ORDER NO. 05-1054

ENTERED 09/29/05

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 164/UM 1214

In the Matter of	)	
	)	
CASCADE NATURAL GAS	)	
	)	
Reflects Changes in the Cost of Purchased	)	ORDER
Gas and Technical Adjustments. **(UG 164)**	)	
	)	
Requests Reauthorization of the PGA	)	
(Purchased Gas Adjustment) Deferral	)	
Mechanism. **(UM 1214)**	)	

DISPOSITION: TARIFF REVISIONS EFFECTIVE; WAIVER GRANTED

On August 15, 2005, Cascade Natural Gas Corporation (Cascade or company) submitted its annual gas cost tracking and technical adjustment filing, commonly known as its Purchased Gas Cost Adjustment (PGA) filing, with the Public Utility Commission of Oregon (Commission). 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 balancing account and other deferred accounts. This filing included a proposed increase in annual revenues in Advice No. CNG/O05-08-01, docketed as UG 164, effective October 1, 2005. In a concurrent filing, docketed as UM 1214, Cascade requested reauthorization of deferrals under the company's PGA mechanism. A description of the filing is found in Staff's Report, attached as Appendix A, and incorporated by reference.

On September 8, 2005, Cascade filed replacement tariff sheets to correct minor errors found by Staff, along with a request to waive statutory notice (L.S.N.). The corrections do not revise the company's filed rates. Cascade requested that all proposed tariff sheets become effective October 1, 2005.

At its public meeting on September 22, 2005, the Commission adopted Staff's recommendation to approve the L.S.N. and allow the tariff revisions of Advice No. CNG/O05-08-01 to become effective with service on and after October 1, 2005. Staff also recommended reauthorization to use deferred accounting in accordance with the PGA balancing account.

ORDER

IT IS ORDERED that:

1. Cascade Natural Gas Corporation's request for amortization of deferred accounts, base gas cost changes, and rate changes as requested in Docket No. UG 164 is granted.

2. Cascade Natural Gas Corporation's tariff revisions in Advice No. CNG/O05-08-01 are allowed to go into effect October 1, 2005, and the L.S.N. is approved.

3. Cascade Natural Gas Corporation's request for reauthorization of deferred accounting in Docket No. UM 1214, for the Purchased Gas Cost Balancing Account mechanism, Schedule No. 177, for one year beginning October 1, 2005, is granted.

Made, entered, and effective SEP 29 2005.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

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 to a court pursuant to applicable law.

ITEM NO. 1 & 2

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: September 22, 2005

REGULAR _X_ **CONSENT** ____ **EFFECTIVE DATE** **October 1, 2005**

DATE: September 19, 2005

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 164/Advice No. O05-08-01) Reflects changes in the cost of purchased gas and technical adjustments. (Docket No. UM 1214) 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. CNG/O05-08-01 to become effective with service on and after October 1, 2005. This filing increases the company's annual revenues by $9.5 million, or 13.1%.

We also recommend the Commission approve the company's request for reauthorization to use deferred accounting pursuant to its Purchased Gas Adjustment (PGA) balancing account.

DISCUSSION:

On August 15, 2005, 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 balancing account and other deferred accounts. This filing consisted of a proposed increase in annual revenues in Advice No. CNG/O05-08-01 (docketed as UG 164), effective October 1, 2005. In a concurrent filing docketed as UM 1214, Cascade requested reauthorization of deferrals under the company's PGA mechanism.

On September 8, 2005, Cascade filed replacement tariff sheets to correct minor errors found by Staff, along with an L.S.N. The corrections do not revise the company's filed rates. Cascade requested that all proposed tariff sheets become effective October 1, 2005.

UG 164

This application requests authority to increase rates to: (1) track increases in purchased gas costs, and (2) make technical adjustments to amortize Cascade's deferred revenue, gas cost, and Demand Side Management (DSM) accounts. The change in annual revenues is summarized below, and shown in Attachment A.

PGA Base Gas Cost Change	$ 8,675,148
Removal of Prior Year Temporary Credit Increment	$ 1,670,584
Addition of New Temporary Credit Increment	$ (850,987)
Total Proposed Increase	$ 9,494,745

With these changes, the monthly bill of a typical residential customer using 63 therms per month will increase by $8.74, or 13.5 percent, from $64.71 to $73.45. In January, a typical residential customer's consumption of 131 therms would result in a billing increase from $131.31 to $149.50.

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 65 therms plus the monthly customer charge, divided by 65 therms. The graph shows that Cascade's residential customers have an effective rate of $1.16448 per therm, while Avista's and NW Natural's effective rates are $1.42223 and $1.38398, 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 2001 and 2004, and the current proposal.

Date	Customer Charge	Rate Per Therm	Percentage Change*
October 2001	$3.00	$0.91034	
October 2002	$3.00	$0.88603	-2.7%
October 2003	$3.00	$0.90402	2.0%
October 2004	$3.00	$0.97948	8.3%
October 2005 (Proposed)	$3.00	$1.11833	14.2%

Cascade offers customer assistance programs. Specific information on these programs is readily available to customers on their monthly bills, by telephone, and on the company's web site.

Staff Review of Gas Costs

National and Regional Natural Gas Markets

An unprecedented crisis[1] in the natural gas industry has evolved over the last 10 years. The price of natural gas has risen over 300% and, barring a dramatic reduction in demand or huge new supplies, will rise further. Moreover, because North American natural gas production has plateaued,[2] reliability of supply is now also an issue. It is clear that the mistakes of the middle to late 1990s in quantifying remaining North American natural gas reserves and the continuing construction of gas-fired generation to meet the US growing demand for electricity are primary causes of the current crisis. The nonsensical coupling of natural gas and oil prices[3] also contributed to a run-up in natural gas futures price which forced the cash market to follow. Since 1999, over 395 GW of new gas-fired generation has come on line, with more expected to be built. This is to meet electricity demand that is expected to grow at or near 2% a year through at least 2010. By 2015, power generation will likely consume nearly 11 Trillion cubic feet

* 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 2005, when the rate per therm is combined with the monthly customer charge of $3.00, the average customer's bill is increased about 13.5%, as shown on Attachment B.

[1] American Chemical Council, American Council for an Energy Efficient Economy, Matt Simmons, Joseph Riva, senior geologist Colorado School of Mines, Frank Clemente, Andrew Weissman, National Petroleum Council (which refrains from actually using the word crisis), the International Energy Agency, the US Energy Information Administration, Exxon/Mobile, Royal Dutch Shell, Chevron, Total, and Alan Greenspan.

[2] See Andrew Weissman and the International Energy Agency in particular.

[3] The two are generally not substitutable except in limited circumstances. Oil and natural gas prices were not historically linked and supply/demand for the two are not generally interconnected. Finally, the physical characteristics of the two are very different, as is their production.

(Tcf) a year more natural gas than it did in 2003. This generation was constructed and continues to be constructed based on erroneous information that North American natural gas supplies would remain plentiful for many decades.[4] This, combined with the low upfront capital cost and generally low emissions of such generation compared to other options, made gas-fired generation seem a clear winner. This has left the US with a continually expanding demand for natural gas that it cannot supply domestically (or even from North America). In short, the US has now entered a chronic (continuing) undersupply situation[5], made worse by the over 232 Tcf of estimated US outer continental shelf and Rockies natural gas that remains off limits for production due to federal restrictions. The push to quickly build more LNG terminals in the US to access world natural gas supply is clear evidence of this US undersupply situation.

Current Cash (Spot) Price of Natural Gas

National prices for natural gas have risen consistently over the last year and are expected to continue to increase through the end of 2005. Many forecasters believe the upward trend will subside in the second or third quarter of 2006. The pattern of volatility in natural gas prices appears unabated during the last year, but did not become more intense. Intra-month volatility has been particularly pronounced over the last 2 years. The Henry Hub spot (cash) natural gas price began the period (October 2004) near $6.25/MMBtu, remained relatively constant at that level through February 2005, and began to increase noticeably in March 2005. The Henry Hub price is expected to close the period (September 2005) at about $8.80, a more than 40% increase in price from October 2004.

Northwest natural gas cash prices followed the same general pattern as the Henry Hub, with a basis difference between the Henry Hub and the Northwest averaging about negative $1.25. Northwest prices began the period at $5.05 and ended at just over $7.60, a more than 50% increase in price. Price patterns in the Midwest and Northeast were similar to but not identical to those in the Northwest.

The primary factors that appear to explain these changes in natural gas price are:
1. Increased consumer demand (particularly for electric generation), tight supplies, and record crude-oil prices
2. No significant change in LNG imports
3. Increases in Rockies production are primarily unconventional (more expensive)

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[4] A few claim large supplies remain untapped due to government restrictions. While it is true that large known supplies are off-limits due to government restrictions, these supplies are not large enough to avert the crisis.
[5] Undersupply refers to both depletion of supply and the peaking of production capability in North America.

4. Continuing decline in US production
5. Continuing decline in Canadian production
6. Continuing growth in the US economy

NYMEX Price

NYMEX natural gas futures prices also increased noticeably over the period, particularly for winter 2005-2006 gas supplies. The table below depicts the changes in the price for each month over the period on the NYMEX exchange as of August 11, 2005. As of September 13, the NYMEX price for most months through September 2006 was up, especially for the winter months which averaged almost $12. The average increase in the NYMEX price over the period since October 2004 is now 55.62 %. A large share of this increase is the result of the shut-ins caused by Hurricane Katrina, but some is systemic and is likely to remain throughout the coming year.

Month	Price – October 2004	Price – August 11, 2005	Change %
October 2005	$7.00	$11.00	+57%
November	$7.00	$10.90	+56%
December	$7.50	$11.70	+56%
January 2006	$7.60	$10.90	+43%
February	$7.60	$11.90	+57%
March	$7.40	$10.60	+43%
April	$6.25	$8.50	+36%
May	$6.20	$8.20	+32%
June	$6.10	$8.50	+39%
July	$6.00	$8.60	+43%
August	$6.10	$8.65	+42%
September	$6.05	$8.60	+42%
AVERAGES	$6.73	$9.84	+46%

Over the last year the NYMEX has established a significant premium over current spot (cash) prices, averaging currently over $2 per MMBtu.

As of September 14, 2005, forecasts of natural gas prices for the upcoming winter and beyond have congealed around several values, including the effects of Hurricane Katrina. First, the price at the Henry Hub is expected to be between $11.00 and $11.50 for the final quarter of 2005. This translates to an expected Northwest price of $9.75 to $10.25. Prices at the Henry Hub are forecasted to decline slightly in 2006, averaging just below $8.50, or $7.25 for the Northwest. First, second, and third quarter prices for the Henry Hub in 2006 are expected to average $10.02, $7.53, and $7.20, respectively, according to the EIA. This translates to approximately $8.77, $6.28, and $5.95, respectively, expected for the Northwest. Changes in weather, demand, or supplies could, of course, lead to changes in these price forecasts or to the actual prices experienced.

In addition to the factors listed above under "Current Cash (Spot) Price of Natural Gas," other factors that appear important in explaining the NYMEX price are:

1. The tendency of many NYMEX traders to discount the notion that prices can be controlled through either supply or demand response (e.g., storage, conservation)
2. The tendency of NYMEX traders to focus more on bad news than good, and to place more credence in bad news than good
3. The role definition of "NYMEX" traders as price makers
4. NYMEX traders' generally shallow knowledge of energy engineering and politics, apart from commodity economics[6]
5. Treating natural gas as *only* a commodity[6]

Gas Supply and Production

The American Gas Association estimates that 57% (or 1,600 billion cubic feet) of the natural gas flowing to America's homes during the coldest month of the 2005-2006 winter will come from domestic production. This estimated proportion is down by 7% from the 64% from domestic production in 2001-2002. Natural gas from underground storage is expected to supply about 30% of the natural gas used during the 2005-2006 peak winter month, followed by Canadian imports (10.8%), LNG (1.8%) and supplementals, such as propane-air facilities (0.3%). This indicates the increasing importance of storage gas and LNG in meeting US peak winter gas needs.
Many factors can influence production. Hurricanes are certainly one of these factors. The effects of hurricane Katrina on natural gas production in the Gulf of Mexico were substantial. As of August 31 at 4 PM (EST), 8.345 billion cubic feet per day of Gulf natural gas production was shut-in, equivalent to 83.46% of daily Gulf natural gas production (which is 10 Bcf per day). Prices reflected this reduced supply. The NYMEX price reached a high of nearly \$11.50/MMBtu at the close of trading on 8/31. The Henry Hub spot price was \$12.69/MMBtu on 8/31, up \$2.84/MMBtu from the price of Friday, 8/26. At market locations across the Gulf region, price increases ranged up to \$4.10/MMBtu with an average of \$0.91/MMBtu. The overall average change in price was \$0.58/MMBtu.

The price at Northwest trading hubs also increased. The price at AECO went up to \$8.75, while Sumas and Rocky Mountain gas increased to near \$9.00. As of

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[6] An indication of both this ignorance and the treatment of natural gas as only a commodity is a quote in the text, *Trading Natural Gas: A Nontechnical Guide* at page 11, "The supply of natural gas is essentially dependent on only one factor: price." This is nonsense since the major factors determining supply are physical (e.g., geology, physics and chemistry), both in terms of total supply and production.

September 13, 2005, the price effects of Katrina on NYMEX, the Henry Hub, and other trading hubs across the country had dissipated to a large extent. However, as of this date, an increase of about $0.50/dekatherm over the pre-Katrina price was visible at most Northwest hubs, while an $0.80/dekatherm increase was visible at the Henry Hub and about a $1.00/dekatherm increase was visible on NYMEX. It is unlikely that all of this price increase is due directly to Katrina, since prices were rising at all hubs and on NYMEX prior to Katrina. Katrina apparently has had little impact on receipts of shipments at the LNG terminal at Lake Charles, Louisiana. While no major shortages of natural gas have resulted thus far from Katrina, it now seems possible that shortages could be experienced this winter as a result of Katrina, depending on the severity of the winter. The Mineral Management Service reported on September 13, 2005 that 3.720 Bcf/d, or 37.20% of daily gas production offshore remained shut-in as a result of Katrina. There are also concerns that it may be as long as four months before full natural gas production from the Gulf is restored.

Cascade's Natural Gas Purchasing Strategy

Portfolio 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. This theory is based upon a mathematics of diversification. 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.

The general elements of an effective LDC gas supply portfolio are laid out in the table below. All portfolios should include each of these options, 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 MDQ 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 and likely to continue crisis in natural gas price and supply means that it is even more important that LDCs learn, understand, and apply portfolio practices in their gas purchasing. And because of the ongoing crisis, LDCs will need to work to expand these practices not only to include additional portfolio components but also to include more sophisticated means to evaluate portfolios.

According to Cascade's responses to Staff's data requests regarding its filed 2005 PGA, the "portfolio included in the 2005 PGA is based on the Company's actual gas supply contracted volumes and prices for the upcoming winter along with a small amount of "Spot" supply purchases which would be required to meet the load requirements associated with core customer weather-normalized volumes for the 12 months ending June 30, 2005." Cascade's purchasing process is straight forward. A needs forecast is prepared, the availability of existing supply-side and demand-side resources is assessed, expected weather is considered, and transport needs are assessed. This data is entered into the Sendout optimization model, and the model determines the level of "unserved" demand under each of the alternative weather forecasts (average, colder than normal, warmer than normal). An internal company committee then chooses the scenario which will guide gas purchases. All incremental gas supply needs are met through a bidding process at the available purchase hubs. Approximately 90% of the supply purchases of Cascade are hedged financially through swaps. The company has made an effort to quantify (although not compare with other options) the monetary impact of these swaps. In 2004, Cascade modified its procurement strategy to include physical gas supply purchases for up to 5 years. Cascade does not currently have any physical gas supply contracts with terms longer than 5 years, primarily, according to the company, because of concerns about the possible impact of a longer term commitment on Cascade's creditworthiness.

While Cascade's gas purchasing process intuitively adheres to the portfolio philosophy, if not always portfolio methods, the process should apply portfolio methods more rigorously to achieve a balanced, diverse, and flexible purchasing strategy. Today Cascade does not explicitly apply portfolio theory and its associated mathematics. If applied, portfolio practices would add both more rigor and accountability to the purchasing process. This means Cascade does not directly assess the balance, flexibility, and diversity of its chosen or other alternative gas supply portfolios mathematically. Second, and on a more practical level, Cascade does not analyze the options it might employ to reduce the price it pays for natural gas. Through financial hedging Cascade fixes the price paid, but does not consider viable options for reducing the price paid. Bidding alone in not sufficient for this task, since bidding in a tight market such as natural gas has limited potential to reduce price paid. For example, contract pricing formulae that allow Cascade to change the index used for pricing (e.g., first-of-the-month vs. daily) or change from index to fixed pricing, could allow Cascade to take advantage of short-term decreases in market price and avoid short-term increases in market price.

However, Cascade does seem to have an intuitive understanding of the benefits of balance, flexibility, and diversity in a gas supply portfolio. Adding the specifics of portfolio methods to this intuitive understanding would help Cascade see and consider the options which could be used to reduce its cost of gas. This is a very important objective in light of the trends in current natural gas markets toward higher and more volatile prices, and fewer options for LDCs to mitigate these trends. Cascade and Staff need to work constructively together over the next few months to ensure this objective is achieved in time for the next purchasing season, beginning in April 2006. Cascade, like many LDCs, perceives itself as overwhelmed by the current natural gas supply market, largely seeing itself "at the mercy" of this market. While it is true that LDCs have fewer options for controlling gas price than they had in the past and that natural gas is in crisis, it is false that LDCs are wholly at the mercy of the gas market. But taking advantage of these options will require more than just learning and applying portfolio methods and their associated mathematics. It will require that Cascade more directly and actively "manage" its gas supply cost on a monthly and sometimes even daily basis, especially during the peak winter period. It also means it will no longer be feasible for Cascade to financially hedge almost all volumes purchased unless the hedging strategy is in line with the general requirements of portfolio methods and the specific portfolio practices designed for the Cascade system and circumstances.

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 MDQ, 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.

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.

Cascade's Natural Gas Costs

For the time during which Cascade purchased gas for the period October 2005 through September 2006, the average cash (spot) price in the Northwest was approximately $6.00/MMBtu, with prices noticeably higher during the last two months of the period (July and August 2005). The NYMEX price closed the period (September 2006) at over $9.00 ($7.75)/MMBtu,[7] with prices between $11 ($9.75) and $12 ($10.75) per MMBtu for the winter months of 2005-2006. However, the NYMEX price for September 2006 ranged from $6.75 ($5.50) to near $7.25 ($6.00) during April and May of 2005, began to rise noticeably in early June, ending finally just over $9.00 ($7.75) at the end of August. After a spike during March and early April over $8.50 ($7.25), the NYMEX price for the winter months declined below $8.00 ($6.75) in April before beginning a climb in May which, thus far, has produced a high near $12.00 ($10.75).

For the current PGA, Cascade proposes to pass through to its sales customers an average delivered natural gas cost of $0.68892/therm ($6.89/dekatherm (MMBtu)) This delivered cost of gas is adjusted for normalized sales volumes and line losses, and an adjustment is made for revenue sensitivity. The result is the sales WACOG proposed by Cascade of $0.70529. This pass through proposal is reasonable.

Noting once again that future natural gas prices are very likely to be even higher and perhaps more volatile, the changes proposed for Cascade's purchasing process should

[7] Prices in parentheses are estimated Northwest prices based on an average basis difference from national price of ($1.25).

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.

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 $1,670,584.
- Addition of new temporary increments to refund $850,987 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 an increase of $819,597 on an annual basis.

Earnings Review and 3% 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 are exempt from an earnings review.

ORS 757.259(6) and (7) states that the overall annual average rate impact of the amortizations authorized under the statute may not exceed 3% 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 amortizations are below the 3% cap and may be implemented as proposed.

UM 1214

In this filing, Cascade requests reauthorization of deferrals pursuant to its automatic adjustment clause, the 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. Staff recommends the Commission approve the request for reauthorizing the PGA deferral mechanism, effective October 1, 2005.

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 164 be approved; 2) the associated tariff sheets of Advice No. CNG/O05-08-01 be allowed to go into effect October 1, 2005, and the L.S.N. be approved; and 3) reauthorization of deferred accounting for Cascade's Purchased Gas Cost Balancing Account mechanism, Schedule No. 177, for one year beginning October 1, 2005, be approved.

Attachments

Cascade (Docket UG 164-UM 1214)

CASCADE NATURAL GAS CORPORATION
Summary of Proposed Rates and Revenues
Effective 10/01/05

RATES (in Cents Per Therm)

Ln	Customer Class (a)	Schedule (b)	Current Tariff Commodity Rate (c)	Current Average Total Rate /2 (d)	Proposed Changes: PGA Base Gas Cost (e)	Proposed Changes: Temporary Rate Increments: Remove 04 (f)	Proposed Changes: Temporary Rate Increments: Add New (g)	Proposed Changes: Total Change (h)=e+f+g	Proposed Average Total Rate /2 (i)=d+h	Proposed Tariff Commodity Rate (j)=d+h	Normalized Therm Sales/Thruput (k)
	CORE MARKET SERVICE										
1	Residential	101	97.948	102.703	12.688	2.443	(1.246)	13.885	116.588	111.833	33,654,428
2	Commercial	104	87.928	89.025	12.688	2.443	(1.246)	13.885	102.910	101.813	25,839,158
3	Com-Ind Dual	111	80.401	80.401	12.688	2.443	(1.246)	13.885	94.286	94.286	5,663,309
4	Industrial Firm	105	83.947	84.361	12.688	2.443	(1.246)	13.885	98.246	97.832	3,215,958
5	Industrial Interr.	170	77.643	77.643	12.688	2.421	(1.270)	13.839	91.482	91.482	0
	NONCORE MARKET SERVICE										
6	Distribution Transportation Schedule Nos. 163 & 164										23,477,749 \1
	Blocking										
7	R/S 163 & 164 First 10,000		12.646		0.000	0.001	0.004	0.005	12.651		2,615,056
8	R/S 163 & 164 Next 10,000		11.432		0.000	0.001	0.004	0.005	11.437		2,092,776
9	R/S 163 & 164 Next 30,000		10.756		0.000	0.001	0.004	0.005	10.761		4,281,872
10	R/S 163 & 164 Next 50,000		6.700		0.000	0.001	0.004	0.005	6.705		3,893,447
11	R/S 163 & 164 Next 100,000		3.519		0.000	0.001	0.004	0.005	3.524		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 (a)	Schedule (b)	Revenue at Current Avg Rates /2 (c)	Proposed Changes: PGA Base Gas Cost (d)	Proposed Changes: Temporary Rate Increments: Remove 04 (e)	Proposed Changes: Temporary Rate Increments: Add New (f)	Proposed Changes: Total Change (g)=d+e+f	Revenue at Proposed Avg Rates /2 (h)=c+g	Percent Change /2 (i)=h/c
	CORE MARKET SERVICE								
13	Residential	101	$34,564,195	$4,270,074	$822,178	($419,334)	$4,672,917	$39,237,112	13.5%
14	Commercial	104	$23,003,253	$3,278,472	$631,251	($321,956)	$3,587,767	$26,591,020	15.6%
15	Com-Ind Dual	111	$4,553,357	$718,561	$138,355	($70,565)	$786,350	$5,339,708	17.3%
16	Industrial Firm	105	$2,713,009	$408,041	$78,566	($40,071)	$446,536	$3,159,545	16.5%
17	Industrial Interr.	170	$0	$0	$0	$0	$0	$0	0.0%
	NONCORE MARKET SERVICE								
18	Dist Transportation	163/164	$1,833,450	$0	$235	$939	$1,174	$1,834,624	0.1%
19	Other		$5,552,213	$0	$0	$0	$0	$5,552,213	0.0%
20	Total Revenues		$72,219,477	$8,675,148	$1,670,584	($850,987)	$9,494,745	$81,714,221	13.1%

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
(October 2005 PGAs)

Class of Service	Rate Schedule	RATE IMPACTS: Current Rate per Therm	Proposed Rate per Therm	Change Rate per Therm	%-Change Rate per Therm	BILL IMPACTS: Average January Therms	Customer Charge	Current January Bill	Proposed January Bill	Change January Bill	%-Change January Bill	Annual Therms/ Month	Customer Charge	Current Monthly Bill	Proposed Monthly Bill	Change Monthly Bill	%-Change Monthly Bill
Residential																	
Avista	410	$1.08689	$1.34531	0.25842	23.8%	114	$5.00	$128.91	$158.37	$29.46	22.9%	53	$5.00	$62.61	$76.30	$13.69	21.9%
Cascade	101	$0.97948	$1.11833	0.13885	14.2%	131	$3.00	$131.31	$149.50	$18.19	13.9%	63	$3.00	$64.71	$73.45	$8.74	13.5%
NW Natural	2	$1.10784	$1.29167	0.18383	16.6%	122	$6.00	$141.16	$163.58	$22.42	15.9%	59	$6.00	$71.36	$82.21	$10.85	15.2%
Commercial																	
Avista	420	$1.00313	$1.26155	0.25842	25.8%												
Cascade	104	$0.87928	$1.01813	0.13885	15.8%												
NW Natural	3	$1.02239	$1.19803	0.17564	17.2%												
Industrial																	
Avista	424	$0.94671	$1.20513	0.25842	27.3%												
Cascade	105	$0.83947	$0.97832	0.13885	16.5%												
NW Natural	31	$0.99346	$1.15524	0.16178	16.3%												
Interruptible																	
Avista	440	$0.77803	$1.01367	0.23564	30.3%												
Cascade	170	$0.77643	$0.91482	0.13839	17.8%												
NW Natural	32	$0.77579	$0.93900	0.16321	21.0%												

Attachment C