Before the Washington Utilities and Transportation Commission

Report on Natural Gas Procurement Practices of Cascade Natural Gas Company

Docket UG-121592 & UG-121623

On Behalf of Public Counsel

March 8, 2013

REDACTED

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I. Introduction

A. Commission Concerns and Objectives

The Commission issued a complaint and order suspending the Purchased Gas Adjustment (PGA) filing of Cascade Natural Gas Company (Cascade or Company) on October 31, 2012.[1] The Commission allowed the proposed rate decrease to go into effect on a temporary basis, subject to revision. The Commission's Order stated that an investigation is warranted to determine whether the natural gas procurement and hedging practices of Cascade result in fair, just, reasonable, and sufficient rates.

The Commission further stated that it would hold hearings and conduct workshops as may be required, and required Staff to file a report on the status of the investigation no later than March 1, 2013, including a recommendation on the disposition of the tariff filing by Cascade or the need for further process to make the appropriate determination.

B. Public Counsel Objectives

The issues and concerns raised by Staff and the Commission are also of great concern to Public Counsel. Retail customers have paid higher rates as a result of the gas procurement policies and practices of Cascade during the past decade.

In this report, we will outline our initial findings and preliminary recommendations for continuation of this proceeding and improvements to the PGA mechanism. Our approach in this review was not solely to assess past performance and examine any potential failings of the Company's gas procurement practices, but also to propose ways to make future PGA proceedings more robust and transparent.

We issued in excess of 30 data requests inquiring on a variety of issues related to the PGA and the underlying gas procurement policies and practices of the Company, and particularly its price hedging program. Data requests covered the period 2003 to 2013 for the following areas:

- The information filed in the annual PGA and Deferred Gas Cost Account regulatory proceedings and support information.
- Gas supply sources and related purchase pricing arrangements.
- The cost of gas passed on to customers during each year.
- Interstate transportation and gas storage capacity.
- Price hedging policies and procedures.
- Specific price hedging transactions.
- Hedging gains, losses and costs of fixed price gas purchase contracts.
- The percent of the gas portfolio hedged and how early price hedges were placed before actual gas delivery.
- Hedging tools and methods employed.

[1] *WUTC v. Cascade,* Dockets UG-121592 & UG-121623, Order 01 (October 31, 2012).

- Analysis on the cost and effectiveness of the hedge program.
- Corrective steps taken to minimize price hedging costs to customers.

The Company provided answers to some, but not all, of the data requests for the time period covered, and therefore we were often hampered by insufficient information provided by the Company. In our analysis we also reviewed and made extensive use of the responses and data requested by Staff.

The cost of gas passed on to customers through the PGA mechanism represents from 75% to 80% of the customer's gas bill. Yet, the amount of regulatory scrutiny that it receives pales in comparison to the level of scrutiny for a general rate case that impacts about 20-25% of the customer gas bill. The Commission must have a deeper understanding of how the Company's gas procurement policies and practices, and particularly price hedging strategies, will impact customer bills before those policies and strategies are implemented.

C. Report Author

To analyze the gas procurement and hedging strategies of the Company and to prepare this report of findings and recommendations, the Public Counsel employed the services of Mr. Sebastian Coppola, President of Corporate Analytics, Inc. Mr. Coppola is a gas industry expert intricately familiar with regulated natural gas utilities, gas price hedging programs and gas cost recovery mechanisms similar to the PGA.

He has more than thirty years of experience in public utility and related energy work, both as a consultant and utility company executive. He has testified in several regulatory proceedings before State Public Service Commissions. He has prepared and filed testimony in gas cost recovery mechanisms, gas general rate case proceedings, revenue and cost tracking mechanisms and riders, and other regulatory proceedings.

During his tenure at SEMCO Energy, a natural gas utility with 260,000 customers, he held the position of Chief Financial Officer and also had responsibility for certain storage and pipeline operations as President and COO of SEMCO Energy Ventures, Inc. Prior to SEMCO, Mr. Coppola was Senior Vice President of Finance for MCN Energy Group, Inc., the parent company of Michigan Consolidated Gas Company (MichCon). MichCon is a gas utility with more than a million customers and $1.4 billion in revenue.

In his role as Treasurer and Chairman of the MCN/MichCon Risk Committee from 1996 through 1998, Mr. Coppola was involved in reviewing and deciding on the appropriate gas purchase price hedging strategies, including the use of gas future contracts, over the counter swaps, fixed price purchases and index price purchases.

In March 2001, Mr. Coppola testified before the Michigan House Energy and Technology Subcommittee on Natural Gas Fixed Pricing Mechanisms. Mr. Coppola frequently participates in natural gas issue forums sponsored by the American Gas Association and stays current on various energy supply issues through review of industry reports and other publications issued by various trade groups.

Appendix A provides more details on Mr. Coppola's experience and regulatory credentials.

D. Key Definitions

Financial hedging – The use of financial tools, such as price swap agreements, futures contracts, option contracts, etc., where a financial counterparty guarantees a fixed price for a set volume of gas to be delivered at a specified location for a specified period of time. The Company will buy gas in the spot market and the gas utility will make a payment to the financial counterparty if the spot market price is lower than the fixed price. If the spot market price is higher than the fixed price, the financial counterparty will make a payment to the gas utility to get its cost of gas down to the fixed price.

Hedging losses – The difference between an agreed to fixed price and the spot market price in the month of delivery of the gas, where the fixed price is higher than the spot market price.

Hedging gains – The difference between an agreed to fixed price and the spot market price in the month of delivery of the gas, where the fixed price is lower than the spot market price.

Physical hedging – An arrangement between the utility and a gas supplier to deliver an agreed volume of gas at a specified location at a fixed price for a specified period of time.

Physical hedging cost and benefits – Hedging losses and gains generally relate only to financial hedging. With regard to physical hedging there are not losses or gains per se since the utility does not settle with a financial counterparty. In a physical hedge, the utility agrees to buy a quantity of gas at a fixed price with a gas supplier and pays that price when the gas is delivered. In these transactions, there is a cost premium or a benefit that is calculated against the spot market price. So, a physical hedging cost premium occurs when the fixed price exceeds the spot market price in the month the gas is delivered. A physical hedging benefit occurs when the fixed price is below the spot market price in the month the gas is delivered.

II. Executive Summary

A. Summary of Findings

The initial findings from our preliminary review of the Company's gas procurement and hedging program has shown the following:

1. The Company's gas price hedging program has resulted in large losses and higher cost of gas for retail customers.
2. For the 2011-2012 PGA year, we estimate Cascade's Washington customers incurred approximately **[Begin Confidential]** XXXXXX **[End Confidential]** in higher gas costs from both financial and physical price hedging.
3. Based on our calculations, we estimate fixed price hedging has created **[Begin Confidential]** XXXXXX **[End Confidential]** in higher costs over the past 10 years for Cascade's Washington customers.
4. Cascade's hedging strategy of locking in gas prices up to three years before the gas is actually needed has not significantly reduced PGA rate volatility.

5. The 34% of total gas supply that the Company has recently hedged has declined from prior years but may still be relatively high. A high percent of hedging of the gas supply portfolio has not proven to have been beneficial to customers over the past 10 years.
6. The Company has continued generally on the same path of locking in fixed prices even in the face of mounting hedging losses and significantly above market fixed price hedges.
7. As a result of price hedges put in place in prior years, significantly higher gas costs and hedge losses will continue into 2013 and future years.
8. We find that the Company did not act prudently to limit hedge losses and higher gas costs during the 2011-2012 PGA year.
9. The current PGA and Deferred Gas Cost Adjustment procedures do not provide sufficient scrutiny of gas procurement practices and do not provide an early warning of potentially costly strategies, such as price hedging that may harm customers.

B. Summary of Recommendations

Based on our initial findings and analysis, we make the following preliminary recommendations:

1. The Commission should disallow recovery of at least **[Begin Confidential]** XXXXXX **[End Confidential]** from gas costs included in the current Deferred Gas Cost Account. As explained in greater detail later in this report, we base this conclusion on the fact that the Company entered into fixed price financial hedges **[Begin Confidential]** XXXXXXXXXXXXXX**[End Confidential]** the start of the 2011-2012 PGA year, when clear evidence existed from prior months that cash spot market prices were much more advantageous than forward hedge prices.
2. The Commission should order the Company to reduce the Deferred Gas Cost Adjustment tariff rate to reflect the disallowance.
3. The Commission should order the Company to suspend entering into any new hedging transactions until it has received recommendations from Staff, Public Counsel and other parties on an appropriate hedging program in collaboration with the Company.
4. The Commission should order Staff to organize and lead a Technical Collaborative with the Company and Public Counsel. The purpose of the Collaborative is to develop recommendations to the Commission on appropriate price hedging guidelines, policies and technical aspects of an effective hedging program, including percentages of the gas supply to be hedged, the length or window in which to hedge and acceptable hedging tools to minimize hedging costs.
5. In conjunction with or separately from the investigation in the current docket, the Commission should undertake a rule making process to modify and strengthen the PGA initial filing requirements and the subsequent gas cost reconciliation. The Commission should include the following objectives in initiating a new rule making for the PGA in order to achieve more uniformity:

a. The annual PGA filing should include testimony that describes the entire gas procurement plan in detail and with exhibits identifying sources of supply, short and long term gas purchase arrangements, forecasted pricing, price hedging strategies, pipeline transportation arrangements and cost, gas storage utilization plans, gas sales forecast including peak day demand and plans on how to meet that peak demand.
b. The PGA filing should also include a forecast of gas costs, sources and strategies for the subsequent four years. This longer term forecast would provide an early warning of events that could significantly affect gas prices.
c. At the end of the PGA year, the Company would file a gas recovery reconciliation case presenting testimony to explain its actual gas supply procurement decisions and costs with detailed cost schedules and exhibits.
d. Both the PGA filing and Cost Gas Recovery reconciliation proceedings should be contested cases similar to a rate case to ensure transparency and a full assessment of the prudency and reasonableness of the utility gas supply purchase decisions.
e. The PGA rate could be adjusted at least quarterly, if needed, to reflect changes in actual versus forecasted gas costs. This would insure customers get charged for gas costs in the year incurred and not in subsequent years as currently done with the deferred gas cost account.

These recommendations will result in more robust and transparent regulatory oversight to ensure gas costs have been appropriately reviewed by the Commission and found to be reasonable and prudently incurred. A more robust and transparent process also will give customers renewed confidence that the largest cost component of their gas bills is receiving sufficient scrutiny and appropriate oversight by the Commission.

It is also worth noting that a significant number of Regulatory Commissions in States such as Michigan, Maryland, New Jersey, Ohio and Pennsylvania have moved from a simplified PGA filing procedure to a more robust regulatory process similar to the one outlined above.

III. Profile of Cascade Natural Gas[2]

Cascade serves more than 260,000 customers in 96 communities – 68 of which are in Washington and 28 in Oregon. Cascade's service areas are concentrated in western and south central Washington and south central and eastern Oregon. Cascade serves approximately 197,000 customers in the State of Washington.

The Company had gas sales of 30.5 million Dth and reported $323 million of revenues for 2011 for both Washington and Oregon. Washington represents approximately 75% of total sales. Two interstate pipelines, Gas Transmission Northwest (GTN) and Northwest Pipeline, transport

[2] Information obtained from Company official website, Form2 FERC Report for 2011 to UTC and MDU Resources Form 10-K.

Cascade's natural gas from production areas in the Rocky Mountains and western Canada. Cascade utilizes 1.2 million Dth of gas storage capacity in the Jackson Prairie underground storage facility and 562,200 Dth of liquefied natural gas from Northwest pipeline to supplement its gas supply during peak demand periods.

Cascade has a Purchased Gas Adjustment (PGA) mechanism in retail natural gas rates to recover variations in natural gas supply and transportation costs.

Cascade is a subsidiary of MDU Resources Group, Inc. As such, its disclosure of publicly available information is limited.

IV. Major Findings

A. Gas Procurement Policies and Practices

Gas Supply Purchases, Sources and Pricing Methods – The Company has disclosed that for the period November 2011 to 2012 it obtained natural gas supplies from three primary supply sources: the AECO Hub, the Sumas Hub, and the Rockies area basin. The Rockies basin accounted for **[Begin Confidential]** XXX **[End Confidential]** of the total purchases with the AECO Hub and Sumas Hub supplies at **[Begin Confidential]** XXXXXX,**[End Confidential]** respectively.[3] The AECO and SUMAS supplies are imported from Canada. These two sources make up **[Begin Confidential]** XXX **[End Confidential]** of the total supply. The Company did not provide information for prior years, so it is not possible to assess how its supply strategy may have changed over time.

The Company reported that for spot market purchases it uses mainly monthly price indices tied to the delivery hubs and gas basins in which it purchases natural gas supplies.[4] The use of these index prices allows the Company to cover also the basis (location price) differential risk. The Company's use of fixed price purchases will be described below.

In its annual PGA filings, the Company did not specify its supply sources, pricing or strategy in any great detail. Therefore, it is difficult to conclude whether or not its basic gas procurement practices are prudent and reasonable at this time

Price Hedging Policies and Strategies – The Company has employed price hedging strategies since 2003 with the objective of locking in a fixed price for a percentage of its gas purchases. The Company has adopted the MDU Resources Corporate Derivatives (Hedging) Policy.[5] Under this policy the Company can hedge up to 90% of its projected one-year gas supply. Hedging can start up to 36 months before delivery of the gas with hedging targets of 60% and 30% for year two and three prior to the year of delivery. Financial derivative transactions are allowed to span up to 42 months.

The Company's recent gas hedging strategy has been to hedge up to 40% of the contracted physical supplies for the upcoming year, 30% of year 2 and 15% of year 3 on a rolling basis. As

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[3] Cascade Response to Public Counsel Informal Data Request No. 17 (Confidential).
[4] *Id.*
[5] Cascade Response to Staff Informal Data Request No. 6.

the months roll forward, the company will add price hedges to year 2 and 3 to reach the 40% target by the beginning of the upcoming year.[6] The typical means for hedging until recent years has been through the use of financial swaps. Beginning with the 2009-2010 hedging program period, the Company moved to the use of physical fixed price gas purchase contracts instead of financial swaps.[7] According to the Company, the move was precipitated by the risk of collateral calls, gas portfolio flexibility and new regulatory requirements from the Dodd-Frank Wall Street Reform Act.

Oversight of the Company's gas supply strategy is the responsibility of the Gas Supply Oversight Committee (GSOC), which consist of representatives from supply procurement, regulatory and financial areas. For the 2011-2012 PGA year, the Company fixed the price on approximately 34% of its gas purchases using almost entirely fixed price physical gas purchase contracts.[8]

The Company did not provide the total hedged percent of its supply portfolio for prior years inclusive of physical contract hedges. However, during the past 10 years, the Company had hedged as much as 77% of its gas supply portfolio using financial hedging tools.[9]

The Company's Risk Policy allows price hedging using a variety of financial tools (price swaps, options, etc.) and also fixed price gas purchases directly from suppliers. Since 2009, the Company has relied more on physical fixed price purchases contracted directly with gas suppliers and less on financial price swaps and other financial hedging tools.

A review of the fixed price hedges entered into for the 2011-2012 PGA year shows that fixed price financial swap contracts were entered into **[Begin Confidential]** XXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX. **[End Confidential].**[10] Those transactions settled at a price of **[Begin Confidential]** XXX **[End Confidential],** or about 50% below the fixed price. The Company did not provide requested physical hedging transaction information prior to the 2011-2012 PGA period. Thus, it is not possible at this time to determine the cost premium paid in prior years.

Results of Financial Hedging – The Company was asked to report the results of its price hedging strategies during the past ten years. For the 10-year period, the Company reported financial hedging losses of $141 million system-wide. It is instructive to note that the Company incurred financial hedging losses in six of the ten years, with consistent losses in the last four years. Table 1 shows the gains and losses from financial hedges over the ten-year time period.[11]

[6] *Id.*
[7] *Id.*
[8] Cascade Response to Public Counsel Informal Data Request No. 19.
[9] Cascade Response to Staff Informal Data Request No. 12.
[10] Cascade Response to Staff Informal Data Request No. 31 (Confidential).
[11] Cascade Response to Staff Informal Data Request Nos. 17 and 18.

Table 1

Cascade System-Wide Financial Hedges Gains & Losses

Period	Financial Hedges Net Gains & (Losses) [1]
11/1/02 - 10/31/03	$ -
11/1/03 - 10/31/04	(366,203)
11/1/04 - 10/31/05	14,906,106
11/1/05 - 10/31/06	17,596,975
11/1/06 - 10/31/07	(26,756,599)
11/1/07 - 10/31/08	1,039,635
11/1/08 - 10/31/09	(91,004,888)
11/1/09 - 10/31/10	(41,624,466)
11/1/10 - 10/31/11	(14,506,003)
11/1/11 - 10/31/12	(679,980)
Total	$ (141,395,423)

[1] Cascade financial gains & losses system-wide

Physical Contract Hedging – We do not yet know the extent of the excess cost paid on physical fixed price gas purchase contracts over the past 10 years. As of the date of preparation of this report, the Company had not disclosed that information. However, for the 2011-2012 PGA year, the Company reported that it entered into fixed price physical purchase contracts for 10,983,843 Dth.[12] Based on fixed price and index price information provided by the Company[13] for the 2011-2012 PGA year, we have calculated an estimated fixed price cost premium over spot market prices of approximately**[Begin Confidential]** XXXXXX **[End Confidential**] system-wide.

This cost premium was calculated as the difference between the average fixed price on transactions the Company reported as being hedged as of November 2011 and the monthly index spot price in the month the gas was delivered. In other words, the cost premium reflects how much more the Company paid for buying fixed price supply instead of buying that gas at the typical spot market index price. The cost premium is approximately **[Begin Confidential]** XXX XXXXX **[End Confidential].**[14]

Therefore, when we combine the financial hedging losses with the cost premium paid for physical hedges in 2011-2012, we can reasonably say that the total cost to Cascade gas

[12] Cascade response to Public Counsel Informal Data Request No. 19.
[13] Cascade response to Staff Data Request DR-31 (Confidential).
[14] Cascade response to Staff Data Requests DR-13 and DR-31 (Confidential).

customers from the price hedging program in the past 10 years exceeds **[Begin Confidential] XXXXXXX [End Confidential]** system-wide. Washington gas customers absorbed about 75% of this amount or about **[Begin Confidential]** XXXXXX. **[End Confidential]** Once the Company discloses the remaining information on physical price hedges, the total cost premium to Washington customers will certainly be much higher. Furthermore, since the Company has entered into fixed price arrangements for the next three years, in many cases at above market rates, additional losses likely will continued to accumulate into 2013 and future years.

Off-System Gas Sales – In balancing natural gas retail load requirements with resources, the Company most likely engages in off-system sales of natural gas (gas marketed outside Cascade's service territory). Generally, these sales occur when actual customer loads fall below forecasted levels and excess gas supply must be disposed of. It is not clear from the information provided to what degree the Company engages in off-system sales transactions.

Also, it is not known from the information provided by the Company at what prices the off-system sales are occurring. If a portion of the off-system sales is occurring as a result of surplus natural gas supplies, it is likely that these volumes are being sold at spot market prices. With the Company purchasing 34% of its gas supplies at fixed prices significantly above spot/index prices, it is possible that off-system sales are resulting in a financial loss and an incremental cost to retail customers.

Unfortunately, the current PGA and Deferred Gas Cost Account process does not allow an opportunity to scrutinize these transactions to ensure they are reasonable, prudent and necessary.

Pipeline Transportation Capacity – The Company uses interstate pipelines to transport natural gas to its distribution system and gas storage facilities. The Company plans for sufficient natural gas delivery capacity to serve its retail customers on a theoretical peak day. During non-peak day periods, it generally has more pipeline and storage capacity than needed. To generate economic value and partially offsets net natural gas costs, most gas utilities will release pipeline capacity in the open market and earn fees.

The level of pipeline capacity, which is reflected in the PGA tariff, and the capacity release transactions do not appear to be sufficiently scrutinized in the current annual PGA/Deferred Account process. Thus, there is not an opportunity to ensure the Company has contracted for the appropriate level of capacity and that gas costs have been reasonably and prudently incurred.

B. Assessment of Gas Procurement Practices

Cascade Hedging Policy Objectives – In its Corporate Hedging Policy the Company has stated the following risk management philosophy: "The use of derivative products will allow the Corporation to efficiently manage and minimize commodity price … within define parameters of risk."[15] In response to a question posed by Public Counsel, the Company answered that it believes it has a duty to (1) minimize the cost of gas to customers over time and (2) provide gas price stability in executing a price hedging program.[16]

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[15] Cascade Response to Staff Informal Data Request No. 6.
[16] Cascade Response to Public Counsel Informal Data Request No. 19

The hedging losses and cost premiums paid over the past 10 years clearly indicate that the Hedging Policy objectives have not been met. They have not minimized gas costs for Cascade customers. To the contrary, my analysis above shows that the Company has incurred large losses and cost premium year after year which have harmed gas customers.

PGA Rate Volatility – With regard to reducing volatility, a review of the PGA rates charged to customers from 2005 to 2012 shows that the hedging program has not provided as much rate stability as claimed or intended. Table 2 below shows that PGA rates, including the annual deferred account cost adjustments, have varied significantly. The accompanying line graph in Table 3 shows clearly the volatility in the combined PGA rate.

Table 2

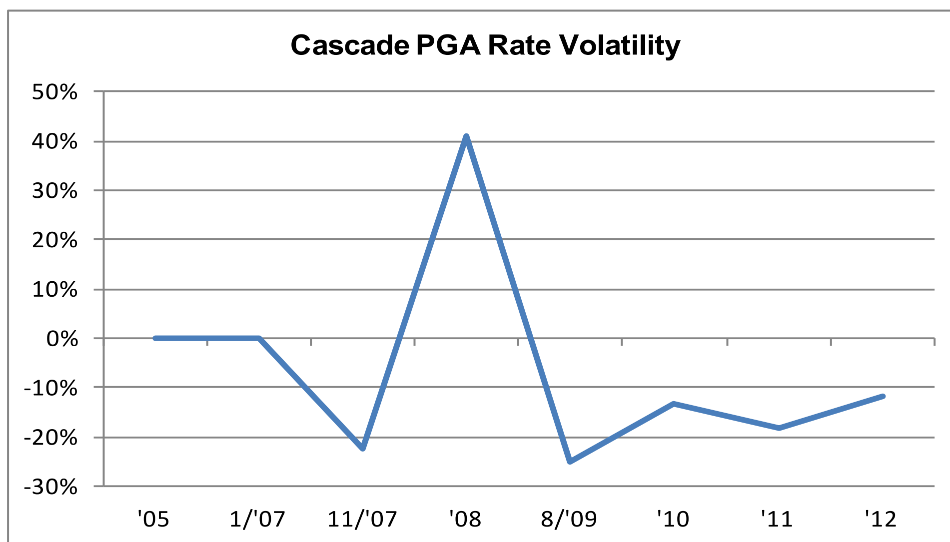
Cascade PGA Rates in ¢ Per Therm

Date	PGA WACOG[1]	PGA Adjustment[2]	Total PGA Rate	Percent Inc. (Decr.)
11/1/2005	91.942	6.118	98.060	-
1/19/2007	91.942	6.118	98.060	0%
11/1/2007	86.623	(10.619)	76.004	-22%
11/1/2008	100.724	6.317	107.041	41%
8/1/2009	82.800	(2.486)	80.314	-25%
11/1/2010	69.721	(0.062)	69.660	-13%
12/1/2011	62.552	(5.503)	57.049	-18%
11/1/2012	58.059	(7.617)	50.442	-12%

[1] Schedule 503 for Residential Service.

[2] Deferred Account adjustment from Schedule 595.

Table 3



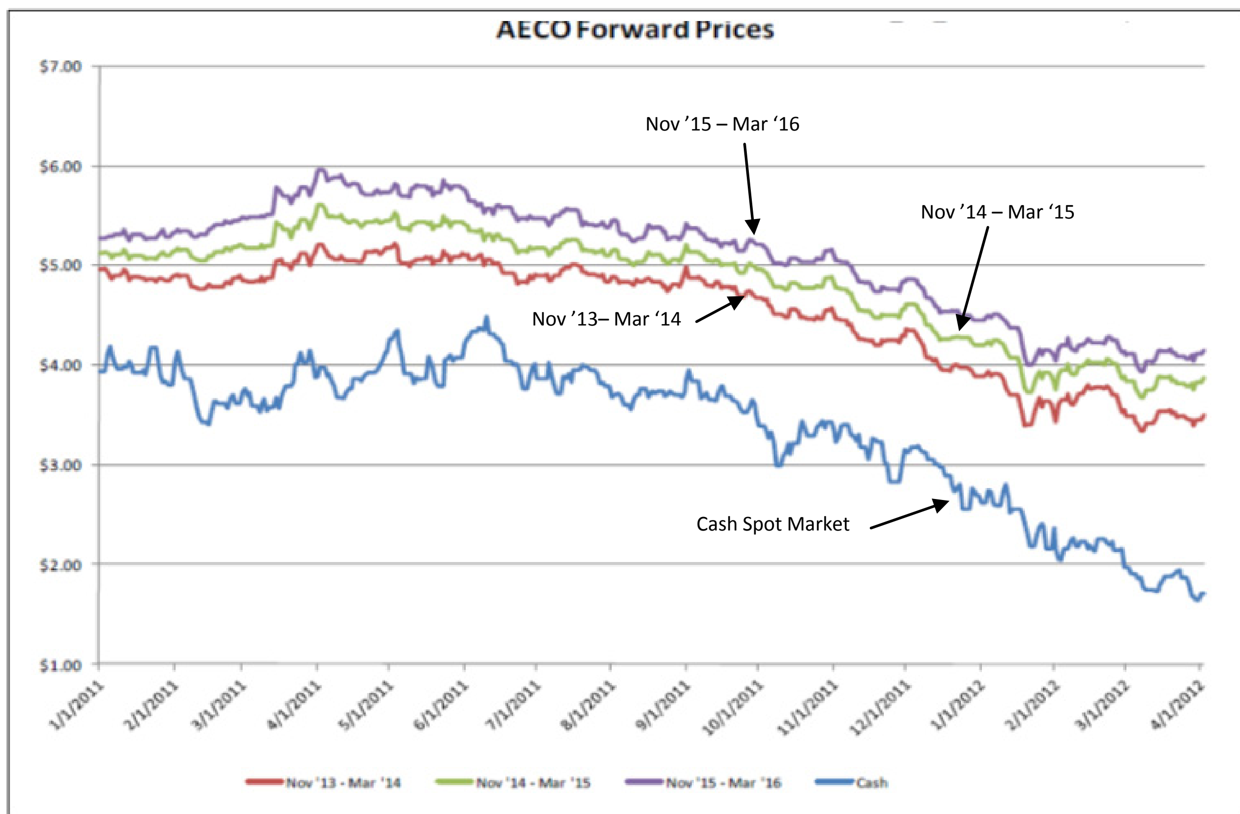
If we consider the combination of high hedging costs and PGA rate volatility, it is obvious that the fixed price hedging program has not served retail customers well.

Analysis of Hedging for 2011-2012 PGA Year – It is perplexing then why the Company would continue with the same hedging strategies year over year in the face of mounting losses and higher gas costs. In a data request, the Company was asked if it had evaluated its hedging program over the past years to assess its effectiveness and if it had taken steps to improve it. No response was received as of the date of preparation of this report.

Disregarding the negative impact of the hedging program on utility customers is inconsistent with the Company's duty to minimize gas costs. In the most recent two PGA years, it should have been quite obvious that spot market prices were significantly outperforming the forward market prices. Yet, the Company continued to hedge its gas purchases by locking in fixed prices at generally the same level for the upcoming years. In my opinion, this was a very imprudent decision.

The following graph in Table 4 clearly shows the large gap between the AECO forward prices and the cash spot market price. This information was certainly available to the Company and should have given management a reason to pause on any further hedging for the upcoming years.

Table 4



Nevertheless, the Company continued to hedge for the coming year (prompt year). In response to a data request, the Company provided information that it entered into additional fixed price gas contracts between **[Begin Confidential]** XXXXXXXXXXXXXXXXXXXXXXX **[End Confidential]** for the 2011-2012 PGA year.[17] Despite clear evidence that spot market prices were declining significantly, well below forward hedge prices, the Company decided to hedge an additional **[Begin Confidential]** XXXXXXX **[End Confidential]**at an average price of **[Begin Confidential]** XXX **[End Confidential]**per Dth. In comparison, the index/spot market price of the 2011-2012 PGA year averaged **[Begin Confidential]** XXXXXXXXXXXX **[End Confidential]** lower. The result of entering into these hedges was an additional cost to customers of approximately **[Begin Confidential]** XXXXXXXXXXXXXXXXXXXX **[End Confidential]** is applicable to Washington customers. Appendix B shows this calculation.

Disallowance of Gas Costs – In my opinion, the Company was imprudent in proceeding with fixing the price on **[Begin Confidential]** XXXXXXX **[End Confidential]**of gas purchases that were still un-hedged **[Begin Confidential]** XXXXX **[End Confidential]**before the beginning of the 2011-2012 PGA year. It is also likely that the Company continued to add other physical fixed price hedges after November 2011 for the 2011-2012 PGA year. Information provided by the Company on the total volume of gas purchases hedged supports this conclusion.[18] Unfortunately, the Company did not provide detail information to allow us to include those transactions in our calculations.

Although the Company also reported losses from hedges put in place in prior years, one can understand there was not much that could have been done with those transactions by **[Begin Confidential]** XXXXXXX **[End Confidential]**. However, to compound the problem by entering into additional hedging transactions after multiple years of hedging losses is incomprehensible.

The historical losses and past experience should have given the Company reason to reduce the amount and percentage of gas volumes to be hedged. In other words, why continue on the same strategy that had created losses and increased gas costs for customers year after year? The Company's decisions were neither reasonable nor prudent and ultimately hurt customers. Therefore, I recommend that the Commission consider disallowing at least **[Begin Confidential]**XXXXXXX **[End Confidential]** from recovery of gas costs from the Company's deferred gas cost account and order the Company to file a revised tariff to reflect this disallowance.

Suspend Hedging Program – Also, the Commission should order the Company to suspend its current hedging strategy until Staff and the Public Counsel have had an opportunity to review that strategy in more detail and recommend appropriate modifications in collaboration with the Company. Experience with similar hedging programs at other utilities has shown that it is not necessarily advantageous to hedge a large percent of the supply portfolio or begin hedging years before the gas is needed.

Utilities can reduce the percent of gas supply hedged and also shorten the hedging window from three years to less than one year and still achieve significant reduction in gas price volatility. Most importantly, with a shorter window the price of the hedged volumes is more reflective of

[17] Cascade Response to Staff Informal Data Request No. 31, Confidential.
[18] Cascade Response to Public Counsel Informal Data Request No. 19.

current spot market prices, therefore avoiding large losses and gains. Although gas prices may appear attractive today against historical levels and the temptation exists to try and lock in perceived attractive prices for future gains, such practice would be pure price speculation and not a sound strategy to reduce price volatility.

There are also important questions with regard to off-system sales and pipeline transportation capacity that need to be addressed going forward. The Commission should consider undertaking additional rule making to revamp the PGA filing process to ensure adequate regulatory scrutiny of these costs take place in a more robust PGA review process. This topic will be discussed in more detail later in this report.

C. Assessment of PGA Regulatory Process

Under the current regulatory procedures outlined in WAC 480-90-233, the Company is required to:

1. Make a PGA filing within a maximum of fifteen months since the effective of last PGA or file supporting documents demonstrating why a rate change is not necessary.
2. Accrue the difference between actual gas costs and the amount billed to customers in a deferred account and accrue interest on the balance at the FERC rate.
3. File a monthly report showing the activity in the deferred account.

WAC 480-90-194 and other applicable rules require the Company to provide public notification to customers about any rate changes and also follow other filing procedures.

PGA Filings – A review of recent PGA filings shows that typically the Company will make a filing two to three months before the start of the next PGA year to update both the Weighted Average Cost of Gas (WACOG) rate and the Deferred Gas Cost Account Adjustment rate. This Adjustment rate recovers or refunds the difference between billed and actual gas costs for the prior year.

The filings typically consist of a few schedules providing a summary of gas commodity purchases and pipeline transportation costs. Most of the exhibits show the calculation of demand and commodity tariff rates for each customer rate schedule. The package is usually accompanied by a cover letter summarizing this information and pointing out unusual events and compliance with the customer notification rules.

What is clearly lacking from the package is a comprehensive discussion of the Company's gas procurement plan for the coming year, including purchases it plans to make from each basin, the price assumptions, the annual and peak day demand it forecasts, the amount of pipeline capacity needed to meet peak demand, the utilization of gas storage versus winter purchases, the short term and long term price hedging strategies, the expected cost of hedging versus spot market prices and other gas procurement strategies to minimize the cost of gas to customers. This discussion should be supported by detailed volume and cost schedules. Without this information it is not possible for Staff, Public Counsel and other parties, who have an interest in these proceedings, to adequately assess that the proposed PGA rates and WACOG are reasonable and in the best interest of customers.

The current concern with the amount of hedging losses accumulated by Washington gas utilities has highlighted the fact that gas procurement issues have not had sufficient visibility and scrutiny. The hedging issue would not have been a surprise in recent months if a more rigorous regulatory oversight process would have been in place.

Deferred Gas Cost Account Adjustment Filings – A similar concern must be voiced with regard to the gas cost deferred account reconciliation process. From what we have observed, the process is merely an accounting reconciliation. The actual costs included in the account do not undergo any significant regulatory oversight to ensure the amounts and the Company decisions that created those costs were reasonable, prudent and in the best interest of the gas utility customer. The Commission rules and regulatory process do not seem to contemplate a rigorous review. Unlike rate case filings where the Staff and intervenors perform considerable discovery and due diligence reviews, the PGA costs are not reviewed with the same rigor.

Additionally, there is not an easy mechanism for the Company to increase the PGA rate during the current year to recover higher gas costs or reduce the rate to pass through to customers lower gas costs in a timely fashion. For example, at the end of October in each year 2010, 2011 and 2012, the Company had over collected gas costs and was deferring respectively $17.6 million, $14.7 million and $15.6 million of customer refunds.[19]

The current procedure defers refunding or surcharging gas costs from the current year, when the costs were incurred, to the following year. This delay potentially shifts the responsibility of gas costs to customers who did not take service in the prior year and now either pay for costs they should not be paying or benefit from a refund of costs they never paid. Each year, the Company has a significant number of customers who disconnect service and move out of the service area. Likewise, a number of customers relocate or begin service in the utility's service area. This turnover in customers reinforces the point that PGA costs and adjustments need to occur as much a possible during the same year.

V. Recommendations

Our initial findings and analysis support the following preliminary conclusions and recommendations:

1. The Commission should disallow recovery of at least **[Begin Confidential]** XXXXXXX **[End Confidential]** from gas costs included in the current Deferred Gas Cost Account. We base this conclusion on the fact that the Company entered into fixed price financial hedges within **[Begin Confidential]** XXXXXXXXXXXX **[End Confidential]** the start of the 2011-2012 PGA year, when clear evidence existed from prior months that cash spot market prices were much more advantageous than forward hedge prices.
2. The Commission should order the Company to reduce the Deferred Gas Cost Adjustment tariff rate to reflect the disallowance.

[19] Cascade Response to Public Counsel Informal Data Request No. 13.

3. The Commission should order the Company to suspend entering into any new hedging transactions until it has received recommendations from Staff, Public Counsel and other parties on an appropriate hedging program in collaboration with the Company.
4. The Commission should order Staff to organize and lead a Technical Collaborative with the participation of the Company and Public Counsel. The purpose of the Collaborative is to develop recommendations to the Commission on appropriate price hedging guidelines, policies and technical aspects of an effective hedging program, including percentages of the gas supply to be hedged, the length or window in which to hedge and acceptable hedging tools to minimize hedging costs.
5. In conjunction with or separately from the investigation in the current docket, the Commission should undertake a rule making process to modify and strengthen the PGA initial filing requirements and the subsequent gas cost reconciliation. The Commission should include the following objectives in initiating a new rule making for the PGA in order to achieve more uniformity:
    a. The annual PGA filing should include testimony that describes the entire gas procurement plan in detail and with exhibits identifying sources of supply, short and long term gas purchase arrangements, forecasted pricing, price hedging strategies, pipeline transportation arrangements and cost, gas storage utilization plans, gas sales forecast including peak day demand and plans on how to meet that peak demand.
    b. The PGA filing should also include a forecast of gas costs, sources and strategies for the subsequent four years. This longer term forecast would provide an early warning of events that could significantly affect gas prices.
    c. At the end of the PGA year, the Company would file a gas recovery reconciliation case presenting testimony to explain its actual gas supply procurement decisions and costs with detailed cost schedules and exhibits.
    d. Both the PGA filing and Cost Gas Recovery reconciliation proceedings should be contested cases similar to a rate case to ensure transparency and a full assessment of the prudency and reasonableness of the utility gas supply purchase decisions.
    e. The PGA rate could be adjusted at least quarterly, if needed, to reflect changes in actual versus forecasted gas costs. This would insure customers get charged for gas costs in the year incurred and not in subsequent years as currently done with the deferred gas cost account.

These recommendations will result in a more robust and transparent regulatory oversight process to ensure gas costs have been appropriately reviewed by the Commission and found to be reasonable and prudently incurred. A more robust and transparent process also will give customers renewed confidence that the largest cost component of their gas bill is receiving sufficient scrutiny and appropriate oversight by the Commission.