left about 26% of its portfolio open to such pricing. However, Cascade indicates it will financially hedge further during the PGA year and thus reduce this 26%. During the upcoming workshops on the PGA the appropriate level of financial hedging and related criteria will be discussed further. Staff hopes those workshops will lead to a specific agreement on appropriate hedging levels for LDCs of various sizes and circumstances. For Cascade's 2006 PGA, Staff is satisfied that Cascade's limitation of its total level of financial hedging to 90% of required volumes is sufficient.

Second, also as noted earlier, it is Staff's conclusion that the level of future spot natural prices forecasted by Cascade, and especially the methodology upon which that level is based, are not appropriate. Even if Cascade eventually financially hedges 90% of its PGA volume needs, leaving only about 4%[5] open to current index (spot) pricing, the reasonableness of the spot price forecast is important. To the extent Cascade 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. Cascade has not done this. The company has only superficially and indirectly included fundamentals forecasting in its spot price forecasting and has not yet developed a process to fully integrate market intelligence and fundamentals forecasting results in forecasting spot natural gas prices. 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.

At the end of June 2006 both interstate pipelines that Cascade 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

[5] Cascade expects to receive about 6% of its annual gas supply from storage.

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 Cascade's PGA filing except to ensure the increase fairly reflects the rates proposed by the two interstate pipelines.

The company's workpapers support the overall natural gas commodity and transportation cost related increase in revenues proposed by Cascade of $6,584,967.

**Technical Adjustments - Deferred Accounts**

Cascade's application proposes to make technical adjustments in amortizing credit and debit balances in its deferred accounts. This activity consists of the following components, as shown on Attachment A.

- Removal of temporary credit increments currently in place, increasing revenues by approximately $835,183.
- Addition of new temporary increments to refund $1,214,592 in net credit balances in the company's deferred revenue, gas cost and DSM accounts. The Commission previously authorized all of the deferred amounts subject to amortization.

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 $379,409 on an annual basis.

**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. Cascade'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 proceeding calendar year, unless the Commission finds that allowing a higher amortization rate is reasonable under the circumstances. Cascade's proposed amortization for 2006 is a negative 2.6%, easily below the three percent of the gross revenue and should be implemented as proposed

## UM 1278

In this filing, the company requests deferral for all of the gas cost differences associated with purchases of gas supplies for system requirements that differ from gas costs embedded in rates, consistent with the procedures outlined in its Schedule 177 for 12 months starting November 1, 2006. 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 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. 06-569, 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:

Cascade Natural Gas Corporation's request for: 1) amortization of deferred accounts, base gas cost changes, and rate changes as requested in Docket No. UG 175 be approved; 2) the associated tariff sheets of Advice No. CNG/O06-08-06A be allowed to go into effect with service on or after November 1, 2006, and the L.S.N. be approved; and 3) request for reauthorization to use deferred accounting pursuant to its Schedule 177, for one year beginning November 1, 2006, be approved.

Attachments

# 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 Cascade'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.

Appendix to Staff Report Cascade Natural Gas PGA Filing
October 16, 2006
Page 4

**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)**

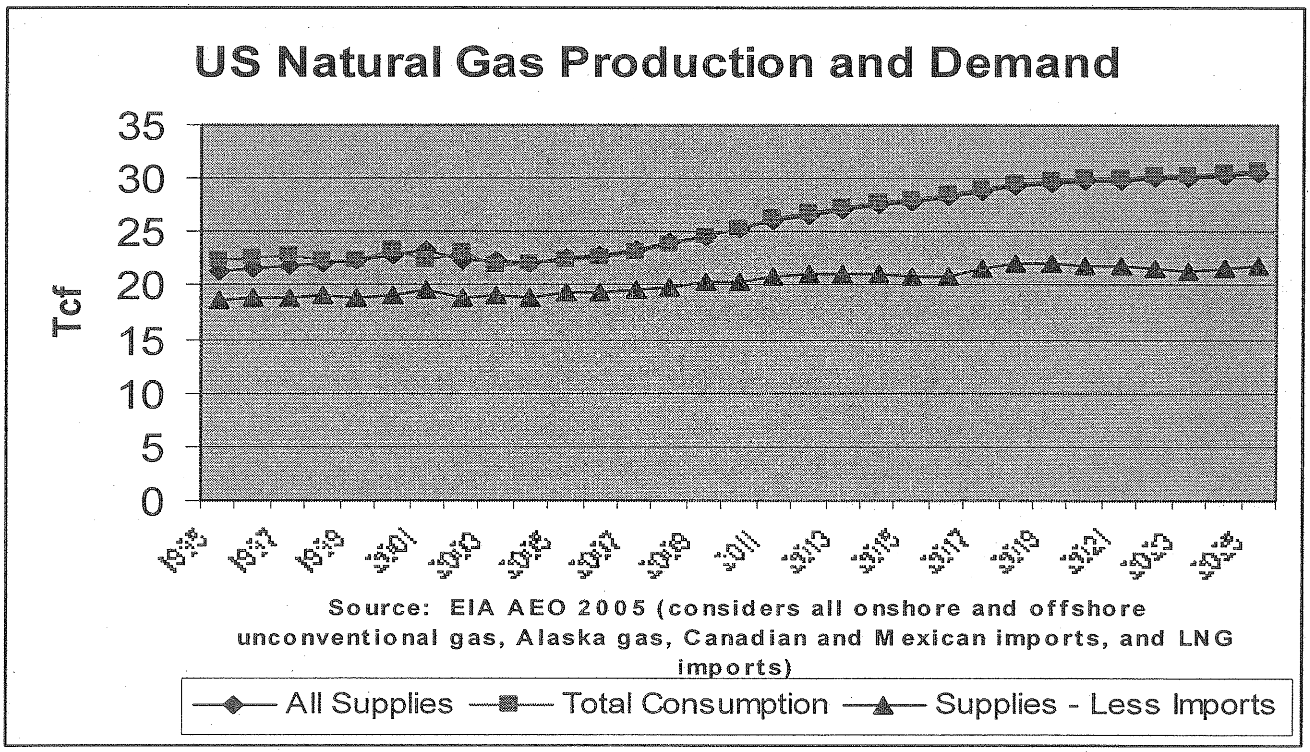
| Month | August 31, 2006 |
|---|---|
| October | $5.25 |
| November | $7.43 |
| December | $9.18 |
| January 2007 | $9.83 |
| February | $9.86 |
| March | $9.68 |
| April | $7.54 |
| May | $7.39 |
| June | $7.48 |
| July | $7.59 |

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

Gas Supply, Production, and Demand

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.

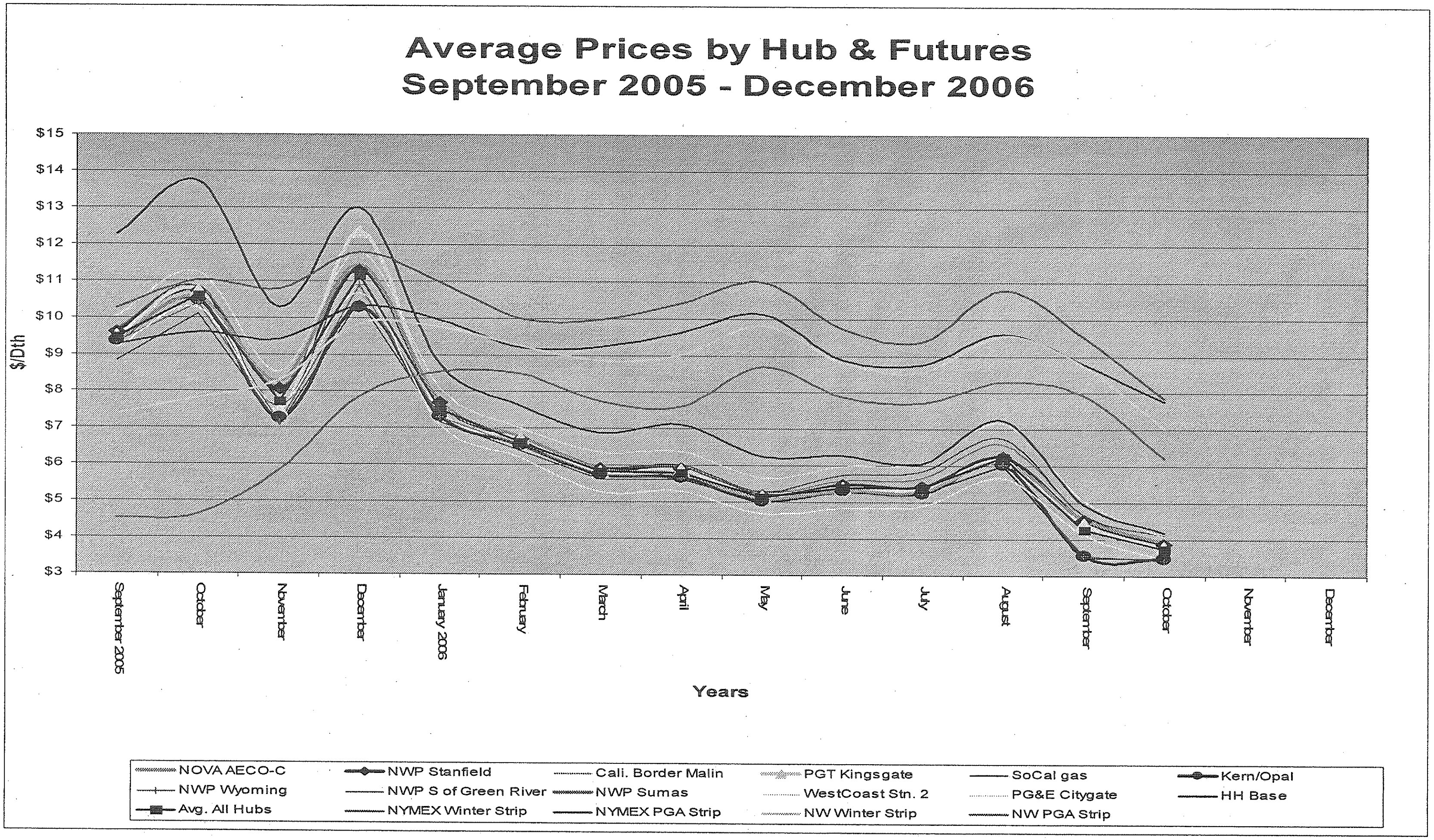
**Figure 1 - EIA's Estimate of Expected US Natural Gas Demand and Supply**



## 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 | $8.08 |
| 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 | $7.35 |
| | | | | | | | | | | | | | | | | | |
| Jan - Aug Strip Avgs. | | | | | | | | | | | | | | | | $9.20 | $8.12 |
| Feb - Aug Strip Avgs. | | | | | | | | | | | | | | | | $9.12 | $8.06 |
| Apr - Aug Strip Avgs. | | | | | | | | | | | | | | | | $9.15 | $8.04 |

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



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# CASCADE NATURAL GAS CORPORATION
Summary of Proposed Rates and Revenues
Effective 10/01/06

RATES (In Cents Per Therm)

| Ln | Customer Class | Schedule | Current Tariff Commodity Rate | Current Average Total Rate /2 | Proposed Changes: PGA Base Gas Cost | Temporary Rate Increments: Remove 05 | Temporary Rate Increments: Add New | Total Change | Proposed Average Total Rate /2 | Proposed Tariff Commodity Rate | Normalized Therm Sales/Thruput |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h)=e+f+g | (i)=d+h | (j)=d+h | (k) |
| | CORE MARKET SERVICE | | | | | | | | | | |
| 1 | Residential | 101 | 111.833 | 116.698 | 9.813 | 1.246 | (1.810) | 9.249 | 125.947 | 121.082 | 35,583,782 |
| 2 | Commercial | 104 | 101.813 | 102.929 | 9.813 | 1.246 | (1.810) | 9.249 | 112.178 | 111.062 | 26,422,097 |
| 3 | Com-Ind Dual | 111 | 94.286 | 94.286 | 9.813 | 1.246 | (1.810) | 9.249 | 103.535 | 103.535 | 1,941,679 |
| 4 | Industrial Firm | 105 | 97.832 | 98.247 | 9.813 | 1.246 | (1.810) | 9.249 | 107.496 | 107.081 | 3,156,963 |
| 5 | Industrial Interr. | 170 | 91.482 | 91.482 | 9.813 | 1.247 | (1.810) | 9.250 | 100.732 | 100.732 | 0 |
| | NONCORE MARKET SERVICE | | | | | | | | | | |
| 6 | Distribution Transportation Schedule Nos. 163 & 164 | | | | | | 0.000 | | | | 23,477,749 \1 |
| | | Blocking | | | | | | | | | |
| 7 | R/S 163 & 164 | First 10,000 | 12.651 | | 0.000 | (0.004) | 0.000 | (0.004) | 12.647 | | 2,615,056 |
| 8 | R/S 163 & 164 | Next 10,000 | 11.437 | | 0.000 | (0.004) | 0.000 | (0.004) | 11.433 | | 2,092,776 |
| 9 | R/S 163 & 164 | Next 30,000 | 10.761 | | 0.000 | (0.004) | 0.000 | (0.004) | 10.757 | | 4,281,872 |
| 10 | R/S 163 & 164 | Next 50,000 | 6.705 | | 0.000 | (0.004) | 0.000 | (0.004) | 6.701 | | 3,893,447 |
| 11 | R/S 163 & 164 | Next 100,000 | 3.524 | | 0.000 | (0.004) | 0.000 | (0.004) | 3.520 | | 10,594,598 |
| 12 | R/S 164 ONLY | Over 500,000 | 2.000 | | 0.000 | 0.000 | 0.000 | 0.000 | 2.000 | | 1,263,053 |

REVENUES (In dollars)

| Ln | Customer Class | Schedule | Revenue at Current Avg Rates /2 | Proposed Changes: PGA Base Gas Cost | Temporary Rate Increments: Remove 04 | Temporary Rate Increments: Add New | Total Change | Revenue at Proposed Avg Rates /2 | Percent Change /2 |
|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g)=d+e+f | (h)=c+g | (i)=h/c |
| | CORE MARKET SERVICE | | | | | | | | |
| 13 | Residential | 101 | $41,525,396 | $3,491,837 | $443,374 | ($644,066) | $3,291,144 | $44,816,540 | 7.93% |
| 14 | Commercial | 104 | $27,196,068 | $2,592,800 | $329,219 | ($478,240) | $2,443,780 | $29,639,848 | 8.99% |
| 15 | Com-Ind Dual | 111 | $1,830,732 | $190,537 | $24,193 | ($35,144) | $179,586 | $2,010,318 | 9.81% |
| 16 | Industrial Firm | 105 | $3,101,636 | $309,793 | $39,336 | ($57,141) | $291,988 | $3,393,624 | 9.41% |
| 17 | Industrial Interr. | 170 | $0 | $0 | $0 | $0 | $0 | $0 | 0.00% |
| | NONCORE MARKET SERVICE | | | | | | | | |
| 18 | Dist Transportation | 163/164 | $1,854,624 | $0 | ($939) | $0 | ($939) | $1,853,685 | -0.05% |
| 19 | Other | | $12,533,975 | $0 | $0 | $0 | $0 | $12,533,975 | 0.00% |
| 20 | Total Revenues | | $88,042,431 | $6,584,967 | $835,183 | ($1,214,592) | $6,205,558 | $94,247,989 | 7.05% |

1/ R/S 163 & 164 Volumes exclude therms in $.02 tail block since OPUC directive establishes that this block is not affected by any rate changes.
2/ Reflects inclusion of monthly customer service charges, which does not change in this tracking filing. as well as division of costs by normalized therms sales.

**Attachment B**

**Comparison of Proposed Rate and Bill Increases for Oregon Local Distribution Companies by Class of Service**
**(November 2006 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 | $1.34729 | $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**